. . . . Emergency Preparedness for Interruption of Petroleum Imports into the United States

. . . . April 1981

A Report of the National Petroleum Council . . . .

. . . . . Emergency Preparedness for Interruption of Petroleum Imports into the United States . . . . April 1981

A Report of the National Petroleum Council . . . .

. . . . . . Prepared by the National Petroleum Council's Committee on Emergency Preparedness . . . . C. C. Garvin, Jr., Chairman . . . . with the Assistance of the Coordinating Subcommittee . . . Edward T. DiCorcia, Chairman. . . . .

NATIONAL PETROLEUM COUNCIL

C. H. Murphy, Jr., *Chairman*
H. J. Haynes, *Vice Chairman*
Marshall W. Nichols, *Executive Director*

U. S. DEPARTMENT OF ENERGY

James B. Edwards, *Secretary*

The National Petroleum Council is a federal advisory committee to the Secretary of Energy.

The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

Library of Congress Catalog Card Number: 81-81826

Printed in the United States of America

TABLE OF CONTENTS

INTRODUCTION

During the last decade there has been a large increase in U.S. dependence on oil from Middle East and African nations. In 1970, oil from these nations made up 10 percent of U.S. imports and 2 percent of total petroleum supplies. By 1980, this share had grown to about 50 percent of imports and nearly 25 percent of total supplies. Unfortunately, military conflicts, terrorism, and political instability have been commonplace in these areas and pose a well recognized threat to oil exports. Four disruptions in oil exports from the Middle East within the past eight years bear witness to this danger: a politically motivated, selective embargo by Arab oil exporters beginning in late 1973, the loss of Iranian oil exports due to internal turmoil both in 1978 and in 1979, and the Iraq-Iran war in 1980-1981. In the first three instances, and potentially the latest if the conflict should worsen or spread, the disruption was accompanied by sharp increases in world oil prices.

The Senate Committee on Energy and Natural Resources recently completed a study on the geopolitics of oil.[1] In its assessment of U.S. dependence on Persian Gulf oil, the study states, "The United States and our allies are likely to experience at least two more decades of vulnerability to supply disruptions, political manipulation of oil supplies, and periods of panic buying on the spot market." The United States had a taste of the effects of supply disruptions in 1973 and again in 1978 and 1979. But the economic losses and hardship of these three experiences could be considered small by comparison with the potential effects of a complete interruption of oil exports from the Persian Gulf. The history of the past decade and the outlook for the next make an obvious case for the need to improve U.S. energy security.

In formulating appropriate government policies to increase energy security, it is important to distinguish between two concepts: dependence and vulnerability.[2] Dependence is defined as the amount of oil imported. Vulnerability is defined as the potential damage from a supply disruption. In theory, an oil consuming nation might have a high level of dependence but low vulnerability if its imports are widely dispersed among relatively secure sources. In practice, the United States is unlikely to achieve this goal given the distribution of world oil reserves.

---

[1] Committee on Energy and Natural Resources, United States Senate, Staff Report, The Geopolitics of Oil, December 1980.

[2] A discussion of the concepts of dependence and vulnerability is contained in Summary Findings, Conference on Petroleum Interruptions and National Security, May 9-11, 1980, sponsored by the Energy Committee of the Aspen Institute for Humanistic Studies, Alvin L. Alm, Chairman.

Reducing long-term dependence on oil imports is an essential part of national energy policy. Lower levels of dependence can help alleviate pressures on world oil markets, reduce balance of payment problems, reduce the margin of vulnerability by extending the protection provided by stockpiles or conversely by reducing the required volume of stockpiles, and strengthen the strategic position of the United States and its allies.

The primary focus of U.S. energy policy development, beginning with Project Independence in 1973 through passage of the Energy Security Act of 1980, has been on reducing import dependence. Despite these important efforts, energy analysts now generally agree that, due to the lead times involved, the nation will still remain dependent on substantial volumes of oil imports for at least the next decade or two. Moreover, even if the nation could somehow achieve independence from imports, U.S. allies and major trading partners would still be heavily dependent on imported oil. Economic links and oil sharing agreements with these nations would make it highly unlikely that the United States could escape the effects of a major world oil supply disruption.

Oil supply disruptions are damaging in three ways. First, the disruption results in physical loss of oil supplies which can create personal hardship and reduce business activity. Second, the upward ratcheting of oil prices which may follow the disruption generates substantial wealth transfers, induces productivity losses, and increases inflation. Third, the economic dislocations as well as any military threats or political coercion which accompany the disruption can result in serious foreign policy implications.

Preparations to date to minimize the nation's vulnerability to these threats have been few. Two positive steps were taken in the wake of the 1973-1974 embargo: the creation of an emergency oil sharing program under the International Energy Agency (IEA) and of a U.S. Strategic Petroleum Reserve (SPR). Two prior National Petroleum Council studies, Emergency Preparedness for Interruption of Petroleum Imports into the United States (September 1974) and Petroleum Storage for National Security (August 1975), strongly endorsed the establishment of a Strategic Petroleum Reserve. Implementation of the SPR program, however, has fallen short of the timetable set for capacity and fill rates. In previous oil shortfalls, the U.S. response has relied on the use of comprehensive oil price and allocation controls, voluntary and government-mandated demand reduction and fuel switching steps, and private inventories which happened to be available.

Broad standby emergency authority for crude oil and product allocation and price controls under the Emergency Petroleum Allocation Act of 1973 (EPAA) is scheduled to expire on September 30, 1981. Other statutes, unless changed, will continue to provide government with certain standby authorities for use during supply emergencies. Included in these statutes are limited authorities for actions necessary to implement U.S. obligations under the International Energy Agency agreement, authorized by the Energy Policy and Conservation Act of 1975 (EPCA); conservation contingency programs which may not include rationing, fees, taxes, rebates, or other mechanisms affecting oil prices (EPCA); adjustment of foreign imports (Trade Expansion Act); and actions necessary to divert supplies for military priorities and maximize domestic energy supplies (Defense Production Act). (See Appendix D for additional information on existing emergency authorities.)

On June 3, 1980, Deputy Secretary of Energy John C. Sawhill requested that the National Petroleum Council (NPC), an industry advisory committee to the Secretary of Energy, undertake a study of certain issues bearing on emergency preparedness in the event that imported energy supplies are interrupted. The three areas of particular concern to be addressed were:

- The ability of the nation's supply and distribution system to operate under constrained conditions
- The regulatory and statutory climate needed to minimize damage to the nation
- The organization and method of operation of the industry/government relationship under emergency conditions.

(See Appendix A for the complete text of the Secretary's request letter and a description of the National Petroleum Council.)

In response to this request, the Council established the Committee on Emergency Preparedness under the chairmanship of Clifton C. Garvin, Jr., Chairman of the Board, Exxon Corporation. Deputy Secretary Sawhill served as the Committee's Government Cochairman. The Committee was assisted by a Coordinating Subcommittee chaired by Edward T. DiCorcia, Vice President, Supply Department, Exxon Company, U.S.A. Barton R. House, Deputy Administrator, Operations and Emergency Management, Economic Regulatory Administration, U.S. Department of Energy (DOE), served as the Subcommittee's Government Cochairman. The membership of the study groups and the Council reflects a broad spectrum of oil and gas companies and also includes representatives of labor, research, and public interest and academic organizations (see Appendix B for rosters of participants). With such a wide diversity of representation, this report frequently reflects either the majority or consensus view of the Council, and does not always reflect a unanimous view.

The scope of the study is specifically limited to emergencies stemming from major cutoffs of oil imports into the United States. It does not deal with public issues related to the petroleum industry during non-emergency conditions. In addressing the areas of concern identified by Deputy Secretary Sawhill, the NPC has considered the identification of steps which should be taken by the government in advance to prepare for future disruptions as well as the development of government strategies to be implemented during the emergency to minimize negative effects on the nation. Five oil import disruption scenarios, ranging in magnitude of from 1.0 million barrels per day (MMB/D) to 4.6 MMB/D and in duration of from six to 12 months, were provided by DOE for analysis. The study recognizes, however, that in an actual oil supply emergency, the ultimate magnitude and duration of the disruption are very likely to be among the many uncertainties at the outset, and the study recommendations attempt to deal with this uncertainty.

The Council has attempted to achieve in this study several characteristics which were reflected in earlier NPC studies on emergency preparedness: (1) recommendations for government action which are practical and specific; (2) timely completion in order to meet current needs of government; (3) a primary focus on national interest but appropriate consideration of regional, sector, and private interests; (4) a sensitivity to opposing points of view; and (5) advice based on sound analysis and petroleum industry expertise.

Considerable research on emergency preparedness issues has been conducted in the recent past by both private and government groups. To ensure consideration of a diversity of views, the study participants examined recent reports prepared by academicians, consultants, and government agencies. A bibliography of some of the resource materials examined by the Subcommittee during the study is provided in Appendix C. The study participants also had the benefit of firsthand discussions with the authors of a number of these studies at its meetings.

It is soon apparent to those who study the vulnerability problem that there is no obviously best plan for minimizing the negative effects of supply disruptions. This study attempts to present a comprehensive review of the options available for use in an emergency, but preparedness plans must be flexible enough to deal with contingencies as they occur and should be continually reviewed and updated as the world energy situation evolves. At best, a major disruption in imported oil supplies will substantially depress economic activity, increase unemployment, add to inflation, inconvenience consumers, and perhaps cause personal hardship. At worst, it could seriously threaten the nation's security. The American public should clearly understand that emergency preparedness plans are not designed to make the nation invulnerable -- that can only be accomplished over many years by substantially reducing oil import dependence both in the United States and in other major consuming nations. What preparedness plans can hope to do is to help protect national security and make a very painful problem somewhat less painful.

OVERVIEW

During the course of the study, the following broad objectives were identified for plans formulated to manage oil import disruptions:

- Paramount among these is the protection of national security and the foreign policy interests of the United States. The introduction to this report has already pointed out the vital links between the United States and its major allies and trading partners and the need to work in concert in developing emergency preparedness plans. Such plans should be designed to buy time and take pressure off top level government decision-makers to allow them to focus on critical foreign policy and national security issues which may accompany major interruptions of petroleum supplies.

The plans should also:

- Provide for the protection of public health and safety and maintenance of vital services.

- Minimize macroeconomic losses during the disruption. Appropriate government monetary and fiscal policies will be needed to offset the effects of price increases which may occur during a supply disruption. In a severe disruption, existing tax laws would potentially yield large increases in revenue to both federal and state governments as oil prices rise. These governments must be prepared to adjust revenues and outlays in an emergency to minimize distributional inequities and fiscal problems.

- Encourage actions which help to restrain disruptive increases in world oil prices. Demand restraint should be encouraged, and maximum use of available supplies should be facilitated. Actions which increase competition for limited available supplies of oil during a disruption such as panic buying or hoarding by either suppliers or consumers should be discouraged.

- Bolster public confidence and encourage cooperation both in preparing for and responding to energy emergencies. Provisions should be made for educating the public in advance of a crisis and for effective communications during the crisis. An important part of this effort should be to encourage suppliers and consumers to develop contingency plans for disruptions.

- Promote efficient petroleum industry operations during the emergency. Import disruptions will create dislocations in U.S. petroleum refining and logistics systems, so plans should facilitate -- not hinder -- the operational adjustments needed to ensure efficient use of available resources.

- Minimize to the extent possible intrusions on the achievement of long-term national goals such as the preservation of environmental quality, personal freedoms, a competitive economy, an equitable tax structure, and the reduction of oil imports dependence.

- Be made as simple as possible to administer and enforce. Any government-mandated programs which may be needed to deal with disruptions should be designed to minimize special exceptions.

While it is not difficult to agree that these are desirable objectives, it should be recognized that, in reality, no plan can fully achieve all these goals.

- Conflicts are inevitable and tradeoffs will be necessary. National interests must be balanced against regional or sectoral interests. Long-term goals may have to be compromised against short-term realities. While plans should be developed with as rational a basis as possible, they must also be politically and practically workable.

- A large degree of humility in approaching these problems seems especially appropriate. Pre-planning for energy emergencies is certainly prudent, but caution is needed against false confidence in the ability to choose in advance the best response to specific situations the nation may be confronted with in future crises. Likewise, the hard lessons learned from dealing with past import curtailments can be valuable, but they should not automatically be applied without very careful consideration in severe disruptions which are beyond the bounds of knowledge and experience.

There appears today to be widespread acceptance that competitive markets provide the most efficient allocative mechanism of resources under non-emergency conditions. Further, academicians and consultants who provided their views express strong support for reliance on market mechanisms even in the most severe import disruptions. They argue that efficient distribution of resources in a crisis is even more urgent than under normal circumstances. They also point to the distortions that have been experienced under comprehensive oil price and allocation control systems in the past.

While not unanimous in reaching its recommendations, the Council's majority view recognizes that neither pure free-market mechanisms nor regulatory mechanisms are perfect in real-world circumstances and that, under emergency conditions, either might have serious shortcomings.

- It is the majority view that, in an emergency situation, economic efficiency represents a persuasive argument for maximum reliance on competitive market mechanisms to the extent practicable.

- However, it is also recognized that sudden major interruptions of imported petroleum supplies may, due to the unevenness of their impacts, create exceptional hardships for individual consumers and their suppliers which may not be rapidly accommodated by competitive market adjustments. The primary concern in the most severe disruptions is not the elegance of the theoretical solution, but rather the practical considerations of ensuring that all petroleum consumers have a supplier, that limited available supplies are handled in as efficent and equitable a manner as possible, and the recognition that <u>all</u> are likely to suffer some hardship but will be asked to cooperate with the government for the national good.

- Putting aside ideological pre-conceptions or political preferences, participants in this study have struggled to find a workable approach which would leave the petroleum industry adequate flexibility in emergencies to fulfill its role of being an efficient supplier of available petroleum products, while ensuring that government has available through a limited program of standby emergency measures the tools it may need to deal with the distributional inequities and hardships which are likely to occur.

The measures recommended in the report do not eliminate sacrifices in true national emergencies.

- Some companies would be required to share their oil supplies with others more severely affected by the disruption; but, on the other hand, the disadvantaged companies would not be fully protected.

- Some companies might, in the most severe disruptions, be faced with inoperable plants.

- All companies would have certain obligations to maintain continuity in supplying customers.

- Consumers would be faced with paying higher prices and doing with less.

- Certainly government will need to exercise prudence and restraint while under extreme pressure from special interests to intervene for the purpose of mitigating perceived inequities.

In summary, the overall approach recommended is one of maximum reliance on market mechanisms coupled with an array of available, flexible, and constructive emergency standby measures so that the Administration would attempt to match and adjust the response options selected with the ongoing assessment of the severity and nature of the disruption.

- The Council recognizes that discretionary implementation of emergency measures could lead to their use in minor disruptions or, even worse, during normal fluctuations in markets. It is believed to be virtually impossible, however, to define specific pre-determined trigger mechanisms which would adequately anticipate all of the many factors that might appropriately enter into future decisions by the President to activate emergency measures.

- This study, therefore, proposes the concept of an emergency management process which requires as a necessary element for activation specific events which either threaten or cause a sudden disruption in world oil supplies. In addition, before activating emergency procedures, an assessment would be required that such an event would result in severe consequences for the United States. These consequences might, for example, include a threat to national security, significant foreign policy implications, major distributional inequities, and sharp and disruptive increases in world oil prices.

- While the system would be flexible going into an emergency, explicitly defined termination provisions are recommended. So-called "sunset" mechanisms would specify a limited period of time after which a new Presidential or Congressional finding would be required for continuation of any emergency measures put into effect.

- This approach would give the President adequate flexibility in activating emergency plans while providing reasonable assurances that these measures would not be triggered at inappropriate times or, as in past experience, become permanent fixtures even after the emergency is over. It would also preserve the President's discretionary authority to take the steps he decides are needed to meet U.S. obligations to the International Energy Program.

DOE provided the Council with oil import disruption scenarios, ranging in magnitude from a 1.0 MMB/D to 4.6 MMB/D shortfall and in duration from six to 12 months, to be used as a basis for analysis in the study. The Council and the DOE both recognize that it is impossible to capture in a set of paper scenarios all the actual complexities which might exist in future emergencies. However, the scenarios proved to be a valuable tool in this study. They provided clear points of reference on which to focus discussions and made it possible to quantify the effects of various emergency supply/demand response strategies and test them for reasonableness.

To provide useful advice to government, it is at least inadequate and possibly dangerous to discuss a flexible approach to response strategies in the context of ambiguous terms such as "small disruptions" or "large disruptions" without providing some clearer guidance as to order of magnitude. Therefore, the recommendations of this study are organized in terms of strategies for import disruptions to the United States of up to approximately 1

MMB/D and 2 MMB/D and those larger than approximately 2 to 3 MMB/D. Caution is needed, however, that this matching of disruption magnitude to specific strategies not be taken too literally, because there are obviously many factors, in addition to the size of imports disruption, which would be considered in selecting response options. It is also useful to distinguish between "imports disruption" which is the level of gross initial curtailment of imported oil and "shortfall" which is the level of net remaining unsatisfied demand after taking recommended emergency demand and supply management steps. With effective emergency management, the resulting "shortfall" could be much smaller than the initial "imports disruption."

The discussion in Chapter One illustrates how the DOE scenarios may be used to examine the flexible approach recommended for responding to oil import disruptions, and shows, for selected months in each scenario, the estimated effects of implementing the recommended sequence of response options.

- Competitive market mechanisms would be relied on as the primary adjustment mechanism to the extent practical.
- Market mechanisms would be reinforced by a program to communicate the need for voluntary actions by suppliers and consumers to reduce oil consumption, substitute alternate fuels where possible, and use privately held inventories. These voluntary measures, if effectively implemented, might be adequate to cushion the effects of import disruptions of up to about 1 MMB/D to the United States.
- For imports disruptions ranging up to about 2 MMB/D to the United States, market mechanisms and voluntary responses would be supplemented by further government actions such as mandated switching from oil to gas or coal, mandated wheeling of electricity to displace oil and gas with coal and nuclear-generated power, temporary emergency relaxations of environmental standards where necessary to facilitate use of higher sulfur fuels, state and federal actions to facilitate emergency domestic oil and gas production, and mandating of limited demand reduction steps such as lower speed limits and commercial thermostat management. In addition, current SPR fill would be diverted to the market.
- The demand reduction, fuel switching, diversion of SPR fill, and emergency production steps identified in the study have the potential for cushioning the impact of import disruptions of roughly 2 to 2.5 MMB/D. In very severe disruptions as illustrated by DOE Scenarios 3 and 4, cumulative net shortfalls in the United States of about 300 million barrels would be left which would have to be balanced by some combination of additional price-induced demand reduction, use of consumption taxes or import fees, rationing, and drawdown of private inventories and SPR reserves.

- Crude oil stocks in the SPR above a level of about 200 million barrels should be readily available for use in cushioning the impacts of supply disruptions of varying sizes. However, stocks below this level should be held in reserve for vital defense, health, and safety needs. Making SPR stocks more readily available to cushion the impacts of disruptions represents a change from the 1975 NPC Petroleum Storage for National Security study recommendation and reflects a recognition of the need to try to both minimize the harmful effects on consumers of very severe interruptions as well as cushion the significant impacts which may be unnecessarily experienced in early months of even smaller interruptions when the full effect of the cutoff hits the United States but before emergency supply/demand management measures have become fully effective.

- For oil import disruptions in excess of 2 to 3 MMB/D, the study recommends that, in addition to relying on market mechanisms and the steps prescribed for smaller disruptions, a limited standby program of emergency crude oil and product distribution and product margin measures be available to the government. The program would include crude oil sharing to bring all refiners to a common crude oil run ratio based on pre-emergency crude oil runs; a limited system of priority user designations, state set-aside, and product distribution guidelines; and simplified margin limitations on refiners, jobbers, and dealers. It is recognized that these measures are both fundamentally flawed and, as implemented by the DOE in the past, have been unsatisfactory. Unlike other options, however, the measures recommended have been tested and analyzed in actual practice.

- The use of emergency consumption taxes, emergency import fees, or coupon rationing is not specifically recommended, but this is more a matter of the state of existing knowledge of these steps rather than a deliberate choice to foreclose their use. The Council recognizes that consumption taxes, import fees, and coupon rationing are potential standby mechanisms for use during severe supply disruptions. However, these are highly complex measures that require more study before recommendations can be made with confidence.

Some of the factors that motivated selection of the flexible and mixed approach require explanation. While considerable input was received from experts in market economics, the subject is not one that can be precisely dealt with based on hard facts, research, and analysis. There has been much said and written about various aspects of the problem of what to do in the event of a supply disruption, but this study is one of the few attempts to deal in an overall and specific fashion with the problem. While any emergency management strategy has broad policy implications, this study deals primarily with the practical supply problems likely to accompany an imports disruption in a way that improves the prospect that all consumers will be served, while at the same time seeking to minimize undesirable side effects. While political acceptability is a factor considered, the recommendations have not been developed for political expediency but rather in the belief that at this time they are most likely to serve this country well in the event of an actual supply disruption.

The study is neither totally free-market oriented nor does it call for government intervention until the need is apparent. Comments have been received from those who would like greater reliance on a free market, while there are others who are appalled at the potential exposure to competitive market forces contemplated by this study. However, the recommendations are based on a judgmental compromise that suggests that the government's overall strategy for emergency management of oil import disruptions should be to rely to the maximum extent on market mechanisms, but to have available a variety of emergency standby options of increasing severity to deal with shortages of increasing magnitude.

The actions called for in this report in dealing with supply disruptions of up to about 2 MMB/D are the type of actions that would be prompted by competitive market forces, and the study recommendations are designed to facilitate these actions. This is not to say that petroleum prices will not rise if the recommended steps are taken. However, the clear intent is that price impacts accompanying a supply disruption will not be nearly as great as they would otherwise be if these steps were not taken. In very severe disruptions, as illustrated in Chapter One by DOE Scenarios 3 and 4, large cumulative shortfalls would be left after taking all the steps recommended. Thus, supply disruptions in excess of 2 to 3 MMB/D have the potential to strain the fabric of the nation. In order to alleviate that strain, this report recommends that, for disruptions in excess of roughly 2 to 3 MMB/D, the government have available (at least until such time as other options are advanced beyond drawing-board status) a limited framework of crude oil distribution and product margin and distribution measures.

A complex contract structure connects refiners to the marketers and end consumers they serve. During severe supply disruptions, individual refiners will likely be disproportionately impacted in their access to crude oil and that disproportionate impact will be transmitted to the marketers, consumers, and regions of the country they serve. Contractual commitments may constrain other refiners, whose access to crude oil has not been as severely disrupted, from attempting to alleviate the effects on the disproportionately impacted refiners or their customers.

To those who are supporters of competitive market forces it must be conceded that, given time, the market would probably sort out these problems -- but perhaps not before severe financial impact on many refiners and marketers, and perhaps not before extensive inconvenience to many individual consumers and various regions of the country. Wide variations in product prices should also be expected across the country in response to disproportionate availability.

One emergency standby mechanism not recommended deserves special discussion, namely the reimposition of domestic crude oil price controls. Adherence to a policy of continued market pricing of domestic crude oil during normal as well as disrupted markets offers a number of advantages.

- It maintains proper signals to consumers and producers, and encourages increased production, demand restraint, and fuel switching.
- It allows the composite of domestic and imported crude oil prices to clear markets as efficiently as possible.
- It supports agreements with other oil importing governments to refrain from actions which subsidize crude oil imports, and limits the opportunity for roll-in of higher imported crude oil prices.
- It avoids pressures for cost-equalization systems like the entitlements program.
- It preserves the opportunity for a return to normal market conditions, with little or no government intervention, within a short time after the cessation of a crude oil imports disruption. Even with clear "sunset" provisions, experience has shown that domestic crude oil price controls may be extremely difficult to eliminate or phase out after a disruption.

To the extent that domestic crude oil prices rise during a disruption, the so-called crude oil "windfall profit" tax would direct a substantial percentage of the increased revenues to federal and state governments.

Those standby mechanisms that are recommended to be available to the government for dealing with the more severe supply disruptions also deserve discussion. As mentioned earlier, crude oil access may be expected to be a serious refiner concern, especially during a major crude oil imports disruption. Recognizing this concern, the study offers the controversial recommendation that a standby crude oil distribution program be available in a severe disruption to distribute available crude oil among all domestic refiners on a common national crude oil run ratio. The pricing basis for crude oil transactions among refiners required to achieve the common crude oil run ratio is designed not to provide unwarranted benefits either to buyers or sellers. Such a program would facilitate a reasonably uniform geographic distribution of the available crude oil and allow each domestic refiner an opportunity to continue serving its customers during the crisis. In order to enhance operational efficiency, no restrictions on exchanging or processing crude oil among refiners should be imposed.

It is recognized that any mandated crude oil distribution program would act as a disincentive to private stockbuilding, would require a bureaucracy to maintain the data and compliance systems necessary for successful operation, and would have the potential for building constituencies against its deactivation. Thus, implementation of a standby crude oil distribution program should occur only after a clear assessment that a major disruption has occurred. The program should include a sunset clause providing for discontinuation within a set period of time, probably three to six months. The program should also exclude provisions for distribution of initial stocks held by refiners to reduce disincentives to private stockbuilding. Objectionable features of past programs of this type such as the so-called buy/sell program and freeze rule should not be included.

Once refiners are provided reasonable access to crude oil during a severe supply disruption, the recommended strategy assumes that those refiners should continue serving their customers on a reasonably proportionate basis. Most jobbers, dealers, and large end consumers have contracts with their suppliers that would adequately address product distribution concerns in most situations. Those contracts are backed up by an extensive body of law, some of which is unique to the petroleum industry (such as the Petroleum Marketing Practices Act). Even in severe emergencies, many if not most suppliers would assure their customers of continued equitable distribution of available supplies, but some suppliers might take action, such as contract termination or market withdrawal, that would raise public concern. To address these concerns during a severe supply disruption, this study recommends that government have available the following standby measures:

- Require the continuation of product supplier/purchaser relationships for the duration of the disruption.
- Limit the designation of priority users to those required for protection of national defense and public health and safety.
- Establish a state set-aside program to provide limited volumes for distribution within each state's discretion during the crisis.

During a severe crude oil supply disruption, there is also likely to be considerable public concern for downstream "windfalls" in petroleum manufacturing, distribution, and marketing. This concern will likely be most evident immediately following a supply disruption before crude oil prices rise sufficiently to clear the market. These potential public concerns are addressed through a standby product margin limitation program. Such a program could be developed to allow refiners and marketers to continue earning adequate margins while allaying public pressures for a downstream "windfall profit" tax.

These federal standby emergency supply distribution measures for crude oil and products, as well as the product margin measures, may also be required in order to pre-empt any state or local regulatory programs to the extent they are developed to deal with national supply emergencies.

Among the important options available in dealing with oil import disruptions are emergency energy demand reduction and fuel switching measures. Although much of the "easy" conservation potential which existed in the early 1970's has already been achieved as a result of higher energy prices and mandated conservation programs, the report identifies a large number of measures which in aggregate could provide potential oil demand reductions of up to 2.3 MMB/D in an emergency. Some of the measures could be implemented voluntarily by energy consumers; others would require government actions either to facilitate or mandate implementation. Price increases which would likely occur during a severe disruption would also provide incentives for consumers to implement many of these measures to some degree.

It must be recognized that these are "best estimates" of potential savings available from these measures, and depending upon public cooperation and other uncertainties, there may be wide variations in the actual amount of such savings. Opinions were sought and obtained from various end users, academicians, and industry associations on the potential savings available from these steps. In some cases, the estimated savings, such as those from electric utility fuel switching, were significantly reduced based on advice received. The potential for savings is also likely to decrease in the future as consumers continue to respond to higher prices and to modify their energy consumption patterns.

It is recognized that there will be numerous practical impediments to the implementation of these demand management measures. The feasibility of implementing the four-day work week, for example, has been questioned by some because of problems associated with labor relations, contractual commitments, and disruption of plant operations. None of these measures will be perceived as being fair to everyone, and many consumers may feel that they will be disadvantaged by mandated programs which affect them directly. Some measures would be difficult to enforce, and compliance beyond the level motivated by higher prices could be difficult to obtain. Some steps will also impose unseen costs on the economy, such as the adverse effects which lower speed limits would have on the reduced productivity of personnel and equipment. In order to achieve the full potential of these measures, programs should be developed in advance to inform the public of the potential savings available, to encourage voluntary actions to reduce energy consumption, and to facilitate necessary relaxation of regulatory impediments in an emergency.

The report also offers recommendations on how the government might organize its emergency preparedness effort and how the experience and expertise of industry and other private sector groups can be used to enhance the total effort. The Council does not believe that it is practical or feasible for the government to maintain a fully manned or heavily manned organization on a standby basis for possible use in managing a severe oil supply emergency. Instead, the study recommends a small core group of highly competent people responsible for emergency preparedness and reporting at a high level in the DOE.

The emergency planning group's responsibilities would include the following:

- Pre-emergency planning. This would include laying out plans and developing procedures and courses of action prior to an emergency to facilitate the flexible approach recommended by this study. Proper advance preparation can prevent needless panic and anxiety when or if a serious emergency occurs and allows the plans to be properly thought through. There is, though, no intent that pre-emergency planning should lead to "cook book" formulas for handling emergencies. It is also envisioned that this planning function would have access to the advice of private sector groups through the mechanism described later in this section.

- Assisting the Secretary of Energy and the President in assessing threatened or actual oil import disruptions. The organization would utilize data collected by governmental agencies and draw on information that exists in the government, the energy industry, and elsewhere in the private sector. This governmental entity would be the focal point for the assessment of when governmental action is needed in an energy emergency and when it is not needed.

- After assessment and a decision on the need to act, this group would be responsible for developing and evaluating the appropriate response options for dealing with the emergency. This responsibility would include assisting the Secretary of Energy and the President in selecting options for implementation and also for their termination.

- The group would also be responsible for providing the basic organizational framework for coordinating emergency measures while they are operational. A key role would be in laying the foundation for and assisting in the rapid buildup of personnel from the small core staff in the event of a serious disruption.

- Finally, the emergency planning group's responsibilities would include educating the public prior to an emergency and developing plans to provide effective communications during an emergency. The importance of this role should not be underestimated. Unless the public receives credible, timely, and accurate information during an emergency, mistrust and cynicism can quickly develop, thereby undermining even the best of programs. Public acceptance of the response options selected will depend in no small way on accurate, effective communications.

As a vehicle for providing private sector input to the government energy emergency group, the study recommends that an advisory group be set up under the Federal Advisory Committee Act to serve at the request and under the guidance of the Secretary of Energy. The committee would be staffed with, or have access to, people who could provide the energy industry experience and expertise needed by the government to deal effectively with an emergency. In addition, the membership of the committee would also include a wide spectrum of other constituency views as required by the Federal Advisory Committee Act to provide a proper balance.

The advisory committee would be a source of comprehensive understanding on the workings of the energy industry, both domestically and internationally, and would assist the government in planning for emergencies by doing studies and performing analyses as needed. The committee could provide counsel and analysis in assessing the energy scene, particularly during the difficult period when a potential supply disruption is developing. In the event of an emergency, the committee could perform necessary evaluations and technical guidance on policy responses. The advisory committee would be a logical vehicle for providing the information and counsel needed by the U.S. government in fulfilling its commitments to the IEA. Further, the advisory committee can provide the vehicle for working out more fully and in greater detail the industry/government relationships for dealing with a major supply disruption.

The advisory committee is envisioned as having a flexible design, expanding in size and scope as needed to fit the situation. Technical subcommittees could be formed as needed to do special studies or serve other functions. The technical subcommittees would be formed with the concurrence of the Secretary of Energy, and all output would flow through the advisory committee.

Chapter One

EMERGENCY PREPAREDNESS PLANS FOR OIL IMPORT DISRUPTIONS

INTRODUCTION

Petroleum Outlook

Increasing supplies of oil from the Middle East and North Africa can no longer be counted on to fuel the world's rising energy demands. Various forecasters have projected that oil exports from these areas may not increase significantly over the next decade. With the long lead times required to develop alternative supplies of oil or other energy forms, oil importing nations will remain vulnerable to disruptions in supplies for at least the next decade. Oil demand in the United States is currently 17 MMB/D and has been forecast to remain at about that level through 1985. Fuel substitution and conservation, stimulated by higher oil prices, are expected to result in trends toward lower requirements for heavy fuel oil, heating oil, and motor gasoline. On the other hand, demand for diesel and turbo fuels and petrochemical feedstocks is forecast to increase. Domestic production of crude oil and natural gas liquids is projected by various forecasters to remain near 10 MMB/D through the mid-1980's. However, such projections are sensitive to exploratory drilling success and to efforts to offset normal declines in production from existing reserves. More pessimistic estimates have been offered which indicate declines in indigenous production. In either event, U.S. oil import dependence is likely to remain at about 7 MMB/D or more through 1985 and beyond.

Effects of Oil Supply Disruptions

Petroleum supply shortfalls resulting from an oil import disruption may be mitigated to a limited extent by implementing emergency supply measures such as temporarily increased domestic crude oil production, substitution of other available fuels, and drawdown of inventories of privately or publicly held oil stocks. In a major import disruption, however, it is anticipated that a substantial supply shortfall will remain, even after implementing all feasible supply options.

In this situation, there are a number of options which may be considered for reducing demand for petroleum products and/or allocating among consumers the reduced level of supplies which are available. These range on the one hand from competitive market mechanisms, to complex systems of government controls on the other. However, any substantial shortfall of petroleum will have painful economic effects, regardless of the options employed to manage that shortfall. These effects include the following:

- World oil prices will rise, resulting in higher prices for petroleum products and a higher rate of inflation in the United States.

- Increased expenditures for petroleum will probably reduce total demand and output of other sectors of the economy.

- The Gross National Product is likely to be reduced and unemployment likely to be increased.

- Higher petroleum prices will lead to higher prices for other products, higher wages, and increased federal outlays for indexed transfer payments.

- Inconveniences and hardships for various sectors of the economy will likely occur.

It should be noted that the "fairness" of any emergency management strategy depends upon individual perceptions, and no particular option is likely to be perceived as being "fair" to all consumers, suppliers, regions, or sectors of the economy. Some redistribution of income would occur under any demand management option. Income would be transferred from petroleum consumers to foreign petroleum producers. Within the United States, there would also be a transfer of income among sectors of the economy or classes of consumers. In the absence of domestic crude oil price controls, there would be a transfer of income to domestic producers. However, under existing tax laws it is estimated that about 80 to 90 percent of the revenue from higher domestic crude oil prices would accrue to federal and state governments in higher royalties and severance, income, and excise or "windfall profit" taxes. (See Appendix E for further explanation of the distribution of additional revenue from crude oil price increases.)

Sudden major interruptions of imported petroleum supplies may also, due to the unevenness of their impacts, create exceptional hardships for individual consumers and suppliers. A complex contract structure links refiners to the particular marketers and consumers that they serve. During severe supply disruptions, individual refiners will likely be disproportionately affected in their access to crude oil supplies, and this disproportionate effect will be transmitted to particular marketers, consumers, and regions of the country.

This study attempts to deal with the problem of minimizing the potential hardships and disruptive economic effects that may result from an oil import interruption.

DOE Scenarios

Five oil import disruption scenarios, summarized in Table 1, were provided by the Department of Energy as a basis for analysis in the study. The scenarios range in magnitude from a 1.0 MMB/D to a 4.6 MMB/D oil imports curtailment to the United States and in duration from six to 12 months. Two of the scenarios (1 and 1A) postulate interruption of supplies only to the United States, and three scenarios (2, 3, and 4) assume interruptions involving both the United States and other importing nations.

TABLE 1

Oil Import Disruption Scenarios*

Case	Description	Duration	IEA Sharing Activated	Imports Reduction (MMB/D) Free World	Imports Reduction (MMB/D) U.S.
1	OAPEC† Plus Iran Export Interruption of 5 % Against U.S. Only	6 Months	No	1.0	1.0
1A	OAPEC Plus Iran Export Interruption of 10% Against U.S. Only	6 Months	No	2.0	2.0
2	OAPEC Plus Iran Export Interruption of 25%	6 Months	Yes	4.9	2.2
3	OAPEC Plus Iran Export Interruption of 40%	12 Months	Yes	7.8	3.2
4	Persian Gulf Interruption of 50-100%	3 Months @ 100% 3 Months @ 75% 6 Months @ 50%	Yes	16.4 @ 100% 12.3 @ 75% 8.2 @ 50%	4.6 @ 100% 3.5 @ 75% 2.5 @ 50%

---

*Caveats to Scenarios: In a potential interruption of imported oil supplies, government and private decision-makers are faced with a variety of uncertainties. These include the volume of the disruption, its likely duration, its potential economic effects at home and abroad, its military and foreign policy implications, and a host of others. The seriousness of a potential disruption cannot be defined with reference to only one or two of these criteria. A small disruption with major foreign policy effects or significant impact on the world price of oil could be more serious from the point of view of the United States than a disruption which is larger by volume of import reduction but whose duration is likely to be short and whose secondary effects are minimal.

Only in the context of a specific disruption and with as much information available as possible can decision-makers reasonably relate policy options to specific conditions. Thus, it is not possible to precisely define which policy option is appropriate in each possible real life situation. However, a seriatim of policy options can be provided for consideration by decision-makers at the time of the disruption based on an evaluation of their relative appropriateness.

While the DOE scenarios have been helpful in providing some rough parameters for analysis, they are not meant to provide a "cookbook" approach to management of disruption responses. Specifically, because the scenarios include information on only two important types of information (volume and duration), they do not fully define the real world scenarios decision-makers are likely to face. Moreover, even this information may not be known with precision until after the disruption is at an end.

†Organization of Arab Petroleum Exporting Countries.

In Scenarios 2, 3, and 4, the International Energy Agency crude oil sharing mechanism is assumed to be activated. The IEA was formed in 1974 in order to provide an international forum among oil importing nations of the free world. It provides for a mechanism to assess the level and potential impacts of an emergency supply disruption and a system by which participants share in the impacts of such disruptions. The system is based in part on the efforts and cooperation of many international oil companies in helping to facilitate the sharing mechanism. The IEA sharing system has never been activated and tested under actual emergency conditions, but the scenarios assume that all IEA participants honor the agreement and that the sharing system results in the U.S. imports reductions indicated. Additional discussion of the IEA system is contained in Chapter Eight and Appendix M.

At the outset of an actual supply disruption, there would be a great deal of uncertainty as to the magnitude and duration of the emergency. The point is frequently made that scenarios may be flawed or have serious limitations when used in studies of this nature. Scenarios are seldom complete in detail and require important assumptions. For example, an assumption might be made that U.S. crude oil and product inventories are "normal" at the outset of an interruption. Obviously, higher or lower initial inventories would alter the effects of the interruption on the nation. Some further caveats to the use of scenarios are discussed in a footnote to Table 1.

Despite these limitations, the DOE scenarios were used throughout the development of the study and proved to be a valuable tool. First, the scenarios provided a common point of reference for discussion by focusing an infinite variety of possible import disruptions into five different situations covering a wide range of possibilities. Second, the scenarios made it possible to quantify the effects of various emergency supply/demand response options and to test them for reasonableness. Third, the quantification also made it possible to examine the ability of the nation's supply and distribution systems to operate under constrained conditions. While scenarios do have serious limitations that will be quickly recognized, they have been an important and useful device in arriving at the recommendations of this study.

This study analyzes steps available to increase supplies and to deal with changes in demand in the event of a disruption in oil imports. Additionally, the study looked at various approaches to reduce the demand for products and for allocating available supplies of both crude oil and products. From this analysis, the study makes a number of recommendations. These recommendations include steps which need to be taken now to prepare for an emergency, as well as strategies for dealing with an emergency once it occurs.

The underlying analyses for these recommendations, as well as specific actions which need to be taken now, are described in subsequent chapters. However, a summary is provided here as a basis for understanding the recommendations made at the end of this chapter. A more complete understanding can be gained from the remaining chapters and appendices of this report.

EMERGENCY SUPPLY FLEXIBILITY

The analysis of supply flexibility covered four major areas:

- Emergency oil and gas production
- Emergency refining and logistics operations

- Emergency fuel switching from oil to more plentiful fuels -- gas, coal, and nuclear

- Security stocks, including the Strategic Petroleum Reserve, as well as private inventory reserves.

Emergency Oil and Gas Production

Crude Oil

Domestic crude oil fields are currently producing at maximum efficient rates as defined by state and federal regulatory agencies. A limited number of fields have the capability to produce at somewhat higher rates for short periods in an emergency situation without substantially impairing estimated ultimate recovery of the reserves (as discussed in Chapter Four). Emergency surge production will require approval by the appropriate regulatory bodies to exceed maximum allowable rates. Some relaxation of conservation and environmental rules with regard to gas flaring and emissions limitations will also be necessary.

The current maximum additional domestic crude oil capability deliverable to refineries on a temporary emergency basis is about 320 thousand barrels per day (MB/D). Most of this capability comes from the Prudhoe Bay Unit in Alaska and the East Texas field. An additional 80 MB/D (180 MB/D in 1982-1985) might be made available by means of additional pumping capacity on the Trans-Alaska Pipeline System (TAPS). These figures include emergency production capability from the Naval Petroleum Reserves (NPR), which by government estimates is limited to about 16 MB/D from the Elk Hills field (NPR-1). Four to six months would be required in order to reach maximum surge capacity. The length of time these rates could be sustained is uncertain, but some decline could be expected over a period lasting more than 12 months.

As the reserves in these fields are depleted through normal production and TAPS capacity is filled by new production, the capability for surge production without additional TAPS pumping capacity will decrease. By 1985, surge capability will be limited to about 140 MB/D, mostly from the East Texas field, unless additional pumping capacity is installed on TAPS. Of course, new discoveries may add to surge capacity in the future.

Natural Gas

Natural gas can be used as an emergency substitute for fuel oil in industrial and utility boilers and furnaces which are equipped for dual-firing and which have access to natural gas distribution facilities. In Chapter Two of this study, opportunities were identified for making an additional 350 to 500 MB/D of oil available by switching to natural gas. To supply this demand, potential sources of additional gas were examined. Additionally, Chapter Two identifies measures which would free gas for use in fuel switching. The amount of emergency gas supplies varies by season. Chapter Five identifies approximately 600 thousand barrels per day crude oil equivalent (MB/D COE)[1] which could be made available from summer swing capacity in the summer, when less gas is required under normal conditions. In the winter, 300 to 350 MB/D COE of gas can be drawn from immediately usable underground storage in addition to normal withdrawal. In short, the additional production from swing capacity appears adequate to satisfy additional gas demand resulting from fuel switching in the summer. In winter, gas available from storage can provide a major portion of this potential demand. However, some winter gas demand reduction will be necessary if the maximum oil-to-gas substitution capability is to be realized.

The 1979 NPC study entitled Petroleum Storage and Transportation Capacities indicated that the existing gas transmission system, which in 1977 operated on an overall daily average basis at 68 percent of capacity, should have the capability to absorb additional volumes. However, absent knowledge of specific oil customers with flexibility to convert to gas and specific geographic areas of increased production, it is impossible to state with certainty that transportation bottlenecks will not occur. This is especially true during intermittent periods of peak delivery in the winter, when portions of the nation's existing transmission and distribution system may be filled to capacity. In addition, in Petroleum Administration for Defense (PAD) V (West Coast), limited winter storage capacity may necessitate transportation of additional gas from the Gulf Coast to California. This is an area which may deserve additional study as a part of ongoing studies for future emergencies.

Some additional gas availability might be obtained by regulatory action to accelerate the determination of initial allowables and permitting on new wells and suspending the requirement to make up previous overproduction on existing wells.

In summary, emergency oil production can replace 300 to 400 MB/D of imported oil in case of a disruption. However, it is likely to take four to six months to achieve this additional production. Thus, this option may not be appropriate for disruptions of short duration. Additional gas can also be made available in an emergency. Its use to free oil by fuel switching is discussed later in this chapter and in Chapters Two and Five.

Emergency Refining and Logistics Operations

Under emergency conditions involving substantial denial of imported oil, U.S. refiners may have to make major adjustments in product yields, the overall level of equipment utilization, the mix of crude oils processed at individual refineries, and the specifications for some products. It appears that U.S. refineries have adequate processing flexibility to meet potential emergency product

---

[1] "Crude oil equivalent" is a measurement that can be applied to all forms of energy based on their heat content relative to that of oil.

slates for all the study scenarios (see Chapter Six). To the extent that demand reductions are taken proportionally for all products, the required adjustments in refinery yields are obviously minimized. On the other hand, most U.S. refineries have substantial capability to adjust yields, and this capability can be utilized to selectively take the shortfall in products which are determined to have the least adverse impact on the nation's economy. Refinery flexibility to reduce gasoline yields was analyzed by the NPC Committee on Refinery Flexibility.[2] This study concluded that "in the event of an import supply interruption in the range of 2 to 5 million barrels per day, there is sufficient flexibility in the U.S. refining system to reflect 75-80 percent of the volume loss in reduced motor gasoline output as opposed to other products such as heating oil."

A major crude oil curtailment may reduce average utilization of some refinery processes, such as crude oil distillation, to near or below minimum operable levels. Under these conditions, extended shutdown of unutilized capacity may be more practical, economical, and energy efficient than attempting to operate all units at reduced throughputs. Government policy should not impede processing agreements, exchanges, and similar arrangements essential to enhancing refining efficiency and flexibility in an emergency.

It is doubtful that sulfur specifications could be met for all products under emergency conditions for operational reasons. For example, as reformer feed is reduced to selectively lower gasoline yields, hydrogen supply in many refineries may be inadequate to meet the needs for desulfurization. The availability of a standby government-approved plan for relaxation of fuel sulfur specifications and exhaust gas sulfur limits would enhance flexibility for emergency operations and has the potential for reducing oil demand by about 50 MB/D.

Producibility of diesel fuel, turbo fuel, and heating oil could also be enhanced by emergency relaxation of product quality specifications. The need for standby emergency specifications has been reviewed with the American Society for Testing and Materials (ASTM). ASTM is the proper organization to establish emergency specifications among producers and users and has authorized steps to develop such emergency specifications and procedures for rapid response balloting.

