REFINING ECONOMICS OF A NATIONAL LOW SULFUR, LOW RVP GASOLINE STANDARD

A study performed for

The International Council for Clean Transportation

by

MathPro Inc.

P.O. Box 34404
West Bethesda, Maryland 20827-0404

October 25, 2011

TABLE OF CONTENTS

EXECUTIVE SUMMARY

In 2009, MathPro Inc. completed a study for the Alliance of Automobile Manufacturers (Alliance) dealing with the technical and economic effects in the U.S. refining sector of the Alliance's proposed federal standard for a national "clean gasoline" (NCG) for use throughout the United States (ex California).[1] The proposed NCG standard was intended to augment the federal standard for reformulated gasoline (RFG) and to cover all special gasolines ("boutique fuels") and conventional gasoline outside of the RFG areas.

More recently, other proposed new gasoline standards have been discussed, most notably lower sulfur and lower RVP standards. A recent report issued by the American Petroleum Institute API)[2] addressed several such standards. The International Council for Clean Transportation (ICCT) retained MathPro to update and extend the 2009 NCG analysis to cover standards that EPA might consider in its forthcoming rule-making on Tier 3 gasoline. The updates involve the analytical methodology, modeling tools, and assumptions. The extensions comprise modeling runs to assess the economics of proposed gasoline standards bearing on sulfur content and summer RVP.

This report delineates the technical approach for the present analysis and presents its findings.

Scope of the Analysis: Gasoline Standards Considered

The analysis covers regional refining operations, *summer* and *winter*, in four refining regions: PADD 1, PADD 2, PADD 3, and PADD 4.

Table ES-1 shows the three prospective gasoline standards considered in the analysis.

Table ES-1: Gasoline Standards Considered

Gasoline Property		Standards 1	2	3	Type	Comments
		Sulfur	RVP			
Sulfur	(wppm)	10	10	10	Avg.	Summer and winter
RVP	(psi)				Max.	All RVP standards apply to finished gasoline after ethanol blending
Summer						
Conventional gasoline			9	8		Proposed new standard
Low RVP gasoline			7.8/7.0	7.8/7.0		Existing standard, as required by local programs
Federal RFG			≤ 7	≤ 7		As needed for certification via the Complex Model
Winter			--	--		Varies by region

[1] *Refining Economics of a National Clean Gasoline Standard for PADDs 1-3*; submitted to the Alliance of Automobile Manufacturers by MathPro Inc.; June 2008

[2] *Potential Supply and Cost Impacts of Lower Sulfur, Lower RVP Gasoline*; submitted to the American Petroleum Institute by Baker & O'Brien, Inc.; July 2011

The *sulfur* limit in Table ES-1 would apply to all gasoline: conventional gasoline (CG), low-RVP gasoline (LRVP), and federal reformulated gasoline (RFG). Of the *RVP* limits in Table ES-1, only the limit for CG would be a new standard; the RVP limits for LRVP and RFG are the current standards. (Federal and California RFG have an effective RVP limit of about 6.8 psi after ethanol blending. The ethanol RVP waiver does not apply to RFG.)

Other gasoline property standards represented in the analysis are the same as in the 2009 Alliance analysis – in particular, benzene content = 0.62 vol% average (consistent with MSAT2), and average Driveability Index (DI) = 1220 at the refinery (but including the 24 number adjustment established by ASTM to account for ethanol blending).

Technical Approach

We analyzed the refining economics of the proposed sulfur and RVP standards by means regional refinery LP modeling, using MathPro's proprietary refinery modeling system, **ARMS**. We applied four models, representing aggregate refining operations in PADD 1, PADD 2, and PADD 3, and PADD 4, respectively.[3] The target time period for the analysis was 2015 (summer and winter gasoline seasons).

Using price and national volume projections from *AEO 2011* (Reference Case) and recent MathPro studies, we developed regional (i.e., PADD-level) projections of (1) demand for and domestic refinery production of gasoline – RFG, CG, and LRVP – and other refined products and (2) regional aggregate crude oil slates for 2015.

The refinery modeling for *each region* encompassed 2010 Calibration Cases (summer and winter), 2015 Baseline (Reference) Cases (summer and winter), and three 2015 Study Cases (summer and winter) – one for each of the three prospective standards shown in Table ES-1.

Study Case 1 addresses only the 10 ppm sulfur standard (i.e., with no change in the Baseline RVP). Study Cases 2 and 3, respectively, address the 9 psi and 8 psi RVP standards for finished CG, with the sulfur standard fixed at 10 ppm.

The Baseline and Study Cases represent essentially all finished gasoline as ethanol-blended at 10 vol% (E10) (with only minimal volumes of E85 sold in 2015).

All of the Study Cases represent the U.S. refining sector *maintaining regional and total U.S. gasoline production at the 2015 Baseline volumes.* That is, they represent the U.S. refining sector meeting the indicated sulfur and RVP standards without reducing gasoline out-turns.

[3] We did not consider PADD 5 in the analysis, because (i) most of the gasoline volume produced and consumed in PADD 5 is produced in California and (ii) California's gasoline standards are more stringent than those considered here.

Comparison of the results returned by the regional refining models for each Study case with those returned for the corresponding Baseline case yielded estimates of the investment requirements and refining costs associated with the contemplated sulfur standard and with the contemplated RVP standards.

Where more than one reasonable assumption could be made regarding a particular study parameter, we strove to make conservative choices, such as:

- *All* existing FCC post-treaters would require revamping to meet the 10 ppm sulfur standard
- The average capital investment (CapEx) for revamping the fleet of FCC post-treaters is 50% of the CapEx for grassroots post-treaters (even though some of the existing units may require no revamping)
- The base CapEx for new process capacity in PADD 4 is 50% higher than that of the base (U.S. Gulf Coast) CapEx estimates used for the other PADDs, to reflect the small size of the PADD 4 refineries
- The target rate of return on refinery investments is 10% after tax

The study included a sensitivity analysis to assess the effects on the study's findings of three key economic parameters in the regional refining models:

- The capital investment required for revamping existing gasoline desulfurization capacity to meet the 10 psi sulfur standard (50% → 30% of grassroots CapEx)
- The value of butane and pentane rejected from the summer gasoline pool to meet tighter RVP standards (gasoline blendstock value → fuel value)
- Return on investment (10% after tax → 7% pre-tax)

Results of the Analysis

Table ES-2 shows the estimated total (PADDs 1, 2, 3, and 4) capital investment, annual refining cost, and per-gallon refining cost associated with the 10 ppm sulfur standard, the 9 psi RVP standard, and the 8 psi RVP standard.

Table ES-2 shows two per-gallon refining costs for Study Cases 2 and 3. One of these reflects the cost of sulfur control and RVP control allocated to all U.S. gasoline production, year-round; the other reflects the indicated cost of sulfur control (1.4¢/gal) plus the cost of RVP control allocated only to the gasoline volume affected by the RVP standard: summer CG (about 30% of total annual U.S. gasoline production, but with significant regional variation).

The estimated investment, annual refining cost, and per-gallon refining cost of meeting the 10 ppm sulfur standard (*Study Case 1*) are about **$3.9 billion**, **$1.5 billion**, and **1.4¢/gallon**, respectively.

Table ES-2: Primary Results: Estimated Capital Investment and Refining Cost (PADDs 1-4)

		Notes		Study Case 1	Study Case 2	Study Case 3
			Sulfur ▸	30 ppm ⇨ 10 ppm	10 ppm	
			RVP ▸	10 psi	10 psi ⇨ 9 psi	10 psi ⇨ 8 psi
Gasoline Volume	**(K b/d)**			**7,080**	**7,080**	**7,080**
Capital Investment	**($Bil)**			**3.9**	**4.2**	**5.2**
Debutanization				0	0.23	0.27
Depentanization				0	0.00	0.21
Alkylation				0	0.05	0.13
FCC Naphtha Desulfurization				3.20	3.32	3.61
All Other				0.72	0.65	0.93
Annual Refining Cost	**($MM/yr)**			**1.5**	**2.7**	**4.2**
Capital Charge and Fixed Cost				1.00	1.13	1.31
C4/C5 Interseasonal Transfer		1		0.04	0.21	0.75
Refining Operations		2		0.49	1.38	2.15
Per-Gallon Refining Cost	**(¢/gal)**	3				
Entire Gasoline Pool				**1.4**	**2.5**	**3.9**
RVP-Affected Summer Gasoline				**1.4**	**5.3**	**10.2**
Energy Density-Related Savings	**(¢/gal)**	4		**0**	**0.2**	**0.6**

Notes:

1 **C4/C5 Interseasonal Transfer** cost is the sum of inter-seasonal storage and transport costs for transferring to the winter season C4 and C5 material rejected in the summer season to achieve RVP control.

2 **Refining Operations** cost includes catalysts and chemicals, changes in refinery inputs and outputs, and additional refinery energy use and hydrogen consumption.

3 **Per-Gallon Refining Cost** for *sulfur* control (Case 1) applies to all U.S. gasoline, year-round, in all three cases.
Per-Gallon Refining Cost for *RVP* control (Cases 2 and 3) is incurred only in producing conventional gasoline in the summer.
Cost of RVP control is allocated in two ways: to Entire Gasoline Pool and to the RVP-Affected Summer Gasoline only.

4 **Energy Density-Related Savings** is the national savings/(cost) associated with a change in the energy density (BTU/gal) of gasoline produced under the contemplated standards, relative to the baseline energy density.

The estimated investments and annual refining costs of meeting the 9 psi RVP standard *and* the 10 ppm sulfur standard (*Study Case 2*) are about **$4.2 billion** and **$2.7 billion**, respectively. The estimated incremental cost of achieving the 9 RVP standard alone is **1.1¢/gal** (= 2.5¢ – 1.4¢) allocated across all U.S. gasoline production and **3.9¢/gal** (= 5.3¢ – 1.4¢) allocated only to summer CG.

The estimated investments and annual refining costs of meeting the 8 psi RVP standard *and* the 10 ppm sulfur standard (*Study Case 3)* are about **$5.2 billion** and **$4.2 billion**, respectively. The estimated incremental cost of achieving the 8 RVP standard alone is **2.5¢/gal** (= 3.9¢ – 1.4¢) allocated across all U.S. gasoline production and **8.8¢/gal** (= 10.2¢ – 1.4¢) allocated only to summer CG.

The sensitivity analysis indicates that (i) reducing the average CapEx for revamping gasoline desulfurization facilities (to 30% of grassroots) and (ii) reducing the return on investment (to 7% before tax) has the cumulative effect of reducing the estimated cost of sulfur control (alone) from 1.4¢/gal (as shown in Table ES-2) to 0.8¢/gal. Conversely, downgrading the value of rejected butane and pentane (to fuel value) significantly increases the estimated cost of RVP control.

The line item **Energy Density-Related Savings** in Table ES-2 denotes the estimated effect of the proposed gasoline standards on the energy density of the entire gasoline pool and consequently on the *national cost* of gasoline consumption. This change accrues to consumers and not the refining sector.

All of these estimates apply to refining operations that meet the specified sulfur and RVP standards while maintaining U.S. and regional gasoline production at the baseline values.

1. SULFUR AND RVP STANDARDS CONSIDERED IN THE ANALYSIS

Table 1.1 shows the three prospective gasoline standards considered in the analysis.

Table 1.1: Gasoline Standards Considered

Gasoline Property		Standards			Type	Comments
		1	2	3		
		Sulfur	RVP			
Sulfur	(wppm)	**10**	**10**	**10**	Avg.	Summer and winter
RVP	(psi)				Max.	All RVP standards apply to finished gasoline after ethanol blending
Summer						
Conventional gasoline			**9**	**8**		Proposed new standard
Low RVP gasoline			**7.8/7.0**	**7.8/7.0**		Existing standard, as required by local programs
Federal RFG			**≤ 7**	**≤ 7**		As needed for certification via the Complex Model
Winter			--	--		Varies by region

The *sulfur* standard in Table 1.1 would apply to all finished gasoline: conventional gasoline (CG), low-RVP gasoline (LRVPG), and federal reformulated gasoline (RFG). This standard is less stringent than the proposed sulfur standard considered in the 2009 Alliance study (10 ppm *cap* at the refinery)

Of the *RVP* limits in Table ES-1, only those for CG would be new; the RVP limits for LRVPG and RFG are the current standards. (Federal and California RFG have an effective RVP limit of about 6.8 psi after ethanol blending. The ethanol RVP waiver does not apply to RFG.)

The proposed *RVP* limits shown in Table 1.1 apply to finished gasoline, *after* ethanol blending. They represent reductions of 1 psi and 2 psi, respectively, from the current RVP standard for CG, which is 10 psi after application of the 1 psi ethanol waiver. For purposes of this analysis, the contemplated standards apply to all conventional gasoline (CG),[4] but not to LRVPG or RFG. (Federal and California RFG already have a more stringent RVP standard: 7 psi with no ethanol RVP waiver. In practice, as-produced RFG has RVP ≤ 6.8.)

The 9 RVP standard for finished, ethanol-blended gasoline is less stringent than the proposed RVP standard addressed in the 2009 Alliance study (7 psi before application of the 1 psi ethanol RVP waiver). The 8 RVP standard is essentially the same as the RVP standard in the 2009 Alliance study. In contrast, the RVP standard addressed in the recent study published by API is 7 psi with no ethanol waiver. This standard is considerably more stringent, and therefore more costly to implement, than either of the RVP standards shown in Table 1.1.

[4] However, for the 9 psi RVP standard (only), the analysis recognizes the existing low-RVP CG areas.

2. REFINERY MODELING METHODOLOGY

We analyzed the refining economics of the proposed sulfur and RVP standards by means of four refinery LP models, representing regional refining operations in PADD 1, PADD 2, PADD 3, and PADD 4, respectively.[5]

We constructed the four refining models using MathPro's proprietary refinery modeling system (**ARMS**), which includes a crude assay database, technical characterizations of more than fifty refining processes, and representative blending properties of refined product blendstocks. Though developed from a common data base, the regional models are distinct in terms of aggregate refining process capacity, composite crude oil slate, refinery inputs and outputs, and refined product specifications.

We developed and applied the four regional refining models through a sequence of *Calibration*, *Baseline* (or *Reference*), and *Study* cases. Each such case included summer and winter components.

The target time period for the analysis was 2015 (summer and winter gasoline seasons).

2.1 Cases Analyzed With the Refining Models

2.1.1 Calibration Cases (2010)

Consistent with our standard practice in studies of refining operations, our first step in applying the regional models was to calibrate each model to the corresponding regional refining operations in a prior time period – in this instance, 2010 summer and winter. Well-calibrated models provide assurance that subsequent uses of the models will adequately represent refining operations under alternative sets of requirements, such as refined product standards, and/or with different crude and product slates.

Calibrating a refining model involves adjusting some of the model's internal technical coefficients – such as yields from certain refining processes, blending properties of refinery streams, or process capacity utilization rates – as needed so that solutions returned by the model closely approximate reported refining operations.

The reported 2010 regional refining operations to which we calibrated included crude oil throughput; feed rates to fluid cat cracking, delayed coking, and fluid coking; average gasoline properties (including octane, sulfur content, RVP, benzene content, and aromatics content); and

5 We did not consider PADD 5 in the analysis, because (i) most of the gasoline volume produced and consumed in PADD 5 is produced in California and (ii) California's gasoline standards are more stringent than those considered here.

the marginal costs (shadow values) of producing the major refined product categories (gasoline, jet fuel, diesel fuel, and residual fuel).

