EPA-600/2-76-161a
June 1976

Environmental Protection Technology Series

IMPACT OF SO_x EMISSIONS CONTROL ON PETROLEUM REFINING INDUSTRY

Volume I

Study Results and Planning Assumptions

Industrial Environmental Research Laboratory
Office of Research and Development
U.S. Environmental Protection Agency
Research Triangle Park, North Carolina 27711

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IMPACT OF SO_X EMISSIONS CONTROL ON PETROLEUM REFINING INDUSTRY

VOLUME I: STUDY RESULTS AND PLANNING ASSUMPTIONS

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Contract No. 68-02-1332, Task 1
ROAP No. 21ADC-030
Program Element No. 1AB013

EPA Task Officer: Max Samfield

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Prepared for

U.S. ENVIRONMENTAL PROTECTION AGENCY
Office of Research and Development
Washington, DC 20460

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I. EXECUTIVE SUMMARY

A. INTRODUCTION

This report summarizes a study performed for the Environmental Protection Agency, which was part of a three-phase program undertaken in parallel using a similar conceptual approach and data base. The other two studies are entitled, "The Impact of Lead Additive Regulations on the Petroleum Refining Industry" and "The Impact of Producing Low-Sulfur, Unleaded Motor Gasoline on the Petroleum Refining Industry." Significant coordination of data gathering, scenario development, computer simulation time and subsequent analysis was achieved by performing the three separate studies as part of an integrated work program. However, the combined cost of implementing all three regulations cannot be obtained by direct summation of the results of the three individual reports.

Initial work on this program began in late 1973. An interim Phase I report was published in May, 1974, entitled "Impact of Motor Gasoline Lead Additive Regulations on Petroleum Refineries and Energy Resources - 1974-1980, Phase I", EPA report number 450/3-74-032a. In this Phase I study, the U.S. refining industry was simulated as a single composite model which allowed a rapid overview analysis, but lacked the desired level of precision.

Accordingly, a more detailed simulation of the U.S. refining industry was developed via a "cluster" model approach which was used in this three-phase effort. This project included collection and collation of an extensive base of refinery data supplied by the Bureau of Mines and individual oil companies, which was used to achieve satisfactory calibration of the cluster models. It is felt that the development and calibration of the cluster models represent a significant achievement in the area of refinery simulation.

In the present report, several scenarios are developed to describe how

the petroleum refining industry will likely operate for the next decade, with and without potential regulations controlling SO_x emissions from the petroleum refining industry. The report then summarizes the detailed planning assumptions required to execute the task, along with the methodology used to develop these assumptions. The primary study results are then presented herein, defining the impact of control of SO_x emissions in terms of capital investment requirements, increased refining costs per gallon of total refinery products, and energy penalties. A complete presentation of planning assumptions, calculational methods, and study results is contained in the appendices of Volume II of this report.

B. SCOPE AND APPROACH

The objective of this study is to determine the impact on the petroleum refining industry of a limitation on SO_x emissions, within reasonable limits of existing technology, from refinery process heaters and boilers, fluid catalytic cracking units, and sulfur recovery units.

The specific goals of the study are to determine for the period through 1985 the impact of the control of refinery SO_x emissions in terms of (a) capital investment requirements; (b) composite increase in refining costs per gallon of total products, including return on capital, manufacturing cost, and yield losses; (c) increased crude oil requirements; and (d) net energy penalties, reflecting increased crude oil requirements less the heating value of an increase in the production of refinery by-products such as liquefied petroleum gases (LPG).

In the study, limitations of present and future refinery configurations are taken into consideration. However, considerations outside the scope of the study include availability of capital requirements, impact upon the competitive structure of the industry, and ability of the construction industry to meet the associated refinery construction needs. The study focused upon the large, complex refineries processing about three-fourths of the crude oil refined in the United States. The impact upon the small refineries comprising over half of the number of U.S. refineries has not been fully assessed. On a relative basis, the penalties to the small refiner probably exceed those reported herein.

In approaching this problem, it was recognized that there are many complex interactions in the petroleum refining industry. Also, there is a necessity for consideration of the secondary impact of certain SO_x control techniques on refinery process units, including consideration of their capital investments and operating costs. Therefore, a standard analytical tool of the petroleum industry was applied to this problem, computer refinery model simulation with an associated linear programming (L.P.) optimization algorithm. This provided an assessment of the impact of the control of SO_x emissions with an optimal, minimum cost selection of processing and blending schemes to achieve this end.

Although this analytical method has been used by the petroleum industry for more than a decade for studies of individual refineries, its use in simulation of the entire U.S. refining industry has been limited. Therefore, one of the requirements of this program was the development of a methodology for industry-wide simulation, collection and utilization of a data base to confirm the utility of this methodology, and definition of a means to utilize model results to determine national implications of a proposed policy. Equally important was the careful assessment of the planning assumptions regarding the constraints which may be imposed on the petroleum refining industry over the next decade. In all of these activities, Arthur D. Little, Inc., cooperated extensively with representatives of the Environmental Protection Agency and with members of a task force comprised of representatives of the American Petroleum Institute (API) and the National Petroleum Refiners Association (NPRA). As a result of these efforts, the utility of the model in faithfully representing the likely behavior of the petroleum refining industry over the next decade was greatly enhanced.

The modeling approach developed in this study provided for a specific simulation of the existing U.S. refining industry, processing domestic crude oils, including Alaskan North Slope crude oil, to the extent available. Any additional crude oil required to meet petroleum product demand was assumed to be imported. Two simulation models, called "grassroots models," were developed to provide for any new refining capacity which would be required to meet product demands in 1980/1985. The grassroots model for the western U.S. used North Slope crude oil, whereas a separate grassroots model for the eastern U.S. used imported oil.

The existing U.S. refining industry was simulated by six individual computer models, constructed to represent clusters of three refineries each in six geographical areas of the United States. These cluster models, therefore, represented refineries typical of the refining industry in terms of crude oil type, processing configuration, and product slate. They ranged in crude oil capacity from 48,000 to 350,000 bbls/day. To ensure that the cluster models adequately represented the industry, an extensive data base on these 18 refineries was collected and analyzed. Processing yield and property data were assimilated to ensure adequate representation of the refinery processes and blending operations. Finally, each cluster model was calibrated by comparison to the extensive data base.

In addition, a methodology for scaling up the results of the cluster models to the entire United States was developed, including these 18 cluster model refineries as well as atypical refineries. In a comparison with 1973 Bureau of Mines data, the most recent year for which complete information was available, the total petroleum products output and crude oil consumption predicted by the model agreed with Bureau of Mines data within 2%. This scale up technique allows assessment of the national impact for the four specific goals of the present program, including an estimate of the impact on small refiners.

Several planning assumptions were required; each of these required auxiliary studies of considerable detail, because of the importance of these planning assumptions to the study results.

Since the SO_x emission level from petroleum refineries is dependent on the nature of the crude oil being refined, a separate study was made to determine the types of crude oils to be processed by the U.S. refining industry over the next decade. Estimates of domestic crude oil availability were made, including quantity and disposition of Alaskan North Slope and offshore fields. Also, estimates of world-wide crude oil production and disposition were made, taking into account future product demand in Europe, Japan and the United States in terms of product type and sulfur level requirements. Likely production rates from the North Sea, OPEC countries, and Far East countries, including China, were included in this analysis, as was the likely availability of non-oil energy sources

such as coal and nuclear power. When more than one future scenario for the next decade was likely, sensitivity studies were included in the current program to determine the effect of this uncertainty on the study results.

Since the total cost of controlling the refinery SO_x emissions depends directly upon the demand for petroleum products, a separate forecast was made of petroleum product supply/demand for the next decade. This forecast included an evaluation of the demand for products by individual end-use sector, including the effects of non-petroleum energy sources, conservation, import levels, expanded petrochemical demand for certain products, and the future course of governmental regulation in improving energy self-sufficiency for the U.S.

The impact of SO_x controls also depends upon certain key product specifications on the fuel oil as well as other major refinery products. Present and possible future octane requirements on unleaded gasoline were evaluated. Projections were also made of the future sulfur level requirements of residual fuel oil. To assist in this evaluation, field interviews were conducted with East Coast utilities, accounting for over 90% of the utility fuel oil consumption on the East Coast. Again, certain sensitivity studies were required to define the effects of uncertainties in projections on the study results.

Several other significant assumptions were made in the execution of this program, discussed in detail in the following report.

C. CONCLUSIONS

1. Calibration Summary

In order to simulate the existing U.S. petroleum industry, six cluster models were developed to describe the regional characteristics of the refining industry and the processing configurations typical of the industry. Each of these six cluster models represented a cluster of three similar, existing refineries in the United States.

A critical component of the model development was to ensure that these models effectively represented the refineries as well as the section of the United States containing the refineries. Therefore, an extensive calibration

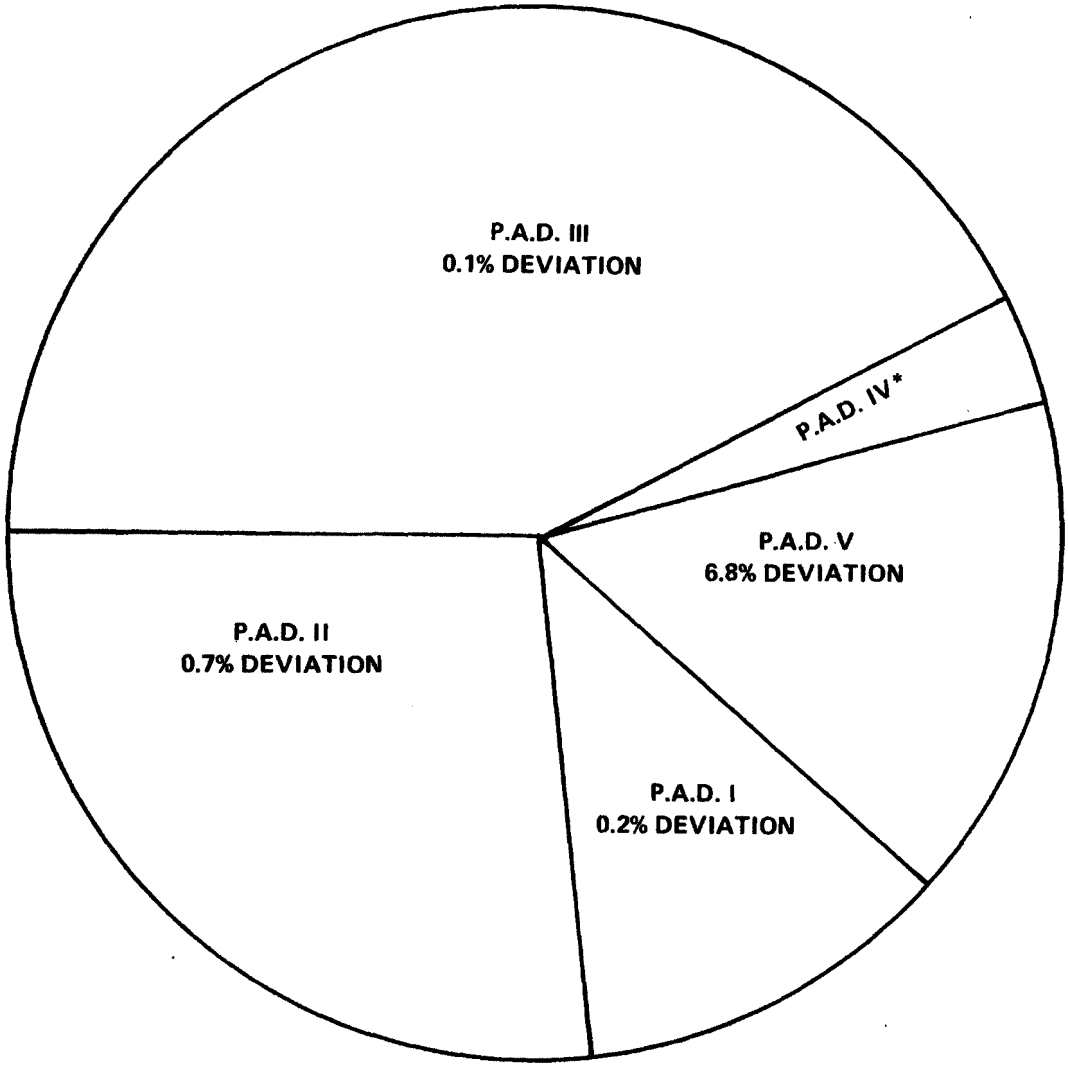
effort was undertaken by Arthur D. Little, Inc., in collaboration with the representatives of the Environmental Protection Agency (EPA) and a task force of the American Petroleum Institute/National Petroleum Refiners Association.

Data on raw material intake, fuel consumption, and product outturns for each of the refinery clusters and for the regions of the U.S. containing these clusters were furnished by the Bureau of Mines. Proprietary operating data on these refineries were compiled and combined for each cluster by representatives of the EPA. Processing information was obtained from sources in the petroleum industry. Using this processing information the individual cluster models were run on the computer and compared with the industry data. This task was continued until each cluster model was calibrated with the industry data.

The results of these calibrated cluster models were then scaled up to determine the accuracy with which the refining districts in the U.S. were described. In Figure 1 is shown the deviation of the model predictions from the total raw material intake for the several Petroleum Administration for Defense (PAD) districts in the U.S. As noted therein, the maximum deviation was 6.8% (PAD V), and the deviation from the total U.S. raw material intake was 1.0%. PAD IV (less than 5% of U.S. crude oil capacity) was not simulated by a cluster model, but was included in the scale up method. Thus, as a result of this extensive calibration effort, the cluster models demonstrate an excellent ability to simulate the existing U.S. petroleum refining industry, using processing information describing individual refinery units.

2. Qualitative Study Results

Refinery sulfur oxide (SO_x) emissions emanate from three primary sources. The first is from refinery process furnaces and boilers. Control of these emissions can be achieved either by restricting the sulfur level in refinery fuel or by scrubbing the stack gases prior to discharge into the atmosphere. The second source of SO_x emissions is from fluid catalytic cracking (FCC) units. These can be controlled to some extent by desulfurizing the hydrocarbon feed to the unit or by scrubbing the regenerator stack gas prior to discharge. The third source of SO_x emission is from the refinery process



U.S. Total Deviation = 1%
*Not simulated, but included in scale-up

FIGURE 1. AGREEMENT OF MODEL PREDICTION WITH 1973 B.O.M. TOTAL REFINERY RAW MATERIAL INTAKE DATA
(Area on chart represents percentage of total U.S. refinery intake by P.A.D. District)

which ultimately recovers the sulfur removed in the various treating processes in an elemental form (for example, a Claus unit). Control of these emissions is obtained by increased levels of sulfur recovery or by stack gas scrubbing.

Stack gas scrubbing has not been included as an alternative in the detailed computer model in this study of the control of refinery SO_x emissions, except for Claus units. Preliminary calculations have indicated that the capital investment requirements to install stack gas scrubbing to control refinery SO_x emissions will be at least as great as the alternatives of reducing refinery fuel sulfur levels and FCC feed sulfur levels. Furthermore, FCC feed sulfur reduction results in significant yield benefits in the FCC unit and would also be required by the majority of refiners to meet proposed reductions in the maximum allowable sulfur levels in gasoline.

To reduce emissions from process furnaces and boilers, refinery fuel sulfur levels were reduced consistent with potential regional regulations for combustion sources.

Emissions from FCC units were controlled by feed desulfurization to a level that was compatible with existing technology for the desulfurization of feed to FCC units. The FCC feed was desulfurized to a level of 0.2 wt.% sulfur or 85% sulfur removal, whichever was the lower.

Emissions from the sulfur recovery plants were reduced by increasing the level of sulfur recovery to 99.95%. This level of sulfur removal can be obtained by using the Beavon-Stretford process, for example, to clean up the tail gases from Claus plants.