A major oil import disruption would create significant dislocations in U.S. petroleum logistics systems and require adjustments to maintain efficient operations. There appears to be enough flexibility in the logistics systems for finished and unfinished products and for natural gas liquids to accommodate the redistribution of supplies during a disruption (see Chapter Seven). Crude oil systems also appear adequate with the exception of the need during the crisis for additional west-to-east movement of PAD V crude oils

---

[2] Refinery Flexibility, National Petroleum Council, December 1980.

required to rebalance crude runs in PADs I-IV. To the extent that U.S. flag tankers are not sufficient for this movement, the constraint could be alleviated on an emergency basis by government waivers to allow the use of foreign flag tankers in this service and/or to allow the use of subsidized U.S. vessels (subject to semiannual review), and by exchange of PAD V crude oil with contiguous or noncontiguous foreign nations. Either type of exchange would require considerable time to obtain the necessary clearances, and the latter type would also require legislative action. This highlights the national interest benefits of long-term debottlenecking of west-to-east crude oil logistics systems.

In summary, with some regulatory accommodation, particularly on west-to-east crude oil movements and on quality specifications, there appears to be adequate refining and logistical flexibility to meet changed demand patterns resulting from an oil import interruption. In fact, future oil emergencies will be characterized by a shortage of raw material (crude oil) creating excess capacity in processing and transportation facilities. Hence, an objective of emergency strategies should be to permit use by industry of these existing facilities in the most efficient manner.

Emergency Fuel Switching

Opportunities to make additional oil available by switching existing oil uses to other fuels are discussed in detail in Chapter Two. The principal opportunities and the potential oil savings are:

- Conversion from oil to gas in the electric utility sector (240 MB/D) and in the industrial sector (260 MB/D)
- Wheeling of electricity from coal-fired and nuclear plants into areas served by oil-fired plants (30 MB/D)
- Increased electricity generation from nuclear reactors by maximizing the use of existing units and by accelerated licensing of units in areas served by oil-fired plants (30 MB/D)
- Increased electricity imports from Canada (30 MB/D)
- Conversion of oil-fired industrial boilers to coal (50 MB/D).

These measures appear attractive in that they could generally be implemented quickly and would provide substantial reductions in oil demand without reducing total energy supply if the alternate fuels are in adequate supply.

Realization of the maximum fuel switching will require 500 MB/D COE [2.8 billion cubic feet per day (BCF/D)] of additional natural gas supplies. As mentioned earlier, approximately 600 MB/D COE of additional supplies could be available in summer, but emergency supplies in winter are likely to be limited to 300 to 350 MB/D COE.

Hence, maximum fuel switching in winter would have to be accompanied by some gas demand reduction measures to free additional natural gas supplies. Deliverability of emergency gas supplies may be a problem in localized areas due to transmission or distribution system bottlenecks.

To obtain the maximum potential benefits from some of these measures changes to certain laws or regulations would be required, such as temporary relaxation of requirements under the Clean Air Act or Power Plant and Industrial Fuel Use Act. In addition, the cooperation of the various federal, state, and local government agencies which regulate utilities would be required.

Security Stocks

Security stocks consist of inventory reserves, such as the publicly owned Strategic Petroleum Reserve, and those held by private suppliers and consumers above levels needed for normal operations. Security stocks provide flexible emergency supply options primarily because they can be withdrawn at high flow rates to meet immediate needs (see Chapter Three). Other types of emergency supply options, such as standby production capability, are limited in their withdrawal rate and, for short periods of production, require a much higher investment commitment to achieve the same supply capability.

Strategic Petroleum Reserve

The potential benefits of strategic stockpiles in emergency preparedness planning were recognized in two previous NPC reports: Emergency Preparedness for Interruptions of Petroleum Imports into the United States, September 1974, and Petroleum Storage for National Security, August 1975. Many of the recommendations made in these previous studies have been implemented and form the basis for the existing federal Strategic Petroleum Reserve. Presently, SPR capacity is about 250 million barrels with inventories of approximately 120 million barrels. Fill rates of 100 to 300 MB/D are currently under way. Current government plans for development of the SPR up to a capacity of 750 to 1,000 million barrels by 1990 are considered realistic in view of the present physical constraints and the time required to build the necessary additional storage capacity and acquire oil supplies to fill this capacity. The immediate focus should be on filling the current and projected reserve capacity as quickly and efficiently as possible. The government should take all reasonable steps to maintain or accelerate the SPR development and fill rate without causing a disruption in oil markets. Government oil acquisition procedures should be streamlined and sufficiently flexible to utilize a mix of government-owned reserves, term supply contracts, and spot purchases as market conditions permit.

Distribution of SPR stocks in a very severe emergency may be accompanied or preceded by a national crude oil sharing program. Under this circumstance, SPR stocks should be distributed in the same manner as any other crude oil sales to ensure fair and equitable access by refiners. In the event a drawdown of SPR stocks is deemed appropriate and necessary at times when a crude oil sharing program is not in effect, the distribution should be conducted through an auction bid system. These approaches will return to the federal government full value for its investment and ensure efficient utilization of limited stocks while minimizing administrative complexity and potential abuses and subsidies.

While decision rules for SPR use should not be automatic or pre-determined, SPR stocks above about 200 million barrels should be readily available for use in cushioning the impacts of supply disruptions of varying sizes. However, strategic stocks below levels of about 200 million barrels should be held for use in very severe disruptions to meet national security, health, or safety needs. In addition, current SPR fill itself represents a source of supply flexibility in a shortfall. Crude oil supplies already contracted for filling the SPR could be diverted to the market, providing additional oil supplies promptly during a disruption.

Private Inventories

Privately held petroleum stocks can provide a limited but useful buffer against the sudden disruption of oil imports. The existing petroleum distribution system, however, was designed for the efficient movement of large volumes of crude oil and unfinished and finished products. It was not designed to hold a static stockpile of strategic supplies for major interruptions in the flow of oil imports. In this huge and complex transportation and storage network, a large amount of tankage is necessary to maintain flexibility for smooth day-to-day operation of the supply system. Attempts to set aside a portion of the existing system for strategic storage without substantial construction of additional facilities would disrupt the efficient operation of the petroleum distribution system.

However, in view of the likelihood of future disruptions in oil imports and the limited near-term availability of stocks in the Strategic Petroleum Reserve, increased holding of inventories by suppliers and consumers is desirable. Oil price and allocation controls act as disincentives to the building of private stocks by discouraging profit-motivated inventory acquisitions. The recent removal of price and allocation controls was an essential first step toward removal of these disincentives, but it is equally as important that any legislation which provides authority for standby emergency measures explicitly exclude initial privately held stocks from any distribution program which might be implemented. Even with the removal of price and allocation controls, the existence of what economists call "external benefits" from strategic storage suggests that private inventory accumulation may nevertheless remain below levels desirable from an overall emergency preparedness standpoint in the absence of tangible government incentives. Petroleum security stocks serve to protect the broadest national interest against a threat to its economic well being and military security. Since these benefits accrue to the nation as a whole, they may justify a system of government incentives to encourage a level of privately held stocks higher than would otherwise prevail. The costs and benefits of providing such incentives for private stocks is a complex subject which deserves further study by the government as a potential supplement to publicly owned SPR stocks.

This study assumes that private stocks, by definition, are utilized on a voluntary basis in response to supply and demand conditions.

EMERGENCY DEMAND REDUCTION AND SUPPLY DISTRIBUTION

In severe import disruptions, substantial supply shortfalls will remain, even after utilizing all feasible emergency supply options. There are a number of options that may be considered either individually or in combination for reducing petroleum products demand and/or allocating among consumers the reduced level of available supplies. Despite the natural inclination to adopt measures to "correct" the problems caused by an interruption, experience over the past decade indicates that many such measures intended to alleviate problems can, in fact, have the opposite effect. Much information and analysis indicate that controls, no matter how clearly or cleverly designed, cannot adequately anticipate changing demand requirements during supply disruptions and do not permit crude oil and products to flow as efficiently as the competitive market system. Allowing the market to balance supply and demand, even during a supply disruption, provides the maximum incentives for conservation and production. It allows available products to go to those uses with the higher economic value, thereby minimizing the loss to the economy as a whole. Thus, this study is based on the belief that the competitive market system is capable and best able to respond to disruptions and should be permitted to operate to the maximum extent practicable. This conclusion is generally consonant with much recent research on emergency preparedness issues, as listed in Appendix C.

This primary reliance on the competitive market is reached with the clear recognition that, despite emergency supply measures, in a large disruption, market clearing prices could be perceived as very high. The study concludes that hardship and equity considerations are best dealt with by using increased government revenues resulting from the higher prices to mitigate these concerns, rather than attempting to control directly the allocation and prices of petroleum products. This approach will necessitate advance consideration by government of standby programs to accomplish this recycling of revenues. Otherwise, public pressure for relief is likely to result in extensive controls on both the oil industry and consumers which will probably worsen the problems caused by a disruption.

The NPC recognizes, however, that some levels of interruption considered herein are well beyond anything in the nation's experience. This led to a general conclusion that while strategies to deal with oil import disruptions should rely to the maximum practicable extent on market mechanisms, there should also be available a variety of standby options of increasing severity to deal with shortages of increasing magnitude. Therefore, in addition to the emergency supply measures, this study considered a number of demand reduction and supply distribution options:

- Voluntary or mandated demand reduction steps
- Petroleum industry regulation
- Consumer tax and allocation measures.

Voluntary or Mandated Demand Reduction Steps

A large number of demand reduction measures could be employed on either a voluntary or mandatory basis to reduce oil demands, with varying degrees of difficulty in implementation. The potential oil demand reduction from measures considered to have minimum difficulty in implementation is estimated to be about 900 MB/D, with an estimated additional 300 MB/D with moderate difficulty, and another 300 MB/D from measures with major difficulty. These measures are discussed in detail in Chapter Two. It must be recognized that these are best estimates of potential savings, and depending upon public cooperation and other uncertainties, there may be wide variations in timing and in the amount of such savings. Examples of steps judged to have minimum difficulty in implementation and their potential oil savings include:

- Increased carpooling (380 MB/D)
- Reduced speed limits (90 MB/D)
- Driver education, vehicle inspection, and maintenance (155 MB/D)
- School bus utilization (60 MB/D)
- Reduced personal travel (50 MB/D)
- Thermostat management (50 MB/D).

Measures judged to have moderate difficulty in implementation include:

- Odd-even auto and light truck fuel sales (145 MB/D)
- Vehicle use stickers (50 MB/D)
- Increased airline seat load factors (85 MB/D).

Further steps judged to have major difficulty in implementation include such items as:

- Banning weekend fuel sales (240 MB/D)

- Instituting the four-day work week (35 MB/D)
- Banning the recreational use of fuels (30 MB/D).

Programs should be developed in advance for use during an emergency to inform the public of the potential savings available and to encourage voluntary actions to reduce energy consumption. The price increases which may occur during an imports disruption would provide an incentive for consumers to implement many of these measures to some degree.

Consideration should be given to which, if any, of these demand reduction measures should be mandated and under what conditions. It is recognized that there will be numerous practical impediments to the implementation of some measures. The feasibility of implementing the four-day workweek, for example, has been questioned by some because of problems associated with labor relations, contractual commitments, and disruption of plant operations. Mandated demand reduction measures may also impose unseen costs, as users of petroleum shift to more costly modes of operation. For example, reduced speed limits might save fuel but would increase costs related to reduced productivity of personnel and equipment. Additionally, many of these measures would be difficult to enforce, and compliance beyond the degree motivated by higher prices may be difficult to obtain. If voluntary and mandated measures are deemed to be potentially desirable, standby measures for implementation in an emergency should be developed in advance of the actual crisis.

Petroleum Industry Regulation

In addition to the demand reduction measures directed toward end users, there is the obvious question of what regulations should be imposed on petroleum industry operations. Possibilities include price and distribution controls on crude oil, as well as margin and distribution controls on products. These regulatory structures can be grouped into two basic approaches. One approach is to impose comprehensive price/margin and distribution controls throughout the industry from wellhead to service stations. Use of this approach is also likely to lead to restrictions on individual consumers as well. A second approach is to allow the competitive market to operate to the maximum degree practicable. Limited controls would be imposed flexibly, only to the extent necessary to effectively manage the crisis. A crucial difference between these two approaches lies in whether an attempt is made to limit domestic crude oil prices.

Limitations on Domestic Crude Oil Prices

Rising crude oil prices will present the government with a choice of maintaining a policy of market pricing of domestic crude oil or imposing domestic crude oil price limits. To the extent crude oil prices rise during an oil supply disruption, it is estimated that the crude oil excise tax, or "windfall profit" tax, and other existing taxes and royalties would direct approximately 80 to 90 percent of the overall domestic crude oil price increase to government (see Appendix E).

Continued adherence to a policy of market pricing of domestic crude oil during even severe supply disruptions would offer a number of advantages. Market pricing of domestic crude oil would give proper signals to both consumers and producers -- encouraging increased production, demand restraint, and fuel switching. Market pricing of domestic crude oil would allow the composite of domestic and imported crude oil prices in the United States to rise to clear the market as efficiently as possible. This would preserve the opportunity for a return to normal market conditions, with little or no government intervention, within a short time after the crude oil imports disruption. Even with clear sunset provisions, domestic crude oil price controls (and resulting crude cost equalization and entitlements systems) may be extremely difficult to eliminate or phase out after the emergency. Experience over the past several years reinforces this concern.

If the United States were to impose domestic crude oil price limits during a shortage, this action could be expected to increase the demand for limited crude oil supplies. Price controls would allow opportunity for the roll-in of higher imported crude oil prices which, in turn, could be expected to put upward pressure on international crude oil prices. Because the United States imports about 25 percent of the crude oil traded on the international market, by far the greatest proportion imported by any single nation other than Japan, crude oil demand in the United States can have a significant impact on international markets.

Once higher prices are achieved, crude oil exporting nations have demonstrated in the past an ability to maintain crude oil prices at the higher level. These higher prices could have an adverse effect on the U.S. economy and possibly an even greater impact on the economies of other oil importing nations with greater dependence on oil imports as an energy source. Limiting domestic crude oil prices would tend to go against agreements with other oil importing country governments to refrain from actions which subsidize crude oil imports. In addition to the direct economic effects, any system of limiting domestic crude oil pricing would require a complex regulatory system to distribute the benefits of controlled crude oil prices among the domestic refiners with resulting pressures for exceptions and subsidies.

In sum, limitations on domestic crude oil prices, even in severe shortfalls, have negative consequences which appear to outweigh any political or equity justification for their imposition. Equity considerations can be dealt with more directly and efficiently by government programs funded by increased tax revenues from domestic crude oil price increases. Additionally, it is likely that limitations on domestic crude oil prices would also necessitate extensive additional control systems, such as rationing and entitlements, in an attempt to offset some of the consequences of below-market crude oil prices. Based on these factors as well as on extensive unsatisfactory past experiences, this study concludes that any emergency controls or regulations on the petroleum industry should be the minimum necessary to effectively manage the crisis.

Emergency Standby Crude Oil Distribution

Crude oil access may be expected to be a serious refiner concern during a major crude oil imports disruption. Individual refiners' crude oil access will likely be affected disproportionately due to loss of the imported crude oil source or due to participation in the IEA crude oil sharing agreement. Most refiners have product supply contracts with the jobbers, dealers, and commercial consumers they serve. Through this contract structure, the disproportionate impact of a disruption on individual refiners could be transmitted downstream to the respective customers and regions of the country they serve. While these impacts could be mitigated and buffered by fuel switching, demand restraint, and drawdown of private stocks, there is concern that these steps may not be sufficient during the larger interruptions of petroleum imports considered. The Uniform Commercial Code requires a seller to fulfill contractual commitments to existing customers before seeking new business or taking on new customers that may have been served by other sellers. In a severe supply disruption, even those refiners whose crude oil access has not been significantly affected may have only sufficient supplies to meet contractual commitments to their existing customers.

In the event of a severe oil import disruption, the disproportionate impacts could be mitigated through the use of a standby crude oil distribution program designed to distribute available crude oil among all domestic refiners on a common national crude oil run ratio. The pricing basis for crude oil transactions among refiners required to achieve the common crude oil run ratio should be designed so as not to provide unwarranted benefits either to buyers or sellers. Such a program should provide for a reasonably uniform geographic distribution of the available crude oil and allow each domestic refiner an opportunity to continue serving its customers. This recommendation is made even with the knowledge, based on prior experience, of the distortions created and the difficulties of administering such programs in an efficient manner.

Any mandated crude oil distribution program would act as a disincentive to seeking diversified supply sources and to private stockbuilding, would require a bureaucracy to maintain the data and compliance systems necessary for successful operation, and would have the potential for building constituencies against its deactivation. Thus, implementation of a standby crude oil distribution program should be taken only after a clear assessment that a major disruption has occurred. The program should include a sunset clause providing for discontinuation within a set period of time, probably three to six months. The program should also exclude provisions for distribution of initial stocks held by refiners to reduce disincentives to private stockbuilding. Included in Appendix F is a more complete discussion of the possible features, benefits, and shortcomings of a standby crude oil distribution program, as well as the analysis that supports the recommendations presented at the end of this chapter.

Emergency Standby Product Distribution

Most jobbers, dealers, and commercial consumers have a product supply contract with their petroleum product suppliers. These contracts generally include terms dealing with contract volumes, product price, credit terms, and force majeure in the event of supply disruptions. Existing contracts and supplier assurances would adequately address product distribution concerns in most situations. The existing contract structure is backed by an extensive body of law. The Petroleum Marketing Practices Act generally prohibits arbitrary termination of contracts with branded motor fuel jobbers/dealers and deals with some aspects of market withdrawal. The Uniform Commercial Code requires fair and reasonable allocation of available volumes where inadequate to meet contract obligations. The antitrust laws prohibit attempted monopolization (Sherman Act), price discrimination (Robinson Patman Act), and unfair methods of competition (Federal Trade Commission Act). Many suppliers voluntarily allocated middle distillate among their customers pursuant to their contracts with generally favorable experience during the supply disruption in 1979 following the Iranian revolution.

With no further regulation even in an emergency, many, if not most, suppliers would likely again assure their customers of continued equitable distribution of available supplies. On the other hand, some suppliers might take actions that would raise public concern. Hence, during severe crude oil imports disruptions, pressures may build for protection beyond that supplied by supplier/purchaser contracts and the existing contract and antitrust law. These pressures are likely to be driven by concerns over market withdrawals and nonrenewal of jobber/dealer or commercial account contracts.

In an emergency, should government intervention in product supplier/purchaser relationships be deemed necessary, intervention should be limited to mandating the continuation of existing product supplier/purchaser relationships and providing for priority user designations. Under the priority user program, classifications should be designated by the government and should be strictly limited to the protection of national security, health, and safety interests. Under such a program, priority users should generally be assured of only their base period volumes. The priority user program should be complemented by a state set-aside program to provide limited volumes for distribution within each state's discretion in meeting priority and emergency needs, such as increased needs for mass-transit during the crisis. As in the case of standby crude oil distribution measures, these recommendations are made even with the knowledge, based on prior experience, of the distortions created and the difficulties of administering such a program in an efficient manner. Action beyond this level is considered unnecessary and would likely be more responsive to special interest concerns than the overall public interests and could easily lead to the building of constituencies against the discontinuation of the market intervention. Federal standby emergency supply disruption measures should be accompanied by specific provisions that the terms of these programs pre-empt any state or local programs to the extent they are in conflict with provisions of the federal program.

Included in Appendix G is a more complete discussion of the possible features, benefits, and shortcomings of a standby product distribution program, as well as the analysis that supports the recommendations at the end of this chapter.

Emergency Standby Product Margin Limitations

During a crude oil supply emergency, there may be considerable public concern over potential windfalls in petroleum product manufacturing, distribution, and marketing. This concern would likely be most evident immediately following an oil import disruption, before crude oil prices have risen sufficiently to clear the market. Public concern may also be voiced over the actions of individual refiners or marketers during a supply disruption that the public perceives to be generating windfalls.

These potential public concerns could be addressed through a standby product margin limitation program. Such a program could be developed to allow refiners and marketers to continue earning adequate margins while allaying public concern over downstream windfalls. Included in Appendix G is a further discussion of the possible features, benefits, and shortcomings of a standby margin limitation program, as well as the analysis that supports the recommendations at the end of this chapter.

Even a limited framework of margin and distribution measures such as that described herein carries with it costs in terms of regulatory complexity, as well as suboptimum use of petroleum at a time when it is in short supply. Hence, this study recommends that limited crude oil and product distribution and margin controls normally be considered only in the case of a very severe crude oil shortfall. The way in which these emergency standby measures fit into an overall emergency management system is discussed at the end of this chapter.

Consumer Tax and Allocation Measures

In addition to regulatory measures dealing primarily with operations of the petroleum industry, there are a number of measures which are aimed at reducing final consumer demand or allocating available product to specific end users. These include consumption or excise taxes, import fees or tariffs, and coupon rationing.

Emergency Consumption Taxes/Import Fees with Rebate Systems

This option would impose an emergency tax to increase the price of petroleum products above the level which would otherwise exist as a means of reducing demand to balance the reduced supply level. This type of tax differs from an "excess profits" tax which would not directly raise product prices above the market level or curtail demand. The tax could be an excise tax on all petroleum products or on one or more selected products, such as gasoline. Alternatively, an import fee or tariff could be applied to petroleum imports. Various other taxes or combinations of taxes could be designed to give similar results. Government receipts from such a tax would be very large and could be rebated to the public to mitigate, to some extent, the income effects of higher product prices on consumers. Tax revenues could be rebated through various systems of reductions in income or social security taxes or increases in transfer payments. An excise tax on gasoline, with the revenue rebated to owners of registered vehicles, is an alternative to coupon gasoline rationing.

The emergency tax/rebate option has the advantage of being a market-based mechanism to balance supply and demand, and might potentially result in greater economic efficiency than allocation and price controls. The complex regulatory and administrative burdens of allocation and price controls or rationing would be avoided. Once approved by Congress, a consumption tax, if imposed only on gasoline, could be implemented rapidly as the collection system is already in place (rebating systems, however, are not). Many economists believe that early imposition of high taxes on imports, if coordinated among most major importing nations, would restrain the opportunity for foreign producers to raise crude oil prices sharply during a disruption.

On the other hand, the appropriate level and timing for a tax to balance supply and demand during the emergency would be difficult to determine. An excessive tax rate could exacerbate the adverse economic effects of the shortfall. Frequent changes in the level of tax may be needed to maintain a balance without the adverse economic effects of depressing demand more than necessary. Congress is unlikely to delegate taxing authority; thus, legislation would be required to implement or adjust the tax. Past experiences suggest that imposition of a consumption tax in the face of rapidly increasing prices would be very difficult politically. The basis for distribution of the revenue from the tax would be a major point of contention. Once in place, a strong constituency may be established for continuation of the tax beyond the period of the imports disruption. A consumption tax imposed by the United States alone might have only marginal effects on world oil prices and could cause the United States to bear a disproportionate share of the burden of the disruption. Revenue from the tax would have to be rebated rapidly and efficiently to minimize the adverse effects on the economy.

Coupon Rationing Plans

Most discussion of standby rationing plans has centered on rationing of automobile motor fuel only. Under such a plan, coupons would be issued periodically to owners of registered vehicles in quantities determined to be appropriate for the extent of the shortage. The price of rationed products would be held below the market clearing price either through price controls or by limiting the number of coupons, and trading of coupons in a "white market" would be permitted.

Rationing would provide a direct and quantitative reduction in consumption with a uniform method for distributing the right to purchase product. Opinion polls indicate that coupon rationing appears to have fairly broad public support and, at least initially, might be generally perceived as equitable. Rationing could result in fewer and shorter gasoline lines than allocation programs. Consumers of average quantities would be able to obtain product at prices below the market clearing level, while those persons willing and able to pay the market clearing price for the privilege of using more than the average amount could obtain additional motor fuel by purchasing coupons on the "white market" from those willing to use less. However, the implementation of a standby rationing plan would be difficult and costly and would require at least several months to be put into operation. A new national "currency" would be established, with major requirements for handling, distribution, and security. A high potential for fraud and counterfeiting would probably be created. Product distribution would not necessarily match the distribution of coupons within the "white market." Thus, long lines may occur even with rationing, particularly during the early stages, perhaps leading to a collapse of public confidence and cooperation with government emergency management measures. Rationing tends to focus demand reduction on gasoline, possibly causing other, less costly, conservation measures in other products to be foregone.

As with standby oil distribution and margin limitation measures, both the tax/import fee and rationing options should be considered only in the case of a severe supply shortfall. Use of these options is not specifically recommended, but this is more a matter of the state of existing knowledge and experience with these measures rather than a deliberate choice to foreclose their use. Specific concerns include the feasibility of implementing a workable coupon rationing system and the increase in the adjustment cost an emergency tax measure would impose at a time of rapidly increasing worldwide product prices resulting from an oil supply interruption. The NPC recognizes the complexity and need for further study of the tax/import fee and coupon rationing options to determine whether these approaches may represent viable alternatives to a limited framework of margin and distribution controls for possible use in a severe disruption. These studies should be undertaken promptly by a wide range of knowledgeable institutions and individuals. This recommendation should not be construed as supporting any particular level of DOE budgeting for such programs.

Recycling of Increased Government Revenues

The unevenness and arbitrariness with which sudden disruptions impose hardships on individuals, social groups, firms, and industries pose major problems for the management of crises and for the reliance on the market mechanism. These hardships may arise from the sharp increases in energy prices that may accompany even moderate crises or from the sudden disruption of normal supply relationships that might accompany a severe and sudden loss of specific sources of crude oil supply. The social acceptability of reliance on the market mechanism (in a crisis severe and profound enough to inflict major hardships) will probably depend upon the extent to which government can deal with the inequitable distribution of hardships through other means at its disposal. It is noted in this connection that in a severe oil import disruption, existing tax laws will yield very large net revenue increases to both the federal government and some state governments as the price of oil rises. To the extent emergency consumption taxes or import fees may be imposed, these revenues may be further increased. Readiness to adjust federal and state revenues and outlays in a crisis may be an urgent requirement for both distributional and fiscal policy reasons. The study urges that the Administration and the Congress devote high priority to the identification of such distributional measures, relying primarily on monetary compensation by government (so-called rebates) to those affected particularly severely by price increases, as the method that interferes least with the allocative functions of the market.

RECOMMENDED APPROACH TO MANAGING OIL IMPORT DISRUPTIONS

Market mechanisms are believed to offer the most efficient means of allocating resources in a crisis, as they do also under normal circumstances. Efficiency in an energy crisis is an even more urgent matter than it is under normal circumstances, and it is particularly urgent with respect to oil and other energy resources whose scarcity has precipitated the crisis. The more severe the crisis, the greater this urgency is. In reaching these conclusions, the study did not compare an idealized free market process with idealized government regulatory instruments, but the actual market mechanism as it is known with government regulatory instruments of the sort which have been experienced and realistic assessments of others that have been proposed. Both a market-based strategy and a regulatory strategy are imperfect under normal circumstances; both would have serious shortcomings under crisis conditions. Nevertheless, among the realistic alternatives for coping with a crisis, a market-based strategy will maintain the highest efficiency in resource use and will recover faster than a regulatory-based strategy.

The government's overall strategy for emergency management of oil import disruptions should be to rely to the maximum extent on competitive market mechanisms but to have available a variety of flexible and constructive emergency standby measures to match and adjust with an ongoing assessment of the nature and severity of the disruption.

There has been considerable concern that allowing discretionary implementation of emergency measures may lead to use of these measures to deal with minor disruptions or, even worse, in normal fluctuations in the market. The NPC supports the concept of an emergency management process which would be triggered only by a specific event which threatens or causes a sudden disruption in world oil supplies. Such an event would be a necessary but not sufficient element for activation of emergency procedures. To activate emergency procedures, there would also have to be an assessment that severe consequences to the United States would occur from this event. Examples of such consequences might be that anticipated U.S. shortfalls would be large enough to threaten oil availability for defense, health, and safety needs; that foreign policy or treaty obligations of the United States would be affected; that major regional inequities would be likely to occur; and that sharp, disruptive increases in foreign crude oil prices would occur.

The first step to be taken by the government in an emergency should be a thorough assessment of the world strategic situation and an evaluation of potential impacts on the United States. The ultimate magnitude, nature, and duration of any disruption is unlikely to be known at the outset. For this reason, the specific actions to be used should not be automatically implemented but rather should be implemented based on an assessment of the realities at the time the disruption occurs with the benefit of petroleum industry expertise and advice.

In addition, any mandatory emergency measures should be temporary and should have provisions to be automatically terminated after the emergency. Mandatory deactivation mechanisms should be explicitly defined, such as sunset provisions which specify a limited period of time after which a new Presidential or Congressional finding would be required for continuation.

The approach that has been utilized during this study to organize strategy planning for oil supply disruptions is to deal with import disruptions to the United States in terms of those up to about 1 and 2 MMB/D and those larger than approximately 2 to 3 MMB/D. It is at least inadequate and perhaps dangerous to discuss responses to "small" or "large" disruptions without some guidance as to what is small and what is large; otherwise, the chance for misuse is great. Thus, the suggested responses for disruptions of increasing severity have been cast against order of magnitude disruptions. The match of disruption size to specific response must not be taken too literally, however, for many other factors will also affect the appropriateness of a specific response to the disruption at hand.

Figure 1 illustrates this concept and the flexible, gradualist approach for responding to an imports disruption and seeking to minimize the net remaining shortfall. Selected months for DOE Scenarios 1, 1A, 3, and 4 have been shown. The vertical scaled bars indicate the total level of imports curtailment and the quantitative levels of demand reduction, fuel substitution, SPR diversion, and emergency surge production identified within the study as potential response steps. The net remaining shortfall for a specific scenario month is represented by the white space within the top portion of the bars. The total cumulative net shortfall for the full period of each scenario is noted in the box below each scenario and reflects the amount of shortfall which must be dealt with through mechanisms other than demand reduction, fuel substitution, SPR diversion, and emergency production steps. These other mechanisms might include price increases, private stock drawdown, SPR drawdown, excise taxes, import fees, or coupon rationing. (Appendix H provides a more complete description of each scenario by month for the full period of the particular disruption.)

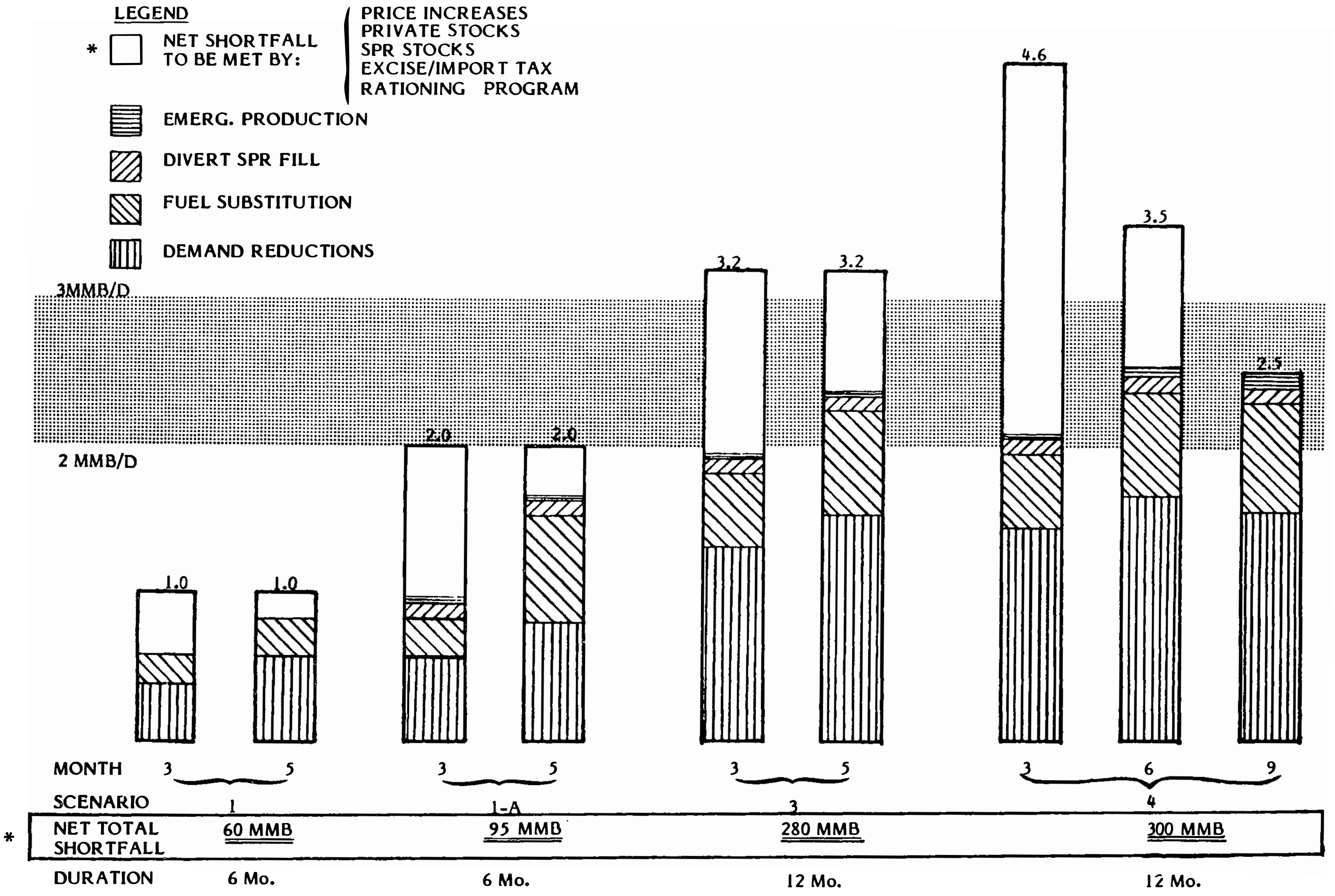


Figure 1. Emergency Supply Demand Management—DOE Scenarios, 1985 (MMB/D).

As can be seen from Figure 1, the emergency preparedness response steps identified in this study could potentially be expected to offset a disruption of petroleum supplies up to a maximum of about 2.5 MMB/D. Scenario 4 would represent an extreme disruption equivalent to blockage of the Straits of Hormuz. The nation has never experienced a disruption approaching this magnitude; it represents a scenario of greatest uncertainties. The horizontal shaded area across Figure 1 notionally represents the range of disruption above which additional government intervention may be needed.

In light of the foregoing considerations, the following broad recommendations are offered. In disruptions involving a reduction of imports to the United States of up to about 1 MMB/D:

- The competitive market should be relied upon as the primary adjustment mechanism.
- Market actions should be reinforced by public information programs to communicate the need for voluntary conservation, voluntary fuel switching, some voluntary wheeling of electric power, and voluntary drawdown of private stocks.
- The SPR fill may be continued initially during a smaller size disruption, but diversion to the market of current SPR purchases already contracted should be considered.

In import disruptions of up to approximately 2 MMB/D to the United States:

- Primary reliance on competitive market mechanisms should continue along with the specific actions recommended for smaller disruptions.
- In addition, the government should consider taking additional steps to increase oil supplies, including the following:
    - Mandated wheeling of electricity from coal and nuclear generating facilities to displace oil and gas
    - Mandated fuel switching from oil to gas and coal in dual-fired facilities
    - Certain emergency exceptions to environmental standards to facilitate fuel switching and use of higher sulfur fuels
    - Work with state governments to clear the way for and encourage emergency oil and gas production.
- Mandating a range of demand reduction steps such as lower speed limits and commercial thermostat management should also be considered.

- Consideration should be given to distribution of SPR stocks above a level of about 200 million barrels to cushion the impact of the disruption.

In crude oil import disruptions to the United States in excess of about 2 to 3 MMB/D, the market should be relied upon to the extent possible supplemented by steps prescribed for lesser shortfalls. It is recommended that domestic crude oil prices remain uncontrolled to assist in bringing demand and supply into balance and to avoid subsidizing imports of foreign oil. However, a limited program of emergency crude oil and emergency product distribution and product margin measures should be available on a standby basis. As explained in the Overview and again earlier in this chapter, further study is needed of tax/import fee and rationing options to determine whether these approaches represent viable alternatives to a limited framework of standby margin and distribution controls for use in a severe disruption. However, at least until such options are developed, adopted by the Congress, and available for use, the recommended standby measures for the most severe emergencies should be structured as outlined below:

- A standby emergency crude oil distribution program bringing all refiners to a common crude oil run ratio based on crude oil runs in the pre-emergency period should be available as detailed in Appendix F. The price of crude oil sales in this program should move with prices in the crude oil market and should not provide unwarranted benefits to either buyers or sellers. Private stocks held by individual refiners at the time such an emergency program is implemented should be excluded from the crude oil sharing program to avoid discouraging private stockbuilding.

- A standby program of emergency products distribution should be available as detailed in Appendix G. Strictly limited priority users, primarily defense, public safety, and public health, should be assured of only their base period volumes. This should be complemented by a state set-aside program to provide limited volumes for distribution within each state's discretion in meeting additional priority and emergency needs. The distribution programs should provide for a continuation of product supplier/purchaser relationships for the duration of the disruption in crude oil imports.

- A simplified margin limitation on refiners, jobbers, and dealers should also be available as detailed in Appendix G. Such margin limitations should be generous enough to allow flexibility and recognize the increased cost of operating under emergency conditions.

- State and local programs should be pre-empted by federal authority to the extent they conflict with federal programs.

- SPR inventories should be distributed to the market as determined by the government to be appropriate.

Various factors entered into the selection of this particular approach. Considerable input was received from experts in market economics, but the subject is not one that can be precisely dealt with based on hard facts, research, and analysis. Much has been said and written about various aspects of the problem, but this study is one of the few attempts to deal in an overall and specific fashion with the problem of what to do in the event of a supply disruption. While any emergency management strategy has broad policy implications, this study has dealt primarily with the practical supply problems likely to accompany an imports disruption in a way that improves the prospect that all consumers will be served, while at the same time attempting to minimize undesirable side effects. While political acceptability is a factor considered, the study recommendations have not been developed for political expediency but rather in the belief at this time that they are most likely to serve this country well in the event of an actual supply disruption.

The study is neither totally free-market-oriented nor does it call for government intervention until the need is apparent. The actions called for in this report in dealing with supply disruptions of up to about 2 MMB/D are the type of actions that would be prompted by competitive market forces, and the study recommendations are designed to facilitate these actions. This is not to say that petroleum prices will not rise if the recommended steps are taken. However, the clear intent is that price impacts accompanying a supply disruption will not be nearly as great as they would otherwise be if these steps were not taken. In very severe disruptions, as illustrated by DOE Scenarios 3 and 4, substantial cumulative shortfalls would be left after taking all the steps recommended. Thus, imports disruptions in excess of about 2 to 3 MMB/D have the potential to strain the fabric of the nation. In order to alleviate that strain, this report recommends that for imports disruptions in excess of about 2 to 3 MMB/D, the government have available a limited framework of crude oil distribution and product margin and distribution measures.

It should be recognized that a complex contract structure connects refiners to the marketers and end customers they serve. During severe supply disruptions, individual refiners will likely be disproportionately affected in their access to crude oil and that disproportionate impact will be transmitted to the marketers, consumers, and regions of the country they serve. Contractual commitments may constrain other refiners, whose access to crude oil has not been disrupted, from attempting to alleviate these effects on disproportionately affected refiners or their customers. To supporters of competitive market forces, it is conceded that, given time, the market would probably sort out these problems -- but perhaps not before extensive inconvenience to many individual consumers and various regions of the country, and perhaps not before severe financial impact on many refiners and marketers. Wide variations might also be projected in product prices across the country in response to disproportionate availability.

As a caveat to the above recommendations, this study does not provide in-depth quantitative analyses of the dynamics of these measures under the constrained and uncertain conditions imposed by the emergency. These recommendations are more the product of experience and judgment. Obviously, more study would be appropriate on such questions as how the price setting mechanism will work in an emergency crude oil sharing program, how emergency margin limitations could be implemented at various stages in refining and distribution, etc. In addition, there is a danger that some who read the above recommendations will seek to apply them to much smaller imports disruptions than is intended, or worse, even to normal market conditions. These kinds of problems suggest continued industry/government cooperation in emergency preparedness planning, as summarized below.

EMERGENCY INDUSTRY/GOVERNMENT OPERATIONS

Various types of industry/government cooperative mechanisms have been formed in the past to deal with either actual or anticipated energy emergencies. Some [the Petroleum Administration for War (PAW) and the Petroleum Administration for Defense (PAD)] were assembled under wartime conditions and were concerned with maximizing output at a time when domestic crude oil supplies were adequate and the United States was a major oil exporter. The Emergency Petroleum and Gas Administration (EPGA) was formed to prepare for and deal with the threat of direct nuclear attack on the United States and the consequent disruption of petroleum operations. None of these organizations is suitable for the type of major oil imports supply disruption studied by the NPC and the recommended approach to managing import disruption described in the preceding section.

Government Organization for Energy Emergencies

A government entity charged with coordinating and administering the overall response to major oil import disruptions is essential to the effectiveness of emergency preparedness plans. Under the current organization of the Executive Branch, such an agency would logically fit in the Department of Energy and should be given overall responsibility for:

- Pre-emergency planning
- Assisting the Secretary of Energy and the President in assessing threatened or actual oil import disruptions to the United States
- Developing appropriate response options to deal with an ongoing emergency and assisting the President and/or the Secretary of Energy in selecting options for implementation and termination
- Providing the basic organizational framework for coordinating emergency measures during the time they are operational

- Developing plans to educate the public well in advance of an emergency and to provide effective public communications during the emergency.

This agency should require only a small full-time staff. Its ongoing activities would include planning as well as its monitoring and assessment functions. Maintaining a large standby operations staff is not consistent with the thrust of emergency response measures emphasized in this study, which involve maximum reliance on market mechanisms and relatively limited temporary government interventions in the marketplace in severe disruptions. This agency should receive adequate resources and have access to senior Administration officials.

Private Sector Advisory Role

As a suitable vehicle for providing private sector input to the government energy emergency entity, this study recommends that a federal advisory committee be formed as soon as practical to provide continuing advice and assistance to the Secretary of Energy on questions of energy emergency preparedness both prior to and during an emergency. The Secretary of Energy would choose the members of such a private sector advisory committee primarily to provide him direct access to the experience, expertise, and counsel of energy industry executives, but a wide spectrum of other constituencies such as consumers, labor, research, public interest, and academic organizations should also be represented.

The proposed advisory committee could provide a variety of useful inputs to the Secretary of Energy. At the pre-emergency planning stage, it would be a logical source of comprehensive understanding on the workings of the petroleum industry, both in this country and overseas. During the difficult period in which a potential disruption in the normal flow of petroleum exports and imports is developing, its counsel would provide a useful mechanism in assessing the often conflicting and fragmentary data that emerge. In this regard, it would supplement but not replace the various other situation assessments available to the government and would not involve an exchange of proprietary information. During a supply emergency, it could provide evaluations and technical guidance on the policy responses available to the Secretary and the President and on the operational implementation of the policies chosen. It could also provide industry information and counsel that the Secretary may desire in fulfilling U.S. commitments to the IEA. Its role would not include actually recommending government policies or response options for implementation. However, the committee could provide feedback on the effectiveness of the response options selected. In instances where the Secretary of Energy requests specialized technical guidance from the advisory committee, the committee could (with the Secretary's concurrence) set up temporary professional subcommittees to assist the advisory committee in responding to the Secretary.

It does not appear that the private sector activity recommended herein would require changes in the antitrust laws. However, such activities should be carried out pursuant to guidelines provided by antitrust counsel.

SUMMARY OF ACTIONS RECOMMENDED TO PREPARE FOR OIL IMPORT DISRUPTIONS

It is recommended that the following actions be taken now to prepare for future emergencies. Discussion of the recommendations summarized here is contained in various chapters of the report, as noted in parentheses.