Regarding the marginal costs of production returned by the models, the objective of the calibration was to ensure that (1) the marginal costs of the various refined products bear the same general relationship to one another as do the reported market prices for these products, (2) the marginal costs of meeting various product specifications are reasonable, and (3) the marginal value of various intermediate refinery streams and blendstocks are reasonable in relation to product prices.

2.1.2 Baseline Cases (2015)

The next step was to establish 2015 summer and winter Baseline Cases for each regional refining model. Solutions returned by the regional refining models for these cases constitute the baseline values for the analysis.

The Baseline Cases incorporate the primary regulatory programs affecting gasoline and diesel fuel properties that are now in effect or are scheduled to be in effect by 2015. These include (1) continuation of the 1 psi summer RVP waiver for CG and (2) nation-wide implementation of

- The Tier 2 gasoline sulfur standard (average sulfur level in gasoline < 30 ppm);
- The MSAT 2 standard on toxic emissions from gasoline (average benzene levels in gasoline < 0.62 vol%); and
- The Ultra-Low Sulfur Diesel (ULSD) standard (maximum sulfur level in on-road and off-road diesel < 15 ppm)

To establish the Baseline cases, we used projections of total U.S. refinery inputs and outputs for 2015 drawn from the Reference Case of EIA's *Annual Energy Outlook 2011(AEO2011)* and allocated these inputs and outputs to the various PADDs on the basis of recent PADD-level data on refinery inputs and outputs published by the U.S. Energy Information Administration (EIA).

The Baseline cases for each PADD embody the same regional crude slates as the corresponding Calibration cases, because we assumed that crude oil slates would not change significantly between 2010 and 2015.

2.1.3 Study Cases (2015)

Table 2.1 shows the Baseline and Study Cases analyzed.

Study Case 1 addresses only the 10 ppm sulfur standard (i.e., with no change in the Baseline RVP). Study Cases 2 and 3, respectively, address the 9 psi and 8 psi RVP standards for CG, with the sulfur standard fixed at 10 ppm.

Table 2.1: 2015 Baseline and Study Cases Analyzed

Gasoline Property		2015 Baseline	2015 Study Cases 1	2	3	Type	Comments
			Sulfur	RVP			
Sulfur	(wppm)	30	**10**	**10**	**10**	Avg.	Summer and winter
RVP	(psi)					Max.	All RVP standards apply to finished gasoline after ethanol blending
Summer							
Conventional gasoline		10		**9**	**8**		Proposed new standard
Low RVP gasoline		7.8		**7.8**	**7.8**		Existing standard, as required by local programs
Federal RFG		≤ 7		**≤ 7**	**≤ 7**		As needed for certification via the Complex Model
Winter				--	--		Varies by region

The winter portions of Study Cases 2 and 3 (the RVP cases) differ from one another in the volume of refinery inputs of light gases (C_4 and C_5) rejected by refineries in the summer to meet the RVP standard and then stored for use in the winter.

Comparison of the results returned by the regional refining models for each Study case with those returned for the corresponding Baseline case yielded estimates of the investment requirements and refining costs associated with the contemplated sulfur standard and with the contemplated RVP standards.

2.2 Key Elements of the Methodology

- The Baseline and Study Cases represent virtually all finished gasoline as ethanol-blended at 10 vol% (E10) (with only minimal production E85).

- The Study Cases represent the U.S. refining sector maintaining regional and total U.S. gasoline production at the 2015 Baseline volumes.

  Desulfurization leads to some loss of gasoline yield and octane. Debutanization and depentanization remove volumes of high-octane blendstocks, particularly butane. The analysis represents each regional refining sector replacing all of the gasoline volume and octane lost in sulfur control and in RVP control. The solutions returned by the regional refining models indicate the least-cost set of actions for doing so.

  Available options for volume and octane replacement include increasing crude runs, changing various refining operations (e.g., increasing reformer severity, practicing C_5 alkylation), and investing in additional refining process capacity.

- The Baseline and Study Cases maintain regional refinery crude slates comparable to those in 2010.

- The summer and winter components of each Study Case interact in several ways:

- Process unit capacity added in one season (usually the summer) season is available for use in the other season. However, the models represent the capital costs of additional capacity intended for use in only one season as being amortized entirely in that season. This places a high hurdle on investment in seasonal capacity.

- Butane and pentane volumes rejected by the refining sector for RVP control in the summer season are available in like volumes as inputs in the winter season. The implicit sales prices of these rejected volumes in the *summer* reflect their marginal values as gasoline blendstocks in the *winter* (returned by the regional refining models) minus the estimated cost of inter-seasonal transfer, comprising storage, handling, transport, and interest costs.

➢ The estimated costs of inter-seasonal transfer vary by region. The estimates, in ¢/gal, are shown in **Table 2.2**.

Table 2.2: Estimated Costs of Inter-Seasonal Transfer (¢/gal)

PADD 1	PADD 2	PADD 3	PADD 4
47	41	33	64

These costs include the per-gallon cost associated with construction of new storage capacity.

➢ Regional energy prices – crude oil acquisition cost and natural gas price to industrial users – in 2015 are estimated from EIA data on regional prices and *AEO2011* forecast prices. (The estimated regional prices are shown in Appendix, Exhibit A-6).

➢ The regional models represent production of finished E10 gasolines, comprising base blends (CBOBs and RBOBs) produced at the refinery and ethanol blended downstream of the refinery. Accordingly, the RVP limits represented in the model reflect (1) a safety margin in blending (to allow for measurement tolerances) and (2) ethanol's estimated effect on blend RVP (which is > 1 psi in summer E10 and increases slightly with decreasing base blend RVP).

  Table 2.3 (next page) shows the RVP limits specified in the regional models for refinery-produced CBOBs and RBOBs in the summer and winter to accommodate ethanol's RVP "up-lift" plus a small safety margin.

➢ The winter RVP limits embodied in the various regional refining models were based on the average RVPs of finished winter gasoline at the retail level, as reported in the recent *North American Fuels Surveys* published by the Alliance of Automobile Manufacturers

➢ In the regional models' representation of gasoline blending, blend RVP is computed using the RVP blending index (VPBI) method, with $\mathbf{VPBI = RVP^{1.2}}$

Table 2.3: Representation of RVP Standards in the Regional Refining Models

	Summer RVP (psi)			Comments
	CG		RFG	
RVP standard (finished gasoline)	**9**	**8**	**7**	CG standards include 1 psi ethanol waiver
Blending safety margin	0.2	0.2	0.2	
Ethanol's estimated effect on blend RVP	1.09	1.15	1.23	
Refinery gate RVP limit	**7.7**	**6.7**	**5.6**	Specification set in the regional models
	Winter RVP (psi)			**Comments**
RVP target (finished gasoline)	**14**	**13**	**12**	Winter RVP target varies by region
Blending safety margin				Not considered in the winter analysis
Ethanol's estimated effect on blend RVP	0.66	0.74	0.82	
Refinery gate RVP limit	**13.3**	**12.3**	**11.2**	Specification set in the regional models

Notes:

1 Winter RVP targets are intended to denote an average of monthly RVP standards in a given region.

2 Safety margins are not considered in the winter, because RVP targets in each region are based on data captured at the retail level.

- The regional models represent Driveability Index (DI) using the ASTM definition:

$$\mathbf{DI\ (^{o}F) = 1.5{*}T_{10} + 3.0{*}T_{50} + 1.0{*}T_{90} + 2.403{*}(Vol\%\ EtOH).}$$

  The last term in the equation adjusts the DI upwards by about 24 numbers when ethanol is blended at 10%, to reflect ethanol's observed adverse effects on driveability.

  The models include a uniform DI standard – DI $\leq$ 1250 (per-gallon, in the field) – represented as DI $\leq$ 1196 (average, at the refinery gate), where

  1196 = 1250 – 30 (safety margin) – 24 (ethanol adjustment)

- Other gasoline property standards represented in the analysis are the same as in the 2009 Alliance analysis – in particular, benzene content = 0.62 vol% average (consistent with MSAT2).

- The models add refinery hydrogen production capacity (with purchased natural gas as feed) to support the additional hydrotreating required for sulfur control.[6]

[6] This assumption is convenient for analytical purposes. Many refineries would meet their requirements for additional hydrogen not by adding refinery capacity but rather by purchasing merchant hydrogen. However, the choice of hydrogen sourcing is not important to the analysis.

2.3 Representation of Capital Costs for Sulfur and RVP Control

Refiners will meet more stringent sulfur and RVP standards through some (refinery-specific) combination of:

- *Adding* new, "grassroots" process units
- *Expanding* the throughput capacity of existing process units
- *Revamping* (or *retrofitting*) existing process units to enable operation at higher severity (e.g., more stringent sulfur control)

The regional refining models used in this study represent one of these investment routes for each process (e.g., revamp economics for existing FCC naphtha desulfurizers, grassroots economics for new FCC naphtha desulfurizers[7]). We assumed that (1) the capital investment (*CapEx*)[8] per unit of FCC post-treating capacity added by expansions and revamps is 50% of the capital cost per unit of capacity (ISBL+OSBL) for a grassroots unit.

Each investment alternative is represented in terms of an estimated process-specific capital cost (ISBL+OSBL) per barrel/day of capacity. These estimates represent the investments required for capacity increments corresponding to representative size units (e.g., 40 K Bbl/day for FCC naphtha hydrotreating). (In practice, larger units would have lower per-barrel capital costs; smaller units would have higher per-barrel capital costs.) All capital costs are expressed in $2010.

Table 2.4 summarizes capital investment factors in the regional refining models for a representative sub-set of the refining processes involved in sulfur and RVP control. The regional models include analogous values for all refining processes represented.

The grassroots capital investments shown in Table 2.4 apply specifically to a U.S. Gulf Coast location. **Table 2.5** shows the regional multipliers used in the analysis to account for regional differences in capital costs for refinery projects.

In addition, for PADD 4, we increased the capital cost factors by 50% to reflect the adverse scale economies due to the small average size of the PADD 4 refineries.

[7] New FCC naphtha desulfurizers would be required in those refineries that now meet the 30 ppm sulfur standard with FCC feed desulfurization alone.

[8] For brevity, we use the term "*CapEx*" to denote capital investment.

Table 2.4: Capital Cost Factors in the Regional Refining Models

Purpose	Process	Grassroots Capital Cost (ISBL+OSBL) (K$/Bbl/day)	Comments
Sulfur Control	FCC Naphtha Desulfurization	1.83	Grassroots and revamp investments, as appropriate
	FCC Feed Desulfurization	6.7	Not included in the analysis
	Hydrogen Production	43.3	Grassroots economics
RVP Control	Fractionation: Debutanization	3.6	Grassroots economics
	Fractionation: Depentanization	0.44	Grassroots economics
Octane-Barrel Replacement	Alkylation	12.1	Doubled and allocated to the summer season

Notes:

1 Grassroots capital costs are for a U.S. Gulf Coast location and are in $2010.

2 Grassroots capital cost for the hydrogen plant is in **K$/foeb/day**.

3 Capital cost for Debutanization is in **K$/Bbl butane removed**.
Capital cost for Depentanization is in **K$/Bbl depentanizer feed**.

Table 2.5: Investment Location Factors

PADD 1	1.5
PADD 2	1.3
PADD 3	1.0
PADD 4	1.4

For estimating the per-gallon capital charges associated with the investments in refining capacity, we used the following assumptions:

- Rate of return: 10% after tax[9]
- Operating life: 15 years
- Depreciation schedule: 10 year double declining balance
- Construction period: 3 years
- Tax rate: 40% (federal and state)

[9] This rate of return typifies what refiners use when evaluating conventional refinery investment opportunities. EPA uses lower rates of return (e.g., 7% before tax) when estimating the "social" (national) costs of regulations.

3. Technical Considerations

This section discusses the technical routes represented in the regional refining models for achieving more stringent sulfur and RVP standards.

3.1 Sulfur Control

At present, all U.S. refineries produce gasoline with an average sulfur content of 30 ppm (the Tier 2 standard). In a typical U.S. conversion or coking refinery, FCC naphtha is the primary source of sulfur in the gasoline pool. It constitutes approximately 35% of the gasoline pool, and by virtue of its volume and its sulfur content accounts for about 95% of the sulfur content of untreated gasoline. Consequently, the primary task in meeting a stringent gasoline sulfur standard is reducing the sulfur content of FCC naphtha. Meeting the current 30 ppm standard requires that the FCC naphtha have average sulfur content of ≈ 50 ppm.[10]

U.S. refineries achieve this level of sulfur control by one of three means:

- FCC feed hydrotreating ("pre-treating") to reduce the sulfur content of FCC feed to a level sufficiently low that the FCC naphtha produced by the FCC unit has sulfur content of around 50 ppm (This requires a suitable crude slate and severe FCC feed hydrotreating.)

- FCC naphtha hydrotreating ("post-treating") to reduce the sulfur content of the FCC naphtha to about 50 ppm.

- A combination of pre-treating and post-treating.

Table 3.1 shows the number of gasoline-producing U.S. refineries using each approach, by PADD, as well as the total FCC capacity of the refineries in each category.

Table 3.1: Distribution of FCC Pre-Treating and Post-Treating Capacity, by PADD

	PADD 1	PADD 2	PADD 3	PADD 4	PADD 5	Total
Number of refineries with FCC units	**9**	**24**	**38**	**13**	**14**	**98**
Pre-treater and post-treater	1	3	19	1	7	31
Pre-treater only	0	8	5	4	4	21
Post-treater only	7	12	12	3	2	36
Neither one	1	1	2	5	1	10
Total capacity of FCC units (K Bbl/day)	**610**	**1,179**	**2,920**	**175**	**816**	**5,700**
Pre-treater and post-treater	48	286	1631	19	475	2,459
Pre-treater only	0	316	319	57	230	922
Post-treater only	497	555	908	53	90	2,103
Neither one	65	23	62	46	21	217

[10] Meeting the 30 ppm standard also requires desulfurization of other sulfur-containing gasoline blendstocks (such as natural gasoline, straight run naphtha, and coker naphtha).

Table 3.1, derived from the most recent *Oil & Gas Journal* and EIA surveys of U.S. refining capacity, indicates that the majority of U.S. refineries use post-treating, either alone or in combination with pre-treating.[11]

Producing gasoline with average sulfur content of 10 ppm (the proposed standard) requires reducing the average sulfur content of FCC naphtha to ≈ 10 ppm. In general, there are three prospective routes for doing so, all of which are represented in the regional refining models.

- Revamp an existing FCC feed hydrotreater ("pre-treater") to reduce the sulfur content of FCC feed to a level sufficiently low that the FCC naphtha produced by the FCC unit has sulfur content of around 10 ppm.

- Revamp an existing FCC naphtha hydrotreater ("post-treater") to reduce the sulfur content of the FCC naphtha to about 10 ppm.

- Install a new, grassroots FCC naphtha hydrotreater to reduce the sulfur content of the FCC naphtha to about 10 ppm.

Each of these requires additions to hydrogen supply, refinery energy supply, sulfur recovery facilities, and off-sites.

