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Key Factors Influencing Future U.S. Refining Profitability

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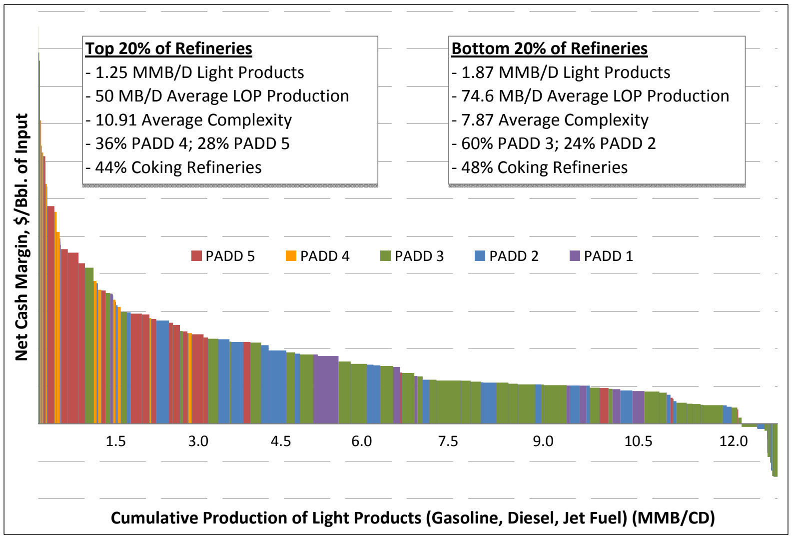
The global refining industry has experienced an abrupt transition from a “golden age”[1] to an uncertain and challenging future, leading to the announced shutdown of at least 1.4 million barrels per day (MMB/D) of Atlantic Basin refining capacity since January of 2009. Questions of portfolio performance, relative competitive positioning, and survivability are receiving considerable attention across the refining industry. This paper highlights some of the factors that are likely to influence relative refinery financial performance in the near term.

Each refinery possesses a set of unique characteristics that provides certain advantages and disadvantages versus other refineries. These characteristics (including location, process configuration, and scale, to name a few) ultimately translate into a wide range of cash margin[2] performance as illustrated in Figure 1.

Figure 1 – U.S. Refinery Net Cash Margins, Q3 2009[3]



[1] The “golden age” of refining is generally considered to include the years 2005 through 2008, a period during which global refining margins sustained record or near-record levels.

[2] Cash Margin (analogous with earnings before interest, taxes, and depreciation [EBITDA] margin) represents revenue minus plant cash costs, on a United States dollar per barrel (US$/Bbl.) of refinery input basis.

[3] Third quarter 2009 cash margins for United States (U.S.) fuels refinery as reported by Baker & O’Brien, Inc. (Baker & O'Brien) to subscribers of the *PRISM*™ refining industry data service.

A refinery's profitability is a function of its unique characteristics and a number of external factors. While it is tempting to rely on simple metrics, such as refinery complexity or size to make judgments regarding the future viability or the relative competitive positioning of refineries, these simple metrics fail to capture the interrelationship of other key factors that influence refinery competitiveness.

In this paper, we examine three important factors that are expected to influence the "relative" competitive positioning of individual U.S. refineries versus their U.S. peers as well as offshore refining centers:

1. The price differential between light and heavy crude oil grades will influence the attractiveness of full conversion coking refineries relative to their historically less profitable and less complex competitors;
2. The implementation of carbon regulation in the U.S. may make U.S. refineries less competitive compared to offshore refineries; and
3. The Atlantic Basin gasoline/distillate price differential, coupled with different refinery yield patterns, both in the U.S. and Europe, may contribute to determining the ultimate "winners" and "losers."

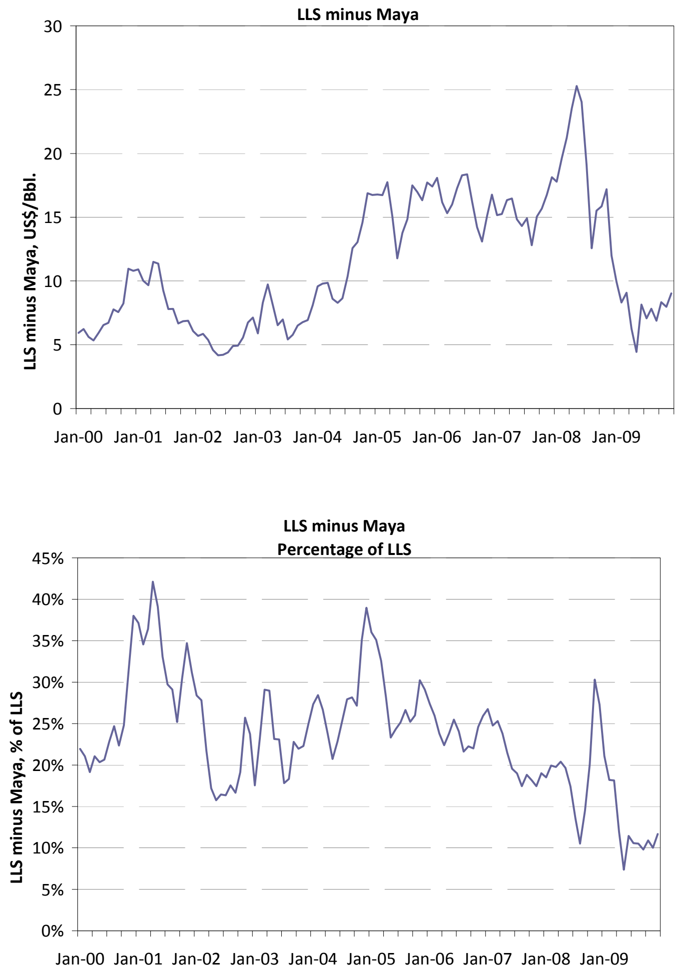
Light/Heavy Crude Oil Price Differential

One of the more distinguishing characteristics of a particular refinery is the degree to which the refinery can transform low quality crude oil (i.e., heavy, high sulfur) into higher valued products such as gasoline, distillates, and petrochemicals. Historically, refiners that convert heavy sour crude oil into light oil products (LOP)[4] have generally realized higher operating cash margins compared with those that can process only light sweet crude oil. This is because the gross margin advantage (resulting from lower input costs) has historically outweighed the higher operating costs. The resulting cash margin advantage for refiners that process heavy sour crude oil is highly correlated with the light/heavy crude oil price differential, which for the U.S. Gulf Coast (USGC) can be represented by the difference between the spot price of Light Louisiana Sweet (LLS) at St. James and the Mexican Maya formula price (free on board Mexico), see Figure 2.

