

**The American Clean Energy and Security Act:
An EPRINC Assessment of Capacity and
Employment Losses in the Domestic Refining
Industry**

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Energy Policy Research Foundation, Inc.

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I. Introduction

The Obama Administration and the U.S. Congress are pursuing a wide range of policy and legislative initiatives to limit emissions of greenhouse gases (GHGs). While the proposals vary widely by industrial sector and end user, the leading legislative vehicle for regulating CO₂ emissions for the U.S. refining industry and refined products imported into the U.S. can be found in the American Clean Energy and Security Act (ACES), H.R. 2454, also known as the Waxman-Markey energy and climate bill (W-M). The bill passed the U.S. House of Representatives on June 26, 2009 and provides a detailed and specific regulatory program to limit emissions of carbon dioxide (CO₂), the primary GHG emitted through the combustion of fossil fuels. The regulatory program specified in the legislation provides for constraints on emissions regulated through a so-called cap and trade program. The Senate has not yet taken action on climate legislation but is expected to do so sometime in late 2009.

Under the Waxman-Markey bill, both manufacturers (refiners) and importers of transportation and other fuels derived from crude oil would be required to purchase allowances to account for the carbon emitted into the atmosphere as a result of combustion of these fuels. U.S. refiners would also have to purchase allowances to account for fuel use at the refinery site required for processing crude oil into refined petroleum products. The legislation does not seek to tax fossil fuel combustion directly, but instead create a financial penalty for emissions of CO₂ into the atmosphere. By placing a financial cost, i.e., the requirement to purchase allowances for carbon emissions from petroleum products, either imported into the U.S. market or produced by domestic refiners, the legislation would raise the cost of these fuels.

An underlying assumption in the legislation is that the financial cost borne by both importers and refiners could be fully passed through to end users. Under the legislation, both importers and refiners would likely face a rising cost of carbon as binding constraints come into force on the amount of CO₂ that can be emitted into the atmosphere.¹ In the early years of the program, refiners would be granted, at no cost, a limited number of allowances to assist in adjusting to the new constraints and to presumably place them on a level playing field with foreign refiners. These allowances would cover approximately one third of refiners' stationary emissions and nothing more. Refiners would be required to purchase additional allowances to cover any emissions not covered by the initial allocation.

Table 1 below shows the emission allowances for U.S. refiners under Waxman-Markey through the year 2030.

¹ Note that Waxman-Markey does not preempt other regulatory initiatives, such as a low carbon fuel standard, but these proposals are not part of the current legislative program.

**Table 1. Emission Allowances for U.S. Refineries under Waxman-Markey
(millions of metric tons of CO₂ per annum)**

Year	Total CO ₂ Emissions Permitted for US Economy	U.S. Refiners' Emissions (Stationary Source)	U.S. Refiners' Emissions (Product Combustion)	Refiners' Total Emission Compliance Obligation	Emission Allowances Provided at No Cost	Net Emission Allowance Purchase Requirement
2015	5,003	256	2,029	2,285	100	2,185
2020	5,056	250	1,980	2,230	101	2,129
2025	4,294	248	1,964	2,212	86	2,126
2030	3,533	249	1,973	2,222	0	2,222

Source: H.R. 2454, EPA Data, EIA W-M Basic Case Projected Refinery Crude Throughputs, and EPRINC Calculations. *Actual emissions for the entire U.S. will be higher as ACES covers only 86% of the U.S. economy. Does not include allowances allotted to small business refiners, 0.25% of the free allowance pool. All estimates are prior to trade flow adjustments from higher cost of U.S. refinery operations under W-M.

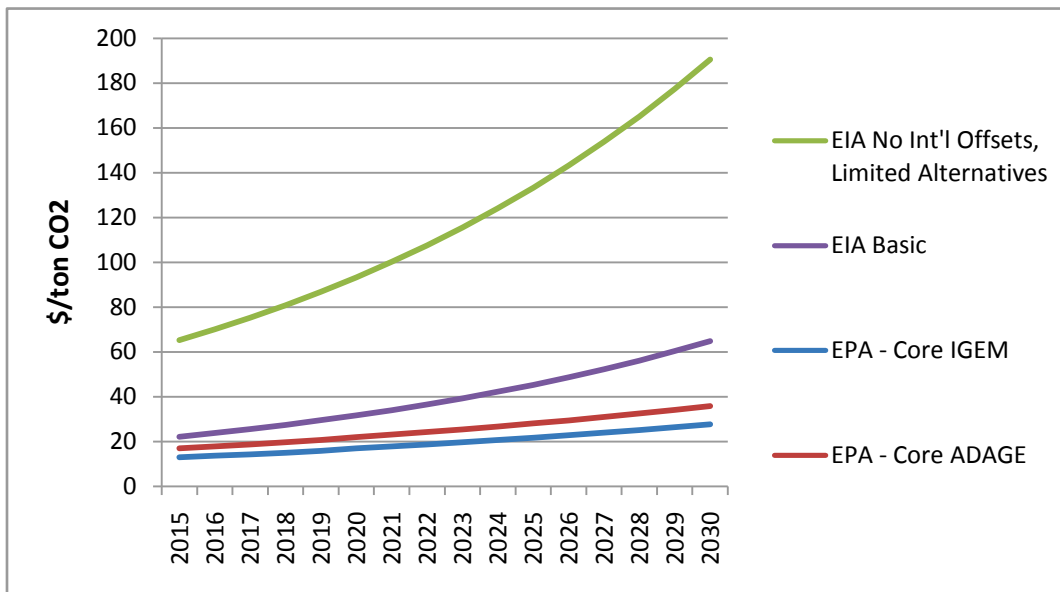
The legislation requires reductions in total carbon emissions from the U.S. economy from the 2005 (calculated) baseline level of 3 percent beginning in 2012 and then proceeding on a schedule of reductions that reaches 17 percent below 2005 levels in 2020, 42 percent in 2030 and ultimately to more than 80 percent reduction of 2005 levels by 2050. In any case, no calculated CO₂ emissions (for both on site use and volume of product produced) would be permitted unless accompanied by an allowance granted by EPA or purchased through an authorized trading regime. From the perspective of refiners and importers, however, the central concern is how much are carbon prices likely to increase over time as GHG allowances are reduced. EPA has projected costs for GHG allowances for CO₂ of \$13/ton in 2015 and \$28/ton in 2030 in the low price core scenario and \$17/ton of CO₂ in 2015 and \$36/ton in 2030 in the high price core scenario.

EPRINC has used EPA's core scenario price forecasts (shown in red and blue in Figure 1) as an initial assumption of the cost structure facing the transportation fuels sector in our assessment. EPA's allowance cost estimates are considered to be some of the most conservative estimates produced thus far. However, these costs include considerable uncertainties, including an expectation that there will be full utilization of international offsets and that efforts at carbon control and storage will be largely successful. According to EPA, if international offsets are not implemented, allowances are likely to be 96% higher than in the core scenarios and EPRINC has evaluated a higher cost scenario in this report as

well.² EIA’s basic scenario, which assumes alternative and low emission technologies reach the market as expected under ACES and that the use of domestic and international offsets are not severely restricted in any way, projects prices that are 70% to 130% higher than those in EPA’s core scenarios.³

Figure 1 below shows carbon price forecasts from both EPA and EIA.

Figure 1. EPA and EIA CO₂ Allowance Price Forecasts



Source: EPA and EIA Forecasts

²Of course, the number of moving parts in any carbon cost forecast is almost limitless. The uncertainties were summarized in a recent CRS report as follows, *The already tenuous assumption that current regulatory standards will remain constant becomes more unrealistic as time goes forward, and other unforeseen events (such as technological breakthroughs) loom as critical issues which cannot be modeled. Hence, long-term cost projections are at best speculative, and should be viewed with attentive skepticism.* See Congressional Research Service, **Climate Change: Costs and Benefits of the Cap-and-Trade Provisions of H.R. 2454**, September 14, 2009.

³ADAGE refers to the APPLIED DYNAMIC ANALYSIS OF THE GLOBAL ECONOMY. It is a dynamic computable general equilibrium (CGE) model capable of examining many types of economic, energy, environmental, climate change mitigation, and trade policies at the international, national, U.S. regional, and U.S. state levels. To investigate proposed policy effects, the CGE model combines a consistent theoretical structure with economic data covering all interactions among businesses and households. IGEM refers to the INTERTEMPORAL GENERAL EQUILIBRIUM MODEL. It is a model of the U.S. economy with an emphasis on energy and environmental aspects. It is a detailed multi-sector model covering 35 industries. IGEM is a dynamic model, which depicts growth of the economy due to capital accumulation, technical change and population change. It also depicts changes in consumption patterns due to demographic changes, price and income effects. The model is designed to simulate the effects of policy changes, external shocks and demographic changes on the prices, production and consumption of energy, and the emissions of pollutants. The main driver of economic growth in this model is capital accumulation and technological change. It also includes official projections of the population, giving us activity levels in both level and per-capita terms. For a full discussion of both models see <http://www.epa.gov/climatechange/economics/modeling.html>

Table 2 below shows the projected costs of the program to U.S. refiners prior to any adjustments that may take place as a result of the rising cost of operations from the cap and trade program.

Table 2. Annual Compliance Costs for U.S. Refineries under Waxman-Markey*
(U.S. dollars in billions, carbon prices derived from EPA estimates)

Year	Cost of Allowances to Cover Stationary Source Emissions	Cost of Allowances to Cover Product Combustion	Value of Allowances Allocated under W-M to U.S. Refiners	Total Cost of Allowances, Stationary Source and Product Combustion – net of 2 % allocation
2005	-----	-----	-----	-----
2015	\$3.3---\$4.4	\$26.4---\$34.5	\$1.30---\$1.70	\$28.4---\$37.1
2020	\$4.3---\$5.5	\$33.7---\$43.5	\$1.72---\$2.22	\$36.2---\$46.8
2025	\$5.4---\$7.0	\$42.6---\$55.2	\$1.86---\$2.41	\$46.1---\$59.7
2030	\$6.9---\$8.9	\$54.6---\$70.7	\$0	\$61.5---\$79.6

**Source: EPRINC calculations, financial obligations for imported petroleum products not included. Range of estimates represent EPA estimates for GHG allowance prices under W-M, low and high cost core scenarios resulting in costs of \$26 to \$36/ton in 2030. See <http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf>. Allowance prices in EIA’s W-M Basic Case are 70% - 130% higher than EPA’s low price forecast used in Table 2.*

The emission allowances for the domestic refining sector provided at “no cost” cover less than 50 percent of the requirements for stationary source emissions alone at the refinery site. The other observation from allocations under Waxman-Markey is that the legislation is seeking to place 45% percent of the carbon costs for the entire economy from the products produced from crude oil, i.e., from the entire range of petroleum products (transportation fuels and other products) either imported or processed domestically. Although substitutes are available for some of the products made from crude oil, the EIA base case liquids forecast used in this analysis already assumes an expansion of biofuels use of over 1 million barrels/day across the forecast period.

The allocations under Waxman-Markey recognize that reductions in crude oil use, i.e., reductions in the use of all the products made from crude oil, is a sector that can generate large reductions in GHGs, but the cost of the reductions will be substantial. We can expect the domestic refining industry and the markets its serves to make the following adjustments in response to this rising cost structure: (1) a reduction in demand for petroleum products from rising costs of transportation fuels and other products made from crude oil, and (2) substitution of domestic supplies by foreign producers who are not facing the same cost structure.

These two adjustments represent the primary economic forces that will determine how much of the costs of cap and trade can be passed on directly to consumers and how much of the costs will be absorbed through some combination of lower margins for refinery operations and subsequent capacity adjustments (reductions) among U.S. refiners as additional market share is taken by foreign producers. In an attempt to bring as much understanding as possible to these potential adjustments, EPRINC's assessment begins with a brief historical overview of the structure of the domestic refining industry in Section II.

The carbon control regulatory framework will not be applied in a vacuum but into the current economic and regulatory environment now facing the industry. This current environment reflects growing competition from foreign sources of supply as well as rising costs from new environmental standards and mandates for integrating larger volumes of biofuels into the transportation fuels market. Section III evaluates how the carbon control requirements will shift the cost of operations of domestic refining operations; in effect this is EPRINC's estimate of the long run cost of producing refined products in the domestic market. Section IV evaluates both the cost and availability of foreign supply and resulting shifts in net demand for refined products. The scenarios on foreign supply and potential demand response provide an estimated range of capacity adjustments, employment loss, and price increases from the carbon control regime.

The extent of the pass through of these costs, the subsequent affects on the structure of the U.S. refining industry, and likely price consequences to domestic consumers of refined products is the central focus of EPRINC's assessment. Although beyond the scope of this assessment, it should be noted that the costs of the carbon reduction program for the refining sector will extend well beyond the transportation fuels market, including such uses as asphalt for road construction, plastics, and pharmaceuticals.⁴ This is why the issue of how much of the costs of the program can be effectively passed through to end users is so important and goes well beyond the competitive consequences to the domestic refining sector.⁵ Those sectors of the economy that rely upon refined products that are subject to intense foreign competition from industries not subject to a similar carbon control cost structure, and are not captured through the allowance program for importers, will remain at a competitive disadvantage and will see their market share decline.