The refineries that now meet the Tier 2 sulfur standard with post-treating (with or without pre-treating) would most likely follow the second route: revamp the existing post-treater. [12]

> We understand that many of the FCC naphtha hydrotreaters installed to meet the Tier 2 sulfur standard are already capable of producing treated FCC naphtha with sulfur content < 10 ppm. Only those units that do not have this capability would require revamping. However, to be conservative, we assumed that all existing FCC naphtha hydrotreating capacity would require revamping to meet the 10 ppm standard.

The refineries that now meet the Tier 2 sulfur standard *solely* with pre-treating (i.e., no post-treating) could adopt either the first or the third route: revamp the existing pre-treater to further reduce the sulfur content of the FCC feed or install a grassroots post-treater. We assumed that refineries now meeting the Tier 2 sulfur standard *solely* with pre-treating would adopt the third route: install a grassroots post-treater.

> If the refinery's sole focus is on gasoline sulfur control[13], then installing a grassroots post-treater is likely to be the less costly route, in terms of both investment and operating cost.

---

[11] Table 3.1 shows 10 refineries meeting the 30 ppm standard with neither pre-treating nor post-treating. This likely reflects mis-reporting of process capacity.

[12] We assumed that all refineries reported as having neither FCC pre-treating or post-treating capacity have post-treating capacity.

[13] That is, gasoline sulfur control as opposed to controlling gasoline sulfur in conjunction with improving FCC performance and/or reducing refinery emissions of SOx.

The required post-treater would (1) be smaller than the FCC pre-treater (because it would process only FCC naphtha rather than FCC feed), (2) have lower per-barrel capital cost than the FCC pre-treater, and (3) require less additional hydrogen and energy to meet the sulfur standard.

Using these criteria and the data on FCC post-treating capacity shown in Table 3.1, we estimated the number of refineries that would likely add grassroots post-treating capacity and the number likely to revamp existing units, as well as the total associated FCC capacity in each category, by PADD. These estimates are embodied in the regional models.

3.2 RVP Control (Summer)

Refiners can reduce summer gasoline RVP from current levels to the levels considered in this analysis by several routes, either alone or in combination (depending on the RVP standard, refinery crude slate, and refinery configuration). The most economical route in most situations would be to first increase the scope and extent of debutanization, to reduce the butane content of the gasoline pool as much as possible, and then – if necessary – supplement debutanization with depentanization of a limited number of refinery streams (primarily light FCC naphtha and straight run naphtha, but also alkylate, isomerate, and light hydrocracked naphtha).

In general, reducing finished gasoline RVP to 9 psi or 8 psi (corresponding to about 7.7 psi and 6.7 psi, respectively, before ethanol blending) should be feasible in many refineries through enhanced debutanization alone, without depentanization or other measures. However, reducing finished gasoline RVP to 7 psi (corresponding to about 5.6 psi before ethanol blending) – as is now required in federal and California RFG – would likely require depentanization (as refiners' experience in producing federal and California RFG indicates).

Because of the tight specification on the pentanes content of butane sold as LPG or petrochemical feedstock, the C_4/C_5 separation in debutanizers must be performed so as to leave some C_4s in the C_5+ material going to the gasoline pool. However, suitably upgrading refinery debutanization facilities and light ends recovery systems to sharpen the C_4/C_5 separation can reduce the butane content of the gasoline pool to $\leq$ 1 vol%, without degrading the quality of product butane. This approach involves (1) modifying debutanizers to take more pentane overhead at the processing units, thereby reducing the butane content of the debutanized streams, and (2) sending the debutanizer overhead streams to a refinery light ends plant designed to make a sharp C_4/C_5 separation. The butane-free C_5 stream can be blended to gasoline or segregated for other dispositions.

Then, depentanization can be added to remove much of the residual butanes as well as larger volumes of pentanes, as may be needed to meet the specified RVP standard. Residual C_4 material can be removed from the depentanizer overhead, and the stabilized C_5 stream can have various dispositions (including inter-seasonal transfer).

Reducing gasoline RVP may require further changes in refinery operations. For example, it may require rejecting some volume of heavy gasoline components to the distillate fuel pool, in order to maintain compliance with the gasoline DI standard. In addition, it may involve increasing alkylate production to replace the gasoline volume and octane lost as a result of further debutanization and depentanization.

The alternative dispositions of C_4s (and possibly C_5s) removed from the summer gasoline pool include:

- Storing them, either at the refinery or a remote storage facility, for use in the winter season (or, equivalently, selling them to a third party in the summer and purchasing them in the winter);

- Using them as alkylation feed, with suitable investment in expanding and/or revamping the alkylation unit;

- Using them as hydrogen plant feed, to displace purchased natural gas; and

- Using them as refinery fuel, or selling them at a distressed price level approximating fuel value).

The first option, inter-seasonal transfer, implies that butane and pentane (if any) removed and stored in the summer season become refinery inputs, in like volumes, in the winter season. Refineries would have an economic incentive to practice inter-seasonal transfer if the marginal values of the butane and pentane in the winter are greater than the sum of (1) the cost of inter-seasonal transfer and (2) their value in the summer in alternative uses (e.g., as refinery fuel).

The marginal values of butane and pentane generally are higher in the winter than in summer because of the relaxed RVP standards in the winter. Butane and pentane can be used in the winter to maintain gasoline and other refined product out-turns with reduced crude through-put and other cost-reducing changes in refinery operations.

Each refinery would face its own set of circumstances – geographic and economic – that would influence its disposition of choice for butane (and possibly pentane) removed from the summer gasoline pool. For purposes of this study, we assumed that refineries would choose storage and inter-seasonal transfer. (However, we conducted a sensitivity analysis to assess the effects of selling the C_4s and C_5s at fuel value.)

4. RESULTS OF THE ANALYSIS

4.1: Summary of Primary Results

Table 4.1 shows the estimated capital investment, annual refining cost, per-gallon refining cost, and energy density-related savings for each Study Case.

Table 4.1: Primary Results: Estimated Capital Investment and Refining Cost (PADDs 1-4)

		Notes		Study Case 1	Study Case 2	Study Case 3
			Sulfur ▶	30 ppm ⇨ 10 ppm	10 ppm	
			RVP ▶	10 psi	10 psi ⇨ 9 psi	10 psi ⇨ 8 psi
Gasoline Volume	**(K b/d)**			**7,080**	**7,080**	**7,080**
Capital Investment	**($Bil)**			**3.9**	**4.2**	**5.2**
Debutanization				0	0.23	0.27
Depentanization				0	0.00	0.21
Alkylation				0	0.05	0.13
FCC Naphtha Desulfurization				3.20	3.32	3.61
All Other				0.72	0.65	0.93
Annual Refining Cost	**($MM/yr)**			**1.5**	**2.7**	**4.2**
Capital Charge and Fixed Cost				1.00	1.13	1.31
C4/C5 Interseasonal Transfer		1		0.04	0.21	0.75
Refining Operations		2		0.49	1.38	2.15
Per-Gallon Refining Cost	**(¢/gal)**	3				
Entire Gasoline Pool				**1.4**	**2.5**	**3.9**
RVP-Affected Summer Gasoline				**1.4**	**5.3**	**10.2**
Energy Density-Related Savings	**(¢/gal)**	4		**0**	**0.2**	**0.6**

Notes:

1 **C4/C5 Interseasonal Transfer** cost is the sum of inter-seasonal storage and transport costs for transferring to the winter season C4 and C5 material rejected in the summer season to achieve RVP control.

2 **Refining Operations** cost includes catalysts and chemicals, changes in refinery inputs and outputs, and additional refinery energy use and hydrogen consumption.

3 **Per-Gallon Refining Cost** for *sulfur* control (Case 1) applies to all U.S. gasoline, year-round, in all three cases.
Per-Gallon Refining Cost for *RVP* control (Cases 2 and 3) is incurred only in producing conventional gasoline in the summer.
Cost of RVP control is allocated in two ways: to Entire Gasoline Pool and to the RVP-Affected Summer Gasoline only.

4 **Energy Density-Related Savings** is the national savings/(cost) associated with a change in the energy density (BTU/gal) of gasoline produced under the contemplated standards, relative to the baseline energy density.

Table 4.1 shows one estimated per-gallon refining cost for Study Case 1 because the cost of meeting the 10 ppm *sulfur* standard would apply to all U.S. gasoline considered in this study (i.e., production in PADDs 1, 2, 3, and 4), year-round. Table 4.1 shows two per-gallon refining costs for Study Cases 2 and 3. One of these reflects the cost of sulfur control and the cost of RVP control allocated to all U.S. gasoline production; the other is the sum of the per-gallon cost of RVP control (1.4¢/gal) plus the cost of RVP control allocated only to the gasoline volume affected by the RVP standard: summer CG. (Summer CG constitutes about 30% of total annual U.S. gasoline production, but this share varies from region to region – smallest in PADD 1, largest in PADD 4.)

The estimated investment, annual refining cost, and per-gallon refining cost of meeting the 10 ppm sulfur standard (*Study Case 1*) are about **$3.9 billion**, **$1.5 billion**, and **1.4¢/gallon**, respectively.

The estimated investments and annual refining costs of meeting the 9 psi RVP standard *and* the 10 ppm sulfur standard (*Study Case 2*) are about **$4.2 billion** and **$2.7 billion**, respectively. The estimated incremental cost of achieving the 9 RVP standard alone is **1.1¢/gal** (= 2.5¢ – 1.4¢) allocated across all U.S. gasoline production and **3.9¢/gal** (= 5.3¢ – 1.4¢) allocated only to summer CG.

The estimated investments and annual refining costs of meeting the 8 psi RVP standard *and* the 10 ppm sulfur standard (*Study Case 3)* are about **$5.2 billion** and **$4.2 billion**, respectively. The estimated incremental cost of achieving the 8 RVP standard alone is **2.5¢/gal** (= 3.9¢ – 1.4¢) allocated across all U.S. gasoline production and **8.8¢/gal** (= 10.2¢ – 1.4¢) allocated only to summer CG.

The per-gallon costs shown in Table 4.1 are the result of dividing the estimated annual refining cost by the total annual U.S. gasoline production in PADDs 1, 2, 3, and 4. The cost of meeting the 10 ppm *sulfur* standard (Study Case 1) would apply to all U.S. gasoline considered in this study (i.e., production in PADDs 1, 2, 3, and 4), year-round. However, the cost of meeting the *RVP* standards (Study Cases 2 and 3) would apply to CG only, not to LRVPG and federal RFG, and only for the summer season. To highlight this point, Table 4.1 shows the estimated total annual cost of RVP allocated in two ways: across the total annual volume of all gasoline produced in PADDs 1, 2, 3, and 4, year-round and across only the summer volume of CG.

The line item **Energy Density-Related Savings** in Table 4.1 denotes the estimated effect of the proposed gasoline standards on the energy density of the entire gasoline pool and consequently on the *national cost* of gasoline consumption. Removing C_4 and C_5 volumes from the gasoline pool to meet more stringent RVP standards leads to an increase in the energy density of the complying gasoline, which translates directly into a corresponding change in vehicle fuel economy. Hence, an increase in the gasoline pool's energy density means a decrease in total gasoline consumption (at constant vehicle miles traveled), most likely leading to a net decrease in gasoline imports.

Table 4.2 (next page) shows the estimated capital investment, annual refining cost, per-gallon refining cost, and energy density-related savings, by PADD, for each Study Case.

In general, the estimated per-gallon costs of sulfur and RVP control are lowest in PADD 3 and highest in PADD 4. The PADD 3 results reflect PADD 3's lower regional investment factor and the existing (baseline) share of LRVPG and RFG in the PADD 3 gasoline pool. The PADD 4 results reflect high CapEx costs – the consequence of the high location factor for refinery investment in PADD 4 and the 1.5 multiplier that we applied to capital costs in PADD 4 (Section 2.3), which apply to both process capacity and storage facilities.

Table 4.2: Estimated Capital Investment and Refining Costs, by Study Case and PADD

		Study Case 1				
		Sulfur: 30 ppm ⇨ 10 ppm / RVP: 10 psi				
		PADD 1	PADD 2	PADD 3	PADD 4	Total
Gasoline Volume	**(K b/d)**	**681**	**2,009**	**4,091**	**299**	**7,080**
Capital Investment	**($Mil)**	**473**	**1,193**	**1,810**	**441**	**3,917**
Debutanization						
Depentanization						
Alkylation						
FCC Naphtha Desulfurization		459	1,002	1,512	223	3,196
All Other		14	191	297	218	720
Annual Refining Cost	**($MM/yr)**	**121**	**544**	**739**	**127**	**1,531**
Capital Charge and Fixed Cost		135	331	434	99	999
C4/C5 Interseasonal Transfer		5	18	14	1	38
Refining Operations		-19	194	291	27	493
Per-Gallon Refining Cost	**(¢/gal)**					
Entire Gasoline Pool		**1.2**	**1.8**	**1.2**	**2.8**	**1.4**
RVP-Affected Summer Gasoline		**1.2**	**1.8**	**1.2**	**2.8**	**1.4**
Energy Density-Related Savings	**(¢/gal)**	**0.0**	**0.0**	**-0.1**	**0.0**	**-0.1**
Increase in CO2 Emissions	**(K MT/day)**	0.3	4.1	3.2	0.3	8.0

		Study Case 2				
		Sulfur: 10 ppm / RVP: 10 psi ⇨ 9 psi				
		PADD 1	PADD 2	PADD 3	PADD 4	Total
Gasoline Volume	**(K b/d)**	**681**	**2,009**	**4,091**	**299**	**7,080**
Capital Investment	**($Mil)**	**520**	**1,443**	**1,806**	**472**	**4,241**
Debutanization		6	152	56	13	227
Depentanization						
Alkylation		47				47
FCC Naphtha Desulfurization		459	1,067	1,567	226	3,319
All Other		8	224	183	233	648
Annual Refining Cost	**($MM/yr)**	**185**	**805**	**1,569**	**159**	**2,718**
Capital Charge and Fixed Cost		148	432	437	108	1,125
C4/C5 Interseasonal Transfer		33	101	64	15	213
Refining Operations		4	272	1,068	36	1,380
Per-Gallon Refining Cost	**(¢/gal)**					
Entire Gasoline Pool		**1.8**	**2.6**	**2.5**	**3.5**	**2.5**
RVP-Affected Summer Gasoline		**5.2**	**4.2**	**6.2**	**5.4**	**5.3**
Energy Density-Related Savings	**(¢/gal)**	**-0.1**	**0.2**	**0.3**	**0.2**	**0.2**
Increase in CO2 Emissions	**(K MT/day)**	0.7	3.9	4.0	0.3	8.9

		Study Case 3				
		Sulfur: 10 ppm / RVP: 10 psi ⇨ 8 psi				
		PADD 1	PADD 2	PADD 3	PADD 4	Total
Gasoline Volume	**(K b/d)**	**681**	**2,009**	**4,091**	**299**	**7,080**
Capital Investment	**($Mil)**	**611**	**1,412**	**2,614**	**520**	**5,157**
Debutanization		20	165	56	33	274
Depentanization				204	8	212
Alkylation		133				133
FCC Naphtha Desulfurization		459	1,149	1,762	238	3,608
All Other			98	591	241	930
Annual Refining Cost	**($MM/yr)**	**297**	**1,237**	**2,433**	**244**	**4,211**
Capital Charge and Fixed Cost		175	429	583	124	1,311
C4/C5 Interseasonal Transfer		86	195	402	64	747
Refining Operations		36	613	1,448	57	2,154
Per-Gallon Refining Cost	**(¢/gal)**					
Entire Gasoline Pool		**2.8**	**4.0**	**3.9**	**5.3**	**3.9**
RVP-Affected Summer Gasoline		**12.1**	**8.1**	**11.3**	**12.4**	**10.2**
Energy Density-Related Savings	**(¢/gal)**	**0.0**	**0.8**	**0.7**	**0.3**	**0.6**
Increase in CO2 Emissions	**(K MT/day)**	0.9	4.0	5.7	0.3	10.9

Appendix A presents more detailed results of the analysis.