The effects of the imposed operational constraints on total refinery SO_x emissions is summarized for 1985 in Table 1 for each region in the U.S. By reducing refinery fuel sulfur levels, desulfurizing FCC feed, and increasing sulfur recovery from the Claus plant, SO_x emissions from refineries were reduced by 76% for the total U.S., on a weight basis, relative to projected base emissions levels. The regional variations in percentage emissions reduction can be attributed to such variables as crude sulfur content, FCC throughputs and feed quality, level of refinery fuel sulfur allowed, and the ability to dispose of sulfur in products, given product quality constraints.

Table 1. REDUCTION OF SO_x EMISSION LEVELS, 1985

PAD District	Model	Reduction after SO_x control, wt.%[a]
I	East Coast	76
II	Large Midwest	81
II	Small Midcontinent	75
III	Louisiana Gulf	88
III	Texas Gulf	62
V	West Coast	72
I-IV	East Grassroots	82
V	West Grassroots	65
I-V	Total U.S. average	76

[a]Relative to projected base levels of SO_x emissions in petroleum refining industry (Scenario C).

In general, those clusters with high sulfur content crude slates -- the East Coast, Large Midwest and East of the Rockies grassroots -- showed the highest level of SO_x emissions reduction.

In Figure 2 is shown the disposition of sulfur oxides emissions by refinery source, for the Large Midwest cluster model in 1985 with and without imposition of SO_x controls. The areas on this chart attributable to each source of SO_x emissions are proportional to the total SO_x emissions levels in tons/day. Before controls, the Claus plant was responsible for 25% of all SO_x emissions in the refinery, accounting for 3.1% of the sulfur in the crude oil entering the refinery. After controls, the Claus unit was responsible for 1% of all SO_x emissions in the refinery, or 0.03% of the crude oil sulfur. After controls, 83% of the SO_x emissions from the refinery originate in the process heaters and boilers; the sulfur limitation on the fuel burned in these furnaces varied from 0.3 wt.% to 0.5 wt.%, depending upon the geographic region in which the refinery existed. Obviously, a high level of SO_x emissions control has been attained.

In this regard, note also that, before controls, 88% of the sulfur entering the refinery in crude oil is contained either in liquid products or as elemental sulfur product (i.e., not present as SO_x emissions). After control, 97.6% of this sulfur is contained either in liquid products or as elemental sulfur product.

3. Economic Penalties

The economic impact by 1985 on the U.S. refining industry for the control of SO_x emissions is shown in Table 2. This shows estimates of the capital requirements to be 4.5 billion dollars on a first quarter 1975 basis. The final capital requirements are expected to be on the order of 8.8 billion dollars, based on the timing of the investments and forecasted inflation rates in refinery process construction. The additional cost to the U.S. refining industry is estimated to be 0.71 cents per gallon of total products, based on first quarter 1975 costs. This includes an annual capital charge of 25% of the total additional capital investment required.

Of this economic penalty, 65% was for investment related costs, 11% was for increased operating costs, and 17% was for crude oil costs.

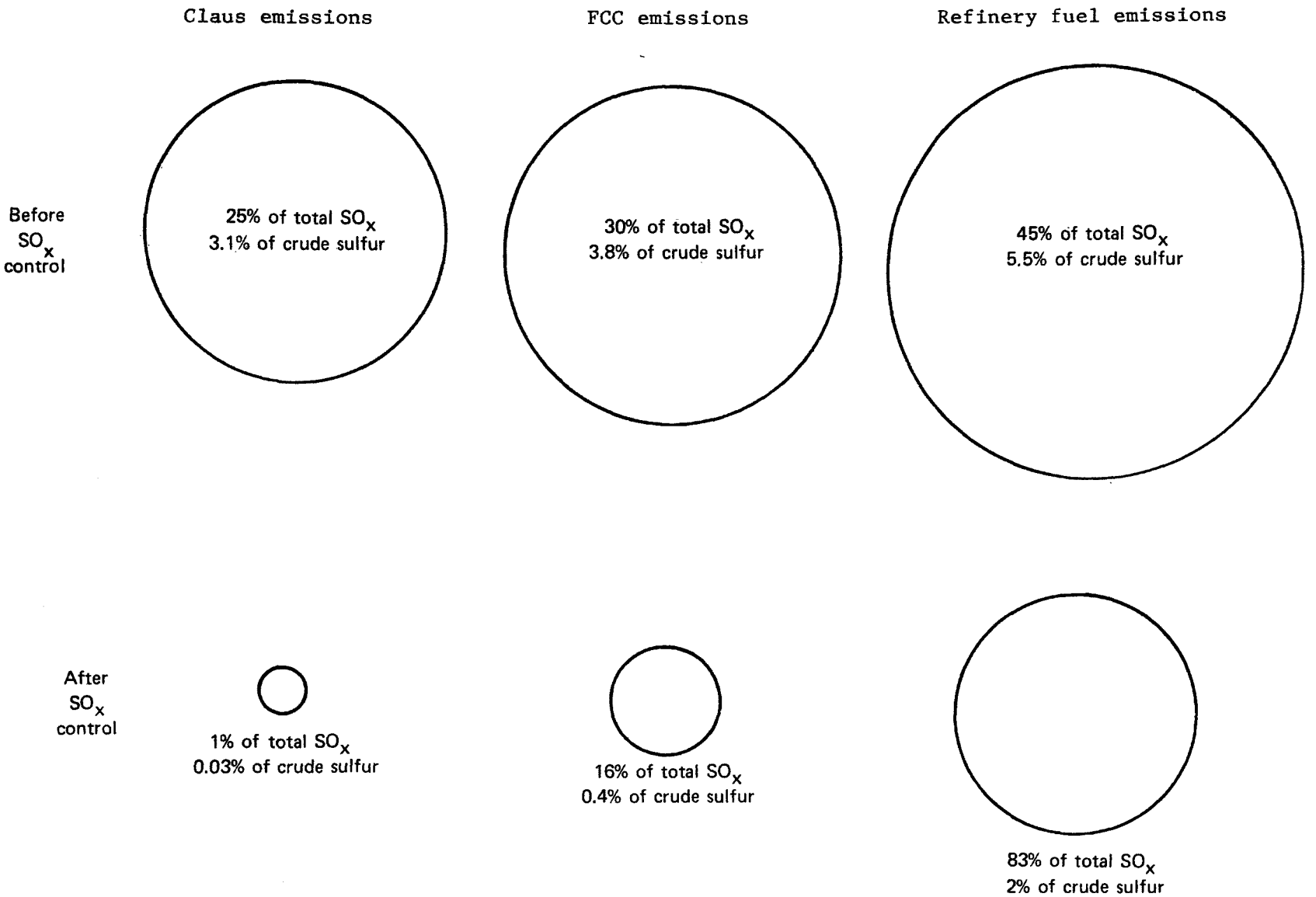


FIGURE 2 CONTROL OF SO_x EMISSIONS BY SOURCE, LARGE MIDWEST CLUSTER, 1985
(AREA ON CHART REPRESENTS RELATIVE SO_x EMISSIONS LEVEL IN TONS/DAY)

Table 2. PENALTIES FOR THE REDUCTION OF SO_x EMISSIONS BY 1985[a]

Capital investment required – billions of dollars	
Non-inflated (1Q 1975 basis)	4.5
Inflated	8.8
Total economic penalty	
cents per gallon of total products	
(1Q 1975 basis)	0.71
Additional crude oil required, MB/CD	63
Net energy penalty (MB/CD FOE)	96

[a]Relative to Scenario C.

4. Crude Oil and Energy Penalties

The estimates of the crude oil and energy penalties for SO_x emissions controls are also shown in Table 2. By 1985 it is estimated that the U.S. refining industry will have to process additional crude oil in excess of 60,000 barrels per day. Furthermore, the model results indicate less LPG is produced, so the net energy penalty by 1985 is estimated to be nearly 100,000 barrels per calendar day of fuel oil equivalent.

5. Sensitivity Studies

A number of sensitivity studies were evaluated; as would be expected, the impact of reducing SO_x emissions depends upon the sulfur level of the crude oil being processed. Furthermore, the study projections indicate that the sulfur content of imported oil for the next decade is uncertain. Since imported oil is the only source of crude oil assumed for the new grassroots refineries East of the Rockies, sensitivity analyses were conducted with this model.

The effects of reducing refinery SO_x emissions on the East of Rockies grassroots refineries were determined by model runs for both a sweet crude oil refinery (processing a 50/50 Algerian/Nigerian crude mix) and for a sour crude oil refinery (processing 100% Saudi Arabian Light crude). Model results were scaled up for the base case on the basis that one-third of East of Rockies grassroots refineries will process a sweet crude slate and two-thirds will process sour crude. This sensitivity study examines the effects on 1985 economic penalties if all grassroots refineries East of Rockies were based on 100% sour crude, and if all were based on 100% sweet crude.

The results of this sensitivity analysis are shown in Table 3. With grassroots capacity used for processing all sweet crude, capital investment for reduction of SO_x emissions would be 4.1 billion dollars (first quarter 1975 basis), 430 million dollars less than the base case. If East of Rockies grassroots capacity is for processing sour crude, the capital investment for emissions reduction will be 216 million dollars higher than the base case. Similarly, the economic penalty is .04 cents lower and 0.03 cents higher than the base case for the all-sweet and all-sour crudes, respectively.

Table 3. EFFECT OF IMPORTED CRUDE SULFUR CONTENT ON 1985 ECONOMIC PENALTIES

	Base case	Crude for East of Rockies Grassroots Model	
		100% Sour	100% Sweet
Crude oil sulfur, wt%	1.18	1.68	0.17
Capital investment Billion dollars (1Q 1975 basis)	4.5	4.7	4.1
Economic Penalty Cents per gallon total products (1Q 1975 basis)	0.71	0.74	0.67

Thus, the sulfur content of the crude processed does significantly affect the magnitude of investment and economic penalties. Furthermore, other changes in imported crude type, such as higher utilization of Arabian Heavy crude oil, would be expected to significantly alter the investment impact of SO_x emissions controls.

6. Other Major Implications

The choice of six different cluster models to represent the existing U.S. refining industry was made to provide a reasonable representation of the different types of refineries operating today. Over 80% of U.S. refining capacity has been represented in the cluster models. However, no cluster model was constructed which could be considered representative of the small refiner (less than 50,000 barrels per day), nor would such a model be sufficient to a study of the impact on small refiners. These refiners represent less than 20% of total U.S. refining capacity and any understatement of their penalties will not significantly affect the overall conclusions. However, the control of SO_x emissions could have a significant impact on the smaller refiner. He does not have the wide choice of blending components available to the larger refiners and little, if any, existing treatment equipment. For example, few of the small refiners have any existing Claus plants for sulfur recovery. Although costs for addition of these plants have been included in the present study, assessments have not been made of the ultimate means of disposition of the sulfur product or the financing ability of the small refiner to install these plants. Because of these considerations and the economies of scale, the unit cost to the small refiner for SO_x emission control will be higher than those indicated in this study. This could have a significant impact on the competitive structure of the refining industry.

As is apparent from Figure 1, the emissions from Claus units and FCC units have been greatly reduced. In fact, the emissions from process heaters and boilers constitute 83% of the refinery SO_x emissions after SO_x controls are instituted, and these flue gas emission controls are more stringent than normally in effect at the present time in the utility industry. This raises the possibility that the SO_x emissions control requirements of the present study were too stringent for the Claus and FCC units, relative to their

importance in contributing to total refinery SO_x emissions. A detailed assessment of this possibility and proposals of alternative control strategies have not been made in the present study.

One means of controlling SO_x emissions is by hydrotreating FCC feed; also, FCC gasolines constitute a primary source of sulfur in unleaded gasoline, possibly leading to sulfate emissions from automobiles employing catalytic converters. Hence, significant improvement in sulfur content of unleaded gasoline can be obtained as an indirect result of the strategy employed herein for refinery SO_x emissions control. No economic benefit has been included in consideration of the impact of SO_x controls for this improvement.

D. RECOMMENDATIONS FOR FURTHER ACTION

In order to assess more fully the impact of refinery SO_x emissions controls, several areas are worthy of more consideration than possible with this study:

1. Exploitation of the synergy available from simultaneous regulations on refinery SO_x emissions and sulfur content of unleaded gasoline should be explored more thoroughly. It is possible that there is a point of minimum cost control for both, with sharply increasing penalties as control of either variable is made more stringent. This could lead to a more economic level of control for both sources of sulfur.

2. The impact of SO_x emissions control should be assessed more fully for the small refiners processing less than 50,000 barrels per day. Such studies should examine the economic impact on the refiners as well as the likely effect on the competitive structure of the industry.

3. Studies should be conducted of interactions of SO_x emissions regulations and other environmental regulations applicable to the petroleum refining industry. This investigation should include examination of possible processing changes used to meet SO_x regulations but which are precluded by other environmental regulations.

II. STUDY BASIS

A. APPROACH

The objective of this study is to determine the impact on the petroleum refining industry of a possible Environmental Protection Agency (EPA) regulation requiring the reduction of refinery sulfur oxides emissions, taking into consideration limitations of present refinery configuration and potential grassroots refinery construction. Since the processing interactions in any single refinery are exceedingly complex, and indeed even more complex for the industry as a whole, such an assessment of the impact of this potential regulation could be addressed by two possible approaches.

First, a survey could be conducted by sending out a questionnaire[1,2] to individual refiners across the country, requesting an assessment of their individual costs for meeting the potential regulation. The results could then be composited to define the cost to the industry. Although this is a valid approach, it is often difficult to determine if the specific regulation is being interpreted equivalently by all refiners across the country, if they are using a similar analytical procedure, if they are using the most efficient means of meeting the regulation, and if they are using a common basis for cost estimation. This method, however, does have the decided attribute of allowing each individual refiner to assess his unique problems in meeting the regulation.

An alternative approach, used in the present study, is to simulate the U.S. refining industry using computer models. Computer simulation of individual refineries is well-known and has been practiced for over a decade. Such a simulation normally utilizes a linear programming (L.P.) model to represent the individual process units and the process interactions of the refinery. In the present study, however, simulation of a single refinery is not sufficient in that no single refinery can be said to

represent the entire refining industry. Therefore, eight computer models were used simulating individual refineries which, when composited, would be typical of the industry as a whole.

In the use of any L.P. model, it is necessary to define the types of crude oils available to the model, the individual process yields, the streams that can be used to connect the processes, and the products produced from the refinery. The model then uses an optimization algorithm to select the optimal combination of process units meeting the objective of the study. If all product prices are given as input to the model, the model will select that set of product outturns and processing configurations which will maximize profit derived from the complex. However, this method of L.P. optimization may not assure that the quantities of products being produced from the complex meet the product demands of the region being served by that refinery. If this happened in the actual operation of the refinery, market forces would increase the prices of those products in short supply and decrease those in excess supply, so that the entire refinery operation would be adjusted with the product outturns just meeting the product demands. In a computer simulation of a refining industry, however, it is very difficult to predict those product prices which are required to match the product outturns with the market demands. In the present studies, an alternate approach was taken, wherein the product outturns from the refinery were fixed in order to meet the projected product demands imposed upon the U.S. refining industry. Therefore, the L.P. algorithm selected a set of processing configurations which allowed this specified product demand to be met at minimum cost. However, it is necessary that the problem being optimized be carefully constructed such that the real-world constraints on the industry in meeting these minimum cost objectives would be met, allowing a realistic simulation of the operation of the industry. The definition and inclusion of these constraints is an exceedingly important component of a study of the impact of any potential regulation on the industry. This activity was greatly benefited by the results of a Federal Energy Administration/National Petroleum Refiners Association conference on refining industry modeling.[3]

In order to meet the constraints which would be imposed upon the refining industry, comprised of nearly 300 individual refineries spread throughout the United States, Arthur D. Little, Inc., (ADL), representatives

of the EPA, and a task force comprised of representatives of the American Petroleum Institute and the National Petroleum Refiners Association selected three refineries in each of six geographic regions to simulate the existing U.S. refining industry. These six refinery models (cluster models) were constructed and calibrated[4] against the three actual refineries in each region to ensure that the product blend flexibility and the processing configuration flexibility did not exceed that available to these refineries. In simulating these existing refineries over the next decade, the crude run for the individual cluster models was not allowed to exceed the crude capacity for those refineries being simulated. All new crude capacity required to meet increased product demand was met by the construction of new, grassroots refineries.