[4] LOP are defined to include gasoline, kerosene, jet fuel, and diesel.

The LLS-Maya benchmark reached and sustained record high levels (US$/Bbl. basis) during the "golden age" of refining as a result of a number of factors, including:

Figure 2 – LLS-Maya Trends



- An increase in the amount of residuum on the market due to high "simple" refining margins, which caused refineries without bottoms conversion to maximize throughput;
- Insufficient refining conversion capacity (mostly in the form of delayed coking) to process excess residuum on the market; and
- The high absolute price of crude oil and the subsequent displacement of residual fuel oil with natural gas in the electricity generation sector.

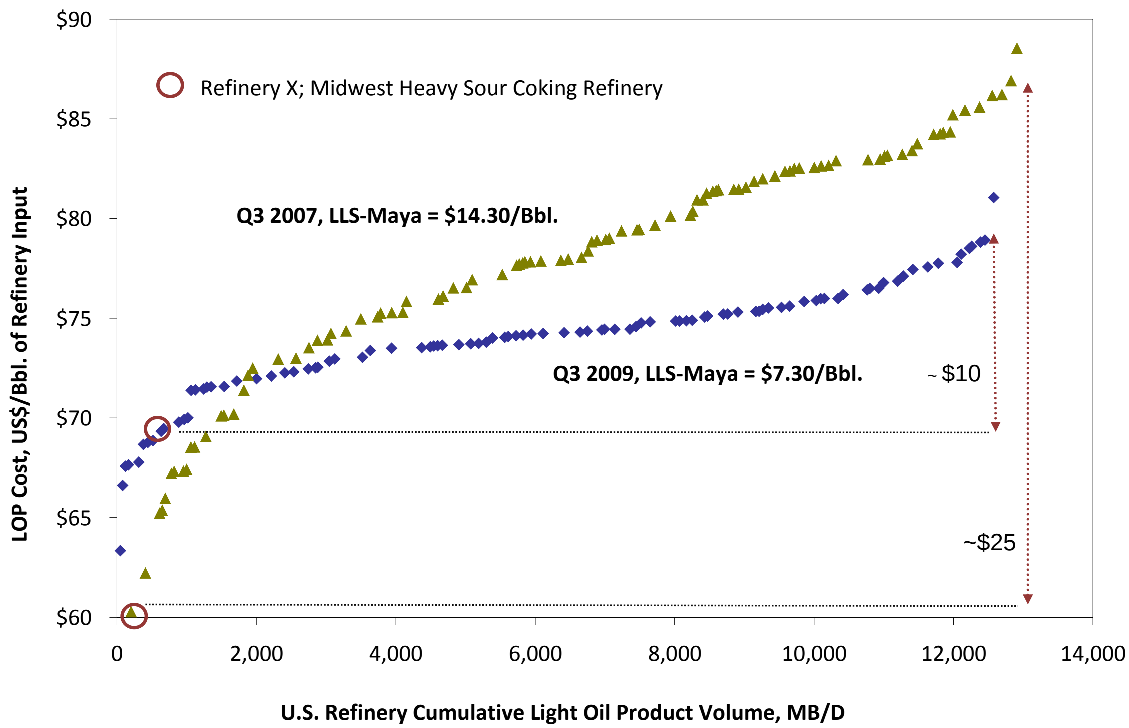
However, the collapse of the light/heavy crude oil price spread toward the latter part of 2008 has led some to question the value advantage of refineries that process heavy sour crude oil.

The significance of the light/heavy crude oil price differential on relative refinery profitability can be inferred from Figure 3 which provides a generalized LOP cost curve[5]

[5] A focus on LOP cost provides insight into the cost of producing or delivering the most desired and largest volume refined products. A refinery's LOP cost is calculated by adding total refinery cash operating cost, crude oil, and feedstock cost, and subtracting revenue received for by-products (fuel oil, liquefied petroleum gas, aromatics, etc.), all on a US$/Bbl. of LOP basis.

for select U.S. refiners for the third quarter of both 2007 and 2009,[6] periods during which LLS crude prices averaged between US$70.00 and US$80.00/Bbl. In the third quarter of 2009, a relatively narrow LLS-Maya crude oil price differential (US$7.30/Bbl.) contributed to the development of a relatively flat LOP cost curve compared to the third quarter of 2007 when the LLS-Maya crude oil price differential was relatively wide (US$14.30/Bbl.)

Figure 3 – Generalized U.S. Refinery LOP Cost Curve



SOURCE: *PRISM*

Under the premise that light refined product prices are influenced by the LOP cost of refineries operating at the far right portion of the cost curve, one would expect that a steeper cost curve would result in higher industry margins, as was indeed observed in 2007. Additionally, with respect to an individual refinery, one might expect the cash margin of a "Refinery X" (as shown on Figure 3) to be materially higher in 2007 as compared to 2009, because its LOP cost advantage versus refineries operating at the high end of the cost curve is approximately US$15/Bbl. greater in 2007 versus 2009.

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[6] A generalized cost curve is presented in order to conceptually illustrate the significance of the light/heavy crude oil differential. In practice, the development of a cost curve for a particular U.S. market is more complex and requires the consideration of other factors such as transportation costs, product quality, and foreign source supply.

An assessment of future U.S. refinery profitability would be incomplete without an assessment of the future light/heavy crude oil price differential and the primary factors that influence this differential. Insights into these factors can be gained by examining the near-term supply/demand balance for coker feedstock. Table 1 presents an overview of the coker feedstock balance for the U.S., indicating the major sources of supply and demand.