- **Exhibit A-1** shows economic results of the analysis, by PADD, for each Study Case. (It is similar to Table 4.2.)

- **Exhibit A-2** shows estimated refining sector operations, use of existing process capacity, and investments in new process capacity, for each Study Case, by PADD.

- **Exhibit A-3** shows estimated refining sector input and output volumes for each Study Case, by PADD.

- **Exhibit A-4** shows estimated properties of the total gasoline pool, the RFG pool, and the CG/LRVPG pool, for each Study Case, by season and by PADD.

- **Exhibit A-5** shows estimated volume-weighted composition (by blendstock) of the total gasoline pool (RFG, CG, and LRVPG) for each Study Case, by season and by PADD.

- **Exhibit A-6** shows the estimated 2015 crude oil acquisition costs and natural gas prices used in the analysis, by PADD.

4.2 Discussion of Results

4.2.1 Sulfur Control

As discussed in Section 3.1, the analysis posited that

- The refineries that now meet the 30 ppm Tier 2 sulfur standard with *both* pre-treating and post-treating would revamp their existing post-treaters.

- The refineries that now meet the 30 ppm Tier 2 sulfur standard with *post-treating* only would revamp their existing post-treaters.

- The (relatively few) refineries in PADDs 1-4 that now meet the 30 ppm sulfur standard with *pre-treating* only would install grassroots post-treaters.

Exhibit A-2 shows the estimated capacity additions, by PADD, consistent with these "rules."

We understand that many of the post-treating units installed to meet the Tier 2 sulfur standard are already capable of producing treated FCC naphtha with sulfur content < 10 ppm. However, those that do not have this capability would require revamping. In this regard, the estimated costs of sulfur control, shown in Tables 4.1 and 4.2, reflect two conservative assumptions: (1) all existing post-treaters would require revamping to meet the 10 ppm standard and (2) the average CapEx for revamping an existing post-treater is 50% of the grassroots CapEx.

4.2.2 RVP Control

Table 4.3 summarizes the estimated aggregate (PADDs 1–4) additions to refining process capacity required to meet the 9 psi and 8 psi RVP standards (with added capacity required to meet the 10 ppm sulfur standard already in place). Exhibit A-2 shows the estimated capacity additions for each PADD.

Table 4.3: Estimated Capacity Additions for RVP Control

Process	Capacity Additions (K Bbl/day) (1)	
	9 psi	8 psi
Direct RVP Control		
Debutanization	51	60
Depentanization	0	481
Octane Replacement		
Butane Isomerization	0	9
Alkylation	3	7
Volume Replacement		
FCC Naphtha Desulfurization	58	205
Benzene Saturation	-26	-39
Distillate Desulfurization	9	56
Distillate Dearomatization	0	107
Hydrogen Production	1	73

Note:

1 All capacity additions are in K Bbl/day of feed, except as noted below.

Debutanization capacity is in K Bbl/day of C4 removed.
Alkylation capacity is in K Bbl/day of alkylate produced.
Hydrogen capacity is in **MM Scf/day**.

The capacity additions for debutanization and depentanization are to achieve the specified RVP control. The capacity additions for the other processes are to replace the gasoline octane and volume lost to the summer gasoline pool due to the removal of C_4 and C_5 volumes.

As Table 4.3 indicates, enhanced debutanization suffices to meet the 9 psi standard; additional depentanization is not required.[14] In PADDs 1, 2, and 3, meeting the 8 psi standard entails reducing the butane content of the summer gasoline pool to < 1 vol% and requires both enhanced debutanization and depentanization. In PADD 4, enhanced debutanization suffices to meet the 8 psi standard.

As discussed in Section 3.2, the C_4 and C_5 volumes removed in the summer are made available in winter to the refining sector in the same PADD, at a significant inter-seasonal transfer cost (Table 2.2).

[14] In PADD 1, depentanization is already practiced to meet the RVP standards for RFG and LRVPG, which constitute most of PADD 1's total gasoline production. The removed pentanes are blended to CG. Meeting lower RVP standards on the CG produced in PADD 1 would require alternative dispositions for these pentane volumes.

RVP control affects refinery operations in a number of ways beyond the addition of new capacity. The indicated changes are visible in Exhibit A-2. For example:

- Refinery crude runs increase in the summer – reflecting the need to replace lost gasoline octane and volume – and decrease in the winter – reflecting the availability of additional gasoline volumes through the inter-seasonal transfer of C_4 and C_5 volumes.

- FCC feed rates increase, leading to increased production of FCC naphtha, to replace lost gasoline volume and octane. This in turn leads to a requirement for additional FCC post-treating capacity (which is indicated in Table 4.3).

These effects are most pronounced for the 8 psi standard.

4.3 Sensitivity Analysis

After analyzing the Study Cases, we conducted brief sensitivity analyses to assess the effects of three economic parameters on the results of the analysis: the CapEx required for revamping FCC post-treating capacity, the value of C_4s and C_5s, and the return on investment.

Table 4.4 shows the estimated effects of each of these changes on the economic results of the three Study Cases.

- Reducing the assumed average CapEx for revamping FCC post-treaters from 50% to 30% of the grassroots CapEx for the same FCC post-treater capacity:
  - Reduces the estimated investment cost for sulfur control by about $1 billion;
  - Reduces the estimated annual refining cost by about $300 million/year; and
  - Reduces the estimated per-gallon refining cost by 0.3¢/gal.

- Downgrading the value of butane and pentane rejected in the summer from gasoline blendstock value to fuel value:
  - Reduces the estimated investment cost for RVP control by about $0.5 billion;
  - Increases the estimated annual refining cost for the 9 psi and 8 psi RVP standards by about $1 billion/year and $4 billion/year, respectively;
  - Increases the estimated per-gallon refining cost for the 9 psi and 8 psi RVP standards by about 1¢/gal and 4¢/gal, respectively, with the increased costs allocated over the entire gasoline pool; and
  - Increases the estimated per-gallon refining cost for the 9 psi and 8 psi RVP standards by about 6¢/gal and 20¢/gal, respectively, with the increased costs allocated only to the share of the gasoline pool that is affected by the RVP standard.

- Reducing the assumed target return on investment from 10% after tax to 7% before tax:
  - Leaves the estimated investment cost for sulfur control and RVP control unchanged;
  - Reduces the estimated annual refining costs for sulfur control, RVP control to 9 psi, and RVP control to 8 psi by about $0.3 billion, $0.1 billion, and $0.2 billion, respectively;

- Reduces the estimated per-gallon refining cost for sulfur control by 0.3¢/gal;
- Reduces the estimated per-gallon refining cost for the 9 RVP standard and 8 RVP standards by about 0.1¢/gal and 0.3¢/gal, respectively, with the increased costs allocated over the entire gasoline pool; and
- Reduces the estimated per-gallon refining cost for the 9 psi and 8 psi RVP standards by about 2¢/gal and 4¾¢/gal, respectively, with the increased costs allocated only to the share of the gasoline pool that is affected by the RVP standard.

Table 4.4: Results of Sensitivity Analyses

Sensitivity Analysis			Study Case		
			1	2	3
		Sulfur ▶	10 ppm	10 ppm	
		RVP ▶	10 psi	9 psi	8 psi
Cost of Revamping FCC Post-treater					
Change revamp CapEx from 50% to 30% of grassroots CapEx					
Capital Investment	($Mil)		-1,027	-1,027	-1,027
Annual Refining Cost	($MM/yr)		-299	-299	-299
Per-Gallon Refining Cost	(¢/gal)		-0.3	-0.3	-0.3
Value of Rejected C4/C5 Volumes					
Downgrade rejected C4/C5 volumes (summer) to fuel value					
Capital Investment	($Mil)		0	-533	-533
Annual Refining Cost	($MM/yr)		0	1,018	4,148
Per-Gallon Refining Cost	(¢/gal)				
Entire Gasoline Pool			0	0.9	3.8
RVP-Affected Summer Gasoline			0	6.1	19.9
Return on Investment					
Change the ROI on CapEx from 10% after tax to 7% before tax					
Capital Investment	($Mil)		0	0	0
Annual Refining Cost	($MM/yr)		-298	-395	-630
Per-Gallon Refining Cost	(¢/gal)				
Entire Gasoline Pool			-0.3	-0.4	-0.6
RVP-Affected Summer Gasoline			-0.3	-2.2	-5.0
Gasoline Volume	(K b/d)		**7,080**	**7,080**	**7,080**

4.4 The Economic Effect of Increased Energy Density in the Gasoline Pool

As noted in Section 4.1 and Tables 4.1 and 4.2, removing C_4 and C_5 volumes from the gasoline pool to meet more stringent RVP standards leads to a small increase in the energy density of the complying (nearly butane-free) summer gasoline, which is only partially offset by a small decrease in the energy density of winter gasoline.

A change in gasoline energy density translates directly into a corresponding change in average vehicle fuel economy. Hence, an increase in the gasoline pool's energy density means a decrease in total gasoline consumption (at constant vehicle miles traveled). We assumed, for purposes of this analysis, that the reduction in total gasoline demand would lead to a corresponding decrease in the volume of gasoline imports, with domestic gasoline production volume remaining constant.

The cost savings realized from the energy density effect would not accrue to the domestic refining sector. It would accrue to gasoline consumers, in the form of reduced expenditures for gasoline, thereby providing a partial offset to the national cost of the contemplated RVP standard.

5. Additional Comments

Various study assumptions and premises merit discussion and should be considered in assessing the results of the refinery modeling.

5.1 Maintaining Gasoline Production at Baseline Volumes

As discussed in Section 2.2, we specified that the Study Cases represent the U.S. refining sector maintaining regional and total U.S. gasoline production at the 2015 Baseline volumes. That is, the refining sector as a whole replaces all the octane-barrels lost in sulfur control and in RVP control. The solutions returned by the regional refining models indicate the least-cost set of actions for doing so.

Recent history may offer some perspective for this specification. The past twenty five years have witnessed the enactment of a number of ever more stringent regulatory programs affecting refined product quality, especially for gasoline and diesel. During this period, a number of U.S. refineries have closed; some perhaps due in whole or in part to the investment and other costs required for regulatory compliance. However, during the same period, overall U.S. refining capacity, as well as light product out-turns, has increased. Gasoline and diesel imports have increased, but much of the increase has come from "short-haul" refineries in eastern Canada and the Caribbean that are closely tied to U.S. fuels markets. This history suggests that the U.S. refining sector as a whole – though not necessarily each individual refinery – has the resources and incentives to meet refined product demand even as it complies with new regulatory programs. Moreover, to the extent that they are realized, mandated future increases in the volume of bio-fuels used in gasoline and diesel fuel will tend to exert downward pressure on refinery capacity utilization, thereby easing the task of meeting demand for refined products.

5.2 "Over-Optimization" and "Under-Optimization"

Models of regional refining aggregates, such as those used in this study, essentially represent all regional refining capacity as well as intermediate and final gasoline blendstocks, as though all refining capacity in the region were a single, fully integrated refining complex. Consequently, aggregate refining models are viewed as having a tendency to "over-optimize" – that is, to return solutions that describe operating results somewhat better than the refining sector could achieve in practice, given the market conditions and process technologies represented in the models. However, the possibility of some over-optimization has not proven to be an impediment to the use of aggregate refinery modeling for analyzing the economics of prospective fuels regulations.

One potential source of over-optimization in the results returned by aggregate refining models has to do with capacity utilization. In principle, a regional aggregate model can represent the available process capacity in a region being used somewhat more efficiently than individual refineries can achieve in isolation. For example, a regional aggregate model can, in effect, make spare process capacity in one refinery available for use by other refineries in the region – a seemingly spurious effect. However, to some extent, refiners located in close proximity to one another within a region can and do interact in this manner – buying and selling refinery inputs, sharing capacity via tolling agreements, etc. Such arrangements yield economic benefits to the refining sector that cannot be captured by modeling individual refineries in isolation. A model's ability to capture economic benefits of inter-refinery transactions is not necessarily "over–optimization," as it usually viewed in the context of regional refinery modeling.

More broadly, optimization models, of the kind used in this study, offer a unique and valuable analytical benefit: they represent the collective profit-maximizing behavior of refiners responding to price signals. Such price signals are generated by the relative abundance or scarcity of economic resources: crude oil and other refinery inputs, refining capacity, and refined products.

By contrast, refinery-by-refinery simulation, a non-optimizing approach to modeling refining sector operations, offers no direct means of representing market dynamics or capturing refiners' prospective responses to price signals generated by the actions of other refiners, market participants, and regulators. For example, a refinery's independent decision to shut down or to curtail gasoline production would, in isolation, lead to reduced product supply in its market area. The resulting price signals would likely induce other refiners serving that market area to increase their product out-turns, by changing operations and/or investing in new capacity. Analyses based on refinery-by-refinery simulation appear to capture only rarely the likely economic responses of refiners to changing conditions – even when the changing conditions are themselves the focus of the analysis.

Consequently, one might conclude that while aggregate optimization modeling of refining sector operations return results that tend to be "over-optimized," refinery-by-refinery simulation of refining sector operations leads to results that tend to be "under-optimized."

5.3 The Cost Estimates Developed in This Study Reflect Conservative Assumptions

In this context, "conservative assumptions" means technical or economic assumptions that lead to higher estimated costs of compliance than would other, perhaps equally reasonable assumptions.

Where more than one reasonable assumption could be made regarding a particular study parameter, we strove to choose the more conservative alternative. Examples of the conservative assumptions embodied in this analysis include:

- *All* existing FCC post-treaters would require revamping to meet the 10 ppm sulfur standard.

- The average CapEx for revamping the fleet of FCC post-treaters is 50% of the CapEx for grassroots post-treaters (even though some of the existing units may require no revamping).

- The CapEx for new process capacity in PADD 4 is 50% higher than that of the standard CapEx estimates used for the other PADDs, to reflect the small size of the PADD 4 refineries.

- The target rate of return on refinery investments is 10% after tax.

Our use of conservative assumptions was not intended to inflate the cost estimates, but rather to minimize the likelihood of the analysis producing "low-ball" estimates of the refining costs for complying with the contemplated sulfur and RVP standards.

5.4 Capabilities of Foreign Refiners to Produce Tier 3 Gasoline Were Not Considered

Using EIA's *AEO 2011* Reference Case forecast of refined product imports, we project imports of gasoline blending components to constitute more than 12% of total U.S. gasoline supply in 2015. Most gasoline imports come into PADD 1, where imports constitute about 31% of total gasoline supply (including inter-regional transfers from PADD 3). A handful of refineries in eastern Canada and the Caribbean Basin are consistent suppliers to the U.S., and they account for most of PADD 1's gasoline imports. The rest of the imports come from "opportunity" suppliers, refineries in northern Europe, Africa, the Middle East, and Asia.