⁴ According to the Institute for Energy Research, crude oil has typically been refined into the following product groups, 42% gasoline, 27.8% heating oil and diesel fuels, 22.2% other products, including those derived from petroleum for the manufacturing of chemicals, synthetic rubbers, and plastics, 9.6% jet fuel, and 2.7% asphalt. See Institute for Energy Research, "Fossil Fuels", at <http://www.instituteforenergyresearch.org/energy-overview/fossil-fuels>.

⁵ It is sometimes argued that because of the unique requirements and specifications which often characterized US transportation fuels that foreign producers are unable to easily enter the U.S. market. However, a large component of US imports is so-called blend stocks, which can be blended with US production to meet local specifications. In addition, foreign refiners have demonstrated that if the difference in margins persist they can adapt to US specifications through a wide range of strategies. See EPRINC report, *A Prime on Gasoline Blending*, June 2009 at <http://www.eprinc.org/pdf/primerongasolineblending.pdf>

II. Domestic Refining: Regulatory and Economic Issues

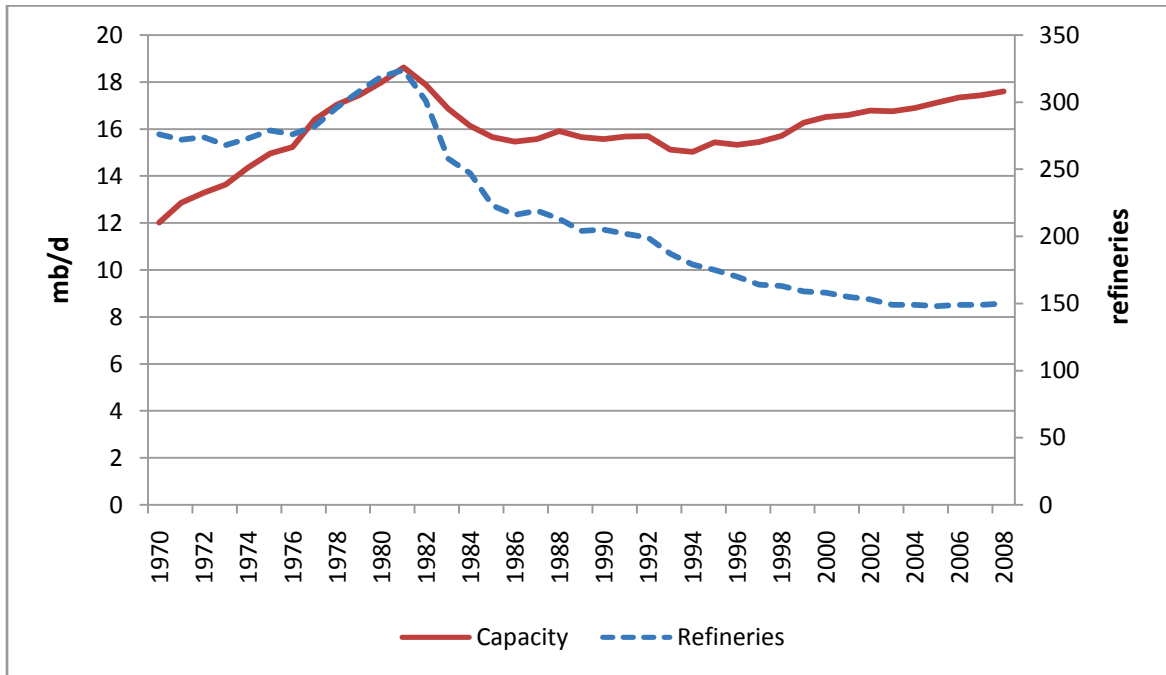
The cap and trade program as outlined in the Waxman-Markey legislation will require the U.S. refining industry to adjust to a new set of cost structures and new regulatory program. This program will not be applied in a vacuum but within the structure of the domestic refining industry that will already be facing rising competition from foreign refiners and a rising mandate to increase biofuels into the transportation fuels market.

Both economic forces and regulatory programs have played a central role in the modern structure of the domestic refining industry. Since the 1973-74 Arab oil embargo, the U.S. refining industry has emerged from a fleet of small plants into an industry characterized by a few number of larger facilities. Much of the capacity is now located in coastal nodes served by waterborne and pipeline infrastructure. The Federal Government subsidized small refineries between the late 1950s until 1979, leading to a surplus of geographically diffuse and largely inefficient plants and excess crude oil capacity not supported by enhanced processing capability needed for manufacturing products such as unleaded gasoline. These subsidies, however, came to an end by 1980 as the U.S. economy entered a recession and price controls were lifted.

The reaction to the end of price controls took little time—by 1983, 66 plants had closed. Small units continued to be closed, and a steady decline in the number of refineries continued until 2002, when the plant count bottomed at 149. The current fleet consists of 150 plants. Firms rationalizing the overall configuration of the refining industry sought economies from large scale processing, and made investments in cracking for better yields of light product, coking for greater light product yields from heavier crudes and hydrotreating for cleaner products. These investments delivered the slate of products consumers demanded through more complexity and modest increases in total capacity, which grew at an annual rate of 90,000 b/d from the mid-1980s onward.

The change in fleet numbers (right scale – blue line) is shown in Figure 2 below.

Figure 2. Number of U.S. Refineries and Capacity



Source: EIA Data

Figure 2 also shows (left scale) that the nation’s total capacity to refine crude declined as the number of plants fell. From a peak of 18.6 mb/d in 1981, crude capacity fell to 15.5 mb/d in 1986, before it began to increase; capacity rose slowly but steadily through 2008, currently standing at 17.6 mb/d.

These forces led to consolidation of fewer but more robust plants at pre-existing sites with expansion capability and water and pipeline transport. Today, most refining takes place in geographic refining centers, like the Gulf Coast, New York Harbor, Chicago, Los Angeles and San Francisco. Optimized transport and logistics facilitate the smaller number of more potent refineries access to crude oil and provide the ability to serve distant markets, giving the forces of competition broader geographic reach. It is worth noting that a well-established trend toward larger facilities began during World War II, as the average size of operating plants grew, seeking economies of scale. In 1960, the average refinery was about 32,000 b/d; by 1981, that figure had nearly doubled to 57,000 b/d, and doubled again by 2007, when the average plant stood at 117,000 b/d.

As U.S. refining became more complex and capacity more streamlined, the global oil market changed as well. Ending a period of price stability, crude oil and product prices - especially diesel and heating fuels -

saw sharp price rises during the 2005 to early-2008 time frame. But the high margins experienced in the industry between 2005 and 2008 have moved sharply lower with domestic industry now experiencing low rates of return and even some recent announcements of plant closures.

Refiner Profitability

Refinery economics depend on producing sufficient fuels to meet consumers' needs without over-supplying low-demand markets and minimizing low-value fuels production. Small amounts of low-value fuels - such as residual fuel - can quickly reduce refiner margins. If the differential between low and high valued products is substantial, investment in upgrading equipment (cokers, hydrocrackers, etc) can generate a positive return on investment (ROI) provided net demand for the entire product slate is adequate

Throughout the 1980s and 1990s, refining and marketing ROI averaged 5.2% according to EIA data; for 12 of those years, ROI was under 5%. Returns underperformed the manufacturing sector until 2004, when for the first time in recent history refining and marketing ROI exceeded 10%. Improvements in margins experienced in recent years have dissipated, and profitability has reverted to historic levels, which are lower than U.S. manufacturing, although recent volatility in oil markets makes generalization difficult.

Regulatory Impact on the Refining Sector

The cost structure of the domestic refining sector has risen as regulatory programs have required both rising capital expenditures and higher operating budgets to address stricter onsite environmental standards and more stringent fuel specifications. For example, Corporate Average Fuel Economy (CAFE) standards have been revised to 35.5 miles per gallon (mpg) in 2016. Under the previous iteration of CAFE auto makers were not required to meet 35.5 mpg until 2020. The Energy Independence and Security Act of 2007 (EISA) set mandates that require large increases in the use of both ethanol and advanced biofuels. If the targets set in EISA are met, biofuels use will rise to 36 billion gallons per year by 2022, of which up to 15 billion gallons could come through the distillation of corn, and the rest from cellulosic or other advanced biofuel sources. Accommodating such fuels into the gasoline supply raises refiners' operating costs and reduces their market share.

Ethanol has contributed to the U.S. fuel supply and reduced net petroleum imports. Federal mandates requiring so-called obligated parties, i.e., refiners, blenders, and importers, to use larger volumes of ethanol in the gasoline pool over the next few years will sustain a high volume of ethanol production for the U.S market, but maintaining and growing the biofuels sector will come at a cost, largely reflected in rising prices of gasoline and middle distillates and likely higher subsidies from federal and state governments. Federal mandates for ethanol are a volumetric requirement, which means once the entire U.S. gasoline pool hits 10 percent ethanol blend, often referred to as the blend wall, additional mandated levels must be marketed as E-85, that is, an ethanol-gasoline mix of 85% ethanol mixed with

gasoline. As federal mandates take the U.S. gasoline pool above 10 percent ethanol blend, and ultimately to higher levels through E-85, the value of additional ethanol supplies is likely to decline dramatically. As the market enters a period of low demand growth for transportation fuels, accommodating increasing volumes of ethanol into the gasoline pool will likely require substantial increases in the price of E-10 (ethanol-gasoline mix of 10% ethanol mixed with gasoline) and diesel fuels as refiners and marketers face the higher costs of meeting the mandate. The higher costs will come from lower utilization rates at U.S. refineries and higher distribution costs for ethanol.

As the volumetric mandates for ethanol use continue to grow over the next 5- 10 years, obligated parties are likely to face a rapidly rising cost structure, particularly if the value of RBOB⁶ remains well below \$2.00/gallon. In this price environment ethanol production incentive programs, farm production subsidies, blenders credits, volumetric mandates, tariff protection, and related programs will all be inadequate to bring enough ethanol into the market at a low enough price to induce consumers to purchase the higher volumes required by law. Ultimately, consumers will not buy the mandated volumes unless the price difference is sufficient to make E-85 a better buy than E-10.

But in a market where the price of RBOB remains below \$2 per gallon, the discount at the pump is only half the story. Blenders and refiners must pay ethanol producers enough (capital and operating costs) to sustain output at adequate volumes to meet the mandate and at the same time install adequate distribution capacity (E-85 pumps, additional storage capacity, etc) to move the mandated volumes into the market. With the renewable fuel standards (RFS) set to increase the minimum amount of “renewable biofuel” from 10.5 billion gallons in 2009 to 12 billion gallons in 2010 (not including advanced and cellulosic biofuels which are mandated beginning in 2009 and 2010, respectively), obligated parties will face rapidly rising costs in meeting the mandate. As a result, the cap and trade provisions will be implemented in an industry environment of rising costs for meeting the growing mandates for biofuels as well as the recent proposals by the Administration to remove the Section 199 manufacturers tax credit as it applies to the oil and gas industry, a policy proposal which will also raise the cost of producing refined products.

Section 199 is a provision in the U.S. tax code that was passed to ensure that U.S. manufacturers face a level playing field when competing with foreign firms.⁷ This provision in U.S. law was originally intended to reduce the U.S. corporate rate to bring U.S. manufacturers closer to the tax treatment of their foreign competitors. Although the most effective method to achieve this goal would have been to

⁶ RBOB, or Reformulated Blendstock for Oxygenate Blending, is the base gasoline mixture produced by refiners or blenders that is shipped to terminals, where ethanol is often added to create the finished RFG, or reformulated gasoline. For a discussion of gasoline blending see EPRINC’s report, *A Primer on Gasoline Blending*, June 2009 at <http://www.eprinc.org/pdf/primerongasolineblending.pdf>. For additional reading on renewable fuels in the transportation sector see EPRINC report, *A Primer on the Renewable Fuels Standard*, July 2009 at <http://www.eprinc.org/pdf/rfsprimer.pdf>.

⁷ For an international comparison on corporate tax rates see the Ernst and Young report on behalf of American Council for Capital Formation (ACCF): http://www.accf.org/media/dynamic/8/media_82.pdf

just lower the U.S. corporate tax rate, Congress chose to achieve this goal through provisions that provided extra tax deductions for enterprises engaged in manufacturing.⁸ In the U.S. petroleum industry, Section 199 is used by oil and gas producers and petroleum refiners to reduce their tax burden. Note that Treasury's proposal seeks to eliminate this provision for U.S. manufacturers of petroleum products and oil and gas producers, but not for the production of any other goods in the domestic economy.

The Global Refined Products Trade

The U.S. refining industry operates in a highly competitive environment in which foreign competition has both low costs and expanding capacity. Much like crude oil, refined petroleum products are traded globally to meet supply and demand imbalances. The U.S. possess 20% of the world's refining capacity (17.5 mb/d of the world's 86 mb/d of capacity) and is the world's largest consumer of refined products, making it one of the most important markets in determining trade flows of refined products.

