Proposal to Designate an Emission Control Area for Nitrogen Oxides, Sulfur Oxides and Particulate Matter

Technical Support Document

Chapter 5
Costs

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5 Costs

The reduction of SO_X, NO_X, and PM emissions from ships has an associated cost that reaches not only to the shipping industry but also to marine fuel suppliers and companies who rely on the shipping industry. Though these cost impacts do exist, analyses presented in this document indicate that the costs associated with the proposed ECA are expected to have a minimal economic impact and to be relatively small compared to the resulting improvements in air quality. This chapter describes the analyses used to evaluate the cost impacts of Tier III NO_X requirements combined with the use of lower sulfur fuel on vessels operating within the U.S. portion of the proposed ECA; including estimates of lower sulfur fuel production costs, engine and vessel hardware costs, and the associated differential operating costs. This chapter also presents cost per ton estimates for ECA-based NO_X and fuel sulfur standards and compares these costs with established land-based control programs.

The costs presented here are based on the application of ECA controls and compliance with ECA standards in 2020. Consistent with the presentation of the inventory (Chapter 2) and the benefits (Chapter 4), the estimated costs are reported for the year 2020. In this year, only new vessels will incur hardware costs, while all vessels (new or existing) will incur additional operating costs in the proposed ECA (e.g. the use of urea on an SCR equipped vessel built in or prior to 2020). A separate analysis is provided for the benefit of ship owners, which presents the estimated one-time hardware costs that may be incurred by some existing vessels to accommodate the use of lower sulfur fuel. These costs are expected to be incurred by 2015 when the fuel sulfur standards take effect, and are not included in the 2020 total. All costs are presented in terms of 2006 U.S. dollars.

5.1 Fuel Production Costs

This section presents our analysis of the impact of the proposed ECA on marine fuel costs. Distillate fuel will likely be needed to meet the 0.1 percent fuel sulfur limit, beginning in 2015, for operation in ECAs.[A] As such, the primary cost of the fuel sulfur limit will be that associated with switching from heavy fuel oil to higher-cost distillate fuel, when operating in the ECA. Some engines already operate on distillate fuel and would not be affected by fuel switching costs. Distillate fuel costs may be affected by the need to further refine the distillate fuel to meet the 0.1 percent fuel sulfur limit. To investigate these effects, studies were performed on the impact of a U.S./Canada ECA on global fuel production and costs. These studies, which are summarized below, include economic modeling to project bunker fuel demand and refinery modeling to assess the impact of a U.S./Canada ECA on fuel costs.

[A] As an alternative, an exhaust gas cleaning device (scrubber) may be used. This analysis does not include the effect on distillate fuel demand of this alternative approach. It is expected that scrubbers would only be used in the case where the operator determines that the use of a scrubber would result in a cost savings relative to using distillate fuel. Therefore we are only estimating the cost of compliance using distillate fuel here as we believe this is the most likely approach.

5.1.1 Bunker Fuel Demand Modeling

To assess the affect of an ECA on the refining industry, we needed to first understand and characterize the fuels market and more specifically the demand for the affected marine fuels both currently and in the future. Research Triangle Institute (RTI) was contracted to conduct a fuels study using an activity-based economic approach.[1] The RTI study established baseline bunker fuel demand, projected a growth rate for bunker fuel demand, and established future bunker fuel demand volumes. The basis for this work was the Global Insights economic model which projects international trade for different categories of commodities. Demand for marine fuels was derived from the demand of transportation of various types of cargoes by ship, which, in turn, was derived from the demand for commodities produced in one region of the world and consumed in another. The flow of commodities was matched with typical vessels for that trade (characterized according to size, engine power, age, specific fuel consumption, and engine load factors). Typical voyage parameters were assigned, including average ship speed, round trip mileage, tonnes of cargo shipped, and days in port. Fuel consumption for each trade route and commodity type was thus a function of commodity projections, ship characteristics, and voyage characteristics.

The bunker demand model included operation off the coasts of the contiguous United States and southeastern Alaska. The bunker demand volumes for this modeling in the Canadian portion of the ECA was based on fuel consumed by ships en route to and from Canadian ports based on estimates from Environment Canada.

These affected fuel volumes which are used in the WORLD model described below, are slightly higher than what we now estimate for the proposed ECA. This difference is because the RTI evaluation of affected fuel volumes was performed before the ECA was defined and was performed independently of the emission inventory modeling described in Chapter 2. However, we believe it is reasonable to use the fuel cost increases, on a per-tonne basis, from the WORLD modeling to estimate the impact of the proposed ECA. In earlier work,[2] EnSys modeled a number of fuel control scenarios where the volume of affected fuel was adjusted to represent 1) different ECAs or 2) various penetration scenarios of exhaust gas scrubbers (as an alternative to fuel switching). This work suggests that the differences in fuel volume between these scenarios have only a small effect on fuel cost. Although this earlier work was based on the older crude oil and refinery costs used in the expert group study, it is sufficient for observing the sensitivity of fuel cost increases to small changes (on a global scale) in affected fuel volume. In addition, the larger affected fuel volume, used in the WORLD modeling, directionally increases the projected fuel cost increases, and therefore allows for a conservative analysis.

5.1.2 Bunker Fuel Cost Modeling

5.1.2.1 Methodology

To assess the impacts of the proposed ECA on fuel costs, the World Oil Refining Logistics and Demand (WORLD) model was run by Ensys Energy & Systems, the owner and developer of the refinery model. The WORLD model is the only such model currently developed for this purpose, and was developed by a team of international petroleum consultants. It has been widely used by industries, government agencies, and OPEC over the past 13 years, including the Cross Government/Industry Scientific Group of Experts, established to evaluate the effects of the different fuel options proposed under the revision of MARPOL Annex VI.[3] The model incorporates crude sources, global regions, refinery operations, and world economics. The results of the WORLD model have been shown to be comparable to other independent predictions of global fuel, air pollutant emissions and economic predictions.

WORLD is a comprehensive, bottom-up model of the global oil downstream that includes crude and noncrude supplies; refining operations and investments; crude, products, and intermediates trading and transport; and product blending/quality and demand. Its detailed simulations are capable of estimating how the global system can be expected to operate under a wide range of different circumstances, generating model outputs such as price effects and projections of refinery operations and investments.

5.1.2.2 Assessment of the Impact of Marine Fuel Standards

During the development of the amendments to MARPOL Annex VI, a Cross Government/Industry Scientific Group of Experts was established, by IMO, to evaluate the effects of the different fuel options that were under consideration at the time. This expert group engaged the services of EnSys to assess the impact of these fuel options using the WORLD model. The final report from this study presents great detail on the capabilities of the WORLD model and provides support for why the WORLD model was chosen as the appropriate tool for modeling the economic impacts of the different fuel options.[4] The following description of the WORLD model is taken from the expert group study:

WORLD is a linear programming model that simulates the activities and economics of the world regional petroleum industry against short, medium or long term horizons. It models and captures the interactions between:

- crude supply;
- non-crudes supply: Natural gas Liquids (NGLs), merchant MTBE, biofuels, petrochemical returns, Gas To Liquid fuels (GTLs), Coal to Liquid fuels (CTLs);
- refining operations;
- refining investment;
- transportation of crudes, products and intermediates;
- product blending/quality;
- product demand; and
- market economics and pricing.

The model includes a database representing over 180 world crude oils and holds detailed, tested, state-of-the-art representation of fifty-plus refinery processes. These representations include energy requirements based on today’s construction standards for new refinery units. It allows for advanced representation of processes for reformulated, ultra-lower sulfur/aromatics fuels and was extended for detailed modeling of marine fuels for the aforementioned EPA and API studies. The model contains detailed representations of the blending and key quality specifications for over 50 different products spread across the product spectrum and including multiple grades of gasolines, diesel fuels/gasoils (marine and non-marine) and residual fuels (marine and non-marine).

The refining industry is a co-product industry. This means that changes in production of one product also affect production volume and/or production costs of other products. As necessary, the model will adjust refinery throughputs and operations, crude and product trade patterns to ensure that a specified product demand slate is met, without surplus or deficit of any product.

To evaluate the impact of changes to marine fuels specifications as a result of any of the options under consideration, the model is run with a future demand scenario for all products. The first run, the base case, assumes marine fuels in line the current Annex VI regulation. The second run is done with marine fuel specifications in line with the option under consideration. Both runs are optimized independently. Since the only thing that is altered between the cases is the change in the projected marine fuels regulation, the difference between both cases is therefore a true assessment of the actual cost and other implications of the change to the marine fuels requirements under consideration. Thus, the incremental refining investment costs, incremental marine fuel costs and incremental refinery/net CO_2 emissions are all directly attributable to - and must be allocated to – the change in regulation.

Prior to the expert group study, EnSys made updates to the WORLD model to be able to perform the analysis of the impacts of different marine fuel options. As part of this effort, the refinery data, capacity additions, technology assumptions, and costs were reviewed. EnSys reviewed relevant regulations to ensure that the WORLD model was correctly positioned to undertake future analyses of marine fuels ECAs. In developing these updates, a number of issues had to be considered:

- the costs of refining, including the capital expenditures required to reduce bunker fuel sulfur content and the potential for process technology improvements;
- likely market reactions to increased bunker fuel costs, such as fuel grade availability, impacts on the overall transportation fuels balance, and competition with land-based diesel and residual fuels for feedstocks that can upgrade fuels;
- the effects of emissions trading; and
- the potential for low- and high-sulfur grade bunker sources and consumption to partially shift location depending on supply volume, potential, and economics.

The analytical system thus had to be set up to allow for alternative compliance scenarios, particularly with regard to (a) adequately differentiating bunker fuel grades; (b) allowing for differing degrees to which the ECA or other standards in a region were presumed to be met by bunker fuel sulfur reductions, rather than by other means such as scrubbing or emissions trading; and (c) allowing for all residual fuel bunker demand to be reallocated to marine diesel. Beyond any international specifications, the analytical system needed to be able to accommodate future consideration of regional, national, and local specifications.

The primary approach taken to manage these issues was to:

- expand the number of bunker grades in the model to three distillates and four residual grades;[B]
- allow for variation where necessary in (regional) sulfur standards on specific bunker grades; and
- enable residual bunker demand to be switched to marine diesel.

Other updates to the WORLD model included product transportation matrices covering tanker, interregional pipeline, and minor modes were expanded to embody the additional distillate and residual bunker grades, adjustments to the yield patterns of the residuum desulfurization, and blocking of paraffinic streams from residual fuel blends. The details of compliance in any particular region must be estimated external to the main WORLD model. As discussed above, we provided our estimates of affected fuel volumes to Ensys.

5.1.2.3 Updates for ECA Analysis

To determine the impact of the proposed ECA, the WORLD model was employed using the same basic approach as for the IMO expert group study. Modeling was performed for 2020 in which the control case included a fuel sulfur level of 0.1 percent in the U.S. and Canadian EEZs.[5] The baseline case was modeled as "business as usual" in which ships continue to use the same fuel as today. This approach was used for two primary reasons. First, significant emission benefits are expected in an ECA, beginning in 2015, due to the use of 0.1 percent sulfur fuel. These benefits, and costs, would be much higher in the early years of the program before the 0.5 percent fuel sulfur global standard goes into effect. By modeling this scenario, we are able to observe the impact of the proposed ECA in these early years. Second, there is no guarantee that the global 0.5 percent fuel sulfur standards will begin in 2020. The global standard may be delayed until 2025, subject to a fuel availability review in 2018. In addition, the 3.5 percent fuel sulfur global standard, which begins in 2012, is higher than the current residual fuel sulfur average of 2.7 percent.

In the modeling for the expert group study, crude oil prices were based on projections released by the U.S. Energy Information Administration (EIA) in 2006.[6] Since that time, oil prices have fluctuated greatly. Using new information, EIA has updated its projections of oil price for 2020.[7,8] In response to this real-world effect, the ECA modeling was conducted using the updated oil price estimates. Specifically, we used a crude oil price of $51.55 for the reference case, and $88.14/bbl for the high price case, both expressed in real (2006) dollars. These crude oil prices were input to the WORLD model which then computed residual and distillate marine oil prices for 2020. The net refinery capital impacts are imputed based on the differences in the costs to the refining industry that occur between the Base Cases and ECA cases in 2020. The

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[B] Specifically, the following seven grades were implemented: MGO, plus distinct high- and low-sulfur blends for MDO and the main residual bunker grades IFO 180 and IFO 380. The latest international specifications applying to these fuels were used, as were tighter sulfur standards for the low-sulfur grades applicable in SECAs.

incremental global refining investment over the Base Case is projected to cost an additional $3.83 billion, with $1.48 billion being used for debottlenecking projects and $1.96 billion used for new units. For the high priced crude case, the incremental capital investments for an ECA is $3.44 billion over the base case, with new units accounting for $2.49 billion while debottlenecking costs are $0.72 billion. For both of the crude oil price cases, refinery investments represent a marginal increase of about 2 percent over the corresponding total base case investments required in 2020. Additionally, the majority of these ECA investments occur in the U.S./Canada refining regions, though smaller amounts also occur in other world regions. In addition to increased oil price estimates, the updated model accounts for increases in natural gas costs, capital costs for refinery upgrades, and product distribution costs.

5.1.3 Results of Fuel Cost Study

5.1.3.1 Incremental Refinery Capital Investments Associated with Desulfurization

5.1.3.1.1 General Overview

The primary refining cost of desulfurization is associated with converting IFO bunker oil into a distillate fuel with a DMA specification. The other significant refining costs are those related to desulfurizing distillate stocks. The bulk of the refinery investments occur in regions located outside of the U.S. and Canada, because capital investments in these regions are approximately 9 and 23 percent of the overall capital for the reference and high priced crude cases, respectively. Table 5.1-1 summarizes the overall capital investments made for both conversion of IFO bunker oil into distillate as well as desulfurization in refineries in the various U.S. regions (East Coast, West Coast and Gulf Coast) and overseas. These cost estimates are based on the WORLD modeling results.