As noted in Section 3, an important premise in the analysis was that the U.S. refining sector would maintain the baseline (Reference Case) volumes of gasoline production in each PADD while meeting the contemplated low sulfur, low RVP gasoline standards. The refining analysis indicated that the U.S. refining sector could do so without significant investment in new capacity beyond what would be needed for compliance with the Tier 3 standard.

Implicitly, the analysis assumed that the off-shore refineries supplying imported CBOBs and RBOBs would likewise be able to maintain their production of gasoline blendstocks at baseline volumes. However, analysis of the capabilities and economics of foreign suppliers was far beyond the scope of this study.

5.5 Downstream Costs Were Not Considered

Our analysis does not address additional costs incurred downstream of the refinery – from the refinery gate to the pump – in moving, storing, and distributing low sulfur, low RVP (Tier 3) gasoline. These costs should be relatively small, because the contemplated standard will be a national one, applying to all CG, and will not involve any additional segregations in pipelines and terminals. There are likely to be some downstream costs incurred to minimize sulfur pick-up due to contact with higher-sulfur streams, primarily jet fuel, in the pipeline system. This cost would be independent of the RVP standard.

APPENDIX A

DETAILED RESULTS OF THE REFINERY MODELING

Exhibit A-1: Summary of Refinery Modeling Results

	10 ppm Sulfur					9.0 RVP/10 ppm Sulfur					8.0 RVP/10 ppm Sulfur				
	PADD 1	PADD 2	PADD 3	PADD 4	Total	PADD 1	PADD 2	PADD 3	PADD 4	Total	PADD 1	PADD 2	PADD 3	PADD 4	Total
Gasoline Pool Volume (K b/d)	**681**	**2,009**	**4,091**	**299**	**7,079**	**681**	**2,009**	**4,091**	**299**	**7,079**	**681**	**2,009**	**4,091**	**299**	**7,079**
Investment ($MM)	**473**	**1,193**	**1,810**	**441**	**3,917**	**520**	**1,443**	**1,806**	**472**	**4,240**	**611**	**1,412**	**2,614**	**520**	**5,158**
Debutanization						6	152	56	13	226	20	165	56	33	274
Depentanization													204	8	213
Alkylation						47				47	133				133
FCC Naphtha Desulfurization	459	1,002	1,512	223	3,196	459	1,067	1,567	226	3,319	459	1,149	1,762	238	3,609
All Other	14	191	297	218	720	8	224	183	233	648		98	591	241	930
Annual Refining Cost ($MM/y)	**121**	**544**	**739**	**127**	**1,531**	**185**	**805**	**1569**	**159**	**2,718**	**297**	**1237**	**2433**	**244**	**4,211**
Capital Charge & Fixed	135	331	434	99	999	148	432	437	108	1,125	175	429	583	124	1,310
C4/C5 Interseasonal Transfer	5	18	14	1	38	33	101	64	15	213	86	195	402	64	747
Refining Operations	-18	194	291	27	494	4	272	1068	36	1,380	36	613	1448	57	2,154
Per Gallon Refining Cost (¢/gal)															
Entire Gasoline Pool	1.2	1.8	1.2	2.8	1.4	1.8	2.6	2.5	3.5	2.5	2.8	4.0	3.9	5.3	3.9
RVP-Affected Summer Gasoline	1.2	1.8	1.2	2.8	1.4	5.2	4.2	6.2	5.4	5.3	12.1	8.1	11.3	12.4	10.2
Energy Density-Related Savings (¢/gal)	**0.0**	**0.0**	**-0.1**	**0.0**	**0.0**	**-0.1**	**0.2**	**0.3**	**0.2**	**0.2**	**0.0**	**0.8**	**0.7**	**0.3**	**0.6**
Increase in CO2 Emissions (K MT/d)	**0.3**	**4.1**	**3.2**	**0.3**	**8.0**	**0.7**	**3.9**	**4.0**	**0.3**	**8.9**	**0.9**	**4.0**	**5.7**	**0.3**	**10.9**

Exhibit A-2: Refinery Modeling Results -- PADD 1
Operations and New Capacity
(K b/d, except as noted)

Type of Process	Process	2010 Calibration Sum	2010 Calibration Win	2015 Reference Sum	2015 Reference Win	2015 10 ppm Sulfur Sum	2015 10 ppm Sulfur Win	2015 RVP Standards 9.0 RVP Sum	2015 RVP Standards 9.0 RVP Win	2015 RVP Standards 8.0 RVP Sum	2015 RVP Standards 8.0 RVP Win
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	1,195	972	1,125	1,011	1,128	1,010	1,135	1,000	1,148	987
Conversion	Fluid Cat Cracker	501	473	508	477	510	493	514	483	526	471
	Hydrocracking	22	10	22	7	22	4	22	5	22	6
	Coking	30	19	44	17	44	17	44	16	44	16
Upgrading	Alkylation*	79	70	79	64	79	64	79	71	79	74
	Iso-octene/octane										
	Catalytic Polymerization*	13		13		13		13		13	
	Dimersol*										
	Pen/Hex Isomerization	17	17	17	17	17	17	17	17	17	17
	Reforming - CCR	49	49	49	49	49	49	49	49	49	49
	Reforming - Other	107	81	107	88	109	80	109	80	108	80
Hydrotreating	Naphtha Desulfurization	244	184	262	199	263	220	265	217	269	213
	FCC Naphtha Desulfurization	295	267	301	273	303	282	306	272	311	262
	Benzene Saturation	12	15	12	15	12	14	12	13	12	10
	Distillate Desulfurization	308	282	297	321	299	298	340	304	340	306
	Distillate Dearomatization										
	FCC Feed Desulfurization (Conv)	39	36	40	37	40	38	40	37	41	36
	FCC Feed Desulfurization (Deep)	295	267	301	273	303	282	306	272	311	262
	Resid Desulfurization										
Hydrogen (MM scf/d)	Hydrogen Production	36	41	41	41	41	41	41	41	41	41
	Hydrogen Recovery										
Fractionation	Debutanization	80	45	79	35	80	41	80	37	80	38
	Depentanization	149		149		149		149		149	
	Lt. Naphtha Spl. (Benz. Prec.)	76	54	76	61	73	63	79	62	90	61
	Med. Naphtha Spl.										
	Hvy. Reformate Spl.	11	23		69		61		60	12	31
	FCC Naphtha Splitting										
	Heavy FCC/Lt Cycle Oil Splitting										
Other	Aromatics Plant*	11	6	11	10	11	9	10	9	10	9
	Benzene Extraction*										
	Butane Isomerization	10	10	10	10	10	4	10	10	10	10
	Lubes & Waxes*	14	15	16	15	16	15	16	15	16	15
	Solvent Deasphalting	18	18	18	18	18	18	18	18	18	18
	Sulfur Recovery* (K s tons/d)	0.61	0.51	0.61	0.49	0.61	0.47	0.61	0.47	0.62	0.47
	Steam Generation (K lb/hr)	3,605	2,831	3,578	2,922	3,595	2,933	3,657	2,969	3,722	2,955
NEW CAPACITY											
Upgrading	Alkylation*							3		7	
Hydrotreating	FCC Naphtha Desulfurization										
	Benzene Saturation			2		2		1			
Hydrogen	Hydrogen Plant* (MM scf/d)					14		33		44	
Fractionation	Debutanization							1		4	
	Depentanization										
	Medium Naphtha Spl.										
Other	Butane Isomerization										
Retrofit/Revamp	Tier 2 Diesel Desulfurization										
	Distillate Dearomatization				1						
	FCC Naphtha Desulfurization					335		335		335	
OPERATIONS											
Fluid Cat Cracker	Charge Rate	557	516	566	522	569	537	574	526	586	513
	Conversion (Vol %)	68.2	68.0	67.8	68.4	67.8	68.5	67.8	68.6	67.8	68.6
	Olefin Max Cat. (%)	8.9		1.2		0.7			9.2	1.3	17.0
	Catalyst Coke (K b/d)	20	21	21	21	21	21	21	21	21	20
Reformer	Charge Rate	170	146	182	163	184	150	184	148	184	146
	Severity (RON)	101.3	97.6	97.0	93.4	97.9	94.3	97.6	95.1	96.9	97.1
FUEL & ENERGY											
Fuel Use	Natural Gas & Refinery Gases (foeb)	55	45	55	47	56	47	57	47	58	47
Energy Use	Fuel & Power (Billion btu/d)	549	478	549	493	554	494	564	493	575	487
CO2 Emissions	CO2 Emissions (K MT/d)	38.5	34.6	38.6	35.4	39.1	35.6	40.0	35.4	40.8	34.9

* Capacity defined in terms of volume of output.

Exhibit A-2: Refinery Modeling Results -- PADD 2
Operations and New Capacity
(K b/d, except as noted)

Type of Process	Process	2010 Calibration		2015 Reference		2015 10 ppm Sulfur		2015 RVP Standards 9.0 RVP		2015 RVP Standards 8.0 RVP	
		Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	3,285	3,171	3,209	3,067	3,218	3,074	3,243	3,053	3,287	3,043
Conversion	Fluid Cat Cracker	1,114	1,070	1,079	1,009	1,054	1,008	1,066	983	1,096	987
	Hydrocracking	234	234	234	234	234	234	234	234	234	234
	Coking	361	346	329	327	335	329	340	327	346	324
Upgrading	Alkylation*	243	234	239	211	242	224	243	222	243	237
	Iso-octene/octane										
	Catalytic Polymerization*	5		5	5	5	5	5	5	1	5
	Dimersol*	3	3	3	3	3	3	3	3	3	3
	Pen/Hex Isomerization	167	167	167	167	167	167	167	167	167	167
	Reforming - CCR	292	292	292	292	292	292	292	292	292	292
	Reforming - Other	281	261	267	220	302	271	304	265	313	262
Hydrotreating	Naphtha Desulfurization	772	716	751	788	781	802	784	795	900	793
	FCC Naphtha Desulfurization	486	463	486	444	486	582	486	582	486	579
	Benzene Saturation			22	26	22	50	22	48	22	45
	Distillate Desulfurization	1,013	1,042	999	997	1,014	1,040	1,008	1,044	1,047	1,041
	Distillate Dearomatization	18	16	18	18	18	18	18	18	18	18
	FCC Feed Desulfurization (Conv)	225	215	216	203	218	204	220	202	225	201
	FCC Feed Desulfurization (Deep)	486	463	486	444	486	582	486	582	486	579
	Resid Desulfurization										
Hydrogen (MM scf/d)	Hydrogen Production	535	535	535	535	535	535	535	535	535	535
	Hydrogen Recovery										
Fractionation	Debutanization	210	161	195	141	202	161	194	172	194	171
	Depentanization	111	111	111		111		111		111	
	Lt. Naphtha Spl. (Benz. Prec.)	253	266	255	197	209	182	204	186	299	189
	Med. Naphtha Spl.										
	Hvy. Reformate Spl.		53	28							
	FCC Naphtha Splitting										
	Heavy FCC/Lt Cycle Oil Splitting		222			135	490	28	479		458
Other	Aromatics Plant*	16	17	22	34	34	34	34	34	32	34
	Benzene Extraction*										
	Butane Isomerization	14	14	14	14	14	14	14	14	14	25
	Lubes & Waxes*	9	9	9	9	9	9	9	9	9	9
	Solvent Deasphalting	16	16	16	16	16	16	16	16	16	16
	Sulfur Recovery* (K s tons/d)	3.26	3.17	3.09	3.02	3.10	3.02	3.14	2.99	3.18	2.98
	Steam Generation (K lb/hr)	9,516	9,461	9,741	9,671	10,159	9,883	10,259	9,796	10,305	9,887
NEW CAPACITY											
Upgrading	Alkylation*										
Hydrotreating	FCC Naphtha Desulfurization					152		179		214	
	Benzene Saturation		24	4	13	36		38		17	
Hydrogen	Hydrogen Plant* (MM scf/d)	377	417	442	401	475	420	485	423	441	402
Fractionation	Debutanization							32		35	
	Depentanization										
	Medium Naphtha Spl.										
Other	Butane Isomerization									9	
Retrofit/Revamp	Tier 2 Diesel Desulfurization			3				10		3	
	Distillate Dearomatization										
	FCC Naphtha Desulfurization					540		540		540	
OPERATIONS											
Fluid Cat Cracker	Charge Rate	1,220	1,163	1,173	1,102	1,180	1,105	1,194	1,095	1,218	1,088
	Conversion (Vol %)	69.2	69.8	70.1	70.3	68.1	69.4	68.3	68.5	68.7	69.1
	Olefin Max Cat. (%)	9.9	22.7	7.4	24.2	10.8	19.9	10.0	12.3	3.3	18.1
	Catalyst Coke (K b/d)	42	40	40	37	40	38	40	37	41	37
Reformer	Charge Rate	587	560	602	518	645	583	645	577	650	565
	Severity (RON)	99.5	99.4	94.8	97.8	95.5	98.1	95.9	97.9	96.8	99.1
FUEL & ENERGY											
Fuel Use	Natural Gas & Refinery Gases (foeb)	186	184	186	179	193	186	194	185	196	185
Energy Use	Fuel & Power (Billion btu/d)	1,695	1,672	1,678	1,602	1,731	1,666	1,741	1,650	1,757	1,649
CO2 Emissions	CO2 Emissions (K MT/d)	123.8	122.2	122.5	116.5	126.1	121.0	126.8	119.9	127.4	119.6

* Capacity defined in terms of volume of output.