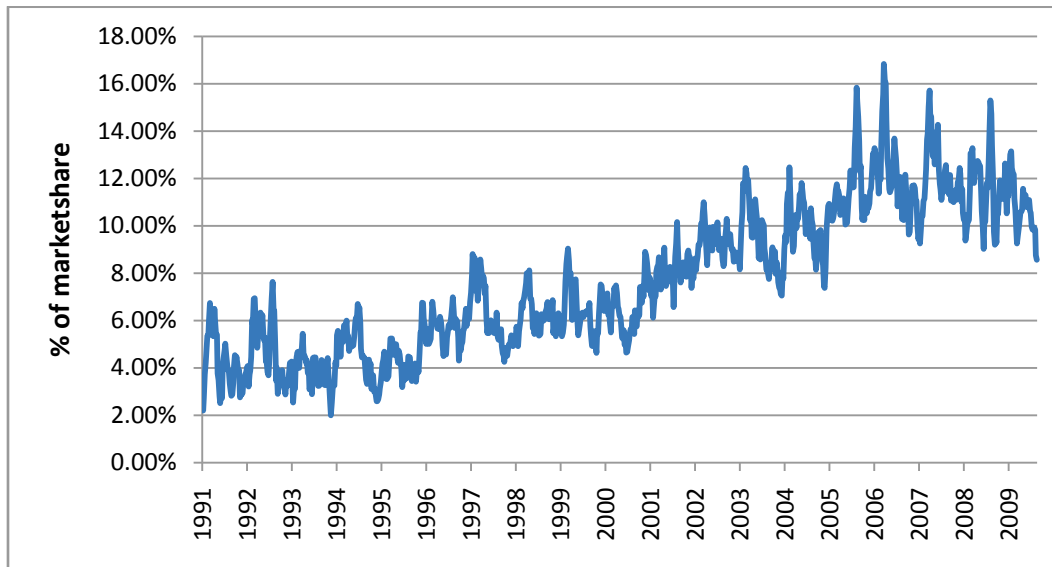
In recent years the U.S. has imported about 10% - 12% of its gasoline and gasoline blending component needs (1 mb/d), an increase from approximately 6% in 2000. Imports' share of supply has held steady as gasoline demand has declined over the past two years and as the supply of ethanol has grown threefold in under 5 years. Production was barely over 200,000 b/d in 2004 and has averaged 672,000 b/d through the first 8 months of 2009. Gasoline imports are and will be a firmly integrated part of the U.S. petroleum supply. The U.S. imports the majority of its gasoline from Canada, the Virgin Islands, and Europe, where the dieselization of passenger cars has left refiners with surplus gasoline.⁹ Figure 3 shows gasoline imports' share of the domestic gasoline supply.

⁸ The new tax treatment was enacted into law with the passage of the American Jobs Creation Act (P.L. 108-357) (October 22, 2004).

⁹ See EIA U.S. Imports by Country of Origin.

http://tonto.eia.doe.gov/dnav/pet/pet_move_impcus_a2_nus_ep00_im0_mdbl_m.htm

Figure 3. Total Gasoline Imports Share of Finished Motor Gasoline Product Supplied

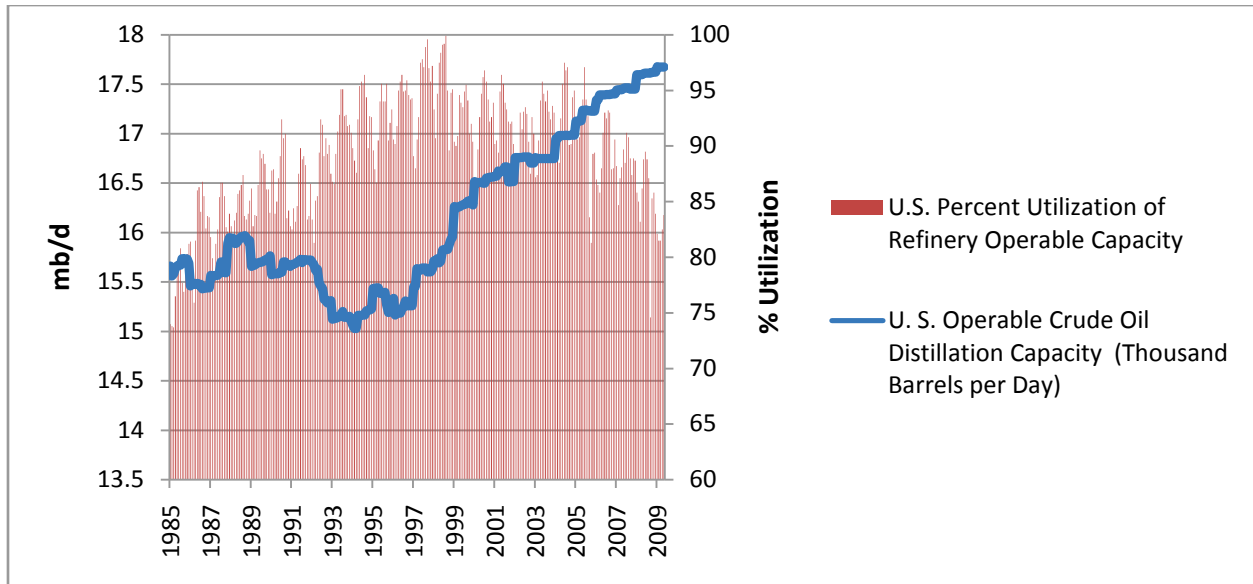


Source: EIA Data, EPRINC Calculations

During the past decade import market share has grown and stabilized during periods of both increasing and decreasing prices and demand. Figure 3 suggests that when U.S. gasoline demand began to decline in 2007 from its peak, the bulk of the resulting supply response (reduction) came from domestic

Refinery utilization has been in decline since 2004 and U.S. refiners cut crude runs sharply beginning in 2008 as demand for refined products of all types declined. Yet gasoline imports in 2008 remained strong at 900,000 b/d (10% of net demand for gasoline) during a period of falling demand and shrinking domestic production, evidence that foreign supplies remain well entrenched in the U.S. market.

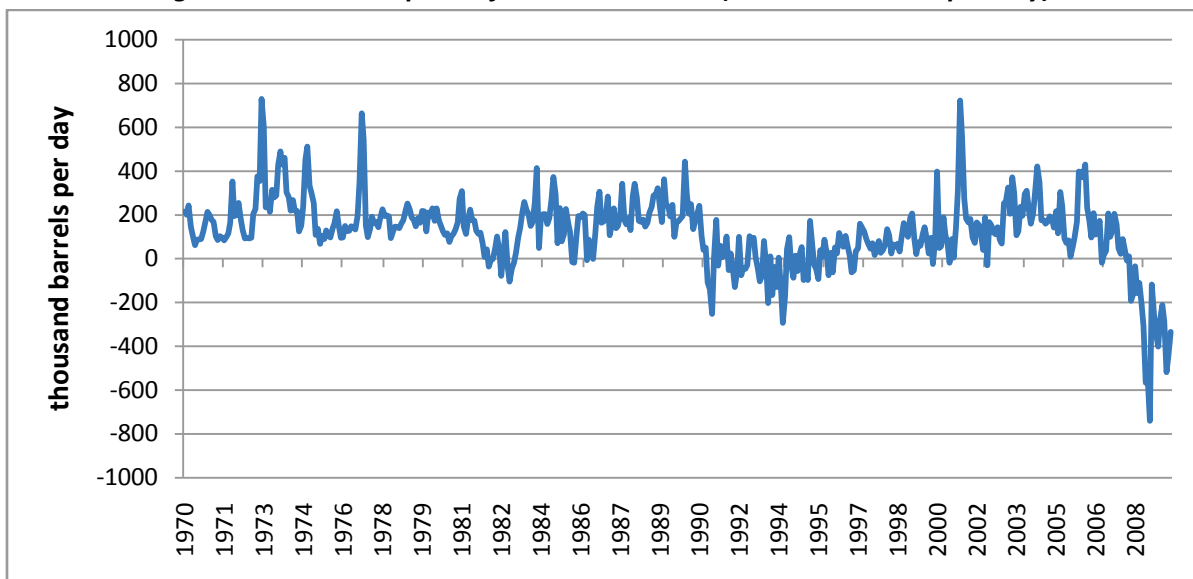
Figure 4. U.S. Refinery Operable Capacity and Utilization Rates



Source: EIA Data

Although the picture has been somewhat grim for the U.S. refining industry with regard to gasoline production, distillate fuel exports have been a bright spot. Until late 2007, the U.S. had generally been a net importer of distillate fuels. Beginning in late 2007 the U.S. became a net exporter and has exported 345,000 b/d through the first six months of 2009. Exports peaked at 740,000 b/d in August, 2008.

Figure 5. U.S. Net Imports of Distillate Fuel Oil (Thousand Barrels per Day)



Source: EIA Data

It is difficult to say if, and for how long, the U.S. will continue to export distillates. The United States' time as a distillate exporter may end up being a short lived anomaly. Increased distillate demand, particularly in Europe and Asia, world constraints on distillate production capacity had pushed prices of the "middle of the barrel" significantly higher than gasoline in recent years. The economic downturn combined with significant refining capacity increases in 2009 have eased distillate markets and as expected distillate exports are well below their 2008 peak. New York Harbor Low Sulfur No. 2 diesel fuel has been trading at essentially the same as New York Harbor Regular Conventional gasoline in recent months. If U.S. refiners continue to cut runs, already historically low, distillate exports will continue to shrink. Large amounts of refining capacity scheduled to come online abroad in the next five years will create a worldwide capacity surplus and should easily soak up new demand following an eventual economic recovery, putting additional pressure on U.S. refiners' margins.

Growth in Export Capacity for Transportation Fuels

Both oil producing countries and major export refining centers have either recently commissioned and/or are planning in the very near term substantial refining capacity additions for the production of refined products. Substantial additions to world capacity will be available as before 2015 and the next few years will see lower utilization rates of reduced growth rates in the demand for petroleum products from the recent economic contraction. Influenced by record crack spreads seen a few years ago, both traditional and new refining centers initiated construction of new distillation facilities as well as expansions in both distillation and deeper refining (complexity) at existing refining centers.

China has until recently been dependent on large volumes of imports of refined products. The surge in middle distillate prices relative to gasoline during 2007-2008 was in part attributable to China's rapidly growing demand for diesel at a time when world refining capacity was stretched thin. China has already undertaken capacity expansions that are likely to eliminate exports the next 10 years and probably enable it to become a net exporter. The director of PetroChina's Planning and Engineering Institute said China's refining capacity would reach 9.92 mb/d in 2010 and 14.4 mb/d by 2015.¹⁰

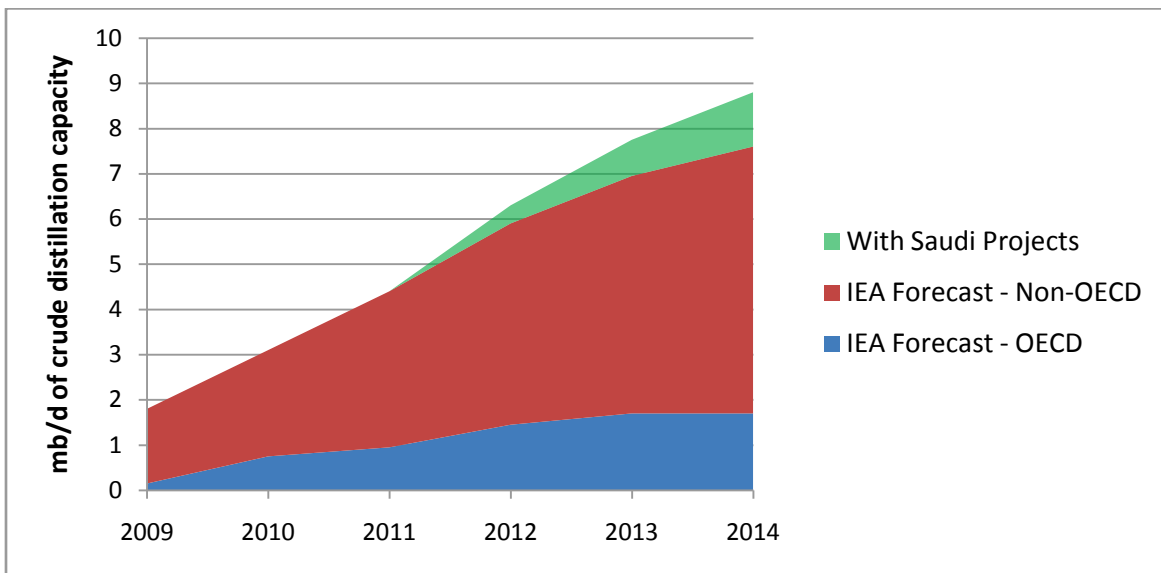
China is not alone in its desire to quickly increase its refining capacity. The International Energy Agency (IEA) projects 7.6 mb/d of new refining capacity will come online between 2009 and 2014, including China. Just 20% percent of this capacity will be built in the OECD; the remaining 80% will be built outside the OECD, primarily in Asia and the Middle East. The IEA forecast does not include three 400,000 b/d projects in Saudi Arabia which now appear to be moving forward and are all scheduled

¹⁰ According to industry trade reports China is expected to reach 14 mb/d refining capacity by 2015. China added around 800,000 b/d of refining capacity in 2008 and should reach 9.95 mb/d by the end of 2009, a 9 % increase over the previous year. More new projects and expansions are due online in the coming months and capacity is expected to rise to more than 11.2 mb/d by the end of 2009. See *China expected to raise refining capacity by 9 % this year*, **Alexander's Oil and Gas Connection**, August 20, 2009 at <http://www.gasandoil.com/goc/news/nts93319.htm>. Estimates of current China's refining capacity vary widely depending on the source.

come online by 2014, although the completion of any one refinery cannot be guaranteed. China is set to be the largest source of new capacity.

