ASSESSMENT OF A 1 Psi REDUCTION IN THE RVP OF CONVENTIONAL GASOLINE BLENDSTOCK (CBOB) IN THE SUMMER GASOLINE SEASON

Prepared for

THE RENEWABLE FUELS ASSOCIATION

By

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INTRODUCTION AND EXECUTIVE SUMMARY

The Renewable Fuels Association (RFA) retained MathPro Inc. to conduct a first-order analysis to estimate the additional costs that would be incurred by U.S. refiners if the RVP of conventional gasoline blendstock (CBOB) were reduced by 1 psi for the summer season – from about 9 psi to 8 psi. The proposed 1 psi reduction in RVP would apply to most CBOB produced for sale in the U.S.[1]

This report is the primary work product of this study.

Background

On July 2, 2021, the U.S. Court of Appeals for the D.C. Circuit overturned the rule (the "E15 rule") issued by EPA on June 10, 2019, extending to E15 gasoline the 1 psi ethanol RVP waiver for conventional gasoline in the summer ozone control season (June 1–September 15). Previously, the RVP waiver had applied only to E10 gasoline. The E15 rule allowed retailers in conventional gasoline (CG) markets to sell both finished E10 and E15 with RVP of 10 psi during the summer season. The E15 rule was designed to facilitate year-round supply of E15 gasoline, by allowing use of the same 9 RVP CBOB in blending either E10 or E15 finished CG in the summer. With the E15 rule overturned, retailers will again have to ensure that any E15 they sell in the summer season meets the prevailing 9 RVP standard for finished CG, while E10 continues to qualify for a 1 psi allowance via the ethanol RVP waiver. The Court's ruling leaves E15 economically uncompetitive with E10 in conventional gasoline markets in the summer season, thereby foreclosing an important pathway for increasing ethanol's share of the gasoline market.

In response, RFA is considering requesting that EPA, using its authority under the Clean Air Act, establish an RVP standard for CBOB of 8 psi. This would require refiners to reduce the current RVP of CBOBs by about 1 psi during the summer season -- from about 9 RVP to 8 RVP. When blended with an 8 RVP CBOB, E15 and E10 gasolines both would meet the 9 RVP standard for finished summer CG, making the use of the RVP waiver for E10 unnecessary. This would allow E15 to be produced using E10 CBOBs and restore the blending options for E15 prevailing before the Court's decision disallowing the use of the ethanol RVP waiver for E15, albeit with both finished E10 and E15 gasolines having lower RVPs.

Implementing the proposed reduction in the RVP of CBOB would increase the refining sector's cost of RVP control. Consideration of such costs would be a key element in any rule-making that EPA would undertake.

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[1] Conventional gasoline not qualifying for the ethanol RVP waiver (upstate New York), low-RVP gasoline, and RFG would not be affected.

Technical Approach

Our analysis covers U.S. regional refining operations in the *summer* gasoline season in each of four refining regions: PADD 1, PADD 2, PADD 3, and PADD 4.[2]

We conducted the analysis by means of regional refinery LP modeling, using MathPro's proprietary refinery modeling system, **ARMS**. We applied four models, each one representing aggregate refining operations in one of the PADDs. We developed the four regional refining models by updating corresponding regional refining models developed in a recent study for EPA.[3]

The target time period for the analysis here was the 2019 summer gasoline season.[4]

Starting from the EPA study and using primarily EIA data sources, we developed regional (i.e., PADD-level) representations of (1) regional refinery production of gasoline – CG, low-RVP CG, and federal RFG – and other refined products, (2) aggregate refinery process capacities, (3) regional aggregate crude oil slates, and (4) composite crude oil costs, all for 2019.

The refinery modeling for *each region* encompasses a Baseline (Reference) Case, and a 2019 Study Case, all for the summer gasoline season.

- The regional *Baseline* cases represent regional refining operations in the 2019 summer season producing, among other refined products, summer finished E10 CG with 10 RVP (i.e., meeting the 9 RVP standard adjusted for the 1 psi ethanol waiver), as well as meeting all other prevailing gasoline standards, including octane ratings, sulfur content (10 ppm average) and benzene content (0.62 vol% average).

- The regional *Study* cases likewise represent the same regional refining operations in the 2019 summer season, but producing summer finished E10 CG with 9 RVP. This requires CBOBs meeting an 8 psi RVP standard – a 1 psi reduction from the current RVP of CBOBs. Otherwise, the Study cases are identical to the Baseline cases.

For each region, the differences between the solutions returned by the refining models for the Baseline and Study Cases indicated the estimated refining costs of reducing the RVP of CBOBs by 1 psi, as well as the changes in refining operations accounting for those costs.

The analysis also included a set of regional *Sensitivity* Cases, to assess the sensitivity of the estimated refining costs to a significant change in average crude oil cost. Each Sensitivity Case

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[2] We did not consider PADD 5 in the analysis, because most (≈ 75%) of the gasoline in PADD 5 is reformulated gasoline produced in California, meets stringent RVP standards, and does not qualify for the ethanol RVP waiver.

[3] EPA Contract No. EP-C-16-020; Work Assignment Nos. 0-11 and 1-11; July 2018

[4] We used 2019 as the target year because the required data for that year was readily available; it is the most recent pre-pandemic year; and gasoline demand in 2019 is representative of demand in the next several years, as projected by EIA and others.

differed from the corresponding Study case only in the assumed composite crude oil costs (≈ $100/b in the Sensitivity cases vs. ≈ $60 in the Study cases).

Results of the Analysis

Study Cases

Table ES-1 summarizes the primary results of the Study Cases. It shows, for each of the four regions considered and for the U.S. (ex PADD 5), the estimated costs in the refining sector – capital investment, annual refining cost, and per-gallon refining cost – of producing summer CBOB meeting a new 8 psi RVP standard[5] – a 1 psi reduction from current CBOB RVP.

Table ES-1: Primary Results of the Study Cases

	Region				
	PADD 1	PADD 2	PADD 3	PADD 4	Total
Composite Crude Oil Cost ($/b)	66	57	62	54	61
Finished Gasoline Volume[1] (K b/d)	66	1,546	2,351	270	4,233
Capital Investment ($MM)	17	147	88	30	282
Summer Refining Cost ($MM)	18	258	374	44	694
Refining Operations	14	214	347	35	610
Capital Charge & Fixed Costs	5	44	27	9	84
Per-Gallon Refining Costs[2] (¢/gal)	3.6	2.2	2.1	2.1	2.1
Refining Operations	2.7	1.8	1.9	1.7	1.9
Capital Charge & Fixed Costs	0.9	0.4	0.1	0.4	0.3
Energy Density-Related Savings[2] (¢/gal)	0.8	0.7	0.7	0.5	0.7
Net Cost[3] (¢/gal)	2.9	1.5	1.4	1.6	1.5

1 Summer E10 CG qualifying for the ethanol RVP waiver.
2 Per gallon of Summer E10 CG qualifying for the RVP waiver.
3 Per-Gallon Refining Costs less Energy Density-Related Savings.

The estimated per-gallon costs of the additional RVP control are higher in PADD 1 than in PADDs 2, 3, and 4. The reason for this is discussed in the report.

As **Table ES-1** shows, the estimated U.S. total capital investment and annual refining cost of the 1 psi reduction in RVP are about **$280 million** and **$700 million/year**, respectively. The estimated average gross national per-gallon cost of achieving the 1 psi RVP reduction is about **2.1¢/gal** for the affected gasoline pool – summer E10 CG qualifying for the ethanol RVP waiver. (In practice, the aggregate investments and capital charges may be lower than indicated because some refineries may have already adequate throughput capacity to handle additional RVP control.)