Table 5.1-1 Incremental Refinery Capital Investment Made in 2020 (2006 dollars)

	REFINERY INVESTMENTS ($ BILLION)					
	Base Case $52/bbl Crude	**NA ECA $52/bbl Crude**	**Delta**	**Base Case $88/bbl Crude**	**NA ECA $88/bbl Crude**	**Delta**
USEC	1.4	1.2	-0.2	1.0	0.9	-0.1
USGCCE	14.5	14.8	0.3	26.2	27.3	1.2
USWCCW	1.4	1.6	0.2	1.4	1.5	0.2
Refinery Investments Total USA+Canada	17.3	17.6	0.3	28.6	29.8	1.3
Refinery Investments Total Other Regions	85.2	88.1	2.9	110.5	115.0	4.4
Total World	102.5	105.7	3.2	139.1	144.8	5.7
Type of Modification						
Debottleneck	0.7	0.7	0.0	1.4	1.4	0.0
Major New Units	97.8	100.8	3.0	132.1	138.0	6.0
Total World	102.5	105.7	3.2	139.1	144.8	5.7

Note: USEC is United States East Coast, USGCCE is United States Gulf Coast and Eastern Canada, USWCCW is United States West Coast and Western Canada, $Bn is Billion U.S. Dollars. The results presented are investments made in 2020 to add new refinery processing capacity to what exists in the 2008 base case plus known projects.

Refinery investments in North America, Greater Caribbean and South American regions account for greater than half of all investments for the reference case, while investments made in China and Middle Eastern Gulf regions account for close to 40 percent of remaining investments. This accounts for greater than 90 percent of investments for the reference case. For the high priced ECA case, investments in U.S., Canada, Greater Caribbean and South American refiner regions again account for greater than half of all investments made, while European north and China regions account for greater than 44 percent of the remaining investments. Table 5.1-2 summarizes overall incremental investments made in all world refining regions for the reference and high priced ECA case.

Table 5.1-2 World Region Refining Investments for ECA Made in 2020

	REFERENCE CASE		HIGH PRICED CASE	
	Capital, $ Billion	% of Capital	Capital, $ Billion	% of Capital
USEC	-0.167	-5.2%	-0.095	-1.7%
USGICE	0.277	8.7%	1.159	20.3%
USWCCW	0.176	5.5%	0.224	3.9%
GrtCAR	0.253	7.9%	0.828	14.5%
SthAM	0.810	25.4%	0.870	15.3%
AfWest	0.004	0.1%	0.002	0.0%
AfN-EM	0.143	4.5%	-0.006	-0.1%
Af-E-S	0.007	0.2%	0.006	0.1%
EUR-No	0.011	0.4%	1.239	21.7%
EUR-So	-0.006	-0.2%	-0.035	-0.6%
EUR-Ea	0.021	0.7%	-0.014	-0.2%
CaspRg	0.157	4.9%	-0.001	0.0%
RusFSU	0.185	5.8%	0.036	0.6%
MEGulf	0.754	23.6%	0.119	2.1%
PacInd	-0.115	-3.6%	0.069	1.2%
PacHi	0.177	5.5%	0.000	0.0%
China	0.490	15.3%	1.305	22.9%
RoAsia	0.018	0.6%	-0.002	0.0%
Total	3.20	100.0%	5.70	100.0%

Note: USEC = US East Coast, USGICE= US Gulf Coast, Interior & Canada East, USWCCW= US West Coast & Canada West, GrtCAR= Greater Caribbean, SthAM= South America, AfWest=African West, AFN- EM= North Africa/Eastern Mediterranean, AF-E-S=Africa East and South, Eur-No=Europe North, EUR-So= Europe South, EUR-EA= Europe East, CaspRg= Caspian Region, RusFSU= Russia & Other Former Soviet Union, MEGulf= Middle East Gulf, Pac Ind= Pacific Industrialized, PacHi= Pacific High Growth / Industrialising, RoAsia= Rest of Asia

5.1.3.1.2 Processing of Residual Stocks

IFO bunker grades are primarily comprised of residual stocks, such as Vacuum Residuals, Atmospheric Residuals, Visbreaker Residuals, and Fluidized Catalytic Cracking (FCC) clarified oil. These fuels also contain distillates that are added as cutter stocks, such as Light Cycle Oil (LCO), Vacuum Gas Oils (VGO), and kerosenes. As such, only the residual fuel blendstocks in IFO bunkers would need to be replaced or converted into distillate volumes to provide for additional lower sulfur distillate marine fuel. For converting residuals to distillates, refiners use two process technologies: Coking Units (Cokers) and Residual Hydrocrackers.

Coking units are used to convert the poorer quality residual feedstocks in IFO bunkers, such as Vacuum residuals. The coking units crack these residuals into distillates, using heat and residence time to make the conversion. The process produces petroleum coke and off gas as byproducts. Residual hydrocrackers are used to convert low and medium sulfur residual streams into distillates. Residual hydrocracking uses fluidized catalyst, heat and hydrogen to catalytically convert residual feedstocks into distillates and other light fuel products. The hydrocracking process upgrades low value residual stocks into high value distillate transportation fuels consuming large amounts of hydrogen.

For processing of residual blendstocks, vacuum tower distillation capacity is added to extract gas oils blendstocks that exist in residuals fuels used in current IFO bunker grades. The extracted gas oils are further processed in either distillate hydrotreaters or gas oil hydrocrackers to produce a distillate fuel that would meet a 0.1 percent fuel sulfur limit. The use of additional vacuum towers capacity minimizes the volume of residual stocks which lowers processing costs, as less volume of fuel is processed in high cost residual coking and residual hydrocracker processes.

5.1.3.1.3 Distillate Stocks Processing

Conventional distillate hydrotreating technology is used to lower the sulfur levels of high sulfur distillate stocks. This technology removes sulfur compounds from distillate stocks using catalyst, heat and hydrogen. Since the ECA sulfur standard is 0.1 percent, conventional distillate hydrotreating would likely be the technology chosen by refiners to make this distillate, rather than the ultra lower sulfur technology that is used to remove sulfur to levels below 15 ppm (0.0015 percent). Conventional distillate hydrotreating refers to the design and conditions in the process, such as catalyst type, catalyst volume, reactor pressure, feed and reactor flow scheme used to lower sulfur levels to 0.05 percent or higher.

Although the cutter stocks in IFO bunkers are distillate fuels, they would need to be desulfurized because the 0.1 percent sulfur limit for the ECA is lower than the nominal sulfur levels for these blendstocks under the “business as usual” projections. The sulfur levels of distillate used directly as bunker fuel (MDO and MGO), are greater than 1,000 ppm, and thus would also need to be treated. Therefore, in addition to converting residuals to distillate fuels, existing distillates used as bunker fuel in MDO, MGO and IFO would also need to be hydrotreated. More distillate hydrotreating capacity would be required to lower the sulfur content of incremental distillate produced from cokers and residual hydrocrackers that do not meet lower sulfur marine fuel standards.

For distillate stocks that are highly aromatic and high in sulfur, the use of technology for hydrocracking lower sulfur gas oil is used to convert these blendstocks into No 2. grade diesel streams. Gas oil hydrocracking is a high volume gain process which produces diesel blendstocks that typically meet ECA sulfur standards, eliminating the need for further processing in hydrotreaters.

5.1.3.1.4 Supportive Processes

The increase in hydrotreating and hydrocracking requires new hydrogen and sulfur plant capacity. Extra hydrogen is required to react with and remove sulfur compounds in refinery hydrotreating process. It is also needed to improve the hydrogen to carbon ratio of products made from converting IFO blend components to distillates, via processing in cokers and hydrocrackers.

5.1.3.2 Capacity and Throughput Changes for the Reference Case

The WORLD model used a total of 140 thousand barrels per stream day (KBPSD) of coking capacity to convert residual stocks to distillates. Of this amount, 110 KBPSD is existing spare or "slack" capacity available in U.S. and Canada refiner regions. This capacity is available based on projections that refiners add excess coking capacity in the base case. The remaining balance of coking capacity, or 30 KBPSD, is new capacity added to refiner regions outside of United States and Canada. In addition to utilizing more coking capacity, the WORLD model also increased residual hydrocracking capacity by 50 KBPSD to convert residual stocks into distillates. These hydrocrackers were added to refiner regions located outside of United States and Canada. Overall, considering the use of cokers and residual hydrocrackers, the total refiner process capacity is 190 KBPSD for residual stocks processing, mirroring the amount needed to process the residual volumes contained in IFO180 and IFO 380 bunker grades. To remove any gas oils in residual blendstocks such as atmospheric and vacuum tower residuals, the model utilized 60 KBPSD of existing vacuum tower capacity, 50 KBPSD in U.S. and Canada and 10 KBPSD in other refiner regions.

Crude throughput is increased by 54 KBPSD, primarily to account for increased energy usage in refinery processes such as hydro crackers and hydrotreaters. Crude throughput is also increased to offset liquid volume loss from residual stocks that are converted to petroleum coke in coking units. Table 5.1-3 summarizes overall crude and non crude throughputs for the base and ECA cases in units of million barrels per stream day (MMBPD).

Table 5.1-3 Refiner Crude and Non Crude Throughputs

		REFERENCE BASE CASE	REFERENCE ECA CASE	DELTA	HIGH BASE CASE	HIGH ECA CASE	DELTA
Crude Throughput	MMBPD	86.7	86.7	0.1	75.6	75.6	0.0
Non Crude Supply							
NGL ETHANE	MMBPD	1.7	1.7	0.0	1.7	1.7	0.0
NGLs C3+	MMBPD	6.3	6.3	0.0	6.1	6.1	0.0
PETCHEM RETURNS	MMBPD	1.0	1.0	0.0	0.8	0.8	0.0

BIOMASS	MMBPD	1.5	1.5	0.0	3.0	3.0	0.0
METHANOL (EX NGS)	MMBPD	0.1	0.1	0.0	0.1	0.1	0.0
GTL LIQUIDS (EX NGS)	MMBPD	0.3	0.3	0.0	0.6	0.6	0.0
CTL LIQUIDS (EX COAL)	MMBPD	0.5	0.5	0.0	0.8	0.8	0.0
HYDROGEN (EX NGS)	MMBPD	1.0	1.0	0.0	0.8	0.9	0.1
Total Non Crude Supply	MMBPD	12.3	12.3	0.0	14.0	14.0	0.0
TOTAL Supply	MMBPD	99.3	99.4	0.1	90.2	90.3	0.1

The model added 70 KBPSD of new ultra lower sulfur gas oil hydrocracking capacity in refiner regions outside of the U.S. and Canada. The distillate produced from these units has a sulfur content low enough to meet ECA standards and therefore does not require further processing in hydrotreaters. The model also reduced throughput by 40 KBPSD in existing base case capacity for Conventional Gas Oil Hydrocrackers located in U.S. and Canada refiner regions.

The model added 160 KBPSD of new conventional distillate hydrotreating capacity, 140 KBPSD to U.S. and Canada refiner regions and 20 KBPSD in refining regions in other areas of the world. In addition to new units, the model used 150 KBPSD of "slack" distillate conventional hydrotreating capacity, 90 KBPSD of this located in U.S. and Canada and 60 KBPSD in other world refiner regions. Considering this, the total net use of conventional distillate hydrotreating for the reference case is 310 KBPSD above the base case, mirroring incremental demand of lower sulfur distillate for ECA. The model used 70 KBPSD of slack capacity for vacuum gas oil/residual hydrotreating in addition to distillate hydrotreating. Of this amount, 40 KBPSD is in U.S. and Canada and 30 KBPSD in other world refiner regions.

The increased hydrotreating and hydrocracking capacity requires new hydrogen and sulfur plant capacity and was added to refiner regions that use more distillate hydrotreating and hydrocracking. Other minor refinery process modifications were required by the model in 2020, although these were not substantial (see Table 5.1-4).

Table 5.1-4 Refinery Secondary Processing Capacity Additions in 2020 Reference Case (Million barrels per stream day)

	USE OF BASE CAPACITY			NEW CAPACITY			**BASE PLUS NEW CAPACITY**		
	US/CAN	Rest of World	Total	US/CAN	Rest of World	Total	US/CAN	Rest of World	Total
Total Additions Over Base	0.00	0.05	0.05	0.00	0.05	0.05	0.00	0.05	0.05
Total Crude Capacity Used 2020	0.02	0.04	0.05	0.02	0.04	0.05	0.017	0.037	0.054
Vacuum Distillation	0.05	0.01	0.06	0.00	(0.02)	(0.02)	0.05	(0.01)	0.04
Coking	0.11	0.00	0.12	0.00	0.02	0.02	0.11	0.03	0.14
Catalytic Cracking	(0.07)	0.01	(0.06)	0.00	(0.01)	(0.01)	(0.07)	0.00	(0.07)
Hydro-Cracking (TOTAL)	(0.04)	0.00	(0.04)	0.00	0.12	0.12	(0.04)	0.12	0.08
- Gasoil Conventional	(0.04)	0.00	(0.04)	0.00	0.00	0.00	(0.04)	0.00	(0.04)
- Gasoil ULS	0.00	0.00	0.00	0.00	0.07	0.07	0.00	0.07	0.07
- Resid LS	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.01	0.01

- Resid MS	0.00	0.00	0.00	0.00	0.04	0.04	0.00	0.04	0.04
Catalytic Reforming with Revamp	0.01	0.00	0.02	0.00	0.07	0.07	0.01	0.07	0.08
Hydrotreating (Total)	0.13	0.08	0.21	0.11	0.05	0.17	0.24	0.14	0.37
- Gasoline – ULS	0.00	(0.00)	(0.00)	(0.03)	0.03	(0.00)	(0.03)	0.02	(0.01)
Distillate -New Conv/LS	0.09	0.06	0.15	0.14	0.02	0.16	0.23	0.08	0.31
- VGO/Resid	0.04	0.03	0.06	0.00	0.00	0.00	0.04	0.03	0.07
Hydrogen, (MMSCFD)	0	70	70	8	211	218	8	280	288
Sulfur Plant, (TPD)	500	500	1000	10	130	140	510	630	1140

While coking and hydrocracking (residual and gas oil) processes primarily produce distillates, to a lesser extent, some low octane gasoline blendstocks are also manufactured, requiring refiners to install additional catalytic reforming unit capacity. As such, in the U.S. and Canada regions approximately 10 KPBSD of existing spare catalytic reforming capacity is used while approximately 70 BPSD of new catalytic reforming capacity is added to other WORLD refiner regions that added cokers and hydrocrackers.