Table 1 - 2009 Supply/Demand for U.S. Coker Feedstock in 2009

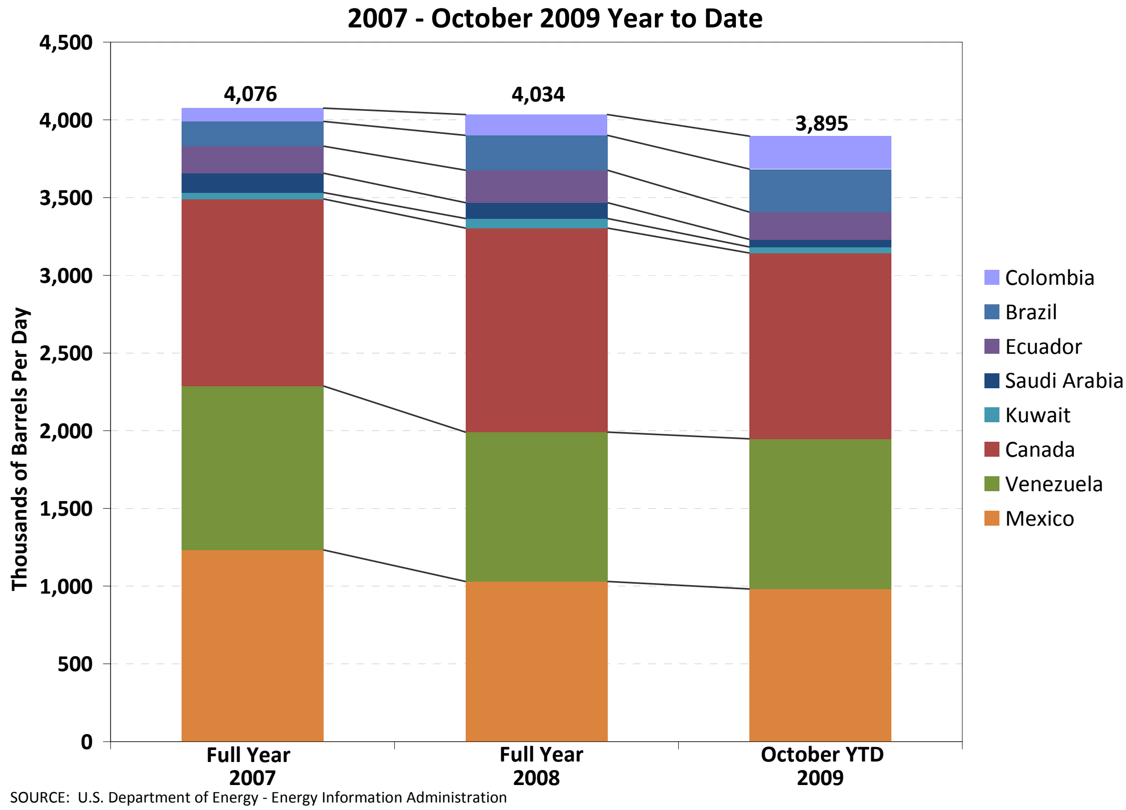
	Estimated 2009	
U.S. Vacuum Residuum Supply	**MB/D**	**2009 versus 2008**
Residuum from U.S. Crude Oil Production	860	Essentially Flat
Residuum from Western Hemisphere Heavy Crude Oil Imports	980	Declined
Residuum from Other Crude Oil Imports	680	Declined
Residuum Imports	170	Declined Slightly
Total	**2,690**	
U.S. Vacuum Residuum Demand		
Vacuum Resid Upgraded in Cokers	1,940	Declined
Asphalt, Inventory Changes, Other	400	Essentially Flat
Bunker Fuel	250	Declined Slightly
Residual Fuel Oil	100	Declined Slightly
Total	**2,690**	

Source: Baker & O'Brien Analysis

Some of the major factors influencing coker feedstock supply and demand and the role they might play in the future are summarized below:

- **Western Hemisphere Heavy Oil Production** – Heavy crude oil in the Western Hemisphere is relatively plentiful compared to other producing basins in the world, especially considering the large resource base still to be fully exploited in Canada (Athabasca) and Venezuela (Orinoco). The primary suppliers of heavy crude oil (<28°API) to the U.S. are Canada, Mexico, and Venezuela, followed by Brazil, Colombia, and Ecuador.

Figure 4 – Recent U.S. Heavy (<28°API) Crude Oil Import Trends



Canada: Growth in the supply of heavy crude oil from the Athabasca oil sands has been stunted by the recent economic turmoil and collapse in crude oil prices, as well as concerns related to potential greenhouse gas (GHG) regulation. Although numerous projects are planned that would result in increased flows of blended bitumen to the U.S., two of the most recent oil sands projects have been integrated with upgraders (CNRL and Nexen), and therefore do not result in incremental supply of heavy oil to U.S. refineries. Although future growth in the supply of Canadian heavy crude oil grades is essentially guaranteed due to the size of total reserves, the rate of growth may be insufficient to offset declines in heavy crude oil imports into the U.S. from Mexico and Venezuela. Imports of Canadian heavy grades into the U.S. increased from 2007 to 2008 by just over 100 thousand barrels per day (MB/D),[7] but appear to have declined in 2009 (through October) by about the same amount. The Canadian Association of Petroleum Producers (CAPP)

7 Source: U.S. Department of Energy, Energy Information Administration.

forecasts a 139MB/D increase in supply of Western Canadian heavy crude oil grades between 2009 and 2012.[8]

<u>Mexico:</u> In Mexico, heavy crude oil production peaked in 2004 and then embarked on a relatively rapid decline. It was recently reported[9] that output from the giant Cantarell field (Maya) has declined from a peak of almost 2.2MMB/D to about 650MB/D today. Growing production from the heavy oil field Ku-Maloob-Zaap (KMZ) has tempered the decline of Cantarell, but it too appears to be near peak at about 800MB/D. Pemex has not reported any major discoveries in the last two decades, and hopes for developing the complex onshore Chicontepec Basin seem to be fading. These factors suggest a continued decline in coker feedstock sourced from Mexican heavy crude oil, and possibly even an acceleration of the decline driven by Mexico's own internal demand for refined products and plans for a new refinery.

<u>Venezuela:</u> Data transparency and accuracy issues complicate assessments of Venezuela's existing production and plans for the future. During 2009, PDVSA reported that production had fallen to near 3MMB/D,[10] a decline of about 200MB/D (6 percent [%]) from the end of 2008, possibly related to reductions in production related to Organization of Petroleum Exporting Countries (OPEC) quotas. However, by early December 2009, OPEC and the International Energy Agency (IEA) cited PDVSA production capability near 2.4MMB/D. U.S. imports of heavy Venezuelan grades were essentially flat in 2009, after falling by 8% in 2008.

<u>Brazil, Colombia, and Ecuador:</u> U.S. imports of Colombian and Brazilian heavy grades have increased significantly in the past two years, albeit from a small base. Combined imports from both countries increased by about 130MB/D in 2009, with Colombia accounting for about 60% of the volume increase. Ecuador imports increased in 2008, but declined over 30MB/D in 2009.