In the construction of new grassroots refineries, the refining industry east of the Rockies was represented by a class of refineries feeding crude oil typical of imported oil likely to be available in the coming decade. Another simulation model was developed for grassroots refineries to be constructed west of the Rockies, feeding Alaskan North Slope crude oil. The product outturn from all of the existing refineries (cluster models) and the new refinery installations (grassroots models) was then composited to ensure that the overall product demand for the United States refining industry was met.

It is also important that the major products of the models meet appropriate quality constraints typical of the product quality demand by the marketplace over the next decade. Projections of future product quality requirements are necessary in order that the study be a realistic representation of the industry over the next decade. Of particular importance in this regard is the sulfur level of the residual fuel oil being produced by the industry. Separate studies were made of these product qualities to determine the likely levels associated with the industry over the next decade, discussed in the planning assumptions for the study.

The impact upon the refining industry which is evaluated in the present study includes: the capital investment requirements for the refinery to meet the potential regulation, the composite capital charge and operating cost expressed per gallon of total product, the crude oil

penalty, and the net energy penalty associated with the regulation (including by-products which have an energy value).

There are other considerations important to the determination of the impact of the regulation. These other considerations were beyond the scope of the study and have not been evaluated in detail. For example, the study determines the capital outlay required to meet the potential regulation by the industry. However, it is likely that, for many of the small refiners in the country, the projected capital outlay will require financing that may not be available to them at the present time. The availability of capital required by the possible regulation is specifically beyond the scope of this study, as was the impact of the regulation on the competitive structure of the industry. Also, many of the processing requirements needed to meet the regulation require significant construction of heavy-walled vessels. The impact of the regulations upon the construction industry, including the fabricators and vendors, is also not considered to be within the scope of the present study.

B. CASE DEFINITIONS

The cluster model approach used in the present study of the possible regulation requiring reduction of sulfur oxide (SO_x) emissions from petroleum refineries was also used in two other studies, which were conducted simultaneously: a study of a possible regulation requiring reduction of the sulfur content of unleaded gasoline, and (2) reassessment of promulgated regulations relating to lead additive content of gasoline (Federal Register, December 6, 1973; January 10, 1973). To conduct these studies, six scenarios were created as possible modes of operation of the refining industry, each of which were evaluated for 1977, 1980 and 1985. These scenarios are:

Scenario A: Unregulated operation and expansion of refining industry to meet projected petroleum product demand over the next decade.

Scenario B: Manufacture of unleaded gasoline to meet projected demands, with no lead restrictions on the total gasoline pool or sulfur restrictions on unleaded gasoline.

Scenario C: Manufacture of unleaded gasoline to meet projected demands, with phased reduction in the lead additive content of the total gasoline pool, and with no sulfur restrictions.

Scenario D: Manufacture of unleaded gasoline with a maximum of 100 ppm sulfur, while reducing the lead content of the gasoline pool.

Scenario E: Manufacture of unleaded gasoline with a maximum of 50 ppm sulfur, while reducing the lead content of the gasoline pool.

Scenario F: Reduction of gaseous refinery sulfur-oxide emissions by restrictions on the sulfur content of the refinery fuel, by restriction of fluid catalytic cracker regenerator emissions, and by restriction of sulfur recovery (Claus) plant emissions, while meeting all the requirements of Scenario C.

The complete definition of the computer cases to be run under these several scenarios requires assumptions of crude intakes to the U.S. refining industry, processing configurations, and product outturns and qualities. However, other planning assumptions which have a possibility of occurring over the next decade were also considered. Variations in study assumptions were investigated by a series of parametric runs, wherein the assumptions were modified, one at a time, to reassess the impact on the industry. The scope of these parametric studies is summarized in Table 4.

For the study of lead in gasoline (Scenarios A, B, and C) five major parametric studies were undertaken. A basic premise of the study in the base case is that unleaded gasoline will be produced by the industry meeting 92 Research Octane Number (RON) and 84 Motor Octane Number (MON). These specifications were set one octane number higher than the minimum required by the EPA regulation to allow for refinery blending margin. To evaluate the effect of producing even higher octane gasoline, two parametric runs were conducted as summarized in Table 4.

Projections of the future sulfur content of residual fuel oil consumed in the United States are between 1.1 and 1.4%. As a base planning assumption, it was considered that the residual fuel oil being consumed in the U.S. would have a sulfur content of approximately 1.3%. Since this requires extensive desulfurization in the new grassroots refinery facilities,

Table 4. PARAMETRIC STUDIES

Lead in gasoline	Low sulfur unleaded gasoline	Refinery sulfur oxide emissions
Unleaded gasoline RON/MON = 93/85	Residual fuel oil Sulfur level projection	Variation in imported crude slate
Unleaded gasoline RON/MON = 94/86	Variation in imported crude slate	Residual fuel oil, sulfur level projection
Residual fuel oil sulfur level projection	Sulfur distribution around FCC unit	Stack gas scrubbing
Variation in product demand	Method of FCC gasoline desulfurization	
Variation in imported crude slate		

an additional parametric run at 1.1% sulfur was conducted to ensure that study results were not being unduly influenced by this assumption. It must be emphasized, of course, that the average sulfur level of the fuel oil consumed by all sectors in the United States is below even 1.1%, because of significant levels of imports of low-sulfur fuel oil into the United States over the next decade.

In the base case studies defined by the above scenarios, it was assumed that all petroleum products would grow at a level of 2% per annum. This is a reasonable estimate of the growth of all petroleum products.[5] However, it is likely that each individual product will not grow at 2% per annum, so parametric runs were undertaken to evaluate the impact of growth rates for petroleum products other than 2%.

Arthur D. Little, Inc., has conducted a worldwide survey of crude oil production and disposition to the various refining regions. This indicated that two alternatives might be considered for the imported crude oil into the East Coast region: (1) the imported oil could be of relatively high-sulfur content characteristic of Arabian crudes, or (2) the imported oil may be of relatively lower sulfur level characteristic of Nigerian crudes. There is great uncertainty as to the demand and availability of various crude oils in the United States,[6] and the ultimate selection of crude oils would depend upon this uncertain demand as well as a variety of political factors. The base case under the above scenarios assumed a predominantly Arabian-type imported oil. An additional parametric run was made with a lower sulfur oil being characteristic of the imported oil.

In the program to evaluate the impact of a reduction of sulfur levels in unleaded gasoline (Scenarios C, D, and E) a similar set of parametric studies were required. As indicated in Table 4, projections of the refinery residual fuel oil sulfur level and variations in imported crude slate, discussed above, were also considered.

The attention of the refinery industry to sulfur levels in gasoline in general has been minimal over the last few decades because of the relative lack of importance of sulfur level as a product specification. Therefore, there is limited information available regarding the sulfur

level of some of the high sulfur gasoline blend components from the various refinery processes under various conditions of operation. One of the most critical refinery units with regard to the sulfur content of unleaded gasoline is the fluid catalytic cracker (FCC). Sulfur levels of the products from the FCC unit were obtained by consideration of available data on the FCC unit, feeding various types of gas oil and under various types of operating conditions. However, since there are uncertainties in the sulfur content of the gasoline from FCC units, a parametric run was instituted to evaluate the impact of higher levels of sulfur in the FCC gasoline than was assumed in the base case scenarios above. This, then, led to a range of potential impact on the petroleum industry in consideration of both the base case sulfur level as well as the new parametric case sulfur level.

Because the interest in the sulfur content of FCC gasoline has been recent, the most efficient means of desulfurizing FCC gasoline has not been determined. One attractive method of reducing the sulfur level in the FCC gasoline is by hydrotreating the FCC feedstock. Another method is to directly desulfurize FCC gasoline, requiring further reforming of the desulfurized product. However, laboratory data has shown that the sulfur distribution in FCC gasoline is heavily weighted toward the heavy gasoline component. This suggests that only the heavy gasoline component need be directly desulfurized, with the light FCC gasoline component going directly into the gasoline blend stock. This method of desulfurization of FCC gasoline could potentially reduce the impact on the refining industry of meeting the possible sulfur regulation. Consequently, one parametric run was made to determine the possible savings from this method of desulfurizing FCC gasoline.

In the study of the impact of proposed regulations reducing the sulfur oxide emissions from refineries (Scenarios C and F), several parametric studies were also undertaken. Variations in the sulfur level of imported crude slate and sulfur level of the product residual fuel oil are clearly of potential importance in the impact of regulations reducing refinery sulfur oxide emissions. These parametric studies, discussed above, were included in this particular task.

It is felt that the most likely general means by which the refining industry will meet possible regulations regarding sulfur oxide emissions is to control the sulfur level of the refinery fuel system, to desulfurize the FCC feedstock (thereby reducing FCC regenerator sulfur oxide emissions), and to add tailgas cleanup processes to the sulfur recovery unit (Claus process). However, it is also possible that the emissions from the FCC unit and the refinery fuel system could be reduced by the utilization of stack gas scrubbing techniques, under extensive study for possible application in the utility industry. Consequently, parametric runs were undertaken to determine if the total impact of the regulations reducing sulfur oxide emissions could be diminished by application of the utility-based stack gas scrubbing techniques.

The present report deals with the impact only of the possible regulation reducing sulfur oxides emissions from the refinery. Companion reports[7,8] have been produced which address the impact of the promulgated regulations for lead additives in gasoline and the consequences of a possible regulation to reduce the sulfur content of unleaded gasoline. All further discussions in the present report will be addressed to the possible regulation on reduction of sulfur oxides emissions.

C. PLANNING ASSUMPTIONS

This subsection defines the methodology used in developing planning assumptions required for the present study, as well as identifying the primary assumptions used. Because of the amount of detail required in presenting these planning assumptions, only an outline of this information will be presented below. Additional detail on all of the topics discussed is presented in the appendices of Volume II of this report.

1. Crude Slate Projections

Projection of the crude slate available for the domestic U.S. refining industry depends upon a complex interaction of the production capability of domestic U.S. crudes, the demand for petroleum products, the influence of alternate energy sources within the U.S., the worldwide availability of crude oils and the demand worldwide for these same international crude oils. Arthur D. Little, Inc., investigated the worldwide oil supply by considera-

tion of production potential from the North Sea, OPEC countries, the United States, South America and the socialist countries. Superimposed upon this production potential was the investigation of world oil demand forecasts and product demand forecasts for the major refining and consuming areas, i.e., the U.S.A., the Caribbean, Western Europe, and Japan. These product demand forecasts indicated, for example, a significant lightening of the future product demand barrel in Europe, a similar but less significant change in Japan, and virtually no change in the relative proportions of demand within the United States. This led to a projection that there would be a tendency for heavier crudes, including Nigerian, to be attracted to the U.S.A. and lighter crudes, including Algerian, to be attracted to Europe. Crude oil demand for Japan included both imports from the OPEC countries as well as probable production of Chinese crude oil. In addition, the demand for sulfur content of various products were investigated, allowing an assessment of the likely movements of crude oils of various sulfur levels into the various consuming regions in the world. The assessment of all these factors in combination allowed projections of the disposition of the various crude oils to the various refining regions.

Superimposed upon any such projection of the availability of crude oils to the United States must be an evaluation of the proportion of the U.S. refineries which can run sweet and sour crudes. Obviously, a refinery designed for sweet crude operation can be redesigned to allow operation with sour crudes, but this would be accomplished only if there is sufficient price driving force between the sweet and sour crudes. For example, the NPRA has evaluated the availability of refineries which depend upon low-sulfur crude oil and have indicated that 9% of the refining capacity would be unavailable if the industry were forced to substitute high-sulfur crude oil for 20% of the sweet crude they are now running.[9]

After consideration of all of these factors the planning assumption for the crude oil to be run by the U.S. refining industry over the next decade is summarized in Table 5. Additional detail on the crude oils run to the refining industry in 1973 as well as the assumptions made in reducing this number of crude oils to a smaller but still descriptive level is contained in Appendices F and I. Additional detail on the methodology utilized to obtain the projected crude run shown in Table 5 is presented in Appendix A.

Table 5. U.S. REFINERY CRUDE RUN
(millions of barrels per calendar day)

	1977	1980	1985
Domestic			
Alaskan North Slope	–	1.3	1.5
Other	9.4	9.0	8.5
Subtotal domestic	9.4	10.3	10.0
Domestic, percent of total	70.7%	70.1%	61.0%
Imported			
Arabian	2.1	2.7	4.0
African	0.8	1.3	2.0
South American	0.5	0.4	0.4
Other	0.5	–	–
Subtotal imported	3.9	4.4	6.4
Imported, percent of total	29.3%	29.9%	39.0%
Total crude run	13.3	14.7	16.4

In addition to the overall crude slate to be processed by the U.S. refining industry, a breakdown between the crudes being processed by existing refineries and those to be processed by new grassroots refineries over the next decade must be specified. As described below, the existing U.S. industry is simulated by means of six cluster models. The cluster models process all available domestic crude over the time span of the next decade and use imported crude as required to meet overall product demand. In the base case, these imported crudes were assumed to be comprised predominantly of Arabian Light crude oil. The grassroots model on the West Coast processes only Alaskan North Slope crude oil, because projections indicate an ample supply of North Slope crude oil to meet the demands of PAD District V. Note, however, that although some published reports[6] indicate an ample supply of North Slope crude oil for PAD District V (even leading to planning for a pipeline transport of excess North Slope oil to the Midcontinent), there is not a consensus among the major U.S. refiners as to whether the North Slope crude will be sufficient to exceed the petroleum product demand in District V.

The crude oil to be processed in the new grassroots refineries east of the Rockies is assumed to be imported oil, predominantly Arabian Light crude oil. However, as noted above, a parametric run was made to investigate the impact of importation of lower sulfur crude oils, such as Nigerian-type oils. This parametric run would also be indicative of the effect of introducing Alaskan North Slope crude oil into the midcontinent, used in new grassroots refinery construction east of the Rockies.

2. U.S. Supply/Demand Projections

Prior to 1973, forecasting the oil demand in the United States was a straightforward exercise, involving the application of historically determined growth rates to base year consumption data. However, the pattern of continuous growth was interrupted by massive increases in foreign oil prices (and later domestic decontrolled prices), the Arab oil embargo, and a period of economic recession.

The general approach which has been used by ADL in product demand forecasting is to conduct an indepth analysis of total energy requirements

by individual end-uses, which are then matched with projections of supplies of basic energy sources, including oil, gas, coal, nuclear and hydroelectric power. Because of the stimulus of high oil prices and considerations of security of supply, non-oil energy supplies are developed as rapidly as possible, limited only by technical, environmental, governmental, and resource considerations on the one hand, and by end-use considerations on the other, such as the nuclear contribution being limited to the base load electric power generation. The availability of non-oil energy sources are also evaluated in the light of the recent declines of United States natural gas production, potential environmental constraints on exploitation of coal reserves, inflation-caused reappraisal of the capital intensive new energy forms such as oil shales, and failure to meet targets for nuclear generation capacity. Furthermore, the product demands incorporate recent changes in the structure of energy use within end-use sectors, such as increased electricity consumption in the domestic sector and an increased use of oil as petrochemical feedstock. Also included is the effect of energy conservation. Of course, the impact of energy conservation is difficult to assess from recent product demand data because of the simultaneous occurrence of economic recession, mild winters, and high oil prices.

In the current study the demand forecast for the United States refining industry was obtained by two different approaches. To facilitate the task of combining the demand forecast with the scale up of the cluster models (Appendix G), one simplistic forecasting approach was utilized which led to a growth rate of 2% per annum for all products from the domestic refining industry. However, to ensure that the study results were not unduly influenced by this simplistic approach, parametric runs were undertaken to evaluate the affect of a more sophisticated forecasting technique. Each of these forecasting techniques will be discussed in summary form here, while additional information of a detailed nature is presented in Appendix B.

a. Uniform Product Growth at 2% Per Annum -

Since the demand forecasts are intended simply to identify differences in refining requirements among the six scenarios, the actual demand forecast for each product may be relatively unimportant. Therefore, the methodology, discussed in additional detail in Appendix B, contains three

key simplifying assumptions: (1) demand for all products grows at one uniform rate of 2% per annum between 1975 and 1985; (2) demand growth occurs in equal increments throughout this forecasting period; and (3) product imports are maintained at 1973 levels.