5.1.3.3 Capacity and Throughput Changes for the High Price Crude Oil Case

For the high priced case, the high cost of crude and high capital costs for processing units push the model to reduce installation of new processing units. The price of natural gas is also reduced relative to the price of crude which induces the model to use more natural gas and reduce the use of crude. Under these conditions, the model uses less crude, more natural gas and installs less capital for refinery processing units. As a result, the model favors the use of more hydrocracking processing which adds hydrogen (made from natural gas) to residual and gas oils, producing lower sulfur distillates stocks that do not require further processing in hydrotreaters. The model also uses more synthetic crudes and less heavy sour crudes, which reduce the amounts of residual stocks that need upgrading.

Crude throughput is increased by 29 KBPSD, which is less than the reference case, as the model preferentially uses natural gas over crude and reduces the use of cokers and hydrotreating. Table 5.1-5 shows crude and non crude inputs for the high priced case.

The WORLD model used a total of 80 KBPSD of “slack” coking capacity to convert residual stocks to distillates. Of this amount, 70 KBPSD was used in the U.S. and Canada regions and 10 KBPSD in regions in other areas of the world. The model also added 80 KBPSD of new low and medium sulfur residual hydrocracking capacity to convert residual stocks into distillates—20 KBPSD in the U.S. and Canada and 60 KBPSD in other world refiner regions. Overall, considering the use of cokers and residual hydrocrackers, the total refiner process capacity for residual stocks processing for use in the ECA is 160 KBPSD for the high priced case.

To extract gas oils from residual blendstocks, the model utilized 90 KBPSD of existing vacuum tower capacity—80 KBPSD in the U.S. and Canada and 10 KBPSD on other refiner regions. In addition, the model added 120 KBPSD of new ultra lower sulfur gas oil hydrocracking capacity in refiner regions outside of the U.S. and Canada. The distillate fuel produced from these units meet ECA sulfur standards. The model also used 30 KBPSD of slack capacity in the U.S. and Canada refiner regions for hydrocracking of conventional gas oil.

The model added 40 KBPSD of new conventional distillate hydrotreating capacity to the U.S. and Canada refiner regions and 20 KBPSD of new capacity to refining regions in other areas of the world. While the model also used 40 KBPSD of "slack" conventional distillate hydrotreating capacity in the U.S. and Canada, other world refiner regions decreased use of base case or slack capacity by 80 KBPSD. Considering the use of the new and slack capacity, a total net use of capacity is 20 KBPSD of conventional distillate hydrotreating capacity. The model also used 60 KBPSD of existing slack capacity for vacuum gas oil/residual distillate hydrotreaters, with 20 KBPSD used in the U.S. and Canada refiner regions and 40 KBPSD in other world refining regions.

The use of additional hydrocracking and hydrotreater capacity requires installation of new hydrogen plant capacity. New sulfur plant capacity is required in refiner regions to process the offgas produced from incremental use of hydro cracking and hydrotreating (see Table 5.1-5 below).

Table 5.1-5 Refinery Secondary Processing Capacity Additions in 2020 High Priced Case (Million barrels per stream day)

	USE OF BASE CAPACITY			NEW CAPACITY			BASE PLUS NEW CAPACITY		
	US/CAN	Rest of World	Total	US/CAN	Rest of World	Total	US/CAN	Rest of World	Total
Total Additions Over Base Case	0.00	(0.05)	(0.05)	0.00	(0.05)	(0.05)	0.00	(0.05)	(0.05)
Total Crude Capacity Used in 2020	0.05	(0.02)	0.03	0.05	(0.02)	0.03	0.054	(0.024)	0.029
Vacuum Distillation	0.08	0.10	0.18	0.00	0.00	0.00	0.08	0.10	0.18
Coking	0.07	0.01	0.08	0.00	(0.00)	(0.00)	0.07	0.00	0.08
Catalytic Cracking	(0.03)	(0.05)	(0.09)	0.00	0.00	0.00	(0.03)	(0.05)	(0.09)
Hydro-Cracking (Total)	0.03	0.00	0.03	0.02	0.18	0.20	0.05	0.18	0.22
- Gasoil Conventional	0.03	0.00	0.03	0.00	0.00	0.00	0.03	0.00	0.03
- Gasoil ULS	0.00	0.00	0.00	0.00	0.12	0.12	0.00	0.12	0.12
- Resid LS	0.00	0.00	0.00	0.02	0.03	0.05	0.02	0.03	0.05
- Resid MS	0.00	0.00	0.00	0.00	0.03	0.03	0.00	0.03	0.03
Catalytic Reforming with Revamp	0.00	0.02	0.02	(0.05)	0.02	(0.03)	(0.05)	0.04	(0.00)
Hydrotreating (Total)	0.06	(0.04)	0.02	0.04	0.02	0.06	0.11	(0.03)	0.08
- Gasoline – ULS	0.00	0.00	0.00	0.00	(0.01)	(0.01)	0.00	(0.01)	(0.01)
Distillate -New Conv/LS	0.04	(0.08)	(0.03)	0.04	0.02	0.06	0.08	(0.06)	0.02
- VGO/Resid	0.02	0.03	0.05	0.00	0.00	0.00	0.02	0.04	0.06
Hydrogen, (MMSCFD)	0	0	0	243	325	568	243	325	568
Sulfur Plant, (TPD)	580	300	880	0	120	120	580	420	1000

5.1.3.4 Overall Increases Due to Fuel Switching and Desulfurization

Global fuel use in 2020 by international shipping is projected to be 500 million tonnes/yr. The main energy content effects of bunker grade shifts were captured in the WORLD modeling by altering the volume demand and, at the same time, consistency was maintained between the bunker demand figures in tonnes and in barrels. The result was that partial or total conversion of IFO to distillate was projected to lead to a reduction in the total global tonnes of bunker fuel required but also led to a projected increase in the barrels required. These effects are evident in the WORLD case results. Based on the WORLD modeling, the volume of marine fuel affected by an ECA encompassing the U.S.[C] and Canadian EEZs would be about 4 percent of total world residual volume. As would be expected, since the shift in fuel volumes on a world scale is relatively small, the WORLD model predicts the overall global impact of an ECA to also be small.

There are two main components to projected increased marine fuel cost associated with an ECA. The first component results from the shifting of operation on residual fuel to operation on higher cost distillate fuel. This is the dominant cost component. The WORLD model computed costs based on a split between the costs of residual and distillate fuels. However, there is a small cost associated with desulfurizing the distillate to meet the 0.1 percent fuel sulfur standard in the ECA. Based on the WORLD modeling, the average increase in costs associated with switching from marine residual to distillate will be $145 per tonne.[D] This is the cost increase that will be borne by the shipping companies purchasing the fuel. Of this amount, $6 per tonne is the cost increase associated with distillate desulfurization. In other words, we estimate a cost increase of $6/tonne for distillate fuel used in an ECA.

The above cost estimates are based on EIA's "reference case" projections for crude oil price in 2020. We also performed a sensitivity analysis using EIA's "high price" scenario. Under this scenario, the increase in fuel costs for switching from residual to distillate fuel is $237 per tonne. The associated increase in distillate fuel cost is $7 per tonne.

Table 5.1-6 summarizes the reference and high price fuel cost estimates with and without an ECA. In the baseline case, fuel volumes for operation are 18% marine gas oil (MGO), 7% marine diesel oil (MDO), and 75% IFO. In the proposed ECA, all fuel volumes are modeled as MGO.

[C] For the contiguous U.S. and southeastern Alaska.
[D] Note that distillate fuel has a higher energy content, on a per tonne basis, than residual fuel. As such, there is an offsetting cost savings, on a per tonne basis, for switching to distillate fuel. Based on a 5 percent higher energy content for distillate, the net equivalent cost increase is estimated as $123 for each tonne of residual fuel that is being replaced by distillate fuel ($200/tonne for the high price case).

Table 5.1-6: Estimated Marine Fuel Costs

FUEL	UNITS	REFERENCE CASE		HIGH PRICE CASE	
		Baseline	ECA	Baseline	ECA
MGO	$/bbl	$ 61.75	$ 62.23	$ 102.70	$ 103.03
	$/tonne	$ 464	$ 468	$ 772	$ 775
MDO	$/bbl	$ 61.89	$ 62.95	$ 102.38	$ 103.70
	$/tonne	$ 458	$ 466	$ 757	$ 767
IFO	$/bbl	$ 49.87	$ 49.63	$ 83.14	$ 82.52
	$/tonne	$ 322	$ 321	$ 538	$ 534

5.2 Engine and Vessel Costs

This section presents the analysis of the potential cost impacts that the proposed ECA may have on new engines and vessels in the year 2020. To assess the potential cost impacts we must understand: the makeup of the fleet of ships expected to visit the U.S. when these requirements go into effect, the emission reduction technologies expected to be used, and the cost of these technologies. The total engine and vessel costs associated with the proposed ECA are based on a hardware cost per unit value applied to the number of affected vessels, and include operational costs. This section discusses an overview of the methodology used to develop a fleet of vessels expected to visit the U.S. portion of the proposed ECA, and presents the methodology used to develop the hardware and operational costs.

5.2.1 Overview

There are a number of technologies available or expected to be available to meet Tier III NO_X standards and to accommodate the use of lower sulfur fuel. We expect that each manufacturer will evaluate all possible technology avenues to determine how to best balance their respective costs while ensuring compliance; however, this analysis makes certain assumptions regarding how manufacturers will comply with the new emission and fuel standards. We expect that selective catalytic reduction (SCR) is the emission control technology most likely to be used to meet Tier III NO_X standards in the proposed ECA; therefore, this cost analysis is based on the use of SCR. With respect to fuel sulfur controls, we expect that switching to lower sulfur fuel is the most likely method of control to meet the fuel sulfur requirements when operating in the proposed ECA; therefore, this cost analysis is also based on switching to the use of lower sulfur fuel.

While fuel sulfur standards will take effect in 2015 and Tier III NO_X standards will take effect in 2016, this cost analysis only presents the hardware and operating costs that are expected to be incurred in 2020. In order to present the costs associated with the proposed ECA in 2020, the hardware costs are only applied to new vessels in 2020 expected to visit U.S. ports, while operating costs apply to all ships operating in the U.S. portion of the proposed ECA in 2020. The cost estimates presented here assume that all of the hardware costs for new ships in 2020 are due exclusively to this proposed ECA, and do not include an adjustment accounting for the potential existence of other ECAs that these ships may visit which would also require Tier III NO_X controls and appropriate fuel sulfur controls. The operational costs described in this section include those incurred in 2020 within the U.S. portion of the proposed ECA as a result of the use of urea on ships built as of 2016 equipped with SCR, and the differential costs associated with the use of lower sulfur fuel.

5.2.2 Methodology

To project future costs, we needed to first develop estimates of the number of ships that may visit the proposed ECA in 2020. To develop a future fleet, an approach similar to that used to estimate the emissions inventory (see Chapter 2) was used here. Specifically, the same inputs were used to develop a fleet of ships by ship type and engine type that may be expected to visit U.S. ports in 2020. Next, we needed to develop the estimated technology hardware costs, and sought input from the regulated community regarding the expected future costs of applying the emission control technologies associated with the proposed ECA. The U.S. Government contracted with ICF International to research the fixed and variable costs associated with the technologies expected to be used to meet Tier III NO_X and fuel sulfur standards.[9] To assess the cost of these new technologies, we developed a series of 'typical' engines with varying sizes and characteristics (e.g. stroke, number of cylinders, etc.) that the technologies would be applied to for the purposes of performing the cost research. The resulting cost estimates of applying different technologies to these 'typical' engines formed the basis for this cost analysis; Table 5.2-1 lists these engine configurations.

Table 5.2-1 Average Engine Characteristics Used in this Study

ENGINE TYPE	MEDIUM-SPEED			LOW-SPEED		
Engine Power (kW)	4,500	9,500	18,000	8,500	15,000	48,000
Cylinders	9	12	16	6	8	12
Liters/cylinder	35	65	95	380	650	1400
Engine Speed (rpm)	650	550	500	130	110	100
BSFC (g/kWh)	210			195		

After initial cost estimates were developed, ICF provided surveys to several engine and emission control technology manufacturers to determine the reasonableness of the approach and cost estimates. Input received from those surveyed was incorporated into the final cost estimates used in this analysis. The resulting costs for the 'typical' engines were plotted and a curve-fit was used to determine an equation to estimate the dollar-per-kilowatt ($/kW) cost for each technology. The hardware costs per vessel were based on average vessel characteristics (e.g. engine type and propulsion power) determined for various ship types. The per vessel costs were used with the estimated number of new vessels in 2020 expected to visit U.S. ports to evaluate the total hardware costs associated with the U.S. portion of the proposed ECA. The total operational costs were determined from the differential fuel cost estimates presented in Section 5.1 and the regional fuel consumption values presented in Chapter 2. For vessels equipped with SCR, urea consumption is expected to be 7.5 percent of the fuel consumption.