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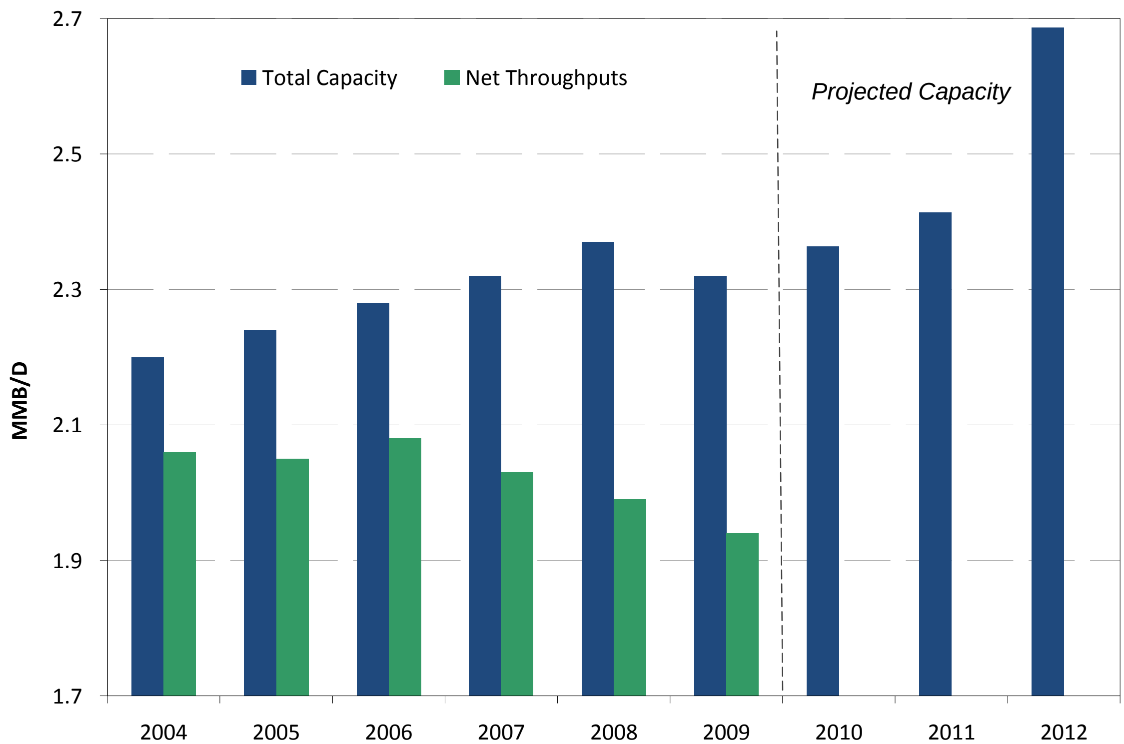
[8] 2009 CAPP Crude Oil Forecast Markets & Pipeline Report, June 2009.
[9] Platts Oilgram News, January 8, 2010.
[10] Ibid.

In the summarizing the outlook for Western Hemisphere heavy crude oil production, growth is likely to be “modest” at best, with the decline in Maya and the KMZ fields perhaps the most significant variable.

- **Global Economic Growth** - As one might have expected, when global crude oil demand declined due to the recent economic recession, evidence suggests that Middle East producers preferentially curtailed production of their lowest value, heavy-sour grades. As global economies recover and demand for crude oil increases, the supply of heavy-sour crude oil grades should increase from this region.
- **U.S. Coking Capacity** - In the U.S. alone, several large coker and related refinery expansion projects are in various stages of completion. These projects are expected to increase U.S. coker capacity by approximately 360MB/D, translating into a requirement for an additional 1.1MMB/D of Maya equivalent (assuming a vacuum residuum content of 33 volume %).

Figure 5 - U.S. Coker Capacity and Throughputs



SOURCE: Baker & O'Brien Analysis

- **Asphalt, Bunker Fuel and Residual Fuel Oil** – These other outlets for vacuum residuum account for an estimated 750MB/D of total U.S.-based residuum demand.[11] It is unlikely that demand for vacuum residuum in these sectors will soften appreciably and release barrels for coker feedstock in the near term. Demand for asphalt in the U.S. is determined largely by state budgets (paving) and new home builds (roofing). Although these sectors may have weakened recently, asphalt pricing has shown strength, and imports of foreign asphalt are required to satisfy total demand. A reduction in U.S.-based asphalt production is only anticipated in those refineries that are converting or expanding delayed coking capacity.

  Residuum consumed in U.S. vessel bunkering activity may have declined somewhat with the fall-off in the economy. However, bunker fuel has historically been a growth market, as oil use increased with rising ocean-based trade (including petroleum). Also, the total volume used for bunkering is relatively small, and large changes in consumption would be required to have a material impact on residuum supply and demand.

  As recently as 2005, 350MB/D of residual fuel oil (RFO) was consumed in U.S. electricity generation. However, as the price of natural gas plummeted relative to RFO, the consumption of RFO in power generation declined significantly, to less than 100MB/D in 2009.[12] This released 250MB/D of RFO into the coker feedstock market, contributing to the extremely wide light/heavy differentials observed through 2008. Since RFO consumption in power generation is near minimum levels, one should not expect substitution of natural gas for RFO to provide any meaningful addition of coker feedstock.

In summarizing, when examining the various supply and demand factors for coker feedstock, it becomes apparent that light/heavy differentials may remain at depressed levels for some time as most of the major determinants appear to be pointing in the same general direction, namely limited heavy oil supply growth resulting in an excess of coking capacity.

[11] Source: U.S. Department of Energy, Energy Information Administration.
[12] Ibid.

In the near term, as shown on Table 2, most signs point to a continued narrow light-heavy spread, moderate coking margins, and relatively higher prices for heavy oil and residuum-based products.