As shown in Figure 6 below, with the completion of the three projects in Saudi Arabia, the world products market will see net additions to refining capacity of 8.8 mb/d by 2014.

Figure 6. Projected Refining Capacity Additions



Source: IEA 2009 Medium-Term Oil Market Report, EPRINC Data and Calculations

Although China is motivated to reduce its reliance on refined product imports, India in contrast has commissioned a 600,000 b/d refinery at Jamnagar targeted largely at export markets. Gasoline exports from the refinery have already begun to arrive in the U.S. The refinery's primary purpose is to export refined products, not serve the domestic market. Saudi projects include both an export refinery and refineries to meet domestic demand. Saudi oil consumption grew by over 50 percent from 2000 to 2008, nearly the rate of China's growth during the same period, and is now greater than the country's refining capacity. Consumption in the Middle East as a whole grew by 40 percent over the same time period. Nevertheless, given the demand outlook considerable excess capacity will be looking for export markets in the coming years.

Some major centers that are now planning refinery additions are shown below in Table 3.

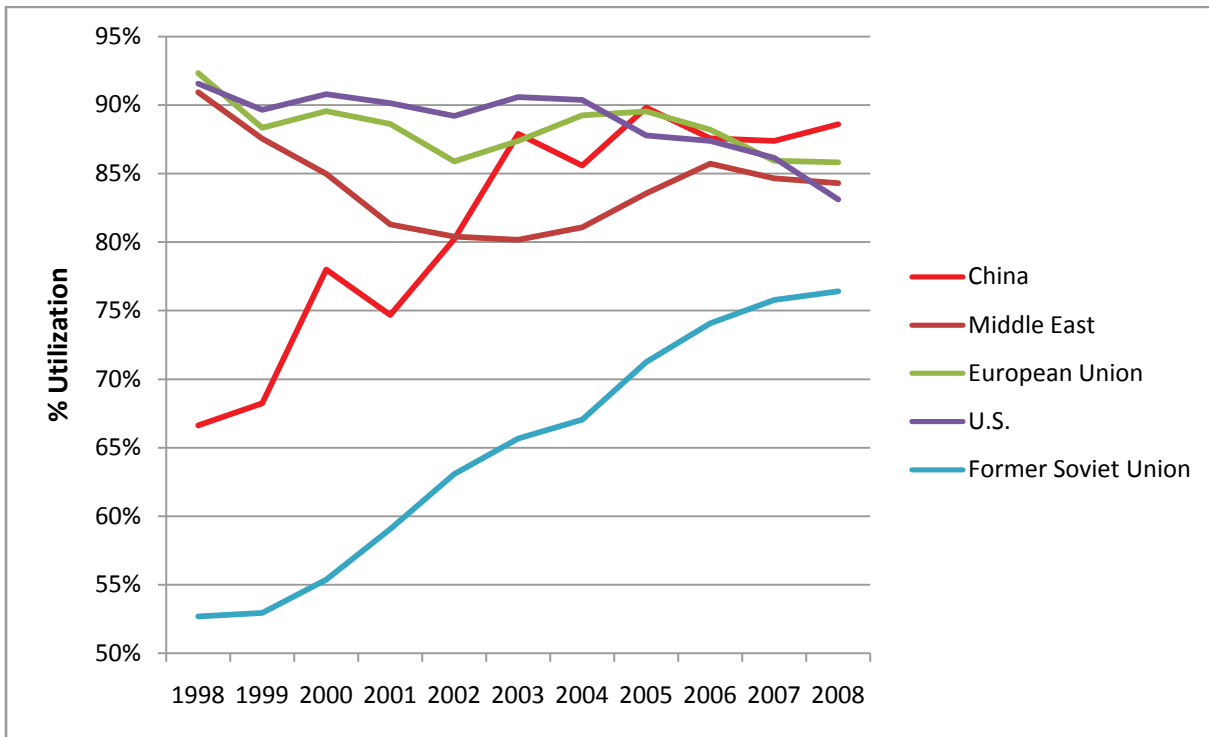
Table 3. Planned Refinery Capacity Additions at Selected Refinery Centers

	Planned Completion Date	Net Addition to Capacity (thousand b/d)
India - Jamnagar Export Refinery	2009	580
China	2014	5,600*
Saudi Arabia - Ras Tanura	2012	400
Saudi Arabia - Jubail	2013	400
Saudi Arabia - Yanbu Export Refinery	2014	400
Abu Dhabi - Ruwais	2014	400
Total:		7,780

As documented in BP's 2009 *Statistical Review of World Energy*, global refinery utilization fell to 84.8 percent in 2008, the lowest rate since 2003.¹¹ Crude throughput averaged 75.2 mb/d, leaving 13.4 mb/d idle. Note the sharp increases in utilization rates in the Former Soviet Union and Asia Pacific region compared to the declines in North America and Europe. These trends are shown in Figure 7 below but the high rates of utilization in both the Middle East and China will quickly fall as new capacity comes online in the coming years.

¹¹ BP *Statistical Review of World Energy* June 2009

Figure 7. Refinery Utilization Rates Around the World



Source: BP Statistical Review, June 2009

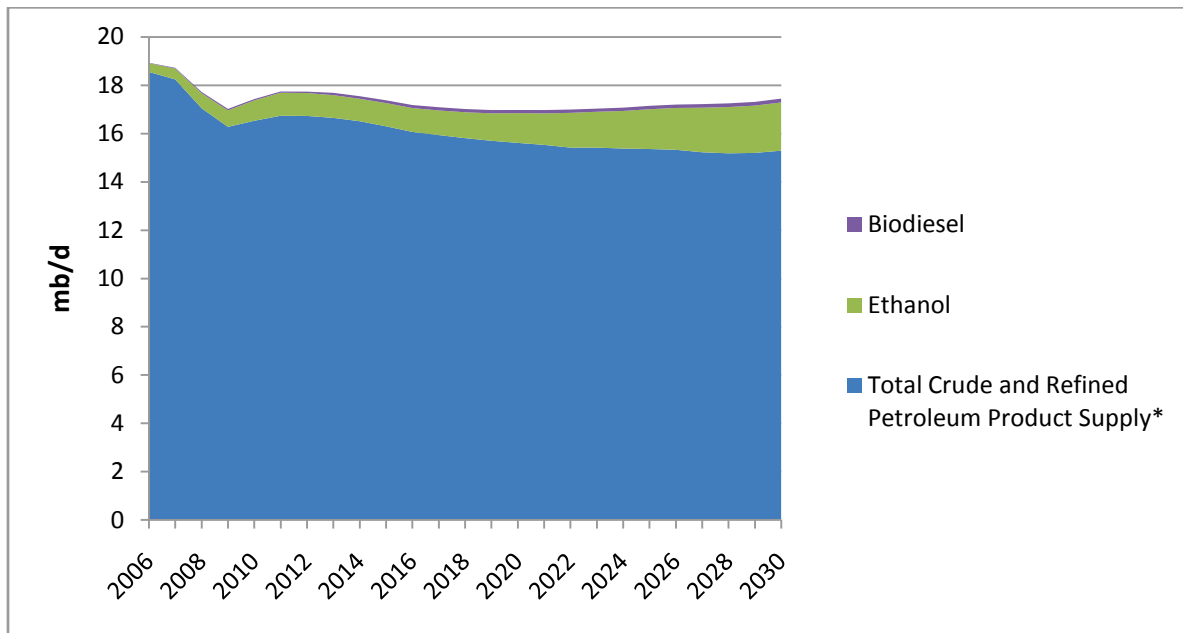
Based on IEA's forecast and estimates of current refining capacity, world refining capacity will reach 96.2 mb/d by 2014, but demand for *all liquids* is not likely to exceed 90.6 mb/d under the EIA *International Energy Outlook 2009* forecast for 2015.¹² Separating out the production of transportation fuels that do not require substantial processing (some of which are promoted through government subsidies) including biofuels, coal-to-liquids, gas-to-liquids, natural gas plant liquids, condensates, and refinery gain bring the call on refinery crude distillation capacity for 2015 to 78.2 mb/d as compared to a potential installed capacity of 96.2 mb/d. Although this market outlook might bring about downward adjustments in both the additions to refining capacity and some contraction in the more expensive substitutes for transportation fuels, the world petroleum market is clearly heading into a period of substantial excess distillation and even deep refining capacity. Drawing on these most recent trends, 2015 could see crude throughputs at 78.2 mb/d, in a market with installed capacity 96.2 mb/d yielding an average world utilization rate 81 percent. This would see world refinery centers sitting on 18 mb/d of excess capacity – an outcome that is not sustainable if demand does not recover substantially above current forecasts and will bring about capacity reductions in refining centers worldwide.

¹² 2009 EIA International Energy Outlook.

Demand Reductions for Transportation Fuels Under ACES

EIA’s analysis of W-M predicts a slight decline in U.S. petroleum consumption as a result of CO₂ allowance costs. Figure 8 shows liquid petroleum demand under W-M in EIA’s base case. In EIA’s reference case (no cap-and-trade program) petroleum demand is only about 1 mb/d higher. In the W-M base case EIA expects U.S. refinery utilization rates to decline into the mid to low 70% range through 2030 with capacity peaking at 18.5 mb/d.

Figure 8. EIA W-M Base Case Petroleum Demand



Source: EIA Data. *Refined Petroleum Product Supply includes domestic crude refinery runs plus refinery gain and refined product imports.

Using historical price elasticities for gasoline and diesel demand it becomes clear that projected CO₂ allowance costs (under the ranges evaluated by EPRINC) do not significantly reduce gasoline demand, supporting both EIA’s and EPA’s¹³ forecasts. At the average EPA allowance cost over the 2015 – 2030 time period of \$22.5/ton, gasoline prices would rise on average just \$0.20/gallon due to allowance costs based strictly on their CO₂ emissions. Diesel prices would rise by \$0.23/gallon.

¹³ See page 13: <http://www.epa.gov/climatechange/economics/pdfs/WM-Analysis.pdf>

Table 4. Incremental Gasoline and Diesel Prices Under W-M

Refiners will be legally responsible for 100% of these costs. This table assumes 100% pass-through to consumers. Section V addresses the question of whether or not 100% will be possible.

Product Price Changes	Stationary Emissions 100% Pass-through (\$/gallon of crude throughput)	Product Combustion Cost – Gasoline (\$/gallon)	Product Combustion Cost – No. 2 Distillate (\$/gallon)
Price Increase @ \$22.5/ton	0.03	0.20	0.23
Price Increase @ \$45/ton (No International Allowances)	0.05	0.40	0.46

Source: EPA Estimates and EPRINC Calculations. * \$22.50 is the average cost for CO₂ from 2015 – 2030 as estimated by EPA.

Beginning with a baseline price of \$3.00/gallon for both gasoline and diesel, the increases in Table 4 for \$22.5/ton allowances represent price increases of 6.7% and 7.7% for gasoline and diesel, respectively. Long-term price elasticities for the two fuels are -0.75 and -.3¹⁴; therefore CO₂ costs can be expected to lower gasoline demand by 5% and diesel demand by 2.3%, about 450,000 b/d and 90,000 b/d relative to a scenario with no CO₂ costs.

EPA’s analysis of demand is consistent with EPRINC’s as it shows a modest reduction in U.S. petroleum consumption through 2030. It projects petroleum consumption to remain flat between 2015 and 2030 relative to its reference scenario in both the W-M draft scenario and the W-M Draft Energy Efficiency scenario. Consumption declines by about 12.5% between 2015 and 2050. Note that EPA does not show changes in demand for petroleum based fuels (from price increases) as the primary contributor to lower GHGs. Instead, EPA’s analysis expects reductions in GHG emissions to occur mostly through energy efficiency improvements, additional nuclear power, coal with carbon capture and storage (CCS) measures, and additions to renewable electricity generation.