Operating costs per vessel vary depending on what year the vessel was built, for example, in 2020, vessels built as of 2016 will incur operating costs associated with the use of urea necessary when using SCR as a Tier III NO_X emission control technology, while vessels built prior to 2016 will only incur operating costs associated with the differential cost of using of lower sulfur fuel. To develop the costs associated with the proposed ECA in 2020, an approximation of the number of ships by age that may visit the proposed ECA in 2020 had to be constructed. To develop this future 2020 fleet, the data from ship calls to U.S. ports in the baseline year of 2002 were used to estimate how many ships would visit U.S. ports in 2020.[E,10]

5.2.2.1 2020 Fleet Development

The U.S. port data from 2002 used in the inventory port analysis and the regional growth rates presented in Chapter 2 were used to estimate how many ships by ship type and engine type may visit U.S. ports in the future. The ships that called on the U.S. in 2002 were cross referenced with Lloyd's database using their IMO numbers to determine the propulsion power, engine type, and ship type of each ship.[11] This allowed for all ships without Category 3 engines to be removed from the analysis. In order to separate slow speed engines (SSD) from medium speed engines (MSD) where that information was not explicitly available, 2-stroke engines were assumed to be SSD, and 4-stroke engines were assumed to be MSD. The research performed for this cost analysis differentiated between SSD and MSD engines, and separate $/kW values were developed for each of these engine types.

The ship type information gathered from this baseline data, for the purposes of both this analysis and the inventory, was categorized into one of the following ship types: Auto Carrier, Bulk Carrier, Container, General Cargo, Miscellaneous, Passenger, Refrigerated Cargo (Reefer), Roll-On Roll-Off (RoRo), and Tankers. The 2002 baseline fleet was also used to develop average ship characteristics shown in Table 5.2-2. These values were used to represent the characteristics of new (and future existing) vessels for the purposes of this cost analysis.

The 2002 port call data were sorted by IMO number to determine the total number of unique ships that visited all included U.S. ports in 2002. Table 5.2-3 shows the breakout by ship type of these approximately 6,700 ships. Next, in order to be consistent with the inventory analysis which presents growth rates by region, the original port call data was separated into the same regions used by the inventory (South Pacific (SP), North Pacific (NP), East Coast (EC), Gulf Coast (GC), Alaska East (AE), Alaska West (AW), Hawaii East (HE), and West Hawaii (HW)). This was done by matching each port-of-call entry in the original port call data file with the corresponding region containing that port as per the inventory analysis.[12] This resulted in a fleet of ships for each region, each with a unique IMO number as shown in Table 5.2-3.

[E] The 2002 U.S. ship call data used to determine the 2002 baseline fleet was also used to construct port inventories, as discussed in the Emissions Inventory Chapter. As such, this fleet includes the same ports and limitations as the inventory analysis (e.g. military vessels are excluded, as are ships powered by engines <30 L/cyl.)

Table 5.2-2 Average Ship Characteristics used in this Cost Analysis

SHIP TYPE	ENGINE SPEED	AVERAGE PROPULSION POWER (KW)	AVERAGE AUXILIARY POWER (KW)	SERVICE SPEED (KNOTS)	AVERAGE DWT
Auto Carrier	Slow Speed	11,000	3,000	19	17,000
	Medium Speed	9,600	2,600	17	13,000
Bulk Carrier	Slow Speed	8,400	1,900	15	47,000
	Medium Speed	6,300	1,400	14	27,000
	Steam Turbine	6,400	1,400	15	19,000
Container	Slow Speed	27,000	6,000	22	45,000
	Medium Speed	14,000	3,000	19	19,000
	Steam Turbine	21,000	4,700	21	30,000
General Cargo	Slow Speed	7,700	2,000	15	26,000
	Medium Speed	5,200	1,300	15	8,700
	Steam Turbine	18,000	4,600	21	23,000
Passenger	Slow Speed	24,000	6,600	210	6,200
	Medium Speed	24,000	6,600	20	6,200
	Steam Turbine	27,000	7,600	19	13,000
	Gas Turbine	44,000	12,000	24	12,000
Reefer	Slow Speed	10,000	4,200	20	11,000
	Medium Speed	7,400	3,000	18	7,600
RoRo	Slow Speed	16,000	4,000	18	30,000
	Medium Speed	8,600	2,200	16	8,400
	Gas Turbine	47,000	12,000	24	37,000
	Steam Turbine	22,000	5,800	25	19,000
Tanker	Slow Speed	9,800	2,100	15	61,000
	Medium Speed	6,700	1,400	15	27,000
	Gas Turbine	7,600	1,600	15	40,000
	Steam Turbine	21,000	4,400	18	59,000
Misc.	Slow Speed	4,700	1,300	14	8,800
	Medium Speed	9,400	2,500	13	6,000
	Steam Turbine	13,000	3,500	21	17,000

Some ships may have visited ports in more than one region which could result in an overestimate of the hardware costs (which are applied to each unique vessel) if the number of vessels in each region were grown, summed together and used for the total costs. To prevent over-counting of vessels visiting U.S. ports, a factor was developed (see Equation 1) to account for this overlap. The number of unique ships in each region (identified by unique IMO numbers) was summed together to produce a total number of "unique" ships visiting all regions, this value was reduced by the total number of actual unique ships that visited U.S. ports in 2002 (from the original baseline data) to provide a factor representing the original number of unique ships visiting U.S. ports. This factor was then applied to the vessel count in each region to provide a regional total that would coincide with the baseline total, and eliminate the over-counting of ships that had visited multiple regions.

Equation 1 Regional Fleet Overlap Reduction Factor Example

$$\frac{\#Unique\_Auto\_Carriers\_in\_Total\_Port\_Call\_Data}{\sum Unique\_Auto\_Carriers\_by\_\mathrm{Re}gion} = \%\_Actual\_Unique\_\mathrm{Re}gional\_Auto\_Carriers$$

For example, a total of 300 unique auto carriers visited all included U.S. ports in 2002, yet when looking at unique ships on a regional basis and totaling all regions, 650 auto carriers appeared to visit. This implied that only 46 percent of the regional auto carriers were "unique" and that the additional 350 auto carriers were ships that had visited multiple regions. Therefore, only 46 percent of all auto carriers within each regional fleet were assumed to be "unique." The growth rates were only applied to this corrected count of "unique" ships in each region to estimate the regional fleet makeup in future years.

Table 5.2-3 2002 Baseline Fleet of Ships and Regional Overlap Factor

SHIP TYPE	TOTAL UNIQUE SHIP VISITS TO U.S. PORTS IN 2020	REGIONAL UNIQUE SHIPS VISITING U.S. PORTS IN 2020	REGIONAL OVERLAP FACTOR
Auto Carrier	300	650	46%
Bulk	2,500	3,600	68%
Container	1,000	1,600	63%
Gen. Cargo	980	1,700	57%
Misc	24	50	49%
Pass	110	200	57%
Reefer	280	400	71%
RoRo	120	200	58%
Tanker	1,400	2,700	52%
Total	6,700	11,000	62%

Within each region, the ship types were further broken down by engine type. The unique ship fleet within each region was then grown by ship type and engine type using the appropriate growth rate to estimate the makeup of the future fleet in 2020. Table 5.2-4 shows the estimated 2020 fleet of ships expected to visit U.S. ports.

Table 5.2-4 Estimated 2020 Fleet by Ship Type and Engine Type

SHIP TYPE	ENGINE TYPE	NUMBER OF NEW VESSELS	NUMBER OF EXISTING VESSELS
Auto Carrier	SSD	45	570
	MSD	4	55
Bulk Carrier	SSD	440	5500
	MSD	8	110
	ST	3	21
Container	SSD	210	2600
	MSD	8	95
	ST	9	72

SHIP TYPE	ENGINE TYPE	NUMBER OF NEW VESSELS	NUMBER OF EXISTING VESSELS
General Cargo	SSD	100	1300
	MSD	57	95
	ST	0	3
Passenger	SSD	1	9
	MSD	8	110
	ST	1	5
	GT	1	8
Reefer	SSD	35	440
	MSD	6	80
RoRo	SSD	7	78
	MSD	3	38
	GT	0	3
	ST	0	2
Tanker	SSD	220	2700
	MSD	16	200
	GT	0	5
	ST	8	59
Misc.	SSD	0	1
	MSD	0	5
Total:		1,200	14,000

5.2.2.2 Existing Fleet That May Require Retrofit to Use Low Sulfur Fuel

Although most ships primarily operate on residual fuel, they typically carry some amount of distillate fuel as well. This distillate fuel is available for use in emergencies such as mechanical breakdown, off-spec bunker delivery, or prior to an extended engine shut-down to clear the residual fuel out of the heaters and piping. Switching to the use of lower sulfur distillate fuel is the compliance strategy assumed here to be used by both new and existing ships when the new fuel sulfur standards go into effect. To estimate the potential cost of this compliance strategy, we first evaluated the distillate storage capacity of the current existing fleet to estimate how many ships may require additional hardware to accommodate the use of lower sulfur fuel. We performed this analysis on the entire global fleet listed in Lloyd's database as of 2008. Of the nearly 43,000 vessels listed, approximately 20,000 vessels had provided Lloyd's with fuel tankage information, cruise speed, and propulsion engine power data. Using this information, we were able to estimate how far each vessel could travel on its existing distillate carrying capacity.

The cruise speed provided by Lloyd's was used to determine the vessel's maximum speed using Equation 2 while transit speed was assumed to be 12 knots, and maneuver speed 5.8 knots.[13] The load factor used at cruise speed was 83 percent; while both the transit and maneuver load factors were estimated by cubing the ratio their respective speeds to the ship's maximum speed. The same low load factors used in the inventory (for loads less than 20 percent) were used here to adjust brake specific fuel consumption (BSFC) because diesel engines are less efficient at low loads and the BSFC tends to increase. It was also assumed that ships spent a total of four hours per call in both transit and maneuver speeds. The fuel consumption values used here were the same as reported in the inventory section, 195 g/kWh for SSD, 210 g/kWh for MSD, and 305 g/kWh for steam and gas turbines. The fuel consumed by auxiliary engines was also taken into account and the same auxiliary power ratios used in the inventory analysis were used here to estimate the total installed auxiliary engine power, as were the auxiliary engine load factors appropriate for when the vessel is at cruise, transit, and maneuver speeds for each ship.

Equation 2: Maximum Speed

$$\frac{Lloyds\_speed}{0.94} * 0.83 = \max imum\_speed$$

In order to determine if the current distillate capacity of a particular ship was sufficient to call on a U.S. ECA without requiring additional hardware, we evaluated whether or not each ship could travel 1,140 nm, the distance between the Port of Los Angeles and the Port of Tacoma. This distance was selected because it represents one of the longer trips a ship could travel without stopping at another port, and should overestimate the number of vessels that would require such a modification. The amount of fuel a ship would consume calling on a port and travelling a total distance of 1,140 nm was determined using the methodology described above. The total fuel used in each mode (cruise, transit and maneuver) by both main and auxiliary engines was summed and compared to the total amount of distillate fuel carried onboard. This provided an estimate of the number of ships that had sufficient distillate capacity onboard, shown in Table 5.2-5. The resulting percentages of ships determined to require a retrofit were then applied to the number of existing ships in the 2015 fleet to estimate the total cost of this compliance strategy for existing ships. The same percentages were also applied to all new ships projected to be built in 2020 to determine the number of ships that may require additional hardware and to estimate the cost of this compliance strategy for new vessels in 2020.

Table 5.2-5 Ships that Can Travel 1,140 nm on Existing Distillate Carrying Capacity

SHIP TYPE	TOTAL # OF SHIPS	TOTAL # OF SHIPS THAT ONLY CARRY DISTILLATE	TOTAL # OF SHIPS THAT CARRY DISTILLATE + ANOTHER FUEL	SHIPS THAT CARRY DISTILLATE + ANOTHER FUEL THAT MAY NEED A MODIFICATION		TOTAL # OF SHIPS THAT CARRY NO DISTILLATE	% NO DISTILLATE	TOTAL OF ALL SHIPS THAT MAY NEED A MODIFICATION	
				#	%			#	%
General Cargo	4600	1900	2300	200	8.9%	370	8.2%	580	13%
Tanker	5900	740	4900	1600	33%	280	4.7%	1900	33%
Container	1900	45	1700	910	53%	140	7.3%	1000	55%
Bulk Cargo	3600	230	3000	1600	53%	400	11%	2000	55%
RoRo	510	70	380	30	7.6%	60	12%	90	18%
Auto Carrier	360	20	310	20	7.1%	40	10%	60	16%
Misc.	1600	1100	210	70	34%	210	14%	280	18%
Passenger	710	170	460	270	59%	85	12%	360	51%
Reefer	530	60	440	20	4.1%	25	4.8%	40	8.2%
Total	19,710	4,335	13,700	4,720	24%	1,610	8%	6,310	32%

5.2.3 Tier III NO_X Emission Reduction Technologies

The Selective Catalytic Reduction (SCR) process involves injecting a reagent, such as ammonia or urea, into an exhaust flow, upstream of a reactor, to reduce NO_X compounds into nitrogen and water. Main system components are: an SCR reactor, aqueous urea injection/dosing, and monitoring/control systems. The SCR system does require storage of urea solution onboard in a separate tank. In addition to SCR, it is expected that manufacturers will also use compound or two-stage turbocharging as well as electronic valving to enhance performance and emission reductions to meet Tier III NO_X standards. Engine modifications to meet Tier III emission levels may also include a higher percentage of common rail fuel injection coupled with two-stage turbocharging and electronic valving.