Table 2 - Near-Term Outlook for Coker Margin Drivers

Driver	Impact	Likelihood	Light-Heavy / Coker Margin Indicator
New Coker Projects	High	High	↓
Western Hemisphere Heavy Oil Production Growth	High	Low	↓
World Oil Demand Increase	High	Medium	↑
Coking Refinery Shutdowns	High	Low	↔
Asphalt, Bunkers, Residual Fuel Oil Demand Decline	Medium	Low	↔

U.S. Carbon Regulation

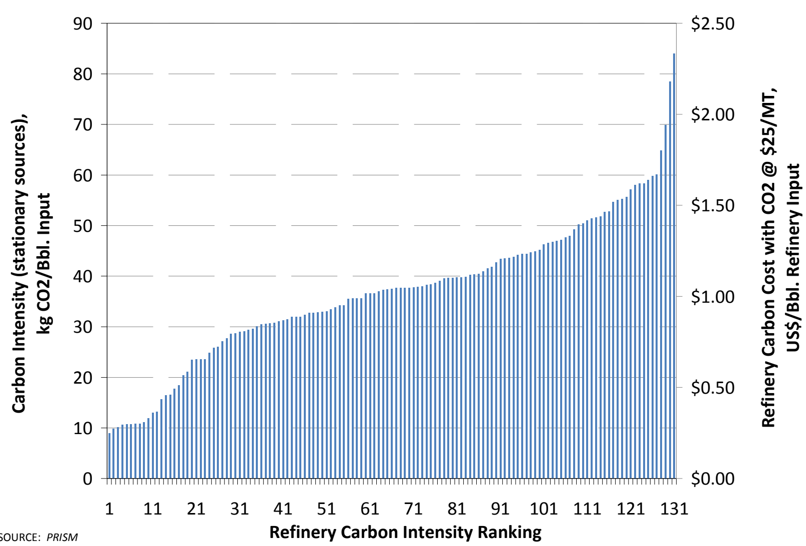
Increasing concerns about climate change and efforts to regulate GHG have gained momentum during the past year. The U.S. House of Representatives passed House Resolution (H.R.) 2454 on June 26, 2009, entitled "American Clean Energy and Security Act of 2009," containing numerous government initiatives that would affect the U.S. refining sector, including a carbon dioxide (CO_2) emission reduction program (using a cap-and-trade type mechanism). In December of 2009, the U.S. Environmental Protection Agency (EPA) announced its finding that GHGs threaten the public health and welfare of the American people. The EPA's endangerment finding covers emissions of six GHGs: carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride.

Although there is much uncertainty regarding the timing, probability, and final form of any U.S. government carbon reduction scheme, Baker & O'Brien has analyzed the directional impact of potential carbon reduction regulations on the cost and competitive position of U.S. refiners relative to their current and potential competitors, and implications for the U.S refining industry.

H.R. 2454 aims to hold refiners accountable for both “stationary source” and “tailpipe” CO_2 emissions. Stationary source CO_2 emissions include those from equipment within the refinery, such as fired heaters and catalyst regeneration units. Tailpipe CO_2 emissions encompass those generated during the consumption of refined products, e.g., emissions resulting from the combustion of gasoline in an automobile. This paper focuses solely on stationary source CO_2 emissions (which represent about 10% of the total), as we expect that final legislation or regulation would treat tailpipe emissions of imported fuels on a relatively level playing field with those from U.S.-produced fuels[13] (i.e., an importer will be accountable for the contained carbon of imported fuels).

The quantity of stationary source CO_2 emissions that are generated by a refinery is related to a number of factors including refinery throughput, process configuration, energy efficiency, and feedstock quality. As illustrated in Figure 6, the carbon intensity[14] of U.S. refineries varies significantly, with the median refinery near 40 kilograms (kg) of CO_2 emitted per barrel of total refinery input. If CO_2 emissions are valued at US$25.00 per metric ton (MT), then 40 kg/Bbl. translates into a median cost of US$1.00/Bbl. of input.

Figure 6 – Carbon Intensity of Select U.S. Refineries (from Stationary Sources)



SOURCE: *PRISM*

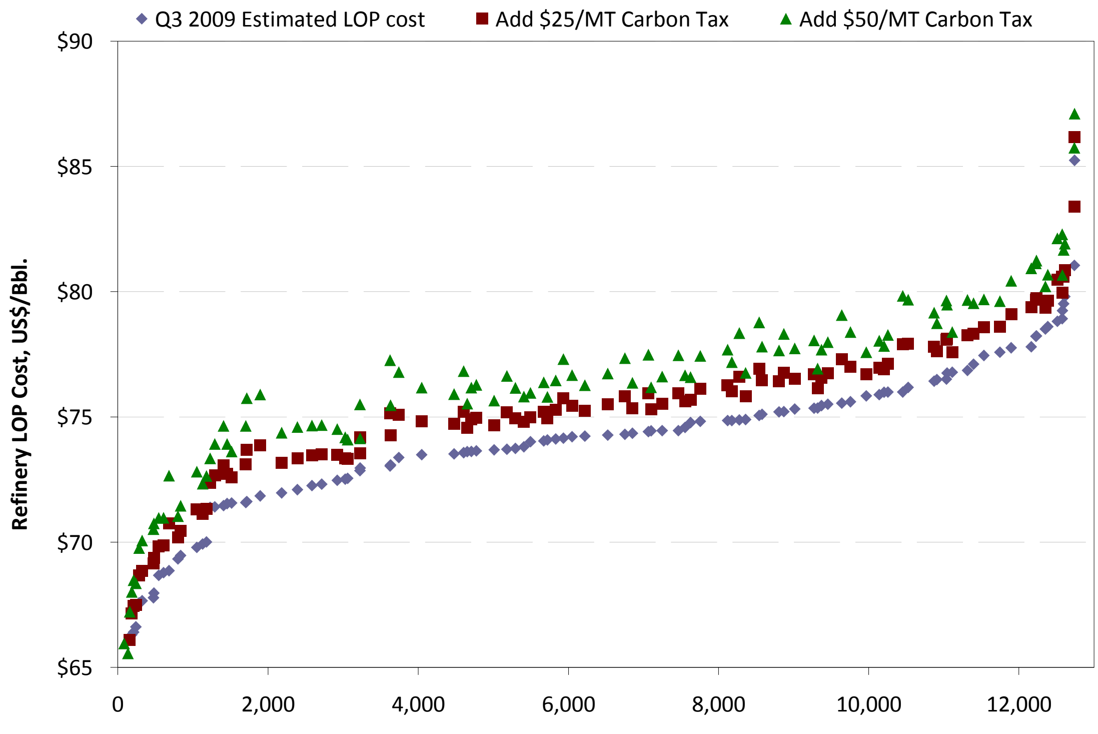
[13] Although a tax on tailpipe CO_2 emissions may have less of an impact on “relative” U.S. refinery costs as compared to a tax on stationary source emissions, one should not discount the enormous consequences of such a tax on the U.S. refining industry. An analysis of these consequences is outside the scope of this paper.

[14] Carbon intensity represents the quantity of CO_2 emitted by the refinery per barrel of crude oil and other hydrocarbon liquid input to the refinery.