¹⁴ See EPRINC’s report *Where is the US Motor Fuels Market Headed?*, 2007, <http://eprinc.org/pdf/TenYearOutlookFuelsJuly.pdf>

III. Cost of Producing Refined Products under Waxman-Markey

Refinery Production Costs

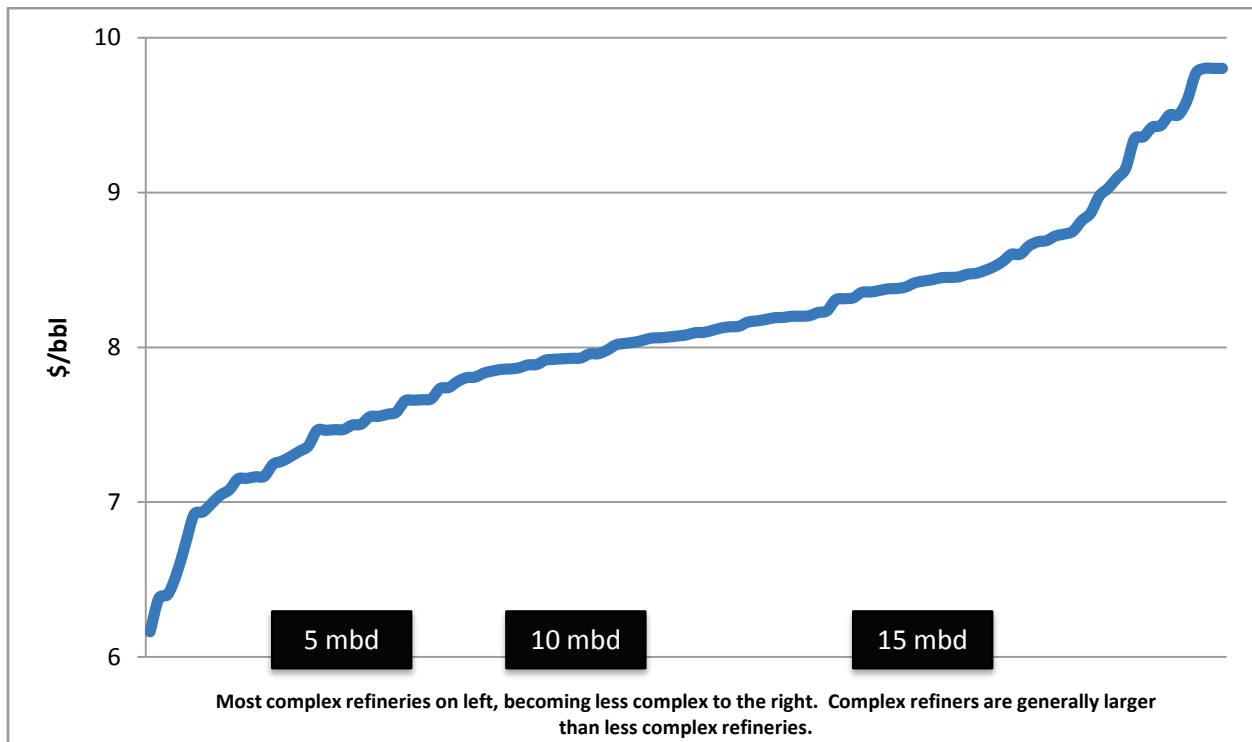
Refineries do not produce a single standardized product slate and individual facilities vary widely in complexity, product mix, and access to markets. In general, complex refineries are more costly to operate than less complex facilities, but more complexity permits the production of a more valuable product slate and/or the capability to process less costly crude oils. Although complexity is important, some refineries have a unique geographic location or produce unique product slates which are not fully captured in refinery complexity indices.

No single production function (or supply curve) can fully capture the cost of producing the entire slate of refined products for the U.S. economy. However, it is possible to approximate the cost of alternative regulatory programs (e.g., biofuels mandates, tax treatment, cap and trade legislation) on the entire refining sector by standardizing different segments of the industry to a common product slate and then evaluating the relative cost of producing the standard product slate across all units. While such a calculation may not yield a precise competitive metric for an individual unit, this approach does permit an estimate of the average cost of alternative regulatory programs and what those programs are likely to do to the cost of producing the standard product slate for the entire economy. Estimating this shift in the cost of producing the product slate is essential for estimating how much of the rising cost can be passed through to consumers as well as subsequent adjustments (losses) in market share to foreign refineries.¹⁵

¹⁵ For a discussion of EPRINC's approach in calculating the supply curve for the U.S. refining sector please refer to the appendix. Note that even in EPRINC's "business as usual scenario" some U.S. capacity will be lost to foreign producers and this is discussed in more detail in Section IV.

Figure 9 below shows EPRINC’s estimate of the cost of production for the entire domestic processing fleet for the 2015-2030 period under the EIA reference scenario – prior to any capacity reductions as a result of rising costs from pending legislative and regulatory programs (blend wall, removal of Section 199 from the tax code, and cap and trade legislation) or as a result of competitive pressures from emerging and expected growth in world refining capacity likely to take place in the 2015-2030 time frame. In this “business as usual” scenario the U.S. production function remains relatively stable with real operating costs reflecting the EIA forecast for modestly rising feedstock prices. This scenario also assumes no substantial capacity expansion as the U.S. faces essentially flat demand for transportation fuels for the forecast period.¹⁶

Figure 9. U.S. Refiners' Effective Cost of Production, 2015-2030

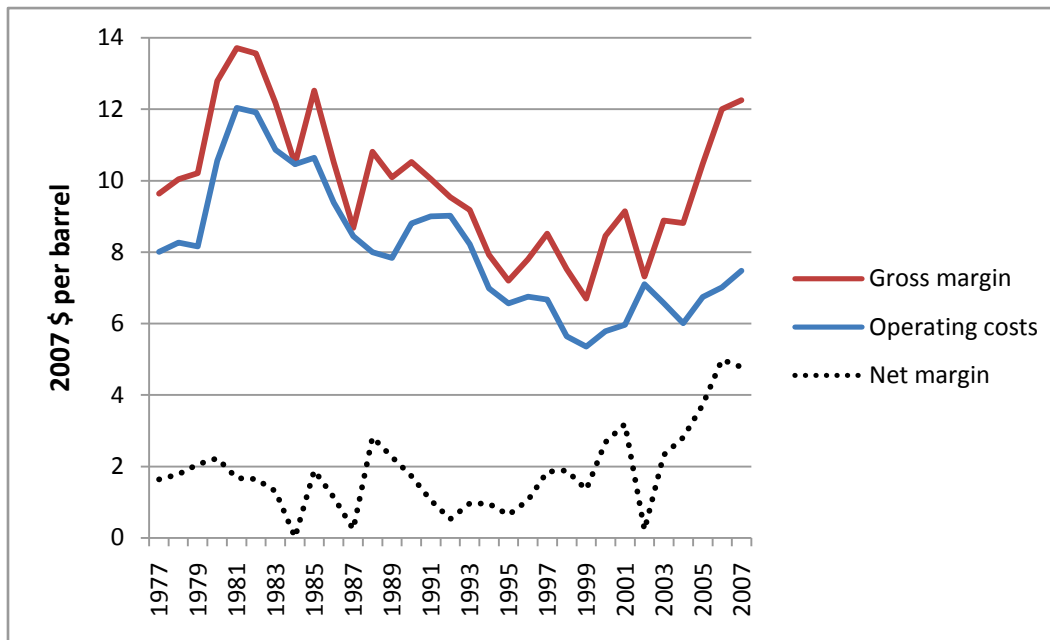


Source: EPRINC Calculations. Some lubricant and small niche refineries have been excluded.

¹⁶In EIA’s reference case, liquid fuels consumption remains virtually flat throughout the forecast period rising at 0.1% per annum, and fuel prices rise at 2.6% per annum. See <http://www.eia.doe.gov/oiaf/aeo/pdf/appa.pdf>

The EPRINC estimate heading into the 2015-2030 timeframe has costs (fixed and variable) of approximately \$6/bbl rising to over \$9/bbl depending on complexity, without any major commitments to capacity expansion. The 50 most complex refineries in Figure 9 account for 10 mb/d of capacity, meaning nearly 60% of total U.S. refining capacity is found in 40% of its refineries.

Figure 10. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1977 - 2007 (EIA)

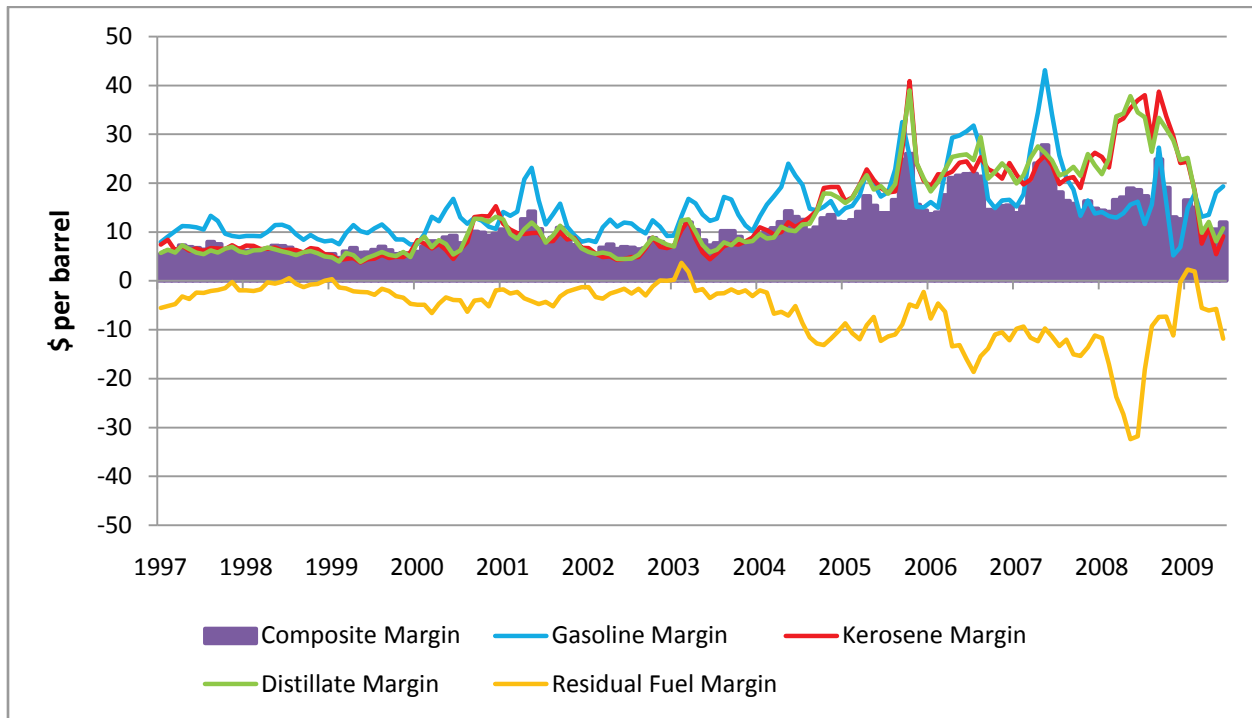


Source: EIA Data

According to EIA’s Financial Reporting System, operating costs, shown in Figure 10, have remained steady in recent years, within their historical range of \$6-\$8/bbl, and are consistent with EPRINC’s estimates in Figure 9. Net margins were strong during the refining “golden era” from 2004 to 2008 but more recent data, shown in Figure 11, suggest net margins have likely returned to their historical level around \$2 per barrel.

Figure 11 below shows gross margins for refined products comprising 85% of the barrel. Gross margins have returned to their historical levels near \$10/bbl after several years at or over \$15 per barrel beginning in 2004. Composite margins shown in Figure 11 do not include bottom of the barrel products which generally sell below crude cost.

Figure 11. Refined Product Gross Margins (for an Average U.S. Refinery)



Source: EIA Data, EPRINC Calculations

Legislative and Regulatory Programs: A Cost Analysis

The industry is likely to face a range of cost pressures in the coming years from both existing regulatory programs and new legislative initiatives. EPRINC has estimated the cost of the following regulatory and legislative initiatives and divided the cost outcomes into two categories, (1) costs faced by U.S. refiners but not by many foreign suppliers, and (2) costs faced by both U.S. and foreign suppliers.

With regard to cost of operations borne by U.S. refiners alone, the cost of acquiring allowances for stationary emissions of GHGs at the refinery site, and adjustments in tax rates (such as removal of Section 199 in the U.S. tax code) are the most prominent. Although refined products entering the U.S. from some foreign sources may have a cost penalty from CO₂ control costs from stationary emissions, a large volume of processing capacity now in place abroad, as well as new capacity scheduled to come on line in the coming years, will be free of a higher cost structure from carbon controls of stationary source emissions and will also not be subject to the higher proposed cost tax structure faced by U.S. refiners.

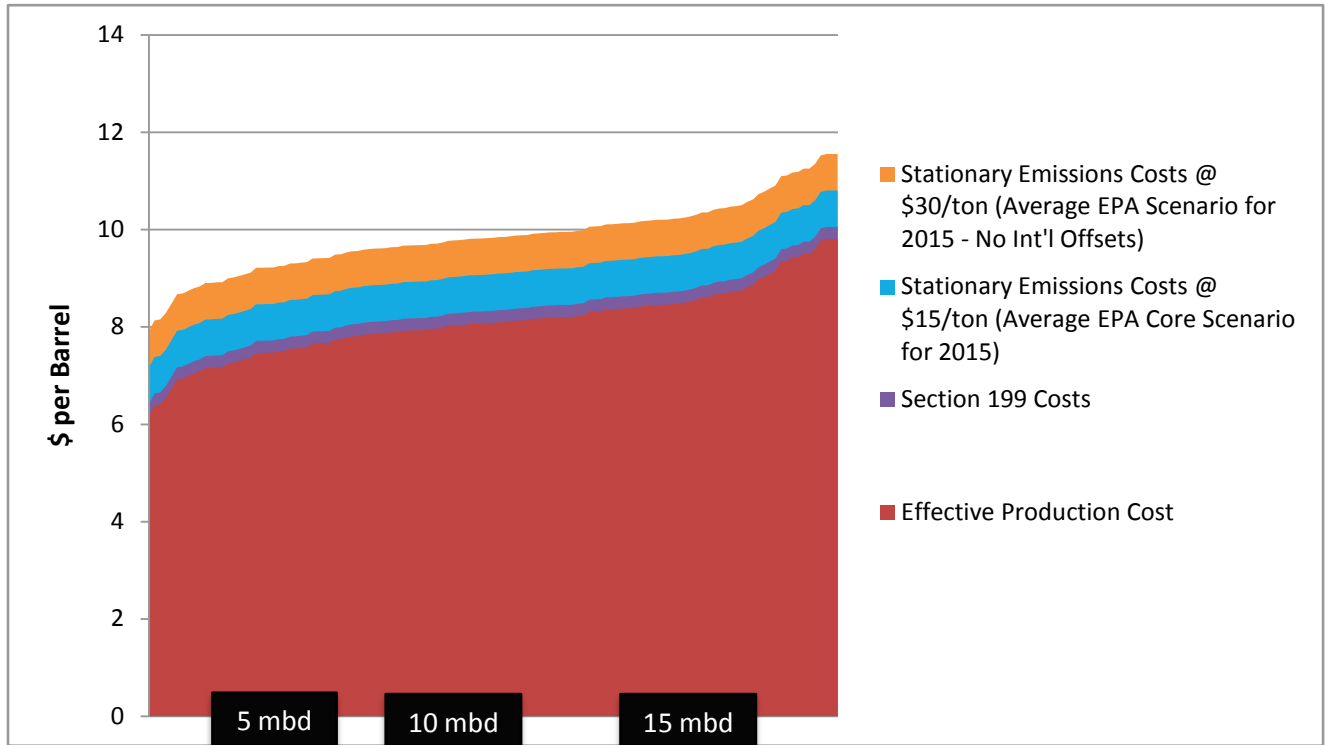
Costs Placed Solely on Domestic Refiners