Emergency Industry/Government Operations

- A government entity with access to senior Administration officials should be charged with pre-emergency planning as well as coordinating and administering the implementation of the overall response to major oil import disruptions. (Chapter Nine)

- A federal advisory committee of representatives from the private sector should be formed as soon as practical to provide continuing advice and assistance to the Secretary of Energy on questions of energy emergency preparedness. (Chapter Nine)

- Plans should be developed to educate the public well in advance of an emergency and to provide effective public communications during the emergency. (Chapters Two and Nine)

- Further study of tax/import fee and coupon rationing options is needed promptly to determine whether these approaches represent viable alternatives for possible use in severe import disruptions. (Chapter One)

- High priority should be given to studies to identify appropriate distributional measures to recycle increased government revenues during oil supply emergencies. (Chapter One)

Emergency Oil and Gas Production

- Standby plans for emergency oil and gas production should be developed by the responsible state and federal regulatory agencies. The plans should include measures for:

  - Definition of maximum allowable emergency production rates for each field with surge capability (Chapter Four)

  - Temporary relaxation of conservation and environmental rules relative to limited gas flaring and emissions (Chapter Four)

  - Procedures for allocating increased production to individual properties (Chapter Four)

  - Temporary suspension of reduced gas allowables due to previous overproduction (Chapter Five)

  - Emergency procedures to expedite approval (e.g., NPGA filings) for production from new gas wells (Chapter Five)

  - Necessary standby legislative and regulatory authorities. (Chapter Four)

- Identification of potential bottlenecks in pipeline capabilities for delivery of additional emergency gas supplies during peak winter periods deserves further study. (Chapter Five)

Emergency Refining and Logistics Operations

- Standby measures for emergency relaxation of product quality specifications for distillate fuel oils and jet fuel should be established. (Chapter Six)

- Measures to reduce response times required to obtain emergency relaxation of environmental sulfur content specifications on heavy fuel oil and distillate fuels under the Clean Air Act should be considered. Legislative changes may be required. (Chapter Six)

- To avoid potential bottlenecks in west-to-east crude oil movements during an oil import disruption, the federal government should:

  - Give priority to completing actions needed to allow the use of U.S.-subsidized tankers on a 12-month basis (subject to semiannual review) and the use of foreign flag tankers on short notice (Chapter Seven)

  - Streamline the legislative authority and regulatory mechanisms required for exchange of domestic crude oil from PAD V with contiguous or noncontiguous countries to allow rapid implementation in emergencies if needed (Chapter Seven)

  - Ensure that current crude oil exchange mechanisms with Canada are extended in order to provide additional flexibility in U.S./Canadian logistics systems (Chapter Seven)

  - Review tax and regulatory factors that act as disincentives to investments in major U.S. pipelines which may be needed longer range. (Chapter Seven)

- The delivery capability of crude oil from the SPR to the petroleum logistics system should be further investigated. (Chapter Seven)

Security Stocks

- The government should take all reasonable steps without causing disruptions in world oil markets to maintain or accelerate the development and filling of the Strategic Petroleum Reserve up to the currently projected capacity of 750 to 1,000 million barrels by 1990. (Chapter Three)

- Government oil acquisition procedures should be streamlined and sufficiently flexible to utilize a mix of government-owned reserves, term supply contracts, and spot purchases as market conditions permit. (Chapter Three)

- Government should minimize disincentives to private stock-building by suppliers and consumers. Such disincentives include price and allocation controls as well as the perceived threat of future price and allocation controls on such stocks during supply disruptions. (Chapter Three)

International Considerations

- The recommended government contingency planning entity should be designated to assist the President in determining whether an IEP emergency should be declared. This entity should have access to private sector advice. (Chapter Eight)

- Emergency standby measures in the United States should take account of potential international emergency oil allocation. (Chapter Eight)

- The recommended government contingency planning entity should make preparations to handle the administrative tasks involved in the international emergency program including, in particular, monitoring company supply positions, evaluating the IEA data and recommendations, and implementing emergency allocations as necessary. Increased attention to training government personnel on IEA procedures would be one step to consider. (Chapter Eight)

- U.S. representation on IEA standing committees should more actively participate in the development of IEA policies. Concentration of representation in a single government entity would facilitate this goal, while other interested agencies should continue to play appropriate roles within the U.S. government on IEA matters. (Chapter Eight)

- Information should be provided to oil companies, government agencies, and other interested parties on the IEA and its activities so that they can better understand and prepare for their role in an international emergency. Plans should also be considered for a public information program during an emergency to explain cooperative international efforts under way. (Chapter Eight)

- Consideration should be given to establishing an estimate of "current demand" for use in determining the true effects of an interruption in oil imports. This would reduce the distortion introduced by the base period concept in a period of declining demand. (Chapter Eight)

- Provisions to facilitate rapid response consultations among IEA member governments should be developed as a means of addressing lower level disruptions. (Chapter Eight)

Chapter Two

EMERGENCY DEMAND REDUCTION AND FUEL SUBSTITUTION OPTIONS

INTRODUCTION

This chapter identifies a set of voluntary and standby mandatory demand reduction strategies and provides estimates of the savings possible through the implementation of these strategies. The identification of these strategies does not imply their recommendation; rather, the intent is only to quantify the effectiveness of various actions which might be considered in managing the shortfall resulting from oil import disruptions.

In order to achieve the various demand saving or fuel switching steps identified in this chapter, various degrees of action would be necessary. Some of the savings which could be viewed under the category of voluntary, or minimum disruptive impact on consumers, are likely to be realized as a result of publicity campaigns by the public and private sectors. Price elasticity will tend to encourage conservation as well. However, as the nation moves toward implementing additional steps, government actions may be needed. As examples, emergency exemptions to the Fuel Use Act will be needed to permit fuel switching from oil to gas in the utility sector. Exemptions to the Clean Air Act will be needed to achieve refinery fuel savings. The government entity in charge of emergency preparedness should maintain an up-to-date list of authorities needed to implement demand management and fuel substitution steps.

Varying degrees of oil disruption severity have been incorporated into scenarios for use in this analysis. These scenarios were developed by the DOE and are based on different levels of exports reduction for three, six, and 12-month periods. These cutbacks are assumed to be initiated by the Organization of Arab Petroleum Exporting Countries (OAPEC) and Iran.[1] In 1979, this group of countries exported about 20 MMB/D, and this level of exports was used to calculate the crude oil denials for the various cases. An oil denial implies a reduction in supply only. The details are summarized in Table 2 and are detailed by product in Appendix I, Exhibit 1.

In order to determine the magnitude of change to normal conditions imposed by the denial scenarios and thereby aid in emergency planning decisions, a seasonalized base line supply and demand forecast was developed from available sources for the years 1980, 1981, and 1985. The proposed planning line summary forecast and additional details are included in Appendix I, Exhibit 2.

---

[1] OAPEC membership includes Algeria, Bahrain, Egypt (suspended following the Camp David Agreements), Iraq, Kuwait, Libya, Qatar, Saudi Arabia, Syria, and the United Arab Emirates.

TABLE 2

Summary of Imports Denials

	Scenarios			
	1	1A	2	3
Description	OAPEC & Iran Export Interruption of 5% Against U.S. Only	OAPEC & Iran Export Interruption of 10% Against U.S. Only	OAPEC & Iran Export Interruption of 25%	OAPEC & Iran Export Interruption of 40%
Duration (Months)	6	6	6	12
Total World Denial (MB/D)	1,000	2,000	4,900	7,800
U.S. Denial (MB/D)	1,000	2,000	2,200	3,200
Crude Oil	825	1,650	1,800	2,600
Products	175	350	400	600

	Scenarios		
	4A	4B	4C
Description	Persian Gulf Interruption of 100%	Persian Gulf Interruption of 75%	Persian Gulf Interruption of 50%
Duration (Months)	3	3	6
Total World Denial (MB/D)	16,400	12,300	8,200
U.S. Denial (MB/D)	4,600	3,500	2,500
Crude Oil	3,750	2,850	2,050
Products	850	650	450

SUMMARY

One of the difficulties facing the United States under any emergency oil denial condition is that much of the "easy" conservation potential that existed during the 1973-1974 oil embargo has already been put in practice as a result of higher energy prices, mandated conservation measures, and fuel switching programs. An indication of this reduced potential is shown in Table 3, which compares two forecasts of 1985 oil demand. The "old" forecast is the NPC's 1974 forecast, while the "new" projection is the one developed for this report.

TABLE 3

Oil Demand Forecast Comparison For 1985
(MB/D COE)

	Old	New	Reduction %
Residential/Commercial	2,834.4	1,996.3	29.6
Transportation	11,243.1	8,837.3	21.4
Industrial	2,503.7	1,786.9	28.6
Non-Energy	2,914.7	2,173.7	25.4
Electric Utilities	1,464.4	838.8	42.7
Total	20,960.3	15,633.0	25.4

Table 4 lists the demand reduction strategies considered for this report. These strategies have been prioritized in order of their impact (i.e., minimum, moderate, or major) as judged by the estimated degree of difficulty of implementation and/or by the severity of their effect; e.g., lifestyle changes, equipment alterations, and effect on the energy consumer. The relative degree of acceptance during strategy implementation is likely to correspond to these classifications. Since each scenario differs as to amount and/or time of denial, the strategies employed and their effectiveness differ for each scenario. With the exception of the savings for the industrial sector, it is assumed that all other strategies could be fully effected in 60 days, if the necessary programs, as described in the body of the report, are already in place. These potential savings were calculated based on currently available data. If greater conservation and fuel switching effects occur in the future than are now expected, these potentials will be reduced accordingly.

Tables 5 through 8 show for each oil denial scenario the net effect after demand reduction steps are taken, as well as required changes in other energy sources. Additional details may be found in Appendix I, Exhibit 1. Time periods used in the analysis are both summer and winter for 1981 and 1985. For each of the

TABLE 4

Summary of Saving Strategies Considered*

		MB/D			
	Estimated Impact†	Oil	Gas	Coal	Electricity
Ground Transportation					
Reduce Speed Limit	Min.	90	--	--	--
Reduce Personal Vehicle Travel	Min.	50	--	--	--
Carpooling	Min.	380	--	--	--
Driver Education	Min.	60	--	--	--
Vehicle Inspection	Min.	95	--	--	--
School Bus Utilization	Min.	60	--	--	--
Intracity Service Trip Planning	Min.	-------------No Estimate--------------			
Trucking Deregulation	Min.	-------------No Estimate--------------			
Odd-even Auto and Light Truck Fuel Sales	Mod.	145	--	--	--
Vehicle Use Stickers	Mod.	50	--	--	--
Ban Weekend Fuel Sales	Maj.	240	--	--	--
Four-day Work Week	Maj.	35	--	--	--
Ban Recreational Fuel Use	Maj.	30	--	--	--
Aviation					
Relaxation of CAB Rules	Min.	-------------No Estimate--------------			
Flight Operation Improvements	Min.	-------------No Estimate--------------			
Voluntary Reduction of Military Flights	Mod.	-------------No Estimate--------------			
Increase Airline Seat Load Factor	Mod.	85	--	--	--
Elimination of Discretionary General Aviation Flights	Maj.	10	--	--	--

TABLE 4 (Continued)

	Estimated Impact†	MB/D			
		Oil	Gas	Coal	Electricity
Electric Utilities					
Oil-to-Gas Conversion	Min.	240	(240)	--	--
Increased Electricity Wheeling	Min.	30	--	(30)	--
Increased Electricity Imports	Min.	30	--	--	--
Voltage Reduction (%)	Min.	20	--	--	--
Emergency Demand Reduction Program	Min.	50	--	--	--
Increased Coal-Fired Generation	Min.	-------------No Estimate--------------			
Nuclear Power	Maj.	30	--	--	--
Residential					
Thermostat Management	Min.	15	30	--	10
Weather Stripping	Min.	5	10	--	5
Insulation	Min.	15	--	--	--
Maintenance	Min.	15	30	--	10
Water Heating	Min.	35	90	--	15
Commercial					
Thermostat Management	Min.	35	85	--	--
Ventilation	Min.	15	35	--	--
Maintenance	Min.	15	35	--	--
Water Heating -- Insulation	Min.	--	5	--	--
Water Heating -- Thermostat Setting	Min	------------(Less Than 5)-------------		--	--
Lighting Reductions	Min.	--	--	--	35
Fuel Switching	Min.	-------------No Estimate--------------			

TABLE 4 (Continued)

		MB/D			
	Estimated Impact†	Oil	Gas	Coal	Electricity
Commercial (Continued)					
Close Schools During Winter Months	Maj.	-------------No Estimate-------------			
Industrial					
Boilers (Oil to Coal)	Min.	50	--	(50)	--
Boilers (Oil to Gas)	Min.	220	(220)	--	--
Nonboiler (Oil to Gas)	Min.	40	(40)	--	--
Electric Drive for Steam	Min.	40	--	--	(40)
Control of Excess Oxygen	Min.	10	--	--	--
Added Insulation	Min.	10	--	--	--
Oil Desulfurization Reduction	Mod.	50	--	--	--
Subtotals					
Minimum		1,625	--	--	--
Moderate		330	--	--	--
Major		345	--	--	--
Total		2,300			

---

*This listing is for representation purposes only. The numbers used are for winter months and implementation is possible by 1985. The individual demand sections tabulate the savings for summer as well as those that could be implemented by 1981. The combination of values used for each scenario is described in the demand section summary tables. Brackets indicate additional energy quantities needed to replace oil in cases of fuel switching.

†Minimum (Min.), moderate (Mod.), and major (Maj.) impact as judged by the estimated degree of difficulty of implementation and/or by the severity of effects.

TABLE 5

DENIAL PERIOD: SUMMER 1981*

Net Impact of Oil Denial After Demand Reduction†
(MB/D)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Gasoline	(65)	360	440	310	910	440	20
Jet Fuel	(30)	25	35	90	160	100	50
Middle Distillate	25	210	250	355	600	400	225
Heavy Fuel Oil	(80)	210	285	375	775	460	160
Total	(150)	805	1,010	1,130	2,445	1,400	455

Other Energy Balances Required to Support Demand Reduction Strategies
(MB/D COE)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Electricity¶	(20)	(20)	(20)	(10)	(10)	(10)	(10)
Gas	250	250	250	335	335	335	335
Coal	40	40	40	50	50	50	50

TABLE 6

DENIAL PERIOD: WINTER 1981*

Net Impact of Oil Denial After Demand Reduction†
(MB/D)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Gasoline	(45)	380	460	355	955	485	65
Jet Fuel	(30)	25	35	90	160	100	50
Middle Distillate	(25)	160	200	290	535	335	160
Heavy Fuel Oil	(150)	140	215	330	730	415	115
Total	(250)	705	910	1,065	2,380	1,335	390

Other Energy Balances Required to Support Demand Reduction Strategies
(MB/D COE)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Electricity¶	(55)	(55)	(55)	(45)	(45)	(45)	(45)
Gas	50	50	50	135	135	135	135
Coal	40	40	40	50	50	50	50

---

*Note: ( ) indicates gain or net energy surplus; no ( ) indicates an energy supply deficit.

†Oil balances must be adjusted for increased production, if available.

§All numbers rounded to the nearest 5 units. Crude oil equivalent barrels are based on a 5.8×10^6 Btu/bbl.

¶Electricity gain does not take into account possible changes in electric utility reduction strategies.

TABLE 7

DENIAL PERIOD: SUMMER 1985*

Net Impact of Oil Denial After Demand Reduction†
(MB/D)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Gasoline	(65)	360	440	310	910	440	20
Jet Fuel	(30)	25	35	90	160	100	50
Middle Distillate	(105)	80	120	300	545	345	170
Heavy Fuel Oil	(220)	70	145	310	710	395	95
Total	(420)	535	740	1,010	2,325	1,280	335

Other Energy Balances Required to Support Demand Reduction Strategies
(MB/D COE)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Electricity¶	--	--	--	--	--	--	--
Gas	395	395	395	395	395	395	395
Coal	80	80	80	80	80	80	80

TABLE 8

DENIAL PERIOD: WINTER 1985*

Net Impact of Oil Denial After Demand Reduction†
(MB/D)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Gasoline	(45)	380	460	355	955	485	65
Jet Fuel	(30)	25	35	90	160	100	50
Middle Distillate	(155)	30	70	235	480	280	105
Heavy Fuel Oil	(290)	0	75	265	665	350	50
Total	(520)	435	640	945	2,260	1,215	270

Other Energy Balances Required to Support Demand Reduction Strategies
(MB/D COE)§

	Scenarios						
	1	1A	2	3	4A	4B	4C
Electricity¶	(35)	(35)	(35)	(35)	(35)	(35)	(35)
Gas	195	195	195	195	195	195	195
Coal	80	80	80	80	80	80	80

---

*Note: ( ) indicates gain or net energy surplus; no ( ) indicates an energy supply deficit.

†Oil balances must be adjusted for increased production, if available.

§All numbers rounded to the nearest 5 units. Crude oil equivalent barrels are based on a 5.8 x 10^6 Btu/bbl.

¶Electricity gain does not take into account possible changes in electric utility reduction strategies.

scenarios, direct oil savings which result from the various demand reduction strategies are totaled by product. These savings are then reduced by the volume of product denied during the oil shortfall and further reduced by refinery output product reductions which result from the loss of crude oil. Additional oil savings are derived from the consequent reduction in refinery runs. (Refineries consume approximately 10 percent of the oil they process.) The balance after these adjustments reflects the oil product savings or deficit estimated for each scenario. (Volumes enclosed in parentheses indicate a net savings; without parentheses, a net deficit.) For example, in Scenario 1, Summer 1981 (Table 5), 150 MB/D over and above the denial volumes is not consumed during the emergency reduction period. For Scenario 4A, the deficit net of demand reductions is estimated to average 2.4 MMB/D. In all scenarios indicating a net deficit an additional strategy beyond those discussed in this chapter must be employed.[2]

In addition to their direct impact on oil demand, the strategies outlined in this report also affect other energy sources.[3] For example, not only oil, but also natural gas use may be reduced in a thermostat control program. On the other hand, fuel substitution strategies (such as the conversion from oil to gas in industrial or utility boilers) increase demand for other energy sources. Later chapters of this report discuss the potential for emergency production and logistical measures.

As indicated in Tables 5 through 8, only in Scenario 1 (the least severe oil denial) are demand reductions by themselves sufficient to offset the reduction in imported crude oil.

While the effects of savings due to the relaxation of environmental and other regulatory restrictions have not been dealt with exhaustively, some of the demand reduction strategies will require the relaxation of environmental or other regulatory restrictions. For example, the emergency substitution of natural gas for oil in the electric utility sector would require exemptions under the Fuel Use Act, and certain changes in refinery operation would require exemptions to the Clean Air Act.

DISCUSSION AND ANALYSIS

Ground Transportation

The use of oil for ground transportation averages approximately 8 MMB/D, roughly half of all oil consumed in the United States. As a result, the ability of this country to accommodate an oil denial

---

[2] These deficits are calculated prior to possible supply adjustments such as increased domestic supplies and refinery yield changes, which are discussed in a later part of this report.

[3] Throughout this report units are expressed either as natural units (MB/D) or in crude oil equivalents (MB/D COE). The conversion to COE is based on 5.8 million Btu per barrel of crude oil.

is in large part dependent on whether ground transportation demand can be reduced. The two primary oil products used as ground transportation fuels are motor gasoline and diesel fuel. Minor amounts of residual fuel oil and liquified gases are also consumed, but their use is relatively insignificant. During 1980, the demand for motor gasoline and diesel averaged 6.7 MMB/D and 1.3 MMB/D, respectively. The continued effects of higher prices, a slow economic recovery, and a growing use of fuel-efficient automobiles are expected to further reduce motor gasoline consumption during 1981 to less than 6.6 MMB/D. On the other hand, the continued penetration of diesel-powered automobiles in the personal transportation market is expected to result in a slight increase in diesel consumption during 1981, despite higher fuel prices.

Oil consumed in ground transportation is used for two major activities: personal transportation use, including fuels used in personal automobiles, light trucks, and vans; and commercial and other use, including freight trucks, commercial vans, and buses. Each activity has an intercity and intracity component. For example, intracity personal transportation includes home-to-work trips and other personal travel (such as shopping). Different strategies are required to maximize the potential oil savings within each subcategory of oil use.

As shown in Table 9, most of the savings which can be realized in the ground transportation area result in reductions in gasoline use. The strategies are ranked according to the ease with which they can be implemented. For Scenarios 1, 1A, and 2, only the first three strategies are employed, while the use of all strategies is assumed for the remaining scenarios. Quantification of each of these strategies is described in the remainder of this section. Not all strategies were quantified, however, either because demand reduction which may result could not be quantified or because oil savings were considered to be negligible.

The strategies outlined here could be used to effect significant oil savings with minimum economic or social disruption. However, the actual level of savings is affected by the extent of consumer compliance with the demand reduction programs. Implementation of any strategy should emphasize actions, such as increasing downtown area parking fees and setting aside carpool/vanpool lanes, which encourage compliance.

Reduction of Speed Limit to 50 Miles Per Hour (mph)

Fuels used for intercity transport comprise 26 percent of all fuels consumed for ground transportation: 17 percent automobiles and light trucks and 9 percent diesel-powered freight trucks. For this strategy, highway speed is assumed to be reduced from a current average of 55 mph to 52 mph during the denial period. As a result of increased vehicle efficiencies, fuel use is estimated to decline 3 percent for automobiles and 5 percent for trucks. Under these assumptions, total savings are estimated at 50 MB/D for gasoline and 40 MB/D for diesel fuel, as shown in Table 10.

TABLE 9

Estimated Oil Savings: Ground Transportation*
(MB/D)

		Motor Gasoline		Diesel	
	Strategies	Winter	Summer	Winter	Summer
A-1	Reduce Speed Limit	50	50	40	40
A-2	Reduce Personal Vehicle Travel	50	50	--	--
A-3	Carpooling	380	400	--	--
A-4	Driver Education	60	60	--	--
A-5	Vehicle Inspection	95	105	--	--
A-6	School Bus Utilization	60	60	--	--
A-7	Odd-Even Auto and Light Truck Fuel Sales	145	155	--	--
A-8	Ban Weekend Fuel Sales	240	255	--	--
A-9	Vehicle Use Stickers	50	50	--	--
A-10	Four-Day Work Week	35	35	--	--
A-11	Ban Recreational Fuel Use	30	30	--	--
A-12	Intracity Service Trip Planning	---------No Estimate Made---------			
A-13	Trucking Deregulation	---------Estimate Not Used--------			

---

*Scenario balances were calculated as follows: for Scenarios 1, 1A, and 2, only Strategies A-1 through A-3 were assumed to be implemented; for Scenarios 3, 4A, 4B, and 4C, Strategies A-1 through A-11 were employed. The average of Strategies A-7 plus A-8 was used in the scenario calculations since these strategies overlap.

Reduction of Personal Vehicle Travel

Reduced personal automobile and light truck travel is estimated to save 49 MB/D of motor gasoline and 1 MB/D of diesel fuel. This estimate assumes that there is a potential savings of 5 percent in

TABLE 10

Savings From Reduction of Speed Limit

Fuel	% of Transportation Fuel	% Fuel Use Reduction	Total Fuel Use (MMB/D COE)	Oil Savings (MB/D COE)	Product Savings (MB/D)
Gasoline (Autos)	17	3	8	41	50
Diesel (Trucks)	9	5	8	36	40

automobile and light truck fuel consumption through planning (e.g., combining trips) and that 30 percent of this potential is realized. The savings potential (5 percent) was obtained by assuming that about half the oil savings potential of 11 percent estimated by the Conference Board in 1977 has already been achieved and that an additional 5 percent potential still remains. The 30 percent compliance rate is judgmental.

Carpooling

Substantial oil savings could be achieved by reducing the number of one-passenger trips used in the home-to-work cycle. It has been estimated that 70 percent of home-to-work trips now involve one-passenger automobiles and light trucks.[4] Assuming that 34 percent of automobile/light truck travel is committed to the home-to-work cycle,[5] motor gasoline and diesel fuel use for this type of travel is approximately 1,830 MB/D and 16 MB/D, respectively. During an oil denial, half the drivers of one-passenger vehicles are assumed to join carpools averaging 2.5 riders. Thus, home-to-work travel fuel use by one-passenger vehicles could be reduced by 30 percent, resulting in total savings of 390 MB/D for gasoline and 3 MB/D for diesel fuel, as Table 11 shows.

Driver Education Programs -- Newer Vehicles

Vehicle efficiency improvements of 5 percent may be achieved for newer vehicles (50 to 60 percent of the fleet) through driver education programs which emphasize fuel-efficient vehicle operation. Fuel consumed by these vehicles is estimated to average 3,130 MB/D of motor gasoline and 46 MB/D of diesel fuel. It is assumed that this strategy affects 40 percent of the drivers of

---

[4] Transportation Energy Conservation Data Book, 1979.

[5] 1974 National Transportation Report, Department of Transportation.

TABLE 11

Savings From Carpooling

Fuel	Total Fuel Use (MB/D)	% of Trips Home-to-Work	% Fuel Use Reduction	Oil Product Savings (MB/D)
Gasoline	1,830	70	30	390
Diesel	16	70	30	3

newer vehicles (and therefore 40 percent of fuel consumed), resulting in an oil savings of 60 MB/D of motor gasoline and 1 MB/D of diesel fuel.

Vehicle Inspection, Maintenance, and Driver Education -- Older Vehicles

In addition to driver education programs, the fuel efficiencies of older vehicles (40 to 50 percent of the fleet) may be improved by vehicle maintenance programs, including such actions as the use of radial tires, proper tire inflation, adequate lubrication, correct brake adjustment, etc. These programs are assumed to result in a 13 percent improvement in vehicle mileage per gallon.[6] Total fuel consumed by these older vehicles is estimated to average 2,480 MB/D of motor gasoline (diesel automobiles and light trucks are nearly all newer than the vehicles assumed to be in need of maintenance). Moreover, during the oil denial, it is expected that approximately 30 percent of these vehicles will be inspected and any deficiencies corrected. As a result, motor gasoline savings among older vehicles are estimated to average 100 MB/D.

School Bus Utilization

The inventory of school, church, and other buses not fully utilized is in excess of 400,000. If an effective park-and-ride system could be organized using neighborhood shopping center parking lots as passenger loading and car storage areas, it is estimated that 60 MB/D of gasoline could be saved. This program requires coordination of working hours with school hours. It has been suggested that a four-day week could be coordinated with a school bus utilization plan to avoid school/work travel time conflicts. For example, buses could transport workers downtown during the 6:00 a.m. to 7:00 a.m. period and then carry students to and from school before transporting workers home in the evening (at 6:00 p.m.). This could be a four-day-a-week routine. However, there are problems with the implementation of a mandatory four-day work week which are discussed elsewhere in this chapter.

---

[6] Mathematica, Inc., Comprehensive Evaluation of Energy Conservation Measures, 1975.

The 60 MB/D estimated savings for this program is the net of the reduced number of one-passenger home-to-work commuter miles (excluding mileage to the park-and-ride facilities) and the increased number of bus miles at a reduced fuel efficiency. It was assumed that 150,000 buses would be used, that each would transport 38 passengers to and from work, that the commutation trip would be 18 miles by bus and 4 miles round trip by car to the park-and-ride lot, that a four-day work week would be in effect, and that the ridership of the home-to-work vehicles displaced was 1.5 passengers.

Odd-Even Fuel Sales to Autos/Light Trucks

After an initial inventory adjustment period, this action, as employed in the past, will have very little effect on fuel use. The initial inventory adjustment period can be shortened if a minimum purchase rule is adopted as part of the odd-even program.

The odd-even program can lead to fuel savings if it is adopted nationwide and if the rule is applied to all travelers (in most instances, travelers from out-of-county have been allowed to ignore the rule for fuel purchases). The program would have to be designed so that the impact would fall on leisure driving rather than business travel. It is estimated that 10 percent of U.S. automobile miles traveled are devoted to leisure driving in excess of 200 miles per round trip.[7] Thus, the savings potential for a complete elimination by mandate (odd-even sales with minimum purchase) of such trips is 400 to 500 MB/D. This estimate is an upper limit in that it assumes that all leisure trips over 200 miles will be eliminated. A more realistic estimate of savings for this program ranges from 150 to 200 MB/D to reflect a reduction in the number of trips or a shortening of trip length rather than their elimination.

Ban On Weekend Fuel Sales

This action would nearly eliminate leisure trips in excess of 200 miles except for the annual vacation. It has been estimated that the potential fuel savings for this action approach 8 percent of fuel sales to auto/light trucks, amounting to 400 MB/D.[8] This estimate is the upper limit of oil savings and represents a complete elimination of weekend trips over 200 miles. A more likely estimate of savings includes the continuation of weekend trips, although of shorter length. According to the 1978 Hershberg and Steinhart study, a reduction of average trip length by 50 percent would save 200 to 250 MB/D. However, these savings are highly seasonal. It should also be emphasized that the oil savings for this action may not be added to those of the strictly enforced national odd-even fuel sales program outlined above, as the programs clearly overlap.

---

[7] Hershberg and Steinhart, 1978 Energy, Summer 1978.

[8] Alan M. Voorhees, 1974.

Reduction in Vehicle Use (Stickers to Eliminate Use One Day Per Week)

This program would save much less fuel than might be anticipated because most drivers have access to more than one vehicle or can readily schedule travel around the "off" day. Oil savings would accrue primarily through reduced home-to-work travel for those dependent on a single vehicle. Although various estimates of potential oil savings range as high as 320 MB/D, a reduction of only 50 to 75 MB/D can reasonably be expected.

Compressed Work Week

If the obvious labor union and contract problems can be overcome, oil savings may be possible with a four-day work week. Assuming that the program savings would not be offset by the disruption of ongoing carpool/vanpool programs and that a worker does not drive on his off day, the oil savings could approach 3 to 4 MB/D for each 1 percent of the work force participating. In making this estimate, it is assumed that 28 billion gallons of gasoline per year are used for home-to-work travel. If 10 percent of the work force worked only four days each week, a 3 percent fuel savings would be achieved. This represents a total savings of 33 MB/D, or 3 to 4 MB/D per 1 percent of the work force. Moreover, in the emergency situation described in the denial scenarios, it is reasonable to expect that 10 percent of the work force would participate in a compression of the work week. Other recent estimates of fuel savings resulting from a four-day work week are considerably higher than the estimate reported here.

The four-day work week has numerous opponents in industry who point out many problems, from implementation to labor union relations. Special concerns have been expressed by those industries which operate on a continuous basis, such as the aluminum industry. An example of their concern has been expressed to the Department of Energy by the U.S. Chamber of Commerce.[9]

> The compressed workweek begs questions relating to pension contributions, sick pay, holiday pay, jury duty, and even lunch money. If there must be a measure to compress the workweek, it must provide flexibility to accommodate special cases. Consideration must be given to problems that will arise in situations such as the following:
>
> - Demand factors and capacity restraints sometimes require that a supplier work an extended week to keep a dependent facility on a normal work schedule.

[9] Docket #CAS-RM-79-507-3/20/80.

- Some manufacturing processes cannot be shut down without causing severe damage to their equipment.
- Excessive idling of such equipment is an unproductive use of energy and an increase in production costs.
- Industrial, commercial, and agricultural activities paced by cyclical weather conditions, or dealing with perishable commodities, would be severely disrupted.

Ban on Recreational Uses of Fuel

Recreational boats currently consume about 60 MB/D, recreational aviation uses less than 10 MB/D, and other recreational vehicles, including bikes and snowmobiles, use about 20 MB/D. A ban on recreational fuel use could result in a maximum oil savings of 90 MB/D if it is assumed that a non-fuel-consuming activity is substituted for these recreational activities. Because this is a highly unlikely assumption, the estimate of fuel savings was reduced by 30 to 50 percent (30 MB/D). It is clear that the total fuel savings from a ban on recreational fuel use is relatively small.

Planning of Trips (Logistics and Night Delivery)

Fuel used by light and medium trucks and vans in the delivery and service industries can be reduced through route planning, trip consolidation, and night deliveries to avoid traffic congestion. No estimate of oil savings is available for these measures.

Regulation of the Trucking Industry

Fuel savings which can be realized in the trucking industry during a short-term supply emergency are relatively small. Conservation measures achieved through trucking deregulation may require months or years to implement. Therefore, no quantification of fuel savings is provided for the scenarios based upon a starting date of January 1, 1981. In the longer term, however, efficiency improvements in trucking can be achieved through:

- Adoption of a standard legal length for interstate highways that will permit use of double-bottom trailers
- Adoption of a standard maximum gross vehicle weight for interstate highways that is consistent with bridge strength and the double-bottom trailer configuration
- Further regulatory reform along the lines of the Motor Carrier Act of 1980.

Two to four years after beginning implementation, the savings in freight truck diesel fuel could reach 100 MB/D from the combined efficiency gains of the first two items listed above. The savings buildup will be slow because a fleet of double-bottom trailers must be built and parking/storage yards must be built along interstate highways to facilitate local delivery and pickup. The last item listed above could (after an adjustment period) lead to more efficient fuel use by reducing the number of empty-truck miles (estimated to be 20 percent of total truck miles), allowing more direct routing and facilitating intermodal shipments. This savings could, within two to three years, average 100 MB/D of diesel fuel.

Aviation Transportation

The average daily consumption of aviation fuels, including aviation gasoline and aviation turbine fuels, is approximately 1.1 MMB/D, with most of the volume used to power commercial and military aircraft. Commercial airlines rely almost solely on high grade kerosine-based jet fuels, while the military consumes a combination of kerosine and naphtha-based jet fuels. In 1980, consumption of kerosine jet fuels averaged approximately 850 MB/D, while the demand for naphtha-type jet fuels averaged 200 MB/D. Relatively small volumes of aviation gasoline, averaging 35 MB/D, are used for pleasure flying and commercial use.

Historically, commercial jet fuel consumption has been closely linked to general economic activity. Slowed business activity, as measured by the Gross National Product, tends to reduce the number of business-related trips and, hence, the number of air miles traveled. Similarly, a reduction in real per capita disposable income results in fewer personal trips taken on commercial airlines. In addition, the recent deregulation of the airline industry has resulted in substantial improvements in aircraft efficiency through changes in various flight operation patterns (e.g., reducing aircraft weight) intended to reduce fuel consumption.

Several measures could be taken to further reduce the nation's use of aviation fuels during a period of reduced supply. The implementation of those measures, as reported in Table 12, could result in oil savings of approximately 85 MB/D of jet fuel and 10 MB/D of aviation gasoline. In addition to these demand reduction strategies, changes in jet fuel specifications could assist in minimizing the impact of an oil denial on consumers of aviation fuels.

Increase in Airline Load Factors

The airline industry could reduce the number of low density passenger flights, either voluntarily or by governmental directive. An increase in the average seat load factor from the current 62 percent up to 70 to 75 percent is considered achievable and would result in an oil savings of 70 to 100 MB/D.

Improvement of Flight Operations

Further emphasis on other airline operational improvements, such as improved maintenance procedures, improved flight preparations, improved flight procedures, and ground taxi procedures,

TABLE 12

Estimated Oil Savings: Aviation Transportation Sector*
(MB/D)

Strategies	Jet Fuel Winter	Jet Fuel Summer	Aviation Gasoline Winter	Aviation Gasoline Summer
B-1 Increase Airline Seat Load Factor	85	85	--	--
B-2 Elimination of Discretionary General Aviation Flights	--	--	10	10
B-3 Voluntary Reduction of Military Flights	--------No Estimate Made-------			
B-4 Relaxation of CAB Rules	--------Minimal Impact---------			
B-5 Flight Operation Improvements	--------Minimal Impact---------			

---

*Scenario balances were calculated as follows: for Scenarios 1, 1A, and 2, only Strategy B-1 was assumed to be implemented. For Scenarios 3, 4A, 4B, and 4C, both Strategies B-1 and B-2 were employed.

would probably not result in significant fuel savings beyond those already planned. The airlines are now actively involved in many programs of this nature in response to rapidly rising fuel prices.

Relaxation of Civil Aeronautics Board (CAB) Regulations

The effects on fuel consumption of further relaxation of CAB regulations governing flight operations is difficult to quantify. The recent deregulation of airline operations by the CAB has already produced significant savings. For example, a recent CAB energy assessment statement asserts that compared to prior restrictive policies, estimated fuel consumption should be 9 percent (65 MB/D) less under deregulation. It is commonly held that little additional fuel can be saved by further relaxation of the regulations.

Elimination of Discretionary General Aviation Flights

Although it is not recommended, the mandatory elimination of all general aviation pleasure flying could result in an aviation gasoline savings of approximately 10 MB/D. Furthermore, the elimination of all general aviation flights would result in a savings of approximately 50 MB/D of aviation turbine fuel and 30 MB/D of aviation gasoline. This would, however, be disruptive to certain businesses and disastrous to others; it could also affect emergency operations.

Voluntary Reductions of Military Flights

Requests for voluntary fuel usage reduction by the U.S. military could result in some savings, but the amount of the savings is difficult to quantify because of the lack of prior experience and the fluctuating needs of the military based on the state of foreign affairs. Based on 1980 consumption, a 10 percent savings would be small, averaging 5 MB/D of kerosine-type jet fuel and 20 MB/D of naphtha-based product.

Changes in Refinery Product Specifications

A significant means of improving the aviation turbine fuel supply position during a shortage would be the manufacture of turbine fuels to the full specification range. Industry-manufactured turbine fuel in 1979 had a flash point of 130°F or higher. Lowering the flash point to a level which would just meet the current specification of 100°F for product delivered to the customer would result in a 15 to 25 percent increase in turbine fuel supply from the current suppliers (20 percent would increase supply by 170 MB/D). This would, however, reduce the availability of motor gasoline.

Further relaxation of turbine fuel specifications, similar in direction to the relaxed E-2 specs (ASTM) adopted on an emergency basis during the 1973 embargo and which later became the standard, could effect an increase in supply. The added supply quantity would depend on the final approval specification. This is currently under study in National Aeronautics and Space Administration (NASA)-funded projects and could be encouraged by future government actions to be ready in the event of an emergency. Because of the many specification variables, the savings cannot be quantified until the final specification is developed. While these savings could be significant, it should be noted that further flash point reduction increases safety hazards; this area has to be approached very carefully.

Electric Utility Sector

The total volume of energy consumed by electric utilities to meet the base and peak load needs of electric consumers currently averages 11.5 MMB/D COE. The predominant fuel used is coal, which makes up about half of all utility input fuels. Hydro and nuclear power each contribute about 12 percent, while natural gas and oil meet remaining energy needs.

In 1980, the amount of oil used by electric utilities averaged about 1,250 MB/D, including 1,100 MB/D of residual and 150 MB/D of distillate fuel oil. Residual fuel is used primarily under utility boilers to generate steam, while distillate is consumed in peaking facilities (gas turbines and internal combustion engines). Oil use has declined since it peaked in 1978 for two reasons: the continued rapid increase in the cost of oil-fired generation has made long-distance transfer of coal-based power increasingly attractive; and natural gas has become available in sufficient quantities to make up for a significant portion of the cutbacks effected since 1972. These reductions in gas availability were, to a large extent, responsible for the increased oil use over the same period.

Despite the wide differential in generating costs, some utility systems continue to rely on oil and natural gas because local environmental regulations inhibit the addition of coal or nuclear units. Regional patterns of utility oil consumption are shown in Table 13.

TABLE 13

1980 Regional Utility Oil Use*
(MB/D)

Region	
PAD I	769
PAD II	141
PAD III	136
PAD IV	2
PAD V	200
Total U.S.	1,248

---

*U.S. oil use has been disaggregated into consumption within the five Petroleum Administration for Defense districts (PADs) as defined by the Department of Energy.

Historically, the majority of utility oil use has been located along the eastern seaboard where utilities had ready access to low priced residual fuel oil from Caribbean refiners. Continued reliance on oil in PAD I has resulted from delays in the scheduled addition of nuclear units (caused by local opposition) and the financial weakness of northeastern utility systems. In California, stringent environmental regulations, combined with siting restrictions on new power plants, contribute to continued reliance on both oil and gas. Indeed, studies by the National Electric Reliability Council (NERC) in late 1978 and May 1980 concluded that the areas of California, Florida, New England, New Jersey, and southeastern New York are particularly vulnerable to a curtailment of fuel oil supplies due both to their reliance on oil for power generation and to constraints on the electric transfer capability from non-oil regions.[12]

Even without the implementation of the Fuel Use Act, which prohibits the use of oil in new power plants, the future construction of new oil-fired units is unlikely because of the high cost of oil-fired generation. During the 1980's, the completion of nuclear and coal-fired generating units will cause oil use to decline as older units are retired and the remaining units are increasingly used to serve the cycling or intermediate load. The continued availability of natural gas to electric utilities will also contribute to a decline in oil consumption. On the other hand, the conversion of existing oil-fired units to coal is not expected to contribute significantly to this decline due to environmental restrictions and the high capital costs of conversion.

Although electric utility oil use comprises only 8 percent of the total oil consumed in the United States, strategies aimed at reducing oil use can achieve relatively large oil savings with minimal economic or social impact because of the fuel switching capability of the utility industry. These strategies and their impact on utility oil use are shown in Table 14. During an oil denial, the sole use of natural gas under utility boilers capable of burning both oil and gas and, to a lesser extent, increased transfers of coal-fired electric power and accelerated nuclear licensing are the primary strategies identified to displace oil without affecting the nation's electric power supply.

Strategies which involve the mandatory reduction of oil use by electric utilities are not recommended. Because oil serves as a marginal source of supply for most utilities, its use fluctuates with small changes in load demand or alternate source availability. In addition, there is a minimum amount of oil required for area protection, plant startup, flame stabilization, and other nonsubstitutable uses. Therefore, mandatory restrictions on oil use could threaten the reliability and adequacy of a region's bulk power supply.

Oil-to-Gas Conversion

Conversion from oil to natural gas in boilers capable of burning both fuels represents perhaps the most rapid and effective strategy to reduce utility oil use. As a result of the Fuel Use Act, utilities are prohibited from increasing their gas use above

---

[12] The National Electric Reliability Council was formed by the electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply of the electric utility industry systems in North America. NERC consists of nine regional councils whose memberships comprise all electric utility systems in the United States and the Canadian systems in Ontario, British Columbia, Manitoba, New Brunswick, and Alberta. The geographic boundaries of the NERC regions are shown in Figure 2.

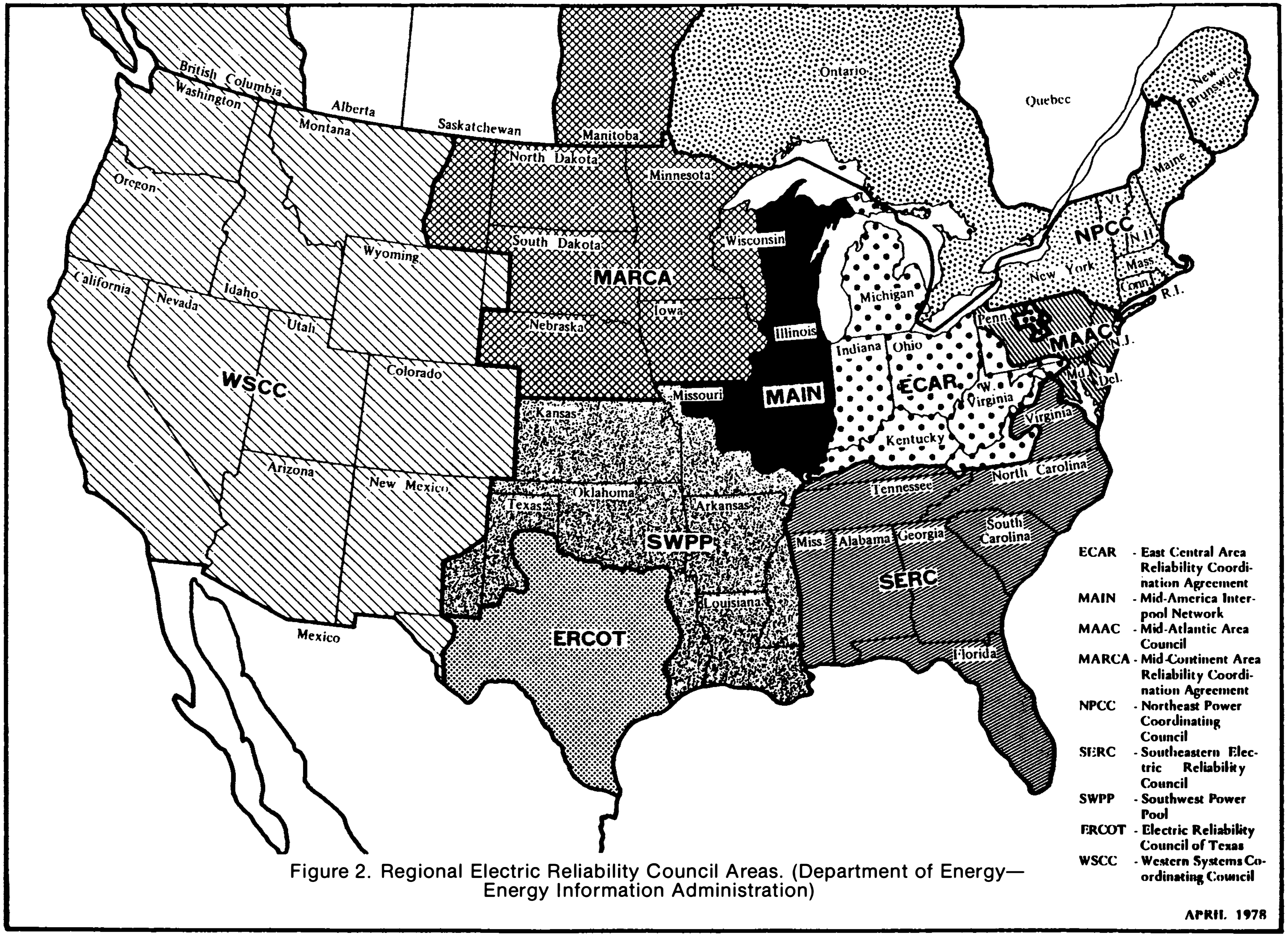


Figure 2. Regional Electric Reliability Council Areas. (Department of Energy—Energy Information Administration)

SOURCE: U.S. Department of Energy, Energy Information Administration, *Plant and Ownership List, Supplementary to the Maps Entitled Principal Electric Facilities 1978*, U.S. Government Printing Office, June 1978.

TABLE 14

Estimated Oil Savings: Electric Utilities*
(MB/D)

Strategies	Residual Fuel Oil Winter	Residual Fuel Oil Summer
C-1 Oil-to-Gas Conversion	240	220
C-2 Increased Electricity Wheeling	30	30
C-3 Increased Electricity Imports	30	30
C-4 Voltage Reduction (5 Percent)	20	20
C-5 Emergency Demand Reduction Program (5 Percent)	50	45
C-6 Nuclear Power	30	60
C-7 Increased Coal-Fired Generation	--No Estimate Made--	

---

*Scenario balances were calculated as follows: for Scenarios 1, 1A, and 2, Strategies C-1 through C-3 were assumed to be implemented. For Scenarios 3, 4A, 4B, and 4C, all strategies were employed.

average consumption levels recorded between 1974 and 1978. However, because of depressed demand in other gas-consuming sectors, substantial supplies of natural gas became available in 1979 for electricity generation. In response, in cases where the use of natural gas resulted in the displacement of distillate and low sulfur residual fuel oil, "special interest" exemptions to the Fuel Use Act were granted by DOE. Because of continued gas availability, this program has been extended through November 30, 1981. Provisions of the Fuel Use Act allow for further extensions of exemptions as judged appropriate by DOE until June 30, 1985. It is estimated that these exemptions resulted in the displacement of approximately 300 MB/D of oil during 1979 and 1980.