Exhibit A-2: Refinery Modeling Results -- PADD 3
Operations and New Capacity
(K b/d, except as noted)

Type of Process	Process	2010 Calibration Sum	2010 Calibration Win	2015 Reference Sum	2015 Reference Win	2015 10 ppm Sulfur Sum	2015 10 ppm Sulfur Win	2015 RVP Standards 9.0 RVP Sum	2015 RVP Standards 9.0 RVP Win	2015 RVP Standards 8.0 RVP Sum	2015 RVP Standards 8.0 RVP Win
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	7,671	7,271	7,328	7,056	7,337	7,056	7,373	7,073	7,497	6,966
Conversion	Fluid Cat Cracker	2,487	2,279	2,454	2,386	2,452	2,406	2,458	2,430	2,524	2,324
	Hydrocracking	727	727	727	727	727	727	727	727	727	727
	Coking	1,149	1,069	1,145	1,075	1,147	1,074	1,167	1,078	1,198	1,059
Upgrading	Alkylation*	581	488	581	479	581	488	581	497	581	494
	Iso-octene/octane										
	Catalytic Polymerization*			20		20		20		20	
	Dimersol*	19	19	19	19	19	19	19	19	19	19
	Pen/Hex Isomerization	213	213	213	213	213	213	213	213	213	213
	Reforming - CCR	820	820	820	820	820	820	820	820	820	820
	Reforming - Other	545	489	497	423	515	428	532	430	567	439
Hydrotreating	Naphtha Desulfurization	1,670	1,465	1,602	1,434	1,604	1,541	1,613	1,545	1,730	1,522
	FCC Naphtha Desulfurization	1,239	1,138	1,239	1,207	1,239	1,325	1,239	1,352	1,239	1,294
	Benzene Saturation	65		64	73	64	73	64	76	64	65
	Distillate Desulfurization	2,386	2,335	2,263	2,248	2,245	2,226	2,261	2,259	2,411	2,210
	Distillate Dearomatization	4	4	4	4	4	4	4	4	4	111
	FCC Feed Desulfurization (Conv)	978	893	972	932	970	939	1,009	954	1,056	913
	FCC Feed Desulfurization (Deep)	1,239	1,138	1,239	1,207	1,239	1,325	1,239	1,352	1,239	1,294
	Resid Desulfurization										
Hydrogen (MM scf/d)	Hydrogen Production	875	875	875	875	875	875	875	875	875	875
	Hydrogen Recovery										
Fractionation	Debutanization	509	410	513	398	520	408	515	429	515	439
	Depentanization	303	303	303		303		303		303	
	Lt. Naphtha Spl. (Benz. Prec.)	561	408	376	518	357	512	413	516	423	455
	Med. Naphtha Spl.										
	Hvy. Reformate Spl.	93	472	478	464	412	463		465		458
	FCC Naphtha Splitting										
	Heavy FCC/Lt Cycle Oil Splitting		586		668		963		1,322		1,265
Other	Aromatics Plant*	110	128	164	121	173	124	145	124	130	132
	Benzene Extraction*										
	Butane Isomerization	50		50		50		50		50	3
	Lubes & Waxes*	137	133	145	137	145	137	145	137	145	137
	Solvent Deasphalting	202	202	202	202	202	202	202	202	202	202
	Sulfur Recovery* (K s tons/d)	10.25	9.91	10.26	9.90	10.31	9.91	10.38	9.92	10.60	9.78
	Steam Generation (K lb/hr)	27,741	25,366	28,811	26,274	29,014	26,605	28,724	26,906	29,050	26,467
NEW CAPACITY											
Upgrading	Alkylation*										
Hydrotreating	FCC Naphtha Desulfurization					140		169		276	
	Benzene Saturation			54		51		23		33	
Hydrogen	Hydrogen Plant* (MM scf/d)	1,679	1,728	1,893	1,941	1,997	1,987	1,994	1,987	2,040	2,037
Fractionation	Debutanization							16		16	
	Depentanization									468	
	Medium Naphtha Spl.										
Other	Butane Isomerization										
Retrofit/Revamp	Tier 2 Diesel Desulfurization			57		51		50		104	
	Distillate Dearomatization				16					107	
	FCC Naphtha Desulfurization					1,377		1,377		1,377	
OPERATIONS											
Fluid Cat Cracker	Charge Rate	2,600	2,374	2,584	2,479	2,579	2,498	2,684	2,538	2,809	2,429
	Conversion (Vol %)	71.9	71.8	71.5	72.3	71.6	72.4	69.6	72.2	68.7	72.0
	Olefin Max Cat. (%)	45.9	48.6	47.9	45.0	48.0	44.4	49.3	39.9	29.8	37.9
	Catalyst Coke (K b/d)	104	98	102	98	102	98	102	99	103	96
Reformer	Charge Rate	1,325	1,317	1,348	1,250	1,363	1,251	1,352	1,254	1,407	1,262
	Severity (RON)	99.2	95.1	93.9	93.7	94.6	94.0	96.9	94.0	96.4	94.3
FUEL & ENERGY											
Fuel Use	Natural Gas & Refinery Gases (foeb)	495	471	499	474	505	479	504	482	515	481
Energy Use	Fuel & Power (Billion btu/d)	4,463	4,236	4,481	4,258	4,519	4,297	4,508	4,324	4,588	4,292
CO2 Emissions	CO2 Emissions (K MT/d)	325.0	309.8	327.4	313.7	331.0	316.6	330.8	318.3	336.4	316.0

* Capacity defined in terms of volume of output.

Exhibit A-2: Refinery Modeling Results -- PADD 4
Operations and New Capacity
(K b/d, except as noted)

Type of Process	Process	2010 Calibration Sum	2010 Calibration Win	2015 Reference Sum	2015 Reference Win	2015 10 ppm Sulfur Sum	2015 10 ppm Sulfur Win	2015 RVP Standards 9.0 RVP Sum	2015 RVP Standards 9.0 RVP Win	2015 RVP Standards 8.0 RVP Sum	2015 RVP Standards 8.0 RVP Win
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	542	526	518	500	519	500	522	497	531	489
Conversion	Fluid Cat Cracker	175	158	162	163	158	164	160	162	166	155
	Hydrocracking	15	12	15	12	15	12	15	12	15	12
	Coking	57	58	50	57	50	57	51	56	53	55
Upgrading	Alkylation*	38	33	37	35	37	35	37	35	38	34
	Iso-octene/octane										
	Catalytic Polymerization*	5	5	5	5	5	5	5	5	5	5
	Dimersol*										
	Pen/Hex Isomerization	5		5	5	5	5	5	5	5	5
	Reforming - CCR	83	62	73	67	77	68	78	67	81	66
	Reforming - Other										
Hydrotreating	Naphtha Desulfurization	124	122	104	116	120	116	120	115	125	113
	FCC Naphtha Desulfurization	65	59	62	61	65	94	65	93	65	91
	Benzene Saturation				8		8		8		8
	Distillate Desulfurization	190	190	182	182	187	184	187	184	192	185
	Distillate Dearomatization										
	FCC Feed Desulfurization (Conv)	24	22	23	22	23	22	23	22	24	21
	FCC Feed Desulfurization (Deep)	65	59	62	61	65	94	65	93	65	91
	Resid Desulfurization										
Hydrogen (MM scf/d)	Hydrogen Production	111	111	111	111	111	111	111	111	111	111
	Hydrogen Recovery										
Fractionation	Debutanization	25	14	23	16	23	16	23	17	23	20
	Depentanization										
	Lt. Naphtha Spl. (Benz. Prec.)	49	48	38	43	39	42	38	43	43	42
	Med. Naphtha Spl.	3	3	3	5	3	5	3	5		5
	Hvy. Reformate Spl.				17		19		19		19
	FCC Naphtha Splitting										
	Heavy FCC/Lt Cycle Oil Splitting						11		11		15
Other	Aromatics Plant*										
	Benzene Extraction*										
	Butane Isomerization	6	6	6	6	6	6	6	6	6	6
	Lubes & Waxes*										
	Solvent Deasphalting	5	5	5	5	5	5	5	5	5	5
	Sulfur Recovery* (K s tons/d)	0.52	0.50	0.47	0.49	0.47	0.49	0.48	0.49	0.49	0.47
	Steam Generation (K lb/hr)	1,366	1,267	1,373	1,320	1,388	1,338	1,402	1,330	1,428	1,314
NEW CAPACITY											
Upgrading	Alkylation*										
Hydrotreating	FCC Naphtha Desulfurization					33		34		39	
	Benzene Saturation			10		10		11		10	
Hydrogen	Hydrogen Plant* (MM scf/d)		1	5	1	9	7	11	7	14	2
Fractionation	Debutanization							2		6	
	Depentanization									13	
	Medium Naphtha Spl.		2	2	2						
Other	Butane Isomerization										
Retrofit/Revamp	Tier 2 Diesel Desulfurization			2		5		5		5	
	Distillate Dearomatization										
	FCC Naphtha Desulfurization					73		73		73	
OPERATIONS											
Fluid Cat Cracker	Charge Rate	182	166	177	172	173	173	175	171	186	164
	Conversion (Vol %)	71.7	71.2	69.1	71.0	68.8	71.2	68.9	70.9	67.3	70.9
	Olefin Max Cat. (%)	6.7	39.9	13.9	35.7	16.6	38.5	15.7	32.7	13.1	23.4
	Catalyst Coke (K b/d)	7	6	7	7	7	7	7	7	7	6
Reformer	Charge Rate	83	62	73	67	77	68	78	67	81	66
	Severity (RON)	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0	116.0
FUEL & ENERGY											
Fuel Use	Natural Gas & Refinery Gases (foeb)	27	25	26	25	26	26	26	25	27	25
Energy Use	Fuel & Power (Billion btu/d)	249	232	238	234	242	239	244	237	251	231
CO2 Emissions	CO2 Emissions (K MT/d)	18.3	17.0	17.5	17.3	17.8	17.6	17.9	17.5	18.5	17.0

* Capacity defined in terms of volume of output.

Exhibit A-3: Refinery Modeling Results -- PADD 1
Inputs and Outputs
(K b/d)

Inputs/ Outputs	2010 Calibration Sum	2010 Calibration Win	2015 Reference Sum	2015 Reference Win	2015 10 ppm Sulfur Sum	2015 10 ppm Sulfur Win	2015 RVP Standards 9.0 RVP Sum	2015 RVP Standards 9.0 RVP Win	2015 RVP Standards 8.0 RVP Sum	2015 RVP Standards 8.0 RVP Win
Crude Oil	**1,195**	**972**	**1,125**	**1,011**	**1,128**	**1,010**	**1,135**	**1,000**	**1,148**	**987**
Other Inputs	**163**	**198**	**243**	**220**	**243**	**221**	**243**	**242**	**243**	**270**
Isobutane	10	13	13	13	13	13	13	13	13	13
Butane		16		17		18		17		17
Butylene										
C5s								11		25
Natural Gas Liquids										
Gasoline Blendstocks	8		8		8		8		8	
Straight Run Naphtha	10	5	32	24	32	24	32	24	32	24
Kerosene										
Heavy Gas Oil	54	60	70	60	70	60	70	60	70	60
Resid	40	65	74	63	74	63	74	63	74	63
Ethanol -- RFG	41	39	46	43	46	43	46	43	46	43
All Other	8	8	24	24	24	24	24	24	24	24
Purchased Energy										
Electricity (MM Kwh/d)	7.8	6.8	7.7	7.0	7.8	7.0	8.0	7.1	8.2	7.1
Natural Gas (K foeb/d)	30	23	31	26	31	26	33	26	34	25
Refined Products[1]	**1,369**	**1,185**	**1,395**	**1,266**	**1,397**	**1,265**	**1,412**	**1,266**	**1,440**	**1,266**
Aromatics	12.0	7.0	12.0	10.0	12.0	10.0	12.0	10.0	12.0	10.0
Ethane/Ethylene										
Propane	25	21	23	21	24	20	24	21	24	21
Propylene	19	18	16	16	16	16	16	16	16	16
Butanes/Butylenes	15		17		17		17		15	
C5s	1		3		3		11		25	
Aviation Gas										
Naphtha to PetroChem										
Special Naphthas	1	1	1	1	1	1	1	1	1	1
Gasoline:	655	617	693	668	693	668	693	668	693	668
Federal RFG	413	394	455	431	455	431	455	431	455	431
Conventional	242	223	209	237	209	237	209	237	238	237
Low RVP			29		29		29			
E85										
Jet Fuel	88	81	84	84	84	84	84	84	84	84
Diesel Fuel	392	326	375	344	375	344	375	344	375	344
EPA Diesel	2	1								
Ultra Low Sulfur Diesel	267	197	250	213	250	213	250	213	250	213
Off road diesel/HH Oil	123	128	125	131	125	131	125	131	125	131
Unf. Oil to PetroChem										
Residual Oil	72	51	70	53	71	53	71	53	73	53
Asphalt	74	48	82	54	82	54	82	54	82	54
Lubes & Waxes	14	15	16	15	16	15	16	15	16	15
Coke	6	4	8	3	8	3	8	3	8	3
Sulfur (s tons/d)	0.6	0.5	0.6	0.5	0.6	0.5	0.6	0.5	0.6	0.5
Crude Oil Input per Bbl of Finished Gasoline	1.824	1.576	1.624	1.513	1.628	1.511	1.637	1.496	1.657	1.477

1 Total excludes coke and sulfur

Exhibit A-3: Refinery Modeling Results -- PADD 2
Inputs and Outputs
(K b/d)

			2015							
	2010						RVP Standards			
Inputs/	Calibration		Reference		10 ppm Sulfur		9.0 RVP		8.0 RVP	
Outputs	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Crude Oil	**3,285**	**3,171**	**3,209**	**3,067**	**3,218**	**3,074**	**3,243**	**3,053**	**3,287**	**3,043**
Other Inputs	**195**	**254**	**216**	**337**	**216**	**342**	**216**	**364**	**216**	**410**
Isobutane	48	43	46	41	46	41	46	41	46	41
Butane		83		83		88		110		115
Butylene										
C5s										20
Natural Gas Liquids	46	32	42	115	42	115	42	115	42	115
Gasoline Blendstocks	7	7								
Straight Run Naphtha	29	20	58	38	58	38	58	38	58	38
Kerosene	23	22	21	13	21	13	21	13	21	13
Heavy Gas Oil	12	17	16	13	16	13	16	13	16	13
Resid										
Ethanol -- RFG	31	30	33	34	33	34	33	34	33	34
All Other	90	93	168	171	168	164	168	165	168	154
Purchased Energy										
Electricity (MM Kwh/d)	27.2	27.0	26.9	25.5	27.6	26.4	27.7	26.1	27.6	26.3
Natural Gas (K foeb/d)	132	135	142	137	146	140	147	140	146	138
Refined Products[1]	**3,570**	**3,532**	**3,609**	**3,584**	**3,617**	**3,589**	**3,640**	**3,588**	**3,684**	**3,589**
Aromatics	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Ethane/Ethylene										
Propane	72	70	66	62	68	67	69	66	68	67
Propylene	36	39	31	33	31	33	31	33	31	33
Butanes/Butylenes	53	2	40		44		67		72	
C5s									20	
Aviation Gas	3	2	3	2	3	2	3	2	3	2
Naphtha to PetroChem	12	12	15	10	15	10	15	10	15	10
Special Naphthas										
Gasoline:	1,915	1,937	1,992	2,025	1,992	2,025	1,992	2,025	1,992	2,025
Federal RFG	309	304	331	343	331	343	331	343	331	343
Conventional	1,606	1,633	1,428	1,682	1,428	1,682	1,428	1,682	1,661	1,682
Low RVP			233		233		233			
E85			3	3	3	3	3	3	3	3
Jet Fuel	226	225	236	230	236	230	236	230	236	230
Diesel Fuel	977	976	933	952	933	952	933	952	933	952
EPA Diesel	28	21								
Ultra Low Sulfur Diesel	929	936	912	935	912	935	912	935	912	935
Off road diesel/HH Oil	20	19	21	17	21	17	21	17	21	17
Unf. Oil to PetroChem	11	8	11	10	11	10	11	10	11	10
Residual Oil	68	80	65	67	65	67	65	67	65	67
Asphalt	173	157	194	169	194	169	194	169	194	169
Lubes & Waxes	9	9	9	9	9	9	9	9	9	9
Coke	95	92	85	86	86	86	87	85	89	84
Sulfur (s tons/d)	3.3	3.2	3.1	3.0	3.1	3.0	3.1	3.0	3.2	3.0
Crude Oil Input per Bbl of Finished Gasoline	1.715	1.637	1.611	1.515	1.616	1.518	1.628	1.508	1.650	1.503

1 Total excludes coke and sulfur

Exhibit A-3: Refinery Modeling Results -- PADD 3 Inputs and Outputs (K b/d)