In some cases, national governments may decide to participate in an international agreement to reduce GHGs, but may select control strategies that do not raise the cost of industrial operations and instead focus on strategies to promote efficiency and reduce consumption by end users as the European Union is attempting. The potential for widely differing cost structures for the production of refined products in international markets is especially important in the near to medium term. EPRINC has identified substantial foreign refining capacity with open access to the U.S. market that faces neither stationary emission costs for controlling GHGs nor corporate tax levels which would raise their cost structure to levels comparable to the cost structure of U.S. refiners. Depending upon the cost of allowances¹⁷ and whether Section 199 provisions are repealed,¹⁸ the incremental cost of operating the U.S. refining fleet will rise somewhere between \$1-\$2/bbl in 2015 as a result of Section 199's repeal and stationary emission costs. This cost does not include product allowance costs which are also imposed on imports. \$1-\$2/bbl represents an increase in operating costs of 12.5% - 25% for a refinery currently operating at \$8/bbl and 50% - 100% of a refiner earning net margins of \$2/bbl. Inclusion of free allowances granted between 2014 and 2026 lowers the cost to \$0.75-\$1.5/bbl. Pass-through of such costs to consumers will be difficult considering imported fuels will not be subject to them. After 2015 operating costs will rise further as allowance prices become more costly. It is also worth noting that in EIA's analysis of Waxman – Markey basic case allowance prices are 70% - 130% higher than those in EPA's "core" scenario during the 2015 – 2030 timeframe.

¹⁷ The costs imposed on refiners for their stationary emissions is \$0.75/bbl based on the typical amount of refinery emissions per barrel of throughput (0.05 tons per barrel) and the average price of CO₂ allowances in EPA's core scenario for 2015 (\$15 per ton of CO₂ equivalent) to \$1.50/bbl in the same scenario without international offsets. EPA further estimates that real carbon prices would rise at a rate of approximately 5% per annum.

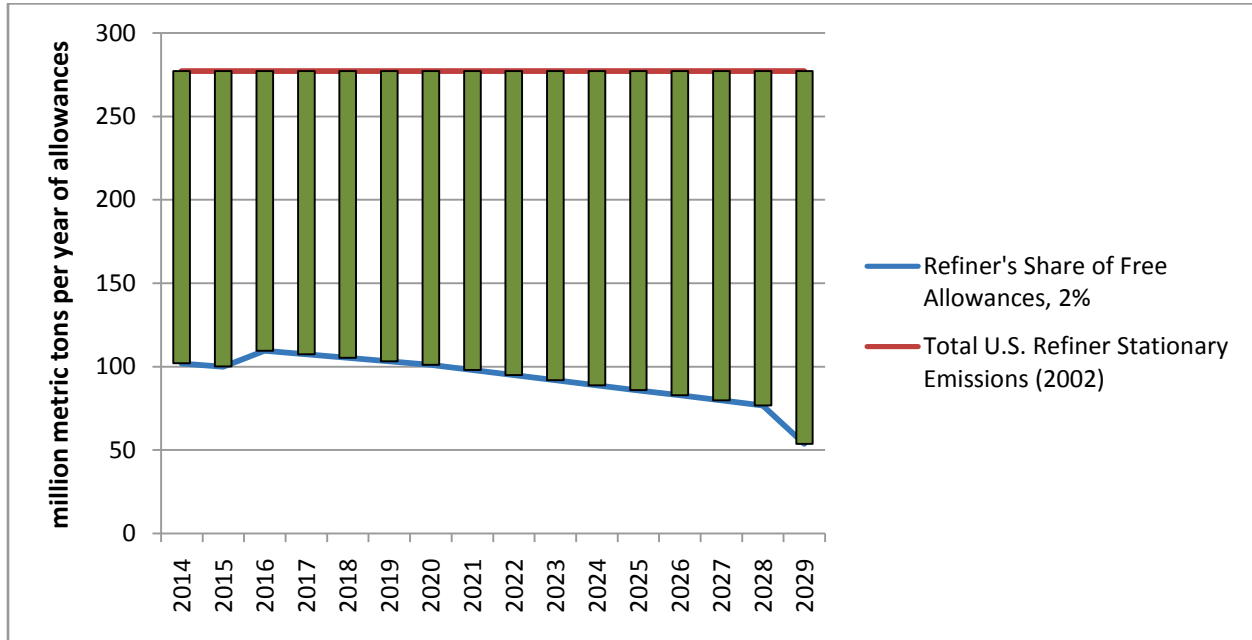
¹⁸ The repeal of the Section 199 manufacturers' tax credit will add about \$0.25/bbl to production costs with refinery runs at 15 mb/d annually. Section 199 was enacted to provide all U.S. manufacturers, not only oil refiners, with a tax treatment that is more competitive with foreign manufacturers. The proposed repeal of the credit would affect only oil refiners and oil and gas companies; it would remain in place for all other domestic industries. For more information on Section 199 please see *Do Higher Oil and Gas Taxes Pose a Threat to U.S. Energy Security*, EPRINC, 2009. <http://eprinc.org/pdf/administrationsfy2010.pdf>

Figure 12. Refiner Operating Costs with Stationary Emissions and Repeal of Section 199



Allowances distributed to refineries will provide some financial relief, but as pointed out earlier in the report “free” allowances cover less than half of all stationary emissions. If free allowances were to be allocated uniformly based on production, U.S. refiners would still face a large purchase requirement for their stationary allowances, a cost of production not faced by foreign refiners operating in an environment with no GHG costs. The green bars in Figure 13 represent stationary emission allowances that domestic refiners must purchase after the allocation of free allowances.

Figure 13. Stationary Emission Allowance Obligations Not Covered by Free Allowances



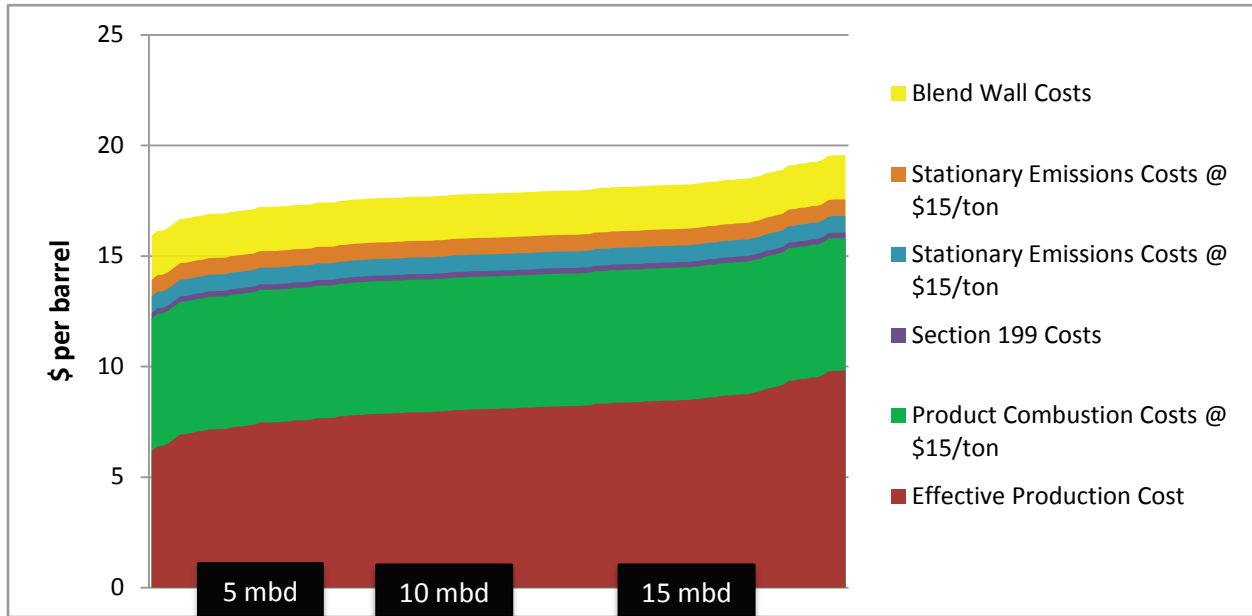
Source: W-M, EIA Data, EPRINC Calculations. *Does not include allowances allotted to “small business refiners,” 0.25% of the total pool.

Costs Placed on Domestic and Foreign Refiners

In addition to rising costs to account for stationary source emissions, refiners will face rising costs for emissions resulting from the combustion of their products. Under W-M, refiners must purchase allowances for the calculated emissions released by the combustion of the entire range of fuels produced, such as gasoline, distillate, kerosene, jet fuel, etc. consumed by motorists and industrial users. In contrast to stationary emissions, refined product importers must also purchase allowances to cover combustion emissions from product imports. U.S. refiners are also likely to face rising costs for incorporating rising and mandated volumes of high cost biofuels into the transportation fuels market. The rising costs of bringing larger supplies of biofuels into the transportation fuels market is somewhat dependent upon how the regulatory program resolves the issue of the blend wall.¹⁹

¹⁹For a full discussion on the potential for the blend wall to raise the cost of transportation fuels See EPRINC report, **Will the Ethanol Mandate Drive Up the Cost of Transportation Fuels?**, February 2009. Report can be found at <http://eprinc.org/pdf/costofethanolmandate.pdf>

Figure 14. Refiners' Future Cost of Production, 2015-2030



Source: EPRINC Calculations

GHG costs associated with product emissions alone could easily double domestic refiners' operating costs. At just \$15/ton of CO₂, product emission allowances would cost around \$6 per barrel of refined product produced. This would represent a 75% increase in operating costs for a refiner operating at a cost of \$8/bbl. As allowance prices rise refiners might see their operating costs double or triple, if not more. The conventional wisdom among policymakers appears to assume that because imported fuels will also face product emissions costs, U.S. refiners will be able to pass through 100% of these costs to consumers. However, as shown in the final section of this report, the emergence of large scale new processing capacity worldwide in low cost environments will make even a modest increase in cost of operations difficult to pass-through.

IV. Price and Capacity Adjustments

As discussed, both historic and likely cost increases from GHG and other regulatory programs will substantially raise operating costs of the domestic refining sector. How much of this rising cost structure can be passed on to consumers depends on several factors, of which foreign competition is probably the most important. In addition, these cost increases will occur in a market with relatively modest outlook for demand growth in petroleum products. U.S. crude oil demand is broadly considered to have peaked. Gasoline demand is likely to remain flat as biofuels and higher fuel efficiency automobiles offset modest demand growth for transportation fuels. Under EIA's basic W-M scenario, crude oil throughput at U.S. refineries would drop by about 1 mb/d through 2030.

What Does This Mean for the U.S. Refining Sector?

U.S. refiners have a number of competitive strengths in serving the domestic product market. They are often close to major consumption centers, can access domestic or imported crude at efficient port facilities, and can move product long distances through a low cost and advanced product distribution system. Some refiners have a unique geographic advantage even though the complexity of their operations is minimal while others produce a unique product slate. A large number of U.S. refiners have very complex operations with capability to deliver deep refining and a high valued product slate. Nevertheless, even with many of these inherent cost advantages capacity additions abroad and cost increases in the domestic market will clearly place some capacity at risk even before the allowance program under Waxman Markey is fully implemented.