Table ES-1 also shows the estimated energy density-related savings resulting from the proposed reduction in the RVP standard. For reasons explained in the report (Section 1), reducing gasoline

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[5] We assumed that refiners would produce CBOBs with RVP $\leq$ 7.7 psi at the refinery gate, 1 psi lower than current CBOB RVP of about 8.7 psi.

RVP (all else equal) would lead to a small increase in the energy density (BTU/gal) of the gasoline pool and a resulting slight increase in average fuel economy (miles/gal). The increase in average fuel economy would serve to decrease the *national (or social) cost* of gasoline consumption, partially offsetting the *refining cost* of an 8 RVP CBOB standard. The increase in fuel economy would be an economic benefit to consumers, not the refining sector.

Accordingly, the estimated *national* (net) per gallon cost of an 8 RVP standard is about **1.5¢/gal**.

Sensitivity Cases

Table ES-2 summarizes the primary results of the Study Cases and the Sensitivity Cases. These results indicate, for each of the four regions considered and for the U.S. (ex PADD 5), the relatively small degree to which a significant change in composite crude oil costs would affect the estimated costs in the refining sector – capital investment, annual refining cost, and per-gallon refining cost – of producing summer CBOB meeting an 8 psi RVP standard.

Table ES-2: Primary Results of the Study Cases and Sensitivity Cases

	Region				
	PADD 1	PADD 2	PADD 3	PADD 4	Total
Composite Crude Oil Cost ($/b)					
Study Case	66	57	62	54	61
Sensitivity Case	107	94	101	89	100
Finished Gasoline Volume[1] (K b/d)					
Study Case	66	1,546	2,351	270	4,233
Sensitivity Case	66	1,546	2,351	270	4,233
Capital Investment ($MM)					
Study Case	17	147	88	30	282
Sensitivity Case	32	165	121	33	351
Summer Refining Cost ($MM)					
Study Case	18	258	374	44	694
Refining Operations	14	214	347	35	610
Capital Charge & Fixed Costs	5	44	27	9	84
Sensitivity Case	21	309	443	47	820
Refining Operations	12	261	406	36	714
Capital Charge & Fixed Costs	9	50	39	11	109
Per-Gallon Refining Costs[2] (¢/gal)					
Study Case	3.6	2.2	2.1	2.1	2.1
Refining Operations	2.7	1.8	1.9	1.7	1.9
Capital Charge & Fixed Costs	0.9	0.4	0.1	0.4	0.3
Sensitivity Case	4.2	2.6	2.5	2.3	2.5
Refining Operations	2.4	2.2	2.2	1.7	2.2
Capital Charge & Fixed Costs	1.8	0.4	0.2	0.5	0.3
Energy Density-Related Savings[2] (¢/gal)					
Study Case	0.8	0.7	0.7	0.5	0.7
Sensitivity Case	0.3	1.0	1.0	0.9	1.0

1 Summer E10 CG qualifying for the ethanol RVP waiver.
2 Per gallon of Summer E10 CG qualifying for the RVP waiver.

Table ES-2 indicates that even a substantial change in crude oil prices would have only moderate effect on the capital and operating costs that the refining sector would incur in reducing the RVP of summer CBOB to meet an 8 RVP standard.

Contents of the Report

Section 1 of the report identifies the technical factors involved in controlling the RVP of refinery-produced gasoline. Section 2 summarizes the analytical approach and methodology for the analysis. Section 3 presents the key results of the analysis and discusses these results.

Appendix A provides additional detail on the analytical methodology used in this study.

Appendix B provides additional detail (in tabular format) on the input data and the results of the analysis.

1. TECHNICAL FACTORS INVOLVED IN RVP CONTROL

Refiners could 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). In most situations, the most economical route to reducing the RVP of all or part of a refinery's gasoline pool would be to reduce the concentration of butanes (C4 material) in the gasoline. The butanes are constituents of crude oil and natural gas liquids, and they are produced in certain refining process. They are the lightest and most volatile – highest RVP – constituents of gasoline. Though their volume in the gasoline pool is small, their high RVP has a disproportionate effect on the RVP of the gasoline pool. But they have high octane.

1.1 Removal of Volatile Components – Debutanization

The most economical and direct way to remove butanes from the gasoline pool is by means of a standard distillation process, called *debutanization.* All gasoline-producing refineries have debutanizers, processing various refinery streams (primarily light FCC naphtha and straight run naphtha, but also alkylate, isomerate, and light hydrocracked naphtha). Reducing CBOB RVP to meet an 8 psi standard (corresponding to about 7.7 psi before ethanol blending) should be feasible in many refineries through enhanced debutanization alone. If further RVP control were required, debutanization can be supplemented with depentanization (C5 removal) of certain refinery streams.

Because of the tight specification on the pentanes content of butane sold as LPG or petrochemical feedstock, the debutanization must be performed so as to leave some C4s in the C5+ material going to the gasoline pool. However, suitably upgrading refinery debutanization facilities and light ends recovery systems to sharpen the C4/C5 separation can reduce the butane content of the gasoline pool to $\leq$ 1 vol%, without degrading the quality of sales butane. This approach involves (1) modifying debutanizers to take more pentanes (C5s) overhead (i.e., commingled with the butanes) at the processing units where they are produced, thereby reducing the butane content of the debutanized streams, and (2) sending the debutanizer overhead streams (containing mostly C4s but with some C5s) to a refinery light ends plant designed to make a sharp C4/C5 separation. The essentially butane-free C5 material leaving the light ends unit can be blended to gasoline or segregated for other dispositions.

1.2 Replacement of Lost Octane and Volume

The butanes have high octane (92-94 AKI), higher than the average octane of the U.S. gasoline pool. Indeed, their octane is sufficiently high so that some refiners buy butanes in the winter season, when the RVP standard is much less stringent than in the summer, to blend into their winter gasoline pool as an economical source of incremental octane.

Consequently, when refiners remove butanes from the gasoline pool for RVP control, they must replace not only the lost volume but also the lost octane, in order to maintain constant volume and octane in their gasoline pool. Doing so involves some combination, unique to each refinery, of:

- Increasing reformer severity and throughput, for octane and volume replacement
- Small increases in utilization of alkylation capacity, for octane and volume replacement
- Small increases in capacity utilization for various processes
- Additional crude oil throughput, to provide additional feedstock for reforming and other operations

Reducing gasoline RVP may require further changes in refinery operations. For example, it may require rejecting some heavy gasoline components to the distillate fuel pool, to maintain compliance with other gasoline standards.

The gasoline blendstocks that would be added to the gasoline pool to replace the butane (and possibly) pentane removed for RVP control are all heavier and denser (in lb/gal) the butane and pentane they replace. This would lead to a small increase in the average fuel economy of the gasoline pool.

Refinery LP modeling, such as that conducted in this study, is the method of choice for capturing the various interactions between processing options and selecting the least cost route for achieving the desired objective – in this case, more stringent RVP control for summer CBOB.

1.3 Disposition of Butanes Removed from Summer Gasoline

The dispositions of C4s (and possibly C5s) removed from the summer gasoline pool are outside the realm of seasonal refinery modeling. But these dispositions influence the economics of RVP control, and we therefore addressed them in the analysis. The alternative dispositions of these streams 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 investment, if needed, to expand and/or revamp alkylation capacity;

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

- Selling the C4s into the LPG market; 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 the butanes and pentanes (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) or as an LPG component.

The marginal values of butane and pentane tend to be 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 this study, we simply assumed that the relatively small additional volumes of produced-butane would be sold at prices prevailing during the summer season of 2019.