Inputs/ Outputs	2010 Calibration		2015							
			Reference		10 ppm Sulfur		RVP Standards			
							9.0 RVP		8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Crude Oil	**7,671**	**7,271**	**7,328**	**7,056**	**7,337**	**7,056**	**7,373**	**7,073**	**7,497**	**6,966**
Other Inputs	**701**	**846**	**891**	**897**	**891**	**901**	**891**	**887**	**891**	**1,082**
Isobutane	99	104	111	97	111	97	111	97	111	97
Butane		115		90		94		110		128
Butylene		13								
C5s										89
Natural Gas Liquids	94	101	90	91	90	91	90	91	90	91
Gasoline Blendstocks										
Straight Run Naphtha	1		46	30	46	30	46		46	
Kerosene	41	50	44	43	44	43	44	43	44	43
Heavy Gas Oil	288	326	382	363	382	363	382	363	382	363
Resid	94	66	129	100	129	100	129	100	129	100
Ethanol -- RFG	84	72	89	83	89	83	89	83	89	83
All Other	140	178	323	328	323	328	323	328	323	328
Purchased Energy										
Electricity (MM Kwh/d)	71.9	68.1	72.4	68.6	72.7	69.2	72.3	69.5	72.2	68.5
Natural Gas (K foeb/d)	358	356	379	368	385	372	375	374	385	379
Refined Products[1]	**8,321**	**8,161**	**8,377**	**8,170**	**8,383**	**8,171**	**8,402**	**8,171**	**8,597**	**8,170**
Aromatics	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0	120.0
Ethane/Ethylene	22	19	20	19	20	19	20	19	20	19
Propane	139	127	130	123	132	124	135	124	135	123
Propylene	214	208	187	190	187	190	187	190	187	190
Butanes/Butylenes	73		85		89		105		122	
C5s									89	
Aviation Gas	12	11	12	10	12	10	12	10	12	10
Naphtha to PetroChem	58	62	64	53	64	53	64	53	64	53
Special Naphthas	35	39	39	42	39	42	39	42	39	42
Gasoline:	3,939	3,901	4,095	4,087	4,095	4,087	4,095	4,087	4,095	4,087
Federal RFG	842	715	892	827	892	827	892	827	892	827
Conventional	3,097	3,186	2,178	3,260	2,178	3,260	2,178	3,260	3,203	3,260
Low RVP			1,025		1,025		1,025			
E85			3	3	3	3	3	3	3	3
Jet Fuel	759	690	785	744	785	744	785	744	785	744
Diesel Fuel	2,283	2,353	2,194	2,173	2,194	2,173	2,194	2,173	2,194	2,173
EPA Diesel	260	134								
Ultra Low Sulfur Diesel	1,748	1,954	1,930	1,921	1,930	1,921	1,930	1,921	1,930	1,921
Off road diesel/HH Oil	275	265	264	252	264	252	264	252	264	252
Unf. Oil to PetroChem	111	106	123	112	123	112	123	112	123	112
Residual Oil	324	312	270	271	270	271	270	271	270	271
Asphalt	96	80	108	89	108	89	108	89	108	89
Lubes & Waxes	137	133	145	137	145	137	145	137	145	137
Coke	364	337	365	342	366	342	370	343	380	336
Sulfur (s tons/d)	10.2	9.9	10.3	9.9	10.3	9.9	10.4	9.9	10.6	9.8
Crude Oil Input per Bbl of Finished Gasoline	1.947	1.864	1.789	1.726	1.792	1.726	1.800	1.731	1.831	1.704

1 Total excludes coke and sulfur

Exhibit A-3: Refinery Modeling Results -- PADD 4
Inputs and Outputs
(K b/d)

Inputs/ Outputs	2010 Calibration		2015 Reference		2015 10 ppm Sulfur		2015 RVP Standards 9.0 RVP		2015 RVP Standards 8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Crude Oil	**542**	**526**	**518**	**500**	**519**	**500**	**522**	**497**	**531**	**489**
Other Inputs	**17**	**23**	**21**	**31**	**21**	**31**	**21**	**34**	**21**	**48**
Isobutane	7	6	8	7	8	7	8	7	8	7
Butane		9		9		9		12		15
Butylene										
C5s										5
Natural Gas Liquids	2	4	3	3	3	3	3	3	3	3
Gasoline Blendstocks										
Straight Run Naphtha			1		1		1		1	
Kerosene										
Heavy Gas Oil	8	4	9	12	9	12	9	12	9	12
Resid										
Ethanol -- RFG										
All Other	9	11	30	30	30	30	30	30	30	30
Purchased Energy										
Electricity (MM Kwh/d)	3.9	3.6	3.7	3.7	3.8	3.8	3.8	3.7	3.9	3.6
Natural Gas (K foeb/d)	17	17	17	17	18	17	18	17	18	17
Refined Products[1]	**562**	**557**	**566**	**558**	**566**	**558**	**569**	**558**	**583**	**558**
Aromatics										
Ethane/Ethylene										
Propane	11	8	9	9	9	9	9	9	9	9
Propylene	1	1	1	1	1	1	1	1	1	1
Butanes/Butylenes	3		2		2		4		8	
C5s									5	
Aviation Gas										
Naphtha to PetroChem	1	1		1		1		1		1
Special Naphthas										
Gasoline:	287	287	295	302	295	302	295	302	295	302
Federal RFG										
Conventional	287	287	159	302	159	302	159	302	295	302
Low RVP			136		136		136			
E85										
Jet Fuel	37	37	39	39	39	39	39	39	39	39
Diesel Fuel	179	179	172	164	172	164	172	164	172	164
EPA Diesel	11	11								
Ultra Low Sulfur Diesel	167	167	172	164	172	164	172	164	172	164
Off road diesel/HH Oil	1	1								
Unf. Oil to PetroChem										
Residual Oil	12	12	11	9	11	9	11	9	11	9
Asphalt	32	32	37	33	37	33	37	33	37	33
Lubes & Waxes										
Coke	14	15	12	14	12	14	12	14	13	14
Sulfur (s tons/d)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Crude Oil Input per Bbl of Finished Gasoline	1.890	1.832	1.757	1.655	1.759	1.655	1.768	1.647	1.801	1.619

1 Total excludes coke and sulfur

Exhibit A-4: Refinery Modeling Results -- PADD 1
Pool Gasoline Properties

Gasoline Volume & Properties	2010 Calibration		2015 Reference		2015 10 ppm Sulfur		2015 RVP Standards 9.0 RVP		2015 RVP Standards 8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Pool	**655**	**617**	**693**	**668**	**693**	**668**	**693**	**668**	**693**	**668**
RVP (psi)	7.5	12.6	7.7	13.8	7.7	13.8	7.5	13.8	7.1	13.8
Oxygen (wt%)	2.5	2.5	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	23.5	20.6	21.9	19.5	22.1	19.2	22.2	19.0	22.3	18.7
Benzene (vol%)	0.57	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
Olefins (vol%)	13.7	12.4	13.2	12.4	11.2	12.4	11.1	12.4	11.2	12.4
Sulfur (ppm)	30.0	30.0	30.0	28.6	9.0	9.0	9.0	9.0	9.0	9.0
E130 (vol% off)	8.3	13.6	8.6	15.0	8.5	15.5	7.9	15.9	6.8	16.9
E200 (vol% off)	47.5	51.9	47.7	54.3	47.6	55.0	46.7	56.1	45.6	57.4
E300 (vol% off)	80.0	81.9	79.2	83.2	79.2	83.4	79.0	83.8	79.0	83.8
Estimated DI[1]	1173	1115	1181	1094	1181	1087	1191	1075	1203	1063
Energy Density[2]	5.127	5.057	5.094	5.007	5.096	5.003	5.105	4.993	5.120	4.980
Octane ((R+M)/2)	88.3	88.4	88.3	88.4	88.3	88.4	88.3	88.4	88.3	88.4
RFG	**413**	**394**	**455**	**431**	**455**	**431**	**455**	**431**	**455**	**431**
RVP (psi)	6.8	12.2	6.8	13.8	6.8	13.8	6.8	13.8	6.8	13.8
Oxygen (wt%)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	22.1	18.8	19.8	18.8	20.2	16.0	20.2	15.7	20.3	15.3
Benzene (vol%)	0.54	0.57	0.54	0.57	0.54	0.57	0.54	0.57	0.54	0.57
Olefins (vol%)	13.5	11.5	13.3	11.5	10.3	11.5	10.5	11.5	10.7	11.5
Sulfur (ppm)	30	30	30	28	9	9	9	9	9	9
E130 (vol% off)	5.6	12.6	5.8	15.3	5.9	16.3	5.9	15.7	5.7	16.4
E200 (vol% off)	45.0	50.8	45.0	54.7	45.0	54.4	45.0	57.5	45.0	56.6
E300 (vol% off)	80.0	83.0	80.0	84.9	80.0	82.2	80.0	84.8	80.0	83.1
Estimated DI[1]	1208	1129	1207	1084	1207	1092	1207	1063	1208	1073
Energy Density[2]	5.138	5.029	5.121	4.999	5.119	4.977	5.119	4.973	5.123	4.983
Octane ((R+M)/2)	88.3	88.4	88.3	88.4	88.3	88.4	88.3	88.4	88.3	88.4
All Other	**242**	**223**	**238**	**237**	**238**	**237**	**238**	**237**	**238**	**237**
RVP (psi)	8.76	13.34	9.33	13.77	9.33	13.77	8.76	13.77	7.80	13.77
Oxygen (wt%)	1.1	1.2	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	26.0	23.8	25.9	20.7	25.9	25.0	25.9	25.0	26.0	25.0
Benzene (vol%)	0.61	0.55	0.61	0.55	0.61	0.55	0.61	0.55	0.61	0.55
Olefins (vol%)	14.0	14.0	13.1	14.0	13.1	14.0	12.2	14.0	12.0	14.0
Sulfur (ppm)	30	30	30	30	9	9	9	9	9	9
E130 (vol% off)	13.0	15.4	13.9	14.6	13.6	14.0	11.5	16.3	9.1	17.9
E200 (vol% off)	51.9	53.9	52.7	53.4	52.6	56.1	49.8	53.6	46.7	58.7
E300 (vol% off)	80.0	80.0	77.7	80.0	77.7	85.6	77.1	82.1	77.0	84.9
Estimated DI[1]	1114	1092	1129	1113	1132	1077	1161	1098	1193	1046
Energy Density[2]	5.109	5.106	5.042	5.023	5.052	5.050	5.079	5.030	5.114	4.975
Octane ((R+M)/2)	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4	88.4

1 ASTM Driveability Index: calculated by formula using modeling results for E130, E200, & E300 plus an ethanol adjustment (2.403 for each percent of ethanol in the finished blend) for all other gasoline.
2 Million Btu per barrel.

Exhibit A-4: Refinery Modeling Results -- PADD 2
Pool Gasoline Properties

Gasoline Volume & Properties	2010 Calibration		2015							
			Reference		10 ppm Sulfur		RVP Standards			
							9.0 RVP		8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Pool	**1915**	**1937**	**1992**	**2025**	**1992**	**2025**	**1992**	**2025**	**1992**	**2025**
RVP (psi)	8.7	13.5	9.1	13.7	9.1	13.7	8.5	13.7	7.7	13.7
Oxygen (wt%)	2.1	2.1	3.3	3.3	3.3	3.2	3.3	3.2	3.3	3.0
Aromatics (vol%)	24.5	21.7	21.4	19.6	21.3	19.0	21.9	18.8	23.5	19.0
Benzene (vol%)	1.13	0.82	0.78	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	9.0	9.8	8.6	9.4	7.1	7.9	7.1	7.1	7.1	7.2
Sulfur (ppm)	30.0	30.3	29.8	29.7	9.0	9.0	9.0	9.0	9.0	9.0
E130 (vol% off)	8.6	15.6	9.5	15.5	9.5	15.5	8.9	15.7	7.8	15.9
E200 (vol% off)	53.1	59.5	54.8	60.4	54.3	61.1	53.6	61.2	52.2	61.4
E300 (vol% off)	82.3	86.2	83.4	85.5	83.3	87.4	82.7	87.5	81.3	87.7
Estimated DI[1]	1122	1036	1112	1042	1115	1029	1125	1027	1145	1023
Energy Density[2]	5.110	5.031	5.049	4.956	5.053	4.950	5.066	4.947	5.092	4.949
Octane ((R+M)/2)	88.7	89.1	88.7	89.1	88.7	89.1	88.7	89.1	88.7	89.1
RFG	**309**	**304**	**331**	**343**	**331**	**343**	**331**	**343**	**331**	**343**
RVP (psi)	7.0	13.4	7.0	13.4	7.0	13.4	7.0	13.4	7.0	13.4
Oxygen (wt%)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	20.4	20.4	18.7	17.2	19.9	20.4	20.5	20.4	20.5	20.4
Benzene (vol%)	0.74	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	8.3	6.0	6.7	6.0	1.8	6.0	2.3	6.0	3.1	6.0
Sulfur (ppm)	30	32	30	28	9	9	9	9	9	9
E130 (vol% off)	5.3	14.8	6.5	14.5	6.1	14.6	5.4	14.8	5.9	14.8
E200 (vol% off)	49.4	53.6	49.4	56.1	49.4	56.8	49.4	57.3	49.4	55.4
E300 (vol% off)	83.6	85.9	83.6	92.4	87.5	86.2	83.6	81.8	83.6	83.8
Estimated DI[1]	1165	1090	1161	1051	1148	1068	1165	1079	1163	1085
Energy Density[2]	5.098	4.958	5.091	4.871	5.075	4.919	5.089	4.978	5.103	4.918
Octane ((R+M)/2)	88.5	88.6	88.5	88.6	88.5	88.6	88.5	88.6	88.5	88.6
All Other	**1606**	**1633**	**1661**	**1682**	**1661**	**1682**	**1661**	**1682**	**1661**	**1682**
RVP (psi)	9.05	13.48	9.52	13.77	9.52	13.75	8.76	13.75	7.80	13.70
Oxygen (wt%)	1.9	1.9	3.3	3.3	3.3	3.2	3.3	3.2	3.3	3.0
Aromatics (vol%)	25.3	21.9	22.0	20.1	21.6	18.7	22.2	18.4	24.1	18.7
Benzene (vol%)	1.20	0.86	0.81	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	9.1	10.5	9.0	10.1	8.1	8.3	8.1	7.4	7.9	7.5
Sulfur (ppm)	30	30	30	30	9	9	9	9	9	9
E130 (vol% off)	9.2	15.7	10.1	15.7	10.2	15.7	9.6	15.8	8.1	16.2
E200 (vol% off)	53.9	60.7	55.9	61.2	55.3	62.0	54.4	62.0	52.7	62.6
E300 (vol% off)	82.1	86.3	83.3	84.0	82.5	87.7	82.5	88.6	80.8	88.4
Estimated DI[1]	1114	1025	1102	1040	1109	1021	1117	1017	1142	1010
Energy Density[2]	5.112	5.044	5.040	4.973	5.049	4.956	5.062	4.940	5.090	4.956
Octane ((R+M)/2)	88.7	89.2	88.7	89.2	88.7	89.2	88.7	89.2	88.7	89.2

1 ASTM Driveability Index: calculated by formula using modeling results for E130, E200, & E300 plus an ethanol adjustment (2.403 for each percent of ethanol in the finished blend) for all other gasoline.
2 Million Btu per barrel.