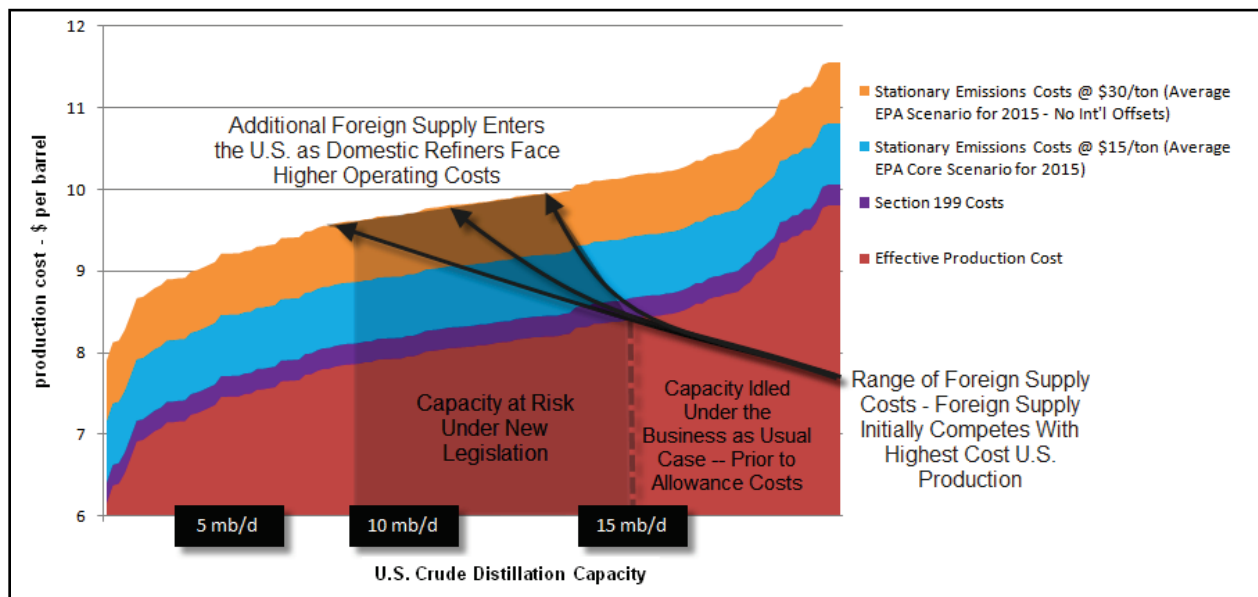
The decision to shut in refining capacity in any market is a complex business decision. The refiner must make judgments on whether low margins experienced for a period of time can be compensated by expected and unexpected opportunities to obtain high margins in subsequent periods. Abandoning a refining facility also requires dealing with permanent and long term costs of rehabilitating the site and removal of equipment. In many cases, it may pay to run the facility at very low utilization rates, at least for a period of time, but eventually facilities which cannot compete will be shut down.

Given the current market environment EPRINC examined how both existing and proposed regulatory changes to domestic refining industry would likely effect product prices, market share of foreign suppliers, capacity, and employment. The likely outcomes on how the U.S. production function (supply curve) would be affected by rising capacity in refining centers abroad under alternative regulatory scenarios.

Figure 15 below shows how two major uncertainties, the value of allowances and cost and availability of foreign refined product capacity would affect the U.S. refining industry. Note that even without higher costs associated with the blend wall and product emissions, U.S. refiners are likely to face a high risk of closure of approximately 2.5 mb/d early in the forecast period. Under EPRINC's three scenarios of foreign supply cost and availability and both the high and low cost allowance estimates, the domestic refining industry could face the loss of over 5 mb/d capacity sometime during the forecast period for

the mid range case of foreign supply availability due to costs related solely to Section 199 and stationary emission costs.

Figure 15. Domestic Refining Capacity at High Risk of Closure from Cost Increases from Station Emission GHG Obligations at \$15/ton for CO₂, 2015-2030



Foreign Capacity Additions Make Cost Pass Through Unlikely

Both domestic refiners and importers of refined petroleum products must purchase allowances for the emissions released from the consumption of the fuels they produce or import. Waxman-Markey assumes that domestic refiners will be able to pass-through 100% of these costs to consumers and will therefore be protected from trade flow risks. However, pass-through of both increases in taxes and feedstock prices is often less than 100%.²⁰ Although pass-through has at times been 100%, and sometimes greater, in an environment of excess worldwide capacity and a cost-structure that will rise more rapidly for domestic refiners than foreign refiners, 100% pass-through is unlikely. Foreign refiners selling into the U.S. market will likely find opportunities to spread allowance costs (paid by importers) among the portion of their product slate not subject to such costs.

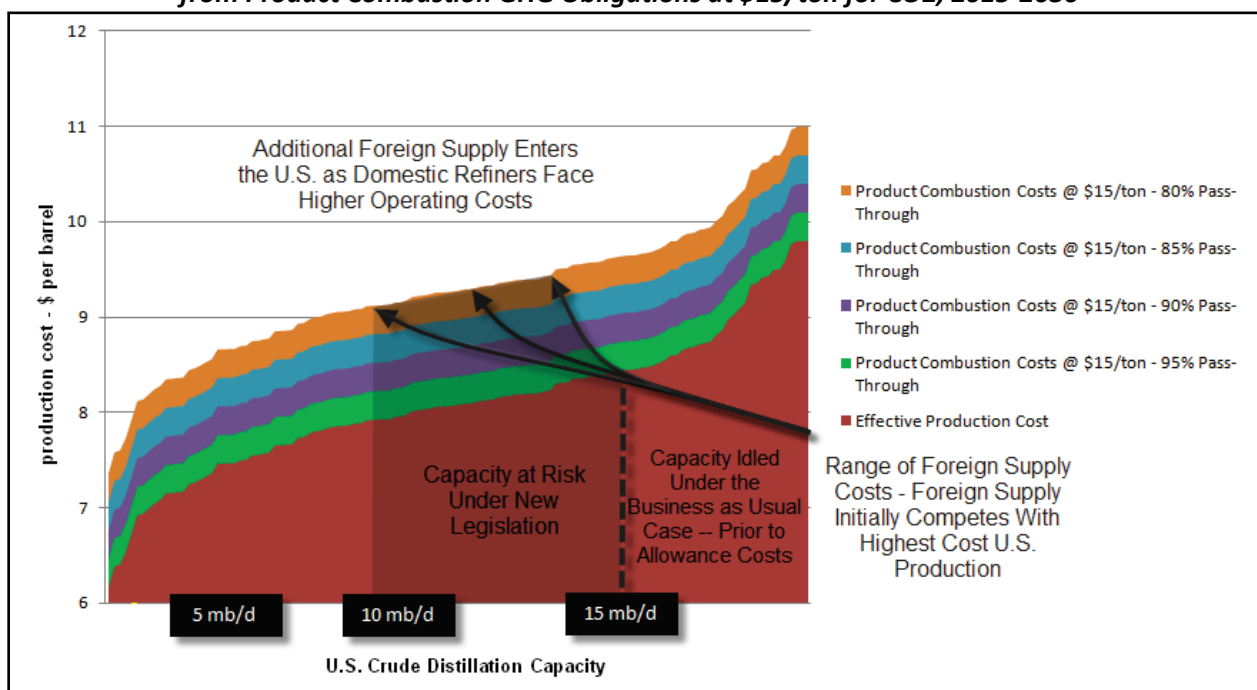
Because the scale of product allowances is so large, over \$30 billion annually at \$15/ton of CO₂ for 15 mb/d of product sales, sub-100% pass-through of product allowance costs will pose a huge risk to refiner profitability and will likely force many to idle or close capacity. Even at a rather optimistic pass-through rate of 90% and an allowance price \$15/ton, refiners must absorb \$0.60 per barrel of product produced (30% of a \$2 per barrel net margin). At \$30/ton, a price closer to EIA estimates of allowance

²⁰ See *The Pass-through of Oil Prices to Gasoline Prices*, Federal Reserve Bank of Cleveland, <http://www.clevelandfed.org/research/trends/2008/0208/04ecoact.cfm>

prices, 90% pass-through would force refiner to absorb \$1.20/bbl, over half of a typical refiner’s net margin.

Failure to achieve full pass-through of product allowance costs will place large segments of the industry at risk of closure - in addition to capacity threatened by stationary emission costs. As shown in Figure 16 below, the range of potential capacity losses relating solely to product emission costs would be from 0.8 mb/d – 2.4 mb/d at 90% pass-through even under the more optimistic scenario of an allowance cost of \$15 per ton of CO₂.

Figure 16. Domestic Refining Capacity at High Risk of Closure from Cost Increases from Product Combustion GHG Obligations at \$15/ton for CO₂, 2015-2030



Considering the large amount of worldwide processing capacity expected to come online in the next 5-10 years, the U.S refining industry will be subject to large losses in domestic market share as their cost structure increases. Although there has been considerable discussion on the capacity of the U.S. refining industry to pass through cost increases, EPRINC’s analysis shows that the more likely outcome is that a rising share of domestic processing capacity will be subject to permanent risk of closure as a direct result of rising operating costs on domestic operations at the very time that foreign producers will have both excess capacity for export and relatively low operating costs.

Tables 5 and 6 below show domestic capacity closures and job losses as a result of stationary emission costs and sub-100% pass-through of product emissions at \$15/ton and \$30/ton.

Table 5. Pass-through, Capacity Closures, and Employment Losses from Product and Stationary Allowance Costs - \$15 per ton of CO₂

	Low Foreign Supply	Medium Foreign Supply	High Foreign Supply
	Capacity at Risk of Closure	Capacity at Risk of Closure	Capacity at Risk of Closure
Product Emission Costs - 90% Pass-through	0.80 mb/d	1.50 mb/d	2.4 mb/d
Stationary Emission Costs	0.75 mb/d	1.50 mb/d	2.25 mb/d
Total Capacity Losses	1.55 mb/d	3 mb/d	4.65 mb/d
Total Job Losses	80,000	160,000	240,000

Source: EPRINC Estimates and Calculations. Employment data derived from the Economic Policy Institute and C. Barnes & Co.

In a scenario where allowance costs reach \$30/ton and 90% pass-through of product emission costs, total capacity losses could rise to as much as 8.0 mb/d and job losses could approach 400,000.

Table 6. Pass-through, Capacity Closures, and Employment Losses from Product and Stationary Allowance Costs - \$30 per ton of CO₂

	Low Foreign Supply	Medium Foreign Supply	High Foreign Supply
	Capacity at Risk of Closure	Capacity at Risk of Closure	Capacity at Risk of Closure
Product Emission Costs - 90% Pass-through	1.3 mb/d	2.3 mb/d	3.0 mb/d
Stationary Emission Costs	2.1 mb/d	4.2 mb/d	5.0 mb/d
Total Capacity Losses	3.4 mb/d	6.5 mb/d	8.0 mb/d
Total Job Losses	180,000	275,000	350,000-400,000

Source: EPRINC Estimates and Calculations. Employment data derived from the Economic Policy Institute and C. Barnes & Co.

Carbon Control Costs Abroad: A Review of Emission Controls in the European Union

While there may be international pressure to bring all world refining capacity under some kind of cap and trade program, it is unlikely a truly level playing field will emerge. Europe provides a good example in this regard. The European Union's Emission Trading System (ETS) is currently the world's only mandated cap-and-trade system. There are two major differences between the ETS and ACES with regards to the treatment of refiners. First, refiners are not responsible for purchasing allowances for emissions released upon consumption of their products. In Europe, attempts to reduce gasoline and diesel demand are targeted at the consumption end of the supply chain in the form of high fuel taxes at the pump, not the supply side. Taxes on fuels are often equivalent to several dollars per gallon. Such a system directly targets fuel consumption without putting elements of the supply chain at risk as is the case with the "upstream" targeted carbon allowance program under ACES.

The ETS also has a mechanism in place to protect carbon intensive industries from losing market share to foreign competitors due to GHG costs. The ETS conducts reviews of its industries to find those vulnerable to "carbon leakage", the increased release of emissions abroad as a result of decreased emissions domestically. The theory behind carbon leakage is that industries might move abroad to avoid GHG costs, thereby reducing emissions from the EU but increasing them elsewhere and taking with them jobs and economic value to the domestic economy. The carbon leakage analysis has a set of criteria which examines industries based on their carbon intensity and trade vulnerability. Those industries found sufficiently at risk of carbon leakage are allotted additional free allowances.

High gasoline and diesel taxes allow the EU to simultaneously attack CO₂ emissions from carbon heavy fuels while protecting domestic industries. The EU has officially determined the European refining industry to be vulnerable to carbon leakage under its carbon leak criteria. The amount of additional allowances the industry will receive has not yet been determined.

Built into ACES is a reserve pool of free allowances to protect certain industries vulnerable to carbon leakage. These allowances can be distributed to trade vulnerable industries and would be distributed in addition to pre-determined allowances. However, refiners were specifically declared ineligible to receive allowances set aside for trade vulnerable industries.

Appendices:

- A. Calculation of Production Function for Domestic Refining Industry**
- B. Explanation of Stationary Source Emissions**
- C. Estimating the Cost of Stationary Source Emissions**

A. Calculation of the Production Function

EPRINC used a derived index of refinery complexity to estimate the cost of operations at individual units throughout the United States based upon engineering reviews for each major category of complexity in the U.S. fleet. Even at complex facilities, the range of equipment at the site is varied. Some facilities have the full range of advanced processing equipment, such as fluid catalytic crackers, hydrocrackers, and cokers (to upgrade heavy fuels and residuals produced during the distillation process) to minimize output of less valuable heavy products. The advanced and more complex processing facilities require large initial investments and also operate at higher cost levels. More complex refineries also use higher amounts of labor, maintenance and catalysts.

A typical U.S. refinery generally has more complexity than refineries abroad and generally produces a product slate consisting of approximately 45-50% gasoline, 35% distillate and kerosene-type jet fuel, and 4-5% residual fuel oil. The remaining 15% (plus refinery gain) is comprised mainly of heavy products such as asphalt and petroleum coke that are often sold below crude cost as well as some light gasses. At the other end of the spectrum are small topping (or simple distillation) plants which produce a product slate of about 20% gasoline, 30% percent middle distillates and kerosene, and nearly 50% residual and heavy fuel oils plus 8% light gasses. A moderately complex refinery will produce a product slate somewhere in between.