5.2.4 SO_X/PM Emission Reduction Technology

In addition to Tier III NO_X standards, the IMO ECA standards also include reductions in fuel sulfur limits that will result in reductions in SO_X and PM. While there are many existing ships that already have the capacity to operate on both heavy fuel oil and distillate fuel and have separate fuel tank systems to support each type of fuel, some ships may not have sufficient onboard storage capacity to accommodate temporary fuel switching to operate both main and auxiliary engines on lower sulfur fuel, since the minimum space practical is devoted to fuel and machinery to maximize cargo space. If additional capacity is required, installation and use of a fuel cooler, associated piping, and viscosity meters to the fuel treatment system may be required to ensure viscosity matches between the fuel and injection system. If a new or segregated tank is desired, ancillary equipment such as pumps, piping, vents, filling pipes, gauges, and access would be required, as well as tank testing.[14]

5.2.5 NO_X Emission Reduction Technology per Unit Hardware Costs

Tier III NO_X standards are approximately 80 percent lower than the existing Tier I NO_X standards set by the IMO. To meet these standards, it is expected that SCR will be used along with additional migration from either mechanically controlled mechanical fuel injection systems (MFI) or electronically controlled fuel injection systems (EFI) to common rail, and engine modifications. The methodology used here to estimate the capacity of the SCR systems is based on the power rating of the propulsion engines only. Auxiliary engine power represents about 20 percent of total installed power on a vessel; however, it would be unusual to operate both propulsion and auxiliary engines at 100 percent load. Typically, ships operate under full propulsion power only while at sea when the SCR is not operating; when nearing ports the auxiliary engine is operating at high loads while the propulsion engine is operating at very low loads. It is estimated that the remaining 20 percent of SSD engines (5 percent MFI and 15 percent EFI) that have not already been upgraded to common rail to meet global Tier II NOx standards will receive that upgrade for Tier III, and 40 percent of MSD (10 percent MFI and 30 percent EFI) will get common rail for Tier III as well. The fixed and variable costs of the six ‘typical’ engines developed for the migration to common rail from MFI are shown in Table 5.2-6.

Table 5.2-6 Fixed and Variable Costs for MFI to Common Rail Fuel Injection Systems

SPEED	MEDIUM	MEDIUM	MEDIUM	LOW	LOW	LOW
Engine Power (kW)	**4,500**	**9,500**	**18,000**	**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**	**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**	**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**	**130**	**110**	**100**
VARIABLE COSTS						
Component Costs						
Electronic Control Unit	$3,500	$3,500	$3,500	$5,000	$5,000	$5,000
Common Rail Accumulators (each)	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Number of Accumulators	3	6	8	9	12	18
Low Pressure Pump	$2,000	$3,000	$4,000	$2,500	$3,500	$4,500
High Pressure Pump	$3,500	$4,500	$6,000	$4,500	$6,000	$8,000
Modified injectors (each)	$2,500	$2,500	$2,500	$3,500	$3,500	$3,500
Number of injectors	9	12	16	18	24	36
Wiring Harness	$2,500	$2,500	$2,500	$3,000	$3,000	$3,000
Total Component Cost	**$40,000**	**$55,500**	**$72,000**	**$96,000**	**$125,500**	**$182,500**
Assembly						
Labor (hours)	120	160	200	200	250	300
Cost ($23.85/hr)	$2,900	$3,800	$4,800	$4,800	$5,900	$7,100
Overhead @ 40%	$1,100	$1,500	$1,900	$1,900	$2,400	$2,900
Total Assembly Cost	**$4,000**	**$5,300**	**$6,700**	**$6,700**	**$8,300**	**$10,000**
Total Variable Cost	**$44,000**	**$60,800**	**$78,700**	**$102,700**	**$133,800**	**$192,500**
Markup @ 29%	$12,800	$17,700	$22,800	$29,800	$38,800	$55,800
Total Hardware RPE	**$56,800**	**$78,500**	**$101,500**	**$132,500**	**$172,600**	**$248,300**
FIXED COSTS						
R&D Costs (1 year R&D)	$688,000	$688,000	$688,000	$688,000	$688,000	$688,000
Retooling Costs	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000	$1,000,000
Marine Society Approval	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Engines/yr.	40	40	40	40	40	40
Years to recover	5	5	5	5	5	5
Fixed cost/engine	**$8,500**	**$8,500**	**$8,500**	**$8,500**	**$8,500**	**$8,500**

The fixed and variable costs associated with the migration from EFI to common rail are shown in Table 5.2-7. A curve-fit to estimate the variable cost of each technology was then used to determine a $/kW equation applicable to other engine sizes and types, Figure 5-1 shows the curve-fit for MFI to common rail variable costs and Figure 5-2 shows the curve fit for EFI to common rail variable costs.

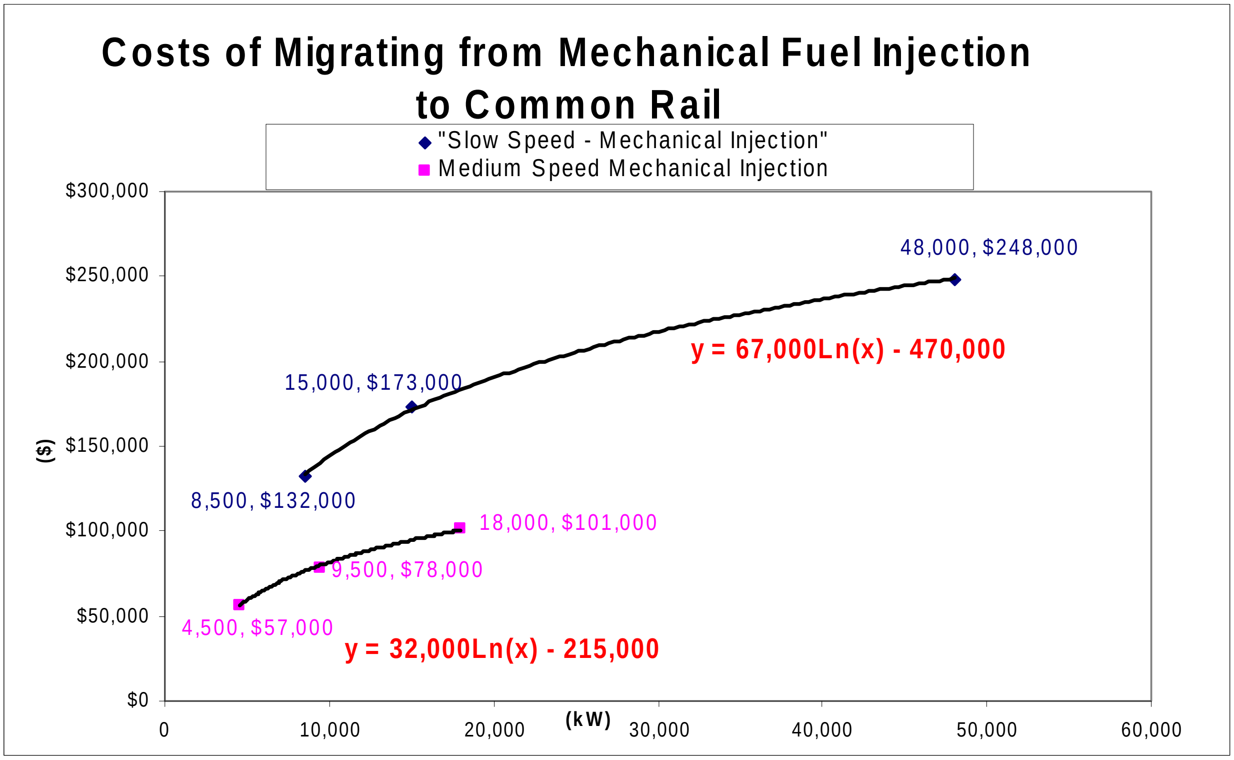

Figure 5-1 Variable Cost Curve-Fit for MFI to Common Rail Fuel Injection Systems

Table 5.2-7 Fixed and Variable Costs for EFI to Common Rail Fuel Injection Systems

SPEED	**MEDIUM**	**MEDIUM**	**MEDIUM**	**LOW**	**LOW**	**LOW**
Engine Power (kW)	**4,500**	**9,500**	**18,000**	**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**	**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**	**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**	**130**	**110**	**100**
Hardware Costs to the Manufacturer						
Component Costs						
Electronic Control Unit	$500	$500	$500	$500	$500	$500
Common Rail Accumulators (each)	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Number of Accumulators	3	6	8	9	12	18
Low Pressure Pump	$1,000	$1,000	$1,000	$1,500	$1,500	$1,500
High Pressure Pump	$1,500	$1,500	$1,500	$2,000	$2,000	$2,000
Modified injectors (each)	$500	$500	$500	$750	$750	$750
Number of injectors	9	12	16	18	24	36
Wiring Harness	$500	$500	$500	$650	$650	$650
Total Component Cost	**$14,000**	**$21,500**	**$27,500**	**$36,150**	**$46,650**	**$67,650**
Assembly						
Labor (hours)	40	60	80	40	60	80
Cost ($23.85/hr)	$950	$1,430	$1,910	$950	$1,430	$1,910

Overhead @ 40%	$380	$570	$760	$380	$570	$760
Total Assembly Cost	**$1,330**	**$2,000**	**$2,670**	**$1,330**	**$2,000**	**$2,670**
Total Variable Cost	**$15,300**	**$23,500**	**$30,200**	**$37,500**	**$48,700**	**$70,300**
Markup @ 29%	$4,400	$6,800	$8,800	$10,900	$14,100	$20,400
Total Hardware RPE	**$19,700**	**$30,300**	**$39,000**	**$48,400**	**$62,800**	**$90,700**
FIXED COSTS						
R&D Costs (0.5 year R&D)	$344,000	$344,000	$344,000	$344,000	$344,000	$344,000
Retooling Costs	$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Marine Society Approval	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Engines/yr.	40	40	40	40	40	40
Years to recover	5	5	5	5	5	5
FIXED COST/ENGINE	**$4,200**	**$4,200**	**$4,200**	**$4,200**	**$4,200**	**$4,200**

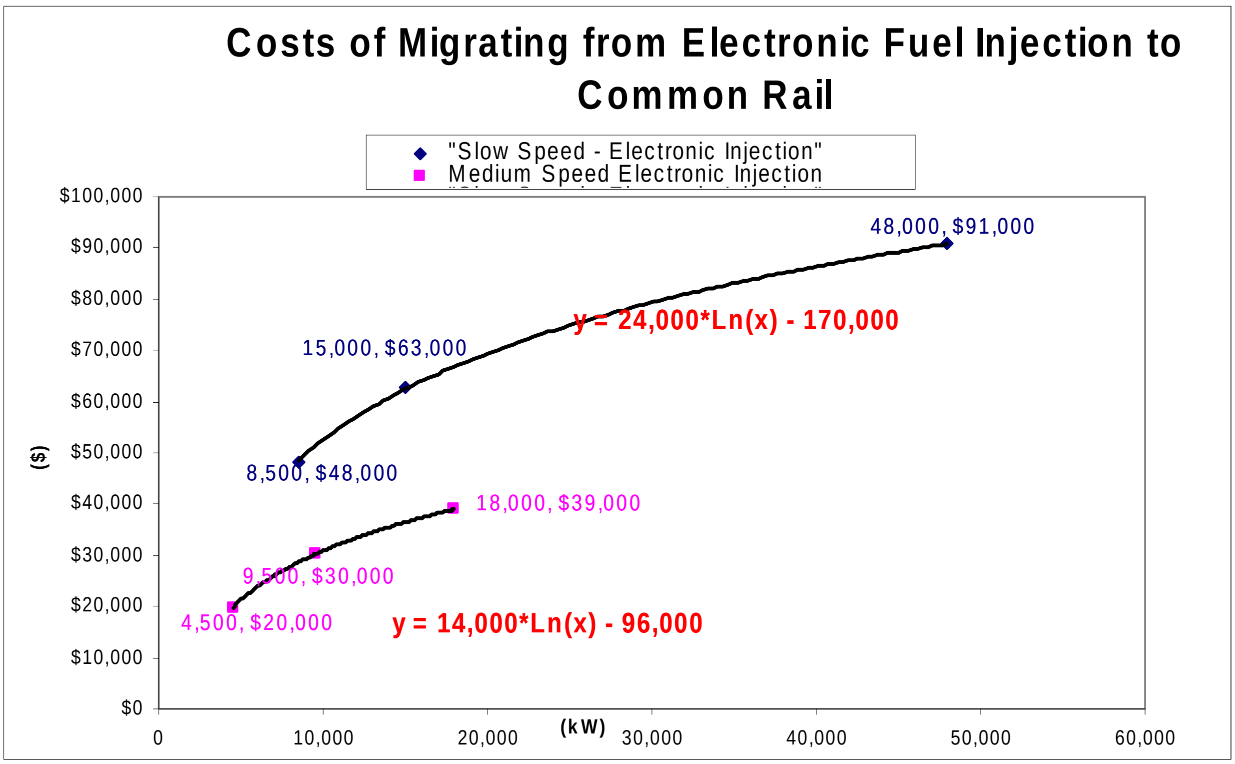

Figure 5-2 Cost Curve-Fit for EFI to Common Rail Fuel Injection Systems

The variable costs associated with the use of engine modifications for Tier III include the use of two stage turbochargers and electronic valve actuation, and are shown with the estimated fixed costs in Table 5.2-8, Figure 5-3 shows the variable cost curve-fit used to determine a $/kW equation applicable to other engine sizes and types. Table 5.2-9 shows the variable costs associated with the use of SCR, these costs include the urea tank, the reactor, dosage pump, urea injectors, piping, bypass valve, the acoustic horn, a cleaning probe and the control unit and wiring. Detailed costs for the urea tank are shown in Table 5.2-10 and are based on estimated storage of urea sufficient for up to 250 hours of normal operation of the SCR. It is envisioned that the urea tank is constructed of 304 stainless steel, 1 mm thick due to the corrosive nature of urea, at a cost of approximately $2,700 per metric tonne.[F] The cost of Tier III technology as presented here was developed using Tier II as a baseline. Figure 5-4 shows the shows the cost curve used to determine a $/kW equation applicable to other engine types and sizes. The total variable hardware costs of Tier III estimated here include the fuel injection changes, engine modifications, and SCR.