Refineries that convert low quality crude oil into a product slate containing a high portion of value-added products tend to have higher carbon intensity than those that process light sweet crude oil grades or those that primarily produce asphalt. In order to provide financial context, the right hand vertical scale of Figure 6 shows each refinery's associated carbon cost based on a carbon tax of US$25.00/MT of CO_2.

Figure 7 provides an estimate of U.S. refinery LOP costs for the third quarter of 2009 as well as an illustration of the impact of a US$25.00/MT and a US$50.00/MT carbon tax.

Figure 7 - Illustrative Impact of a Carbon Tax on the LOP Cost of Select U.S. Refineries

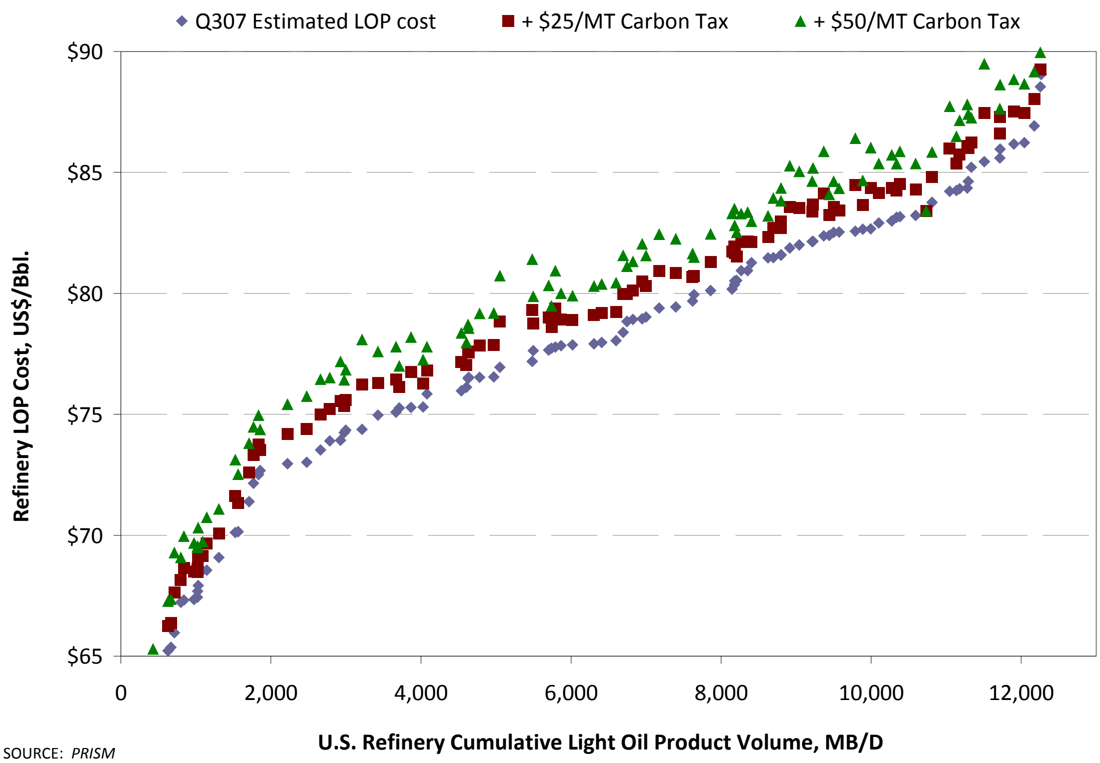


SOURCE: *PRISM*

Not only does the above reflect the impact of an increasing carbon tax on U.S. refinery LOP costs, it also demonstrates the impact on competitive positioning between refineries. Keep in mind that every US$0.10/Bbl. is critical to a refiner, so the scale of the chart can appear to understate the impact of the relative changes.

Note that as previously mentioned, the third quarter of 2009 was a period during which the light/heavy crude oil price differential was relatively low, resulting in a somewhat flat cost curve. Figure 8 provides a similar analysis for the third quarter of 2007 when the light/heavy crude oil price differential was wider (LLS-Maya price spread of US$14.30/Bbl. versus US$7.30/Bbl. in third quarter 2009).

Figure 8 - Illustrative Impact of a Carbon Tax on the LOP Cost of Select U.S. Refineries

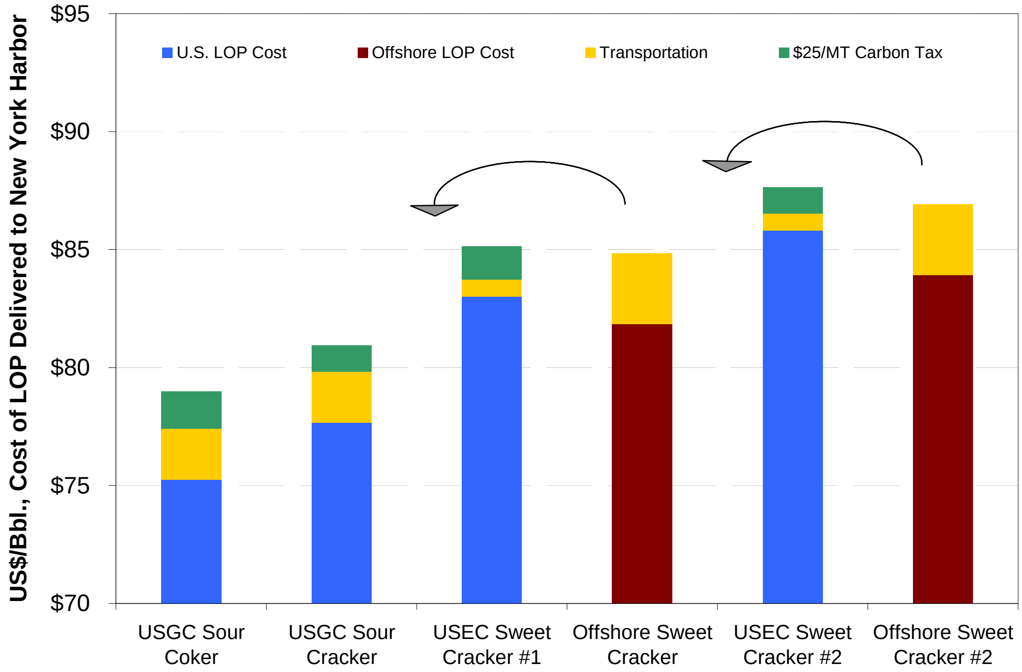


SOURCE: *PRISM*

The steeper 2007 cost curve reduces the impact that CO_2 regulation would have had on the "relative" positioning of refineries. However, it does not change the fact that refiners would realize a significant increase in their cost structure.