From the base year, 1973, product demand was forecast to realize zero growth over 1974 and 1975, and average 2% per annum thereafter. Beyond 1975, published projections of oil demand growth rate range between 1% and 3.5% per annum, depending upon assumptions regarding oil prices, consumer price sensitivity, conservation incentives, the availability of alternate energy forms, and U.S. government policy. An estimate of 2% average annual growth was selected to reflect generally slower than historical growth rates resulting from higher oil prices, but assuming some optimism regarding the future economic growth of the country.

It is not likely that this demand forecast will closely approximate the real growth of petroleum products over the next decade; however, this was demonstrated elsewhere[7] to be an adequate assumption of this product growth rate. To arrive at this conclusion, a parametric run was made utilizing more detailed evaluations of product demand growth, the methodology for which is discussed below.

b. Non-Uniform Petroleum Product Growth Rates -

In this more sophisticated projection of product demand growth rate, two sets of assumptions were used to develop a definitive range of energy supply/demand balances. In one case, economic growth was assumed to be somewhat slower than historical rates, but high enough to permit a rising standard of living. Higher energy prices alone (but not governmental action) are assumed to result in consumer energy conservation. Likewise, higher energy prices provide the incentive for the development of domestic energy resources. A second case was defined in which economic and total energy growth fall further off historic rates as a result of both strong governmental action and higher energy prices. Government action in the form of conservation incentives, selective taxes on oil, import tariffs on oil, etc., is taken to enhance the effects of higher prices in dampening demand and stimulating the development of domestic resources.

In both of these categories, coal production and consumption, which have declined in recent years, are expected to be rejuvenated as a result of higher energy prices. After development of the coal industry, production capacity will no longer be such a severe limitation on coal consumption after 1980. Natural gas is assumed to be supply-constrained throughout the forecast period, as production from the contiguous United States fields continues to decline and is not offset by volumes from Alaskan sources until very late in the forecast period. Nuclear power is expected to be the most rapidly growing primary energy form, showing 25- to 30-fold increase over the forecast period. Nonconventional energy sources, such as solar, are not expected to play a significant role during the time frame of this forecast.

The demand for energy was developed by breaking down the total energy consumption into demand by various end-use sectors (e.g., transportation, industrial, residential/commercial, etc.). At the end-use sector level, the historical growth trends in energy consumption were identified and then modified in line with the basic assumptions described above. The modification of historic growth rates took into account our expectations of the impact of consumer conservation, government policy, energy prices, and macro-economic conditions.

The breakdown of oil demand by product was accomplished by examining the oil consumption patterns of specific end-use sectors. To project future oil consumption patterns in the transportation sector, for example, separate forecasts were developed for automotive, rail, marine, and air transport, and the fuels were projected accordingly, taking into account any efficiency improvements expected.

The product forecast from this analysis is shown in detail in Appendix B. Imported petroleum products were assumed to be constant in the results of both of these demand forecasts at the 1973 level, as a result of governmental policy considerations. It is therefore possible to compare product imports with the domestic U.S. demand to arrive at the domestic refinery demand for the next decade. These refinery production expectations were used in the L.P. model studies.

c. Gasoline Grade Distribution -

For both of these demand forecasts, it is necessary to project the gasoline grade requirements over the next decade, under the scenarios pertaining to lead regulations. By consideration of the expected growth rate of introduction of new cars (requiring unleaded gasoline), new car imports, and automotive distribution by weight, the grade distribution under these scenarios was projected as defined in Table 6.

3. Key Product Specifications

The definition of future product specifications is quite important to the successful operation of the cluster and grassroots models. For example, in the study of regulations on sulfur oxides emissions, the most likely method to reduce fluid catalytic cracker (FCC) regenerator sulfur oxides emissions is to hydrotreat the fluid catalytic cracker feedstock. When this hydrotreating is accomplished, the sulfur levels of all of the FCC products are diminished, including the sulfur levels of blending components in the fuel oil pool. To actually represent the cost of emissions reduction, therefore, a specification must be placed to prevent the fuel oil pool sulfur level from changing. Hence, in any study of the impact of a potential regulation on the refining industry, accurate definition of the product inspection for the major petroleum products must be considered in order that the computer model operate in a fashion which would be realistic in terms of petroleum industry flexibility or market demand.

The importance of economic factors in the determination of petroleum product specifications is well known. For example, there is usually a price premium associated with the lower sulfur levels of heavy fuel oil. In addition, there are performance requirements for certain product specifications, such as the distillation and volatility characteristics of motor gasoline. In recent years, however, the impact of governmental regulations on the specifications for petroleum products has become increasingly pronounced, a regulation which would specify the lead level of motor gasoline. Hence, an assessment is required of the likely future course of governmental regulations on all major products over the next decade.

Complete identification of product specifications in the computer models is contained in Appendix C. The highlights of the analysis and the principal product specifications used are summarized here.

Table 6. GASOLINE GRADE REQUIREMENTS BY PERCENT

Grade Distribution %		1977					1980					1985					U.S. average		
	PAD	I	II	III	IV	V	I	II	III	IV	V	I	II	III	IV	V	1977	1980	1985
A. No lead regulations																			
Premium (100 RON)		27	16	25	13	38	33	22	31	19	44	40	29	38	26	50	24	30	37
Regular (94 RON)		65	76	68	80	52	64	75	67	79	52	58	69	60	72	48	68	68	61
Unleaded (92 RON)		8	8	7	7	10	3	3	2	2	4	2	2	2	2	2	8	3	2
B. Unleaded with no lead phasedown																			
Percent of pool																			
Premium		15	5	13	3	22	4	1	3	1	5	0	0	0	0	0	12	3	0
Regular		54	63	56	66	42	37	39	38	40	31	0	0	0	0	0	56	37	0
Unleaded		31	32	31	31	36	59	60	59	59	64	100	100	100	100	100	32	60	100
C. Unleaded with lead phasedown[a]																			
Promulgated lead phasedown pool average, grams/gal.				1.0					0.5					b			1.0	0.5	b
Allowable grams of lead per gallon of leaded gasoline				1.74					1.66					b			1.74	1.66	b

[a]same distribution pattern used as in unleaded (Item B.)

[b]100% unleaded gasoline

a. Motor Gasoline Specifications -

Among the most important product specification for motor gasoline in such a study is the octane number of the several grades of motor gasoline to be produced from the refining industry. Survey data on the three grades of motor gasoline is shown in Table 7. In the modeling studies of the present investigation, the projected research and motor octane numbers for regular, premium and unleaded gasoline, respectively, over the remainder of the decade varied by region (Appendix C), but were approximately 93/85, 99/91, and 92/84. Some studies[10,11] may be interpreted to indicate that the unleaded gasoline octane numbers shown in Table 7 will be increased over the next decade to satisfy the octane requirements of an aging automotive fleet. Evaluation of the impact of producing higher octane unleaded gasoline is discussed elsewhere.

In Table 8 are shown selected results of a survey on unleaded gasoline, broken down by district. It is apparent that the 92/84 specification on the research and motor octane numbers used in this study describes a large fraction of the United States marketing area, particularly since MON is the limiting specification. The average sensitivity is somewhat larger than used in the present study. This will make the study results conservative in principle; in practice, it will have no effect due to MON being the limiting specification.

The Reid vapor pressure of the gasoline pool, as shown in Table 7, varies significantly between summer operation and winter operation. Previous studies[12] have shown that the summer/winter operation can be effectively simulated by means of an average Reid vapor pressure, reflective of both summer and winter operations. Consequently, in the present program all gasoline specifications were set at 10.5 lbs. RVP.

It has also been reported[13] that realistic distillation specifications on motor gasoline must be used in computer simulations to ensure that the model adequately represents the refining industry. Table 7 provides historical data on distillation specifications for comparison to those placed on gasoline products as follows. For premium gasoline the 150°F distillation temperature is reached between 20 and 28% distilled overhead,

Table 7. MOTOR GASOLINE SURVEY DATA

	Grades of motor gasoline				
	Regular		Premium		Unleaded
	Winter 1974-1975	Summer 1974	Winter 1974-1975	Summer 1974	Winter 1974-1975
Research octane no.	93.4	93.4	98.9	98.9	92.3
Motor octane no.	86.1	85.9	91.6	91.5	84.0
Lead, g/gal	1.58	1.90	2.10	2.32	0.02
Reid vapor pressure, lb.	12.0	9.6	11.8	9.7	10.9
Distillation, °F					
20% evaporation	129	142	134	146	139
30% evaporation	152	164	161	172	166
50% evaporation	202	211	210	217	214

Source: U.S. Dept. of Interior, Bureau of Mines, Petroleum Products Survey Motor Gasolines, Summer 1974 and Energy Research & Development Administration, BER C/PPS–75/1 – Motor Gasolines, Winter 1974–75.

Table 8. MOTOR GASOLINE SURVEY, WINTER 1974-75
AVERAGE DATA FOR UNLEADED GASOLINE IN EACH DISTRICT

District name	Gr., ASTM D287 °API	Sulf., ASTM D1266 wt. %	Octane number			RVP, ASTM D323 lb
			RON ASTM D2699	MON ASTM D2700	$\frac{R+M}{2}$	
Northeast	59.2	0.029	92.8	83.9	88.4	11.0
Mid-Atlantic Coast	60.2	.027	92.5	83.8	88.2	11.4
Southeast	59.8	.024	92.5	83.7	88.1	11.0
Appalachian	60.6	.022	92.9	84.5	88.7	11.8
Michigan	61.7	.033	91.9	83.9	87.9	12.1
North Illinois	61.2	.026	92.3	84.3	88.3	12.2
Central Mississippi	62.5	.024	92.0	83.8	87.9	10.9
Lower Mississippi	61.2	.034	92.5	83.8	88.2	11.5
North Plains	63.3	.052	92.0	84.3	88.2	11.1
Central Plains	65.1	.037	92.0	84.3	88.2	10.8
South Plains	63.9	.033	92.0	84.6	88.3	10.8
South Texas	60.6	.019	92.0	83.7	87.9	11.1
South Mountain States	61.9	.038	91.5	83.4	87.5	9.7
North Mountain States	63.8	.033	91.5	83.6	87.6	10.0
Pacific Northwest	61.8	.010	92.7	84.7	88.7	11.0
North California	56.9	.016	93.2	83.9	88.6	9.4
South California	59.0	.044	92.5	83.5	88.0	9.7
Average	61.3	.029	92.3	84.0	88.2	10.9

Source: Energy Research & Development Administration, BER C/PPS–75/1 – Motor Gasoline, Winter 1974-1975.

and the 210°F distillation temperature is reached between 42 and 54% distilled overhead. With regular and unleaded grades the 150°F distillation point is reached between 20 and 30% distilled overhead, whereas the 210°F specifications were identical to those of the premium grade gasoline.

b. Sulfur Content of Residual Fuel Oils -

As indicated above, one of the key product specifications required to ensure that the model approximates realistic operation is the sulfur level of the residual fuel oil. This specification is important because the minimum cost approach of the LP model is to produce higher sulfur fuel oils rather than adding desulfurization and Claus plant investment. This subsection summarizes the methodology and results of our forecast for the U.S. fuel oil demand of differing sulfur contents. Of particular emphasis here is the sulfur level of residual fuel oils produced from domestic U.S. refineries, in contrast to the sulfur level of total U.S. residual fuel oil demand, which is influenced by imported fuel oils.

To determine the allowable sulfur content of fuel oil to be burned as refinery fuel (and not marketed) for each of the cluster models, an evaluation was made of the existing state regulations on allowable SO_x emissions. This analysis included an investigation of the regulations applicable to the particular refineries being simulated in the cluster models as well as those for the PAD district the model was intended to simulate. From this analysis of regulations, sulfur specifications were determined for refinery fuel for each cluster model, ranging from 0.6% to 1.5% depending on the geographical location of the cluster model simulation. A complete discussion of the methodology and results of this analysis is presented in Appendix D.

The remainder of this section deals with the sulfur specification of residual fuel oils manufactured and marketed in the U.S. (as distinguished from fuel oils burned within the refinery or imported for domestic sales).

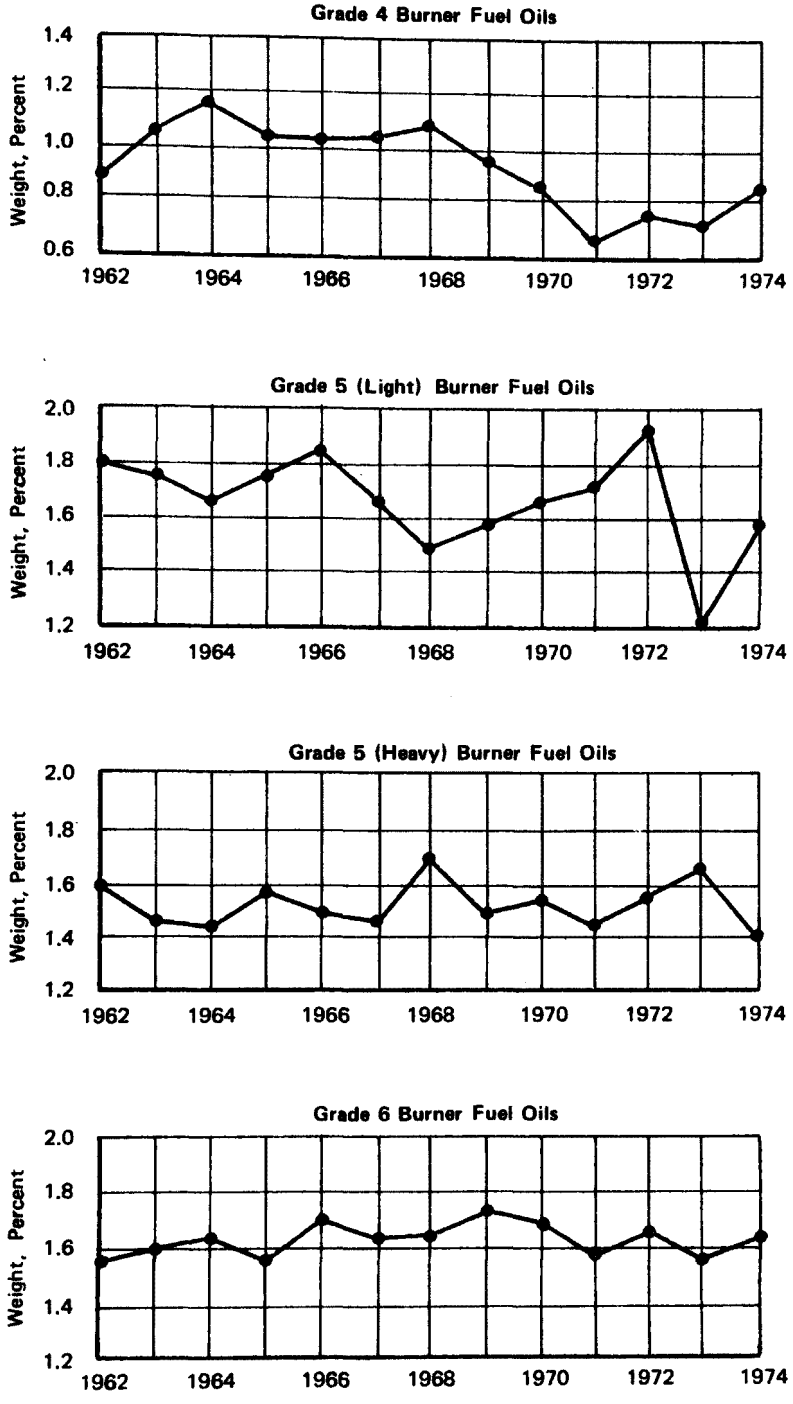
The forecast of the sulfur level of residual fuel oils manufactured and marketed in the U.S. was based upon an analysis of the current air quality regulations required by federal, state, and city agencies; the

current status of these regulations, with particular attention to variances being granted; the likely future trend of environmental regulation; and the overall economic environment. In the course of this program, discussions have been held with federal, state, and city environmental protection authorities. A program of interviews with East Coast electric utility companies, accounting for over 90% of the total fuel oil consumed by East Coast utilities, was also conducted.