2. REFINERY MODELING METHODOLOGY

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

We did not consider PADD 5 in the analysis, because (i) most (≈ 75%) of the gasoline volume produced and consumed in PADD 5 is produced in California, the RVP standard for California gasoline is already more stringent than 8 psi (and the ethanol RVP waiver does not apply).

We developed the four refining models used in this study from regional refining models calibrated to summer 2016 from a recent study conducted for EPA (referenced earlier). The regional models are distinct in terms of aggregate refining process capacity, composite crude oil slate, refinery inputs and outputs, refined product specifications, and other region-specific elements. The target time period for this analysis is the 2019 summer gasoline season.

2.1 Cases Analyzed with the Refining Models

2.1.1 Calibration/Baseline Cases (2019)

We updated regional refining models from the EPA study so that they reflected refining operations in summer 2019. Specifically, we:

- Incorporated the Tier 3 gasoline sulfur standard (average sulfur level in gasoline < 10 ppm);
- Modified refinery inputs and outputs to reflect data reported by EIA for summer 2019;
- Modified refining process capacity to reflect EIA's refinery-by-refinery process capacity reported as of January 2019;
- Updated crude oil acquisition costs, energy prices, and LPG prices as reported by EIA;
- Updated representations of composite crude oils to reflect reported API gravities and sulfur content, relative shares of domestic and imported crude oils, and properties of refinery imports of crude oil;
- Adjusted certain model coefficients so as to more closely represent butane balances in summer 2019;
- Adjusted capacities for minor process representations not reported by EIA, but that are required processes for refinery modeling (e.g., debutanization, naphtha splitting), as needed; and
- Maintained the environmental fuel standards represented in the 2016 models, such as MSAT 2 and ULSD standards.

Solutions returned by the regional refining models for these cases constitute the baseline values for the analysis.

2.1.2 Study Cases (2019)

The Study Cases differ from the corresponding Baseline Cases only in the RVP standard for CBOB.

Comparison of the results returned by each regional refining model for its Study Case with the results returned for the corresponding Baseline Case yielded estimates of the investment requirements and refining costs associated with the contemplated RVP standard.

2.1.3 Sensitivity Cases (2019)

Crude oil acquisition is by far the largest cost that refiners incur. For that reason, we chose it as the one input assumption to vary in a sensitivity analysis. The crude oil prices in the regional Study Cases are average regional refinery acquisition costs reported by the EIA for 2019.

The (significantly higher) crude oil acquisition costs in the Sensitivity Cases reflect an assumed U.S. average crude oil acquisition cost of $100/b. This is comparable to average refinery acquisition costs (in nominal terms) in 2010-2014 – that is, to crude oil prices that the U.S. has experienced at times in the last decade. We considered these prices as representative of crude oil acquisition costs that *could* be experienced again in, say, the next decade. Crude oil acquisition costs for each PADD, relative to the assumed national $100/b average, were estimated based on patterns of crude oil acquisition costs reported over the last decade

The *Sensitivity* Cases in the analysis serve to assess the sensitivity of the estimated refining costs to a significant change in average crude oil acquisition costs. The Sensitivity Cases differ from the corresponding Study Cases only in the average crude oil acquisition costs (and in the prices of propane and butanes, which were increased in step with the increased crude oil prices).

Table 2.1 shows the regional average crude oil acquisition costs in the Study Case and in the Sensitivity Case, for the 2019 summer season.

Table 2.1: Average Cost of the Composite Crude Oil in the Refining Models
2019 Summer Season, ($/b)

	Region				
	PADD 1	PADD 2	PADD 3	PADD 4	U.S
Study Case	66	57	62	54	61
Sensitivity Case	107	94	101	89	100

2.2 Key Elements of the Methodology

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

- The Baseline, Study, and Sensitivity Cases incorporate regional refinery crude slates comparable to those in 2019.

- The Study and Sensitivity Cases represent the U.S. refining sector maintaining regional gasoline production at the 2019 Baseline volumes.

  Table 2.2 shows the estimated regional distribution (in terms of volumes and volume shares) of the various gasoline types produced in U.S. refineries, by region. These values apply in the models for the Baseline, Study, and Sensitivity Cases. They were derived from various EIA and EPA data sources.

  The **Total** volumes and the corresponding volume shares (**Share)** in Table 2.2 do not include PADD 5 volumes or imports (which are mainly to PADD 1).

Table 2.2: Distribution of Gasoline Production by Gasoline Type and PADD, Summer 2019

Gasoline Type	Region				Total
	PADD 1	PADD 2	PADD 3	PADD 4	
Volume (K b/d)	**532**	**2,198**	**4,642**	**356**	**7,728**
RFG	332	278	830	0	1,440
Conventional, waiver	66	1,546	2,351	270	4,233
Low-RVP	112	340	713	83	1,248
Clear (no Eoh)	5	21	32	3	61
Export	17	13	716	0	746
Share (%)	**100%**	**100%**	**100%**	**100%**	**100%**
RFG	62%	13%	18%	0%	19%
Conventional, waiver	12%	70%	51%	76%	55%
Low-RVP	21%	15%	15%	23%	16%
Clear (no Eoh)	1%	1%	1%	1%	1%
Export	3%	1%	15%	0%	10%

Note: Low-RVP includes all non-waivered and low-RVP E10 gasoline.

- As noted in Section 1, additional RVP control through debutanization and depentanization leads to a loss of gasoline yield and octane. The models represent each regional refining sector replacing all the gasoline volume and octane lost in RVP control. The models represent the various options for volume and octane replacement discussed in Section 1. These include increasing crude runs, changing various refining operations (e.g., increasing reformer throughput and/or severity, increasing FCC unit conversion, and investing in additional refining process capacity.

  Butane and pentane volumes rejected by the refining sector for RVP control in the summer season are assumed to be sold at regional prices estimated for the summer, based on average prices for butane at Mont Belvieu.

Regional energy prices – crude oil acquisition cost, natural gas prices, and power prices – in 2019 are estimated from EIA data.

- Other gasoline property standards represented in the Study and Sensitivity Cases are the same as in the Baseline Case (noted above).

Appendix A provides additional detail on and discussion of several aspects of the modeling methodology.

3. RESULTS OF THE ANALYSIS

3.1 Summary of Primary Results

Tables 3.1 and 3.2 show the estimated capital investment, annual refining cost, per-gallon refining cost, and energy density-related savings for the regional Study Cases and the Sensitivity Cases, respectively.

Table 3.1 Summary of Primary Results of the *Study* Case, by Region

	Region				
	PADD 1	PADD 2	PADD 3	PADD 4	Total
Composite Crude Oil Cost ($/b)	66	57	62	54	61
Finished Gasoline Volume[1] (K b/d)	66	1,546	2,351	270	4,233
Capital Investment ($MM)	17	147	88	30	282
Debutanization & Depentanization	0	91	70	27	188
All Other	17	56	18	2	94
Summer Refining Cost ($MM)	18	258	374	44	694
Refining Operations	14	214	347	35	610
Capital Charge & Fixed Costs	5	44	27	9	84
Per-Gallon Refining Costs[2] (¢/gal)	3.6	2.2	2.1	2.1	2.1
Refining Operations	2.7	1.8	1.9	1.7	1.9
Capital Charge & Fixed Costs	0.9	0.4	0.1	0.4	0.3
Energy Density-Related Savings[2] (¢/gal)	0.8	0.7	0.7	0.5	0.7

1 Summer E10 CG qualifying for the ethanol RVP waiver.
2 Per gallon of Summer E10 CG qualifying for the RVP waiver.

Table 3.2 Summary of Primary Results of the *Sensitivity* Case, by Region

	Region				
	PADD 1	PADD 2	PADD 3	PADD 4	Total
Composite Crude Oil Cost ($/b)	107	94	101	89	100
Finished Gasoline Volume[1] (K b/d)	66	1,546	2,351	270	4,233
Capital Investment ($MM)	32	165	121	33	351
Debutanization & Depentanization	4	91	109	28	231
All Other	28	75	13	5	120
Summer Refining Cost ($MM)	21	309	443	47	820
Refining Operations	12	261	406	36	714
Capital Charge & Fixed Costs	9	50	39	11	109
Per-Gallon Refining Costs[2] (¢/gal)	4.2	2.6	2.5	2.3	2.5
Refining Operations	2.4	2.2	2.2	1.7	2.2
Capital Charge & Fixed Costs	1.8	0.4	0.2	0.5	0.3
Energy Density-Related Savings[2] (¢/gal)	0.3	1.0	1.0	0.9	1.0

1 Summer E10 CG qualifying for the ethanol RVP waiver.
2 Per gallon of Summer E10 CG qualifying for the RVP waiver.

In these tables,

- **Capital Investments** (*CapEx*) reflect expansion of existing process units (that is, no grassroots investments are indicated in the solutions returned by the regional models).