Although relative positioning between U.S. refineries is an important issue for individual refineries, a much more significant issue may be the positioning of these refiners relative to offshore refiners. This issue is illustrated in Figure 9 which provides the cost for delivering LOP into New York Harbor (NYH) from representative refineries located in the USGC, the United States East Coast (USEC), and the offshore Atlantic Basin. Costs are classified into three categories: 1) refinery LOP cost at the refinery gate; 2) the cost for delivering product into NYH; and 3) the cost that a refinery would incur if a carbon tax of US$25.00/MT of CO_2 is applied on refinery stationary sources.

Figure 9 – Illustrative Impact of a U.S. Carbon Tax (Stationary Sources) on the Competitive Positioning of U.S. Refineries



Source: Baker & O'Brien Analysis and *PRISM*

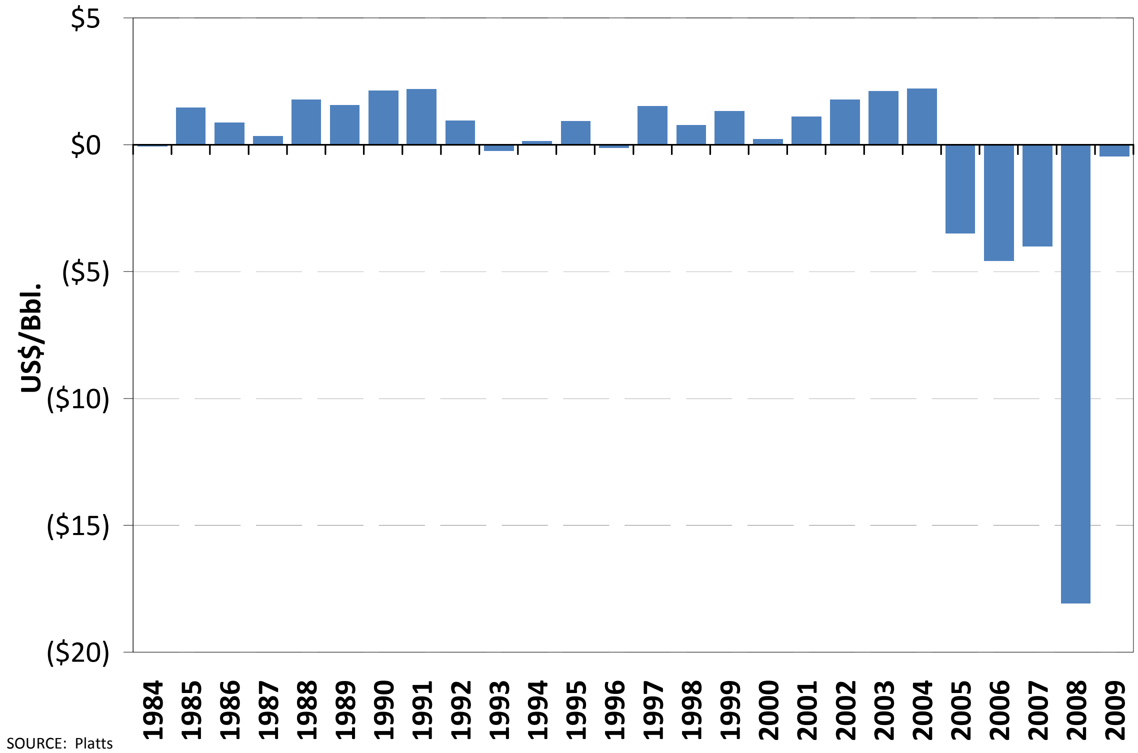
In an environment where offshore refineries are not subject to a carbon tax like their U.S. counterparts, they may move lower on the U.S. refining cost curve, potentially resulting in a compression of U.S. refinery margins and/or the shutdown of U.S. refining capacity.

In summary, even without considering the negative effects of demand destruction that would likely result from U.S. carbon reduction regulations, such regulation would likely have a meaningful impact on the relative competitive positioning of U.S. refiners. Moreover, such regulations are likely to reduce the global competitiveness of the U.S. refining industry.

Gasoline/Distillate Price Differential

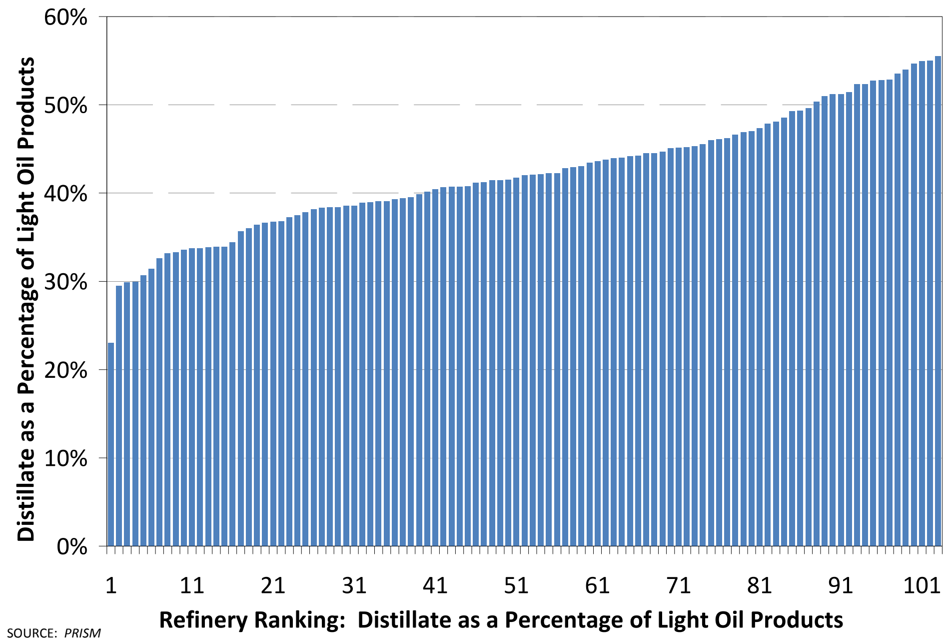
One of the most profound changes that occurred during the refining "golden age" was a significant inversion in the gasoline/distillate price differential driven primarily by diverging trends in demand for gasoline versus distillates (see Figure 10).