The current inflationary tendency in the United States and the U.S. policy of energy independence could be contributory factors to the relaxation of air pollution regulations, particularly if the use of domestic coal is to be emphasized. Tendencies to use higher sulfur fuel oils when meteorological conditions are favorable and lower sulfur oils when meteorological conditions are adverse will also play a potential role in the average sulfur level of the fuel oil burned in the U.S. during the next decade. On the other hand, environmental regulations now in effect will not be rapidly changed. Most of the existing variances are temporary and there will still be areas in the United States which are unlikely to grant or renew exemptions.

The historic trend of the sulfur content of heavy fuel oils manufactured and marketed in the United States is shown in Figure 3. It is apparent that the sulfur content of the lighter grade fuel oils has diminished considerably in the last five years. However, the trend of the heavier grade fuel oils is less evident. Table 9 shows the availability of residual fuel oil by sulfur level for the year 1973 and it is apparent that the refinery residual fuel oil production in each of the PAD districts has been at relatively high sulfur levels, between about 1 and 1.5% on average. However, considerable quantities of imported low sulfur oil is marketed, which allows the burning of fuel oils that will meet the statewide sulfur regulations discussed in Appendix D.

Our projections of future sulfur levels for U.S. fuel demand stem from the foregoing discussion and also draw upon more detailed information about likely developments in individual states. From a consideration of such factors, it was projected that the sulfur content of the U.S. residual fuel oil demand would be between 1.1 and 1.4%.



Source: U.S. Dept. of Interior, Bureau of Mines, Petroleum Products Survey, Burner Fuel Oils, 1974

FIGURE 3 HISTORIC TREND OF HEAVY FUEL OIL SULFUR CONTENT AS PRODUCED AND MARKETED IN U.S.

Table 9. AVAILABILITY OF RESIDUAL FUEL OIL BY SULFUR LEVEL, 1973

(Thousands of Barrels)

P.A.D. District	Fuel oil source	Sulfur content, wt%				
		0-0.5	0.51-1.00	1.01-2.00	over 2.00	Total
I	Refinery production	11,743	15,834	16,112	8,569	52,258
	imports	232,889	130,258	74,732	160,814	598,912
II	Refinery production	985	30,368	25,952	13,815	71,120
	imports	1,654	1,964	1,719	770	6,107
III	Refinery production	12,790	26,462	9,927	39,276	88,455
	imports	201	2,303	547	1,408	4,459
IV	Refinery products	824	2,451	3,323	3,266	9,864
	Imports	0	0	0	0	0
V	Refinery production	70,348	7,385	47,528	7,639	132,900
	Imports	9,542	32	1,464	221	11,259
U.S. Total	Refinery production	96,690	82,500	102,842	72,565	354,597
	Imports	244,286	134,557	78,860	163,212	620,736

Source: U.S. Dept of Interior, Bureau of Mines, Availability of Heavy Fuel Oils by Sulfur Level, Dec, 1973.

For purposes of this study we assumed an overall U.S. average sulfur content for residual fuel oil of 1.3 wt.%, representing maximum sulfur levels of 1.4 wt.% east of the Rockies and 0.9 wt.% west of the Rockies. A parametric analysis assumed a U.S. average residual fuel sulfur content of 1.1 wt.%, the weighted average of 1.2 wt.% sulfur east of the Rockies and 0.75 wt.% west of the Rockies.

The importance of testing the sensitivity of study results to the overall U.S. average residual fuel sulfur level is highlighted in Table 10 for the East of Rockies grassroots, Scenario A. It can be seen that the impact on the industry simulation for variations between 1.4% (base case) and 1.2% (parametric run) sulfur level of the East of Rockies residual fuel oil pool is quite marked. As shown in that table, the imported residual fuel oil and the production from existing refineries must be added to the production from new East of Rockies grassroots refineries in 1985 to match the total residual fuel oil sulfur content on the East Coast. Because of the leverage effect of the small volume of residual fuel oil produced from grassroots refineries versus the volume available from imports and existing refineries, the variation in sulfur content of residual fuel oil produced in East of Rockies grassroots refineries is from about 0.6 wt.% to 1.8 wt.% depending upon whether the East of Rockies pool is at 1.2 wt.% or 1.4 wt.% (corresponding to overall U.S. pool averages of 1.1 wt.% and 1.3 wt.%, respectively). Obviously the cost of desulfurization capability in the grassroots refineries varies accordingly.

4. Processing and Blending Routes

The computer simulation of the U.S. refining industry utilized cluster models, chosen to represent the existing refinery structure, and grassroots models, chosen to represent either new grassroots refinery constructions or major expansions of existing refineries. The cluster models were allowed to add new downstream process equipment of reasonable economic size. Accordingly, these models had essentially the same processing and blending capability during the study period.

The unit yields and product properties were obtained from a variety of petroleum industry sources. The ability of the cluster models to represent actual refineries when using these unit yields and product properties was confirmed in calibration studies, discussed below. These

Table 10. GRASSROOTS REFINERY FUEL OIL SULFUR PROJECTION – 1985
SCENARIO A – EAST OF ROCKIES ONLY

Total East-of-Rockies[a]		Imports		Existing refineries[b]		Grassroots refineries[b]	
Sulfur content (wt%)	Fuel oil (MBPD)	Sulfur content (wt%)	Fuel oil (MBPD)	Sulfur content (wt%)	Fuel oil (MB/CD)	Sulfur content (wt%)	Fuel oil (MBPD)
1.2	2,852	1.28	1,797.7	1.44	561.3	0.63	493
1.4	2,852	1.28	1,797.7	1.44	561.3	1.78	493

[a]Fuel oil produced in refineries plus imports

[b]Fuel oil produced and marketed in U.S.

same unit yields and product properties were also used in the grassroots refinery simulations. A complete discussion of the unit yields and product properties available in the computer program is contained in Appendix H.

Hydrogen generation in the cluster models was obtained solely from refinery gas or imported natural gas. In the grassroots refinery, the first option was also allowed, as well as the ability to generate hydrogen from petroleum naphtha.

Coking capacity for the cluster refineries was maintained at a level similar to that derived during the calibration runs. No coker capacity was allowed to be constructed in the East Coast grassroots refinery, because of market demand considerations. Coker capacity in the West Coast grassroots refineries for the several scenarios discussed above was not allowed to exceed that available from Scenario C. There was a tendency for coker capacity to be greatly increased as an inexpensive means to remove sulfur for Scenario F, resulting in coke production exceeding likely West Coast demand capabilities. Visbreaking and solvent deasphalting were not allowed in the grassroots models.

In the cluster refineries desulfurization of atmospheric bottoms and vacuum bottoms was not allowed, because the cluster refineries were intended to be descriptive of the current operation of certain existing refineries. In the grassroots refineries, both atmospheric and vacuum bottoms desulfurization were allowed.

As discussed above, the properties of the primary products and by-products from the fluid catalytic cracking (FCC) unit are particularly significant to the assessment of the impact of the possible EPA regulation. For reasons already described, the sulfur distribution of the products from this processing unit is not well defined at present. Moreover, FCC gasoline is a major source of sulfur to the unleaded gasoline pool and the combustion of coke in the regenerator is a major source of gaseous sulfur oxides emissions in the refinery. In a parallel study on reducing sulfur in unleaded gasoline,[8] the sulfur distribution among several products of the FCC unit were varied in a parametric run, with the distribution shown in Table 11. It can be seen that the percentage of feedstock sulfur going

Table 11. FCC UNIT SULFUR DISTRIBUTION LARGE MIDWEST CLUSTER, 65% CONVERSION

Stream	Percentage distribution of feed stock sulfur	
	Base, 1985	Parametric run
H_2S	39.7	40.0
Gasoline	4.3	6.0
Gas oil	27.7	33.0
Clarified oil	22.5	15.0
Coke	5.9	6.0

to coke does not change considerably between the base case and parametric run. Hence, the effect of FCC sulfur distribution on reducing sulfur oxides emissions was not further examined in a parametric study. Additional detail on the product properties for the FCC unit as well as the many other units used in the models are discussed in Appendix H.

Another unit critical to the success of any study of the refining industry is the catalytic reforming unit. A significant amount of effort was expended in the development and confirmation of the yields and properties of this particular unit. Yields for low pressure operation, high pressure operation, and an average operation of reformers across the industry were simulated in detail for several different cases to ensure that the assumptions made in the yield patterns of this critical unit did not significantly detract from the assessment of the impact of the possible regulation under consideration. A detailed discussion of the reformer evaluations is contained in Appendix H.

Another factor critical to the success of the impact study is the blending octane numbers of reformate, FCC gasoline, etc., for the variety of feedstocks, operating conditions, and gasoline pool compositions used in the study. Because of their importance, blending numbers used in this study were circulated to representatives of the API/NPRA Task Force assisting in the study. In general there was good agreement between the blending numbers utilized in the present study and the suggestions made by members of this task force, as summarized in Table 12.

In the model, two distinct hydrogen systems were employed. A high purity hydrogen system was fed by steam-methane reforming and was delivered to high pressure desulfurization and hydrocracking units. The low purity hydrogen system was produced from catalytic reformer units and was distributed to low pressure desulfurization units. Allowances were provided for interchanges from the high purity hydrogen system to the low purity hydrogen system. In addition normal allowances for solution losses and flaring circumstances were also provided. Careful analysis of this hydrogen distribution system indicates that it is a reasonable simulation of refinery systems and will be an adequate description for the purposes of the study. If additional purification of the low purity hydrogen system is required

Table 12. ILLUSTRATIVE BLENDING OCTANE NUMBER COMPARISON
(Clear Motor Octane Number)

Stream	ADL model	Ethyl	DuPont	Marathon	Citgo
90 Sev. reformate	80.1	81-82	82	–	–
100 Sev. reformate	86.0	87-88	87	–	87.1
FCC gasoline (full range)	80.0	80	79-80	82-83	79.9
Alkylate	89.8	–	–	92-93	88.7

cryogenic units can be added without having a major impact on the overall capital investment penalty associated with the potential regulations.

5. Calibration of Cluster Models

The U.S. refining industry is composed of nearly 300 individual refineries scattered throughout the country, each characterized by a unique capacity, processing configuration, and product distribution. There are, however, logical regional groupings of major refineries with similar crude supply patterns, processing configurations, and product outputs. Therefore, the cluster model approach was developed for this study, in which the existing U.S. refinery industry was simulated by the average operation of three similar refineries located in each of six selected regions. The selection of the three refineries as well as the six selected regions was accomplished with the assistance of the API/NPRA Task Force cooperating in this study. The most important criteria guiding the selection of these cluster models were: (1) each cluster model was to represent, as closely as possible, a realistic mode of operation, in that processing units were to be of normal commercial size and that plants would be allowed normal flexibility in regard to raw material selection and product mix, (2) the cluster model crude slate, processing configurations, and product outputs were to bracket has best as possible, those variations peculiar to each geographic region.

The final selection of refineries to be represented by the cluster models is shown in Table 13.

PAD District I was simulated by three refineries in the Philadelphia-New Jersey area with capacities ranging from 160,000 to 255,000 bbls/day. PAD District II was characterized by two refinery clusters, one represented by the Large Midwest cluster model simulating the Indiana/Illinois/Kentucky district and processing high sulfur crudes. The Small Midcontinent cluster was also used to represent PAD II, simulating refineries in the Oklahoma/Kansas/Missouri district. This Small Midcontinent model was also used to represent small refiners in PAD District II, as described in Appendix G. PAD District III, which represents about 40% of the U.S. refining capacity, was simulated by two models because of its overall importance and because

Table 13. REFINERIES SIMULATED BY CLUSTER MODELS

PAD district	Cluster identification	Refineries simulated	1973 Crude capacity, MB/CD
I	East Coast	Arco – Philadelphia, Pa.	160.0
		Sun Oil – Marcus Hook Pa.	163.0
		Exxon – Linden, New Jersey	255.0
II	Large Midwest	Mobil – Joliet, Illinois	160.0
		Union – Lemont, Illinois	140.0
		Arco – East Chicago, Illinois	135.0
II	Small Midcontinent	Skelly – El Dorado, Kansas	67.0
		Gulf Oil – Toledo, Ohio	48.8
		Champlin – Enid, Oklahoma	48.0
III	Texas Gulf	Exxon – Baytown, Texas	350.0
		Gulf Oil – Port Arthur, Texas	312.1
		Mobil – Beaumont, Texas	335.0
III	Louisiana Gulf	Gulf Oil – Alliance, La.	174.0
		Shell Oil – Norco, La.	240.0
		Cities Service – Lake Charles, La.	240.0
V	West Coast	Mobil – Torrance, California	123.5
		Arco – Carson, California	165.0
		Socal – El Segundo, California	220.0

differing types of refinery configurations could be identified. The Texas Gulf cluster was typified by a crude capacity exceeding 300,000 bbls/day and heavy involvement in petrochemicals, lubes and other specialty products. The Louisiana Gulf Coast cluster represented refineries between 174,000 and 240,000 bbls/day and processed a single source of sweet crude. PAD District V was simulated by a West Coast cluster model and was represented by refineries in the Southern California area. PAD District IV was not explicitly simulated because it represents less than 5% of the total U.S. refining capacity. It was included in the scale up, however, as discussed in Appendix G.

Additional detail on the development of the cluster model concept is contained in Appendix F.

Upon completion of the development of the cluster refinery modeling concept, an extensive calibration effort was undertaken by ADL with the assistance of the Bureau of Mines, Environmental Protection Agency, and the API/NPRA Task Force. A complete discussion of the calibration effort is contained in Appendix I. Only the highlights of this effort will be summarized here.

The annual refining surveys published in the Oil and Gas Journal were used as the basic reference source for determining the cluster model processing configurations, allowing simulation of those refineries listed in Table 13. This source also provided the processing unit capacity available in these cluster refineries, used to limit the available capacity in the cluster models.

The 1973 annual input and output data was furnished by the Bureau of Mines for the aggregate of the three specific refineries comprising each individual cluster model (Table 13). These data included the following: (1) crude oil and other raw materials fed to the refineries, broken down by individual state of origin for domestic crudes and by country of origin for foreign sources; (2) statistics on fuel consumed for all purposes in the refineries; and (3) all petroleum products manufactured by refineries for the year.

Each individual oil company furnished EPA the following proprietary data for 1973: (1) gasoline grade distribution and the associated octane

levels and lead levels for each grade; (2) total gasoline volumes and average sulfur contents; (3) crude slates and sulfur levels; and (4) intakes and operating conditions on selected units. The EPA averaged these data to obtain information representing the cluster models, and supplied these data to ADL.

As summarized in Appendix I, four main areas were considered to compare the degree of calibration to the cluster models. These were: (1) overall refinery material balance (i.e., volume of the crude intake required to balance specified product demands and internal fuel requirements); (2) refinery energy consumption; (3) processing configuration, throughputs and operating severities; and (4) key product properties (e.g., gasoline clear pool octanes, lead levels, etc.).

A selected result showing a portion of the calibration results for the Large Midwest cluster is presented in Table 14. Shown here is the crude intake, as specified by the Bureau of Mines data and industry data to provide a given product outturn, as well as a result of the computer model simulation. Also shown is the energy consumption required for this crude intake and product outturn, and a summary of the principle refinery process operations. It is apparent that the agreement of the model prediction and the data base for this Large Midwest cluster is excellent. Additional detail on other clusters as well as other calibration criteria are contained in the discussions of Appendix I.