Approximately 97,000 megawatts of utility generating capacity were originally designed to burn both oil and gas. Table 15 shows that these units consumed 700 MB/D of oil and 1,050 MB/D of natural gas in 1978 (1979 data are not currently available on a plant-specific basis). By far, PADs I and V burned the greatest volumes of oil, with primary consumption located in the states of Florida, New York, New Jersey, and Virginia, each historically having access to abundant supplies of low-valued residual oil from Caribbean refiners. Utilities in Louisiana and Arkansas (PAD III) have consumed substantial quantities of oil under dual-fired boilers when

TABLE 15

Oil Displacement Potential Under Dual-Fired Boilers
(MB/D COE)

Region	1978 Fuel Use Total	Gas	Oil	(1) 1979-1980 Oil Displacment Achieved	(2) Estimated 1981 Fuel Use Reduction	Oil Savings*
PAD I	330	60	270	(100)	(80)	90
PAD II	170	130	40	(10)	(10)	20
PAD III	790	680	110	(90)	(10)	10
PAD IV	10	10	--	--	--	--
PAD V	450	170	280	(100)	(50)	130
Total U.S.	1,750	1,050	700	(300)	(150)	250

---

*Potential oil savings are computed by deducting from regional oil use in 1978 the estimates of oil displacement already achieved (Column 1) and expected reductions in demand for both oil and gas (Column 2). Thus, the expected oil savings for PAD I in 1981 represents 270 MB/D of oil used in 1978 less 100 MB/D of oil displaced in 1979 and 1980 and 80 MB/D of oil which will not be used because of lower electrical demand or the planned replacement of oil by coal or nuclear power.

gas was not available. PAD V includes fuel use by California utilities only (which rely almost solely on oil and gas for steam-electric generation).

If sufficient supplies of natural gas were available, an upper bound for the oil reduction possible during an oil shortfall would therefore be 700 MB/D. However, a more realistic estimate is much lower, limited by the extent to which:

- The utilization of dual-fired units is reduced by the availability of power from new coal and nuclear units
- Natural gas has already displaced oil during the 1979-1980 gas "surplus."

During 1981, the utilization of oil-, gas-, and dual-fired generating units is projected to decline as generation from existing nuclear reactors increases and new coal-fired units enter commercial service. With reduced use of dual-fired plants, the total fuel requirements of these units are expected to decline. In estimating this reduction, it is assumed that the combined decline in utility oil and gas consumption between 1978 and 1981, shown in the consensus forecast, would be shared equally by all oil- and gas-burning facilities, based upon their 1978 use. Thus, approximately half the 310 MB/D decline in oil and gas demand should result from reduced requirements by dual-fired units. Lower total fuel consumption among these units reduces the oil displacement potential of natural gas. As noted previously, natural gas had already displaced 300 MB/D of oil in 1979 and 1980 through "special interest" exemptions of the Fuel Use Act. Table 15 shows that these two factors combine to reduce estimated oil savings from 700 MB/D COE to approximately 250 MB/D COE.[13]

Conversion of oil-fired units to coal has been suggested as another fuel conversion strategy to reduce utility oil use quickly. Legislation providing for the mandatory conversion of coal-capable units was passed by the Senate in 1980 and may be reconsidered by the 97th Congress in 1981. A number of obstacles to a conversion program have been identified, including stringent environmental standards, the availability of capital funds needed to make the conversions, the age of generating units, and the ability to store/handle coal volumes at the plant. In the near term, however, the time required to make those technically feasible conversions limits the importance of coal-to-oil conversions under emergency conditions.

Increased Electricity Wheeling

Electric wheeling, or the transfer of power through the national electric power grid, represents an immediate supply response to an emergency oil shortage. In effect, wheeling allows power suppliers to substitute domestic fuels used in the generation of electricity (coal, nuclear, and hydropower) for oil with minimal disruption to consumers. In evaluating potential oil savings, however, it should be recognized that the existing power system is highly interconnected and that extensive power exchanges now occur to achieve greater reliability and to minimize utility oil use. The potential for increasing electricity transfers is difficult to

---

[13] The estimate is considerably lower than a similar American Gas Association (AGA) estimate of "Category 1" or the immediate gas substitution potential of utility power plants. In a recent paper, the AGA suggests that 600 MB/D of residual fuel oil could be saved (above those volumes already displaced in 1979 and 1980) by substituting natural gas in dual-fired boilers. Although the difference in these estimates cannot be fully reconciled, it is believed the AGA data represent a maximum substitution capability irrespective of electric generating needs. The estimates provided in this report reflect the planned addition of coal and nuclear units and a negligible growth in electricity use during 1981. These two factors will cause utilities to reduce their use of both oil and natural gas. As a result, achievable oil savings are shown to be less than the installed capability of dual-fired units.

estimate because transmission capacity and load diversity limit the industry's ability to wheel power. However, based upon a comparison of reported emergency transfer capabilities and normal load flows during 1979, it is estimated that a maximum of 30 MB/D of oil could be displaced by additional power transfers.

The chief vehicles for the interchange of power are power pools, formal organizations established by two or more utilities to improve service reliability through joint planning and operation. Individual utilities and power pools are combined into nine regional reliability councils (shown in Figure 2) which coordinate system planning and utilization. Power pooling allows utilities to take advantage of load diversity; that is, peak loads in different systems may occur at different times, so that power can be provided by neighboring systems when generating facilities in the neighboring system are not fully utilized. If the diversity is large enough and is expected to endure, interchange agreements, or scheduled transfers, are made for the period of expected load diversity. In addition to scheduled transfers, power pooling allows utilities to "economically dispatch" generating facilities in order of increasing variable operating costs. This means, for example, that one utility can operate its base load nuclear or coal unit longer, thereby allowing a neighboring utility to reduce its use of more expensive oil-fired units.

The potential for increased interchange among utility systems to further reduce oil use is unclear. Because of the interdependence of transmission lines and the dispersion of lines and equipment throughout the entire service area, line capacities cannot easily be determined. In addition to voltage levels, many factors affect transmission capacity, including the number of conductors, conductor size and type, length of line, terminal facilities (transformers, circuit breakers, etc.), characteristics of the network in which the line is placed, and allowable voltage differences between line terminals.

Emergency power transfer capability, the total amount of power which can be scheduled for interregional transfers (above the net contracted purchases and sales), is reported by the nine regional reliability councils for the current year (see Table 16). This transfer capability is required to handle such unexpected events as large scale loss of generating capacity, transmission system accidents, and unforeseen increases in demand. Emergency transfer capabilities, however, are not good indicators of incremental power wheeling potential for two reasons: they represent transfer capacities that can be sustained over only short periods of time (generally several days), and transfers to any one council (or from one council) are not simultaneous. Individual capabilities reported in Table 16 are not additive because the circuit conditions under which power is transferred differ for each individual transfer. For example, the maximum emergency power that the Southeastern Electric Reliability Council (SERC) could receive from the East Central Area Reliability Council (ECAR) and the Southwest Power Pool (SPP) together is less than the sum of the individual power transfer capabilities of the latter two regions.

TABLE 16

Inter-Council Emergency Transfer Capability As Reported April 1, 1980 By the Regional Reliability Councils

Direction of Power Flow*		Emergency Transfer Capability (Megawatts)†
From	To	Summer 1979
ECAR	MAAC	3,300
ECAR	NPCC (NYPP)	2,200
ECAR	MAIN	2,340
ECAR	SERC (TVA)	1,800
ECAR	SERC (VACAR)	1,250
NPCC (NYPP)	ECAR	3,300
NPCC	MAAC	2,250
MAIN	ECAR	4,000
MAIN	MARCA	1,000
MAIN	SERC (TVA)	750
MAIN	SPP	2,000
MAAC	ECAR	2,450
MAAC	NPCC	1,650
MAAC	SERC (VACAR)	1,800
MARCA	MAIN	600
MARCA	WSCC	100
MARCA	SPP	700§
SERC (TVA)	ECAR	2,000
SERC (VACAR)	ECAR	2,700
SERC (VACAR)	MAAC	2,000
SERC	MAIN	1,100
SERC	SPP	1,550
SPP	SERC (TVA)	2,650
SPP	MARCA	800
SPP	MAIN	2,000
WSCC	MARCA	100
WSCC (U.S.)	WSCC (Canada)	2,000
WSCC (Canada)	WSCC (U.S.)	2,000

---

*See Figure 2 for definition of acronyms.

†All transfers to a Council (or from a Council) are not simultaneous. The total of all transfers to a Council (or from a Council) does not represent the total emergency power actually transferable because circuit conditions are different for each individual transfer.

§Total of scheduled and emergency capability.

Estimates of oil displaced through wheeling are based upon actual flows between major power pools, reported weekly to DOE's Power Supply and Reliability Division. The Department of Energy surveys utilities in 10 eastern power pools, the Mid-Continent Area Reliability Coordination Agreement (MARCA), and subregions within the Western Systems Coordinating Council (WSCC). The objective of the survey is to measure the volume of oil displaced through each of the three strategies: electricity imports, electricity transfers, and incremental natural gas usage. Daily consumption of oil by reporting utilities comprises approximately 89 percent of the total oil used by electric utilities. Although they are only rough measures of non-emergency transfer capability, the DOE data do demonstrate that power pooling is currently used by utilities to reduce oil use by approximately 300 to 350 MB/D. Oil displacement in 1980 appears to have increased over 1979 levels by 50 MB/D.

In addition, industry analyses of the effectiveness of the utility industry in conserving oil through electricity transfers show that approximately 300 to 400 MB/D of oil is currently being displaced and that an additional 30 MB/D may be saved during an oil denial. Additional savings are constrained by transmission capabilities and practical limitations on load dispatch techniques.

While oil savings resulting from electricity transfers have risen to about 350 MB/D, barriers standing in the way of increased transfers may be difficult to remove; examples are rate-setting procedures by state regulatory commissions which discourage out-of-state power transfers, state "export taxes," and other differential pricing practices. The oil displacement potential of these additional transfers cannot be quantified. It is recommended, however, that state regulatory commissions establish mechanisms to coordinate regional power planning and to encourage multistate pooling, particularly during emergency conditions.

Increased Canadian Electricity Imports

Because the cost of Canadian generation (primarily from hydroelectric and coal plants) is lower than the cost of domestic oil-fired electricity, much of the available Canadian electricity is now being imported. In 1979, Canada exported 30 billion kilowatt-hours of electricity, or 150 MB/D COE to U.S. markets. Primary sources of Canadian power include the New Brunswick Electric Power Commission (to Maine), Quebec Hydro (to New York), Ontario Hydro (to Michigan and New York), Manitoba Hydro (to North and South Dakota), and British Columbia (to the Pacific Coast states). In the near term, increased Canadian imports offer some potential for oil displacement. However, the ability to import additional Canadian power is limited by the availability of power supply and, to a lesser extent, transmission line capabilities. These two factors combine to restrict an expected increase in Canadian imports to 5 to 7 billion kilowatt-hours, or an additional oil displacement of 25 to 35 MB/D COE.

Although several Canadian utilities are now investigating the possibility of increasing power transfers to the United States, large increases in power imports could not begin until 1987, the earliest that new transmission lines could be completed.

The potential for increasing Mexican imports in the near term is constrained by the need to build more inter-ties and uncertainty about load diversity. Only marginal oil displacement could be expected from Mexican power transfers.

Five Percent Reduction in Service Voltage

Utilities deliver electricity to their customers at approximately 115 volts, a level at which most appliances operate with greatest efficiency. However, in order to assure customers at the end of a distribution line at least 114 volts (the minimum voltage limit used by the appliance manufacturing industry), customers near the front often receive as much as 126 volts. Depending on the type of appliance, recent Electric Power Research Institute (EPRI) studies show that narrowing this range could result in total energy savings of 1.0 to 1.5 percent for each percent reduction in voltage without a significant change in service quality. In addition, a reduction in maximum voltage lengthens the operating lifetime of many appliances.

In 1977, California utilities were ordered to cut maximum voltage to 122, provided that no new equipment would be required by the reduction. An estimated 9 MB/D of oil was saved by this change. To date, discussions have centered around a reduction of maximum service voltage from 126 to 120 (a 5 percent reduction) without reducing the minimum voltage levels. Given this voltage drop, a maximum of 50 MB/D of oil could be saved.

Achievable oil reductions, however, are lower for several reasons:

- Utilities have attempted voltage range reduction on feeders that are not voltage limited. If feeders are at present voltage limited or become voltage limited because of these reductions, additional equipment in the form of regulators, capacitors, or larger conductors will be required to maintain minimum specified service voltage. This would require large expenditures by utilities and would reduce the immediate oil savings potential of the voltage reduction.

- It is considerably more difficult to narrow the voltage range on older systems, particularly in rural areas.

- Some loads, such as air conditioning at certain ambient temperatures and humidity levels, increase energy consumption as voltage is reduced. Because the effectiveness of voltage reduction for all utility systems is doubtful, the oil savings which may actually be achieved are less than the maximum estimate shown above. At best, oil displacement would be small, averaging less than 20 MB/D.

Emergency Electricity Demand Reductions -- The Los Angeles Experience[14]

When the oil embargo of 1973-1974 was imposed, over half the electricity generation for the city of Los Angeles came from oil, and because the low sulfur oil needed to meet pollution requirements was in short supply, prospects for meeting normal demands were poor. After reviewing possible alternatives (such as burning high sulfur fuel, curtailment of business activities to 50 hours per week, and rolling blackouts) and after consulting with a broad representation of consumer groups, the Mayor and the City Council on December 13, 1973, passed a rationing scheme, "The Emergency Energy Curtailment Plan of the City of Los Angeles." Under Phase I of the plan, residential and industrial customers were required to cut energy use by 10 percent and commercial customers by 20 percent below the corresponding billing period a year before. Under Phase II, residential use was restricted to 12 percent, industrial to 16 percent, and commercial use to 33 percent below that of the corresponding billing period. The penalty for excess use was a surcharge of 50 percent of the entire bill for the first period violation and cutoff of service for subsequent violations. As originally enacted, the ordinance had no provision for averaging between two billing periods if consumption in one period was out of line. A later amendment to the ordinance permitted averaging.

Response was rapid, and in the first 11 days electricity generation fell about 15 percent compared to the same period in 1972. The reduction was considered so significant that Phase II was never invoked. Enforcement of penalties was also postponed, and the ordinance was suspended on May 22, 1974. Table 17 is a summary of the results.

Several conclusions can be drawn from the results of the program:

- This ordinance seems to have a lasting effect on the pattern of consumption, leading to a slower rate of growth.
- The basic provisions for relying on a rate surcharge based on historical consumption could be applied to other public utility commissions in most states.
- The large overall reduction in Los Angeles is probably not completely transferable to other utilities as their customer

---

[14] This section describes the results of a study on the emergency demand reduction program implemented in Los Angeles during the Arab oil embargo of 1973-1974. Additional details of this study may be found in "Regulatory Rationing of Electricity Under a Supply Curtailment," Jan Paul Acton and Ragnhild Mowill, Land Economics, November 1976.

mix is different from the national average; i.e., 50 percent commercial sales in Los Angeles vs. 38 percent nationally.

- The slower growth of electricity sales nationally since this emergency period indicates that the attainment of the Los Angeles reduction levels will be more difficult.

- The ordinance does create a significant administrative burden which would have been even higher if the penalties had actually been levied.

TABLE 17

Summary of Curtailment Targets and Observed Reduction in Electrical Sales by Sector (January through May 1974)

Sector	Target Reduction (Phase 1 of Ordinance) (%)	Average Actual Reduction Over Preceding Year (%)	Average Reduction in Excess of Predicted Use* (%)
Residential	10	17	9
Commercial	20	27	31
Industrial	10	4	8
Total	12	19	22

---

*The predicting equation implied that price and daylight hours were significant for residential customers only. Most commercial establishments met their reduction goals with only changes in lighting.

Nuclear Power

Several actions have been suggested by the electric utility industry to increase the production of electricity from new and existing nuclear reactors during an oil denial period. Oil savings resulting from the implementation of these actions are estimated to average 30 MB/D during a six-month curtailment and 60 MB/D during a 12-month period. This expected level of savings is limited by two factors: while nuclear power directly displaces oil-fired generation in oil-dependent regions of the country, oil savings in coal-dominant areas may be negligible; and the consensus forecast for nuclear power in 1981 represents a return to relatively normal levels of plant availability[15] and the commercial operation of three recently licensed reactor units (Salem-2, Sequoyah-1, and North Anna-2) during the year. Estimated oil savings from nuclear power are based upon the ability to increase nuclear generation above that already anticipated.

There are some additional strategies which could increase oil displacement by nuclear power during an emergency period; these are described in the following sections. However, it should be noted that because of continuing concerns in some quarters regarding nuclear safety, the implementation of these strategies will be difficult.

- Accelerating the Licensing of Nuclear Units Nearing Completion. The Edison Electric Institute has identified six nuclear units (in addition to the three units named above) which could achieve full power operation in early 1981 if full power operating licenses are granted by the NRC (see Table 18).

  Under the Atomic Energy Act, the NRC is required to hold a public hearing, if requested, before issuing an operating license to a nuclear unit. To expedite this process during an emergency period, the NRC might be authorized to grant "interim" operating licenses to speed up the process.

  Direct oil savings from the accelerated addition of nuclear reactor units can occur only if the operating utility is located in an oil-dependent region. This requirement excludes three of the six units listed above: McGuire-1 (Duke Power); Farley-2 (Alabama Power); and Sequoyah-1 (TVA). Moreover, due to the design of nuclear units, they must be operated continuously and thus are committed to base load service. Even if utilities operating these new reactors consume oil, they may not be able to displace that oil if it is consumed in facilities which serve the peaking or cycling load. Given this additional requirement, it is estimated that the maximum amount of oil which can be displaced by the addition of the six units identified by Edison Electric Institute is 30 to 60 MB/D.

---

[15] In 1978, U.S. nuclear reactors produced 276 billion kilowatt-hours of electricity. Nuclear generation fell to 255 billion kilowatt-hours in 1979, however, following the incident at Three Mile Island (TMI) and the subsequent series of Nuclear Regulatory Commission (NRC)-ordered reactor shutdowns. The unavailability of nuclear units during 1979 and 1980 reduced their utilization to less than 58 percent, down from the 65 percent considered normal for the industry. (Because nuclear electricity is, on average, cheaper than coal-fired generation, nuclear units are used as much as possible to meet the continuous or base load.) Nuclear units were shut down by the NRC for safety evaluations and equipment modifications recommended from studies of TMI. In addition to TMI Units 1 and 2, two other reactors were also permanently closed down during 1979.

TABLE 18

Nuclear Units Which Could Achieve Full Power Operation Early in 1981

Unit Name/No.	Rating (Megawatts)	NERC Region (Subregion)*	Remarks†
Diablo Canyon-1	1,084	WSCC (N. Cal.)	Construction completed 1/80. Operating license expected 3/81.
McGuire-1	1,080	SERC (VACAR)	Construction expected to be completed 12/80. Low power license 4/81.
Farley-2	807	SERC (Southern)	Undergoing low power testing and fuel-loading.
LaSalle-1	1,048	MAIN	Construction expected to be completed 12/80. Low power license expected 3/81.
Summer-1	900	SERC (VACAR)	Construction expected to be completed 6/81 -- 95% complete.
Sequoyah-2	1,148	SERC (TVA)	Construction expected to be completed 6/81 -- 90% complete.

---

*See Figure 2 for definition of acronyms.

†From "Electric Utility Status Report," Electric Power Monitoring Center, November 20, 1980.

- Allowing Three Mile Island Unit 1 (TMI-1) to Resume Commercial Operation. According to utility experts, TMI-1 could be operated safely at its rated capacity of 776 megawatts. As a result of the accident at TMI-2, Unit 1 was shut down in March 1979. To return the unit to commercial service during the oil curtailment scenarios, special hearings required prior to restart would have to be accelerated. TMI-1 could displace approximately 20 MB/D of oil if returned to service, although this is not assumed in this analysis.

- Maximizing the Use of Existing Nuclear Units. During an oil denial period, the NRC may be required to defer regulatory action which could cause existing plants to shut down or reduce power. For example, the NRC is currently implementing the second phase of the TMI "Lessons Learned" Action Plan (NUREG-0660), a set of short-term measures to upgrade reactor equipment and to train operators and other nuclear plant personnel. In addition, the NRC has proposed additional safety modifications to all existing and planned nuclear plants following a June 1980 incident at the Tennessee Valley Authority Brown's Ferry Unit 3, including the installation of pressure valves, changes in the design of the fuel core, and the addition of automatic features to safety machines. A third uncertainty to the short-term nuclear outlook is the requirement that all states have approved NRC emergency evacuation plans by January 1, 1981. Reactors in states without approved plans will be closed. (However, these reactors could remain operational if the NRC deemed that there was sufficient need for the plant's power.)

Because these actions do not affect nuclear operations in the 1981 consensus forecast, no estimate of oil savings resulting from their deferral was made.

Increased Coal-Fired Generation

Increasing electricity generated by coal to reduce the need for oil-fired generation during an oil denial has been recommended by various industry analysts. To implement this strategy, the licensing and startup of new coal-fired units located in oil-dependent regions would have to be accelerated, and the utilization of coal plants currently in commercial service would have to be increased.

In 1979, the average capacity factor of coal-fired plants was 55 percent. If increased to 65 percent during an oil curtailment, an additional 185 billion kilowatt-hours of electricity could be generated, displacing approximately 900 MB/D COE of oil. However, several important constraints on increasing the utilization of coal-fired power plants exist which make this level of savings literally impossible to achieve. These include technical limitations on operating these units at very high levels, daily load requirements which may not match the electricity supply, and constraints on the ability to transfer coal-fired electricity to oil-dependent regions.

Although the average capacity utilization in 1979 was 55 percent, the variance around this mean value is extremely large. Some plants, used to meet the base or continuous load, operate at between 60 and 65 percent of capacity, while older, less efficient plants are used for the cycling or intermediate load and operate at about 30 to 40 percent of their net capability. In order to increase the average factor, base load plants would have to operate at rates very near their availability factors (i.e., that portion of the year that the units are capable of generating power after consideration of downtime for maintenance and repair). Cycling plants would also have to be used more intensively; however, increased usage tends to reduce their reliability and, hence, their availability. In addition, because of additional technological features, newer base load units have reduced availability factors (approximately 70 to 75 percent). Plant availability may be increased by delaying normal operating and maintenance procedures during an emergency or by bypassing non-essential equipment on the units (such as flue gas desulfurization systems or cooling towers).

This latter type of action would clearly require the relaxation of federal and state air and water quality standards. The need to increase plant availability should be evaluated against the potential reduction in environmental quality which would result in the process.

The second limitation on plant utilization, demand, is difficult to assess with available data. Since higher capacity factors are achieved in part by operating generating plants 24 hours a day, consumers would be required to spread their daily electrical usage to conform to its availability. The ability to shift load to off-peak hours is somewhat limited, although peak load pricing may be of use.

Most of the oil used by utilities is located along the East Coast and California. The ability to wheel power to these oil-dependent regions was described and quantified earlier. Interregional transmission facilities are now being loaded to near their maximum potential to reduce the use of oil. As a result, the ability of additional coal-fired electricity to displace oil is limited to approximately 30 MB/D.

Because additional power transfers are constrained by capacity, accelerating the addition of coal-fired units in oil-fired regions would be effective in reducing oil use. The Edison Electric Institute identified 11 units (shown in Table 19) whose expedited

TABLE 19

New Coal Plants Whose Licensing Could Be Expedited During an Oil Denial

Unit Name/No.	Rating (Megawatts)	Scheduled Service Date	NERC Region (Subregion)*
Sandow 4	545	4/81	ERCOT
Indian River 4	400	9/80	MAAC
Deerhaven	235	2/81	SERC (FL)
Roxboro	720	9/80	SERC (VACAR)
Nearman 1	235	10/80	SPP
Big Cajun 2-1	540	9/80	SPP
Northeastern 4	450	9/80	SPP
Sooner 2	515	10/80	SPP
Big Cajun 2-2	540	12/80	SPP
White Bluff 2	740	5/81	SPP
Grand River Dam Authority	490	5/81	SPP
	5,410		

---

*See Figure 2 for definition of acronyms.

licensing during an oil denial could result in oil savings. However, because these units have been included in the consensus forecast, an estimate of incremental oil savings resulting from their addition to the grid was not made.

Residential Sector

During 1980, the total energy requirements of residential housing units averaged approximately 5 MMB/D. Most of the energy in this sector is used for space and water heating, while smaller volumes are used for air conditioning, lighting, cooking, and refrigeration (see Table 20).

TABLE 20

Residential Energy End-Use Patterns
(Percentage)

Space Heating	57
Water Heating	15
Air Conditioning	5
Cooking	5
Lighting	6
Refrigeration/Freezing	7
Other	5
Total	100%

Several factors contribute to the overall level of residential energy use. In the long run, the number of households is a key indicator because it roughly approximates the total number of energy-consuming housing units. However, energy use per household, a measure of residential energy conservation, has declined steadily over the last decade as consumers have responded to real increases in energy prices. A continued decline in per-household energy consumption is expected as the stock of energy-consuming equipment becomes more efficient.

In the short run, however, residential energy use reflects variations in weather conditions as well as immediate responses to sudden price changes. For example, many residential consumers reacted to the Iranian supply disruption of 1979 by lowering thermostats in the winter and adding insulation to their homes. Another denial period will likely lead to further reductions in residential energy use, although the magnitude of this reduction may not be as great.

Oil comprises less than a third of the total energy consumed inthe residential sector, or approximately 1.5 MMB/D. Virtually all oil is used in space and water heating applications, including the use of distillate fuel oil, kerosine, and propane. The consumption of oil for residential heating has declined since 1976 due to price-induced conservation and the use of natural gas or electricity in place of oil in new homes. Recent data show that this trend has accelerated since 1979.

The strategies identified to reduce oil use in the residential sector are shown in Table 21. Total energy savings during an oil denial period are shown for the winter and summer months; the seasonal differential reflects the various end-use activities (e.g., space heating vs. space cooling) and attendant fuel requirements associated with the two periods.

TABLE 21

Estimated Energy Savings: Residential*
(MB/D)†

Strategies		Distillate Fuel Oil		Natural Gas		Electricity	
		Winter	Summer	Winter	Summer	Winter	Summer
D-1	Thermostat Management	15	--	30	--	10	20
D-2	Weather Stripping	5	--	10	--	5	--
D-3	Insulation	15	--	--	--	--	--
D-4	Maintenance	15	--	30	--	10	--
D-5	Water Heating						
	Insulation	10	10	45	45	5	5
	Thermostat Setting	5	5	5	5	--	--
	Flow Limiters	20	20	40	40	10	10

---

*In calculating scenario balances, Strategies D-1, D-2, D-4, and D-5 were assumed to be implemented for Scenarios 1, 1A, and 2. For Scenarios 3, 4A, 4B, and 4C, all strategies were employed.

†Estimates of distillate fuel oil are reported in thousands of daily product barrels. Natural gas and electricity volumes were converted from physical units to crude oil equivalent barrels using 5.8 million Btu per barrel of crude oil.

Because the decline in residential oil use is expected to continue, additional oil savings resulting from the implementation of these strategies will be small. Additionally, the adoption of these various conservation practices is likely to affect not only oil, but other residential fuels.

Reduction of Thermostat Setting (Winter)

Reducing the thermostat setting will result in an average savings of 1 percent for each degree that the setting is lowered from 72°F. Actual savings vary depending on the geographic region, the severity of the winter, and the condition of the housing unit.

A recent Opinion Research Corporation study found that 79 percent of American homeowners lowered their winter thermostat settings in 1979. Additional education and a real/recognized state of emergency would probably lead to further reductions of settings. Furthermore, additional efforts could result in thermostat timer installations, a 4°F to 5°F nighttime setback, additional setbacks when the homes are not occupied, and further daytime setbacks for occupied homes. With a concerted effort, it would be possible to achieve the equivalent of an additional 2°F setback in 50 percent of the homes, yielding winter savings of 31 MB/D COE of natural gas, 13 MB/D COE of fuel oil, and 9 MB/D COE of electricity.

Raising of Thermostat Setting (Summer)

Approximately 2 percent of the energy used for air conditioning can be saved for each 1°F that the thermostat setting is raised. It is estimated that 50 percent of the homes have already increased their thermostat settings and that another 20 percent never will. If the remaining 30 percent were to increase their settings by 5°F and the 50 percent who have changed would move up an additional 1°F, the savings would be about 4.5 percent of the energy used for air conditioning, resulting in savings of 11 MB/D COE. These savings occur in the summer only and only affect electricity consumption.

Additional Weather Stripping

In the early 1970's it was estimated that about 20 million existing one- and two-unit homes were candidates for retrofit attic insulation, storm or thermopane windows, or weather stripping. A recent DOE publication estimates that between April 1977 and December 1978, 10 million homes received weather stripping, 17 million homes were caulked, and 7.3 million homes received additional insulation. This same study suggests that in early 1979 there were about 15 million units that could benefit from additional insulation. About three million of these units heat with oil.

An Opinion Research Corporation study found that 55 percent of American homes had received weather stripping or were caulked in late 1979 and that 31 percent had received additional insulation. With this background, it is estimated that there are 10 million units that could benefit from weather stripping/caulking and that there are 12 to 15 million that could benefit from insulation. Weather stripping, caulking, and plugging leaks will reduce space heating energy needs by about 5 percent in the 10 million units in need of such measures. This equates to about 17 MB/D COE. The summer estimate for air conditioning savings is 2 MB/D COE.

Improved Insulation

It would be impossible to insulate the 12 to 15 million deficient homes in the time frame of the scenarios. However, a concerted effort involving government and industry in a crisis situation could insulate 50 percent of the three million deficient oil-heated homes. This would reduce their oil needs for space heating by 8 to 10 percent and would yield nearly a 1 percent reduction in fuel oil and kerosine use for home heating. Daily winter savings of fuel oil/kerosine in these 1.5 million homes would be about 13 MB/D.

Equipment Maintenance

Maintenance of air conditioning and space heating units can increase their efficiencies by about 5 percent. Many heating and air conditioning units are already being properly maintained or are new; their efficiencies would therefore not be improved by maintenance attention. If the efficiencies of 40 percent of all heating units were improved by 5 percent, the savings would average 56 MB/D COE (winter).

Proper maintenance of air conditioning units is practiced by nearly all the owners of centrally air conditioned homes (over 50 percent of the air conditioning total). The remaining room air conditioning units will not only benefit less from maintenance but are less likely to receive it. These savings are considered to be extremely small and have not been quantified.

Additional Insulation of Water Heating Unit

Most water heaters (60 percent) use natural gas, while 12 percent are oil fired and 28 percent are electric. Increasing insulation from the usual 1 inch to 5 inches on an oil or gas water heating unit will improve efficiency by 20 percent. The conventional electric unit has 2 inches; adding insulation to a total of 5 to 6 inches improves efficiency by only 6 percent. Assuming that half of the 60 million water heaters in the United States can be insulated, a total energy savings of 60 MB/D COE can be achieved: 45 MB/D COE of natural gas, 9 MB/D COE of oil, and 6 MB/D COE of electricity.

Reduction of Water Heating Thermostat Setting

Lowering the thermostat setting by 10°F will reduce energy use by about 5 percent for the typical gas or oil heater and about 3 percent for electric heaters. If the tank is properly insulated (5 to 6 inches), the savings is 1 percent for each 10°F regardless of heater type. A recent survey indicates that about 50 percent of the homeowners in the United States have lowered their water heater thermostat settings as of late 1979. Additional participation and further lowering of already reduced settings can be expected. Assuming that 80 percent of those who have already reduced settings will lower them 10°F more and that 40 percent of those who have not lowered settings will lower them 20°F, an average thermostat setting reduction of 8°F will be realized. If half these reductions occur in 5- to 6-inch insulated units and half in typical units, the percentage savings would be about 1.5 percent, or 11 MB/D COE.

Use of Water Heating Flow Limiters

Water flow limiters can save energy when placed in spigots, shower heads, etc., where water flow quantity can be reduced without decreasing the flow's effectiveness. This basically restricts the flow limiter's utility to showers. Assuming that the limiter reduces shower flow from 6 gallons per minute to 3 gallons per minute, a hot water savings of 70 MB/D COE can be achieved: 42 MB/D COE of natural gas, 8 MB/D COE of oil, and 19 MB/D COE of electricity.

Other actions which can save hot water include washing clothes in cold water whenever possible, fixing leaking faucets, and running only full loads in dish and clothes washers. No estimate of their energy saving potential is provided.

Additional Measures

Reduced lighting, energy-conscious appliance use (dishwashers, dryers), and adjustment of freezer/refrigerator temperatures are other measures that can save energy. Most save electricity and many are already being done by a majority of people.

Commercial Sector

Commercial buildings include not only nonmanufacturing business establishments and office buildings but also schools, hospitals, and other similar institutions. In 1980, the commercial sector consumed approximately 3 MMB/D COE in such end-use activities as space heating and cooling, water heating, and lighting. The distribution of activities is displayed in Table 22.

TABLE 22

Commercial Sector End-Use Activities
(Percentage)

Space Heating	52
Air Conditioning	12
Water Heating	12
Refrigeration	5
Lighting	13
Other	6
Total	100%

Most of the space heating and water heating energy requirements are met by natural gas. Oil, primarily residual fuel oil, is the source of the remaining energy needs for this end-use activity. In 1980, oil used by commercial establishments is estimated to have averaged 500 MB/D.

Table 23 lists the strategies which can be used to reduce energy consumption in this sector. As with the residential sector, the implementation of these strategies will yield savings of all fuels used by commercial consumers. Because of the relatively greater use of natural gas in the commercial sector, more natural gas will be displaced than oil or electricity. Consequently, these supplies will be available to further reduce oil use by other sectors, such as industry or electric utilities.

TABLE 23

Estimated Energy Savings: Commercial*
(MB/D)

Strategies	Oil† Winter	Oil† Summer	Natural Gas Winter	Natural Gas Summer	Electricity Winter	Electricity Summer
E-1 Thermostat Management	35	--	85	5	--	15
E-2 Ventilation	15	--	35	--	--	5
E-3 Maintenance	15	--	35	--	--	10
E-4 Water Heating -- Insulation	--	--	5	5	--	--
E-4 Water Heating -- Thermostat Setting	--------------------Less Than 5--------------------					
E-5 Lighting Reductions						
Decorative	--	--	--	--	30	30
Task Lighting	--	--	--	--	5	5
E-6 Close Schools During Winter Months	------------------No Estimate Made------------------					
E-7 Fuel Switching	------------------No Estimate Made------------------					

---

*In calculating all scenario balances, Strategies E-1 through E-5 were assumed to be implemented.

†Oil savings are reported in thousands of daily product barrels and are comprised of 25 percent distillate and 75 percent residual fuel oil. Natural gas and electricity volumes were converted from physical units to crude oil equivalent barrels, using 5.8 million Btu per barrel of crude oil.

Because of the seasonal nature of energy use in the commercial sector, savings are estimated for both the winter and summer seasons. These differences reflect seasonal patterns of end uses and the fuel consumption associated with each.

The analysis takes into account the fact that, due to price increases and government efforts to encourage conservation in this sector, many conservation measures have already been implemented. Furthermore, the strategies identified in Table 23 are easily and quickly accomplished and can therefore be implemented within 180 days; for this reason, all strategies are included in the scenarios.

Thermostat Management

Previous sources indicated that 8 to 10 percent of space conditioning energy could be saved by reducing thermostat settings to 68°F in the winter and raising them to 78°F in the summer. However, at least half of this potential has already been achieved and the realization of another 20 percent is considered doubtful. Thus, an additional savings of 60 MB/D COE for an average day is achievable. Winter savings are estimated to average 120 MB/D COE, of which 30 percent is oil.

Reduced Ventilation

This measure can reduce space conditioning energy requirements by 5 to 8 percent in old buildings. The potential may be as high as 200 MB/D COE; however, implementation is more difficult than for thermostat management and fewer savings are expected. Additional average daily savings from reduced ventilation during oil denial is no greater than 25 MB/D COE.

In winter, savings are somewhat higher, averaging 50 MB/D COE, 30 percent of which is oil. The implementation time required will range from a few days to a month.

Improved Maintenance

A high proportion of commercial structures (schools, office buildings, stores, hospitals, hotels, and others) could save some energy through better maintenance of furnaces and air conditioning units. A lower proportion could benefit from improved weatherization.

The savings achievable through improved (proper) maintenance is about 5 percent for both space heating and air conditioning. It is estimated that about 30 percent of the sector's buildings could benefit and that about 50 percent of these would respond to an urgent call to conserve, as would occur in the scenarios. Thus, the average daily savings would be 15 MB/D COE.

A weatherization program (caulking, etc.) could save about 5 percent in those structures that would benefit (approximately 25 percent of the total). Assuming that half of these structures are weatherized in an emergency, 12 MB/D COE can be saved. Winter savings are higher. The combined effect of weatherization and maintenance during the winter season is to reduce oil use 15 MB/D COE and natural gas use about 35 MB/D COE.

More Efficient Water Heating -- Insulation

This activity consumes about 12 percent of the sector's energy. About 70 percent of the water is heated with natural gas and about 30 percent with oil. The use of flow limiters, automatic spigot shutoff devices, and insulation of hot water tanks and pipes can reduce energy use by 10 to 20 percent. Of course, many such systems have already had these conservation measures applied. A concerted effort could result in an additional 15 percent of the commercial systems' being improved by an average of 13 percent. Under these assumptions, the savings would average 7 MB/D COE, 2 MB/D of which is oil and 5 MB/D natural gas.

More Efficient Water Heating -- Thermostat Setting

As discussed previously, the reduction of thermostat settings results in a savings of about 1 percent for each 10°F reduction in water temperature in a properly insulated system and is a relatively easy measure to implement. Consequently, it is likely that it has already been done in 75 percent of the locations where it is feasible. Assuming that an additional 10 percent will reduce temperatures 20°F and that half of the 75 percent will reduce temperature settings by an additional 10°F, the weighted average setting reduction would be about 6°F. Estimated savings from this would be 2 MB/D of natural gas and 1 MB/D of oil.

Reduction of Decorative Lighting

Decorative lighting consumes about 13 percent of the commercial sector's energy. If all decorative and outdoor lighting were eliminated, energy consumed for lighting would be reduced by 7 percent, yielding an average savings of 27 MB/D COE of electricity.

Task Lighting and Reduction of Lighting Standards

Task lighting and reduced lighting to minimum standards can save 7 to 10 percent of the lighting energy where such measures are feasible and have not already been put into practice. Assuming that 50 percent of such potential savings are now being achieved, that 20 percent will never be achieved, and that half the remaining 30 percent could be achieved in an emergency, the savings would be approximately 5 MB/D COE of electricity.

Two additional strategies have been suggested: closing schools during winter months and fuel switching. To our knowledge, no data exist that would enable realistic savings estimates to be developed for these proposals.

Industrial Sector

Oil saving potential for crude oil disruption scenarios as summarized in Table 24 reflect savings potential when confronted with a serious, but not critical, oil supply disruption (Scenarios 1, 1A, 2) and when confronted with a more severe disruption (Scenarios 3, 4A, 4B, 4C). Data projected are the daily consumption savings achievable in 60 days and indicated savings available at the beginning of the denial period.

The oil product saved is predominantly residual fuel oil. It is estimated that residual fuel oil savings would account for 55 percent of the total and distillate for 45 percent.

The following references provided most of the data used for this analysis:

- Energy Information Administration (EIA) data on industrial market energy consumption by fuel type
- The Major Fuel Burning Installation survey of industrial boilers, their fuel use, and interfuel substitution potential
- The Energy Consumption Data Base and FEDS Data Base maintained by the EIA
- The Industrial Fuel Choice Analysis Model developed by Energy and Environmental Analysis, Inc., for the U.S. Department of Energy
- The Industrial Sector Technology Use Model developed by Energy and Environmental Analysis, Inc., for the U.S. Department of Energy
- U.S. natural gas industry data submitted to the EIA
- State Energy Data Report prepared by the EIA.

The Energy Consumption Data Base, the FEDS Data Base, the Major Fuel Burning Installation survey, the Industrial Fuel Choice Analysis Model, and the Industrial Sector Technology Use Model use 1974 data as a base. Many changes by industry in response to the growing awareness of potential energy supply disruptions have undoubtedly taken place, but these cannot be totally reflected due to the unavailability of more current data. Some projections of potential oil savings are likely to be understated or overstated as a result.

The maximum potential oil savings shown in Table 24 are projected to be possible without reducing industrial output. The data listed are the maximum yearly savings which have been estimated by each type of industry action. With the exception of oil desulfurization reductions, these savings should be possible without product quality compromises. Quality tradeoff savings have only been defined for reduced oil product desulfurization, but additional

TABLE 24

Estimated Oil Savings: Industrial*
(MB/D)

Strategies		Action Required	Scenarios 1+1A+2	Scenarios 3, 4A, 4B, 4C	Maximum Potential†
F-1	Boilers (Oil to Coal)	Clean Air Act Exemptions	8	20	50
F-2	Boilers (Oil to Gas)	Fuel Use Act Exemptions	105	180	220
F-3	Nonboiler (Oil to Gas)	Voluntary	10	20	40
F-4	Electric Drive for Steam	Voluntary	20	30	40
F-5	Control of Excess Oxygen	Voluntary	1	5	10
F-6	Added Insulation	Voluntary	1	5	10
F-7	Oil Desulfurization Reduction	Clean Air Act Exemptions	5	40	50

Additional Oil Not Consumed Through Reduced Refinery Runs
(MB/D)

	Scenario 1	Scenario 1A	Scenario 2	Scenario 3	Scenario 4A	Scenario 4B	Scenario 4C
Distillate	40	75	75	100	165	125	90
Residual	45	85	85	125	190	145	100
	85	160	160	225	355	270	190

---

*Savings are considered not affected by seasonality. Oil saved is estimated to be 45 percent distillate, 55 percent residual.

†Potential savings used for all 1985 scenarios.

actions may be possible. Other options would require more extensive study on an industry-by-industry basis. For the refining industry, actions such as reducing reflux to fractionating columns or reducing gasoline quality and adding octane-improving chemicals could result in savings. Defining the amount of reduction possible through these actions while ensuring adequate product quality will require additional study.

Potential for Boiler Fuel Switching

The Major Fuel Burning Installation survey results indicate that 270 MB/D of oil can be displaced (50 MB/D by coal and 220 MB/D by natural gas). This potential was defined for 1974 and assumes that any equipment revisions or additions to achieve the fuel changes can be made within a six-month to one-year time period.

Boiler reconversions to coal from oil may require Clean Air Act exemptions. Natural gas substitution for oil will be limited by the provisions of the Fuel Use Act. Revisions to the act or emergency legislative authorization to override it would be necessary in some cases.

Nonboiler Natural Gas Substitution for Oil

Oil fuel use and substitution potential of 5 percent (40 MB/D COE) was derived from the Energy Consumption Data Base. Industrial natural gas fuel curtailments through 1978 were reviewed to cross-validate the approximate volumes projected from natural gas fuel switching. Data submitted to the EIA by the natural gas industry indicated that the natural gas curtailments totaled 290 MB/D COE. This compares favorably with the 260 MB/D COE daily savings from boiler and nonboiler substitution for oil that is projected in this analysis.[16]

Electric Drive Operation

Steam drive operation can be replaced by electric drive at many facilities where spare equipment is required for smooth continuous plant operation. Although spare large horsepower equipment drive systems are not available in many plants, it is estimated that there are potential savings of 40 MB/D COE. The oil savings would

---

[16] An estimation of natural gas substitution potential has been published recently by the AGA. This estimate is 500 MB/D of oil switching capability, substantially higher than that shown in this report. The difference is largely due to a lower estimate in the report of the amount of oil which can actually be displaced by natural gas or which, if displaced, can be readily used by other markets. For example, the AGA projection does not reflect the relatively large volumes of oil byproducts and coproducts derived from various industrial processes which are subsequently used as fuels. These products include petroleum coke derived from heavy oil upgrading, still gas from petroleum refining, and still gas from chemical process units -- uses which average approximately 800 MB/D

result from reduction of oil-dependent steam generation or electricity generation by manufacturing plants; consumption of purchased electricity would increase, but this is normally generated more from coal and nuclear energy than from oil.

Control of Excess Oxygen

Based upon data from the Industrial Sector Technology Use Model, it is assumed that the equivalent of one and one half years of normal savings from control of excess oxygen in combustion flue gas could be accomplished in a single year under emergency conditions.

Installation of Insulation

Data published by the Thermal Insulation Manufacturers Association were used to develop the savings potential from additional insulation. Since installation would require budgeting and maintenance planning, it was assumed that first year progress would be relatively modest. A 3 percent savings of energy which would otherwise have been lost has been assumed.

Reduced Desulfurization of Product Streams

Shown in Table 25 are savings from reduced desulfurization. The analysis of refining operations has assumed that only hydrotreating of distillate and residual fuel oil components can be

TABLE 25

Refining Energy Savings

(MB/D COE)

Distillate Hydrotreater	31
ATF Saturator	1
Residual Desulfurization	6
Hydrogen Plant	7
Inefficiency Factor	5
Total	50

COE. Because there is no existing market for these byproduct fuels other than for specific industrial uses, their displacement by gas would not alleviate oil shortages in other markets. To reflect this constraint, use of these fuels was deducted from the initial estimate of potential oil savings.

In addition, oil used for machine drive, which averages 200 MB/D COE, was deducted from the estimate of oil which can be displaced by natural gas. In addition, industrial uses of LPG were deducted from the potential oil savings because LPG is produced in conjunction with natural gas. These uses average 200 MB/D COE.

As a result of these factors, nearly 1.2 MMB/D COE of the 2.3 MMB/D COE oil used for industrial power either cannot be displaced by natural gas or will not result in an oil savings if displaced. According to the AGA, 20 percent of the total oil used by industry can be displaced immediately by natural gas. Applying this ratio to the estimated potential oil savings of 1.1 MMB/D COE, approximately 220 MMB/D COE of oil may be displaced during an oil denial period.

eliminated. Treatment of naphtha is prevalent today, but subsequent processing uses sulfur-sensitive catalytic reforming catalysts and precludes reducing desulfurization of this stream.

Savings through reduced desulfurization of product stream or through increased use of gasoline octane-enhancing additives would cause violation of product quality or environmental laws. The extent of necessary emergency legislation to allow energy savings through these activities is uncertain at this time. A rather extensive study may be required to define the impact of these energy-saving actions upon consuming markets and the environment.

Perspective on Oil Savings Potential

During the 1973-1974 oil embargo period (similar in size and duration to Scenarios 1A and 2), industry was able to reduce oil consumption by 650 to 700 MB/D on an equivalent industrial output basis.

Industrial energy savings of 315 MB/D COE (about half of those achieved in the earlier oil embargo period) have now been projected for somewhat similar conditions. This lower potential for oil savings appears to be directionally correct and is a result of four changes which have occurred since the 1973-1974 crisis.