Figure 10 – USGC Gasoline/Distillate Price Differential



Although distillate consumption was negatively impacted more severely than gasoline during the global recession, distillate demand is widely expected to increase as world economies recover and subsequently expand, and as Europe continues down the path of dieselization. In contrast, a number of factors are likely to continue to put downward pressure on demand for petroleum-based gasoline in the Atlantic Basin, including a shift to more fuel efficient automobiles, substitution by renewable fuels, and an increase in consumer gasoline prices resulting from carbon regulations. These diverging trends lead many to forecast a return to an inversion of the gasoline/distillate price differential. Refiners that are more oriented toward distillates should directionally benefit from such a trend. Figure 11 provides an overview of the distillate yield as a percent of LOP for select U.S. refineries.

Figure 11 - Distillate Production as a % of LOP for Select U.S. Refineries



To provide financial context for Figure 11, Table 3 provides a comparison between two USGC refiners positioned near the extreme ends of the distillate yield spectrum, but otherwise similar with respect to the quality of crude oil processed and their LOP yield as a percent of refinery input.

Table 3 – Illustrative Impact of Gasoline/Distillate Price Differential on Relative Refinery Economics

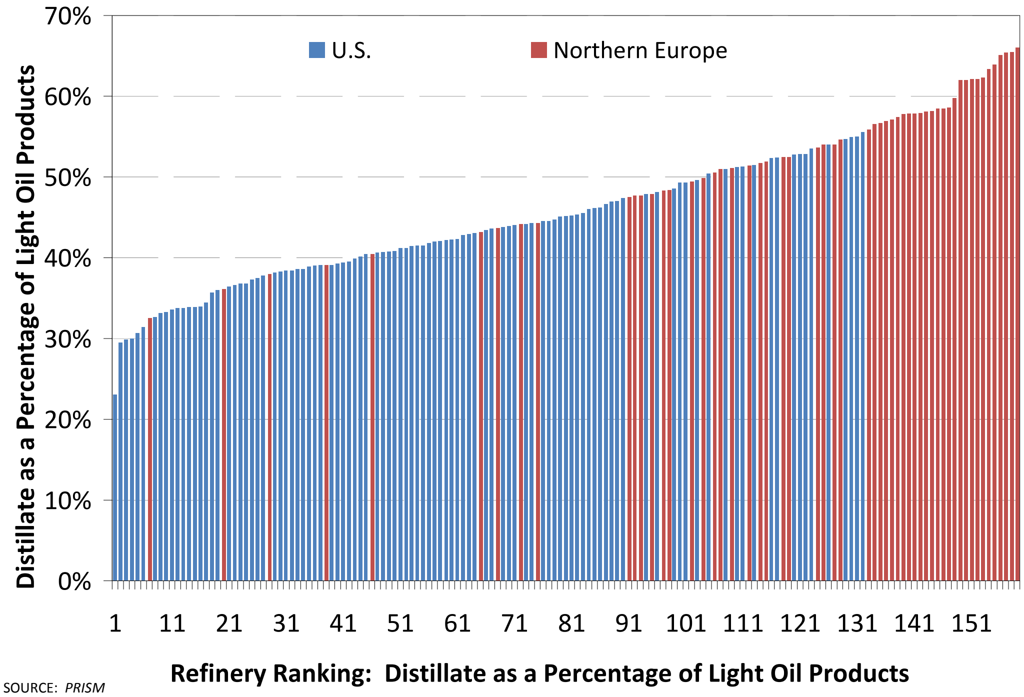
	Refinery A	Refinery B	Refinery A vs. Refinery B
Distillates as a % of LOP	31%	56%	
Estimated Refinery Cash Margin, Q309 Year-to-Date, US$/Bbl. Input[15] (gasoline minus diesel = zero)	2.41	1.41	+1.00
Implied cash margin at 2005-2008 average gasoline/distillate price differential and constant WTI 321 crack spread[16] (gasoline minus diesel = negative US$7.50/Bbl.)	2.28	2.76	US$(0.48)

15 Source: Baker & O'Brien *PRISM*.

16 Corresponds to a $5.00/Bbl. increase in the price of distillates and a $2.50/Bbl. decline in the price of gasoline.

During the third quarter of 2009, the gasoline/distillate price differential was essentially zero. Refinery A's cash margin exceeded that of Refinery B by US$1.00/Bbl. of input. If the gasoline/distillate price differential were to revert to the average level observed during the 2005-2008 period (negative US$7.50/Bbl.), then all else being equal, one would expect that Refinery B's cash margin would exceed that of Refinery A by roughly US$0.50/Bbl., a US$1.50/Bbl. swing in relative profitability. Therefore, a meaningful change in the gasoline/distillate price differential can have a significant impact on the relative competitiveness of certain refiners. European refiners generally yield a higher portion of distillate as a percentage of LOP, compared to their U.S. counterparts as illustrated in Figure 12.

Figure 12 - Select U.S. and Northern Europe Refineries – Distillate Production as a % of LOP



SOURCE: *PRISM*

While there are a number of factors that will ultimately determine the relative competitiveness of the U.S. refining industry versus other regions, a substantial and sustained inversion of the gasoline/distillate price ratio would directionally enhance the relative positioning of the European refining industry relative to U.S. refiners.

Conclusions

When assessing the relative profitability of a refinery or a refining region, one should use caution when applying simple rules of thumb or classifying assets or regions into traditional stereotypes. For instance, the competitive advantage traditionally attributed to large scale, heavy sour coking, gasoline-oriented refineries may not be realized in an environment characterized by a low light/heavy crude oil spread, an inverted gasoline/distillate price differential, and a high carbon tax. An assessment of a refinery's competitive position should consider the degree to which a refinery's unique characteristics align with one's market outlook.

This paper examined the degree to which three market factors can have a significant influence on the relative competitiveness of refineries. Additional factors which we have not addressed but that should be considered when assessing a refinery's future profitability or viability include:

- Proximity to an undersupplied product market and/or oversupplied crude oil market. This can provide logistics advantages that may translate into higher refining margins. For example, in the late 1980s and early 1990s, some PADD[17] 5 refineries realized the highest margins in the world, because the region had surplus crude oil supply combined with an undersupplied product market. Similar margin advantages have recently been realized by certain refineries located in PADDs 2 and 4.
- Operating effectiveness, including refinery safety, reliability, and operating costs.
- Sustaining capital requirements, including requirements to maintain the facility and to comply with regulations.
- Local cost of doing business, including the local labor and regulatory environments, and/or utility costs and policies.
- Size/Scale. Large, single train units typically result in the lowest unit operating costs.
- Upstream, downstream and/or petrochemicals integration. Integration can (but does not always) lead to cost, product, and/or market synergy.

[17] Petroleum Administration Defense District.