6. Existing and Grassroots Refineries

The existing U.S. refinery industry was simulated by means of the six cluster models, as discussed above. New grassroots capacity was required when atmospheric distillation requirements exceeded 90% of the calendar day capacity listed in the Oil and Gas Journal for the specific refineries being simulated by these cluster models. In practice, operation at 100% of the calendar day capacity cannot be achieved due to unscheduled refinery turnarounds, limitations on secondary processing capacity imposed by product specifications, variations in crude slate, crude supply restrictions, regional and logistical constraints, and imbalances between individual product output and market demand. The industry has historically achieved about 90% of calendar day capacity,[14] so this limitation was used

Table 14. CALIBRATION RESULTS FOR LARGE MIDWEST CLUSTER

		BOM Data	Industry data	Model run
Material balances				
Total crude intake MB/CD		146.1	145.5	145.5
Energy consumption				
Purchased natural gas MB/CD (F.O.E.)		.2	–	.2
Total fuel consumption MB/CD (F.O.E.)[a]		8.1	–	8.4
Electricity MKWH/D		843	–	545
		Oil and gas capacity MB/SD	**Industry data**	**Model run**
Processing summary				
Catalytic reforming	Intake MB/CD	32.7	27.8	27.6
	severity RON	–	90.7	90.0
Catalytic cracking	Intake MB/CD	55.0	51.2	48.7
	conversion % vol.	–	74.9	74.3
Alkylation	Production MB/CD	13.4	11.4	12.0
Coking	Intake MB/CD	15.8	13.6	14.1

[a]Excludes catalyst coke

to provide a conservative assessment of when new capacity is required, thereby providing a conservative assessment of the penalties associated with the potential regulation. However, since all penalties are reported as differences between the various scenarios considered, a precise figure of calendar day utilization is unnecessary.

To meet increased product demand and provide additional crude required when reducing refinery SO_x emissions, an increase in crude run to each cluster is required as the decade proceeds. The existing refining industry (cluster model) is allowed to expand down-stream processing capacity as required to meet these constraints. However, when the crude run reaches the limitation of the atmospheric distillation capacity, the expansion of the cluster model is no longer allowed, and new grassroots facilities must be constructed.

The grassroots models used in this study represent either new, basic grassroots refineries to be built in the United States over the next decade or major expansions in crude distillation capacity in existing refineries.

Those major expansions of existing refining capacity which have taken place within the last few years are often noted by new atmospheric distillation capacity, new tankage requirements, and frequently new or greatly expanded production of refinery products which have otherwise been only a minor component of total product outturn. An example of such major new expansion is the production of large quantities of low sulfur fuel oil. In any event, this type of new major refinery expansion frequently exhibits relatively little interaction with existing refinery processing units, and little additional flexibility for product blending over that of a refinery built on a segregated grassroots basis. Therefore, any requirements for distillation capacity in the industry were simulated by addition of new grassroots capacity. The product outturn and therefore the crude run required for this new grassroots capacity was chosen to be sufficient to balance the product demand and product quality requirements for the United States as a whole. New grassroots construction was simplified by consideration only of a location typified as "east of the Rockies" and another location typified as "west of the Rockies", each location with its own crude slate as discussed in Appendix A.

The yields and product qualities for new capacity additions were identical to those provided in the cluster model operation, with the exception of catalytic reforming, wherein all new capacity was assumed to utilize a yield structure and investment representative of low pressure, bimetallic reformers.

The refinery fuel system for both the cluster models and the grassroots models was constrained to meet environmental regulations typical of the refining regions in which these models operated. A complete discussion of the allowable refinery fuel sulfur level and the methodology by which it was determined is contained in Appendix D.

7. Economic Basis for Study

The estimation of capital investments and operating costs for petroleum processing units is difficult at the present time because of the rapid rate of inflation and the long elapsed time that it takes to build a large and complex petroleum refinery. Investment estimates were obtained by using data from a variety of literature sources, such as the Oil and Gas Journal, and by extensive discussions with process licensors and contractors. In order to minimize the effect of future cost escalations on the cost estimations, the investment estimates were made on a 1975 first quarter basis. This investment estimate will be applicable for refineries which were conceived, designed, equipment ordered, and constructed all within the first quarter of 1975. Escalation of these costs are reported separately in order to allow recalculation of these ultimate investments on other inflation schedules if so desired.

Onsite capital investments were estimated by compositing the information available from these several sources. The onsite process unit estimates used in this study are typified in Table 15. Additional detail of the specific information on capital investments is contained in Appendix H.

The primary purpose of the economic study was to determine the capital investment and operating costs associated with the reduction of refinery SO_x emissions. Consequently, economic penalties for the cluster models were determined by comparing Scenario F with Scenario C. Therefore, for the cluster model, only the incremental downstream capacity required for

Table 15. ONSITE PROCESS UNIT COSTS

Process unit	Size basis, MB/SD	Investment, $/B/SD 1975, 1st quarter
Atmospheric distillation	100	165
Vacuum distillation	40	185
Catalytic cracking	40	925
Catalytic reforming (low pressure)	20	800
Alkylation (product basis)	10	1,400
Isomerization – once through	10	620
Isomerization – recycle	10	1,240
Hydrocracking (high severity)	25	1,400
Naphtha hydrotreating	20	235
FCC/coker gasoline hydrotreating	15	320
Light distillate hydrotreating	30	230
Heavy distillate hydrotreating	30	250
Vacuum gas oil desulfurization (also FCC feed)	25	370
Atmospheric residual desulfurization	50	775
Vacuum residual desulfurization	15	1,500
Coking – delayed	10	930
Hydrogen generation – Methane $/MMSCF/SD	50	230[a]
– Naphtha $/MMSCF/SD	50	260[a]
Sulfur recovery (95% removal) – $/short tons/SD	100	25,000
Sulfur recovery (99.95% removal) – $/short tons/SD	100	50,000

[a]$/MSCF/SD

Scenario F versus Scenario C was determined and costed. As part of this analysis, charges were assessed for the utilization of spare, idle capacity which was available in 1974 but was incrementally consumed at a faster rate for Scenario F than for Scenario C. Any processing unit severity upgrading that was required was also costed. For example, if the severity of the catalytic reforming unit required was higher in Scenario F than in Scenario C, then the incremental cost was charged to Scenario F for upgrading this existing catalytic reformer capacity. To determine whether or not the catalytic reformer severity needed to be upgraded, discussions were held with industry sources, who estimated that approximately 25% of the existing catalytic reformer capacity was already capable of 100 RON severity operation. Therefore the remaining 75% of catalytic reformers which were not capable of this mode of operation required an upgrading cost if 100 RON severity were required. Additional discussions of the method of calculation for spare capacity utilization and severity upgrading for all the refinery processing units is contained in Appendix E.

Associated with the onsite costs of incremental downstream capacity in the cluster models is the cost requirement for offsite investment and working capital. As discussed in Appendix E, these costs were taken as a constant 40% of the onsite costs for the cluster models.

For the grassroots models the complete refinery was costed as required for each scenario. For example, the capital cost for the grassroots refinery in Scenario F was then compared to that of Scenario C to determine the incremental costs associated with the potential regulation. In this case the onsite process costs were determined in a fashion analogous to that discussed for the cluster model. However, the offsite costs were determined by the Nelson complexity factor approach[17] and a separate assessment of working capital requirements was made, at approximately 70% of the total onsite capital investment. A summary of the items included is shown in Table 16. The net effect of this method of calculation was that offsite and associated costs (including working capital) were approximately 200-300% of onsite costs. For these grassroots refineries the complete onsite plus offsite refinery costs range from about $2900 per barrel

Table 16. OFFSITE AND OTHER ASSOCIATED COSTS OF REFINERIES USED IN ESTIMATING COST OF GRASS ROOTS REFINERIES
1st Quarter 1975 Basis
(% onsite cost)

Type of cost	Refinery complexity[a]							
	3	4	5	6	7	8	9	10
Mainly complexity-related offsites, %								
Utilities, safety, fire and chemical handling	61.0	51.4	46.2	41.0	39.2	36.9	35.7	34.0
Buildings	14.0	9.8	8.2	6.6	6.2	5.6	5.2	4.7
Piping, product handling	40.0	26.0	21.4	16.8	15.6	14.1	13.2	12.0
Site preparation, blending, roads and others	23.0	15.8	13.1	10.3	9.4	8.3	7.6	6.7
Subtotal, complexity-related	138.0	103.0	88.9	74.7	70.4	64.9	61.7	57.4
Other offsites, %								
– Includes tankage, ecology and land	87.0	67.0	59.0	51.0	48.0	44.2	42.0	39.0
Total offsites	225.0	170.0	147.9	125.7	118.4	109.1	103.7	96.4
Associated costs								
Chemicals and catalysts	6.0	5.0	4.5	4.0	3.8	3.5	3.3	3.0
Marine or equivalent facilities	20.0	15.5	12.8	10.0	8.8	7.8	6.8	5.8
Working capital	70.0	70.0	70.0	70.0	70.0	70.0	70.0	70.0
Other	20.0	20.0	20.0	20.0	20.0	20.0	20.0	20.0
– Includes training, spares, autos, telephone, domestic water, cafeteria and recreation								
Total associated	116.0	110.5	107.3	104.0	102.6	101.3	100.1	98.8

[a]See reference #17.

per day for a low sulfur crude up to about $3500 per barrel per day for a high sulfur crude, on a 1975 first quarter basis. An illustration of the investment requirements for a grassroots refinery of the present study is shown in Table 17.

Operating costs were determined by a direct assessment, on a unit-by-unit basis, of either the additional downstream processing requirements of the cluster models or the complete refinery requirements for the grassroots models. Catalysts and chemicals, cooling water and electricity were determined from the processing unit intakes themselves and tetraethyl lead was determined as required to meet the gasoline blend requirements. Maintenance and manpower assessments were determined on an off-line basis, i.e., they were not determined by the computer model directly. Manpower requirements were determined both for severity upgrading and for new unit construction by examination of operating requirements of the particular units under consideration. Maintenance costs were assessed at a level of 3% of onsite investments and 1.5% of offsite investments.

In addition a capital charge was assessed for new investment in any processing unit, either in a cluster model or a grassroots model. The capital charge was taken to be 25% of the total capital investment, which is approximately 12% rate of return, on an after tax, discounted cash flow basis. The same capital charge was applied to both the downstream capacity additions in the cluster model and new grassroots facilities in a grassroots model, on the philosophy that the amortization for both types of investments must be approximately equivalent in the present economic climate. A typical level of cash operating expenses (exclusive of capital charge) for the grassroots refinery was approximately 80¢ per barrel of crude capacity.

An assessment of cost escalations over the next decade was made to reflect the actual capital investment which may be required in the time interval in which the actual refinery construction will take place. This escalation of costs can result from increases in the costs of refinery equipment which outpace the general inflationary trend in the United States. As a basis for this cost escalation, an approach similar to the usual construction S-curve escalation analysis was conducted, in which the annual

Table 17. GRASS ROOTS REFINERY CAPITAL INVESTMENT

Location: East of Rockies **Scenario: C**
Crude processed: Arabian Light
Refinery complexity: 7.01

Process unit	Throughput (MB/SD)	Onsite investment (millions of dollars)
Atmospheric distillation	231.7	28.1
Vacuum distillation	100.1	12.5
Catalytic reforming	52.2	36.5
Catalytic cracking	47.4	42.0
Hydrocracking	26.6	32.2
Isomerization-recycle	11.5	13.8
Alkylation (product basis)	14.9	17.8
Hydrogen manufacture (MMSCF/SD)	62.1	13.3
Desulfurization		
Full range naphtha	62.9	9.4
Straight run distillate	26.4	6.7
Vacuum residue	21.1	27.0
Sulfur recovery and amine treat (short tons/SD)	366	9.4
Total onsite investment		248.7
Offsite and associated costs at 151.0% onsite investment		375.6
Working capital at 70.0% onsite investment		174.1
Total cost		798.4
Investment/B/SD		3,446

escalation for the years 1975-1985 were taken to be 20%, 17%, 15%, 10%, 10%, 10%, 9%, 9%, 8%, 8%, 8%. Clearly, assessments of the rate of cost escalation for the coming decade are highly intuitive and will depend upon a variety of factors, such as further increases in foreign oil prices, general inflationary tendencies in the United States, and many others which are difficult to predict with any degree of precision. Indeed, cost escalation now appears to be flat through 1975. Therefore, the impact of the potential regulation on the refining industry will be summarized in the following body of the report both on a 1975 first quarter basis and on an escalated basis, with the above assumed escalation schedule.

8. Scale Up to National Capacity

In the cluster model approach, the U.S. refining industry has been simulated by six individual cluster models, each cluster representing three existing refineries in different regions of the United States. To represent the impact on the U.S. refining industry, it is necessary to scale up the results of the cluster model analysis to a regional and a national basis. From this estimate of the total production capability of the existing U.S. refining industry, requirements of the new grassroots models are obtained by subtracting existing capability from the total product demand of the U.S. refining industry. Appendix G discusses the scale up method and the derivation of product demands for grassroots refineries in detail.

The general method employed in scaling up data from the cluster runs to the existing U.S. refining industry is to compare the gasoline outturn of the region being simulated by the cluster model to that of the cluster model itself. For example, the East Coast cluster represents the refineries in PAD District I, so a scale up factor in 1973 of 7.127 is used, since this is the ratio of gasoline production of District I to the gasoline production of the East Coast cluster. However, the cluster model used for PAD I is known to be typical only of the major gasoline producing refineries in that region. Therefore, there is, by definition, a quantity of atypical refining capacity which is not represented by the yields used in the East Coast cluster model. Hence an estimate was made also of the atypical refining capacity in PAD I, to be included as a component of the scale up of the East Coast cluster model results to PAD I.

PAD II is represented by two cluster models. It has been assumed in scale up that the Small Midcontinent cluster represents operations of the Oklahoma/Kansas/Missouri district and that the balance of District II is represented by the Large Midwest cluster. Similarly, in PAD III, it has been assumed that the Louisiana Gulf cluster represents the Louisiana Gulf refining district and the Texas Gulf cluster represents the balance of PAD III.

The West Coast cluster is assumed to represent the operation of PAD V. PAD IV was not represented by a specific cluster model so that the total refining capacity of PAD IV was similarly included as an atypical factor in the scale up analysis.

The results of the application of this scale up method, when composited for the total U.S. refining industry are shown in Table 18, for 1973. Here, the crude consumption by the cluster models agrees with the Bureau of Mines data to within about 2% and the total refinery intake agrees to within about 1%.

The major refinery products agree with the Bureau of Mines data within about 5%, with the exception of LPG (which was a swing product in the computer runs) which deviates from the Bureau of Mines data by about 15%. The total product outturn agrees with the Bureau of Mines data to within about 2%. Therefore, it is felt that the model scale up method is calibrated well with the Bureau of Mines data for the purposes of the present study, which emphasizes total energy penalties of the refinery and addresses itself to gasoline production capability. For other types of studies, the scale up method could be further refined, if so desired, to provide a closer match of the other minor products from the refining industry.

Model results for the study years of 1977, 1980, and 1985 were scaled up using the atypical refining concept described above. In 1977 scale up factors were based on meeting gasoline demand for the total U.S. For 1980 and 1985, however, the scale up factor approach was based on total crude run in each cluster and the effective crude oil distillation capacity for the region being simulated by that cluster. The scale up factors used were calculated by making the crude run in each region equal to the effective

Table 18. MODEL SCALE-UP COMPARISON, 1973

U.S. total input/output data, thousands of barrels

Refinery intakes/outturns	Cluster model results	Bureau of Mines data	Deviation of model from B.O.M. data (%)
Intakes:			
Crude oil	12,713.6	12,430.7	2.3
Butanes	254.2	219.8	15.6
Natural gasoline	365.2	439.2	16.8
Other	167.6	281.3	–
Total intake	13,500.6	13,371.0	1.0
Outturns:			
LPG	401.2	349.8	14.7
Gasoline	6,572.1	6,572.2	0
Naphtha	227.5	234.7	3.1
BTX	164.5	156.7	5.0
Distillate fuel oil	3,157.9	2,992.8	5.5
Residual fuel oil	956.0	971.5	1.6
Other	1,886.7	1,849.7	–
Total outturn	13,365.9	13,127.4	1.8

crude oil distillation capacity for that region, defined as 90% of the calendar day rated capacity.