Table 5.2-8 Fixed and Variable Costs for Engine Modifications Associated with Tier III

SPEED	MEDIUM	MEDIUM	MEDIUM	LOW	LOW	LOW
Engine Power (kW)	**4,500**	**9,500**	**18,000**	**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**	**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**	**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**	**130**	**110**	**100**
Hardware Costs to the Manufacturer						
Component Costs						
2 Stage Turbochargers (Incremental)	$16,250	$20,900	$46,750	$28,000	$42,000	$61,000
Electronic Intake Valves (each)	$285	$285	$285			
Intake Valves per Cylinder	2	2	2			
Electronic Exhaust Valves (each)	$285	$285	$285	$425	$425	$425
Exhaust Valves per Cylinder	2	2	2	4	4	4
Controller	$3,750	$3,750	$3,750	$3,750	$3,750	$3,750
Wiring	$2,800	$2,800	$2,800	$2,800	$2,800	$2,800
Total Component Cost	**$33,000**	**$41,000**	**$72,000**	**$45,000**	**$62,000**	**$88,000**
Markup @ 29%	$10,000	$12,000	$21,000	$13,000	$18,000	$25,000
Total Hardware RPE	**$43,000**	**$53,000**	**$93,000**	**$58,000**	**$80,000**	**$113,000**
Fixed Costs						
R&D Costs (1 year R&D)	$688,000	$688,000	$688,000	$688,000	$688,000	$688,000
Retooling Costs	$1,000,000	$1,000,000	$1,000,000	$1,320,000	$1,320,000	$1,320,000
Marine Society Approval	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Engines/yr.	40	40	40	40	40	40
Years to recover	5	5	5	5	5	5
Fixed cost/engine	**$8,500**	**$8,500**	**$8,500**	**$10,000**	**$10,000**	**$10,000**

[F] http://www.metalprices.com/FreeSite/metals/stainless_product/product.asp#Tables for 2006.

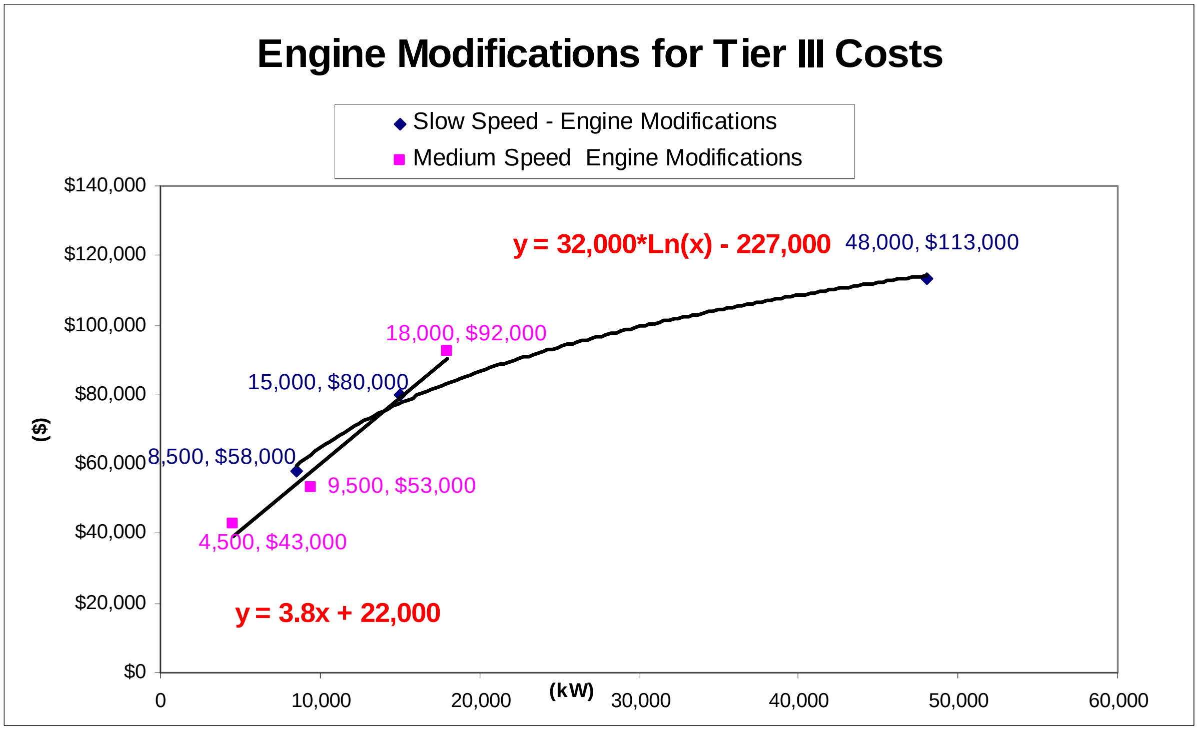

Figure 5-3 Variable Cost Curve-Fit for Engine Modifications Associated with Tier III

Table 5.2-9 Fixed and Variable Costs Associated with the Use of SCR

SPEED	**MEDIUM**	**MEDIUM**	**MEDIUM**	**LOW**	**LOW**	**LOW**
Engine Power (kW)	**4,500**	**9,500**	**18,000**	**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**	**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**	**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**	**130**	**110**	**100**
Hardware Costs to the Supplier						
Component Costs						
Aqueous Urea Tank	$1,200	$1,900	$2,800	$1,700	$2,400	$4,600
Reactor	$200,000	$295,000	$400,000	$345,000	$560,000	$1,400,000
Dosage Pump	$9,500	$11,300	$13,000	$11,300	$13,000	$15,000
Urea Injectors (each)	$2,400	$2,400	$2,400	$2,400	$2,400	$2,400
Number of Urea Injectors	3	6	8	12	16	24
Piping	$4,700	$5,600	$6,600	$5,600	$7,500	$9,500
Bypass Valve	$4,700	$5,600	$6,600	$5,600	$6,600	$7,500
Acoustic Horn	$9,500	$11,300	$13,000	$11,700	$14,000	$16,400
Cleaning Probe	$575	$575	$575	$700	$700	$700
Control Unit/Wiring	$14,000	$14,000	$14,000	$19,000	$19,000	$19,000
Total Component Cost	**$251,000**	**$360,000**	**$476,000**	**$429,000**	**$662,000**	**$1,530,000**
Assembly						
Labor (hours)	1000	1200	1500	1200	1600	2000

Cost ($23.85/hr)	$23,900	$28,600	$35,800	$28,600	$38,200	$47,700
Overhead @ 40%	$9,500	$11,400	$14,300	$11,400	$15,300	$19,100
Total Assembly Cost	**$33,400**	**$40,000**	**$50,100**	**$40,000**	**$53,500**	**$66,800**
Total Variable Cost	$284,800	$399,700	$525,800	$469,400	$715,000	$1,597,100
Markup @ 29%	$82,600	$115,900	$152,500	$136,100	$207,300	$463,200
Total Hardware RPE	**$367,400**	**$515,600**	**$678,300**	**$605,500**	**$922,300**	**$2,060,300**
Fixed Costs						
R&D Costs (1 year R&D)	$1,376,000	$1,376,000	$1,376,000	$1,376,000	$1,376,000	$1,376,000
Retooling Costs	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Marine Society Approval	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Engines/yr.	40	40	40	40	40	40
Years to recover	5	5	5	5	5	5
Fixed cost/engine	**$16,900**	**$16,900**	**$16,900**	**$16,900**	**$16,900**	**$16,900**

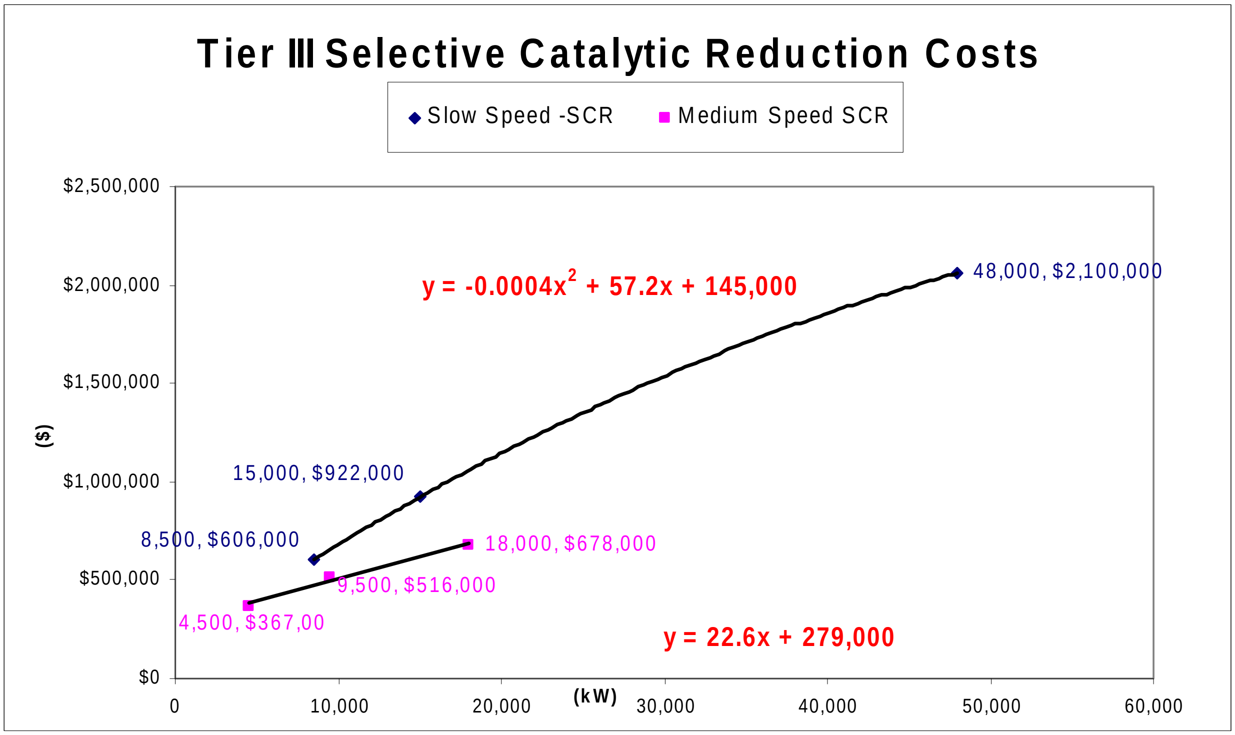

Figure 5-4 Variable Cost Curve-Fit for SCR Systems

Table 5.2-10 Detailed Urea Tank Variable Costs

SPEED	MEDIUM	MEDIUM	MEDIUM		LOW	LOW	LOW
Engine Power (kW)	4,500	9,500	18,000		8,500	15,000	48,000
Cylinders	9	12	16		6	8	12
Liters/cylinder	35	65	95		380	650	1400
Engine Speed (rpm)	650	550	500		130	110	100
Urea Tank Costs							
Urea Amount (kg)	12,910	27,255	51,642		22,645	39,961	127,875
Density (kg/m^3)	1,090	1,090	1,090		1,090	1,090	1,090
Tank Size (m^3)	14	30	57		21	37	117
Tank Material (m^3)	0.04	0.06	0.09		0.05	0.07	0.14
Tank Material Cost ($)	$758	$1,248	$1,909		$977	$1,426	$3,093
Assembly							
Labor (hours)	5	6	7		10	12	15
Cost ($/hr)	$119	$143	$167		$238	$286	$358
Overhead @ 40%	$48	$57	$67		$95	$114	$143
Total Assembly Cost	$167	$200	$234		$334	$401	$501
Total Variable Cost	$925	$1,448	$2,143		$1,310	$1,826	$3,594
Markup @ 29%	$268	$420	$621		$380	$530	$1,042
Total Hardware RPE	$1,194	$1,868	$2,765		$1,690	$2,356	$4,636

5.2.6 SO_X and PM Emission Reduction Technology per Unit Hardware Costs

As discussed above, this cost analysis is based on the use of switching to lower sulfur fuel to meet the ECA fuel sulfur standards when operating in the U.S portion of the proposed ECA. This section discusses the costs that may be incurred by some newly built ships if additional fuel tank equipment, beyond that installed on comparable new ships, is required to meet lower sulfur fuel standards in the proposed ECA. We estimate that nearly one-third of new vessels in 2020 may need additional equipment installed to accommodate additional lower sulfur fuel storage capacity. The size of the tank is dependent on the frequency with which the individual ship owner prefers to fill the lower sulfur fuel tank. The size of the tanks as estimated here will carry capacity sufficient for 250 hours of propulsion and auxiliary engine operation while within an ECA. Similar to the urea tank size estimation presented in this analysis, this is most likely an overestimate of the amount of lower sulfur fuel a ship owner would need to call on the proposed ECA. The hardware costs include additional distillate fuel storage tanks assumed to be constructed of cold rolled steel 1 mm thick and double walled, an LFO fuel separator, an HFO/LFO blending unit, a 3-way valve, an LFO cooler, filters, a viscosity meter, and various pumps and piping. These costs are shown in Table 5.2-11. This cost analysis does not reflect other design options such as partitioning of a residual fuel tank to allow for lower sulfur fuel capacity which would reduce the amount of additional space required, nor does this analysis reflect the possibility that some ships may have already been designed to carry smaller amounts of distillate fuel in separate tanks for purposes other than continuous propulsion.