- **Refining Operations** costs include catalysts and chemicals, changes in refinery inputs, additional energy use, and additional consumption (if any) of purchased hydrogen.

- **Per-Gallon Refining Cost** is the Summer Refining Cost allocated over the volume of affected E10 CG in the summer.

- **Energy Density-Related Savings** is the value of the small increase in energy density (BTU/gal) of the gasoline pool and hence vehicle fuel economy resulting from an 8 RVP standard for summer CBOB (allocated to the affected E10 CG).

The indicated Capital Investment for expansion of debutanization and depentanization are to achieve the specified RVP control. The Capital Investment for all other processes reflect expansion of minor processes needed to support debutanization or to maintain certain gasoline standards, such as benzene standards. The regional refinery models did not add new process capacity for octane replacement.

The estimated investment and annual refining costs of the 1 psi RVP reduction in the Study Case ($61/b average crude oil price) are about **$300 million** and **$700 million/year**, respectively. The estimated average incremental cost of achieving the 1 psi RVP reduction standard is **2.1¢/gal** allocated across the affected summer E10 CG pool, with a high of **3.6¢/gal** in PADD 1 (where CBOB volume is low) and a low of **2.1¢/gal** in PADDs 3 and 4.[6]

The estimated investments and annual refining costs of meeting the 1 psi RVP reduction in the Sensitivity Case ($100/b average crude oil price) are about **$350 million** and **$800 million/year**, respectively. The estimated incremental cost of achieving the 1 psi RVP reduction is **2.5¢/gal** allocated across the affected summer E10 CG pool, with a high of **4.2¢/gal** in PADD 1 (where CBOB volume is low) and a low of **2.3¢/gal** in PADD 4.

The line-item **Energy Density-Related Savings** in Table 3.1 (**0.7¢/gal**) and Table 3.2 (**1.0¢/gal**) denotes the estimated value of the small improvement in the energy density of the gasoline pool of producing summer CBOB meeting an 8 RVP standard, allocated over the affected E10 CG pool.

Appendix B presents additional, more detailed results of the analysis, in tabular form.

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[6] PADD 1 refineries produce a higher share of low-RVP gasoline and RFG than the other PADDs. We estimate that conventional gasoline (CG) constitutes only ≈ 12% of gasoline production in PADD 1. According to our modeling results, this results in PADD 1 having much lower concentrations of C4s in the conventional gasoline pool than do other PADDs. This, in turn, increases the difficulty of RVP control in PADD 1 and requires depentanization to reduce the RVP of the relatively small share of E10 CG produced by PADD 1 refineries.

3.2 Discussion of Results

Comparison of the results of the Study Case ($61/b average crude oil price) and the Sensitivity Case ($100/b average crude oil price) indicates that the cost of the proposed 1 psi reduction in the RVP of summer CBOB is relatively insensitive to changes in the average crude oil price – even the substantial change embodied in the Sensitivity Case.

The Study and Sensitivity Cases call for similar changes in refining operations. The Sensitivity Case reflects the higher costs associated with the purchase of additional crude oil and slightly larger losses from the sales of butanes.

The expansion of process capacity in the solutions returned by the regional refinery models to meet the 1 psi reduction in CBOB RVP involves “minor” or “secondary” process units for which EIA does not report process capacities. The regional refinery models were set up so that “existing” capacity for such processes (1) reflected capacity from the 2016 Calibration cases from the recent study for EPA, and (2) incorporated minor capacity additions (if any) based on the calibration of those models to 2019. In the latter case, the refinery models are “tight” on those processes (just enough capacity). It may well be that refineries have sufficient capacity in these minor processes to increase RVP control without needing to expand capacity. If this were the case, Capital Investment could be significantly less than estimated here, and Per-Gallon Refining Cost would be closer to that in the sub-line-item labeled Refining Operations. In any case, the capital charges associated with our estimates of RVP control are low – about 0.3¢/gal.

The estimated **Energy Density-Related Savings** is a significant partial offset to the estimated refining cost of reducing the RVP of summer CBOB by 1 psi. These savings occur because removing C4 and C5 volumes from the gasoline pool to meet the more stringent RVP standard and replacing those volumes with heavier hydrocarbon blendstocks results in a small increase in the energy density of the gasoline pool, which in practice would bring about a corresponding small increase in average vehicle fuel economy. Consumers could purchase slightly less gasoline to drive the same number of miles. Hence, an increase in the gasoline pool’s average energy density would mean a decrease in total U.S. gasoline consumption (at constant vehicle miles traveled).

This decrease in gasoline consumption and consumer expenditures would accrue to consumers and would reduce the *national* cost (not the *refining* cost) of the 1 psi reduction in the RVP of summer CBOB. This cost savings would not accrue to refiners but would partially offset the refining cost of meeting the 8 RVP standard.

APPENDIX A: ADDITIONAL INFORMATION ON METHODOLOGY

A.1 RVP Representation

The regional models represent production of finished E10 gasolines, comprising base blends (CBOBs, Low-RVP BOBs, and RBOBs) produced at the refinery along with ethanol blended downstream of the refinery. The RVP limits for all gasolines (conventional and low-RVP) that qualify for the 1 psi ethanol RVP waiver are set at the RVP standard for those gasolines *ex the ethanol waiver*, adjusted for a 0.3 psi safety margin.[7] The RVP of ethanol blended in those gasolines is set equal to their RVP standard (ex the ethanol waiver). The RVP limits for all gasolines not qualifying for the ethanol waiver – mostly RFG, but also some low-RVP and conventional gasoline – are set at the RVP standard for those gasolines, but, importantly, the RVP of ethanol blended in those gasolines is set so that it reflects its uplift on RVP. For the latter gasolines this forces the corresponding BOBs to have RVPs about 1.2 to 1.3 psi lower than the RVP standard for the finished gasoline.

The result is that the CBOB for E10 CG qualifying for the ethanol waiver has an RVP of 8.7 psi, whereas the "implicitly produced" RBOB for E10 RFG has an RVP of about 5.6 psi.

In the regional models' representation of gasoline blending, blend RVP is computed using the RVP blending index (**VPBI**) method widely used in the refining industry.

The RVP blending index for each blend component is given by

$$\mathbf{VPBI_i = RVP_i^{1.2}},$$

where the subscript **i** denotes the **i**$^{\mathbf{th}}$ hydrocarbon blendstock. The computed RVP of the CBOB is then computed as

$$\mathbf{RVP_{BOB} = \Sigma i(VPBI_i)^{-1.2}}$$

for each BOB represented in the regional models.