- Industrial response to higher energy prices and the threats of supply disruptions have resulted in dramatic improvements in energy use efficiency. Over several decades, industry reduced energy use per unit of industrial output by about 2 percent annually, but in the 1973-1978 period efficiency improvement grew to 3.8 percent per year. This dramatic improvement in efficiency has reduced the options for energy savings in supply disruption periods.

- The natural gas supply problems of 1976-1977 resulted in some industry gas restrictions which encouraged a switch away from gas use, and the ability to use natural gas has been limited by permanent conversion to other fuels.

- Passage of the Fuel Use Act, which prohibits natural gas use for new major fuel-burning installations, may prohibit gas in new nonburner equipment and in existing facilities, and limits fuel substitution capability.

- Industry is increasingly using coproduct fuels which have limited marketability. These fuels include coke, pyrolysis pitch, olefin plant off-gases, and residue streams from various other sources. Use of these energy sources which have no readily available market builds efficiency but limits oil displacement opportunities.

These factors appear to support the lower oil savings defined by this study in comparison with the 1973-1974 experience.

Possible emergency energy savings in the industrial market center around the capability of the industrial sector to substitute natural gas for oil. An integral part of encouraging industry to provide flexibility in fuel use is some legislative initiative to allow early writeoff of standby equipment which would be used only during emergency curtailment of normal fuel. If expenditures to accomplish a complete tie-in to a fuel system which is only infrequently used are to be made, some form of partial compensation to companies for such installations would be necessary.

Another consideration is the importance of promoting effective market use for the "saved" oil products. Much of the oil savings which are possible are in residual fuel oil, which is not suitable for the higher grade oil product markets which may be most hurt in an oil import curtailment period. An environment which encourages industry to provide residual fuel upgrading investments could significantly improve oil product balancing capability when substituting gas for oil in the industrial market.

Oil savings are also possible in some industries through minor product quality compromises and through furnace excess air control and improved process insulation.

DEMAND ELASTICITIES

Gasoline Price Elasticity

Various studies have produced conflicting views concerning the price elasticity of demand for gasoline. Estimates range from below 0.1 for the short term (one year or less) to well over 1 for the long run (more than one year). For gasoline, the primary source of estimates of elasticity is a review paper by Rolando F. Pelaez.[17] A secondary source is work by Robert S. Pindyck.[18]

It has been argued by some analysts that large price increases cause a temporary shock effect which results in a large impact elasticity. If such an effect existed, it would imply that large increases in price (resulting either from market responses or from sudden large increases in the gasoline tax) could substantially reduce consumption quickly. The existence of such an effect has not been well documented, however.

A weakness of most studies of gasoline price elasticity is that they have not dealt adequately with the mandated fuel efficiency standards which quite probably have reduced the long-term price elasticity of demand.

Electricity Price Elasticity

For electricity, demand elasticity estimates also vary considerably. Many studies have reported estimates of long-term price elasticities of demand which are considerably greater than 1.0 for

---

[17] Rolando Pelaez, "U.S. Gasoline Demand: The Price Elasticity Issue," unpublished manuscript, 1980.

[18] Robert S. Pindyck, "The Characteristics of the Demand for Energy," pp. 22-45 in Energy: Conservation and Public Policy, edited by John C. Sawhill, Prentice-Hall, Inc., 1979.

residential, commercial, and industrial uses. Estimates of short-run elasticities (less than one year), however, range from about 0.15 to 0.9. Most estimates are in the lower end of the range. There is little evidence that elasticities for the residential, commercial, and industrial sectors differ significantly. It should be noted that, unlike the residential sector, there have been relatively few attempts to estimate price elasticities for the commercial and industrial sectors. The primary souce for electricity elasticity is a survey article by Lester D. Taylor;[19] a secondary source is the previously cited paper by Robert S. Pindyck.

Pindyck has argued that the price elasticity of demand for electricity is likely to be less than that for other fuels because its uses are more specialized. (Gasoline may be an exception.) It is quite conceivable that sudden and large increases in the price of electricity (through either rate changes or large changes in excise taxes) may have a significant initial impact on electricity consumption, especially in the residential sector. Since electricity rate schedules are the product of regulatory commissions (except for fuel adjustment clauses), they tend to change slowly. This could make large (and preferably temporary) changes in excise taxes on electricity appealing as a means of temporarily reducing consumption significantly.

Studies of price elasticity for electricity have been subject to numerous methodological difficulties. One is that relatively few studies have dealt with the fact that users of electricity face rate schedules characterized by declining block rates rather than prices which are independent of the quantity consumed. Also, little consideration has been given to the distinction between peak and nonpeak demand. Finally, as it is likely that price elasticity varies considerably across industries in the industrial sector, the industrial sector should be studied on an individual industry basis.

Other Considerations

A final caveat concerning both the gasoline and electricity price elasticity estimates outlined above is appropriate. The elasticities indicate the relative change in quantity consumed in response to a relative price change, assuming other things such as real income and industrial output are not changed. It is well known that large changes in oil prices which would be likely to accompany any emergency situation would also significantly reduce real income and industrial output, at least temporarily. Gasoline demand is quite sensitive to changes in real income (the short-term income elasticity is likely to be at least as great as the short-term price elasticity) and electricity demand is also likely to be sensitive to changes in real income and industrial output. Consequently, the actual reductions in consumption of both gasoline and electricity in response to a large rise in oil prices would be considerably greater than indicated by the price elasticities defined above.

---

[19] Lester D. Taylor, "The Demand for Electricity: A Survey," The Bell Journal of Economics, Volume 6, No. 1, Spring 1975, pp. 74-110.

Chapter Three

INVENTORIES AND STRATEGIC STOCKS

INTRODUCTION

The potential contribution that a petroleum stockpile can make to cushion the shock of an imports disruption was outlined in two previous NPC reports: Emergency Preparedness for Interruptions of Petroleum Imports into the United States, September 1974, and Petroleum Storage for National Security, August 1975. Many of the recommendations made in these previous studies have been implemented by the federal government and form the basis for the Strategic Petroleum Reserve (SPR) program that exists today in the United States. This portion of the study covers the current SPR program and its potential capabilities for utilization in the event of a major disruption in petroleum imports. Also in this chapter is a discussion of the role that privately held inventories could potentially play in an emergency preparedness plan.

SUMMARY

- Government plans calling for development of the SPR up to a capacity of 750 to 1,000 million barrels by 1990 appear physically feasible recognizing the time required to build the necessary additional storage capacity and to acquire oil supplies to fill this capacity. Short-term government emphasis should be to maintain the momentum that has been generated for developing and filling the current and projected Reserve capacity as efficiently as possible.

- Government oil acquisition procedures should be streamlined and made sufficiently flexible to utilize a mix of government-owned oil production, term supply contracts, and spot purchases as may be appropriate to changing crude oil market conditions.

- Diversion to the marketplace of crude oil under current contract for fill of the SPR should be considered during less severe import disruptions as an option in supplementing emergency supplies. Implementation of this option should require approval of the President, and under current Energy Security Act provisions, will require a Congressional waiver to avoid shut-in of NPR production.

- While decision rules for SPR use should not be automatic or pre-determined, SPR stocks above about 200 million barrels should be readily available for use in cushioning the impacts of supply disruptions of varying sizes.

- Strategic stocks below levels of about 200 million barrels should be held in reserve for use in very severe disruptions for the nation's vital security, health, and safety needs. A decision to draw down SPR stocks should recognize that, once SPR reserves are drawn, their utility is eliminated until refill, and in the interim, the nation's vulnerability to a developing, worsening, or future shortage is increased.

- While activation of SPR drawdown during a severe disruption of supplies should be subject to a flexible, judgmental decision-making process, in order to ensure conservation of this limited national resource it is desirable for termination of SPR draw to be automatic unless specifically extended by the Secretary of Energy or the President.

- SPR stocks which are drawn down during periods when a crude oil sharing program is in effect should be priced and distributed under provisions of the crude oil sharing mechanism. The government should be considered a seller under the program and should price SPR crude oil at approximately the average price being charged for comparable quality crude oil by all other sellers under the program. Pricing SPR crude oil in this manner would return to the government full value for its investment but not add to upward market price pressure, minimize any unwarranted advantage or disadvantage from SPR crude oil access, and assist the return to normal market mechanisms when the crisis is over.

- In the event SPR stocks are drawn down in the absence of a crude oil sharing mechanism, the U.S. government should offer SPR crude oil through an auction bid system. This approach ensures efficient utilization of SPR crude oil while returning full market value to the U.S. government. Pricing SPR stocks below competitive market levels would undermine demand reduction and fuel substitution responses and divert refiners' attention to the SPR as a preferred source of marginal crude oil. An auction bid system would minimize administrative complexities and potential abuses and provide no unwarranted advantage or disadvantage to prospective buyers.

- The existing petroleum inventory system in the United States was not designed to hold a large and static strategic stockpile. Thus, mandating of a portion of existing petroleum industry inventories for strategic reserves without providing for the construction of substantial additional storage capacity and acquisition of additional oil inventory will have a disruptive effect on the efficient operation of the petroleum distribution system.

- The government should minimize disincentives to private stockbuilding by suppliers and consumers. Such disincentives include price and allocation controls as well as the perceived threat of future price and allocation controls on such stocks in the event of a supply disruption. Excessive reliance on early drawdown of SPR stocks in a disruption could also undermine efforts to encourage private stockbuilding and consumer conservation.

DISCUSSION AND ANALYSIS OF THE SPR

This part of the study evaluates alternatives and offers recommendations on utilization of the crude oil stored in the SPR during a potential petroleum supply disruption occurring in the 1981-1985 period. This study will also attempt to:

- Develop recommendations, as appropriate, on actions which should be taken by the federal government to improve the overall effectiveness of the SPR relative to emergency preparedness for the near term (1981-1985)
- Develop recommendations for the longer term ultimate volumetric size and associated physical characteristics of the SPR
- Recommend short- and long-term government approaches which should be considered for securing crude oil fill for the SPR
- Offer analyses and recommendations regarding the role of suppliers' and consumers' privately held petroleum inventories to be available during an emergency supply disruption.

Background of SPR Plan and Amendments

The Energy Policy and Conservation Act provided the legislative authorization for the establishment of the Strategic Petroleum Reserve. The SPR is to provide for the storage of up to 1 billion barrels of petroleum in order to diminish U.S. vulnerability to the effects of a severe petroleum supply interruption. The EPCA required the submission to Congress of a Strategic Petroleum Reserve plan detailing the proposals for designing, constructing, and filling the Reserve. The SPR plan was submitted to Congress on February 16, 1977, and became effective on April 18, 1977. That SPR plan called for storing 500 million barrels of oil by December 3, 1982.

The planned schedule for filling the reserve was accelerated by SPR Plan Amendment No. 1. This amendment was submitted to Congress on May 25, 1977, and became effective on June 20, 1977. The schedule was accelerated by establishing a goal of 500 million barrels to be in storage by December 22, 1980, two years earlier than was recommended in the SPR plan, and by establishing a December 1978 goal of 250 million barrels.

Amendment No. 2 to the SPR plan authorized an increase in the SPR size from 500 million barrels to 1 billion barrels of stored oil. The amendment was transmitted to Congress on May 18, 1978, and became effective on June 13, 1978. The amendment described government plans to store 750 million barrels of petroleum in underground storage facilities. Authority was also provided for development of a 250-million-barrel industry-held reserve.

On October 31, 1979, the Department of Energy submitted to Congress the Distribution Plan for the SPR (Amendment No. 3). In accordance with the provisions of the EPCA, the plan amendment became effective on November 15, 1979. The SPR Distribution Plan provides the Secretary of Energy broad authority to distribute SPR crude oil to cover national or regional supply disruptions. Four methods of crude oil distribution are authorized. They are:

- Standby Buy/Sell Program (implementation of additional buy/sell orders was eliminated with President Reagan's decontrol order of January 28, 1981)
- Standby Crude Allocation Program (scheduled to expire September 30, 1981)
- Competitive sale
- Alternate allocation system (method left open; to be determined by DOE when conditions warrant).

A provision of the Energy Security Act passed in June 1980 requires that effective October 1, 1980, the SPR must be filled at a rate not less than 100 MB/D and the fill must continue at that minimum rate until a fill level of 1 billion barrels is achieved. The Energy Security Act also provided that government production from NPR-1 (Elk Hills) may be utilized directly or by exchange to sustain the 100 MB/D minimum fill rate. This provision requires that the 100 MB/D fill rate be met and maintained, or production from NPR-1 is to be reduced.

In addition, an amendment to the Department of Interior and Related Agencies Appropriations Act for the Fiscal Year Ending September 30, 1981, provides that the President shall seek to undertake crude oil acquisition for the SPR at an average rate of at least 300 MB/D or a quantity that would fully utilize appropriated funds for SPR storage. This amendment became effective December 12, 1980, but imposes no sanctions if the 300 MB/D rate is not achieved.

Background on SPR Development Plan

In developing the SPR system, storage sites were chosen which would be most accessible to major interstate crude oil distribution pipelines and port facilities. These locations facilitate withdrawal from the reserve if needed and entry into the nation's primary crude oil distribution systems.

A significant amount of foreign crude oil entering the United States is received via Gulf Coast terminals to supply refineries along the upper Texas and Louisiana coasts or to be transported to inland refineries through major pipeline systems. These pipeline systems include Seaway, Texoma, and Capline. Other pipelines further distribute crude oil from these major lines throughout the midwest. Water terminal connections are also available for shipping SPR crude oil by ocean tanker to West Coast or East Coast ports if necessary. Thus, the Gulf Coast region is a highly desirable location for storage of petroleum held in reserve against an import disruption.

The method of storing petroleum reserves was chosen to be caverns leached (solution mined) in underground salt dome formations. This method of storage in remote and underground locations is preferred for reasons of security and safety as well as cost. Also favoring salt dome storage is that there are more than 350 known salt domes along the Gulf Coast with many located near major refining centers, pipeline terminals, and inland waterways.

Currently Congress has authorized the development of the first 750 million barrels of storage through SPR Plan Amendment No. 2. This development is to occur in three phases, as shown in Table 26. Although the ultimate size of the SPR has been authorized by Congress to be up to 1 billion barrels, decisions and plans have not been submitted by the Executive Branch for the development of the remaining 250 million barrels of SPR capacity.

TABLE 26

SPR Development Plans

Phase	Description	Incremental Storage Capacity (Million Barrels)	Cumulative Storage Capacity (Million Barrels)
I	Existing Cavern & Mines -- at Five Sites	248	248
II	New Leached Caverns -- Expansion of 3 of Phase I Existing Sites	290	538
III	One New Site -- Expansion of 2 Existing Sites	212	750

The storage capacity of Phases II and III will come on stream incrementally as new caverns are available. Figure 3 indicates the current projection by the DOE for bringing this new capacity on stream. Based on these projections, Phase II availability will begin in the second quarter of 1982 and will be completed in the first quarter of 1988. Figure 3 also illustrates the phase-in schedule of Phase III, which will begin in the third quarter of 1985 and will be completed in the second quarter of 1989. Appendix J of this report provides a complete breakdown of the phase-in schedule by quarter through the completion of Phases II and III.

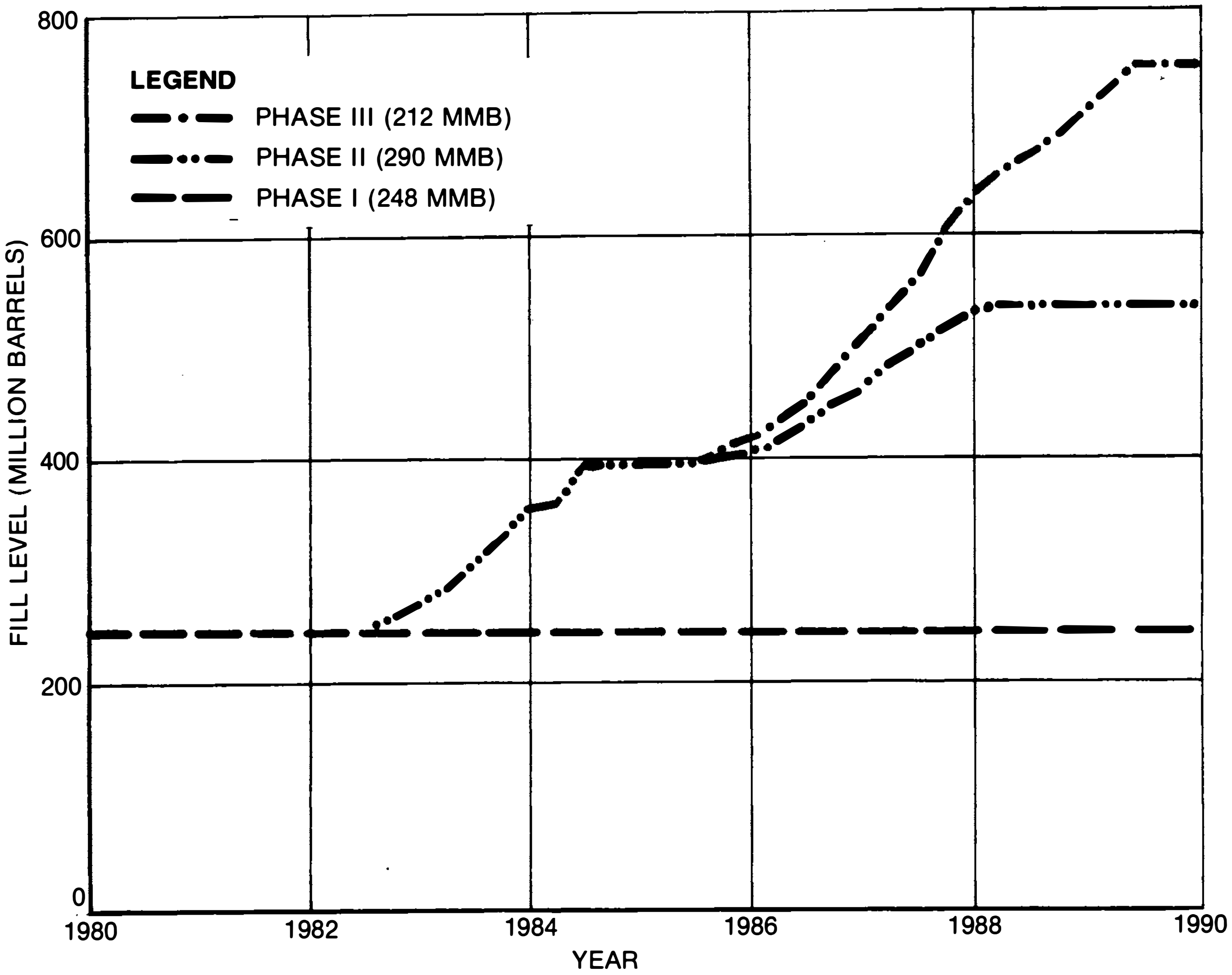


Figure 3. Projected SPR Storage Capacity.

Resumption of fill began October 1, 1980. At a 100 MB/D rate, it would be late 1984 before the Phase I capacity would be filled. The accelerated fill rate of 300 MB/D would raise the level of reserves up to the current SPR capacity of 248 million barrels by mid-1982. It should be noted that the SPR can be filled very rapidly when reserves as a percentage of capacity are low (rates up to 600 MB/D are feasible). However, as available storage capacity (ullage) decreases, filling rates become constrained. Once reserve crude oil volumes equal capacity, the SPR can only be filled as new storage wells are completed. Figure 4 illustrates projections of the fill rate of 100 MB/D, the increased fill rate of 300 MB/D, and the SPR's schedule for phased-in storage capacity.

The drawdown capability of the SPR is the rate at which oil stored in the reserve can be delivered out and into the nation's crude oil distribution system. It is important to note that the drawdown rate decreases with the level of oil remaining in SPR storage. That is, as oil is pumped out of storage, some storage caverns will be depleted before others, and as this depletion

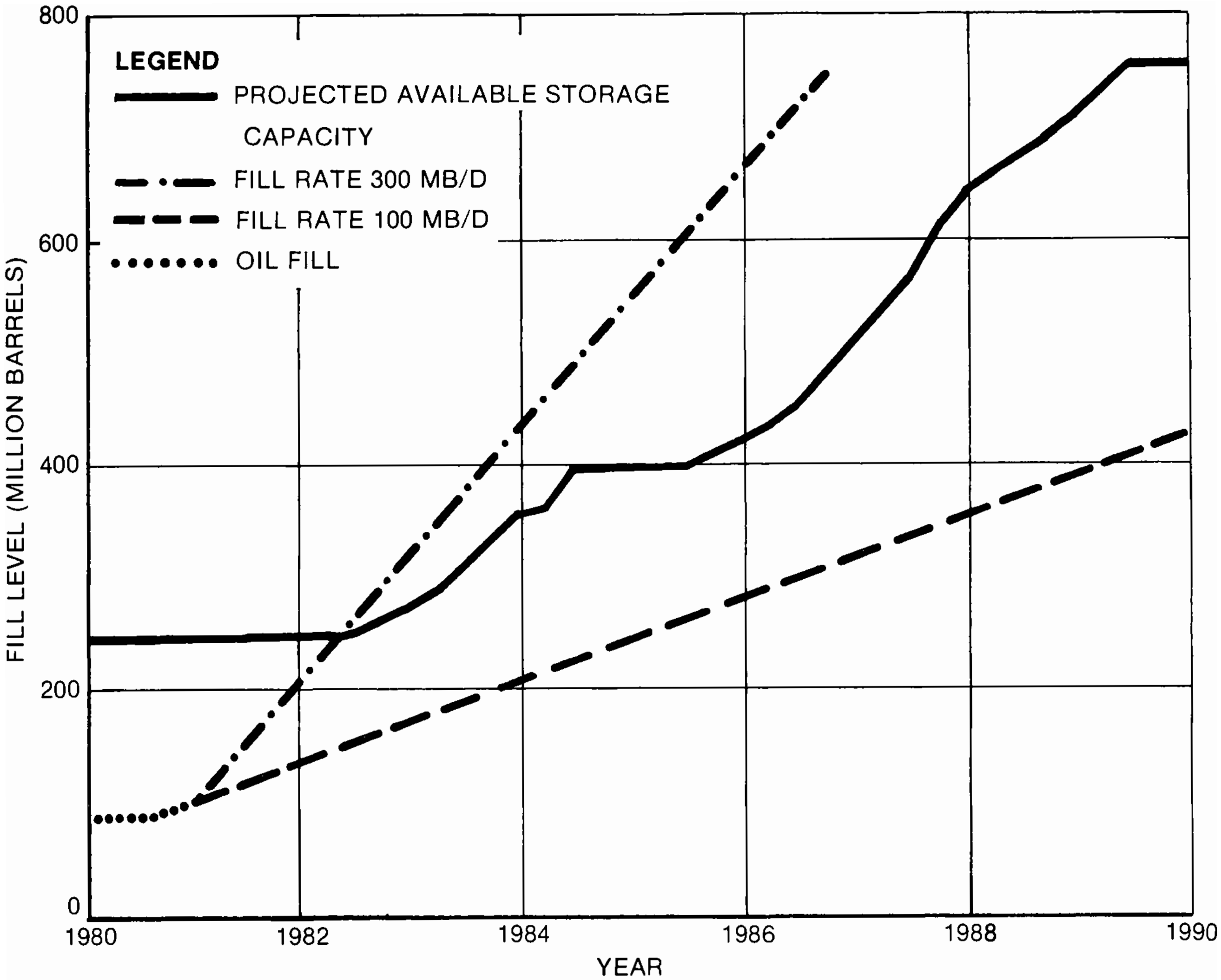


Figure 4. Projected SPR Storage Capacity and Fill Rates.

occurs, the maximum drawdown rate will decline. Figure 5 illustrates the maximum drawdown capability of the SPR.

One factor affecting the drawdown capability of the SPR is the capability of the U.S. logistics system to receive and distribute SPR crude oil. A further discussion of this capability can be found in Chapter Seven of this report.

Potential Uses of the SPR

The Strategic Petroleum Reserve can be thought of in two significantly different ways: as a readily dispatchable supply to moderate or buffer shortfalls of varying magnitudes, or as a supply to be held in reserve for use in relatively large shortfalls that substantially exceed the total of other demand and supply management steps available. Until such time that the SPR has reached a level of about 200 million barrels, it is likely that these stocks will be used in the latter way. However, as will be discussed later, a willingness to use stocks available above this level to buffer the impacts of import disruptions of varying sizes could have important benefits to the nation.

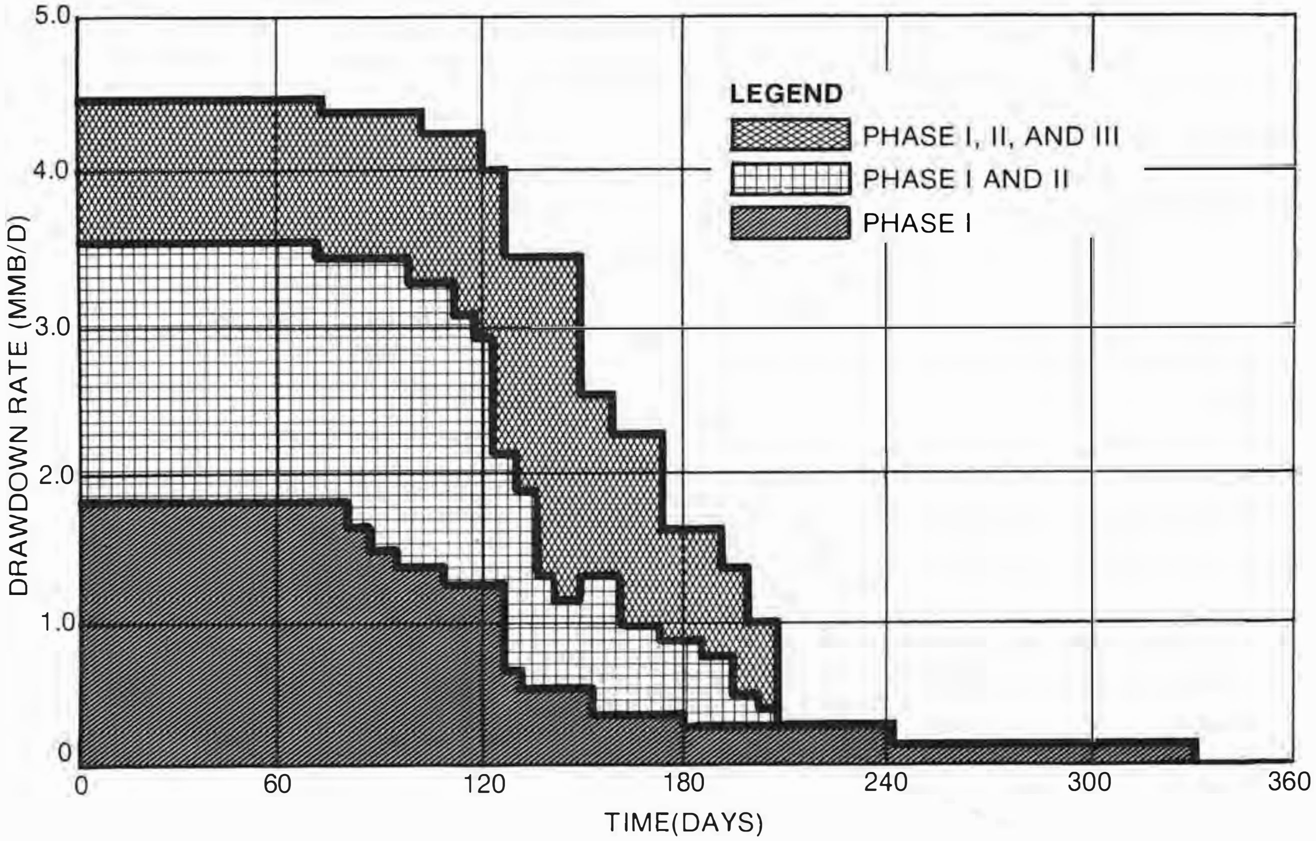


Figure 5. SPR Drawdown Capability.

The major advantages of strategic stocks are that they:

- Are under total control of government, thus enhancing U.S. posture among IEA countries
- Can be a deterrent to politically inspired disruptions of U.S. imports
- Reduce panic buying and hoarding which may accompany a disruption
- Allow additional time for diplomatic and possibly military planning during a major disruption
- Mitigate the export of wealth which may occur as a result of an imports disruption.

The major disadvantages of strategic stocks are that they:

- Must be very large to be effective
- Lose their value once deployed until such time that they can be restocked, probably at much higher replacement cost
- May become a sterile asset without sound facilities management, effective distribution mechanisms, and a logical plan for use.

Without readily available near-term energy alternatives to imported oil, strategic stockpiles are one of several important tools needed to effectively manage a disruption of petroleum imports. The mere presence of a large strategic stockpile of oil has value by signalling the world that the United States intends to protect itself against import disruptions. It can be a deterrent to politically inspired oil embargoes. Thus, its very presence may help preclude the need for its use. However, in the event of a supply disruption, it can offer bridging supplies, thus giving the United States additional reaction time to evaluate the situation and implement effective response steps. A large and effectively managed petroleum stockpile could have a calming effect on the nation and reduce counterproductive panic buying and hoarding which might worsen the emergency situation. Of course, the public knows that the United States produces some 9 to 10 MMB/D of oil domestically. This is the ultimate supply of last resort. However, with a total petroleum demand of approximately 16 MMB/D, the supply of last resort doesn't nearly cover needs in an imports catastrophe such as DOE Scenario 4. While a major limitation of SPR stocks is their finite size, a major advantage is the capacity to withdraw at the very rapid rate of 2 to 3 MMB/D. Thus the dilemma as to their best use: if used early and often, benefits are substantial, but the risk exists of a calamity if used and not replaced before a catastrophic disruption occurs. Very prudent judgments based on many factors including best assessments of the magnitude and duration of the perceived import disruption should be made before implementing drawdown of strategic stocks.

A draft of a Department of Energy report suggests that the size of a dedicated or primary reserve level should be between 250 and 550 million barrels.[1] The Department of Defense is currently engaged in further studies to determine appropriate primary stock levels. These dedicated security stocks would not be utilized during a supply disruption to reduce noncritical economic impacts including acceptable levels of Gross National Product loss and increased national unemployment. This is obviously a very difficult judgment to make.

Some economists argue that a security reserve unnecessarily ties up oil reserves and effectively makes such reserves a "sterile" asset as the primary reserve volume may never be utilized. They argue that an SPR should be drawn down at the first sign of a supply disruption in order to mitigate the historical tendency of supply disruptions to cause increases rather than drawdown in inventories resulting from a fear of worsening supply conditions or complete cutoff of supplies. This is brought out in the recent DOE oil vulnerability study[2] which attempts to quantify the "economic loss avoided" by an immediate drawdown of a portion of strategic stocks. However, this concept is considered valid by the DOE study when coupled with a pre-determined level of dedicated primary reserve which could be held as the security stocks of last resort.

---

[1] DOE analysis of the appropriate size of the Strategic Petroleum Reserve, November 20, 1979.

[2] Reducing U.S. Oil Vulnerability, Energy Policy for the 1980's, Department of Energy, November 20, 1980.

Others argue that the indigenous domestic crude oil and natural gas liquids (NGL) production in the United States of approximately 10 MMB/D is sufficient to protect the vital interests of the nation in the event of a major supply disruption, and, therefore, no attempt should be made to segregate the reserve into priority use categories.

There are, however, several factors which weigh against a plan to begin drawing down SPR reserves at the first indication of a petroleum supply disruption. One is that the SPR may offer only a one-time source of crude oil for dealing with a major supply emergency. Once the SPR reserve is drawn, its utility is eliminated prior to refill, and in the interim, the nation is left more vulnerable to a developing, worsening, or future shortage. Another consideration, as discussed in a later section of this chapter, is the potential for complementing SPR stocks through voluntary stockbuilding by suppliers and consumers. Plans to begin releasing SPR stocks at the first indication of a supply disruption might act as a disincentive to and supplant private stockbuilding efforts. In addition, excessive reliance and freely available SPR stocks may undermine necessary demand restraint and fuel substitution efforts by end users of petroleum products. A final consideration is the impact of drawdown activity on salt dome physical integrity. This is discussed further in the Physical Constraints section of this chapter. Oil can be withdrawn from certain salt cavities and refilled about five times before the storage facility must be abandoned.

Of course, strategic petroleum reserves, above some primary reserve level, could be utilized in a more discretionary and tactical manner. This study has elicited views of approximately 200 to 500 million barrels as being a prudent level of dedicated reserves. Some feel that 50 percent of the then-current level may be an appropriate decision rule. The level of Phase I capacity (248 million barrels) may also be a useful near-term target for a dedicated reserve level.

The benefits of the government-owned and -controlled strategic petroleum stockpile should accrue to the nation as a whole. Many suggestions concerning the uses of a petroleum stockpile have been developed since the 1973-1974 Arab oil embargo. However, the range of possible uses would seem to grow directly with the size of the reserve. Thus, a discussion of the ultimate size of the reserve follows.

Ultimate Size of the SPR

The ultimate capability of the SPR to provide its intended benefits is limited by its volumetric size. This question of SPR size has been addressed since 1973 by many different groups and individuals, both public and private (Table 27). So widespread and diverse are the conclusions of these various sizing studies that a consultant under contract to the Strategic Petroleum Reserve Office has developed a report entitled SPR Size Studies Review. A draft report of this study, dated November 15, 1980, reveals the chronology of events of the sizing issue which began in December 1972 and continued through September 1980.

In spite of the widespread interest and attention received by this question, there is no conclusive consensus of opinion as to the ultimate SPR size. Table 27 represents a list of SPR sizing studies and the corresponding size recommendations. It is evident from the wide range of recommendations that the approach and methodology vary broadly among the studies as do the basic assumptions regarding the parameters of the probable disruption scenarios and the future supply/demand outlook. In view of the depth and mathematical sophistication of many of these recent studies, a similar analysis of ultimate size has not been undertaken as a part of this study. However, drawing from these studies and the preceding assessments of SPR capabilities, an intuitive range of ultimate SPR size can be obtained.

There is one noticeable trend in the SPR size study estimates. As shown in Table 27, these study estimates of ultimate SPR size are becoming larger over time. Since 1977, the range of size estimates has been 750 to 1,000 million barrels. Also, since 1977, these studies utilized more sophisticated mathematical techniques and econometric models to predict the impact of future import disruptions.

The analysis of the optimum size of the SPR is a highly subjective calculation. To carry out the analysis, it is necessary to assume a range of disruption possibilities. The desired volume of oil in security storage depends upon the anticipated magnitude, duration, and frequency of future import interruptions and the degree of shortfall to be covered. Because the assumptions necessary for analysis of size are so speculative in nature, it is difficult to make a convincing argument that one particular SPR size is better than another.

In view of this, it may be far more important to look at the ultimate SPR size from a realistic though general perspective. First, to be effective in mitigating a supply disruption, an SPR must be large. No one really disputes this conclusion. Second, a strategic reserve is not a viable long-range substitute for an expanded energy resource base, but rather a stop-gap measure designed for use of limited duration. Third, the time frame necessary to develop and fill an SPR of even modest size is unusually long due to the complex set of parameters involved. Fourth, discussed in the previous section is the concept of some finite level of primary reserve which would be held for the ultimate strategic emergency.

An examination of the current SPR development plan in view of these four factors is in order. The SPR plan and amendments authorize an SPR of 1 billion barrels of crude oil. A plan for developing the first 750 million barrels has been approved and is scheduled for completion in 1989. The concept of dedicating a certain level of primary reserve, though not as yet a formal part of

TABLE 27

SPR Size Studies

Study Sponsor/Author	Year Completed	Recommended Size (Million Barrels)
Petroleum Industry Research Foundation Studies	1973	550
National Petroleum Council	1974	540
National Petroleum Council	1975	500
Federal Energy Administration	1975	300
Strategic Petroleum Reserve Office	1975	530
Stanford Research Institute	1975	770
Office of Technology Assessment	1975	250-500
Federal Energy Administration	1976	530+
Strategic Petroleum Reserve Office	1976	750
Egon Balas, Carnegie-Mellon University	1976	750
Congressional Budget Office	1976	No Conclusions
Arthur D. Little, Inc.	1976	1,000
Strategic Petroleum Reserve Plan	1976	500
Strategic Petroleum Reserve Office	1977	750+
George C. Sponsler, International Planning Management Corporation	1978	1,000+
Department of Energy	1978	860+
Thomas J. Teisberg, Massachusetts Institute of Technology	1979	1,000
Stanford University	1979	980
Department of Energy	1979	750
Congressional Budget Office*	1980	1,000

---

*Per CBO policy specific SPR size was not recommended, but report indicates that a 1 billion barrel SPR would be of significant benefit to the nation.

the SPR plan, implies a two-tiered reserve with the first tier of fill held as security stocks and the second tier available for more discretionary uses such as cushioning the early economic effects of an oil disruption. Notionally, this study has evolved a subjective concept of dedicated reserve stocks at about 200 million barrels, perhaps increasing up to 500 million barrels as the SPR is developed further. The more readily available secondary reserve begins at levels above about 200 million barrels and increases as the SPR is developed.

The reasonableness of a 1-billion-barrel strategic petroleum reserve can be measured against a near-term and long-term benchmark. Near term, using the approximation of import shortfalls under DOE Scenario 4, a shortfall of 300 million barrels could possibly result even after maximum implementation of all emergency demand and supply management steps identified in this study short of coupon rationing, excise/import taxes, and stock drawdown. Assuming a primary reserve level of 200 million barrels, an SPR of 500 million barrels appears to be a worthwhile objective by 1985.

Looking longer term, in its 1979 Annual Report to Congress the Energy Information Administration projected U.S. import demand in 1990 to be 5.6 MMB/D at the expected mid-price case for world oil. At this level, a 1-billion-barrel two-tiered SPR would offer 90 days of complete protection for the discretionary reserve (500 million barrels). With implementation of demand restraint and emergency production steps, the number of days of protection would substantially increase. As illustrated in the analysis of DOE Scenario 4, a 500-million-barrel discretionary reserve would exceed the net shortfall of 300 million barrels after taking recommended demand and supply management steps. Also, in the case of a prolonged interruption, the primary reserve (500 million barrels) would essentially double the level of protection, perhaps raising a question of overinsurance. The EIA further projected that imports would decrease slowly from 5.6 million barrels in 1990 until the year 2000, at which time petroleum imports will begin to decrease rapidly as new sources of energy become commercially available in large quantities. Thus, the greatest need for an SPR occurs in the 1980's and early 1990's. By late in the 1990's and early in the 21st century, the need for an SPR may be expected to decline as U.S. dependence on foreign oil and thus vulnerability to imported oil supply disruptions diminish.

In summary, the current SPR plan for development of a 1-billion-barrel reserve appears in line with the many recent studies on this subject made in the public and private sectors. Achievement of this level by 1990 will require a major effort by government. Due to the long lead times necessary for construction and fill, it is unlikely that a level in excess of 1 billion barrels is feasible by 1990. Also, in view of the projected reduction in oil imports in the long term (1990 and beyond), it is questionable that a reserve of greater than 1 billion barrels will be desirable. Should imports dependence be reduced faster than projected, there may be a case for a reserve smaller than one billion barrels. There is enough time during the early 1980's to further address the question of ultimate size, and it would be appropriate for government to review this issue periodically to determine if conditions warrant a change in the SPR ultimate size objectives.

Physical Constraints

The current development plan for the SPR outlined in the previous section represents a least cost, maximum benefit approach to provide large levels of reserve capacity as rapidly as is practical. Attempts to accelerate storage availability in the near term (1981-1985, Phase II) are constrained by the physical design factors and facilities already in place or under construction for Phase II. That is, once facilities are in place to leach (solution mine) storage caverns, little can be done to accelerate this leaching rate without a retrofit of equipment and a modification of the physical facilities design. Such a retrofit would include preleaching facilities such as the number and size of injection wells, the size of pipelines for fresh water injection and brine disposal, and the capacity of brine holding or settling ponds as well as the size of pumps necessary to increase the leaching rate. The leaching rate is thus a function of the initial design, and attempts to accelerate the process after the fact may only delay or, at best, meet the original schedule.

In spite of these constraints to increasing storage availability in the near term, it would be appropriate that the Strategic Petroleum Reserve Office undertake an analysis of alternative actions which could be undertaken to increase storage capacity in the near term either by accelerating Phase II development or by the acquisition of additional sites. It is believed that this analysis is currently underway by DOE and includes acceleration of Phases II and III.

Given the physical constraint of the current SPR development schedule and assuming no short-term (1981-1985) actions which will markedly alter this schedule, it is reasonable to conclude that the SPR storage capability, shown in Table 28, depicts the 1981-1985

TABLE 28

SPR Incremental Storage Capacity

Year-End	Storage Capacity (Million Barrels)	Net Annual Increase (Million Barrels)
1981	248	--
1982	272	24
1983	356	84
1984	398	42
1985	421	23
1986	509	88
1987	636	127
1988	705	69
1989	750	45

period base capability with the 1986-1989 period offering the most opportunity for accelerated storage development. Based on the storage capacity shown in Table 28, the utilization of the SPR during the 1982-1985 period could be limited by a lack of available storage capacity for fill in the near term.

Another significant physical constraint of the SPR program is the rate at which stocks can be moved out of storage and into the nation's logistical system. This drawdown rate is dependent upon two interrelated factors: the design drawdown rate, representing the maximum rate at which stocks can be withdrawn, and the level of fill at the time of withdrawal.

Table 29 is a DOE projection of drawdown capability development. However, the drawdown rates shown are the maximum attainable and are dependent upon the level of fill at the time of drawdown. Furthermore, the drawdown rate declines with the volume of oil remaining in SPR storage. During the 1981-1985 period, the withdrawal rate will be constrained due to a projection of less than maximum capacity fill. The attainable withdrawal rate will lie between 1 MMB/D and the projected 3.5 MMB/D.

TABLE 29

Projected SPR Drawdown Capabilities

Year	Drawdown Rate* Permitted by Facilities (MMB/D)
1980	1.7
1981	3.5
1982	3.5
1983	3.5
1984	3.5
1985	3.5
1986	4.4
1987	4.4
1988	4.4
1989	4.4

---

*Actual drawdown capability is dependent on level of oil in storage.

A further possible constraint is the capability of the nation's logistical system to move SPR crude oil if and when the need arises. This topic is discussed in Chapter Seven of this study.

A possible physically limiting factor which in time could affect SPR utilization is the number of fill and drawdown cycles that a salt dome cavern may safely undergo. It is currently estimated that all sites, with the exception of Sulphur Mines, can safely sustain five complete fill and withdrawal cycles. Sulphur Mines can be used only once. The constraint here results from the fluid displacement procedure used to move oil into or out of a storage cavern. For example, an "empty" cavern (that is, one containing no crude oil) contains a brine solution. As oil is pumped in, brine is pumped out. To remove the crude oil, fresh water is pumped in which further leaches the cavern. Each time fresh water is pumped in, leaching increases the cavern size by about 15 percent. After five such cycles, the cavern has almost doubled in size and there can exist a danger that adjacent caverns may begin to coalesce. If this happens, they can become too large and their structural integrity weakened enough to make them unfit for further use as a storage facility. This problem can be effectively eliminated by using brine as the displacement fluid instead of fresh water. To make this change would require costly facilities modifications, and unless the real probability for more than five use cycles exists, it is not considered economical.

A significant factor affecting the ultimate size and near-term development of the SPR is the relatively long lead time necessary to develop new storage facilities. The current SPR program set very ambitious targets initially and was unable to meet them due to the time constraints associated with developing a "grass roots" storage facility. Table 30 illustrates the number of months from start to completion for "normal development" of an incremental 250-million-barrel salt dome storage facility.

It should be noted that it is possible to accelerate the development timetable. To do so will require government action to expedite the permitting and environmental impact requirements and to make funds available for a more aggressive engineering and construction schedule.

Table 30

Timetable for Developing 250 Million Barrel Site
(SPRO Estimate)

Key Events	Cumulative Time From Government Directive (Months)
Begin Environmental Studies	0
Begin Engineering Design	12
Begin Land Acquisition and Order Long Lead Time Materials	12
Acquire Land, Delivery of Well Casing, Begin Drilling and Facilities Construction	24
Delivery of All Pumps, Pipe, Etc.	30
Begin Cavern Leaching	48
Complete Cavern Leaching	84
Complete Oil Fill	96
Normal Development Time	8 Years

A significant constraint to the near-term capability of the SPR system has been oil acquisition. Currently, the SPR has available storage capacity of 248 million barrels and contains about 120 million barrels of oil. The question of filling the SPR has been and is receiving widespread public attention. The major perceived concerns are the federal budget cost of fill and the threat of retaliatory action from oil exporting nations. The subject of oil acquisition is addressed more fully later in this chapter.

SPR Fill Rate Outlook

The rate at which the SPR is filled directly influences its effectiveness at any point in time. During the time frame of this study, it is assumed that there may be periods of both adequate and tight world oil supply/demand. One can infer from this outlook that any attempt to project a constant SPR fill rate over the period would be unrealistic. What is most likely to occur are periods during which supply is more or less readily available for acquisition by the SPR at reasonable cost and market impact. The outlook for SPR fill suggests that the fill rate should be increased to the extent possible in soft crude oil markets and reduced or halted during periods of tight supply. A waiver from the prohibition on the sale of NPR oil if SPR is not filled at the minimum rate of 100 MB/D should be provided in periods of tight supply to avoid the shut-in of needed NPR production.

Figure 6 projects SPR fill levels over the 1981-1990 period based on current inventories, and a base case assuming an average fill rate of 200 MB/D, a low sensitivity case of 100 MB/D, and a high sensitivity case of 300 MB/D, which is assumed to be near the maximum for the short term. Maximum fill rate is sensitive to available SPR cavern storage capacity, crude oil availability, economic effects of oil acquisition, and other factors. The SPR projected inventories under these three fill rate cases are shown in Table 31.

An average fill rate of 175 MB/D between 1981 and year-end 1985 would maximize fill of the planned 420 million barrels of SPR storage capacity for this period. Beyond 1985, Phase II and Phase III of the current SPR development schedule provides for additional storage capacity which would allow for an average fill rate between 1986 and 1990 of 275 MB/D. The combination of present SPR reserves and average fill rates of 175 MB/D (1981-1985) and 275 MB/D (1986-1990) would provide for a total reserve fill of 750 million barrels by 1990, assuming no drawdown in the interim.