Table 5.2-11 Fuel Switching Hardware Costs (New Construction)

SPEED	MEDIUM	MEDIUM	MEDIUM	LOW	LOW	LOW
Engine Power (kW)	**4,500**	**9,500**	**18,000**	**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**	**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**	**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**	**130**	**110**	**100**
Hardware Cost to Supplier						
Component Costs						
Additional Tanks	$3,400	$5,500	$8,300	$4,600	$6,500	$13,700
LFO Separator	$2,800	$3,300	$3,800	$3,800	$4,200	$4,700
HFO/LFO Blending Unit	$4,200	$4,700	$5,600	$4,700	$5,600	$6,600
3-Way Valve	$950	$1,400	$1,900	$1,400	$1,900	$2,800
LFO Cooler	$2,400	$2,800	$3,300	$2,800	$3,800	$4,700
Filters	$950	$950	$950	$950	$950	$950
Viscosity Meter	$1,400	$1,400	$1,400	$1,400	$1,400	$1,400
Piping/Pumps	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Total Component Cost	**$18,100**	**$22,100**	**$27,300**	**$21,600**	**$26,400**	**$36,900**
Assembly						
Labor (hours)	240	320	480	320	480	600
Cost ($23.85/hr)	$5,700	$7,600	$11,400	$7,600	$11,400	$14,300
Overhead @ 40%	$2,300	$3,100	$4,600	$3,100	$4,600	$5,700
Total Assembly Cost	**$8,000**	**$10,700**	**$16,000**	**$10,700**	**$16,000**	**$20,000**
Total Variable Cost	$26,100	$32,700	$43,300	$32,300	$42,400	$56,900
Markup @ 29%	$7,600	$9,500	$12,600	$9,400	$12,300	$16,500
Total Hardware RPE	**$33,700**	**$42,200**	**$55,900**	**$41,700**	**$54,700**	**$73,400**
FIXED COSTS						
R&D Costs (0.25 year R&D)	$172,000	$172,000	$172,000	$172,000	$172,000	$172,000
Marine Society Approval	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Engines/yr.	40	40	40	40	40	40
Years to recover	5	5	5	5	5	5
Fixed cost/engine	**$880**	**$880**	**$880**	**$880**	**$880**	**$880**

In order to apply the hardware costs associated with the installation of equipment required to use lower sulfur fuel in the proposed ECA, we needed to generate an equation in terms of $/kW that could be applied to other engine sizes. The $/kW value hardware cost values for the six data points corresponding to the six different engine types and sizes used in this analysis were plotted. A curve fit was determined for the slow-speed engine as well as for the medium speed engines, see Figure 5-5.

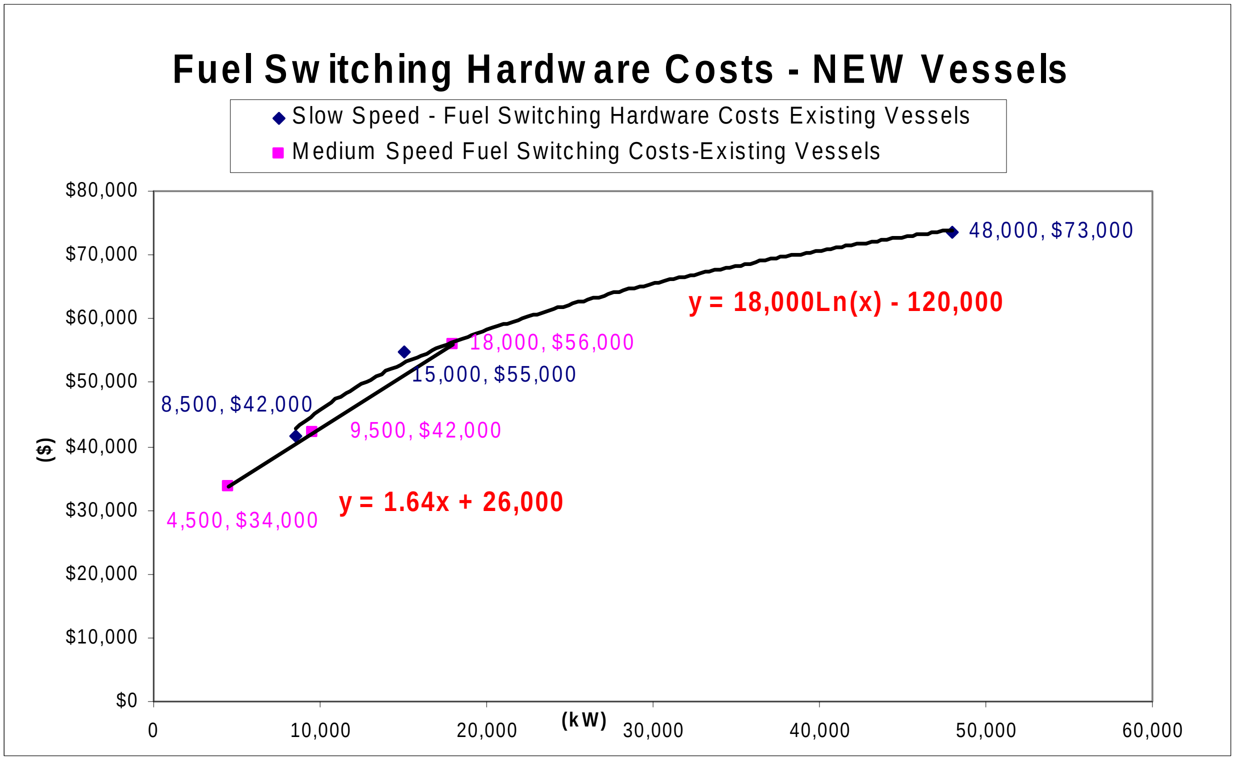

Figure 5-5 $/kW Estimated Hardware Costs Associated with the use of Low Sulfur Fuel

5.2.7 Total Hardware Costs to New Ships in 2020

Total hardware costs associated with the proposed ECA were developed from the number of new ships by ship and engine type estimated to enter the fleet in 2020 as presented earlier in Table 5.2-4. All new vessels were considered to have the average characteristics (including propulsion power) shown in Table 5.2-2. Hardware costs associated with switching to lower sulfur fuel were applied to the percentage[G] of new vessels in 2020 that may require additional tankage, regardless of engine or ship type. The cost estimates developed for the 'typical' engines discussed in Section 5.2.2 were used to develop $/kW equations that could be applied to other engine sizes and types (e.g. SSD and MSD engines). The estimated hardware cost ranges for new vessels, on a per-vessel basis, to meet Tier III NO_X and lower sulfur fuel standards are shown below in Table 5.2-12.

[G] Section 5.1.5 discusses the estimated percentage of the existing fleet that may require modifications to a retrofit, the same percentages were applied to new vessels as it was assumed not all new vessels would require extra hardware to accommodate the use of lower sulfur fuel.

Table 5.2-12 Range of Technology Hardware Costs by Engine Type in $/kW

TECHNOLOGY		ENGINE SPEED	ENGINE SIZE RANGE (KW)	$/KW
SO_X/PM Reductions	Fuel Switching Hardware Costs – *New Vessels*	Medium	4,500 – 18,000	$3.10 - $7.50
		Slow	8,500 – 48,000	$1.50 – $4.90
Tier III NO_X Reductions	SCR Hardware Costs	Medium	4,500 – 18,000	$41.00 - $83.00
		Slow	8,500 – 48,000	$46.00 – $76.00

Table 5.2-13 Total Estimated Variable Hardware Costs per Ship[H]

SHIP TYPE	ENGINE SPEED	AVERAGE PROPULSION POWER (KW)	NEW VESSEL FUEL SWITCHING HARDWARE[a]	AVERAGE PER VESSEL COST OF TIER III[b]
Auto Carrier	MSD	9,600	$42,300	$573,200
Bulk Carrier	MSD	6,400	$36,900	$483,500
Container	MSD	13,900	$49,200	$687,800
General Cargo	MSD	5,200	$34,900	$450,300
Passenger	MSD	23,800	$65,400	$952,500
Reefer	MSD	7,400	$38,500	$511,000
RoRo	MSD	8,600	$40,500	$543,800
Tanker	MSD	6,700	$37,400	$492,800
Misc.	MSD	9,400	$41,900	$566,800
Auto Carrier	SSD	11,300	$48,000	$825,000
Bulk Carrier	SSD	8,400	$42,700	$672,600
Container	SSD	27,500	$63,900	$1,533,100
General Cargo	SSD	7,700	$41,000	$632,900
Passenger	SSD	23,600	$61,200	$1,385,300
Reefer	SSD	10,400	$46,500	$781,000
RoRo	SSD	15,700	$53,900	$1,042,100
Tanker	SSD	9,800	$45,300	$744,200
Misc.	SSD	4,700	$32,000	$453,600

[a] Assumes 32 percent of new vessels would require the fuel switching equipment
[b] The cost estimates presented here represent the average cost per vessel, given that to meet Tier III not all engines are expected to require the same hardware. The costs are determined using the following formula: (5%*($/SHIP_MECH→CR))+(15%*($/SHIP_ELEC→CR))+(T3 ENGINE MODS)+(T3 SCR))

5.2.8 Operational Costs Associated with SCR

In addition to the SCR hardware costs discussed above, ships built as of 2016 would also incur the operating costs associated with SCR's use of urea. The urea operational costs are based on a price of $1.52 per gallon with a density of 1.09 g/cc. The cost per gallon was

[H] Note that not all vessels will need these modifications – it is estimated that only 32% of all vessels will require such additional hardware.

estimated for a 32.5 percent urea solution delivered in bulk to the ship through research completed by ICF combined with historical urea price information.[15,16,17,18] This cost analysis used a urea dosing rate of 7.5 percent that of the brake specific fuel consumption value to estimate how much urea would be used by different engine types and sizes. The total operational costs associated with the proposed ECA are based on the amount of fuel consumed within the proposed ECA in the year 2020. Fuel consumption estimates for 2020 are presented in Chapter 2 of this report including how the amount of fuel used in this area was determined and the fuel costs associated with a U.S. ECA. Based on the U.S. portion of the proposed ECA, the operational costs associated with the use of urea by ships built as of 2016 in 2020 are based on total urea consumption of nearly 100 million gallons are shown in Table 5.2-14 and estimated to be approximately $0.14 billion.

Table 5.2-14 Urea Operational Costs Associated with the use of SCR

SPEED	MEDIUM	MEDIUM	MEDIUM		LOW	LOW	LOW
Engine Power (kW)	**4,500**	**9,500**	**18,000**		**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**		**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**		**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**		**130**	**110**	**100**
Urea Costs							
BSFC (g/kWh)	210	210	210		195	195	195
Load factor	73%	73%	73%		73%	73%	73%
Aequous Urea Rate	7.5%	7.5%	7.5%		7.5%	7.5%	7.5%
Aqueous Urea (kg/hr)	52	109	207		91	160	512
Aqueous Urea Cost per kg	$0.3684	$0.3684	$0.3684		$0.3684	$0.3684	$0.3684
Aqueous Urea Cost per hour	$19	$40	$76		$33	$59	$188

5.2.9 Existing Vessel Hardware Cost Estimates

This analysis also includes cost estimates for retrofitting existing vessels with additional tankage and related fuel system components, see Table 5.2-15. These hardware costs include additional distillate fuel storage tanks, an LFO fuel separator, an HFO/LFO blending unit, a 3-way valve, an LFO cooler, filters, a viscosity meter, and various pumps and piping as well as additional labor to install the systems on a ship and additional R&D to test systems on existing ships. Similar to the lower sulfur fuel tank analysis discussed above, this existing vessel hardware cost analysis assumes 250 hours of operation, which may be an overestimate of the amount of fuel that is necessary to call on U.S. ports in the ECA. The total estimated hardware costs of retrofitting the portion of the existing fleet estimated to require these modifications is $327 million, these costs would be incurred by 2015.

Table 5.2-15 Fuel Switching Hardware Costs - Existing Vessels

SPEED	MEDIUM	MEDIUM	MEDIUM	LOW	LOW	LOW
Engine Power (kW)	**4,500**	**9,500**	**18,000**	**8,500**	**15,000**	**48,000**
Cylinders	**9**	**12**	**16**	**6**	**8**	**12**
Liters/cylinder	**35**	**65**	**95**	**380**	**650**	**1400**
Engine Speed (rpm)	**650**	**550**	**500**	**130**	**110**	**100**
Hardware Cost to Supplier						
Component Costs						
Additional Tanks	$3,400	$5,500	$8,300	$4,600	$6,500	$13,700
LFO Separator	$2,800	$3,300	$3,800	$3,800	$4,200	$4,700
HFO/LFO Blending Unit	$4,200	$4,700	$5,600	$4,700	$5,600	$6,600
3-Way Valve	$950	$1,400	$1,900	$1,400	$1,900	$2,800
LFO Cooler	$2,400	$2,800	$3,300	$2,800	$3,800	$4,700
Filters	$950	$950	$950	$950	$950	$950
Viscosity Meter	$1,400	$1,400	$1,400	$1,400	$1,400	$1,400
Piping/Pumps	$2,000	$2,000	$2,000	$2,000	$2,000	$2,000
Total Component Cost	**$18,100**	**$22,100**	**$27,300**	**$21,600**	**$26,400**	**$36,900**
Assembly						
Labor (hours)	480	640	960	640	960	1200
Cost ($23.85/hr)	$11,400	$15,300	$22,900	$15,300	$22,900	$28,700
Overhead @ 40%	$4,600	$6,100	$9,200	$6,100	$9,200	$11,400
Total Assembly Cost	**$16,000**	**$21,400**	**$32,100**	**$21,400**	**$32,100**	**$40,100**
Total Variable Cost	$34,100	$43,400	$59,300	$43,00	$58,400	$77,000
Markup @ 29%	$9,900	$12,600	$17,200	$12,500	$17,000	$22,300
Total Hardware RPE	**$44,000**	**$56,000**	**$76,500**	**$55,500**	**$75,400**	**$99,300**
Fixed Costs						
R&D Costs (0.33 year R&D)	$227,000	$227,000	$227,000	$227,000	$227,000	$227,000
Marine Society Approval	$5,000	$5,000	$5,000	$5,000	$5,000	$5,000
Engines/yr.	40	40	40	40	40	40
Years to recover	5	5	5	5	5	5
Fixed cost/engine	**$1,160**	**$1,160**	**$1,160**	**$1,160**	**$1,160**	**$1,160**

5.3 Total Estimated ECA Costs in 2020

The total costs associated with improving ship emissions from current performance to ECA standards in 2020 include both the hardware and operational costs as discussed above. The hardware costs include those of SCR systems and equipment that may be installed on ships built in 2020 to accommodate the use of switching to lower sulfur fuel which together total $1.04 billion in 2020. The operational costs associated with the use of urea are estimated to be $0.14 and the additional fuel costs for the U.S. portion of the proposed ECA will be $1.64 billion in 2020. Therefore, the total costs associated with the U.S. portion of the proposed ECA in 2020 are expected to be $2.78 billion, Table 5.3-1 summarizes these costs.