A.2 Representation of Capital Costs for RVP Control

As discussed earlier, refiners would meet a more stringent RVP standard through refinery-specific combinations of:

- Adding new, "grassroots" process units
- Expanding or revamping existing process units

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[7] To reflect (1) a safety margin in blending (to allow for measurement tolerances and pipeline receipt specifications) and (2) ethanol's estimated effect on blend RVP (which is > 1 psi in summer E10 and increases slightly with decreasing base blend RVP).

- Changing operations in existing process units (e.g., increasing reformer throughput and severity, increasing crude oil throughput to support reforming and other processes, etc.)

The regional refining models represent one of the investment routes for each process represented in the models. We assumed that capital investment (*CapEx*)[8] per unit of capacity added by expansions and revamps is 50% of the capital investment per unit of capacity (ISBL+OSBL) for a grassroots unit.[9] All capacity additions in this study were based on these "expansion CapEx" factors.

Each process investment alternative is represented in terms of an estimated process-specific expansion capital cost (ISBL+OSBL) per b/d of throughput capacity added. These unit estimates represent the investments required for capacity increments corresponding to representative size units in U.S. refineries.

All capital costs are expressed in $2019.

The unit CapEx factors available in the literature apply to a U.S. Gulf Coast location (i.e., PADD 3). These Gulf Coast factors are multiplied by regional escalation factors shown in below. to reflect the higher costs of refinery construction in the other PADDs.

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

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

For estimating the per-gallon annual capital charges associated with the CapEx for refining capacity, we used the following assumptions:

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

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[8] *CapEx* denotes capital investment.

[9] *ISBL* and *OSBL* denote investments made Inside Battery Limits (i.e., for the process itself) and Outside Battery Limits (i.e., for off-site investments, such as utilities, tankage, etc.).

[10] 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.

An alternative set of assumptions regarding required rates of return – say 7% pre-tax – and a lower combined tax rate reflecting current federal corporate tax rates – say 26% – would reduce computed capital charges by about 30%.

APPENDIX B: DETAILED RESULTS OF THE REFINERY MODELING

Appendix B provides more detailed results from the refinery modeling for the Study and Sensitivity cases, in the form of six tables.

In the column headings of these tables, the words *Base* and *Study* denote the Reference and the 1 psi RVP Reduction cases, respectively. Further, in the body of these tables, the word Primary denotes the cases with 2019 crude oil acquisition costs.

Table B-1 shows selected refinery modeling results that highlight the most important changes in refining operations associated with reducing the RVP of CG BOBs: crude oil throughput increases; butane sales increase (with the exception of PADD 1, in which butane already is at low levels in E10 CG); debutanization, along with supporting process capacity, is added to remove butanes and maintain compliance with gasoline property standards; and reformer severity increases.

Table B-1: Selected Refinery Modeling Results for the Primary and Sensitivity Cases, by PADD

	PADD 1		PADD 2		PADD 3		PADD 4		Total	
Measure	**Base**	**Study**	**Base**	**Study**	**Base**	**Study**	**Base**	**Study**	**Base**	**Study**
Primary										
Crude Oil Use (K b/d)	939	941	3,903	3,936	8,989	9,036	654	660	14,486	14,572
Butane Sales (K b/d)	13	13	71	96	75	114	3	7	161	230
New Capacity (K b/cd)										
Debutanization*				31		31		6		68
Depentanization										
FCC Naphtha Desulfurization								2		2
Light Naphtha Splitting		13				4				18
Benzene Saturation		1		11		3				15
Reformer Operations										
Charge Rate (K b/d)	142	139	690	694	1,603	1,611	100	103	2,535	2,546
Severity (RON)	96.5	98.0	94.0	95.5	95.7	96.0	93.3	94.1	95.2	95.9
Sensitivity										
Crude Oil Use (K b/d)	940	941	3,901	3,933	8,989	9,035	654	660	14,484	14,570
Butane Sales (K b/d)	13	13	75	99	81	119	3	8	172	239
New Capacity (K b/cd)										
Debutanization*		1		31		48		6		86
Dependentanization		4								4
Naphtha Desulfurization								2		2
Light Naphtha Splitting		15				4				19
Benzene Saturation		3		13		2		1		19
Reformer Operations										
Charge Rate (K b/d)	146	142	711	704	1,620	1,614	101	105	2,577	2,565
Severity (RON)	96.8	97.1	93.4	95.1	95.7	96.0	93.9	94.2	95.0	95.7

Tables B-2a and B-2b show estimated use of existing process capacity, additions of new process capacity, refining operations and fuel use for the Primary and Sensitivity cases, respectively.

Table B-2a: Use of Existing Process Capacity, New Process Capacity, Refining Operations, and Fuel Use for the Primary Case, by PADD
(K b/d, except as noted)

Type of Process	Process	PADD 1		PADD 2		PADD 3		PADD 4		Total	
		Base	Study	Base	Study	Base	Study	Base	Study	Base	Study
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	939	941	3,903	3,936	8,989	9,036	654	660	14,486	14,572
Conversion	Fluid Cat Cracker	317	312	1,124	1,124	2,466	2,510	174	176	4,082	4,122
	Hydrocracking	36	36	342	342	1,076	1,076	26	26	1,480	1,480
	Heavy Oil Hydrocracking					110	110			110	110
	Coking	43	43	485	491	1,181	1,187	71	72	1,781	1,793
Upgrading	Alkylation*	70	70	239	239	553	553	41	41	902	902
	Catalytic Polymerization*	6	6	4	4	3		5	5	18	15
	Dimersol*			1	1	10	10			11	11
	Pen/Hex Isomerization	6	6	112	112	174	174	5	5	298	298
	Reforming	137	137	652	665	1,543	1,555	97	101	2,429	2,458
Hydrotreating	Naphtha Desulfurization	247	252	1,053	1,064	2,303	2,315	172	174	3,775	3,805
	FCC Naphtha Desulfurization	172	169	630	630	1,285	1,315	98	98	2,185	2,213
	Benzene Saturation	16	16	28	28			9	9	53	53
	Distillate Desulfurization	285	286	1,157	1,179	2,752	2,753	227	225	4,421	4,443
	FCC Feed Desulfurization (Conv)	22	22	574	556	1,184	1,204	89	89	1,870	1,871
Hydrogen (MM scf/d)	Hydrogen Production	65	63	626	626	741	741	125	132	1,557	1,562
	Hydrogen Recovery	44	44	223	223	592	592	82	82	941	941
Fractionation	Debutanization	79	79	282	282	557	572	38	38	956	971
	Lt. Naphtha Spl. (Benz. Prec.)	53	53	214	190	763	763	52	52	1,081	1,057
	Heavy FCC/Lt Cycle Oil Splitting										
Other	Aromatics Plant*	2	2	98	77	192	192			292	271
	Benzene Extraction*					12	12			12	12
	Butane Isomerization	12	12	11	11	71	71	2	2	96	96
	Lubes & Waxes*	13	13	8	8	139	139			160	160
	Solvent Deasphalting	13	13	17	17	196	196	5	5	231	231
	Sulfur Recovery* (K std tons/d)	1	1	6	6	10	10	1	1	17	17
	Steam Generation (K lb/hr)	3,038	3,060	11,434	11,581	33,693	33,825	1,897	1,937	50,062	50,403
NEW CAPACITY (K b/sd)											
Fractionation	Debutanization*				31		31		6		68
	Depentanization										
	Light Naphtha Splitting		13				4				18
Hydrotreating	FCC Naphtha Desulfurization								2		2
	Benzene Saturation		1		11		3				15
OPERATIONS & FUEL USE											
Fluid Cat Cracker	Charge Rate	353	348	1,194	1,193	2,532	2,574	195	198	4,274	4,312
	Conversion (Vol %)	67	67	69	69	71	71	67	67	70	70
	Olefin Max Cat. (%)	37	39	6	5	54	50	23	24	38	36
	European Yield Profile										
Reformer	Charge Rate	142	139	690	694	1,603	1,611	100	103	1159	1170
	Severity (RON)	96	98	94	95	96	96	93	94	95	96
Fuel Use	Natural Gas (K foeb/d)	24	24	85	84	199	199	19	20	327	325
	Still Gas (K foeb/d)	27	27	141	144	373	376	16	17	556	564
	Catalyst Coke (K b/d)	18	17	58	59	123	126	9	9	208	210

* In terms of product output.