Summary of SPR Capabilities

The present phased development of the SPR, if continued on schedule, will allow for a maximum average fill rate of 175 MB/D between 1981 and 1985 and 275 MB/D between 1986 and 1990. If these fill rates are achieved, maximum reserve levels will reach 420 million barrels by year-end 1985 and 750 million barrels by year-end 1990.

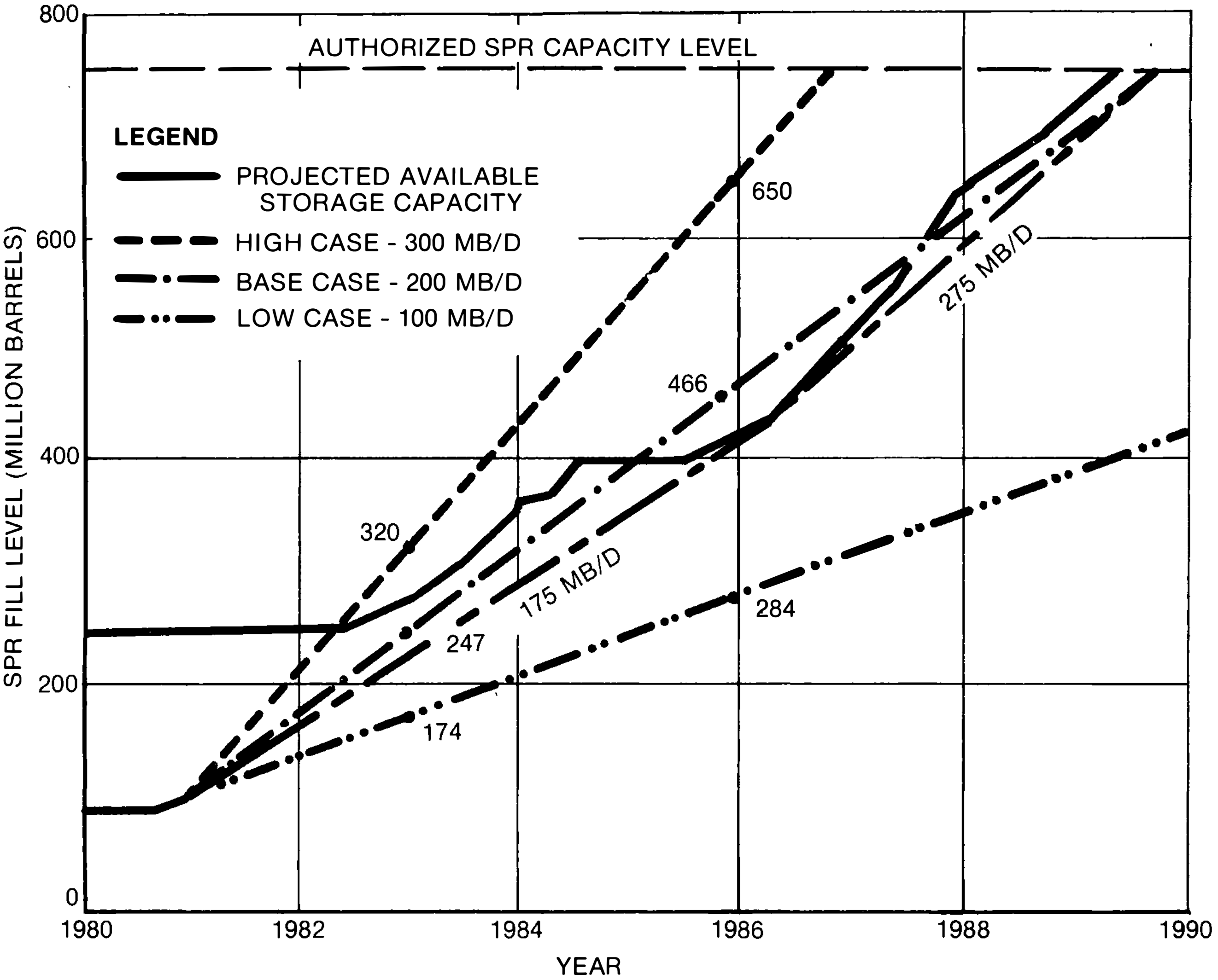


Figure 6. SPR Fill Rate Outlook Cases.

TABLE 31

SPR Projected Fill Level
(Millions of Barrels)

	Year-End 1982	Year-End 1985	Year-End 1990
Low Case (100 MB/D)	174	284	466
Base Case (200 MB/D)	247	466*	831*
High Case (300 MB/D)	320*	650*	1,000+*

---

*Based on current SPR development schedule, these volumes are technically not achievable in the time frame shown due to physical limitations of storage capacity.

Utilization of the SPR

When SPR stocks reach levels which provide flexibility in offsetting emergency disruptions, a standby plan for distribution of secondary reserves should be available for implementation as part of an overall emergency preparedness plan. This standby plan should address activation/deactivation authorities to initiate and terminate SPR utilization, requirements for distribution eligibility by purchasers, and sale pricing mechanisms of inventories withdrawn from the SPR reserve. The following preliminary suggestions are offered in addressing these elements of a future standby SPR distribution plan.

Activation of an SPR Drawdown

In developing a standby plan for utilization of the SPR, the type of mechanism which would trigger its drawdown should be carefully assessed. A trigger which is developed should not be one which will automatically engage a series of actions to start a drawdown of SPR stocks. Rather, the trigger should be one that will set into motion an analysis and further decision-making process which would fully evaluate the conditions and effects that a supply disruption is having on the nation and the manner in which deployment of SPR inventories could reduce those impacts in light of the potential for an extended and/or worsening of disruption conditions.

Subsequent decision-making authority should be designed with appropriate checks and balances to avoid the potential for overreaction to disruption conditions. Impromptu or hasty decisions regarding utilization of a one-time alternative such as SPR stockpiles must be restrained. Once a secondary reserve of oil is in place, the SPR should be more readily available to be used along with other alternatives within the overall emergency preparedness plan for the nation. A trigger to utilize even the secondary level of the SPR should not be automatic. The final decision to effect its use should be made at the highest levels of government after proper assessment and evaluation of the status and projected future conditions of the supply interruption in progress.

It is equally important that an SPR deactivation trigger also be in place. While activation triggers should be slow and deliberate to allow sufficient time to optimize all other alternatives, sunset provisions should be incorporated in the deactivation trigger. A specific rate and period of utilization should be established. Provisions should require that timely interim assessment be made as to the further need to utilize SPR inventories and deactivation should be triggered as appropriate. Utilization of the SPR should be closely controlled during every phase of its deployment because of its high strategic and economic value to the nation. The SPR is a readily dispatchable one-time source of supply. If fully depleted, it may be several years before it can be made available again.

Distribution of SPR Inventories

Efficient utilization of strategic reserves requires that a sound distribution plan be available. The plan should be sensitive to the need to cause minimal interference with refiner incentives to seek out sources of supply. Administrative complexity should also be minimized.

SPR drawdown may occur either with a government crude oil sharing program in effect or in the absence of such crude oil sharing. In the event that SPR stocks are drawn down during periods when a crude oil sharing program is in effect, these SPR stocks should be sold subject to the pricing provisions of this program. A complete description of the crude oil sharing mechanism recommended can be found in Appendix F. Under the crude oil sharing mechanism, the government should be treated as a seller and SPR crude oil should be sold to buyers at approximately the average price being charged by all other sellers under the program for comparable quality crude oil. Pricing SPR crude oil in this manner, during periods when the crude oil sharing program is in effect, would return to the government full value for its investment but not add to upward market price pressures, minimize any unwarranted cost advantage or disadvantage from SPR crude oil access and assist the return to normal market mechanisms when the crisis is over.

Should the government decide on an SPR drawdown in the absence of a crude oil sharing mechanism, the U.S. government should offer SPR crude oil on a basis comparable to any other seller of crude oil in a competitive market. Under these circumstances, SPR crude oil should be auctioned to U.S. refiners based on their willingness to pay competitive market prices for the crude oil. The use of an auction bid system could ensure efficient utilization of SPR crude while returning full value to the U.S. government for its investment. The availability of SPR stocks at competitive prices would provide additional supplies to the marketplace and thus should not add to upward pressure on market prices. Pricing SPR stocks below competitive market levels would undermine demand reduction and fuel substitution responses and divert refiners' attention to the SPR as a preferred source of marginal crude oil. An auction approach would also minimize administrative complexities and potential abuses and avoid unwarranted buyer subsidization. Auction sales of SPR crude oil should be limited to active U.S. refiners.

Sale of SPR crude oil may be expected to draw large sums of money into the U.S. Treasury over a relatively short period of time. Thus, standby fiscal plans should be developed to set aside revenues secured through the sale of SPR stocks for potential use in securing oil stocks for refilling the SPR at a later date.

Storage Capacity Development

The current SPR plan contains the basic elements to provide the desired strategic protection, and the plan should be allowed to continue. It could be counterproductive to divert current SPR development efforts by initiating new and different storage plans. The experience and technology of the last four years provide the SPR program with a sound base for further development.

Should accelerating capacity development be desired, the following factors should be considered:

- The long lead time associated with permitting and environmental issues
- Funding
- Re-examination of "turnkey" sites
- Specific problems associated with the acceleration of Phase II development
- Re-examination of the planned Phase III development schedule.

The rapid development of the SPR is in the national interest. With commitment by the federal government including appropriate legislative action, some acceleration of the SPR program could be accomplished. Acceleration of SPR capacity development, of course, should not greatly exceed the likely rate of oil acquisition.

Oil Acquisition

The DOE objective has been to fill the reserve as rapidly as possible, within the constraints imposed by the world oil market. DOE has also sought to minimize the effects of SPR purchases on world oil prices and on the availability of supplies for domestic consumption. At the Tokyo Economic Summit in June 1979, it was reported that the oil-consuming nations agreed they would not buy oil for strategic stockpiles if it would place undue pressure on prices in the world market, and that the participating countries would consult each other regarding decisions to resume fill of strategic stockpiles.

Methods and procedures for securing oil supplies, including those based on production from the NPR, have presented problems which the government has been seeking to overcome. The DOE and the Defense Fuel Supply Center (DFSC) are burdened by the regulations and administrative paperwork required to consummate crude oil purchasing transactions. These administrative complexities may conflict with market reality where spot purchases of crude oil often must be negotiated quickly to complete an attractive acquisition. Budgeting of funds necessary to purchase a significant level of oil fill for the SPR is currently being debated by Congress. With decontrol of domestic crude oil prices by the President effective January 28, 1981, the entitlements program, which provided an off-budget entitlement subsidy to the government (and offsetting levy on domestic refiners and consumers) for crude oil purchased for the

SPR, was eliminated. Filling of the SPR with crude oil based on exchanges of NPR production does not reduce the budget cost of filling the SPR as the sale and purchase are not offset in the budget accounting procedure. Thus, the full cost of the SPR is reflected in the current budget debate, which seems appropriate for such national security expenditures. Budget constraints will be a continuing reality for the SPR program.

The approach to oil acquisition should continue to be diffuse and market oriented. The government should investigate all available sources of oil within its own production reserves, including NPR crude oil and federal and state royalty oil. It should also establish market-oriented oil acquisition procedures which allow it to act responsibly as market opportunities become apparent. In establishing SPR oil acquisition procedures, the government should rely on voluntary participation and refrain from imposing burdensome mandatory oil acquisition programs on oil suppliers. Such programs can be expected to lead to unfair distribution of burdens, regulatory and administrative complexity, and pressures for exceptions and abuses.

Thus, the government should first continue to exchange or directly use NPR production as a source of SPR fill. It should also investigate options to supplement NPR crude oil with federal and state royalty oil. The utilization of these reserves will ensure that some level of oil fill will be maintained at all times except during supply disruptions when it is decided to divert SPR fill to the market. Second, the government should establish a voluntary offers program in order to facilitate oil company participation in entering contracts for long-term crude oil suppliers to the SPR. Third, the government should develop and implement a crude oil acquisition program to secure spot cargoes of crude oil which may be available in the market from time to time. In order to be successful, such a program must be positioned to move expeditiously in closing sales once a spot offer is made. The government should consider using petroleum brokers and traders to assist in securing oil supplies at competitive prices for the SPR. Should SPR capacity become a constraining factor, spot and contract purchases of crude oil could be reduced while continuing SPR fill based on NPR production.

Overview of Petroleum Stockpiling in Other Oil Importing Nations[3]

The concept of strategic petroleum reserves is not new; in fact, in countries heavily dependent upon imported oil, such stockpiling programs were in existence prior to World War II. In France, for example, stockpiling regulations had their origin in the 1920's. However, it was mainly after World War II that petroleum imports came to displace coal as the primary energy source in most industrialized countries.

---

[3] The majority of this text is compiled from "Storage Policies of IEA Member States," a draft report by Edward N. Krapels, September 1980.

European countries have felt the need for oil security since the Iranian oil shutdown of 1951-1953 and the Suez Canal crisis of 1956. As a result of the Suez crisis, France implemented a stockpiling program which required its refineries to acquire and store stocks equal to 90 days of the prior year's sales of gasoline, heating oil, and residual fuel oil. However, not all European countries began stockpiling immediately. Many countries were shielded somewhat from the effects of the Suez crisis by the international nature of the petroleum industry and thus waited until years later to impose stockpile programs. For example, the 1967 Arab-Israeli war was instrumental in causing the member countries of the European Economic Community (EEC) to establish a petroleum stockpile target of 65 days' stocks. In 1972, the EEC collectively agreed to increase their minimum stock target to 90 days of the prior year's sales on selected products.

In 1974 the International Energy Agreement was signed by 15 nations including the United States.[4] By the end of 1980, 21 countries were members of the IEA in addition to being associated with the Organization for Economic Cooperation and Development (OECD). One of the requirements of IEA member countries is that they each maintain emergency petroleum reserves equivalent to 90 days of imports. Since most of the signatory countries already had some form of stockpiling program in effect, the IEA impact on stockpiling was not very severe.

The various countries' emergency reserve programs can be categorized into three basic types:

- Government acquisitions and ownership of the reserves
- Special storage corporations, with government financial assistance, that own and manage emergency reserves
- Government mandate that the oil industry maintain emergency petroleum reserves.

Table 32 lists the stockpiling programs of 18 of the IEA countries. Also shown is the dependence of each country on imports to its total petroleum consumption. Table 32 indicates the widespread imposition of mandatory stockpiling on industry by foreign governments. These mandatory programs were not implemented in the current world oil supply environment. For the most part, they were conceived and begun at a time prior to the 1973-1974 Arab oil embargo and the subsequent world crude oil price increases. As a result of their early development relative to the present day situation, the petroleum industries in these nations designed their individual distribution systems to include stock storage for emergency use only. Over time, as countries and the industries grew, so did the stock storage facilities and inventories. There are, of course, fundamental differences between the petroleum distribution

---

[4] For a more detailed discussion of the International Energy Agreement, see Chapter Eight of this study.

TABLE 32

Oil Stockpiling Programs of 18 IEA Countries

Country	Import Dependence*	Government Reserve	Public Corporation	Industry Minimum Storage	No Program
Australia	27%			x†	
Austria	86%			x	
Belgium	100%			x	
Canada	8%				x
Denmark	97%			x	
West Germany	96%	x	x	x	
Greece	100%			x	
Ireland	100%			x	
Italy	98%			x§	
Japan	99%	x		x	
Luxembourg	100%			x	
Netherlands	93%		x¶	x	
New Zealand	92%				x
Spain	97%			x	
Sweden	100%	x		x	
Switzerland	100%		x		
United Kingdom	18%	x		x	
United States	43%	x			

---

*OECD quarterly oil statistics, 1st quarter, 1980.

†As of mid-1980, stocks were at 67 days' consumption; the government has announced plans to raise this to 75 days' worth.

§Italy requires major consumers to maintain a minimum storage fill equivalent to 20 percent of their storage capacity.

¶The Netherlands program is in transition from an oil-company run to a public-corporation run strategic storage program.

system of the United States and the majority of those of other IEA member countries. First, the U.S. import dependence on oil and imported energy in total is generally much lower. Second, the geographic size and complexity of U.S. logistical systems dwarf those in most of the other countries. Thus, the U.S. petroleum distribution system was not designed for and is not currently capable of storing crude oil for emergency reserve requirements without disruptive effects on normal petroleum distribution operations. On paper the United States has 90 days' supply in its complex petroleum distribution system. But, of course, most of this oil is needed for the vast system to function. These and other differences set the U.S. petroleum distribution system apart from those in other countries.

Programs to Supplement the SPR

Considering the limited capability of the current SPR program to effectively mitigate a major supply disruption in the first half of the 1980's, it is logical to undertake an evaluation of complementary programs involving the private sector. The loss of Iranian supplies in 1979 brought forth a wave of studies and proposals for increased U.S. petroleum stockpiles. In September 1980, the Iraq-Iran war led to a resurgence of interest in these studies and proposals.

Regardless of the ownership or method of storing petroleum stocks, all programs for storing large amounts of petroleum offer similar benefits and face basically the same difficult problems. One benefit is that the drawdown of petroleum stockpiles would reduce the economic effects incurred by the United States as a result of the disruption. In addition, oil stockpiles tend to deter the intentional, temporary disruption of supplies. On the other hand, both private and public programs face similar difficulties in the acquisition of oil, long lead times for the construction of storage facilities and their subsequent filling, and the large capital investments required. Although the experience of the past four years provides the SPR program with a practical framework for pursuing future development, any new supplementary program would face the additional complexities and problems inherent in beginning any new venture, as well as time-consuming legislative and judicial challenges where such programs might be mandated by government.

A number of suggestions have been made regarding the size of a supplemental strategic stockpile. Most commonly, the range of suggestions is between 150 and 350 million barrels of oil. The current average cost of constructing above-ground steel storage tanks can be approximated at about $15 per barrel, including the cost of the site, tank construction, and pipeline connections. The cost of crude oil to fill these tanks is currently on the order of $35 to $40 per barrel. Therefore, the initial cost of building these storage facilities and filling them with oil would be about $50 to $55 per barrel, or a total of $7.5 billion to $20 billion for the volume range cited above. An investment of this magnitude would impose a significant financial burden on private companies if mandated by government without assurance of an adequate return on such investments. The converse of all the arguments that supported the development of the SPR work against the desirability of privately owned and controlled strategic stocks held in decentralized and expensive above-ground tankage.

The government has a substantial investment of time, experience, technology, facilities, and about 120 million barrels of oil in the existing Strategic Petroleum Reserve program. Caution should be taken in implementing any alternate strategic storage program which might detract from the continued development of the SPR by competing for available crude oil supplies or diffusing the focus on the SPR.

Overview of Methods for Supplementing the SPR

One alternative is for the federal government to mandate that private companies maintain a specified level of petroleum stocks. Authority for such a mandate has been created by the Energy Policy and Conservation Act under which refiners and importers can be required to maintain segregated security storage. A second alternative for augmenting the SPR is for the government to facilitate voluntary stock building by removing disincentives (such as the threat of imposition of price controls or allocation regulations). A third alternative is providing new incentives to build stocks through methods such as tax credits, cash grants, federal loans or loan guarantees, or preferential tax treatment for strategic oil inventories. A fourth alternative could be a joint effort by the public and private sectors in a manner similar to that used to maintain petroleum security stocks in West Germany. The German EBV (Erdoelbevorratungsverband) system is based on a federally chartered oil storage corporation with responsibility for security stocks. Under this system capital investments in storage facilities and petroleum stocks are shifted to the EBV rather than remaining on the balance sheets of either the German government or private corporations. The cost of the storage facilities and oil as well as associated storage costs are passed through to German consumers via a fee system. A fifth alternative is private financing of the government SPR.

Objectives of Private Storage Mechanisms

Several objectives are desirable for any private storage mechanism that might be implemented in the United States. First, the mechanism should lead to creation of additional storage capacity which can meaningfully supplement the SPR program and add flexibility to strategic stocks. The filling of private storage should take place without creation of artificial shortages which could potentially increase the price of oil to all importing countries at a significant additional cost to their economies. Oil stocks should be built during periods of surplus and drawn down during periods of shortage. Another objective of any private storage mechanism should be to offset some of the shortcomings of the SPR, particularly in the acquisition of crude oil. The private sector alternatives avoid direct purchases by the federal government and thereby may provide a lower profile and more diffuse method of acquiring petroleum stockpiles for the United States. From a financial perspective, the building of stocks should be handled in a manner that does not place an undue or inequitable economic burden on industry and on the private sector or unnecessarily divert capital away from energy development investments. Competition for capital could result in the deferral or cancellation of important oil exploration and production programs, and coal or synthetic fuels projects which could increase domestic energy supplies and thereby reduce this nation's dependence on imports. In addition, any private storage mechanism should maintain competitive neutrality among the various firms in the petroleum industry as well as in other areas of the private sector. If one group (industry or other private sector segment) gains significant advantage over another through a private stockpile program, litigation and political opposition would probably result.

There are some who argue that petroleum stocks privately held by the oil industry would not be effectively drawn down during times of shortage, but would be held to maximize profit potential. The profit incentive is considered necessary and basic to the voluntary building of inventories during normal periods of adequate supply. In the event of an oil supply disruption, as with a shortage of any commodity (wheat, corn, beef, etc.), there is a natural tendency to maintain control of scarce resources to maximize return on investments and/or to ensure continuity of operations for the expected duration of the shortage. On the other hand, any attempt by individual companies to unnecessarily hold back critical stocks will be met by consumer dissatisfaction and possible pressure for governmental remedial action. As a result, there exists the potential for long-term economic harm to companies as a result of consumer distrust and lack of confidence in the industry.

Absent government guidelines, the decision to draw down inventories in the face of a crisis will be made individually by each company. These decisions as to when inventories should be drawn down, at what rate, and to what level, will naturally vary among companies depending upon their individual perception of the crisis and its impact on their operations.

Mandated Supplemental Storage

The Energy Policy and Conservation Act grants the federal government the authority to require refiners and importers to maintain strategic storage up to an amount equal to 3 percent of the amount imported or refined during the previous calendar year. The act provides the federal government with authority over retention and drawdown of these supplies. Based on 1979 throughput and imports, the 3 percent requirement could result in mandating stocks of approximately 200 million barrels. Expansion of stocks beyond that level would require new legislation. Current authorities under EPCA for mandating private storage have not been exercised by the government.

Requirements for industry-held strategic storage could potentially shorten the response time for supplementing strategic storage capacity, via steel tankage, over additional government projects to leach out additional salt dome storage capacity. Strategic stock utilization flexibility would also be enhanced if such inventories were located nearer to refining and consuming centers. Also, private acquisition of oil to fill storage may be less susceptible to retaliation by foreign oil-producing governments than direct U.S. government purchases to fill the SPR.

However, mandatory storage requirements on supplies and/or consumers could have significant disadvantages. The mandate could affect various companies' financial viability in an inequitable manner. The effect of such a mandate would be to create a nonproductive asset of substantial size. The capital devoted to mandatory stocks would not be available for other important investments such as those in petroleum exploration and production, coal, synthetics, and energy conservation. Investments in mandated stocks might be offset by reduced investment in private stocks with no net gain in protection and some loss in efficiency and equity.

Mandated storage would lead to a massive federal system of administration. The government would need to create specific rules for storage requirements. These rules would be complicated due to the periodic fluctuations in seasonal stock and working inventories. Additional staff and regulations would be needed to enable the government to verify the existence, accessibility, and quality of mandated petroleum reserves. Another disadvantage of mandated storage would be the potential loss of economies of scale through the building of relatively small steel storage tanks in diverse geographic areas. Finally, a mandated storage system would be encumbered by bureaucratic procedures necessary to supervise the drawdown of such stocks in the face of a developing supply disruption.

Design and Operation of the U.S. Crude Oil Distribution System

To facilitate understanding of proposals to mandate changes to the petroleum distribution system, a discussion of the characteristics of the crude oil portion of the system is provided.

The petroleum distribution system in the United States was designed for the efficient movement of large quantities of petroleum raw materials and finished products. In this huge transportation network, a large amount of tankage is necessary in order to maintain normal flexibility for the smooth, continuous operation of the supply system. Crude oil storage facilities in the form of aboveground steel tanks are provided throughout the system for the following purposes:

- To receive and hold shipments of crude oil which are usually delivered in large but discrete parcels

- To segregate different grades and qualities of crude oils

- To accumulate crude oil before and during planned downtime and maintenance periods
- To handle unavoidable but anticipated events such as equipment breakdown and those which may arise as a result of transportation schedule changes, weather delays, etc.
- To meet seasonal peaks in demands
- To accumulate enough crude oil to make up a complete shipment to a further supply point
- To meet system safety criteria.

In each of the above examples of storage usage, it is apparent that some level of tank ullage must be maintained if the system is to be workable.

Within the petroleum distribution system there exist two primary inventory levels. The first level is termed the "minimum operating inventory" and can be defined as the level of inventory in tank bottoms, pipelines, refinery processing equipment, etc., that is necessary to make the system work or flow. When the actual stock level falls below the minimum operating level, operating problems occur and shortages begin to appear. For emergency planning purposes, this level of inventory is considered unavailable to meet current consumption. A portion of this minimum operating inventory is said to be "completely unavailable" and can never be used unless the distribution system is shut down and operators are willing to utilize expensive, one-time-only options. In addition to the "completely unavailable" inventory, the minimum operating inventory includes an amount of inventory necessary for the "normal" operation of the distribution system. This volume includes product needed to handle unavoidable events and the cyclical shipments which typify the movement of crude oil.

The second measure of inventory level is termed the "maximum operating inventory." This maximum operating inventory is below the physical shell capacity of the available tankage as empty space must always be available for efficient system operation. Part of this space is never filled and is required for safety measures designed to prevent overfilling and allow for thermal expansion of the contents. Operating space is required for the receipt of inventory and for unavoidable events. Each operator in the crude oil distribution system has a maximum operating inventory. If inventory were allowed to go above the maximum level, the results would be a slowdown or interruption in the normal operation of the distribution system.

The 1979 National Petroleum Council report entitled Petroleum Storage and Transportation Capacities identified parameters for crude oil storage in the United States as of September 30, 1978 (shown in Table 33).

TABLE 33

Crude Oil Storage in the United States*
(Millions of Barrels)

	Minimum Operating Inventory	Maximum Operating Inventory	Tank Shell Capacity
Total	290	380	460

Range of Operating Stocks 90

Empty Tankage or Ullage Requirement 80

---

*Excludes SPR capacity.

The U.S. petroleum distribution system operates within a crude oil inventory range of 290 million barrels minimum and 380 million barrels maximum, or with just 90 million barrels of crude oil storage flexibility for seasonal demand adjustments and for noncontinuous operations. Table 33 also indicates that while there are 170 million barrels of tankage above the minimum operating inventory of 290 million barrels, some 80 million barrels of tank capacity is empty space necessary for the normal and efficient operation of the system and cannot be utilized for storage.

It can be concluded from this analysis that the U.S. petroleum industry crude oil distribution system operates within a relatively narrow range of inventory levels and is constrained on both the minimum and maximum sides. Thus, the U.S. system was not designed for the holding of static strategic stocks of oil, and any attempts to specify existing industry storage capacity for stockpiling would have a disruptive effect on the distribution system. Storage of strategic crude oil stocks by the private sector would require the construction of additional storage capacity.

Voluntary Private Security Stocks

In considering measures to increase voluntary security stocks, the potential incentives of suppliers, consumers, and commodity investors to buy and store oil should be considered. Constructive stock-building behavior could be significantly encouraged by removing or preventing disincentives. Price and allocation controls discourage substantial profit-motivated inventory acquisition during periods of oversupply. Furthermore, with respect to the impact on inventory build, the threat of controls has potentially as adverse an effect as controls themselves. Merely discontinuing price and allocation controls by executive order falls far short of achieving the desired effect, as petroleum companies could justifiably expect controls to be reimposed with little delay in the event of a shortage. Accordingly, if a favorable impact on voluntary inventory acquisition of crude oil is to be achieved, existing legislative authorities should be permitted to expire without enactment of substitute crude oil price control measures. In addition, any authority which could provide for mandatory allocation of private crude oil stocks should be amended to preclude such use. Petroleum companies' acquisition of crude oil in a voluntary mode is highly diffuse and balanced relative to changing supply/demand patterns, and thus would be compatible with crude oil acquisition efforts by the Strategic Petroleum Reserve Office.

Private stocks offer the advantage of being readily available for drawdown to mitigate the disruptive effects of a developing supply shortage without the need to consider activation triggers or other bureaucratic procedures. Pressures to hoard or hold private stocks beyond the optimum time of drawdown is a disadvantage, but private decisions are likely to be diffused and diverse as opposed to monolithic government decision-making.

Although the removal of price and allocation controls could have a substantial impact on private inventory accumulation, the existence of what economists call "external benefits" from strategic storage suggests that private inventory accumulation may, nevertheless, remain below levels desirable from an overall emergency preparedness standpoint in the absence of tangible government incentives. Petroleum security stocks serve to protect the broadest national interest against a threat to its economic well being and military security. As these benefits accrue to the nation as a whole, they may justify a system of government incentives to encourage a level of privately held stocks higher than would otherwise prevail.

Elimination of the threat of price or allocation controls on private stocks is prerequisite to the effective operation of any incentive system. The existence of standby crude oil price controls on these stocks would cause concern that, if such controls were applied, the benefit of any promised incentives would thus be denied.

An incentive system that might be considered could be structured in a number of ways. Among the options which have been suggested are:

- Federal loans or loan guarantees for inventory acquisition
- A mechanism to impose import tariffs during supply disruptions thereby increasing the uncontrolled price and the magnitude of prospective inventory gain
- Preferred tax treatment for inventory profits
- Tax credits or cash grants for holding inventories
- Tax credits or cash grants for construction of storage facilities.

These alternatives are discussed in the following paragraphs.

The first option, federal loans or loan guarantees, is unlikely to be effective. Government loan guarantees protect only the private lender against default by the borrower, thus permitting a loan to be granted for an otherwise unacceptable risk. They do nothing to ensure cost recovery by the private borrower. Even with government guarantees, the borrower's repayment obligation is not abrogated -- except in the event of his default. This is likely to be of little comfort to the borrower as guaranteed security storage loans would almost certainly affect industry debt/equity ratios, credit standing, and the ability to borrow capital for other projects. Similarly with direct government loans, to the extent that the program is really a loan creating a firm obligation to repay, it is fundamentally no different than other types of loan financing. It still leaves the borrower with increased debt and problems of cost recovery and provides little effective incentive. If government loans were provided at below-market interest rates, the government would in effect be providing a direct financial subsidy towards inventory acquisition, and the comments that follow regarding the fourth and fifth options would apply.

The second option, a mechanism to impose import tariffs during a supply disruption, might be effective but difficult to implement. It would be difficult to develop a legislative formula which would provide the oil industry or other private sector holders of stock with the necessary level of assurance that the import tariffs would in fact be imposed as promised and that the domestic price would be allowed to rise in an uncontrolled fashion without confiscatory taxes to meet the new import price. However, if these problems could be overcome, an import fee mechanism could provide large incentives for stock building.

The third option would be to provide preferential tax treatment on oil inventory gains. Gains on inventories which have been held in excess of a year could be accorded long-term capital gains treatment, or, as a further incentive, inventory gains could be exempted from taxation. Capital gains treatment would seem desirable on grounds of equity with other types of assets, and because it would encourage prudent long-term accumulation of stocks over the counterproductive crash inventory build which might accompany the onset of a shortage. A 100 percent tax exemption would provide further incentives to hold petroleum security stocks.

The fourth option is a system of tax credits or cash grants provided whenever security stocks are held. This approach allows for any targeted level of subsidy, and it would permit an offset to the tendency of investors to acquire stocks rapidly at the onset of a shortage by lifting the subsidy during periods of disruption. However, such an approach would present significant administrative problems. A regulatory formula would have to be devised to distinguish between subsidized stocks and normal working stocks, and government inspectors or contract auditors would have to verify that subsidized oil was being stored. Since storage subsidies would be prorated by period of time stored, the government would have to keep track of all purchases to prevent back-dating of acquisition, and of all drawdowns to prevent post-dating of drawdown. Reaching agreement on legislative language to define these procedures could be difficult, and, if a bill were enacted, establishment of final regulatory procedures would take time. In the interim, the program could not be fully effective.

The fifth option is a system of tax credits or cash grants for the construction of storage facilities. This option would directly address the shortage of adequate strategic storage capacity. It would avoid many of the administrative problems that may be associated with a system which provides credits or incentives based on inventory levels. Old and new can be automatically distinguished in a system of credits or grants directed at storage facilities. The legislative language could be straightforward and could be enacted as part of periodic tax legislation.

Furthermore, and perhaps more important, a system of incentives for new storage facilities would encourage new investors and ensure that inventory build was not the exclusive responsibility of the oil industry. Given an adequate level of subsidy, companies in many industries could find it attractive to construct new tankage and store crude oil or product, both for themselves and on behalf of other firms and/or private investors. This is desirable from several standpoints. It brings new sources of capital to bear and ensures that capital for inventory build is not provided exclusively at the price of a cutback in other critically important energy programs.

If a system of credits or grants for construction of storage were put in place, the total subsidy should be less than the full cost of storage facilities in order to ensure that storage facilities are constructed in efficient cost-minimizing fashion. To maximize incentives for efficient construction while still providing the greatest possible incentive, it might be desirable to integrate a fixed credit per barrel of tankage with some percentage credit for costs above that level.

Before leaving the subject of voluntary mechanisms, it should be mentioned that there has been discussion regarding the role of commodity futures as a mechanism to bolster private stocks. Assuming the fungibility problems raised by the existence of different qualities and grades of crude oil can be satisfactorily addressed, a commodity futures market in crude oil would be a natural outgrowth of increased private investment in inventories and would effectively complement them. However, as physical commodities are typically held against only a very small fraction of the total volume of contracts outstanding on a commodity exchange, a commodity futures market in oil should not be pursued as an end in itself. Commodity markets facilitate trading activity but do not, of themselves, occasion significant incremental storage.

Security Storage Corporation

One alternative means of supplementing the SPR would involve use of a hybrid public/private "security storage corporation." Its objective would be to take advantage of petroleum companies' expertise without draining scarce private capital resources from investment in new energy development. Other countries have faced these issues and have developed programs consistent with their markets and economic conditions. In highly controlled markets such as in France, Italy, and Japan, mandatory storage appears to be workable. In a more competitive environment such as that in West Germany, other alternatives have been proven more desirable. The similarities between the West German and U.S. situations make a review of the German experience particularly instructive.

As in the United States, the West German market is highly competitive and contains a large number of firms with disparate financial capacities. They include both integrated and independent refiners and independent importers of varying sizes. Mandatory storage regulations, first imposed in West Germany in 1965, contained different required storage levels for different types of firms. The system was not felt to be fair, and increases in storage requirements in 1975 met stiff opposition. Litigation over the next several years made it clear that no mandatory storage program could be fair to all firms in the industry. In many cases, the financial burden imposed by mandatory storage strained the financial capacity of the firms. As a result, the "Oil Storage Association" (EBV) was formed in July 1978.

The EBV is a federally chartered corporation. Its budget and borrowings must be approved by the government, and it is "protected from bankruptcy" through the government assuming any liabilities which remain when the EBV liquidates. This arrangement is not viewed by the government as a direct guarantee of the EBV's debt. All companies engaged in importing or refining oil are required to be members of EBV and pay fees which cover the association's operating expenses. These fees, which primarily cover interest and lease payments, are passed through to consumers. Companies are encouraged to list the EBV fee separately on their invoices.

Storage requirements for the EBV are set by the German government. EBV's initial stocks were provided through a transfer of each member's mandatory stocks to the association. Existing aboveground storage was purchased or leased. In most cases the initial fill of the EBV did not require any movement of oil and the EBV was functional immediately upon its establishment. Its capital was 100 percent debt financed and was used to compensate members for the assets transferred to the association. Members have, through an advisory counsel, a majority vote on all matters affecting the operation of the EBV other than stock drawdowns.

Although any stocks more than 5 percent above the target levels may be disposed of at the EBV's discretion, drawdowns below target levels may be made only on the authority of the German government. Stocks are required to be sold at market price and offered to members first, in proportion to their contributions. Profits from sales are to be used to offset operating expenses and reduce debt. It is not clear when the government would permit drawdown of EBV's stocks, which are currently in excess of 65 days' requirements. In addition to EBV stocks, refiners are required to hold an additional 25 days of stocks (which is roughly the level of normal operating inventories), and the government has an additional 15 to 20 days of strategic stocks in underground storage.

The EBV is often cited as a successful solution to West Germany's security storage needs. Litigation regarding discriminatory storage requirements has been eliminated and industry's financial condition has been strengthened by removing sterile assets from its books. The government does not feel that the public sector burden on the economy has been unduly expanded, as the EBV debt is not directly guaranteed and the fee imposed on companies is not a tax.

Applicability of EBV To U.S. Conditions. Although the concept of a hybrid public/private security storage corporation is interesting, the West German EBV program probably could not be successfully transferred to the United States without significant changes. One reason for this is that the U.S. petroleum industry has no existing mandatory storage. Therefore, a security storage corporation would have to compete with industry and the SPR for scarce oil supplies in building a reserve. Similarly, the absence of an existing mandatory storage program in the United States implies that the storage corporation might face a long lead time in constructing additional tankage. A much more complex organization than EBV would obviously be required in order to accomplish these additional functions.

It is likely that a security storage corporation would face significant opposition. New laws would be required, and Congressional debate could be protracted. Any legislative action would likely be followed by considerable litigation. Only after organizing a staff for the corporation and developing procedures could oil and storage capacity actually be acquired. The cumulative effect of these delays would mean that it would be very unlikely for a security storage corporation to make a significant contribution to the nation's security during the 1980's when it is needed most.

Some of the drawbacks of a security storage corporation could possibly be overcome. Oil acquisition could be accelerated by imposition of an in-kind refinery tax/import tariff designed to absorb the current excess industry inventories. However, any action along these lines would face a great deal of litigation and political pressure. In fact, an EBV-type program would face many of the same problems as the Strategic Petroleum Reserve Office: difficulty in quickly acquiring oil and storage capacity, susceptibility to political pressures, government reluctance to make drawdowns when needed, etc. A security storage corporation would have several possible advantages, however, including the benefits of increased industry involvement and the conservation aspects of direct consumer charges.

The most significant problem with the concept of a security storage corporation is unavoidable: that is, the diversion of national attention and energy from the SPR. With about 130 million barrels of existing unused capacity in the SPR, its expeditious filling would be the logical first step in reaching security storage goals. Although a security storage corporation has been successful in West Germany, it is unclear whether this success could be expeditiously duplicated in the United States. In order not to lose valuable time and momentum, the filling of the existing SPR should remain the first priority, augmented by the avoidance of disincentives to private stockbuilding.

Private Financing of the SPR

As a result of increasing budgetary constraints, the cost of the oil needed for an adequate SPR may prove burdensome to the government. One means of alleviating the SPR's budget impact would involve attracting private capital to finance the acquisition cost of oil. Investors would be given the opportunity to fund the purchase of oil in return for receiving a payment equal to the value of the oil on or before a known date. In order to be workable, such a system would have to have certain features:

- Investors must be able to freely buy and sell their participation shares in the SPR, and must be assured that the eventual disposition of the oil will occur at a free market price, not a controlled price. The oil could be sold at auction (or purchased by the government at an equivalent price), or maturing participation shares could be redeemed through a refunding.

- To be willing to hold SPR participation shares, investors must expect an adequate return on their funds. Some individuals probably believe that the cost of energy will increase faster than general inflation indefinitely and would be willing to simply buy and hold oil for prospective appreciation. To capture the large amounts of capital required, however, some cash return would probably be required in addition to the appreciation in the value of the oil. The lowest efficient return could be achieved in periodic auctions of SPR participations, similar to auctions of government securities. The federal government would probably have to absorb the costs of storage and shrinkage in order to reduce the number of unknowns faced by investors.

- Return of capital (via refunding or sale of oil) must occur within a reasonable period of time, for example 20 to 30 years. (Bonds which do not have a fixed maturity date are not feasible if a portion of the expected return simply accrues each year instead of being paid out.) Investors in the SPR would realize that their capital could be returned at any time up to the final maturity. To ensure fairness, capital should be returned on a "first in, first out" basis.

A program of private investors' participation in financing the SPR might increase public support for the SPR through increased public awareness and involvement. This public support may also reinforce a government policy of market pricing of crude oil during a shortage as investors would want their "stock" to increase in value with the market rather than being limited in value by price controls or other government regulations. However, an SPR "participation shares" program could also promote increased public pressure to draw down stocks during even modest supply disruptions in order to capitalize on the investment. Drawdown of stocks at such times could possibly conflict with national emergency management strategies and policies.

A plan such as this could probably proceed to some extent; however, it is impossible to predict whether or not the full cost of oil to fill the SPR could be raised in this manner. If successful, such a program would enable the government to retain control over the rate and timing of withdrawal from the SPR, while shifting a portion of the cost to private investors and reducing the federal budget deficit over the next several years. There is, however, the danger that a mechanism for investment in crude oil without cost of carry would tend to discourage private stockbuilding as a supplement to government held reserves.

Conclusions Regarding Programs to Supplement the SPR

- Considering the limited capability of the SPR program to mitigate a major supply disruption in the early 1980's, supplementary measures to increase private stocks should be considered.

- Mandated private storage has the disadvantages of affecting different firms inequitably, leading to a massive federal administration system, and diverting capital from equally important investments in energy development, energy conservation, and voluntary private stockbuilding.

- Removal of disincentives to voluntary storage has none of the disadvantages of mandatory storage and could have a significant impact on the level of private stocks.

- Consideration should be given to treating long-term inventory profits as capital gains and to tangible government incentives, either tax credits or cash grants, to encourage private construction of storage facilities. It should, however, be recognized that government would likely control the use of privately held inventories it has subsidized.

- A hybrid public/private security storage corporation has been successful in West Germany. However, it is unclear whether this success could be expeditiously duplicated in the United States. Creation of such an entity would distract the government from its first objective, which should be to progress the existing SPR program. Further study of this complex matter is, of course, appropriate.

- Private financing of the government SPR seems to offer little substantive advantage and may create pressures for premature sale of security stocks. This, too, is a complex proposal and is deserving of further study.

Chapter Four

EMERGENCY OIL PRODUCTION

INTRODUCTION

The objective of this chapter is to quantify the amount of emergency oil production which could be made available in the 1981-1985 time frame to minimize the impact of an import disruption of 2 MMB/D or greater for a period of six to 12 months. The disruption of imports is assumed to occur without significant prior warning. Emergency oil production capability is defined as sustainable oil production above the current normal rate, resulting from temporary production in excess of the maximum efficient rate (MER) by means of production facility modifications and improvements in transportation systems. The following assumptions were used to develop the estimates of potential emergency oil production increases:

- The appropriate regulatory body in each case will permit temporary production in excess of the current legal limits so long as no substantial damage to the estimated ultimate recovery of production reserves is incurred.
- Regulatory bodies will act in a timely fashion to relax conservation and environmental rules, particularly in regard to limited gas flaring and emissions on a temporary basis until permanent facilities can be provided.
- Production allowables are at the present level in all major fields between now and the time of the emergency.
- Any new primary, secondary, or tertiary reserves placed on production between now and 1985 will be at maximum capability.

This chapter attempts to focus on available and secure sources of petroleum supplies. To initially identify existing fields with emergency capability, the 1974 NPC study entitled Emergency Preparedness for Interruption of Petroleum Imports into the United States, which included a detailed review of 23 privately operated major oil fields, was used as a basis. Based on a new survey of major field operators taken in 1980, the fields currently identified as having emergency oil production capability, and shown in Figure 7, are the Prudhoe Bay Unit, three Texas fields (East Texas, Tom O'Connor, and Yates), and Elk Hills in the Naval Petroleum Reserve.

SUMMARY

- The current maximum temporary emergency domestic oil capability deliverable to refineries is about 325 MB/D. Obtaining this level of emergency oil production is dependent upon receipt of the necessary regulatory approval and some incremental level of investments and time delay. Without mechanical pipeline restrictions in the Trans-Alaska Pipeline, the emergency capability could be increased to about 400 MB/D.

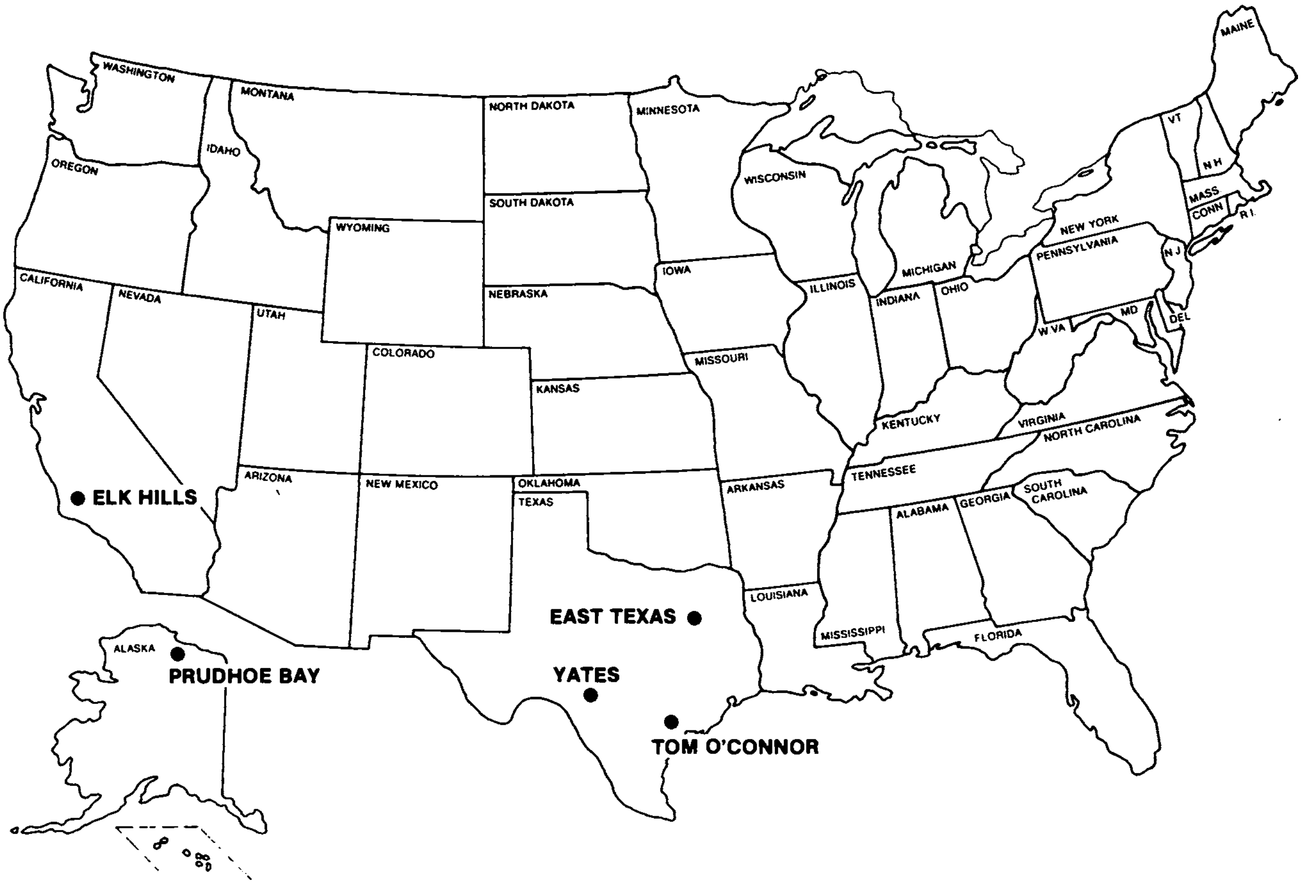


Figure 7. Domestic Oil Fields with Emergency Capability.