As discussed in Appendix B, the import levels of products were held constant at the 1973 level for the coming decade. Therefore, after scaling up of the cluster results, adding atypical factors, and adding import levels, the product outturn from the grassroots refineries could be obtained by difference from the forecast total petroleum products demand. The results showed that by 1980 seven new grassroots refineries at approximately 200,000 BPD each would be required in PAD Districts I through IV and two new refineries would be required to meet PAD District V product demands. By 1985, a total of fifteen new refineries were required for PAD Districts I through IV and a total of three refineries were needed for PAD V.

The utilization of such scale up factors allowed a direct assessment of the total energy penalties associated with each of the scenarios under discussion, as well as an assessment of the operating costs required to meet the possible regulation. However, capital investments were not determined solely by a direct utilization of the scale up approach, because this approach does not weigh sufficiently heavily the capital requirements of the small refineries simulated by the Small Midcontinent cluster. Therefore, an additional factor was utilized in a scale up for capital costs, as discussed in detail in Appendix G. Such an approach adequately includes the dollar cost to the small refiner as a component of the overall cost to the industry, because his percentage of the total cost is relatively small. However, it does not adequately address the total impact on the small refiner nor the possible impact on the competitive structure of the petroleum industry.

III. STUDY RESULTS

A. BACKGROUND DISCUSSION

SO_x emissions in refineries emanate from three distinct sources. The first is from refinery process furnaces and boilers. Control of these emissions can be achieved either by restricting the sulfur level in refinery fuel or by scrubbing the stack gases prior to discharge into the atmosphere. The second source of SO_x emissions is from fluid catalytic cracking (FCC) units. These can be controlled to some extent by limiting the sulfur content of the feed to the unit or by scrubbing the stack gas prior to discharge. The third source of SO_x emissions is from the refinery process which ultimately recovers the sulfur removed in the various treating processes in an elemental form (commonly known as the Claus unit). Control of these emissions is obtained by increased levels of sulfur recovery or by stack gas scrubbing.

With the exception of the Claus plant application, stack gas scrubbing has not been included as an alternative in the computer model in this study of the control of refinery SO_x emissions. Preliminary calculations have indicated that the capital investment requirements to install stack gas scrubbing to control refinery SO_x emissions will be at least as great as the alternatives of reducing refinery fuel sulfur levels and FCC feed sulfur levels. Furthermore, FCC feed sulfur reduction results in significant yield benefits in the FCC unit and would also be required by the majority of refiners to meet possible reductions in the maximum allowable sulfur levels in gasolines.

Since natural gas fuel for refineries was displaced by residual fuel oil over the study period (due to assumed natural gas curtailment), SO_x emissions from process furnaces and boilers became relatively large over the study period. To reduce emissions from process furnaces and boilers,

refinery fuel sulfur levels were reduced consistent with potential regional regulations for new sources (as discussed in Appendix D). Table 19 summarizes the existing and potential future regulations (used for planning assumptions in the present study) on maximum allowable sulfur levels of refinery fuels applied to each computer model. All cluster models and the West of Rockies grassroots model have refinery fuel sulfur levels which are consistent with regulations for their respective PAD districts (see Appendix D). For the East of the Rockies grassroots, representing new capacity in Districts I-IV, the maximum allowable refinery fuel sulfur content under a reduced SO_x emissions scenario was based on the average of PAD I-IV. In all models the sulfur level of residual fuel oils produced was also controlled to levels specified in Appendix C to prevent reduction of emissions by increasing the sulfur level of this product.

Emissions from FCC units were controlled by feed desulfurization to a level that was compatible with existing technology for the desulfurization of feed to FCC units. The FCC feed was desulfurized to a level of 0.2 wt.% sulfur or 85% sulfur removal, whichever was the lower.

Emissions from the sulfur recovery plants were reduced by increasing the level of sulfur recovery to 99.95%. This level of sulfur removal can be obtained by using the Beavon-Stretford process, for example, to clean up the tail gases from Claus plants.[18]

The approach taken in this study on reducing refinery SO_x emissions levels was thus to impose constraints on the operations of the three sources of SO_x emissions as discussed above, within reasonable limits of existing technology.

Finally, it should be pointed out that this study was conducted in parallel with studies on the impact of unleaded gasoline production and lead phase down. Gasoline and LPG production by the cluster models were therefore allowed to vary in reaching an optimal solution when changing operations from the base level of emissions without the above controls (Scenario C) to the controlled level of emissions (Scenario F). Loss of gasoline production as a result of the control of refinery SO_x emissions was then assumed to be made up with the grassroots models.

Table 19. MAXIMUM ALLOWABLE SULFUR LEVELS OF FUELS BURNED IN REFINERIES

Region (cluster)	Sulfur maximum wt %	
	Estimated existing regulations[a]	Potential future regulations
East Coast	0.6	0.3
Large Midwest	1.5	0.5
Small Midcontinent	1.5	0.5
Louisiana Gulf	0.9	0.5
Texas Gulf	0.9	0.5
West Coast	0.7	0.3
West of Rockies Grassroots	0.7	0.3
East of Rockies Grassroots	1.0	0.4

[a]See Appendix D.

Detailed results showing unit throughputs, severities, gasoline blends, inputs and outputs, costs, etc., are given in Appendix J for the base case (Scenario C) and for the reduction of SO_x emissions (Scenario F). Below is a discussion of those results.

B. STUDY RESULTS

1. 1985 Results

The effects on an aggregate U.S. basis of the imposed operational constraints on total refinery SO_x emissions is summarized for 1985 in Table 20. By reducing refinery fuel sulfur levels as specified previously, desulfurizing FCC feed, and increasing sulfur recovery from the Claus plant, SO_x emissions were reduced by 76% for the total U.S. relative to the base case of Scenario C. The regional variations in percentage emissions reduction can be attributed to such variables as crude sulfur content, FCC throughputs and feed quality, level of refinery fuel sulfur allowed, and the ability to dispose of sulfur in products, given product quality constraints. In general, those clusters with high sulfur content crude slates--the East Coast, Large Midwest and East of Rockies grassroots--showed the greatest amount of SO_x emissions reduction.

There are significant changes in the disposition of sulfur and its distribution between recovered elemental sulfur, SO_x emissions and product outturns. Table 21 shows sulfur distributions for the base case (Scenario C) and the reduced emissions case (Scenario F) for the Large Midwest cluster. Sulfur disposed in all products was, of course, essentially unchanged with reduced SO_x emissions. Elemental sulfur production was increased from 59% to 69% of total sulfur output, while sulfur in SO_x emissions was reduced from 12.4% to 2.4% of the total sulfur entering the model refinery. In Table 21 it can also be seen that the dominant source of SO_x emissions changed considerably. In the base case over half the sulfur in SO_x emissions originated in the FCC and Claus plants. By controlling SO_x emissions, over 80% of the sulfur in SO_x emissions originated from the combustion of process refinery fuel. Similar results are found in the other cluster models.

Table 20. SO_x EMISSION LEVELS, TOTAL U.S. BASIS 1985

Model	Short tons/day		Reduction, wt%
	Before control	After control	
East Coast	449	107	76
Large Midwest	1,323	254	81
Small Midcontinent	393	98	75
Louisiana Gulf	188	23	88
Texas Gulf	1,019	387	62
West Coast	572	158	72
West Grassroots	165	57	65
East Grassroots	1,335	240	82
Total U.S.	**5,444**	**1,324**	**76**

Table 21. PERCENTAGE DISTRIBUTION OF SULFUR – LARGE MIDWEST, 1985

	Scenario C	Scenario F
	% of total	% of total
Sulfur output		
To products	28.3	28.3
Elemental sulfur	59.3	69.3
SO_x emissions		
from FCC plant	3.8	0.4
from Claus plant	3.1	
from refinery fuel	5.5	2.0
Total	**12.4**	**2.4**
Total sulfur output	**100.0**	**100.0**
Percent of Total SO_x emissions		
From FCC plant	30.4%	15.6%
From Claus plant	25.2	1.4
From refinery fuel	44.4	83.0
	100.0	**100.0**

Although the total sulfur disposed in final products did not change greatly, the distribution of the sulfur among individual products changed considerably in all clusters. The sulfur contents both before and after SO_x emissions reductions for gasoline, residual fuel oil and internally consumed oil for refinery fuel are given in Table 22. Also shown are total elemental sulfur recovered (indicative of Claus plant throughput) and SO_x emissions. In all clusters the sulfur in gasoline was reduced significantly when SO_x emissions were controlled. The reduction in gasoline sulfur content ranged from a 61% decrease in the Louisiana Gulf to a 94% decrease in the West Coast. FCC gasoline contributes the major portion of sulfur to be found in gasoline. Desulfurization of FCC feed to reduce SO_x emissions also reduces the sulfur content in the total gasoline pool. Some reductions in residual fuel oil sulfur content similarly took place.

To reduce SO_x emissions the cluster models did not require significant changes in the processing configurations other than the FCC feed desulfurization and the Beavon-Stretford tail gas cleanup on the Claus plants.

In the East Coast cluster catalytic reformer and hydrocracker throughput remained essentially the same under a reduced emissions scenario versus the base scenario. FCC throughput was increased 5.9 MB/CD. A 2.4 MB/CD drop in alkylation was balanced by a 2.7 MB/CD increase in isomerization.

The major processing change in the Large Midwest cluster was a decrease of 10.2 MB/CD in FCC throughput and a subsequent 1.1 MB/CD drop in alkylation throughput, resulting in lower gasoline production. Catalytic reformer and isomerization throughputs increased by 4 MB/CD and 0.5 MB/CD respectively.

For the Small Midcontinent cluster there were small throughput increases totaling 1.2 MB/CD in catalytic reforming, FCC, and isomerization. A 1.3 MB/CD decrease in alkylation and reduced FCC conversion resulted in a drop in gasoline production, to be made up in the grassroots refineries.

In the Louisiana Gulf cluster, FCC throughput was reduced 3.9 MB/CD and catalytic reforming was correspondingly increased 3.6 MB/CD. Isomerization and alkylation were reduced a total of about 1 MB/CD.

Table 22. SULFUR RECOVERY, SO_x EMISSIONS, AND SULFUR CONTENT OF GASOLINE, SALABLE FUEL OIL, AND REFINERY FUEL, 1985

Scenario	Cluster												Grassroots					
	East Coast		Large Midwest		Small Midcontinent		Louisiana Gulf		Texas Gulf		West Coast		East of Rockies Sour		East of Rockies Sweet		West of Rockies	
	C	F	C	F	C	F	C	F	C	F	C	F	C	F	C	F	C	F
Elemental sulfur produced (T/D)	114	185	174	204	19	27	60	71	173	229	171	187	311	365	12	18	141	207
SO_x emissions (T/D)	59	14	73	14	24	6	24	2	92	35	47	13	118	22	30	12	55	19
Sulfur content																		
Gasoline (PPM)	394	57	746	148	237	65	217	84	309	65	779	47	433	40	70	7	331	31
Salable fuel oil (% wt.)	1.8	1.03	0.98	1.13	0.33	0.45	0.61	0.30	1.22	1.42	0.69	0.87	1.97	2.12	0.41	0.36	1.63	1.16
Refinery fuel (% wt.)	0.6	0.3	1.5	0.5	1.4	0.5	0.4	<0.1	0.9	0.5	0.7	0.3	1.0	0.4	0.5	0.4	0.7	0.3
Maximum allowable sulfur																		
Salable fuel oil (% wt.)	2.0		1.5		1.5		1.5		1.5		1.0		1.97	2.12	0.82	0.96	1.63	1.16
Refinery fuel oil (% wt.)	0.6	0.3	1.5	0.5	1.5	0.5	0.9	0.5	0.9	0.5	0.7	0.3	1.0	0.4	1.0	0.4	0.7	0.3

A FCC throughput increase for the Texas Gulf cluster was essentially balanced by a drop in volume conversion to gasoline. Alkylation was reduced by 2.3 MB/CD. Catalytic reforming and hydrocracking were decreased 1 MB/CD and 0.4 MB/CD respectively, and isomerization was increased .8 MB/CD.

In the West Coast cluster, catalytic reforming and isomerization were reduced a total of 1.8 MB/CD. FCC throughput was decreased by 4.3 MB/CD, however, conversion to gasoline was raised to 72.5% from 68.6% in the base case.

In the grassroots models, comparisons of process configurations are less meaningful since some differences will result from the variations in the cluster model gasoline production. Specifically, due to the purpose of the grassroots refineries of balancing total demand and refinery outturn from existing clusters under the two scenarios, grassroots refinery gasoline requirements for Scenario F were higher than those under Scenario C. In general, however, the East of Rockies grassroots cluster representing sour crude refining showed increases in the throughput of conversion processes but alkylation was decreased, as well as FCC conversion. The major change in both the East of Rockies grassroots processing sweet crude and the West of Rockies grassroots was an increase in catalytic cracker conversion. All three grassroots clusters showed changes in hydrocracking throughput--the East grassroots with sour crude increased hydrocracking 3.9 MB/CD, the East grassroots with sweet crude decreased 4.1 MB/CD and the West grassroots raised hydrocracking throughput 17.7 MB/CD.

Hydrogen production was either decreased slightly or showed no change in all but the Large Midwest and grassroots clusters. The East of Rockies sour crude grassroots and West of Rockies grassroots increased hydrogen generation 12.1 MMSCF/CD and 33.3 MMSCF/CD respectively. This is to meet higher hydrocracking throughputs mentioned previously in addition to extra hydrogen needs for desulfurization. In the East of Rockies sweet crude grassroots the drop in hydrocracker utilization resulted in a decrease of 7.4 MMSCF/CD of hydrogen manufacture. For the Large Midwest cluster, 15.4 MMSCF/CD of additional hydrogen manufacture was necessary to meet the increased desulfurization requirements.

Desulfurization of straight run distillate and heavier naphtha fractions was increased slightly in the East Coast, Large Midwest, Louisiana Gulf, and East of Rockies grassroots models.

In summary, apart from installation of FCC feed desulfurization capacity, major processing changes did not occur with reductions in SO_x emissions.

2. 1977 Results

In general, the results of reducing refinery SO_x emissions in 1977 directionally followed those of 1985. The major processing configuration differences were those associated with catalytic cracking of desulfurized feed. As in 1985, additional desulfurization of heavier naphtha and distillate cuts was required for the East Coast, Large Midwest and Louisiana Gulf cluster as well as the Texas Gulf cluster.

It is expected that certain processing changes will be required relative to 1985 results, since the gasoline pool in that year was 100% unleaded whereas in 1977 about 70% of the gasoline produced was leaded. For example, in 1985 the base scenario of the Texas Gulf cluster was operating at a higher level of conversion in order to meet the required volume of high clear octane product. In 1977, only 31% of the Texas Gulf gasoline pool was unleaded and hence, total gasoline requirements could be met at a lower level of cat cracker conversion.

Table 23 shows the 1977 cluster results for elemental sulfur recovery and SO_x emissions as well as the sulfur contents of the total gasoline pool, residual fuel oil and refinery fuel. As in 1985, some trade-offs were achieved in redirecting high sulfur fuel streams to blending for residual fuel oil product, given reduced allowable refinery fuel sulfur levels and the capability to absorb additional sulfur in the residual fuel oil. Again, the gasoline pool sulfur content has been significantly reduced with catalytic cracking of desulfurized feed.

Although desulfurization of FCC feed to 0.2 wt. % sulfur and 99.95% sulfur recovery are possible with existing technology, these operations are not commonly practiced at present. Hence, it may be unrealistic to expect that significant installation of these units could practically

Table 23. SULFUR RECOVERY, SO_x EMISSIONS, AND SULFUR CONTENT OF GASOLINE, SALABLE FUEL OIL AND REFINERY FUEL, 1977

Scenario	Cluster											
	East Coast		Large Midwest		Small Midcontinent		Louisiana Gulf		Texas Gulf		West Coast	
	C	F	C	F	C	F	C	F	C	F	C	F
Elemental sulfur produced (T/D)	104	185	156	174	14	21	58	71	186	233	198	221
SO_x emissions (T/D)	51	13	61	13	21	5	18	2	74	25	46	10
Sulfur content												
Gasoline (PPM)	324	58	738	171	178	58	258	74	401	75	673	111
Salable fuel oil (% wt.)	2.00	1.30	0.48	0.94	0.33	0.23	0.60	0.11	1.43	1.29	0.12	0.43
Refinery fuel (% wt.)	0.6	0.3	1.5	0.5	1.3	0.5	0.2	<0.1	0.9	0.5	0.7	0.3
Maximum allowable sulfur												
Salable fuels (% wt.)	2.0		1.5		1.5		1.5		1.5		1.0	
Refinery fuels (% wt.)	0.6	0.3	1.5	0.5	1.5	0.5	0.9	0.5	0.9	0.5	0.7	0.3

be realized by 1977. This factor has been taken into account in the analysis of economic penalties, discussed below.