Table B-2b: Use of Existing Process Capacity, New Process Capacity, Refining Operations, and Fuel Use for the Sensitivity Case, by PADD
(K b/d, except as noted)

Type of Process	Process	PADD 1		PADD 2		PADD 3		PADD 4		Total	
		Base	Study	Base	Study	Base	Study	Base	Study	Base	Study
USE OF IN-PLACE CAPACITY											
Crude Distillation	Atmospheric	940	941	3,901	3,933	8,989	9,035	654	660	14,484	14,570
Conversion	Fluid Cat Cracker	309	310	1,124	1,124	2,436	2,502	174	175	4,042	4,112
	Hydrocracking	36	36	342	342	1,076	1,076	26	26	1,480	1,480
	Heavy Oil Hydrocracking					110	110			110	110
	Coking	43	43	475	480	1,185	1,192	71	72	1,774	1,787
Upgrading	Alkylation*	70	70	239	239	553	553	41	41	902	902
	Catalytic Polymerization*	2	6		4			2	2	4	12
	Dimersol*			1	1	15	15			16	16
	Pen/Hex Isomerization	6	6	112	112	174	174	5	5	298	298
	Reforming	142	139	667	673	1,558	1,558	99	103	2,466	2,473
Hydrotreating	Naphtha Desulfurization	249	249	1,055	1,065	2,312	2,321	172	174	3,788	3,810
	FCC Naphtha Desulfurization	171	167	617	613	1,261	1,304	101	101	2,149	2,185
	Benzene Saturation	17	17	31	31			9	9	58	58
	Distillate Desulfurization	285	285	1,178	1,201	2,760	2,772	231	229	4,454	4,487
	FCC Feed Desulfurization (Conv)	22	22	633	633	1,230	1,214	89	89	1,974	1,958
	FCC Feed Desulfurization (Deep)										
Hydrogen (MM scf/d)	Hydrogen Production	84	84	626	626	741	741	135	138	1,586	1,589
	Hydrogen Recovery	44	44	223	223	592	592	82	82	941	941
Fractionation	Debutanization	79	79	283	283	572	572	38	38	971	972
	Lt. Naphtha Spl. (Benz. Prec.)	53	53	203	180	764	764	52	52	1,071	1,047
	Heavy FCC/Lt Cycle Oil Splitting							2		2	
Other	Aromatics Plant*	2	2	100	77	192	192			295	271
	Benzene Extraction*					12	12			12	12
	Butane Isomerization	12	12	11	11	71	71	2	2	96	96
	Lubes & Waxes*	13	13	8	8	139	139			160	160
	Solvent Deasphalting	13	13	17	17	196	196	5	5	231	231
	Sulfur Recovery* (K std tons/d)	1	1	6	6	10	10	1	1	17	17
	Steam Generation (K lb/hr)	3,017	3,099	11,826	12,088	33,864	33,833	1,889	1,915	50,597	50,935
NEW CAPACITY (K b/sd)											
Fractionation	Debutanization*		1		31		48		6		86
	Depentanization		4								4
	Light Naphtha Splitting		15				4				19
Hydrotreating	Naphtha Desulfurization								2		2
	Benzene Saturation		3		13		2		1		19
OPERATIONS & FUEL USE											
Fluid Cat Cracker	Charge Rate	342	343	1,114	1,115	2,496	2,575	196	198	4,148	4,230
	Conversion (Vol %)	67	67	73	73	71	71	66	66	71	71
	Olefin Max Cat. (%)	23	38	2	6	51	46	6	6	33	33
	European Yield Profile			31	31	20	20			51	51
Reformer	Charge Rate	146	142	711	704	1,620	1,614	101	105	1182	1184
	Severity (RON)	97	97	93	95	96	96	94	94	95	96
Fuel Use	Natural Gas (K foeb/d)	24	24	90	88	202	199	20	20	335	332
	Still Gas (K foeb/d)	27	27	139	143	373	377	16	16	555	563
	Catalyst Coke (K b/d)	17	17	55	55	121	125	9	9	202	206

* In terms of product output.

Tables B-3a and B-3b show estimated refining sector input and output volumes for the Primary and Sensitivity cases, respectively.

Table B-3a: Refinery Inputs and Outputs for the Primary Case, by PADD (K b/d, except as noted)

Inputs/ Outputs	PADD 1		PADD 2		PADD 3		PADD 4		Total	
	Base	Study	Base	Study	Base	Study	Base	Study	Base	Study
INPUTS										
Crude Oil	**939**	**941**	**3,903**	**3,936**	**8,989**	**9,036**	**654**	**660**	**14,486**	**14,572**
Renewable Fuel Inputs	**57**	**57**	**225**	**225**	**393**	**393**	**38**	**38**	**713**	**713**
Ethanol	56	56	219	219	392	392	36	36	703	703
Biodiesel/Renewable Diesel	1	1	6	6	2	2	2	2	9	9
Other Inputs	**70**	**71**	**81**	**79**	**704**	**701**	**22**	**21**	**877**	**871**
Isobutane	11	12	49	47	142	139	7	6	209	203
Butane										
Butylene	1	1			9	9			10	10
Natural Gasoline	2	2	25	25	96	96	5	5	128	128
Straight Run Naphtha	21	21	4	4					25	25
Kerosene			3	3	4	4			7	7
Heavy Gas Oil	29	29			341	341	10	10	380	380
Resid	6	6			112	112			118	118
Purchased Energy & H2										
Electricity (MM Kwh/d)	6	6	29	29	70	71	4	4	109	110
Natural Gas (K foeb/d)	26	26	109	107	228	227	24	25	387	385
Hydrogen (K foeb/d)			33	34	121	120			153	154
OUTPUTS										
Refined Products	**1,049**	**1,049**	**4,095**	**4,122**	**9,906**	**9,946**	**693**	**698**	**15,742**	**15,815**
Aromatics	1	1	60	60	179	179			240	240
Ethane/Ethylene					5	5			5	5
Propane	14	14	59	61	157	158	9	9	239	243
Propylene	14	14	41	41	225	225			280	280
Butanes/Butylenes	13	13	71	96	75	114	3	7	161	230
Pentanes										
Y-Grade					171	171			171	171
Condensate										
Aviation Gas			1	1	10	10			11	11
Special Naphthas	1	1			30	30			31	31
Gasoline:	532	532	2,198	2,198	4,642	4,642	356	356	7,728	7,728
E10 RFG -- Premium	48	48	30	30	121	121			199	199
Regular	284	284	248	248	709	709			1,241	1,241
E10 Conventional -- Premium	6	6	127	127	295	295	46	46	474	474
Reg	60	60	1,419	1,419	2,056	2,056	224	224	3,759	3,759
E10 Low-RVP^2 -- Premium	10	10	27	27	69	69	15	15	121	121
Regular	102	102	313	313	644	644	68	68	1,127	1,127
Clear Finished	5	5	21	21	32	32	3	3	61	61
Exported	17	17	13	13	716	716			746	746
E85	7	7	4	4	3	3	1	1	15	15
Jet Fuel	110	110	288	288	952	952	41	41	1,391	1,391
Diesel Fuel	278	278	1,136	1,136	2,957	2,957	220	220	4,591	4,591
Ultra Low Sulfur Diesel	271	271	1,136	1,136	2,672	2,672	219	219	4,298	4,298
CARB Diesel										
EPA Diesel	3	3			103	103	1	1	107	107
Off road diesel/HH Oil	4	4			182	182			186	186
Unf. Oil to PetroChem			34	34	97	97	8	8	139	139
Residual Oil	36	36	52	52	183	183	14	14	285	285
Low Sulfur	5	5	2	2	42	42	6	6	55	55
Medium Sulfur & Marpol	17	17	5	5	19	19	1	1	42	42
High Sulfur	14	14	45	45	122	122	7	7	188	188
Asphalt	37	37	147	147	84	84	42	42	310	310
Lubes & Waxes	13	13	8	8	139	139			160	160
Other										
Coke	12	12	165	167	336	338	22	22	535	539
Sulfur (Std tons/d)	1	1	6	6	10	10	1	1	17	17