- Most of this present capability comes from the Prudhoe Bay Unit and the East Texas field. The emergency production capability from the Naval Petroleum Reserves is limited to about 16 MB/D from the Elk Hills field (NPR-1).

- These current capabilities are assumed to be available for an emergency production period of six months to one year as most fields are facility limited rather than well capability limited.

- The emergency capability in 1985 from existing fields will be lower because most of these fields can be expected to decline in production capability as reserves are depleted. In the case of Prudhoe Bay, emergency production in 1985 will be limited by pipeline throughput. By 1985, total emergency production capability is estimated to be limited to about 140 MB/D, mostly from the East Texas field.

- Overall, the volume of temporary emergency oil production available is quite small compared to the potential size of an oil import disruption. In addition, there are regulatory requirements that currently preclude the use of this emergency production capability and, at the time of need, could further reduce or restrict its effective utilization. Although the estimated emergency production available is relatively small in comparison to the potential size of an import disruption, it could be of value to an overall emergency response plan.

- Maximum benefit of the emergency oil production capability can be most effectively realized through a government pre-planning effort. One aspect of pre-planning would be to encourage the state regulatory agencies affected to develop action plans that could be used at the time of a declaration of an oil import emergency.

- In some cases, private industry would not realize a return on pre-investments in pipeline and other transportation facilities required to maximize emergency production during an import disruption. The government should review tax and regulatory factors that act as disincentives to industry investments in transportation facilities to minimize potential logistics problems which may occur in the future, during both normal and emergency periods.

DISCUSSION AND ANALYSIS

The identified oil fields have no spare producing capacity unless established MERs (as in Texas) or state-approved offtake limits (as in Alaska) are exceeded. Although the established withdrawal rates represent the maximum rate of production that can be sustained over a long period of time, this report assumes that it would be possible to exceed this rate on an emergency basis for a period of six months to one year with minimum risk of reservoir damage or loss of ultimate recovery. The estimated buildup in emergency oil production which could be brought on stream in 1981 is shown in Figure 8. The volumes shown are those deliverable to refineries for both the privately owned fields and for the total emergency production including Elk Hills in the Naval Petroleum Reserve. About half of the total oil surge capability would be available within two months from the occurrence assuming regulatory clearance within 30 days of application. To reach maximum oil surge capacity would require, on an optimistic basis, about four to six months to make the necessary modifications to production facilities and pipelines at a cost of about $30 million. The estimated emergency oil production capability in 1985 is also depicted in Figure 8.

As shown in Table 34, an estimate has been made of the maximum emergency production that could be obtained from the individual fields based on both reservoir and facility limitations. As indicated, the current (1981) major field production might be increased

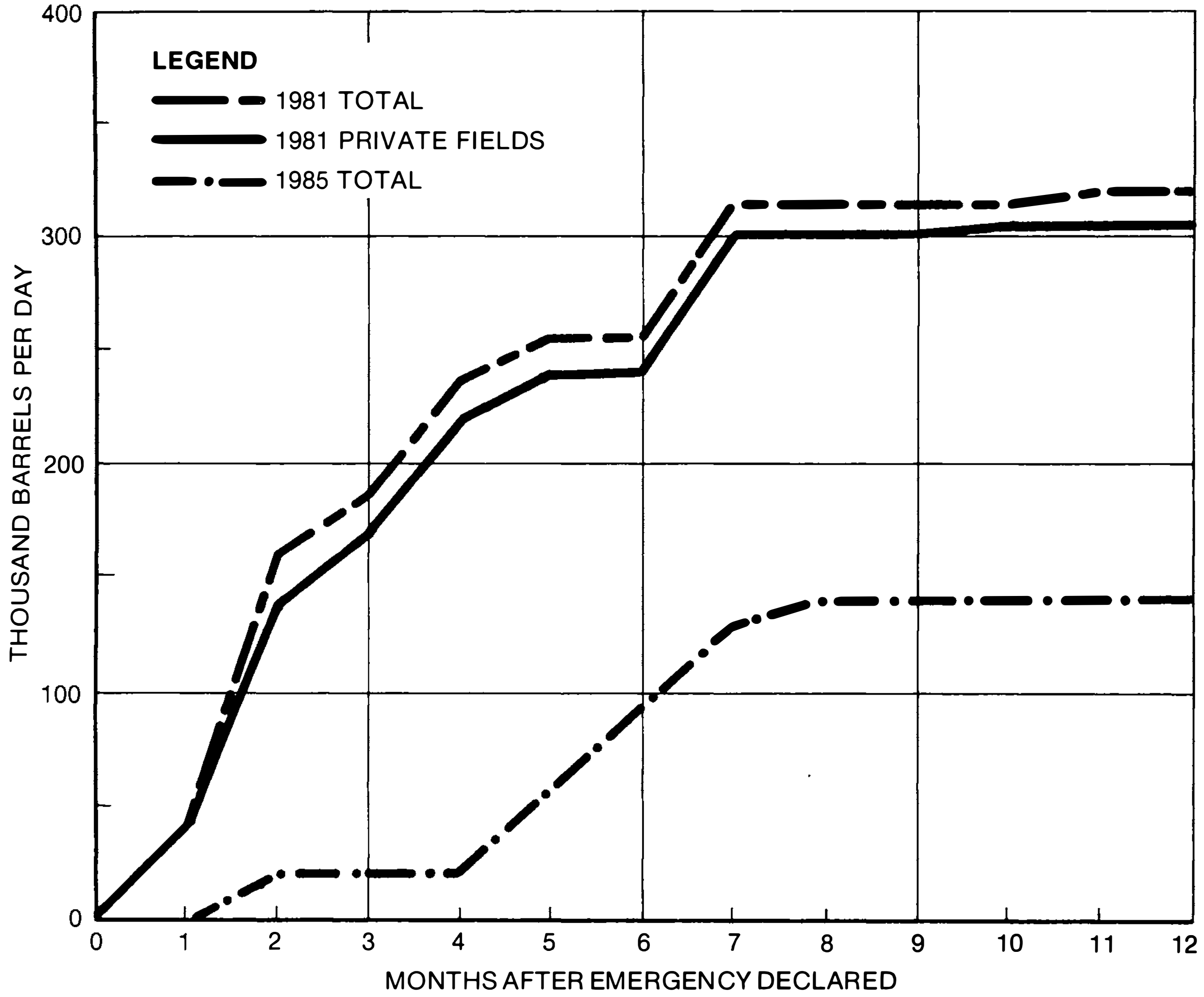


Figure 8. Emergency Production Capability.

by about 400 MB/D based on on-site field production capability and 325 MB/D based on production deliverable to refineries. The length of time that this rate could be sustained is uncertain, but some decline can be expected, particularly over a period lasting beyond 12 months.

As reserves in these fields become further depleted through normal production over time and as reserve-to-production ratios decline, the capability for emergency oil production will decrease. It is estimated that by 1985, only the East Texas field will contain significant emergency capability deliverable to the refineries (about 133 MB/D).

Prudhoe Bay Unit

The Prudhoe Bay field is currently the largest oil field in the United States. Its production is the state-approved maximum offtake rate of 1,500 MB/D, plus condensate production. During 1981,

TABLE 34

Emergency Oil Production
(MB/D)

Field	Current Production	Maximum Field Capacity	1981 Peak Emergency Capacity Field	1981 Peak Emergency Capacity Deliverable to Refineries	1985 Peak Emergency Capacity Field	1985 Peak Emergency Capacity Deliverable to Refineries
Prudhoe Bay	1,500	1,800*	180	100	180†	0
East Texas	162	316	154	154§	133	133
Yates	125	175	50	50	0	0
Elk Hills	183¶	199**	16	16	10	10
Tom O'Connor	59	65	6	6	0	0
Total Emergency Capacity			406	326	323	143

---

*Represents maximum field capacity -- sustained production would be less, on the order of 1,680 MB/D. Maximum pipeline throughput is about 1,600 MB/D.

†Declines throughout year reaching 100 MB/D by year-end 1985.

§Would require about $1 million expansion of the pipeline system.

¶Scheduled average production rate for 1981.

**Increases to 206 MB/D by year-end 1981.

an additional 300 MB/D of field emergency capability (180 MB/D is the expected sustained rate) could be made available immediately (Figure 9), contingent upon the State of Alaska Oil and Gas Division granting emergency production in excess of the current approved maximum offtake rate.

As noted in Figure 9, available Trans-Alaska Pipeline System (TAPS) throughput would likely be less than emergency production capability. The current mechanical capacity of TAPS is 1,420 MB/D since recent startup of Pump Station #7. With the injection of drag reduction additive (DRA), the pipeline had previously achieved sustained throughput of up to 1,570 MB/D and, with Pump Station #7, a slightly greater throughput might be possible (to about 1,600 MB/D). Sufficient supplies of DRA are available to provide this level of throughput if it were required in an emergency situation. When planned production from Kuparuk River field begins in early 1982, it will require substantially all of the incremental TAPS throughput capacity above the Prudhoe Bay field offtake rate, and for this reason, there will no longer be any surge capacity available from the Prudhoe Bay field. A further increase in throughput would be possible only by providing pump additions which would constitute a substantial pre-investment and require considerable lead time for installation.

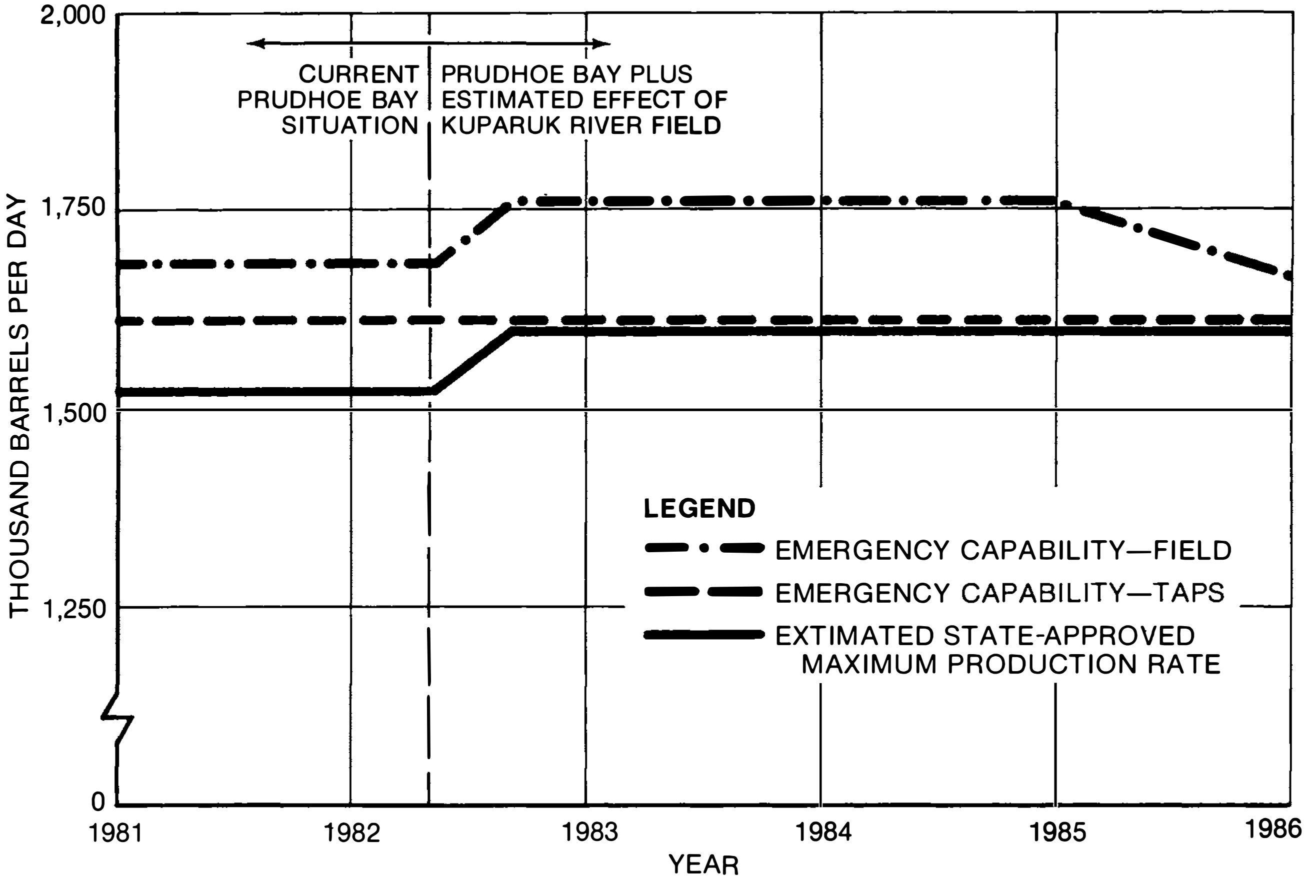


Figure 9. North Slope Emergency Production Capability.

At the beginning of 1985, the oil surge capability of the Prudhoe Bay field and its production facilities will be about 180 MB/D, but there will be no surge capacity deliverable to the refineries unless substantial pre-investment is made in pipeline facilities.

East Texas Field

Current production from the East Texas field is 162 MB/D limited by state allowables. In 1981, maximum short-term field capability in an emergency surge production situation is estimated to be 316 MB/D, an increase of 154 MB/D above current allowable rates. However, there is no surge capacity immediately available because of saltwater disposal system and pipeline transportation limitations. Approximately six months would be required to modify existing saltwater disposal facilities to attain the full incremental emergency production. The ultimate pipeline capacity and the time to attain the full capability is unclear at this time because of the large number of operators with independent pipeline systems.

By 1985, East Texas is expected to be producing 113 MB/D, and total field capability is assessed to be 246 MB/D. This potential production is less than existing pipeline capacity and, therefore, it is not limited by that segment of the system. However, saltwater disposal requirements will be greater in 1985 than for a 1981 emergency production schedule, and at least seven months would be required to reach the incremental 133 MB/D of emergency surge production in excess of MER.

Yates Field

The Yates field in Pecos and Crockett Counties of West Texas currently produces at an MER of 125 MB/D, which was established in 1978. A recent request to the Texas Railroad Commission, still pending, sought an increase in MER to 150 MB/D. In 1981, emergency surge production from existing wells and facilities of 40 MB/D over the present MER is estimated to be available immediately subject to regulatory consent. Sustaining this surge capacity would require investments for infield drilling and remedial well work. Increasing the total surge capacity up to 50 MB/D would require the installation of expanded pressure maintenance waterflood operations.

Without significant pre-investment in field production facilities before 1985, no emergency surge capacity is estimated to be available from the Yates field at that time.

Naval Petroleum Reserves -- Elk Hills

Among the Naval Petroleum Reserves, only the Elk Hills field in NPR-1 has significant emergency production capability. Currently, expansion of facilities and initiation of further waterflood projects are under way to increase production from Elk Hills. These projects are expected to result in an increase in the effective MER to 190 MB/D by the end of 1981.

In 1981, the production facilities are estimated to be able to provide an emergency surge capability of 16 MB/D. It is estimated that this surge capacity could be produced on a temporary emergency basis for at least nine months. This surge capacity could be available as soon as the appropriate Congressional approvals were received, which would be expected to take a minimum of 30 days. With a total production including surge capability estimated at 206 MB/D by year-end 1981, the pipeline throughput capability may be a constraint.

The Elk Hills production rate which meets the definition of MER in the NPR Act will decrease to 135 MB/D by 1985 and will decline steadily thereafter. Initial surge capability in 1985 of 10 MB/D could be made available with Congressional endorsement, but this capability would be expected to decline to about 6 MB/D after a year of emergency production. Under the NPR Act, authority to produce NPR-1 expires April 15, 1982, unless the President submits to the Congress, at least 180 days prior to the expiration date, a certification that continued production is in the national interest. If neither House disapproves the recommendation, production can continue for an additional three years.

Tom O'Connor Field

An emergency surge capability of 6 MB/D has been identified for the Tom O'Connor field located in South Texas. Due to natural decline, it is anticipated that there will be no emergency capability in this field by 1985.

Regulatory Pre-Planning

The emergency surge production estimates provided herein assume that numerous legal and regulatory restraints can be overcome to permit field production levels in excess of the established offtake limits or MERs. These limits have been imposed primarily to prevent waste and promote conservation of natural resources and are administered by state or federal regulatory agencies. It is believed that significant loss in ultimate recovery or reservoir damage would not occur as a result of production at the identified surge levels for short periods (e.g., up to 12 months). However, in order to realize these surge capability potentials, state and federal agencies will have to develop practical standby procedures to respond promptly to the emergency situation.

In Texas, the Railroad Commission has this responsibility and is empowered to issue emergency orders and thereby act in a very short time. The Texas Railroad Commission is chartered to prevent waste and protect correlative rights. In an effort to balance its responsibilities, the Texas Railroad Commission would not likely be in a position to take the prompt actions necessary unless it perceived an emergency of major potential impact and national security importance. Therefore, it is recommended that the Texas Railroad Commission give pre-planning consideration to the level and period of "above-MER" oil production allowable in each field and to a procedure for allocating the production increase to individual properties.

It is also suggested that the State of Alaska Oil and Gas Division be encouraged to develop a contingency production plan for Prudhoe Bay to be used in the event of a national emergency. In developing this plan, conservation hearings might be appropriate to establish the production capability that could be sustained for a six-month to one-year emergency without causing reservoir damage. The pre-planning would permit a more rapid response by the State of Alaska in setting an emergency offtake rate at the time of a declaration of emergency.

For Elk Hills and all other Naval Petroleum Reserves, the production rate is limited by Congressional order to the rate meeting the definition of MER as contained in the NPR Act of 1976 (Public Law 94-258). No specific numerical rate is established and, therefore, the field's maximum production changes constantly with facility installation and reservoir capability. In order to exceed this effective MER, a waiver would have to be passed by Congress after review by three or four committees; this procedure would require 30 to 60 days. It is recommended that Congress be encouraged to amend the regulations to allow production in excess of MER with minimum administrative delays and approvals once it has been determined that emergency surge production is needed.

Chapter Five

EMERGENCY GAS PRODUCTION

INTRODUCTION

The availability of both domestic and other North American natural gas sources must be considered in planning for an interruption of petroleum imports. It is probable that any existing or readily developed additional gas delivery capacity might be used as an alternate fuel source in oil or distillate burning facilities.

Additional gas deliverability may potentially be obtained from several sources, including:

- Spare capacity in lower-48 fields
- Accelerated deliverability through work programs in existing fields
- Underground gas storage
- Production of associated or gas cap gas
- Increased imports from Mexico or Canada
- Liquified natural gas (LNG)
- Alaskan gas
- Nonconventional gas sources.

The magnitude of gas-producing capacity achievable from these sources is difficult to assess exactly. An indication of production potential can be developed based upon reserves, depletion rate, and seasonal demand fluctuations. Each gas supply source is sensitive to timing considerations, involving both the lead time to develop capacity and the season during which an import disruption might occur.

SUMMARY

The assessment of emergency gas production potential further described within this report is summarized as follows:

- Additional gas demands due to oil-to-gas fuel switching in the industrial and electric utility sectors total between 350 and 455 MB/D COE. This potential was identified in Chapter Two and has been built into the various scenario energy balances.
- In 1981, gas surge capacity should be able to provide the additional 2.0 to 2.6 billion cubic feet per day supply

during either winter or summer to meet the above-mentioned demands. This would equate to a 4 percent increase in overall U.S. gas production.

- In addition to satisfying the fuel switching demands identified in Chapter Two, gas production in the near term should be able to supply another 220 to 350 MB/D COE, depending upon the denial scenario and season of the year.
- Sustained gas production above the levels noted would likely require lead times greater than six months, or cause long-term damage to oil- and gas-producing or gas storage reservoirs.
- About 40 percent of the identified fuel switching capability could be realized within one month, and total potential could be obtainable within six months.
- Developing winter gas surge capability would require increased withdrawals from underground storage reservoirs. Although feasible, gas supplies available for winter heating may be compromised should significant volumes be needed in early winter followed by colder than normal temperatures.
- Limited underground gas storage capacity on the West Coast will likely require transportation of additional gas from the Gulf Coast during the winter to satisfy identified fuel-switching potential in California.
- Gas from associated reserves, imports, LNG, and Alaska should not be expected to provide significant emergency production potential prior to 1985.
- The Fuel Use Act represents the most significant single legislative or regulatory constraint to the utilization of gas in an emergency and development of additional fuel switching capability.
- Elimination of various administrative delays in placing new gas wells on production could make about 0.4 BCF/D (70 MB/D COE) available in an emergency.

A summary of emergency gas production potential under the various crude oil denial scenarios is presented in Table 35. Gas substitution potentials from Chapter Two for both the summer and winter seasons are shown on the upper half of the table. The combination of increased gas demand as a substitute fuel in the electric utility and industrial sectors and demand reductions achieved through conservation efforts in the residential and commercial sectors yield net gas demand increases ranging from 50 to 335 MB/D COE.

Additional summer gas demands can be met through an estimated available swing potential of 600 MB/D COE. After the increased demands identified in Chapter Two are met, an additional 265 to 350

TABLE 35

1981 Emergency Gas Production
(MB/D COE)

	Scenario 1		Scenario 1A		Scenario 2		Scenario 3		Scenario 4A		Scenario 4B		Scenario 4C	
	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter	Summer	Winter
Chapter Two Assessments:														
Gas Substitutions for Oil														
Industrial	115	115	115	115	115	115	200	200	200	200	200	200	200	200
Electric Utility	235	255	235	255	235	255	235	255	235	255	235	255	235	255
Demand Reductions														
Residential	(90)	(160)	(90)	(160)	(90)	(160)	(90)	(160)	(90)	(160)	(90)	(160)	(90)	(160)
Commercial	(10)	(160)	(10)	(160)	(10)	(160)	(10)	(160)	(10)	(160)	(10)	(160)	(10)	(160)
Total Demand Change	250	50	250	50	250	50	335	135	335	135	335	135	335	135
Gas Supply Potential:														
Swing Capacity	600	--	600	--	600	--	600	--	600	--	600	--	600	--
Underground Storage Immediately Usable	--	290	--	290	--	290	--	355	--	355	--	355	--	355
Total Supply Change	600	290	600	290	600	290	600	355	600	355	600	355	600	355
Incremental Available Gas*	350	240	350	240	350	240	265	220	265	220	265	220	265	220

---

*Assumes that no geographical constraints exist in applying demand reductions to additional gas demands.

MB/D COE is available in the summer should further fuel switching potential exist. During the winter season, it is estimated that the net increased demand in all the DOE scenarios can be satisfied by additional production of storage zone working gas. These immediately usable storage volumes were developed by reducing the total estimated nationwide oil-to-gas substitution potential to account for possible insufficient storage production capability in PAD V. As shown in Table 36, PAD V fuel switching potential varies between 160 and 180 MB/D COE depending upon import curtailment scenario. Incremental emergency winter storage production in this area is estimated to be no greater than 80 MB/D COE. Therefore, total U.S. winter substitution potential has been reduced by either 80 or 100 MB/D COE, depending upon the scenario.

TABLE 36

PAD V Substitutability Reduction

Sector	PAD V Substitutability (MB/D)		PAD V Emergency Storage Production Capability (MB/D)	Storage Capability Reduction (MB/D)	
	Scenarios 1, 1A, 2	Others		Scenarios 1, 1A, 2	Others
Industrial	30*	50*	--	--	--
Electric Utility	130	130	--	--	--
Total	160	180	80	80	100

---

*Assumed to be one fourth of total U.S. substitutability.

Assuming that no geographic considerations impede the application of gas demand reductions to additional gas demands, incremental available winter gas volumes range from 220 to 240 MB/D COE. These wintertime incremental capabilities are limited by constraining additional underground storage production to volumes usable for fuel switching. Such a constraint is deemed reasonable since it holds production from storage zones to about 30 percent of rates that would totally deplete working gas margin in one winter. It also provides a measure of conservatism to account for distribution bottlenecks and possible problems in directly applying gas made available through demand reductions to newly created needs.

DISCUSSION AND ANALYSIS

Gas Reserves and Depletion Rate Trends

As shown in Figure 10, remaining recoverable U.S. nonassociated gas reserves reached a maximum of 222 trillion cubic

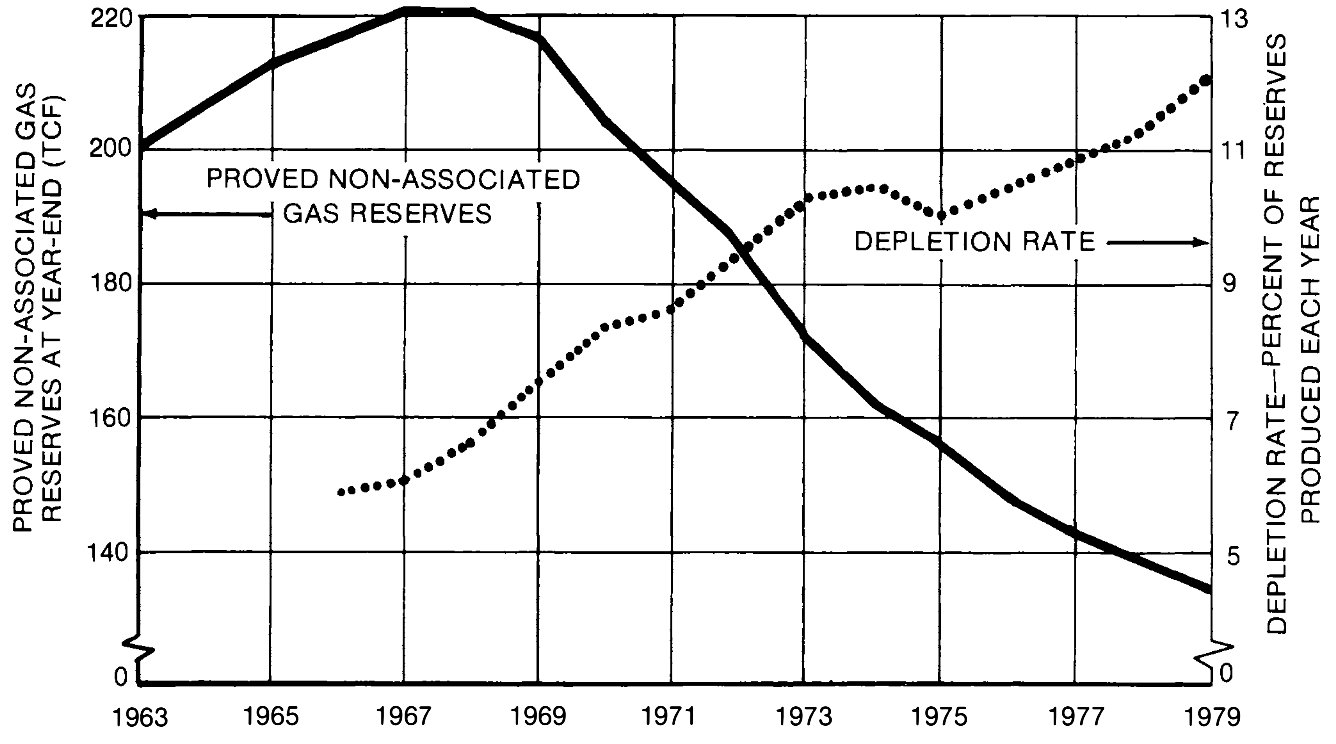


Figure 10. U.S. Non-Associated Gas Reserves and Depletion Rate.

SOURCE: *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, API, AGA, and Canadian Petroleum Institute, Vol. 34, June 1980.

feet (TCF) at year-end 1967 and have since steadily declined at about 3 percent per year to 134 TCF at year-end 1979. During this same period, the depletion rate (annual production divided by remaining recoverable reserves) of non-associated gas increased from 6 percent to over 12 percent per year. Correspondingly, the reserve-to-production ratio (R/P) has declined from 16.3 to 8.2.

Table 37 provides a summary of 1979 gas reserve and production information for both the total United States and the lower 48 states. In order to address the most accessible and prudent source of additional gas for use in an emergency, attention should be focused on lower-48 non-associated gas, which accounted for 16.2 TCF of production in 1979. This gas was producing at an R/P equal to 8.0 years.

A recent presentation by the Gas Research Institute concerning surge capability estimated that the overall lower-48 R/P of 8.3 could possibly be reduced to 7.5 years.[1] By limiting this additional potential to non-associated gas (excluding 34.0 TCF of reserves from associated reservoirs and underground storage), an incremental 1.0 TCF per year (500 MB/D COE) could be realized above 1979 production during 1981. It would appear from the depletion

---

[1] Henry R. Linden, Statement on Gas Surge Capability and Gas Substitutability for Oil, Gas Research Institute, October 1980,p.3.

TABLE 37

1979 Gas Reserves and Production

	Year-End Reserves (TCF)	1979 Production* (TCF)	Depletion Rate (Percent/Year)	R/P† (Years)
	-- United States --			
Non-Associated Gas	134.2	16.4	12.2	8.2
Associated Gas	55.8	3.5	6.3	15.9
Underground Storage	4.9	--	--	--
Total	194.9	19.9	10.2	9.8
	-- Lower 48 States --			
Non-Associated Gas	129.0	16.2	12.6	8.0
Associated Gas	29.1	3.5	12.0	8.3
Underground Storage	4.9	--	--	--
Total	163.0	19.7	12.1	8.3

---

*Excludes change in underground storage.

†Reserve-to-production ratio.

SOURCE: Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979, API, AGA, and Canadian Petroleum Institute, Vol. 34, June 1980.

rate trend depicted in Figure 10 that a 14 percent rate of depletion (R/P = 7) may be deemed a near-term maximum attainable, given a certain amount of lead time to develop and implement acceleration work programs. Such a depletion rate would mean that an incremental 2.2 TCF per year surge capability above the 1979 reference non-associated production level may exist. It is questionable, however, whether such an increase in production could be sustained for more than intermittent periods of time, or, in fact, even be realized at any period of time other than during the summer.

Seasonal Gas Surge Capability

Another means by which gas surge capability may be approximated involves the difference between peak winter and reduced summer rates. This seasonal swing capacity provides a measure of additional gas availability in the event of a summer emergency. Figure 11 depicts a 13-year history of the seasonal difference in marketed U.S. gas production.

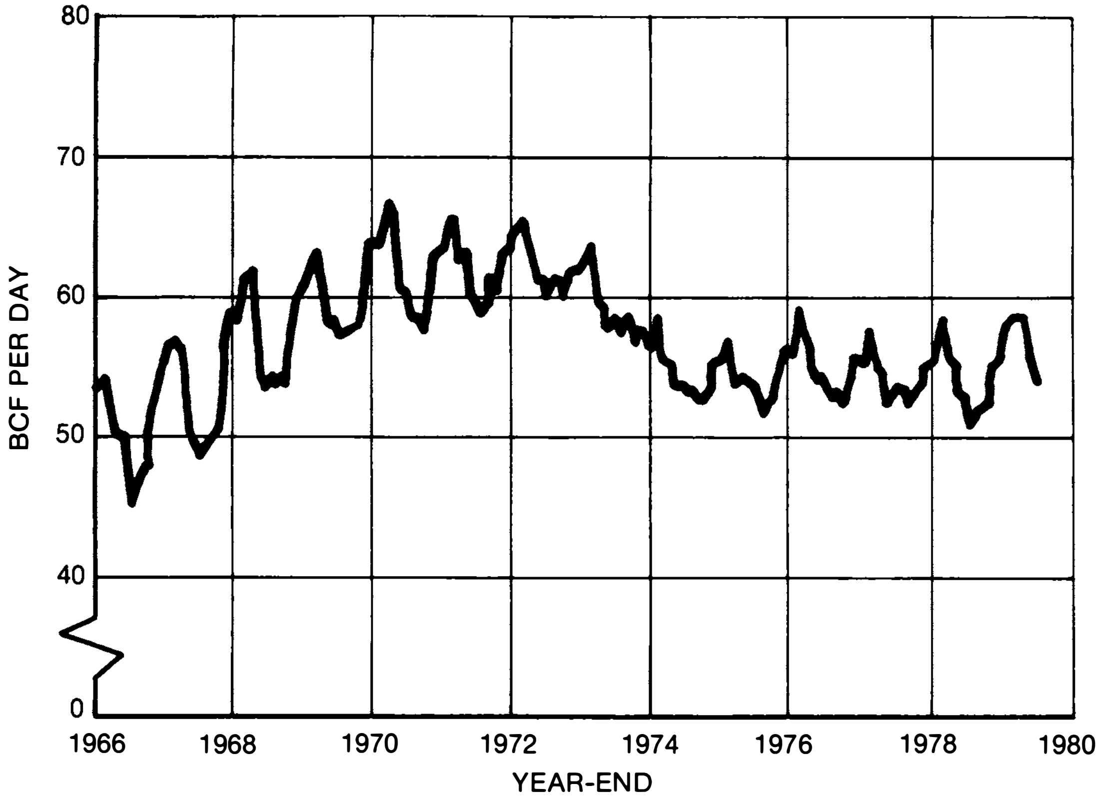


Figure 11. U.S. Marketed Natural Gas Production.

SOURCE: *Natural Gas Production and Consumption Reports*, Department of the Interior, Bureau of Mines; and *Energy Data Reports*, Department of Energy, Energy Information Agency.

As shown, annual production peaks are generally realized during February or March. U.S. natural gas production peaked in 1973 after increasing for several years. A review of the data in the 1972-1975 period would appear to indicate the establishment of a declining producing capability trend and the end of any effective seasonal peaking capability. In fact, these two conclusions were reached in the 1974 NPC study entitled Emergency Preparedness for Interruption of Petroleum Imports into the United States which stated that "...production during the winter of 1974 suggests that currently available swing capacity may be somewhat lower than that available during 1973 and that producing capacity is declining."

However, since 1975 the brief, apparent capacity decline trend has ended and annual average marketed production has stabilized in the 50-60 BCF/D range. With reduced deliveries and possibly some supply improvement, the pronounced seasonal peaks have again become evident. During the 1977-1979 period these maximum swings have averaged 6.6 BCF/D. This would indicate that a maximum additional 6.6 BCF/D, or 1.2 MMB/D COE, could be available during the period of minimum summer demand in the event of an emergency. Two important limitations must be considered with regard to this potential supply.

First, it must be emphasized that the aforementioned 1.2 MMB/D COE summer swing capacity represents a maximum potential. More realistically, given the need for some brief lead time to build to a maximum capacity and the sustainability of maximum production rates through the summer, an average swing potential may more nearly appproximate 50 percent of a maximum, or 0.6 MMB/D COE (3.3 BCF/D). Based upon historical production trends, this emergency capacity would only be available during the seasonal June through October low demand period. This is shown in Figure 12. Assuming that all swing capacity production was developed from non-associated lower-48 reserves, the R/P predicated on annual production would be lowered from 8.0 to 7.7 years.

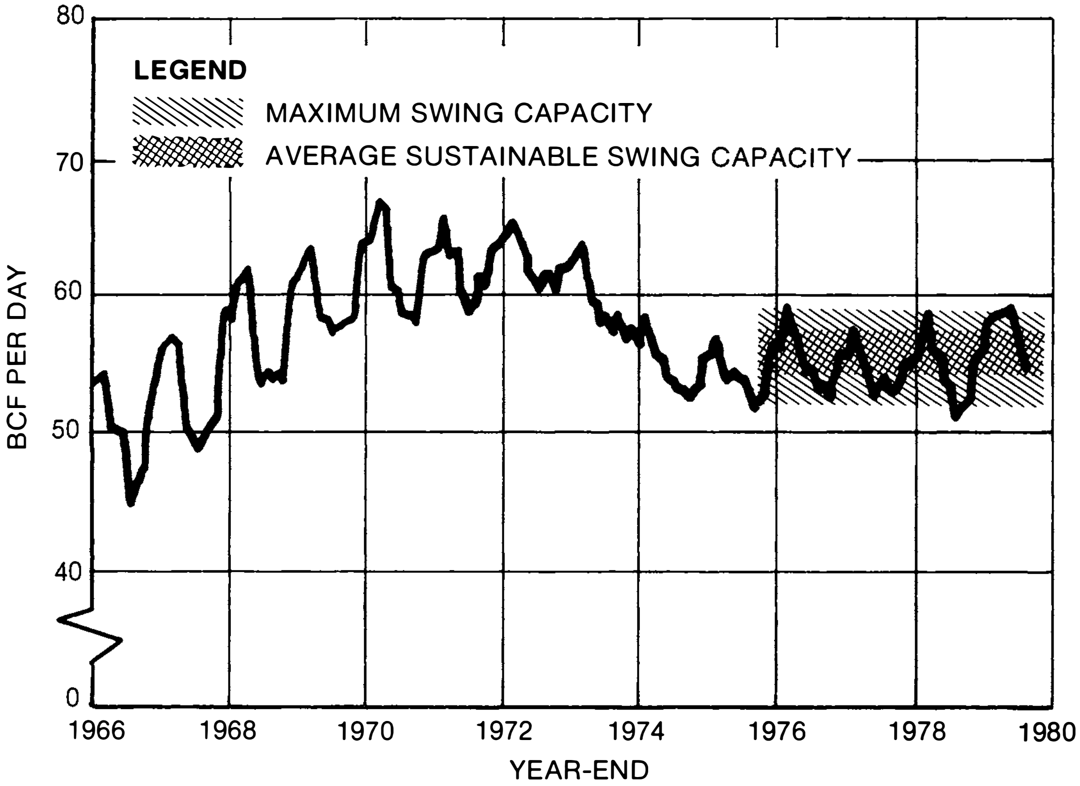


Figure 12. U.S. Marketed Natural Gas Production.

SOURCE: *Natural Gas Production and Consumption Reports*, Department of the Interior, Bureau of Mines; and *Energy Data Reports*, Department of Energy Information Agency.

Second, the ability of consumers to utilize this capacity is dependent upon their capability to convert from oil to gas. Although difficult to assess, this substitutability has been addressed in a recent Energy Analysis by the AGA.[2] In this evaluation, it was concluded that 65 percent, or 5.5 MMB/D COE, of the total 1979 nontransportation use of oil in the United States was potentially replaceable. As a result of a member survey conducted in 1979 by the AGA, it was determined that 1.1 of the 5.5 MMB/D COE could almost immediately be displaced by gas.

---

[2] Potential Substitution of Oil With Gas and Coal in Non-Transportation Uses, American Gas Association, Energy Analysis 1980-10, August 28, 1980.

Oil-to-Gas Fuel Switching Potential

In contrast, Chapter Two of this report estimates that a maximum oil-to-gas substitution potential of 510 MB/D exists. Of this, 250 MB/D is from the electric utility sector and 260 MB/D is from the industrial sector. It therefore appears that estimated swing potential could cover these increased gas demands during the summer. Should fuel switching potential be greater, it is questionable whether additional gas-producing capacity could be developed without lead times greater than the six months needed to implement acceleration workover, drilling, and facility projects.

Another important consideration that arises involves the timing required to effect fuel switching. This aspect is addressed in Figure 13, which profiles the switching capability of various sectors.

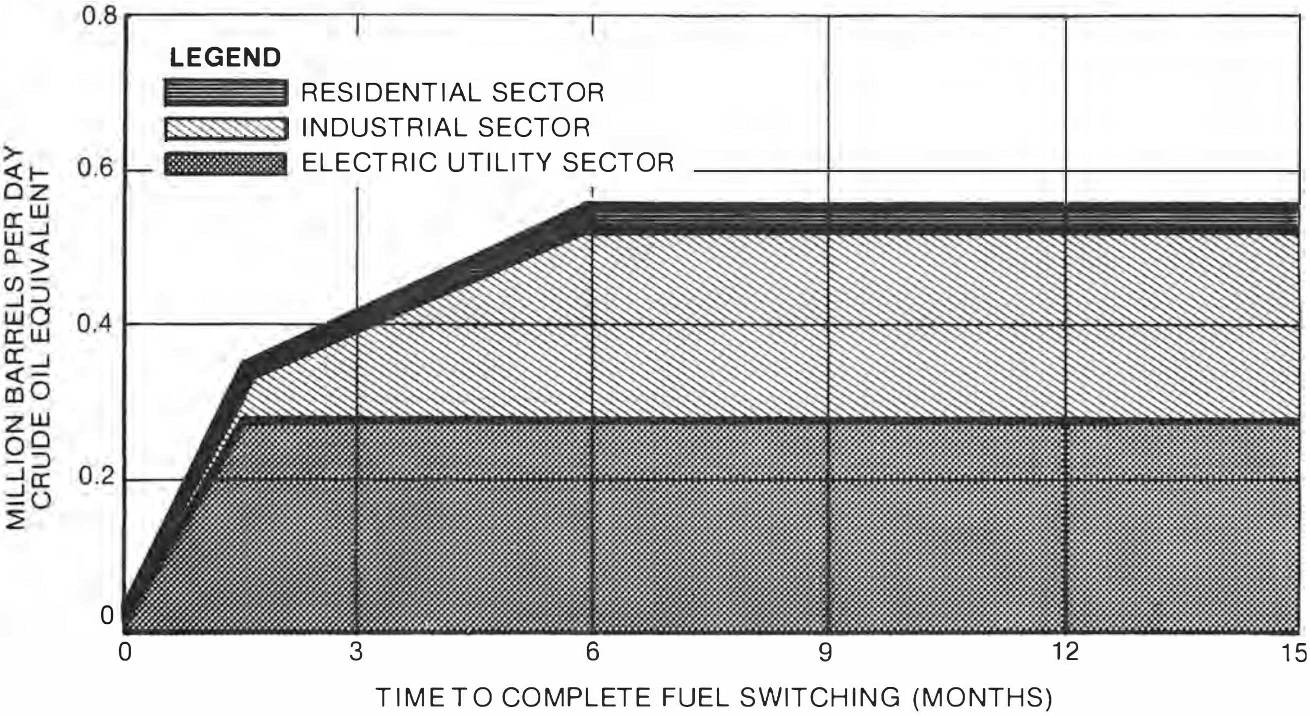


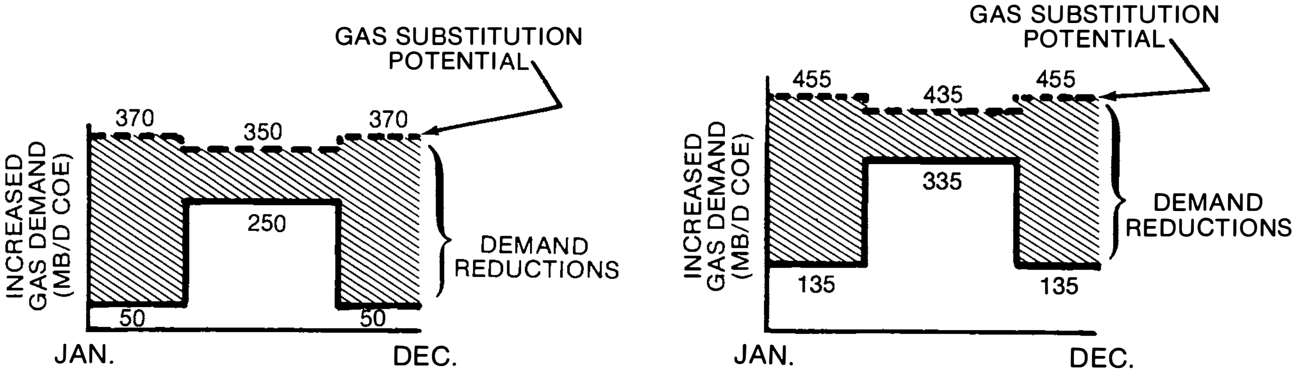
Figure 13. U.S. Oil-to-Gas Fuel Switching Capability.

Based upon data developed in Chapter Two, the electric utility sector is able to provide the most rapid response to conversion needs, obtaining a oil-to-gas substitution potential of 250 MB/D in about 45 days. The industrial sector fuel switching potential of 260 MB/D will require about six months to achieve. These two oil-use sectors, therefore, should be able to substitute for about 210 MB/D after one month, and ultimately obtain the near-term maximum potential of 510 MB/D in six months. This timing has been incorporated in the overall scenario balances developed in Chapter Two.