Exhibit A-4: Refinery Modeling Results -- PADD 3 Pool Gasoline Properties

Gasoline Volume & Properties	2010 Calibration		2015							
			Reference		10 ppm Sulfur		RVP Standards			
							9.0 RVP		8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Pool	**3939**	**3901**	**4095**	**4087**	**4095**	**4087**	**4095**	**4087**	**4095**	**4087**
RVP (psi)	8.2	12.6	8.7	12.8	8.7	12.8	8.2	12.8	7.6	12.8
Oxygen (wt%)	1.9	2.1	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	23.3	20.3	20.5	18.1	20.7	17.9	20.8	17.4	21.6	17.3
Benzene (vol%)	0.77	1.00	0.59	0.72	0.59	0.72	0.59	0.72	0.59	0.72
Olefins (vol%)	9.6	9.9	9.6	10.4	8.2	9.4	8.1	9.3	7.6	8.4
Sulfur (ppm)	29.6	30.0	29.1	30.0	9.0	9.0	9.0	9.0	9.0	9.0
E130 (vol% off)	8.7	14.2	9.3	14.5	9.0	14.5	9.3	14.6	7.3	15.4
E200 (vol% off)	52.2	58.0	53.4	60.3	53.4	60.5	53.1	60.5	49.3	61.4
E300 (vol% off)	82.6	87.0	84.8	87.9	84.5	88.2	82.6	89.0	81.2	89.3
Estimated DI[1]	1126	1050	1117	1037	1120	1035	1127	1031	1167	1021
Energy Density[2]	5.120	5.030	5.045	4.974	5.044	4.972	5.064	4.966	5.099	4.952
Octane ((R+M)/2)	87.8	87.8	88.2	88.2	88.2	88.2	88.2	88.2	88.2	88.2
RFG	**842**	**715**	**892**	**827**	**892**	**827**	**892**	**827**	**892**	**827**
RVP (psi)	6.9	12.8	6.9	12.8	6.9	12.8	6.9	12.8	6.9	12.8
Oxygen (wt%)	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	11.3	26.3	9.5	26.3	18.9	26.3	18.5	24.7	19.3	23.6
Benzene (vol%)	0.50	1.12	0.50	1.12	0.50	1.12	0.50	1.12	0.50	1.12
Olefins (vol%)	7.9	6.9	9.7	7.6	4.1	11.0	4.3	9.0	2.5	7.3
Sulfur (ppm)	28	30	28	30	9	9	9	9	9	9
E130 (vol% off)	6.0	13.8	6.3	13.4	6.4	12.2	5.0	13.1	5.5	15.6
E200 (vol% off)	48.4	56.5	47.8	58.7	47.8	57.5	52.6	59.5	47.8	62.3
E300 (vol% off)	85.0	80.0	86.8	82.2	83.3	80.0	83.3	95.7	89.0	80.0
Estimated DI[1]	1164	1096	1161	1074	1173	1095	1146	1020	1156	1048
Energy Density[2]	5.052	5.057	5.043	5.044	5.090	5.052	5.086	5.000	5.087	5.000
Octane ((R+M)/2)	88.2	88.0	88.2	88.0	88.2	88.0	88.2	88.0	88.2	88.0
All Other	**3097**	**3186**	**3203**	**3260**	**3203**	**3260**	**3203**	**3260**	**3203**	**3260**
RVP (psi)	8.57	12.51	9.17	12.84	9.17	12.84	8.56	12.84	7.80	12.84
Oxygen (wt%)	1.5	1.8	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	26.6	18.9	23.5	16.0	21.2	15.8	21.4	15.6	22.3	15.7
Benzene (vol%)	0.84	0.97	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	10.1	10.6	9.6	11.2	9.3	9.0	9.1	9.3	9.0	8.6
Sulfur (ppm)	30	30	29	30	9	9	9	9	9	9
E130 (vol% off)	9.4	14.2	10.2	14.8	9.7	15.1	10.5	15.0	7.8	15.4
E200 (vol% off)	53.2	58.3	54.9	60.7	55.0	61.2	53.2	60.8	49.7	61.1
E300 (vol% off)	82.0	88.5	84.3	89.3	84.8	90.3	82.4	87.3	79.0	91.7
Estimated DI[1]	1115	1039	1105	1028	1105	1020	1122	1034	1170	1014
Energy Density[2]	5.138	5.024	5.046	4.956	5.032	4.952	5.059	4.958	5.102	4.939
Octane ((R+M)/2)	87.8	87.8	88.3	88.3	88.3	88.3	88.3	88.3	88.3	88.3

1 ASTM Driveability Index: calculated by formula using modeling results for E130, E200, & E300 plus an ethanol adjustment (2.403 for each percent of ethanol in the finished blend) for all other gasoline.
2 Million Btu per barrel.

Exhibit A-4: Refinery Modeling Results -- PADD 4
Pool Gasoline Properties

Gasoline Volume & Properties	2010 Calibration		2015							
			Reference		10 ppm Sulfur		RVP Standards			
							9.0 RVP		8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Pool	**287**	**287**	**295**	**302**	**295**	**302**	**295**	**302**	**295**	**302**
RVP (psi)	8.5	12.6	9.2	13.1	9.2	13.1	8.7	13.1	7.8	13.1
Oxygen (wt%)	1.0	1.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	24.7	17.4	19.1	18.2	19.5	18.0	19.8	17.8	20.5	17.5
Benzene (vol%)	1.10	0.84	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	10.6	12.8	9.5	12.1	8.2	10.8	8.2	10.2	8.4	9.0
Sulfur (ppm)	30.0	30.0	30.0	30.0	9.0	9.0	9.0	9.0	9.0	9.0
E130 (vol% off)	8.3	14.0	9.7	14.9	9.7	14.9	9.0	15.1	7.7	15.9
E200 (vol% off)	52.6	59.0	55.8	61.9	55.8	60.7	55.3	60.6	53.6	61.1
E300 (vol% off)	82.5	83.9	84.1	86.3	84.0	86.6	83.8	86.7	82.8	87.2
Estimated DI[1]	1119	1048	1102	1030	1102	1037	1109	1037	1129	1029
Energy Density[2]	5.178	5.086	5.059	5.003	5.061	5.001	5.069	5.000	5.094	4.982
Octane ((R+M)/2)	87.1	84.1	87.6	87.7	87.6	87.7	87.6	87.7	87.6	87.7
RFG	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
RVP (psi)										
Oxygen (wt%)										
Aromatics (vol%)										
Benzene (vol%)										
Olefins (vol%)										
Sulfur (ppm)										
E130 (vol% off)										
E200 (vol% off)										
E300 (vol% off)										
Estimated DI[1]										
Energy Density[2]										
Octane ((R+M)/2)										
All Other	**287**	**287**	**295**	**302**	**295**	**302**	**295**	**302**	**295**	**302**
RVP (psi)	8.53	12.64	9.18	13.09	9.18	13.09	8.70	13.09	7.80	13.09
Oxygen (wt%)	1.0	1.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Aromatics (vol%)	24.7	17.4	19.1	18.2	19.5	18.0	19.8	17.8	20.5	17.5
Benzene (vol%)	1.10	0.84	0.62	0.62	0.62	0.62	0.62	0.62	0.62	0.62
Olefins (vol%)	10.6	12.8	9.5	12.1	8.2	10.8	8.2	10.2	8.4	9.0
Sulfur (ppm)	30	30	30	30	9	9	9	9	9	9
E130 (vol% off)	8.3	14.0	9.7	14.9	9.7	14.9	9.0	15.1	7.7	15.9
E200 (vol% off)	52.6	59.0	55.8	61.9	55.8	60.7	55.3	60.6	53.6	61.1
E300 (vol% off)	82.5	83.9	84.1	86.3	84.0	86.6	83.8	86.7	82.8	87.2
Estimated DI[1]	1119	1048	1102	1030	1102	1037	1109	1037	1129	1029
Energy Density[2]	5.178	5.086	5.059	5.003	5.061	5.001	5.069	5.000	5.094	4.982
Octane ((R+M)/2)	87.1	84.1	87.6	87.7	87.6	87.7	87.6	87.7	87.6	87.7

1 ASTM Driveability Index: calculated by formula using modeling results for E130, E200, & E300 plus an ethanol adjustment (2.403 for each percent of ethanol in the finished blend) for all other gasoline.
2 Million Btu per barrel.

Exhibit A-5: Refinery Modeling Results -- PADD 1 Gasoline Composition (Vol. %)

Gasoline Blendstock	2010 Calibration		2015 Reference		2015 10 ppm Sulfur		2015 RVP Standards 9.0 RVP		2015 RVP Standards 8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Total (%)	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
C4s	0.7	8.4	0.7	9.5	0.7	10.2	0.6	9.6	0.5	9.5
Natural Gas Liquids	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
C5s & Isomerate	7.7	2.7	7.1	2.7	7.0	2.7	5.7	4.5	4.0	6.7
Raffinate	0.9	0.6	0.9	0.6	0.9	0.6	0.8	0.6	0.7	0.6
Naphthas (C5-250°)	7.8	8.2	6.7	8.1	6.7	8.2	6.8	8.2	7.0	8.1
Hydrocrackate	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.2
Alkylate	11.8	11.0	11.0	9.3	11.0	9.4	11.5	10.5	12.2	10.9
Poly Gas	2.0	0.0	1.9	0.0	1.9	0.0	1.9	0.0	1.9	0.0
FCC Naphtha	42.4	43.3	41.0	41.9	41.2	41.3	41.8	39.7	42.7	38.0
Reformate	18.9	17.8	20.5	17.7	20.5	17.4	20.6	16.7	20.8	16.0
Ethanol	7.5	7.7	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Volume (K b/d)	**655**	**617**	**693**	**617**	**693**	**617**	**693**	**617**	**693**	**617**

Exhibit A-5: Refinery Modeling Results -- PADD 2 Gasoline Composition (Vol. %)

Gasoline Blendstock	2010 Calibration		2015 Reference		2015 10 ppm Sulfur		2015 RVP Standards 9.0 RVP		2015 RVP Standards 8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Total (%)	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
C4s	2.7	10.7	2.7	9.8	2.6	9.7	1.5	9.9	0.7	9.8
Natural Gas Liquids	2.4	1.3	1.2	5.4	0.0	5.7	0.0	5.6	0.0	5.6
C5s & Isomerate	9.4	9.3	9.1	8.1	9.1	8.1	9.9	8.1	9.3	9.1
Raffinate	0.1	0.1	0.1	1.0	0.4	1.0	0.4	1.0	0.1	1.0
Naphthas (C5-250°)	5.7	5.9	6.1	4.0	6.5	3.5	5.3	3.5	6.3	3.6
Hydrocrackate	3.4	3.5	3.5	2.5	3.9	3.1	3.8	3.2	2.5	3.0
Alkylate	12.4	11.6	11.7	10.0	11.9	10.7	11.9	10.7	12.0	11.4
Poly Gas	0.3	0.1	0.3	0.3	0.3	0.3	0.3	0.3	0.1	0.3
FCC Naphtha	33.5	29.5	31.6	29.3	29.8	26.0	31.4	25.9	33.2	25.8
Reformate	23.9	21.6	23.8	19.6	25.6	22.2	25.6	22.0	25.8	21.2
Ethanol	6.3	6.4	10.0	10.0	10.0	9.7	10.0	9.7	10.0	9.2
Volume (K b/d)	**1915**	**1937**	**1992**	**2025**	**1992**	**2025**	**1992**	**2025**	**1992**	**2025**

Exhibit A-5: Refinery Modeling Results -- PADD 3
Gasoline Composition (Vol. %)

Gasoline Blendstock	2010 Calibration		2015 Reference		2015 10 ppm Sulfur		2015 RVP Standards 9.0 RVP		2015 RVP Standards 8.0 RVP	
	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Total (%)	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
C4s	1.8	8.4	1.3	8.0	1.3	8.0	0.9	8.0	0.7	7.6
Natural Gas Liquids	2.4	2.6	1.5	2.2	2.2	2.2	0.0	2.2	0.0	2.2
C5s & Isomerate	7.6	6.5	7.4	5.1	6.5	5.1	7.9	5.1	5.1	7.3
Raffinate	0.2	0.9	1.3	0.7	1.5	0.9	0.5	0.9	0.3	1.2
Naphthas (C5-250°)	7.5	7.4	5.8	7.7	6.2	7.7	6.9	7.7	7.5	7.1
Hydrocrackate	4.3	4.5	4.2	4.3	4.2	4.3	4.2	4.3	4.0	4.4
Alkylate	14.6	12.4	14.0	11.5	14.0	11.7	14.0	12.0	14.7	11.9
Poly Gas	0.2	0.2	0.7	0.2	0.7	0.2	0.7	0.2	0.7	0.2
FCC Naphtha	33.3	27.9	31.7	29.4	31.2	28.9	32.5	28.4	33.2	27.2
Reformate	22.5	22.9	22.2	20.8	22.2	21.0	22.4	21.1	23.8	20.8
Ethanol	5.7	6.4	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Volume (K b/d)	**3939**	**3901**	**4095**	**4087**	**4095**	**4087**	**4095**	**4087**	**4095**	**4087**

Exhibit A-5: Refinery Modeling Results -- PADD 4 Gasoline Composition (Vol. %)

			2015							
	2010						RVP Standards			
Gasoline	Calibration		Reference		10 ppm Sulfur		9.0 RVP		8.0 RVP	
Blendstock	Sum	Win	Sum	Win	Sum	Win	Sum	Win	Sum	Win
Total (%)	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**	**100**
C4s	3.3	9.8	2.9	9.1	2.9	9.1	2.1	9.2	1.0	9.1
Natural Gas Liquids	0.7	1.4	0.0	0.0	0.0	0.4	0.0	0.0	0.0	1.0
C5s & Isomerate	1.7	0.0	1.7	1.6	1.7	1.6	1.7	1.6	1.7	3.4
Raffinate	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Naphthas (C5-250°)	16.2	18.3	15.0	14.9	15.0	14.3	15.0	14.8	13.9	13.5
Hydrocrackate	1.6	1.9	1.3	1.0	1.5	1.0	1.5	1.0	1.5	1.0
Alkylate	12.9	10.5	12.2	10.7	12.2	10.9	12.3	11.0	12.5	11.0
Poly Gas	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7	1.7
FCC Naphtha	35.8	30.5	32.3	30.3	31.4	29.8	31.9	29.8	33.3	28.8
Reformate	22.9	22.0	22.9	20.8	23.5	21.1	23.9	20.9	24.5	20.5
Ethanol	3.1	3.8	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Volume (K b/d)	**287**	**287**	**295**	**302**	**295**	**302**	**295**	**302**	**295**	**302**

Exhibit A-6: Crude Oil Acquisition Costs and Natural Gas Prices

Gasoline Blendstock	2010 Calibration		2015 All Cases	
	Sum	Win	Sum	Win
PADD 1				
Crude Oil ($/b)	74.72	87.69	94.35	94.35
Natural Gas ($/mcf)	9.82	9.82	6.90	6.90
PADD 2				
Crude Oil ($/b)	78.70	96.59	89.71	89.71
Natural Gas ($/mcf)	7.51	7.51	5.94	5.94
PADD 3				
Crude Oil ($/b)	74.28	83.03	89.00	89.00
Natural Gas ($/mcf)	4.64	4.64	4.12	4.12
PADD 4				
Crude Oil ($/b)	74.46	88.61	86.62	86.62
Natural Gas ($/mcf)	6.36	6.36	5.12	5.12
U.S. Average				
Crude Oil ($/b)	76.16	87.07	90.00	90.00
Natural Gas ($/mcf)	6.37	6.37	5.10	5.10

Source: Derived from EIA data and projections.