Table B-3b: Refinery Inputs and Outputs for the Sensitivity Case, by PADD (K b/d, except as noted)

Inputs/	PADD 1		PADD 2		PADD 3		PADD 4		Total	
Outputs	Base	Study	Base	Study	Base	Study	Base	Study	Base	Study
INPUTS										
Crude Oil	**940**	**941**	**3,901**	**3,933**	**8,989**	**9,035**	**654**	**660**	**14,484**	**14,570**
Renewable Fuel Inputs	**57**	**57**	**225**	**225**	**393**	**393**	**38**	**38**	**713**	**713**
Ethanol	56	56	219	219	392	392	36	36	703	703
Biodiesel/Renewable Diesel	1	1	6	6	2	2	2	2	9	9
Other Inputs	**69**	**70**	**81**	**79**	**699**	**697**	**21**	**20**	**869**	**866**
Isobutane	10	11	49	47	137	135	6	5	201	198
Butane										
Butylene	1	1			9	9			10	10
Natural Gasoline	2	2	25	25	96	96	5	5	128	128
Straight Run Naphtha	21	21	4	4					25	25
Kerosene			3	3	4	4			7	7
Heavy Gas Oil	29	29			341	341	10	10	380	380
Resid	6	6			112	112			118	118
Purchased Energy & H2										
Electricity (MM Kwh/d)	6	6	29	29	71	71	4	4	109	110
Natural Gas (K foeb/d)	27	28	114	112	230	228	25	25	396	393
Hydrogen (K foeb/d)			37	39	128	126			165	165
OUTPUTS										
Refined Products	**1,049**	**1,051**	**4,098**	**4,125**	**9,911**	**9,950**	**693**	**698**	**15,751**	**15,825**
Aromatics	1	1	60	60	179	179			240	240
Ethane/Ethylene					5	5			5	5
Propane	14	14	59	61	156	157	9	9	238	242
Propylene	14	14	41	41	225	225			280	280
Butanes/Butylenes	13	13	75	99	81	119	3	8	172	239
Pentanes		2								2
Y-Grade					171	171			171	171
Condensate										
Aviation Gas			1	1	10	10			11	11
Special Naphthas	1	1			30	30			31	31
Gasoline:	532	532	2,198	2,198	4,642	4,642	356	356	7,728	7,728
E10 RFG -- Premium	48	48	30	30	121	121			199	199
Regular	284	284	248	248	709	709			1,241	1,241
E10 Conventional -- Premium	6	6	127	127	295	295	46	46	474	474
Reg	60	60	1,419	1,419	2,056	2,056	224	224	3,759	3,759
E10 Low-RVP[2] -- Premium	10	10	27	27	69	69	15	15	121	121
Regular	102	102	313	313	644	644	68	68	1,127	1,127
Clear Finished	5	5	21	21	32	32	3	3	61	61
Exported	17	17	13	13	716	716			746	746
E85	7	7	4	4	3	3	1	1	15	15
Jet Fuel	110	110	288	288	952	952	41	41	1,391	1,391
Diesel Fuel	278	278	1,136	1,136	2,957	2,957	220	220	4,591	4,591
Ultra Low Sulfur Diesel	271	271	1,136	1,136	2,672	2,672	219	219	4,298	4,298
CARB Diesel										
EPA Diesel	3	3			103	103	1	1	107	107
Off road diesel/HH Oil	4	4			182	182			186	186
Unf. Oil to PetroChem			34	34	97	97	8	8	139	139
Residual Oil	36	36	52	52	183	183	14	14	285	285
Low Sulfur	5	5	2	2	42	42	6	6	55	55
Medium Sulfur & Marpol	17	17	5	5	19	19	1	1	42	42
High Sulfur	14	14	45	45	122	122	7	7	188	188
Asphalt	37	37	147	147	84	84	42	42	310	310
Lubes & Waxes	13	13	8	8	139	139			160	160
Other										
Coke	12	12	163	165	336	338	22	22	533	537
Sulfur (Std tons/d)	1	1	6	6	10	10	1	1	17	17

Table B-4 shows the estimated volume-weighted composition (by blendstock) of the finished E10 conventional gasoline pool for the Primary and Sensitivity cases. The compositions of the RFG, low-RVP, and export gasoline pools in the Study cases were *not* constrained to remain the same as in the Base cases. Thus, the composition of those finished gasoline pools, as returned by the refinery model, changed somewhat in response to required reductions in the RVP of CBOB.

Table B-4: Composition of Finished E10 CG for the Primary and Sensitivity Cases, by PADD

Gasoline Blendstock	PADD 1		PADD 2		PADD 3		PADD 4		Total	
	Base	Study	Base	Study	Base	Study	Base	Study	Base	Study
Primary (K b/d)	**66**	**66**	**1,546**	**1,546**	**2,351**	**2,351**	**270**	**270**	**4,233**	**4,233**
C4s	0.8%	0.5%	2.3%	1.0%	2.8%	1.1%	3.7%	2.5%	2.6%	1.2%
Natural Gas Liquids		0.3%	1.5%	1.5%	4.1%	3.6%	0.1%	1.8%	2.8%	2.7%
C5s & Isomerate	0.5%		7.1%	6.6%	3.9%	5.6%		1.6%	4.8%	5.6%
Raffinate	3.5%	1.0%	5.3%	1.4%	0.7%	5.8%			2.3%	3.8%
Naphthas (C5-250°)	21.5%	25.8%	9.3%	14.9%	8.8%	10.6%	15.3%	18.9%	9.6%	12.9%
Hydrocrackate	6.5%	1.1%	6.3%	6.3%	11.5%	11.6%	2.1%	2.3%	8.9%	8.9%
Alkylate	0.4%	1.1%	12.3%	11.9%	7.9%	10.5%	8.5%	13.7%	9.4%	11.1%
Poly Gas	4.1%		0.1%		0.1%			1.0%	0.2%	0.1%
FCC Naphtha	7.5%	23.9%	35.4%	29.7%	36.8%	19.5%	35.2%	29.1%	35.8%	23.9%
Reformate & Aromatics	45.2%	36.4%	10.3%	16.6%	13.5%	21.8%	25.2%	19.1%	13.6%	20.0%
Ethanol	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Sensitivity (K b/d)	**66**	**66**	**1,546**	**1,546**	**2,351**	**2,351**	**270**	**270**	**4,233**	**4,233**
C4s	0.5%	0.5%	2.3%	1.0%	2.4%	1.0%	3.6%	2.0%	2.4%	1.1%
Natural Gas Liquids			1.5%	1.5%	4.1%	4.1%	1.8%	1.8%	2.9%	2.9%
C5s & Isomerate	1.3%	0.5%	6.5%	4.4%	5.5%	6.8%	0.9%	1.5%	5.5%	5.5%
Raffinate	3.9%	0.4%	6.4%	4.3%	5.6%	0.4%			5.5%	1.8%
Naphthas (C5-250°)	18.2%	16.4%	9.4%	12.8%	8.4%	11.1%	17.9%	14.3%	9.5%	12.0%
Hydrocrackate	7.5%	11.6%	6.6%	6.9%	3.9%	0.1%	2.3%	2.5%	4.9%	2.9%
Alkylate	0.4%	0.7%	7.8%	4.5%	2.5%	7.0%	9.5%	12.6%	4.8%	6.4%
Poly Gas		0.7%	0.0%				0.3%	0.5%	0.0%	0.0%
FCC Naphtha	16.9%	29.1%	30.9%	26.9%	35.2%	46.0%	34.6%	34.4%	33.3%	38.0%
Reformate & Aromatics	41.3%	30.0%	18.6%	27.6%	22.5%	13.6%	19.1%	20.6%	21.2%	19.4%
Ethanol	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%