Table 5.3-1 Total Estimated U.S. ECA Costs in 2020

	TECHNOLOGY	COST IN 2020 (BILLIONS)
Operating Costs (all ships built as of 2016)	Urea Consumption	$0.14
Operating Costs (all ships operating in ECA in 2020)	Fuel Switching	$1.64
Hardware Costs (ships built in 2020)	Fuel Tank Modifications	$0.02
	SCR	$1.02
Total Costs		**$2.78**

5.4 Cost Effectiveness

As discussed in Chapters 3, 4 and 5, the proposed ECA is expected to bring many human health and environmental benefits. Sections 5.1 through 5.3, above, summarize the various costs of the proposed ECA. However, this does not shed light on how cost effective the proposed ECA will be, compared to other control programs, at providing the expected emission reductions.

One tool that can be used to assess the value of the proposed ECA is the measure of cost effectiveness; a ratio of engineering costs incurred per tonne of emissions reduced. The U.S. Government has compared the ECA cost effectiveness to the ratio of costs per tonne of emissions reduced for other control programs. As is shown in this section, the NO_X, SO_X and PM emissions reductions from the proposed ECA compare favorably—in terms of cost effectiveness—to other land-based control programs that have been implemented.

5.4.1 ECA Cost Effectiveness

Chapter 2 of this document summarizes the inventory analyses from which the U.S. projections of pollutant reductions are drawn. The projected U.S. emission reductions due to the proposed ECA are presented above in Table 2-46.

Note that $PM_{2.5}$ is estimated to be 92 percent of the more inclusive PM_{10} emission inventory for marine vessels. In Chapter 2, we generate and present $PM_{2.5}$ inventories since recent research has determined that these are of greater health concern. Traditionally, we have used PM_{10} in our cost effectiveness calculations. Since cost effectiveness is a means of comparing control measures to one another, we use PM_{10} in our cost effectiveness calculations for comparisons to past control measures.

Using the costs associated with NO_X, SO_X and PM control described in sections 5.1 through 5.3 above, and the emission reductions shown in Table 2-46, we calculated the cost per tonne, or cost effectiveness, of the proposed ECA. As described above, the costs of the proposed ECA include costs to refiners to produce additional distillate fuel, as well as costs for engine controls, catalysts and reductants to reduce NO_X emissions and costs for additional tankage for distillate oil. The timing of costs incurred varies, as some costs (i.e. capital expenditures) will be near-term, while others, such as operational costs, are incurred over time in small increments.

The resultant cost per tonne numbers depend on how the costs are allocated to each pollutant. We have allocated costs as closely as possible to the pollutants for which they are incurred. The costs to apply engine controls to meet Tier III NOx standards, including catalysts and reductants, have been allocated to NO_X. In our analyses, we have allocated half of the costs of fuel switching, including production and tankage, to PM and half to SO_X because the costs incurred for control measures to reduce SO_X emissions directly reduce emissions of PM as well.

The resultant estimated cost effectiveness numbers are shown in Table 5.4-1. These include costs and emission reductions that are expected to occur due to compliance with the U.S. portion of the proposed ECA.

Table 5.4-1 Aggregate Long Term ECA Cost per Tonne (2006 U.S. Dollars)

POLLUTANT	30-YR NET PRESENT VALUE DISCOUNTED AT 3%
NO_X	2,600
SO_X	1,200
$PM_{2.5}$	11,000[I]

5.4.2 Land-Based Control Program Cost Effectiveness

The U.S. Government has already imposed restrictions on emissions of NO_X, SO_X, PM and other air pollutants, from a wide range of land-based industrial (stationary) and transportation (mobile) sources as well as consumer and commercial products. We have applied a wide range of programmatic approaches to achieve significant air pollution reductions. Regulatory regimes typically either mandate or incentivize emissions aftertreatment, cleaner fuels or raw materials, improved practices, as well as new processes or technologies.

Significant emission reductions of NO_X and SO_X in the U.S. have been achieved via performance standards for new combustion sources and market-based programs that cap emissions at the regional level. Since 1996, the Acid Rain Program and NO_X Budget Trading Program have been highly successful at drastically reducing both NO_X and SO_X from power plants in the Eastern U.S. Since 2004, NO_X, SO_X and PM emissions from highway and nonroad heavy duty trucks and equipment have been decreasing with performance and emission standards that will be completely phased in by 2010. To allow technology to advance, diesel fuel for use in vehicles in the U.S. and Canada has been reduced to less than 0.0015 percent sulfur (15 parts per million by weight), and diesel fuel for use in off-road equipment, locomotives and domestic marine vessels will be reduced to this level by 2012.

Advanced technology is already required on stationary sources in the U.S., including electricity generation produced by combustion; oil and gas; forest products (including pulp and

[I] Converting to PM_{10} the cost per tonne would be 10,000. This figure is used in Table 5.4-2 below.

paper and wood products); smelting and refining (including aluminum, alumina, and base metal smelting); iron and steel; iron ore pelletizing; potash; cement; lime; and chemicals production, including fertilizers. On mobile sources, advanced technology to reduce NO_X is phasing in by 2010 for engines on heavy duty trucks and by 2015 for engines on harborcraft.

Programs that are designed to capture the efficiency of designing and building new compliant sources tend to have better cost-effectiveness than programs that principally rely on retrofitting existing sources. Even considering the retrofitting programs, the control measures that have been implemented on land-based sources have been well worthwhile when considering the benefits of the programs. An early example of a highly effective NO_X reduction program is the regional NO_X Budget Program. In 1998, the U.S. Government concluded that NO_X emissions reductions from retrofitting power plants that can be made for less than $3,400 per tonne (in 2006 dollars) are "highly cost effective," considering the emissions reduced by the advanced control technology, not including societal benefits.

The cost of reducing air pollution from these land-based sources has ranged greatly, depending on the pollutant, the type of control program and the nature of the source. A selection of programs and their cost effectiveness is presented in Table 5.4-2. Unless otherwise noted, the programs named in the table address newly built sources only.

Table 5.4-2 Land-Based Source Control Program Cost Per Tonne[a] Comparisons

SOURCE CATEGORY[19]	IMPLEMENTATION DATE	NO_X COST/TONNE	SO_X COST/TONNE	PM_{10} COST/TONNE
Highway Diesel Fuel Program [d] 55 *Fed Reg* 34120, August 21, 1990	1993	-	-	11,000
Stationary Diesel (CI) Engines [c] 71 *Fed Reg* 39154, July 11, 2006	2006	600 - 22,000	-	4,000 - 46,000
Locomotives and Harborcraft (Both New and Retrofits) [d] 73 *Fed Reg* 25097, May 6, 2008	2015	800[b]	-	9,300 (New) 50,000 (Retrofit) [c]
Heavy Duty Nonroad Diesel Engines[d] 69 *Fed Reg* 38957, June 29, 2004	2015	1,200 [b]	900	14,000
Heavy Duty Onroad Diesel Engines [d] 66 *Fed Reg* 5001, January 18, 2001	2010	2,400 [b]	6,400	16,000
International Shipping (ECA) (Both New and Retrofits) [d]	**2016**	**2,600**	**1,200**	**10,000**
Light Duty Gasoline/Diesel Engines [d] 65 *Fed Reg* 6697, February 10, 2000	2009	2,800 [b]	6,600	14,000
Fossil Fuel Fired Power Plants (Retrofits) [c] 58 *Fed Reg* 3590, January 11, 1993; 63 *Fed Reg* 57356, October 27, 1998	2000 to 2010	3,400	300	-
Other Stationary Sources (Both New and Retrofits) [c] 67 *Fed Reg* 80186, December 31, 2002	Ongoing	4,000 - 12,000	300 - 6,000	Variable

Notes:
[a] Units are 2006 U.S. dollars per metric ton. To convert to $/short ton, multiply by 0.907.
[b] Includes NO_X plus non-methane hydrocarbons (NMHC). NMHC are also ozone precursors, thus some rules set combined NO_X+NMHC emissions standards. NMHC are a small fraction of NO_X so aggregate cost/ton comparisons are still reasonable.

[c] Annualized costs of control for individual sources, except SO_X for Power Plants is a typical auction price.
[d] Aggregate program-wide cost/tonne over 30 years, discounted at 3%, except Light Duty and Highway Fuel aggregate costs were discounted at slightly higher rates, yielding slightly lower cost estimates.

Another example of one of the earlier programs is the 1990 regulation promulgated by the U.S. Government to reduce the sulfur content of highway diesel fuel. The cost effectiveness of PM reductions from that program varied depending on how the benefit of reduced wear on the engines was credited. Because the cleaner fuel with 0.05% sulfur (500 ppm) lengthened the useful life of the engines, the program could be characterized as having negative costs (with savings up to $100,000 per tonne) if the maximum engine wear credit was attributed to the program. If no engine wear credit was included, the program was estimated to cost a maximum of $11,000 per tonne of PM reduced.

As shown above, the projected cost per tonne of the proposed ECA falls well within the respective ranges of the other programs. The proposed ECA cost-effectiveness is comparable to the cost per tonne of current programs for new land-based sources, and has favorable cost effectiveness compared to land-based retrofit programs.

[1] Research Triangle Institute, 2008. "Global Trade and Fuels Assessment—Future Trends and Effects of Designating Requiring Clean Fuels in the Marine Sector"; Research Triangle Park, NC; EPA420-R-08-021; November. (Available at http://www.epa.gov/otaq/regs/nonroad/marine/ci/420r08021.pdf)

[2] Research Triangle Institute, 2008. "Global Trade and Fuels Assessment—Future Trends and Effects of Designating Requiring Clean Fuels in the Marine Sector"; Research Triangle Park, NC; EPA420-R-08-021; November. (Available at http://www.epa.gov/otaq/regs/nonroad/marine/ci/420r08021.pdf)

[3] International Maritime Organization, Note by the Secretariat, "Revision of MARPOL Annex VI and NOX Technical Code; Input from the four subgroups and individual experts to the final report of the Informal Cross Government/Industry Scientific Group of Experts," Subcommittee on Bulk Liquids and Gases, 12th Session, Agenda Item 6, BLG 12/INF.10, December 28, 2007.

[4] International Maritime Organization, Note by the Secretariat, "Revision of MARPOL Annex VI and NOX Technical Code; Input from the four subgroups and individual experts to the final report of the Informal Cross Government/Industry Scientific Group of Experts," Subcommittee on Bulk Liquids and Gases, 12th Session, Agenda Item 6, BLG 12/INF.10, December 28, 2007.

[5] EnSys Energy & Systems, Inc. and RTI International 2009. Global Trade and Fuels Assessment—Additional ECA Modeling Scenarios. prepared for the U.S. Environmental Protection Agency.

[6] Energy Information Administration, 2006. "Annual Energy Outlook 2006" (DOE/EIA-0383(2006)); Washington, DC. (Available at: http://www.eia.doe.gov/oiaf/aeo/archive.html)

[7] Energy Information Administration, 2008. "Annual Energy Outlook 2008" (DOE/EIA-0383(2008)); Washington, DC. (Available at: http://www.eia.doe.gov/oiaf/aeo/)

[8] Energy Information Administration, 2008. "International Energy Outlook 2008" (DOE/EIA-0484(2008)); Washington, DC. (Available at: http://www.eia.doe.gov/oiaf/ieo/)

[9] ICF International, "Costs of Emission Reduction Technologies for Category 3 Marine Engines" prepared for the U.S. Environmental Protection Agency, March 2009.

[10] ICF International, "Commercial Marine Port Inventory Development," prepared for the U.S. Environmental Protection Agency, EPA Report Number EPA420-R-07-012c, September 2007.

[11] Lloyd's Register of Ships Online, Lloyd's Register, Fairplay. September, 2008 can be found at www.sea-web.com.

[12] "Matched Typical Ports to Modeled Ports" Table 2-33 of section 2.5.2 of "The Commercial Marine Port Inventory Development, 2002 and 2005 Draft Inventories" report to EPA from ICF International, September 2007.

[13] ICF International, "Commercial Marine Port Inventory Development 2002 and 2005 Draft Inventories" prepared for the U.S. Environmental Protection Agency, September 2007.

[14] Entec UK Limited, Quantification of Emissions from Ships Associated with Ship Movements between Ports in the European Community, July 2002, pps. 86-87.

[15] "Nonroad SCR-Urea Study Final Report" July 29, 2007 TIAX for Engine Manufacturers Association (EMA) can be found at:http://www.enginemanufacturers.org/admin/content/upload/198.pdf

[16] http://www.adblueonline.co.uk/air_1/bulk_delivery

[17] http://www.factsaboutscr.com/documents/IntegerResearch-Ureapricesbackto2005levels.pdf

[18] http://www.fertilizerworks.com/fertreport/index.html

[19] Regulation of Fuels and Fuel Additives: Fuel Quality Regulations for Highway Diesel Fuel Sold in 1993 and Later Calendar Years, 55 *Fed Reg* 34120, August 21, 1990.
Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, 71 *Fed Reg* 39154, July 11, 2006.
Control of Emissions of Air Pollution from Locomotives and Marine Compression-Ignition Engines Less Than 30 Liters per Cylinder, 73 *Fed Reg* 25097, May 6, 2008.
Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel 69 *Fed Reg* 38957, June 29, 2004.
Control of Air Pollution from New Motor Vehicles: Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements 66 *Fed Reg* 5001, January 18, 2001.
Control of Air Pollution From New Motor Vehicles: Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements 65 *Fed Reg* 6697, February 10, 2000.
Acid Rain Program; General Provisions and Permits, Allowance System, Continuous Emissions Monitoring, Excess Emissions and Administrative Appeals, 58 *Fed Reg* 3590, January 11, 1993; Finding of Significant Contribution and Rulemaking for Certain States in the Ozone Transport Assessment Group Region for Purposes of Reducing Regional Transport of Ozone, 63 *Fed Reg* 57356, October 27, 1998.
Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NSR): Baseline Emissions Determination, Actual-to-Future-Actual Methodology, Plantwide Applicability Limitations, Clean Units, Pollution Control Projects, 67 *Fed Reg* 80186, December 31, 2002