EPRINC took the complexity, crude variations, and even location to adjust each refiner's operational costs by the incremental value of the apparent product mix based on historical differences in prices between heavy and light products. These were then translated as an adjustment to cost of operations. A given refiner might have a high cost structure but also produce a more valuable product stream. The more valuable product stream was calculated as a lower (or higher) cost of operations relative to other units in the domestic fleet depending upon its ranking in complexity, etc.

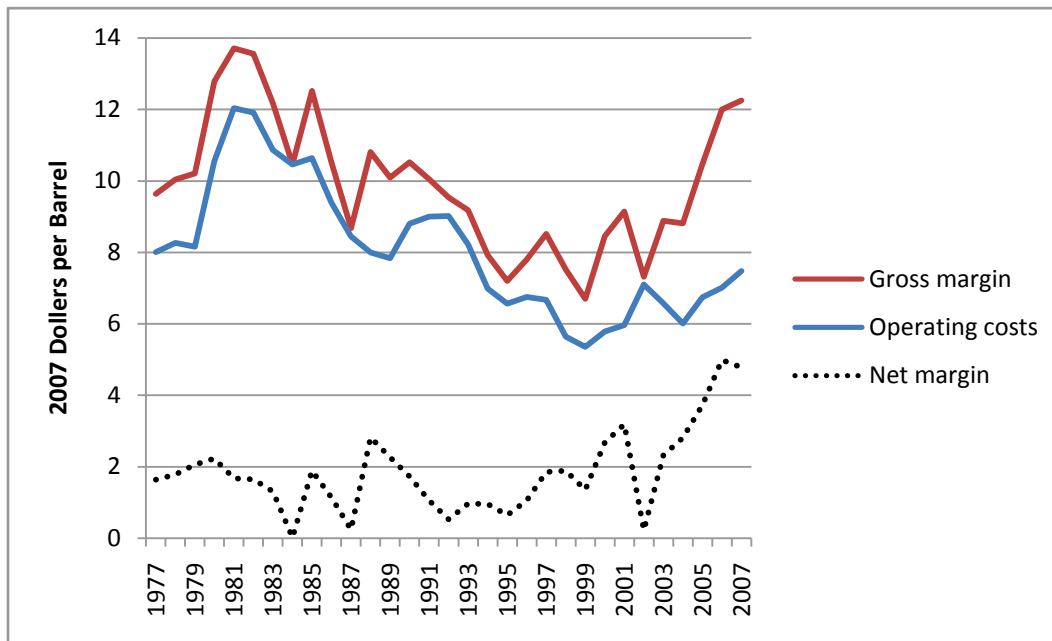
As a matter of reference, European and Asian refineries are on average less complex than U.S. refineries and tailored to produce larger amounts of middle distillates, but sacrifice gasoline production and produce large amounts of lower value residual fuel oil. A typical European refinery produces about 30% gasoline, 45% distillate, 15% residual fuel oil, and 10-15% heavy bottoms and gases. Although for a period of time, European refiners will find themselves long on gasoline and will continue to move those supplies into the U.S., their lack of complexity is harming the competitive position in product markets and we expect capacity reductions in Europe to parallel to some extent capacity reductions in the U.S. market.

Each refinery possesses a different level of complexity with varying values for their product slate depending upon conditions in the product market. In addition, our cost estimate account for variations in the value of feedstocks. For example, when spreads between light and heavy crudes increase, more complex refineries can improve their margins as they often have the ability to maximize production of

light products from heavy crudes. Location also is an important factor in crude feedstock economics and processing ability. For example, many refineries in California were designed to refine Alaskan crude just as many Gulf Coast refineries were designed to handle Gulf of Mexico crude or heavy Venezuelan crude. Should a specific type of crude oil become unavailable to a refinery designed to process it, the refinery may face significant costs in the forms of a less valuable product slate in the short-term or complexity upgrades. Location not only affects a refinery's access to crude feedstocks but in some cases product prices. Several of the costliest refineries in Figure 6 (all over \$9/bbl) are topping plants located in Alaska where gasoline sells at a much higher price than in the contiguous 48 states. Though unsophisticated, these refineries are insulated from competition due to their location and benefit from higher local prices, effectively offsetting their lack of complexity.

Figure A-1 shows operating costs and margins for refiners captured in EIA's Financial Reporting System. In real terms, operating costs were reduced as crude oil prices fell in the 1980's and 1990's, small and inefficient refineries were shuttered in favor of expansion of existing refineries, and as refineries increased complexity and efficiency.

Figure A-1. U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies, 1985-2007 (EIA)



Source: EIA Data

Operating costs have remained relatively steady within a range of \$6-\$8/bbl in recent years which is consistent with the calculated values EPRINC derived for the production function (supply curve) for the domestic refining sector.

B. An Explanation of Stationary Emissions

Waxman-Markey requires allowances to be purchased for the GHG content of both domestic and imported petroleum based fuels. It is the responsibility of the importer to purchase allowances for imported fuels. The bill also requires domestic refiners to purchase allowances to cover GHG emissions released during the manufacturing of refined products (to be referred to as “stationary emissions”).

From the “Definitions” section, page 936:

EMISSIONS.—The term ‘emissions’ includes direct emissions from fuel combustion, process emissions, and indirect emissions from the generation of electricity, steam, and hydrogen used to produce the output of a petroleum refinery or the petroleum refinery sector.

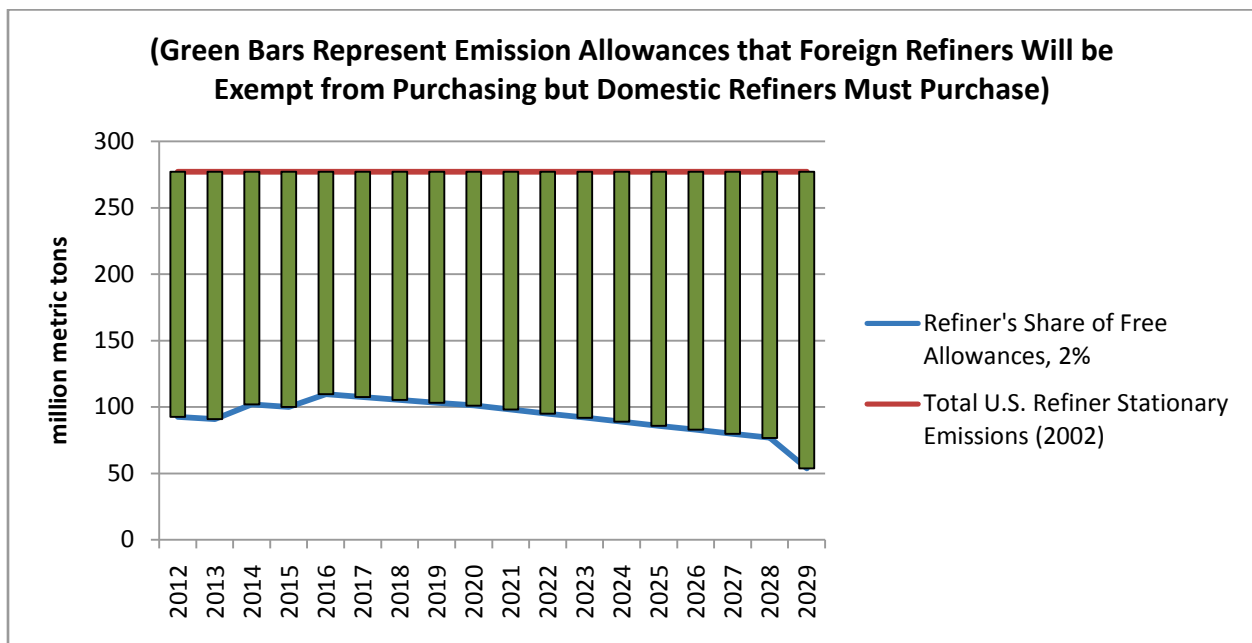
PETROLEUM REFINERY.—The term ‘petroleum refinery’ means a facility classified under code 324110 of the North American Industrial Classification System of 2002.

Foreign refiners are not required to purchase allowances for their stationary emissions nor are importers required to purchase allowances for the emissions released during the manufacture of the imported fuels. Domestic and foreign refiners will face equal costs in terms of allowances for the GHG content of the fuels they produce and sell in the U.S. However, U.S. refiners will be required to purchase allowances for GHG emissions released during the refining process whereas foreign refiners will be exempt from such costs. This discrepancy will provide a significant operating cost advantage to foreign refiners in countries that do not put a cost on GHG emissions.

C. Estimating the Cost of Stationary Source Emissions

In 2002 U.S. refiners emitted 277.6 million metric tons of CO₂.²¹ This is approximately 0.05 ton per barrel of throughput.²² Using 2002 stationary emissions as a baseline, EPRINC has calculated the difference in allowance costs for domestic and foreign refiners under W-M between 2012 and 2029 and these differences are presented below in Figure A-2.

Figure A-2. U.S. vs. Foreign Refiner Stationary Emissions Responsibilities



Assuming emissions remain at 2002 levels of 277.6 mmt, U.S. refiners would have to purchase allowances for, at a minimum, 167 mmt of CO₂ for stationary emissions not covered by the free allowances they were granted. That is in 2016, the peak year for free allowances. In 2029 they will have to purchase 223 mmt of allowances. Foreign refiners will not be required to purchase these allowances if importing fuel into the U.S. If the economy-wide 17% GHG reduction goal set forth in W-M

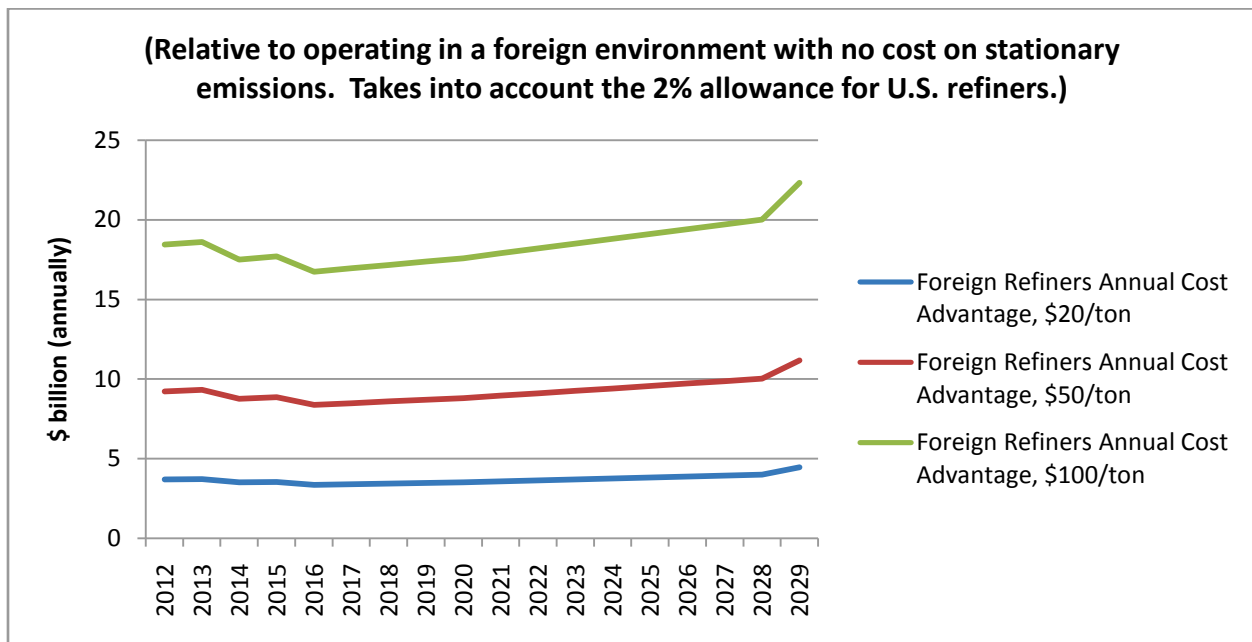
²¹ http://www.eia.doe.gov/oiaf/1605/ggrpt/pdf/industry_mecs.pdf. For refiners classified under code 324110 under NAICS.

²² EPRINC calculation. Net refinery crude imports averaged 14.935 mb/d in 2002. See EIA Weekly U.S. Crude Oil Inputs into Refineries (Thousand Barrels per Day), <http://tonto.eia.doe.gov/dnav/pet/hist/wcrrius2w.htm>. Through the first 8 months of 2009 refiners have processed 14.468 mb/d.

is met by refiners in 2020, they will still have to purchase 129 mmt worth of allowances to cover their stationary emissions.²³

The cost to U.S. refiners will be significant even with relatively low carbon prices. If an allowance for one ton of CO₂ costs an average of \$20 between 2012-2029 U.S. refiners will have to pay from \$3.3 billion to \$4.5 billion annually to cover their stationary emissions. The average cost per barrel would be \$0.60 - \$0.83 at \$20/ton and are shown below in Figure A-3.

Figure A-3. Additional Annual Cost Imposed on U.S. Refiners Due to Stationary Emissions' CO₂ Costs



²³ Assumes 2002 as the baseline year because data is not available for 2005. Crude runs were higher in 2005 than in 2002 and presumably stationary emissions were higher in 2002; therefore a 17% reduction from 2005 would allow for greater emissions compared to a 17% reduction from 2002 levels.