C. SUMMARY OF ECONOMIC PENALTIES

The economic impact of reducing refinery SO_x emissions via the methods studied here were determined for the total U.S. refining industry by scaling up the results of the cluster models (Appendix G).

Table 24 shows that the capital investment required to reduce refinery SO_x emissions will be 4.5 billion dollars (first quarter 1975 basis) by 1985. Taking into account the timing of investment and inflation in refinery construction costs the estimate of ultimate capital investment by 1985 is 8.5 billion dollars. This figure assumes that emissions reductions as defined in the study could be achieved by 1977. Under this assumption, 69% of total investment (on a first quarter 1975 basis) would be required in 1977. A second estimate of inflated capital investment is provided in Table 24 which assumes that all capacity needed by 1985 is installed in 1980. Under this assumption the inflated capital investment for the aggregate U.S. is 8.8 billion dollars.

The economic penalties on a cents per gallon of total products basis for reduction of SO_x emissions is given in Table 25. By 1985 the additional costs required to reduce emissions is estimated to be 0.71 cents per gallon of total products produced. This figure is in terms of first quarter 1975 cost levels and would be increased about two and one-half times to reflect inflated costs. The cents per gallon penalties are calculated on the basis of five factors--capital charge, operating costs, crude penalties, LPG credits and sulfur credits--and are given in more detail in Appendix J. The capital charge has been set at 25% of investment, crude oil has been valued at $12.50/bbl, and LPG and sulfur have been valued at $8.75/bbl and $10/short ton, respectively.

Table 26 shows the breakdown by component of the total penalties for 1985. The largest component of the additional cost is the investment-related penalty at 65% of the total economic penalty. Although on a total U.S. basis there is a 26,000 dollars per day credit for sulfur output in 1985 (as shown in Appendix J), when spread among total U.S. products the credit essentially disappears.

Table 24. CAPITAL REQUIREMENTS TO REDUCE REFINERY SO_x EMISSION LEVELS[a]

millions of dollars

	Clusters representing PAD I-IV										
	East Coast	Large Midwest	Small Midcontinent	Louisiana Gulf	Texas Gulf	Grassroots PAD I-IV	Total PAD I-IV	Cluster PAD V West Coast	Grassroots PAD V	Total PAD V	Total U.S.A.
Uninflated (1st Qtr 1975 basis)											
1977	397	1,017	415	304	599	–	2,732	389	–	389	3,121
1985	38	(49)	(67)	7	263	874	1,066	31	275	306	1,372
Total	**435**	**968**	**348**	**311**	**862**	**874**	**3,798**	**420**	275	**695**	**4,493**
Inflated											
1977	557	1,428	583	427	841	–	3,836	546	–	546	4,382
1985	113	(146)	(199)	21	783	2,604	3,176	92	819	911	4,087
Total	**670**	**1,282**	**384**	**448**	**1,624**	**2,604**	**7,012**	**638**	**819**	**1,457**	**8,469**
Alternate inflated total[b]	850	1,891	680	608	1,684	1,708	7,421	821	537	1,358	8,779

[a]Relative to Scenario C.

[b]Assumes all capacity needed by 1985 is installed by 1980.

Table 25. ECONOMIC PENALTIES FOR REDUCING REFINERY SO_x EMISSIONS[a]
(cents per gallon total products)

	PAD I-IV	PAD V	Total U.S.A.
1977	0.60	0.33	0.55
1985	0.71	0.72	0.71

[a]Relative to Scenario C.

Table 26. BREAKDOWN OF ECONOMIC PENALTY TO REDUCE REFINERY SO_x EMISSIONS[a]

(1st quarter 1975 cost basis)

	1985	
	Cents/gallon total products	% of total penalty
Capital charge[b]	0.46	65
Operating costs	0.08	11
Crude penalties	0.12	17
LPG penalties (credits)	0.05	7
Sulfur credits	–	–
Total	0.71	100

[a]Relative to Scenario C.

[b]25% of capital investment required.

D. SUMMARY OF CRUDE OIL AND ENERGY PENALTIES

As with economic penalties, model results have been scaled up to give an estimate of total crude oil and energy penalties to the U.S. refining industry for reducing SO_x emission levels. Energy penalties are comprised of additional crude oil processed and additional purchased power required. Also, an energy credit is taken for additional LPG produced, or if LPG production is less than that in the base scenario, a penalty is incurred. Table 27 summarizes the scaled up penalties for 1985. By that year, additional crude oil processing required as a result of reducing emissions will be in excess of 60 MB/CD. Because LPG production decreased 39.3 MB/CD relative to the base scenario, an additional energy penalty was incurred. The total U.S. net energy penalty amounts to nearly 100 MB/CD of fuel oil equivalent.

Appendix J contains more detail on the 1985 energy penalties as well as those for 1977.

Table 27. ENERGY PENALTIES FOR REDUCING REFINERY SO_x EMISSIONS[a]

	1985		
	PAD I-IV	PAD V	Total U.S.A.
Basis			
Additional crude oil required MB/CD	47.4	15.2	62.6
Additional LPG produced MB/CD	(38.8)	(0.5)	(39.3)
Additional purchased power required MKWH/CD	7,891	2,224	10,115
Energy penalties 10^9 BTU/CD			
Crude oil	265	85	350
LPG	155	2	157
Purchased power	79	22	101
Total 10^9 BTU/CD	**499**	**109**	**608**
Total MB/CD of fuel oil equivalent	**79**	**17**	**96**

[a]Relative to Scenario C.

IV. SENSITIVITY STUDY RESULTS

A. IMPORTED CRUDE OIL FOR GRASSROOTS CAPACITY

The effects of reducing refinery SO_x emissions on the East of Rockies grassroots refineries were determined by model runs for both a sweet crude oil refinery (processing a 50/50 Algerian/Nigerian crude mix) and for a sour crude oil refinery (processing 100% Saudi Arabian light crude). Model results were scaled up on the basis that one-third of East of Rockies grassroots refineries will process a sweet crude slate and two-thirds will process sour crude, to derive the final results presented in Section III. This sensitivity study examines the effects on 1985 economic penalties if all grassroots refineries East of Rockies were based on 100% sour crude, and if all were based on 100% sweet crude.

The results of this sensitivity analysis are shown in Table 28. With grassroots capacity used for processing all sweet crude, capital investment for reduction of SO_x emissions would be 4.1 billion dollars (first quarter 1975 basis), 430 million dollars less than the base case. If East of Rockies grassroots capacity is for processing of sour crude, the capital investment for emissions reduction will be 216 million dollars higher than the base case, or 16% higher than for sweet crude. Similarly, the economic penalty is .04 cents lower and 0.03 cents higher than the base case for the all-sweet and all-sour crudes, respectively.

Thus, the sulfur content of the crude processed does significantly affect the magnitude of investment and economic penalties. It is expected that processing of crude oils such as Arabian Heavy would have a further significant effect.

Table 28. EFFECT OF CHANGING IMPORTED CRUDE OIL TYPE PROCESSED IN GRASSROOTS CAPACITY ON THE 1985 ECONOMIC PENALTY FOR REDUCING REFINERY SO_x EMISSIONS

	Base case	Imported crude for grassroots	
		100% sour	100% sweet
Crude oil sulfur, wt%	1.18	1.68	0.17
Capital investment million dollars (1Q 1975 basis)	4,493	4,709	4,063
Economic penalty cents per gallon Total products (1Q 1975 basis)	0.71	0.74	0.67

B. EFFECT OF TARGET RESIDUAL FUEL OIL SULFUR LEVEL

The sulfur levels of the residual fuel oils produced in the cluster models were allowed to vary but not to exceed a reasonable maximum specified for each cluster model. The grassroots models were then used to balance the volume of residual fuel oil required from U.S. refineries and also to balance the sulfur level of the fuel oil. Hence, the sulfur level of residual fuel oil produced in the grassroots models will depend on the target sulfur level set for the residual fuel oil produced from all U.S. refineries. A small change in the target sulfur level on residual fuel oil for the whole U.S.A. will have a significant effect on the sulfur level required of residual fuel oil produced in the grassroots models because of the leverage effect of total U.S. residual fuel oil production compared with grassroots residual fuel oil production (see Table 10).

The base case study assumed residual fuel oil sulfur target levels of 1.4 wt. % East of the Rockies and 0.90 wt. % West of the Rockies. This resulted in an East of the Rockies grassroots residual fuel oil sulfur level of 2.12 wt. % when reducing refinery SO_x emissions. West of the Rockies required a residual fuel oil sulfur level of 1.16 wt. % for emissions reduction.

This sensitivity study examines the effect of meeting target residual fuel oil sulfur levels for the whole of the U.S. of 1.2 wt. % East of the Rockies and 0.75 wt. % West of the Rockies. This required the East of the Rockies grassroots models to produce residual fuel oil with a sulfur level of 0.96 wt. % when reducing SO_x emissions. West of the Rockies required a residual fuel oil sulfur level of 0.53 wt. % for reduction of emissions.

The results of the sensitivity study are provided in Table 29. The effect is to increase the capital investment about 100 million dollars, with no change in the economic penalty. Thus, the target residual fuel oil sulfur level has a relatively small impact on the cost of reducing refinery SO_x emissions.

Table 29. EFFECT OF LOWER TARGET SULFUR LEVEL OF PRODUCTION OF U.S. RESIDUAL FUEL OIL ON THE 1985 ECONOMIC PENALTY FOR REDUCTION OF SO_x EMISSIONS

	Base case	Lower residual fuel oil sulfur
Capital investment Millions dollars (IQ 1975 basis)	4,493	4,603
Economic penalty Cents per gallon Total products (IQ 1975 basis)	0.71	0.71

C. USE OF STACK GAS SCRUBBING

A detailed investigation was made of the potential of stack gas scrubbing as a means to control refinery SO_x emissions, as reported in Appendix L. The results indicated that the capital investment requirements to install stack gas scrubbing will be at least as great as the alternatives discussed herein. Since the route of desulfurizing FCC feedstock also results in significant yield benefits in controlling FCC emissions, stack gas scrubbing was not allowed in the computer model studies of the FCC unit. Since the cluster models represent existing refineries with many dispersed stacks, it was also not used to control emissions from process furnaces and boilers. However, stack gas scrubbing was used in the model to control Claus plant SO_x emissions.

V. DISCUSSION

The intent of this study was to assess the impact of imposing operational constraints on the three sources of refinery SO_x emissions--process furnaces and boilers, FCC units, and Claus plants. On a total U.S. basis, final results indicate that a 76% reduction in SO_x emissions below estimated current levels can be achieved within reasonable limits of existing technology but with substantial investment of capital by the refining industry. This assumes the control of SO_x emissions by reducing refinery fuel sulfur content, by desulfurization of FCC feed, and by increased sulfur recovery in Claus plants.

To effect even greater levels of emissions reductions would require stack gas scrubbing. As discussed in Section III, capital investment requirements for installation of stack gas scrubbers are anticipated to be at least as high as the alternatives of reducing refinery fuel and FCC feed sulfur levels. In addition, FCC feed desulfurization exhibits yield benefits that, given the concerns of Project Independence, cannot be overlooked. FCC feed desulfurization also contributes a substantial reduction of sulfur in the gasoline pool and in fact would be required by a majority of refiners to meet possible regulations on maximum allowable unleaded gasoline sulfur contents. Finally, although stack gas scrubbing plants have been employed in the utility industry, they have not been widely demonstrated in the petroleum refining industry. Extensive discussion of the evaluation of the applicability of stack gas scrubbing to the refining industry is contained in Appendix L.

The results of our sensitivity analysis on the type of crude oil processed indicate that the impact of emissions reduction will vary depending on the sulfur content of crudes available to particular refiners. As discussed in Section III, all model runs were required to remove at least

85% of sulfur in FCC feed. However, some Middle East type cuts would require 95% desulfurization to reach the target 0.2 wt. % FCC feed sulfur level. This would, of course, involve greater operating costs and investment penalties.

This study did not specifically address the impact of reducing SO_x emissions on the small refiner by simulation of his operations. Penalties were adjusted by giving greater weight to results from the Small Midcontinent cluster to take account of higher costs due to economies of scale. Since these small refineries represent a relatively small percentage of total U.S. refining capacity, any underestimation of penalties to the small refiner will not appreciably alter the overall results of this study. This is not to say that the small refiner would be uneffected, for impacts on the total U.S. refining industry would translate into higher relative economic penalties for the small refiner which could be difficult to finance, would require installation of Claus plants often not now in place, and could require difficult means to dispose of elemental sulfur produced. These factors could have a significant effect on the competitive structure of the petroleum refining industry.

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TECHNICAL REPORT DATA
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1. REPORT NO.	2.	3. RECIPIENT'S ACCESSION NO.
EPA-600/2-76-161a		

4. TITLE AND SUBTITLE	5. REPORT DATE
Impact of SOx Emissions Control on Petroleum Refining Industry Volume I. Study Results and Planning Assumptions	June 1976
	6. PERFORMING ORGANIZATION CODE
7. AUTHOR(S)	8. PERFORMING ORGANIZATION REPORT NO.
James R. Kittrell and Nigel Godley	
9. PERFORMING ORGANIZATION NAME AND ADDRESS	10. PROGRAM ELEMENT NO.
Arthur D. Little, Inc. 20 Acorn Park Cambridge, Massachusetts 02140	1AB013; ROAP 21ADC-030
	11. CONTRACT/GRANT NO.
	68-02-1332, Task 1
12. SPONSORING AGENCY NAME AND ADDRESS	13. TYPE OF REPORT AND PERIOD COVERED
EPA, Office of Research and Development Industrial Environmental Research Laboratory Research Triangle Park, NC 27711	Task Final; 9/73-5/76
	14. SPONSORING AGENCY CODE
	EPA-ORD

15. SUPPLEMENTARY NOTES IERL-RTP Task Officer for this report is Max Samfield, Mail Drop 62, (919) 549-8411, Ext 2547.

16. ABSTRACT The report gives results of an assessment of the impact on the U.S. petroleum refining industry of a possible EPA regulation limiting the level of gaseous refinery sulfur oxide (SOx) emissions. Computer models representing specific refineries in six geographical regions of the U.S. were developed as the basis for determining the impact on the existing refining industry. New refinery construction during the period under analysis (1975-1985) was also considered by development of computer models representing new grassroots refineries. Control of refinery SOx emissions from both existing and new refineries was defined for the purposes of this study by maximum sulfur levels on refinery fuel and on fluid catalytic cracking unit feedstock and by increased sulfur recovery in the Claus plant. The computer models thus constrained were utilized to assess investment and energy requirements to meet the possible regulation and the incremental cost to manufacture all refinery products as a result of the regulation. Parametric studies evaluated the impact of variations in the types of imported crude oils available for future domestic refining and the projected sulfur level of residual fuel oil manufactured in the U.S.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Air Pollution Control	13B
Sulfur Oxides	Stationary Sources	07B
Petroleum Industry	Refinery Fuel	05C
Petroleum Refining	Claus Plant	13H
Refineries		13I
Catalytic Cracking		07A

18. DISTRIBUTION STATEMENT	19. SECURITY CLASS *(This Report)*	21. NO. OF PAGES
Unlimited	Unclassified	116
	20. SECURITY CLASS *(This page)*	22. PRICE
	Unclassified	

EPA Form 2220-1 (9-73)