Note: The composition of the non-conventional gasoline pool was *not* fixed at the base case composition in the RVP cases.
However, all octane and RVP constraints for the non-conventional gasoline pool had to be satisfied.

Table B-5 shows the estimated properties of the finished E10 conventional gasoline pool for the Primary and Sensitivity cases.

The RVP of the finished CG pool declines by about 0.9 psi, consistent with a 1 psi reduction in the RVP of CBOB (from 8.7 psi to 7.7 psi) and an RVP uplift from ethanol blending of about 1.2 psi.

Other properties of the finished CG pool (octane and benzene and sulfur content) were constrained to meet the same standards as in the Base cases. Likewise, certain properties (octane, RVP, and benzene and sulfur content) of the finished reformulated, low-RVP, and export gasoline pools were constrained to meet the same standards in the Study cases as in the Base cases.

Table B-5: Properties of Finished E10 CG for the Primary and Sensitivity Cases, by PADD

	PADD 1		PADD 2		PADD 3		PADD 4		Total	
Properties	Base	Study	Base	Study	Base	Study	Base	Study	Base	Study
Primary (K b/d)	**66**	**66**	**1,546**	**1,546**	**2,351**	**2,351**	**270**	**270**	**4,233**	**4,233**
RVP (psi)	9.8	8.9	9.8	8.9	9.8	8.9	9.8	8.9	9.8	8.9
Fuel Ethanol (vol%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Aromatics (vol%)	23.9	26.9	14.5	16.6	17.5	17.5	20.4	17.3	16.7	17.3
Benzene (vol%)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Olefins (vol%)	5.9	5.6	7.8	6.6	8.5	4.3	7.5	7.1	8.1	5.4
Sulfur (ppm)	9	9	9	9	9	9	9	9	9	9
E200 (vol% off)	58.1	55.5	55.3	55.0	56.7	56.5	53.3	53.1	56.0	55.7
E300 (vol% off)	94.7	85.5	84.3	84.4	85.1	81.9	82.6	82.4	84.8	82.9
Energy Density[1]	4.677	4.728	4.637	4.653	4.654	4.670	4.697	4.683	4.651	4.665
Octane										
(R+M)/2	88.0	88.0	87.9	87.9	88.1	88.1	87.6	87.6	88.0	88.0
MON	83.7	83.2	83.5	83.6	83.5	83.7	82.9	83.2	83.4	83.6
RON	92.3	92.7	92.3	92.2	92.7	92.4	92.4	92.1	92.5	92.3
Sensitivity	9.3	9.3	8.9	9.0	9.4	8.8	8.9	9.0	9.2	8.9
Sensitivity (K b/d)	**66**	**66**	**1,546**	**1,546**	**2,351**	**2,351**	**270**	**270**	**4,233**	**4,233**
RVP (psi)	9.8	8.9	9.8	8.9	9.8	8.9	9.8	8.9	9.8	8.9
Fuel Ethanol (vol%)	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Aromatics (vol%)	24.1	25.4	18.7	22.2	21.9	19.8	17.5	17.7	20.5	20.6
Benzene (vol%)	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5	0.5
Olefins (vol%)	4.5	7.5	7.1	6.1	8.0	10.0	7.7	7.7	7.6	8.4
Sulfur (ppm)	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.0
E200 (vol% off)	58.3	55.1	55.7	52.9	53.9	53.6	52.9	53.6	54.6	53.4
E300 (vol% off)	94.4	80.5	82.7	81.6	81.0	81.5	84.1	84.6	82.1	81.7
Energy Density[1]	4.679	4.707	4.673	4.712	4.719	4.704	4.677	4.679	4.699	4.705
Octane										
(R+M)/2	88.0	88.0	87.9	87.9	88.1	88.1	87.6	87.6	88.0	88.0
MON	83.6	83.0	83.3	83.1	83.0	83.0	83.1	83.1	83.1	83.1
RON	92.4	92.9	92.5	92.7	93.1	93.1	92.2	92.1	92.8	92.9
Sensitivity	9.3	9.3	9.0	9.1	9.1	9.2	8.9	9.0	9.1	9.1
Energy Density of Entire Gasoline Pool[1]										
Primary Cases	4.729	4.731	4.683	4.696	4.724	4.733	4.685	4.697	4.711	4.720
Sensitivity Cases	4.729	4.730	4.686	4.698	4.723	4.731	4.685	4.698	4.711	4.720

[1] Lower heating value (MM btu/b).

Table B-6 shows the estimated crude oil acquisition costs and the prices for butane, natural gas, and power estimated for the summer of 2019 and used in the refinery modeling. Crude oil acquisition costs, natural gas prices (the lower of industrial or city gate prices), and power prices (retail prices to industrial users) were derived from data reported by EIA. Butane prices were estimated from monthly average spot prices at Mt. Belvieu from Bloomberg, as reported by EIA, with some PADD-level adjustments.

Composite prices for crude oil in the Sensitivity cases were based on an assumed U.S. average cost of composite crude oil of $100/b, with PADD-level adjustments based on relative PADD-level crude oil costs over the past decade. Butane prices in the Sensitivity cases were adjusted upwards based on the relationship of butane prices to crude oil costs over the past decade. Natural gas and power prices in the Sensitivity cases were assumed to remain at those estimated for the summer of 2019.

Table B-6: Composite Cost of Crude Oil and Prices for Butane, Natural Gas, and Power Used in Refinery Modeling for the Primary and Sensitivity Cases, by PADD

	PADD 1		PADD 2		PADD 3		PADD 4		U.S.
	Base	Study	Base	Study	Base	Study	Base	Study	Average
Primary									
Crude Oil ($/b)	65.8	65.8	56.7	56.7	62.0	62.0	54.4	54.4	61.0
Butane ($/b)	27.6	27.6	23.0	23.0	23.6	23.6	23.0	23.0	-
Natural Gas ($/foeb)	42.4	42.4	21.8	21.8	18.0	18.0	18.1	18.1	21.0
Power (¢/kwh)	7.9	7.9	6.6	6.6	5.4	5.4	6.2	6.2	6.0
Sensitivity									
Crude Oil ($/b)	106.6	106.6	93.9	93.9	101.4	101.4	88.7	88.7	100.0
Butane ($/b)	63.2	63.2	56.2	56.2	59.2	59.2	56.2	56.2	-
Natural Gas ($/foeb)	42.4	42.4	21.8	21.8	18.0	18.0	18.1	18.1	21.0
Power (¢/kwh)	7.9	7.9	6.6	6.6	5.4	5.4	6.2	6.2	6.0