For the purposes of illustration, near-term residential sector oil-to-gas conversion potential is also shown. This potential is small and requires a longer lead time. The 23 MB/D deemed achievable within one year has not been included in the conversion potential developed in Chapter Two. Development of residential convertability is based upon a recent Energy Analysis published by the AGA.[3] This study indicated that 365,400 house-heating units converted to gas during 1979, and 383,000 units were expected to be converted to gas in 1980, based upon utility company forecasts. Since 90 to 95 percent of these conversions are from oil to gas and involve an average annual oil consumption of 1,000 gallons, the annual conversion potential of 23 MB/D is obtained. Although some incremental conversions might be possible in an emergency, equipment and manpower constraints would probably limit residential conversions such that significant oil replacements over and above the 23 MB/D annual potential could not be realized. Concurrent industrial conversion would also conflict with the residential to jeopardize attainment of the 23 MB/D potential. On a longer term basis, however, the AGA report states that 33 percent of the current 16 million oil-heated homes have gas available for nonheating purposes. If these homes converted to gas, an estimated 344 MB/D could be saved.

In order to further explore gas production capability in view of gas substitution and conversion potential identified in this study, Figure 14 illustrates the annual gas supply change profile developed in Chapter Two.

As shown by the broken lines in Figure 14, seasonal estimates of available 1981 oil-to-gas conversions range from 350 to 455 MB/D COE, offset by 320 MB/D COE of winter and 100 MB/D COE of summer gas conservation measures in both the residential and commerical sectors. These conservation (or demand reduction) measures result in the increased gas demand profile shown by the solid lines. For



Scenarios 1, 1A, 2 (1981)

Scenarios 3, 4A, 4B, 4C (1981)

Figure 14. Natural Gas Potential for Fuel Substitution.

---

[3] An Analysis of Oil-to-Gas Conversion Trends in the Residential Gas Spaceheating Market, American Gas Association, Energy Analysis 1980-11, September 18, 1980.

example, in Scenarios 1, 1A, and 2, the resultant increased gas needs are 50 and 250 MB/D COE for winter and summer, respectively. These increases are required to satisfy the scenario balances developed in Chapter Two.

It would appear that summer swing capacity during 1981 can probably cover the needed 350 MB/D (irrespective of demand reductions) in Scenarios 1, 1A, and 2, with perhaps an additional 250 MB/D COE of gas capability unused. In all other scenarios, summer capacity would exceed estimated needs for oil substitution by about 165 MB/D COE.

During the winter, the net increased gas needs (after estimated demand reductions) shown in Figure 14 range from 50 to 135 MB/D COE. Meeting normal gas demands will generally preclude any swing capacity during this time of the year. However, it is possible that additional production from underground storage could provide needed coverage for one winter season.

Underground Gas Storage

It has been assumed that gas injected to fill underground storage during summer months would not be diverted to attempt replacement of additional fuel oil. This assumption is based upon:

- The need to maintain normal storage operations to ensure winter gas heating capability
- Lack of indicated need for additional summer oil-to-gas conversion capability
- Possible transportation or distribution system bottlenecks in moving gas scheduled for storage to customers with oil-to-gas conversion capability.

Figure 15, however, illustrates the potential deliverability associated with diversion of gas from storage. During 1977-1979, production to storage reservoirs averaged 10.3 BCF/D (1.8 MMB/D COE) during the May to September period when most injection occurs. Given an extreme emergency, the ability to convert to gas, and adequate distribution systems, any part of this production to storage might be available to offset additional summer fuel oil demands, recognizing that a probable supply shortfall would occur the following winter.

Figure 16 depicts total gas in underground storage during the 1976-1980 period and illustrates the amount of stored gas considered to be either base or working gas. Base gas is the volume required in a storage reservoir to provide the pressure necessary to cycle the normal working storage volume. Some of this volume may be recovered when storage operations are ultimately terminated. For example, although 6.3 TCF of gas is shown in storage reservoirs as of December 31, 1979, only 4.9 TCF of this is deemed recoverable.

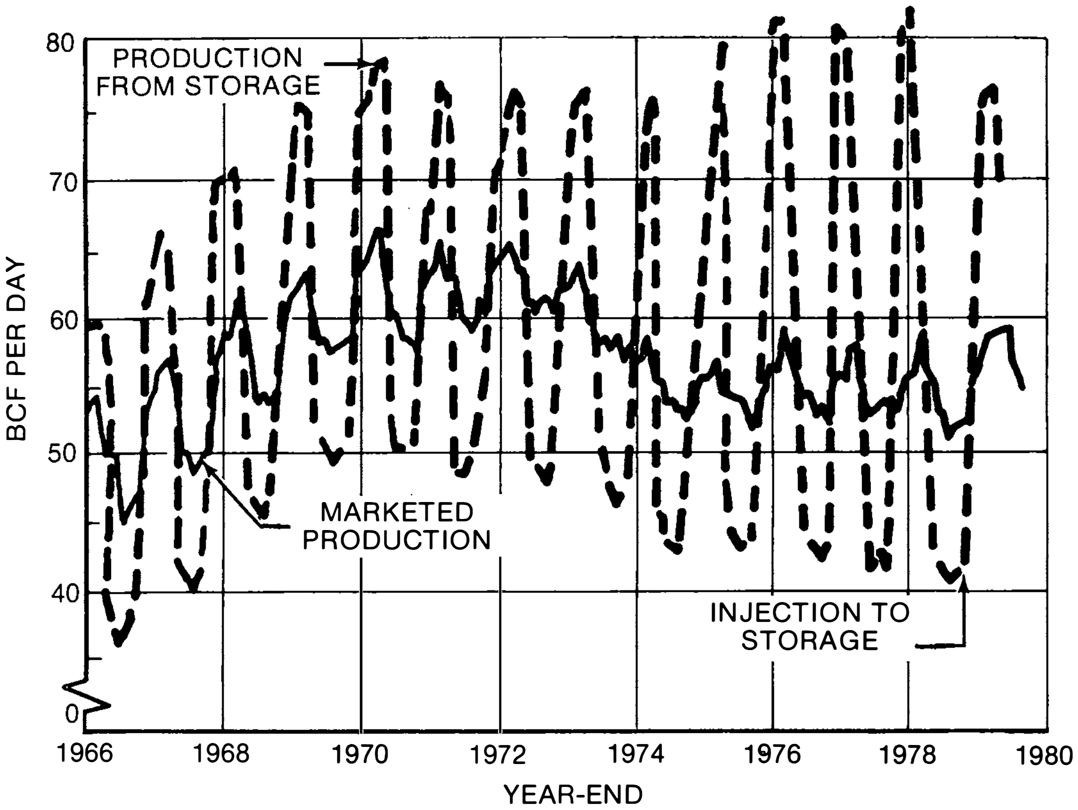


Figure 15. U.S. Marketed Natural Gas Production.

SOURCE: *Natural Gas Production and Consumption Reports*, Department of the Interior, Bureau of Mines; *Energy Data Reports*, Department of Energy, Energy Information Agency; and *Monthly Energy Review*, Department of Energy, Energy Information Agency.

Working gas is that amount shown above required base gas. This gas is withdrawn from storage during the winter at maximum monthly rates of between 15 and 20 BCF/D cycling nearly 2 TCF out of these zones, usually between November and March. Although it would probably not be prudent to withdraw any base gas due to potential storage reservoir damage, Figure 16 highlights a margin of unused working gas that might be available to supplement supplies in a winter emergency. During the past four winters this unused working gas margin has averaged 1.28 TCF, reaching a maximum of 1.59 TCF available in March 1980 due to increasing amounts of underground storage coupled with the mild winter experienced in 1979-1980.

Assuming that the entire average 1.28 TCF working gas margin was exhausted in one winter, this would indicate that an average of 8.5 BCF/D (1.5 MMB/D COE) could be delivered during the five-month (November to March) season. Although the necessary distribution systems may not exist to move this entire amount of gas to users with oil-to-gas conversion capabilities, it would appear that the incremental 0.8 BCF/D or 135 MB/D COE suggested in Chapter Two is achievable.

However, predicating increased withdrawals from storage based upon historical or "normal" winter conditions certainly poses some risk. There may be justifiable reluctance to deliver significant

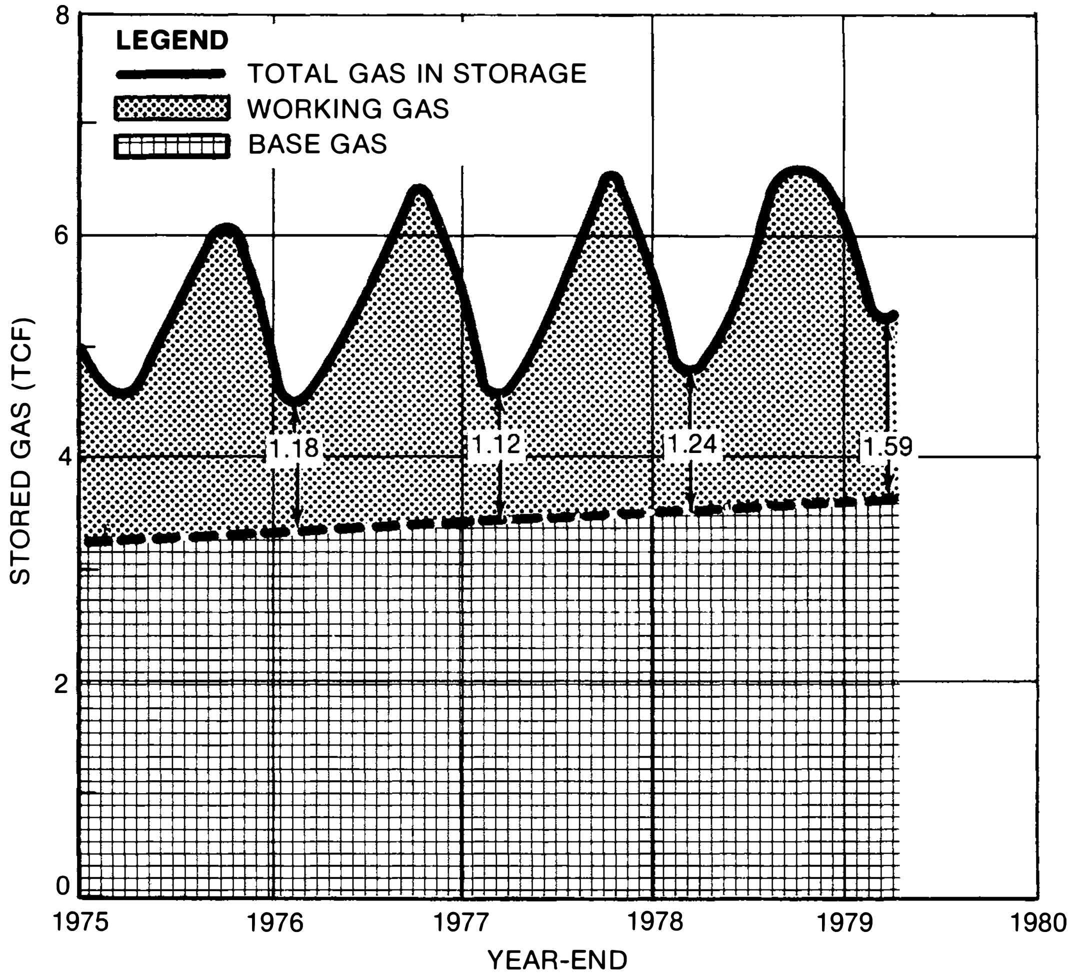


Figure 16. U.S. Underground Storage.

SOURCE: *Monthly Energy Review*, Department of Energy, Energy Information Agency.

additional volumes from storage early in the winter season (November through January) with the expectation of normal weather conditions. The use of working gas margin may, therefore, be limited to the late winter or early spring in order to ensure adequate heating supplies.

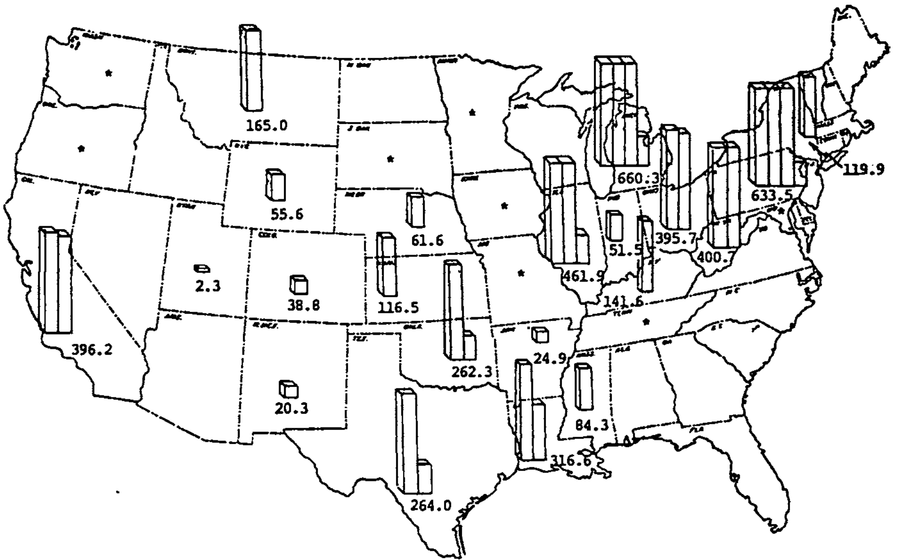
Given that additional production from storage is an effective means to supplant oil usage and that additional stored gas would reduce the risk placed upon heating supplies, emergency planning may have to consider the merits of increasing the nation's capacity to deliver gas from storage reservoirs. A recent report by DOE suggests the potential usefulness of developing a natural gas surge production and delivery capability.[4] While additional gas storage may have some limited utility in mitigating oil supply disruptions, the analyses in this study indicate that, in most areas of the United States, emergency oil-to-gas convertibility may be constrained not by gas supplies but by the availability of suitable end uses.

---

[4] Reducing U.S. Oil Vulnerability, Department of Energy, November 10, 1980, pp. 31-32.

Geographic Distribution of Stored Gas vs. Substitution Potential

For reference, Figure 17 depicts a geographic distribution of the 4.9 TCF of recoverable storage zone reserves as of December 31, 1979.



* Miscellaneous storage totaling 214.6 BCF.

Figure 17. Underground Storage Reservoirs—Total Recoverable Reserves (BCF) as of December 31, 1979.

SOURCES: *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, API, AGA, and Canadian Petroleum Institute, Vol. 34, June 1980.

The importance of oil-to-gas flexibility and adequate transportation facilities to effectively utilize additional storage volumes in the northeast, midwest, and south central states is highlighted. Regional 1981 oil-to-gas potential for the utility sector was developed in Chapter Two of this study. This potential totals 250 MB/D COE for the United States. A comparison of this capability with stored gas reserves is shown in Table 38.

This comparison indicates, for example, that PAD V utility substitution potential of 130 MB/D COE is about 52 percent of the entire U.S. capability. However, the 0.4 TCF of stored gas in PAD V shown in Figure 17 is only 8 percent of the 4.9 TCF currently in underground storage throughout the United States. A comparison of these percentages has been used to detect potential geographic areas of concern related to fulfilling the substitution potential developed in Chapter Two.

As indicated, a reasonable geographic balance exists between storage supplies and electric utility fuel oil substitution potential, with the exception of PADs II and V. It would appear that the only potential problem in achieving the estimated oil replacement by using stored gas during winter months might occur in PAD V (California). The problem may be further aggravated by a geographic variance in the residential/commercial sector gas energy savings. It is reasonable to assume that the 320 MB/D COE winter

TABLE 38

Geographic Comparison of Oil Substitution Potential vs. Underground Gas Storage

Region	1981 Electric Utility Potential Oil Substitutions (MB/D COE)	Percentage of Total	
		Substitution Potential	Storage
PAD I	90	36	25
PAD II	20	8	46
PAD III	10	4	15
PAD IV	--	--	6
PAD V	130	52	8
Total U.S.	250	100	100

demand savings projected in Chapter Two would come mainly from midwestern and northeastern states. This would largely negate use of this source of incremental gas supply to supplement storage zone production in California to meet estimated oil replacement potential.

Although finding enough gas to replace oil during the winter in the California area may be more difficult than in other areas of the country, the data in Table 39 seem to indicate that some of the requirements assumed in Chapter Two can be met.

Table 39 indicates that at the start of the 1977-1978 winter season 172.3 BCF of working gas was available. Average storage output for the years 1977 and 1978 was 107.5 BCF, leaving an average working gas margin of 64.8 BCF. Assuming a five-month winter season, this would provide 0.43 BCF/D (76 MB/D COE) for utility fuel switching from California storage zones. This is slightly over half the utility switching potential used in Chapter Two. Chapter Two also indicates that an additional 115 to 200 MB/D of additional nationwide industrial fuel switching from oil to gas is possible in various scenarios. It is likely that whatever portion of this potential resides in California may require transportation of stored gas from the Gulf Coast and Midwest, utilizing the nation's gas transmission system.

With regard to delivery capacity, the above data show that an additional 1.0 BCF/D capacity exists on the day of maximum withdrawal from storage. There would seem to be no difficulty moving an additional 0.4 BCF/D to utility customers within California.

Unless additional gas can be moved to California during the winter from either Canada or the southwest, it would appear that

TABLE 39

California Gas Storage Data

Total Recoverable Stored Gas Reserves (12/31/77)	396.8 BCF*
1977 Working Gas Reserves	172.3 BCF†
1977 Output from Storage	84.9 BCF§
1978 Output from Storage	130.1 BCF¶
1977 Maximum Daily Output	3.5 BCF/D§
1977 Maximum Design Daily Deliverability	4.5 BCF/D†

---

*Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979, API, AGA, and Canadian Petroleum Institute, Vol. 34, June 1980, p. 127.

†Petroleum Storage and Transportation Capacities, National Petroleum Council, Vol. VI, December 1979, Appendix F.

§AGA Gas Facts: 1977 Data, American Gas Association, Department of Statistics, 1978, p. 46.

¶AGA Gas Facts: 1978 Data, American Gas Association, Department of Statistics, 1979, p. 48.

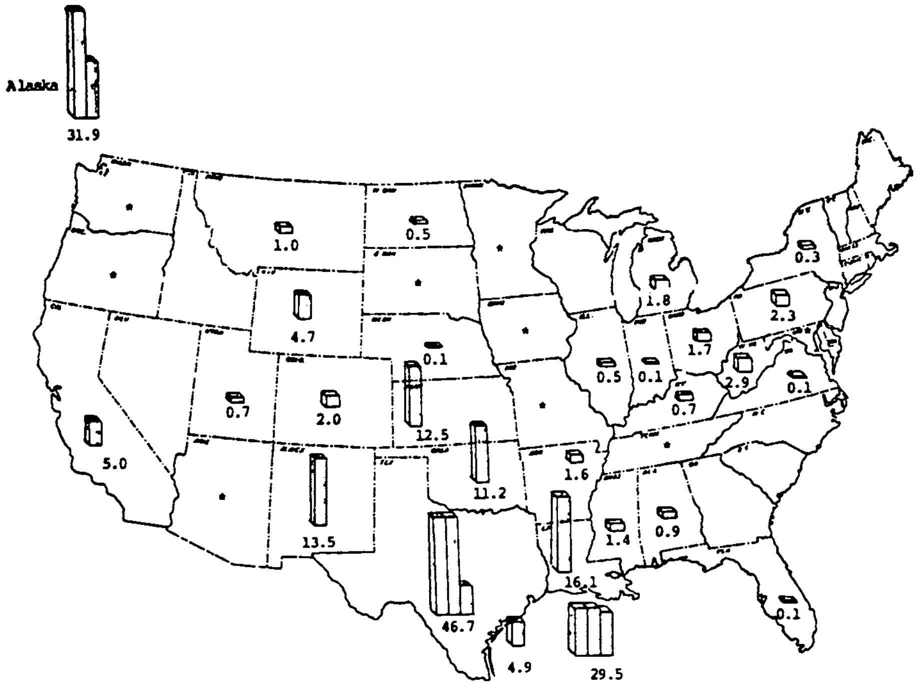
fuel switching capability in PAD V will be limited to 76 MB/D. However, the 1979 Petroleum Storage and Transportation Capacities study by the NPC indicates that an annual average spare flow capacity of 0.8 BCF/D exists from Texas to southern California. It is possible that a portion of this spare capacity may exist during the winter and could be used to transport Texas gas to California. Although potential solutions exist, for the purposes of this study the conservative estimate of 76 MB/D oil equivalent winter surge capacity is adopted for PAD V.

Geographic Distribution of Gas Reserves

Figure 18 illustrates the geographic distribution of the 194.9 TCF of total remaining U.S. recoverable gas reserves as of December 31, 1979. These reserves include non-associated, associated, and underground storage gas. It is clear that the south central United States and Gulf of Mexico are key to providing emergency gas volumes, as they (New Mexico, Texas, Oklahoma, Kansas, Louisiana, and the Gulf of Mexico) contain 82 percent of the nation's lower-48 gas reserves.

Associated Gas Reserves

In addition to spare non-associated gas-producing capacity, swing capacity, and underground storage, several other potential sources of gas merit a brief discussion. Associated reserves (gas cap gas in oil reservoirs) are 55.8 TCF (29 percent of total U.S. reserves) as shown in Figure 19. This gas is being produced at a



* Miscellaneous reserves totaling 0.3 TCF.

Figure 18. Total Gas Reserves (TCF) as of December 31, 1979.

SOURCE: *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, API, AGA, and Canadian Petroleum Institute, Vol. 34, June 1980.

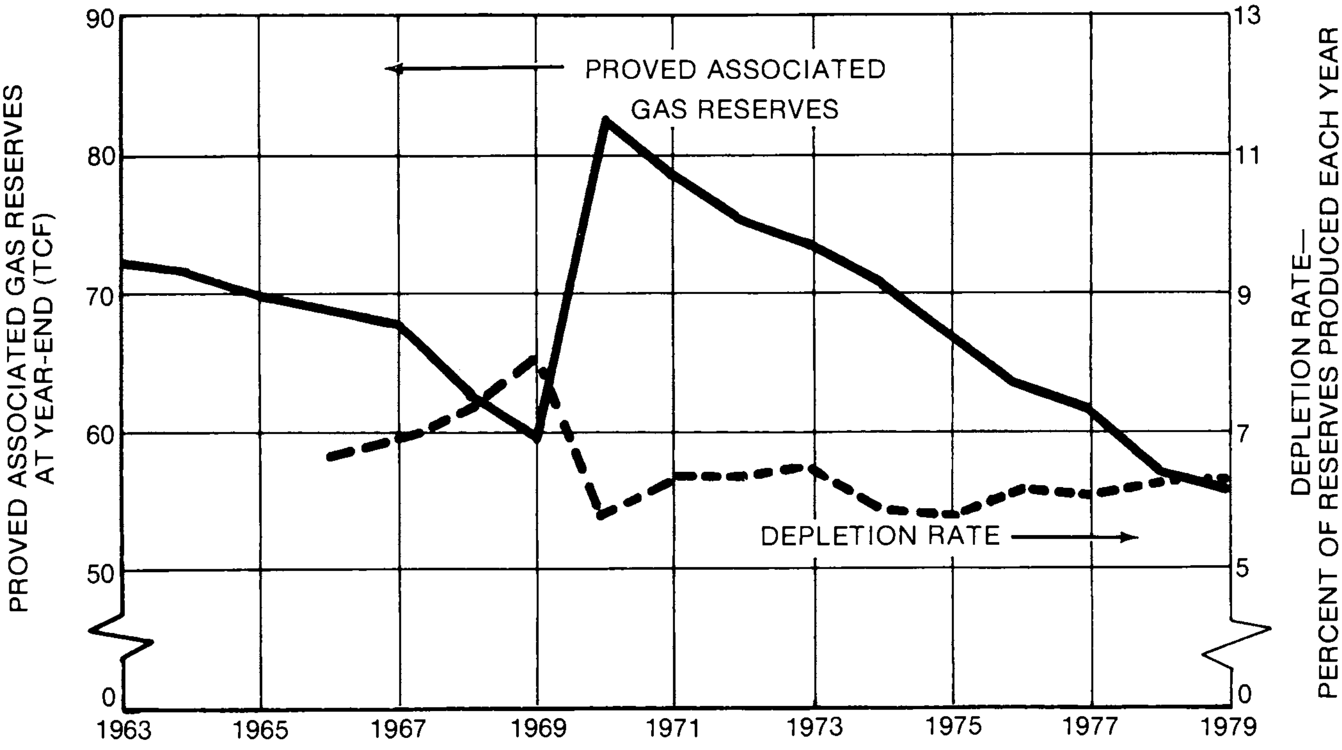


Figure 19. U.S. Associated Gas Reserves and Depletion Rate.

SOURCE: *Reserves of Crude Oil, Natural Gas Liquids, and Natural Gas in the United States and Canada as of December 31, 1979*, API, AGA and Canadian Petroleum Institute, Vol. 34, June 1980.

depletion rate of slightly more than 6 percent per year. Alaskan gas added over 20 TCF to these reserves in 1970 and currently accounts for 48 percent of associated reserves. Lower-48 reserves of 29.1 TCF are being produced on an R/P equal to 8.3, governed by conservation measures to maximize ultimate oil recovery. Although difficult to quantify, some additional gas cap gas could be produced in an extreme emergency. As a measure of additional capability, a 5 percent increase in lower-48 associated gas production would provide an additional 0.5 BCF/D (84 MB/D COE) of gas. This, however, is not considered a viable plan due to reduction in ultimate oil recovery and loss of pressure in oil reservoirs that might decrease oil production capability.

Additional Gas Sources

Gas surge capacity from sources outside the lower 48 states is not considered to be available in any of the denial scenarios. Such sources would include increased gas imports from Mexico and Canada, and increased LNG imports. During the first four months of 1980, U.S. gas imports totaled 467 BCF (3.8 BCF/D), including 75 BCF of Algerian LNG. In an emergency oil curtailment situation, Canada would likely face denials along with the United States, and therefore would attempt to employ their own gas subsitution plans and not increase exports. During the 1981-1983 period, significant increases in Canadian gas exported to the United States will probably not occur. Although gas reserves continue to be developed, Canada has embarked on a determined effort toward energy self-sufficiency. This program seeks to expand markets for their gas in eastern Canada. Depending upon the success of these expansion efforts and future reserve additions, it is conceivable that Canadian gas exports probably will not be significantly increased during the early 1980's, but may be available in greater volumes in the 1984-1985 time frame.

Although Mexican reserves are significant, there exists no capability to transport meaningful volumes of gas to the United States. Pipeline installation would require a significant time and investment commitment. Like Canada, Mexico's long-range plans include maximizing domestic use of their gas reserves. This will require substantial transportation system expansions within Mexico during the 1980's. While this program develops within Mexico, it would appear unlikely that significant volumes of Mexican gas would be made available for the United States through 1985. LNG imports cannot be counted on during an interruption in crude oil supplies as near-term LNG exporters are likely to be supportive of any planned oil export reductions by other Middle East nations. Alaskan gas, capable of providing an additional 2 BCF/D, will not be available before the winter heating season of 1985-1986, the estimated completion date of the Alaskan Natural Gas Transportation System.

Gas Transportation Capability

National gas flow patterns are illustrated in Figure 20. This chart was developed as part of the 1979 NPC study entitled Petroleum Storage and Transportation Capacities, which indicated that on

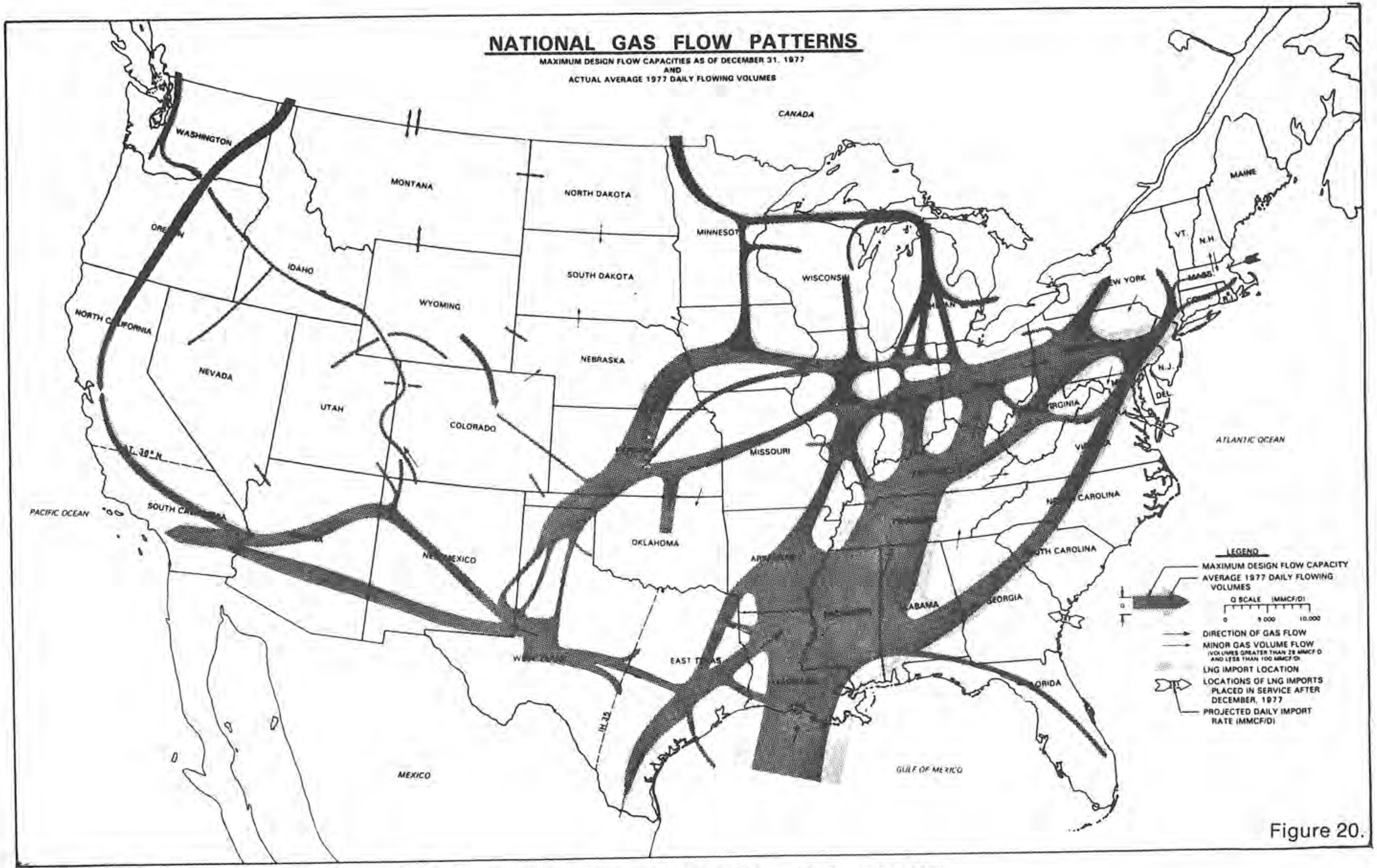


Figure 20.

SOURCE: *Petroleum Storage & Transportation Capacities*, National Petroleum Council, Volume VI, December 1979.

a daily average basis, 68 percent of the design capacity of the total network was utilized during 1977. Certain individual pipelines may from time to time be fully utilized. However, the data acquired by this study and pipeline flexibility demonstrated during the winter emergency of 1976-1977 support the summary statement that "...it is probable that new supplies could be connected to the transmission system network and moved across the country with existing facilities or minimal additions."[5] Absent the knowledge of specific oil customers with flexibility to convert to gas and specific geographic areas of increased production, it is impossible to state with certainty that transportation bottlenecks will not occur. This is especially true during intermittent periods of peak delivery in the winter, when portions of the nation's existing transmission and distribution system may be filled to capacity. Increasing dedication of gas to high priority, temperature sensitive markets may occasionally restrict wintertime capacity to move surge volumes. Attempting to identify specific potential bottlenecks is considered to be beyond the scope of this study.

Since fuel switching to gas depends on the ability of the pipelines to move it, any program to be implemented needs a careful analysis of the pipelines involved to determine their capability. However, based upon the data developed in the 1979 NPC study and upon the fact that annual U.S. gas production has declined about 3 TCF since the early 1970's, it can generally be assumed that available gas surge production will not exceed spare transportation capability.

The recently proposed concept of a "white market program" may provide some impetus toward expanding gas markets, encourage fuel switching capability, and also permit greater efficiency in the transportation of gas among consumers. The issues associated with gas entitlement sales by distributors and end users should be pursued by the Federal Energy Regulatory Commission (FERC) with oil replacement potential in mind.

Legislative and Regulatory Constraints

Some legislative and regulatory constraints exist which would limit the supply and utilization of emergency gas. The Fuel Use Act represents the greatest immediate obstacle towards increasing the use of natural gas in an emergency. Exemptions to the prohibition of increased gas use were granted during 1979 and 1980, and additional exemptions will be needed to realize the oil-to-gas substitution potential in Chapter Two. However, these exemptions do not provide for continuing use of natural gas as a replacement for oil. The removal of end-use restrictions would allow expansion of natural gas markets and be beneficial from the standpoint of future gas availability in an emergency.

---

[5] Petroleum Storage and Transportation Capacities, National Petroleum Council, December 1979, Volume VI: "Gas Pipelines," p. 4.

Various state and federal regulatory bodies may be able to provide a small measure of additional supply in an emergency by ensuring that all allowable restrictions that might be removed on a temporary basis are implemented. For example, allowables reduced as a result of previous overproduction could be suspended during an emergency, and administrative delays associated with initiating production from new gas wells (i.e., Natural Gas Policy Act filings and allowable paperwork) could be eased or eliminated in an emergency. Assuming that a one-month administrative delay could be eliminated during an emergency, an estimated 0.4 BCF/D (70 MB/D COE) could be made available from new wells based upon historical drilling statistics.

Chapter Six

EMERGENCY REFINING OPERATIONS

INTRODUCTION

Under emergency conditions involving substantial denial of imported crude oil and products, U.S. refiners will have to make major operational adjustments in product yields, the overall level of equipment utilization, the mix of crude oils processed at individual refineries, and the typical specifications for some products. The objective of this chapter is to determine if refiners have adequate flexibility to meet the anticipated emergency conditions, to identify likely operational problems, and, where such problems can be anticipated in advance, to recommend appropriate rapid government response contingency plans as a preparedness step.

SUMMARY

The combined net impact of the loss of imported oil supplies and product demand savings through conservation measures will require adjustments in refinery product yields. To the extent that demand reductions can be proportionally achieved for all products, the required adjustment in refinery yields is obviously minimized. On the other hand, U.S. refineries have substantial capability to adjust yields, and this capability can be utilized to selectively take the shortfall in products which have the least adverse impact on the nation. It is likely that the national interest would require that a major portion of a severe shortage be taken by reduced gasoline consumption in the automotive transportation sector. Therefore, a realistic estimate of the refining industry's ability to reduce gasoline yields while severely curtailing crude oil runs is required.

Refinery flexibility to reduce gasoline yields was analyzed by the NPC Committee on Refinery Flexibility with the aid of a linear programmed (LP) computer model validated with available refinery survey data to reasonably simulate the U.S. refinery industry.[1] Studies using this model indicate that in the event of an import supply interruption in the range of 2 to 5 MMB/D, there is sufficient flexibility in the U.S. refining system to reflect up to 75 to 80 percent of the volume loss in reduced motor gasoline output. This level of flexibility would be adequate to meet the desired emergency product slate for all scenarios defined for this report. Such flexibility represents a maximum level and assumes no restraints on commercial trading of crude oils, unfinished oils, or products among refiners to optimize operations. Also, in practice,

---

[1] Refinery Flexibility, National Petroleum Council, December 1980.

some lead time would be required to accommodate the necessary changes in operations and redistribution of crude oils and feedstocks. No changes in product specifications were assumed; however, to help ensure that such flexibility can be achieved in practice or possibly increased in some locations, the development of emergency standby specifications for distillate fuels and heavy fuel oil is warranted as a preparedness step.

The cutoff of imported products could also require adjustment in product yields. All of the emergency scenarios assume that over 60 percent of the reduction in product imports will be in heavy fuel oil imported into the East Coast. The loss of other imported products will have only a minor impact on refinery yield adjustments. The January 1979 NPC Survey of Petroleum Refining Capabilities shows that adequate refinery flexibility exists to make up the shortfall in heavy fuel oil at the expense of other products if an appropriate relaxation of sulfur specification is granted. However, as developed in Chapter Two of this report, the potential demand savings for heavy fuel oil are substantial. In some situations, the demand savings for heavy fuel oil may exceed the product denial, indicating that yields of heavy fuel oil must be slightly reduced under emergency conditions rather than increased. A reduction in heavy fuel oil yields could be achieved by continuing to operate coking capacity at relatively high levels as overall crude oil runs are reduced. Also, if an emergency relaxation of sulfur specifications were granted, refiners would have more flexibility to divert distillate stocks from fuel oil blending and increase production of other products.

Equipment Utilization

A major crude oil curtailment may reduce average utilization of some refinery processes, such as crude oil distillation, to near or below minimum operable levels. Commercial activities to achieve efficiencies through processing agreements, crude oil or product exchanges, and similar arrangements would be essential to enhance overall refining flexibility and should be encouraged by government action.

Crude Oil Substitution Flexibility

A comparison of the estimated quality of the denied imported crude oil mix shows it to be slightly higher in sulfur and slightly lighter than the pre-denial imported crude oil mix. This would be favorable in helping to rebalance crude oil runs and meet sulfur content specifications of products. It appears that PAD I-IV refineries could be rebalanced from a crude oil quality perspective through a redistribution of the remaining imported crude oil and the Alaskan North Slope crude oil diverted from PAD V.

Product Specifications

It is doubtful that all sulfur specifications could be met under emergency conditions for operational reasons. Hydrogen for desulfurization processes is normally produced as a byproduct of reforming naphtha to produce high octane components for gasoline. As reformer feed rates are reduced both by the crude oil denial and the selective reduction of gasoline yields, hydrogen supply in many refineries is likely to be inadequate to meet the needs for desulfurization. This is a potential problem which is highly dependent upon the specific individual refinery processing configuration. The standby availability of a government-approved plan for sulfur specification relaxations on fuel oils which could be quickly implemented would greatly facilitate emergency preparedness.

The need for standby emergency specifications for diesel fuel, jet fuel, and heating oil has been reviewed with the appropriate committees of the American Society for Testing and Materials. ASTM is the proper organization to establish emergency specifications and has authorized steps to develop such specifications and rapid response balloting procedures quickly.

Conclusions and Recommendations

- U.S. refiners appear to have adequate processing flexibility to meet the desired emergency product slate for all scenarios defined for this report, but a lead time of several months would be required to accommodate the necessary changes in operations to fully utilize the maximum flexibility.

- Future trends toward more high sulfur crude oil processing capacity, increased use of diesel as a transportation fuel, and installation of heavy oil processing capacity by more refiners due to displacement of heavy fuel oil by coal should directionally improve the emergency flexibility of U.S. refiners.

- During a severe crude oil disruption, extensive temporary shutdown of processing facilities may be necessary and desirable to efficiently operate onstream equipment above minimum operable rates and to reduce refinery energy consumption.

- Emergency management plans which restrict the ability to make commercial arrangements between refining companies such as crude oil and unfinished oil processing agreements, crude oil and product exchanges, and sales or purchases would inhibit the ability of refiners to meet the desired emergency product slate.

- Efforts by ASTM to develop standby emergency specifications for diesel fuel, burner fuels, and jet fuel should be supported and encouraged. Standby adoption by common carriers and states of all emergency specifications would ensure a smooth transition to emergency quality levels during a crisis.

- Under emergency conditions, many refineries could possibly have difficulty in meeting sulfur content specifications on products while preferentially minimizing gasoline production. Therefore, consideration should be given by government to regulatory procedures for emergency relaxation of environmental sulfur content specifications on heavy fuel and distillate products to ensure that waivers can be granted within a reasonable response time. Also, statutory or other remedies should be considered to remove the existing 120-day limit on sulfur content waivers under the Clean Air Act.

- Regulatory restrictions on the use of the octane additives TEL and MMT should be relaxed under emergency conditions to gain energy savings.

DISCUSSION AND ANALYSIS

Refinery Product Yields

Product balances were developed for refineries in PADs I-IV and PAD V for 1981 to estimate desired emergency production for Scenario 3, which is essentially the same as Scenario 4 over the full 12-month disruption period. It would seem that in later years, emergency scenarios will gradually become easier to meet from the point of view of refinery flexibility, as capacity to handle high sulfur crude oil increases and as diesel displaces gasoline in the transportation sector (i.e., sweet crude oil can readily be run in sour crude oil refining capacity, and curtailment of transportation fuel use would reduce distillate as well as gasoline demand). Also based on recent public announcements, coking capacity is projected to increase rapidly, providing more refiners with the flexibility to upgrade heavy fuel oil released through demand savings steps. Therefore, an early year such as 1981 should be a more severe test of emergency refinery flexibility than 1985 or 1990. Also in the later years, the United States should have more crude oil in security storage to reduce the impact of a crude oil denial.

To calculate the 1981 refinery yield balances, pre-denial total product demands were reduced by domestic natural gas liquids production and product imports to give required pre-denial products production from U.S. refiners. These production levels for each product group were then adjusted to the desired emergency production level by adding the volume of imported product denied and subtracting the projected product demand savings, assuming that such savings are achieved on a geographic basis in direct proportion to pre-denial product demand. To balance with available crude oil supply, all additional demand reductions were taken entirely in gasoline. This procedure thus calculates the maximum degree the shortfall would be taken in gasoline. These balances for PADs I-IV and PAD V are shown in Tables 40 and 41, and are summarized in Table 42.

TABLE 40

PADs I-IV Demand and Refinery Output Balances
Scenario 3 -- 1981
(MB/D)

Product	Demand	Domestic NGL	Imports	Pre-Denial Refinery Output	Imported Product Denial	Estimated Emergency Demand Savings	Required to Balance Supply	Net Denial Refinery Output
Mogas	5,604	(600)	(110)	4,894	70	(875)	(860)	3,229
Jet	748	--	(40)	708	30	(60)	--	678
Distillate	2,962	--	(150)	2,812	85	(330)	--	2,567
HFO	1,870	--	(700)	1,170	405	(580)	--	995
Other	3,567	(970)	(460)	2,137	0	--	--	2,137
Total	14,751	(1,570)	(1,460)	11,721	590	(1,845)	(860)	9,606

$$\text{Percentage Reduction Taken in Gasoline} = \frac{4{,}894 - 3{,}229}{11{,}721 - 9{,}606} \times 100\% = 78\%$$

TABLE 41

PAD V Demand and Refinery Output Balances
Scenario 3 -- 1981
(MB/D)

Product	Demand	Domestic NGL	Imports	Pre-Denial Refinery Output	Imported Product Denial	Estimated Emergency Demand Savings	Required to Balance Supply	Net Denial Refinery Output
Mogas	1,004	--	(10)	994	10	(155)	(155)	694
Jet	300	--	(60)	240	--	(25)	--	215
Distillate	343	--	(20)	323	--	(40)	--	283
HFO	375	--	(20)	355	--	(120)	--	235
Other	331	--	(10)	321	--	--	--	321
Total	2,353	--	(120)	2,233	10	(340)	(155)	1,748

$$\text{Percentage Reduction Taken in Gasoline} = \frac{994 - 694}{2,233 - 1,748} \times 100\% = 62\%$$

TABLE 42

Summary of U.S. Refinery Operations in Pre-Denial and Emergency Mode
Scenario 3 -- 1981

	PADs I-IV		PAD V	
Refinery Output				
Pre-Denial (MB/D)	11,721		2,233	
Emergency (MB/D)	9,606		1,748	
% Reduction	18.0		21.7	
	Pre-Denial	Emergency	Pre-Denial	Emergency
Refinery Yields (% of Output)				
Mogas	41.8	33.6	44.5	39.7
Jet	6.0	7.1	10.7	12.3
Distillates	24.0	26.7	14.5	16.2
HFO	10.0	10.4	15.9	13.4
Other	18.2	22.2	14.4	18.4
% of Shortfall Taken in Mogas	78		62	
Approximate Emergency Crude Oil Run % of Rated Capacity	63		56	

The overall yield patterns should be within the physical capability of the refining industry. Based on computer model studies, the capability exists to take about 75 to 80 percent of the shortfall in gasoline; the required operations are within this range (78 percent in PADs I-IV and 62 percent in PAD V). Therefore, adequate emergency flexibility should exist, but refineries in PADs I-IV would be operating at maximum gasoline deconversion capability. Adequate lead time will be required to accommodate the necessary changes in refinery operations and redistribution of crude oil supplies and other feedstocks. Depending upon the situation, a transition period of several months would be required for assessment, modification of operating plans, and negotiation of commercial arrangements.

The petrochemical industry also has some flexibility to vary feedstock mix which will be valuable in an emergency. For example, olefin plants designed to crack 100 percent ethane can handle about 20 percent propane; plants feeding 100 percent propane can handle about 20 percent ethane. A plant designed to crack light naphtha can easily accommodate up to 50 percent butane and 10 to 15 percent propane. And, perhaps most importantly, about 30 percent light naphtha could be substituted for heavier gas oil feeds. This flexibility will be needed to maintain reasonable levels of petrochemical feedstock supply as overall refinery runs are curtailed.

The availability of wider range emergency specifications for distillate products would provide an added degree of assurance that the theoretical product yield flexibility calculated from the computer studies can actually be achieved. Also, if additional crude oil supplies are made available from emergency domestic production or security storage, they could be used to help restore gasoline production and thus increase gasoline yields to more manageable levels.

Equipment Utilization

Under Scenario 3 emergency conditions, petroleum refineries will be operating at very low levels of capacity utilization -- about 63 percent of crude oil distillation capacity in PADs I-IV and 56 percent in PAD V. The utilization is lower in PAD V largely because a major portion of the shortfall is taken in gasoline and the normal West Coast product demand mix is 43 percent gasoline vs. 38 percent for PADs I-IV.

At these low levels of capacity utilization, some refinery facilities may be below minimum operable levels. The minimum operable rate for refinery units can vary widely depending upon the process and design. Some units may run into operability problems at 80 percent of capacity (i.e., turndown of 20 percent); other units are operable at 50 percent of capacity and perhaps even lower. Furthermore, energy efficiency at the lower levels can be expected to deteriorate rapidly in most units due to internal recycling to maintain operability and other inefficiencies. Therefore, to reduce energy consumption, refiners will find it desirable to temporarily shut down many processing units, especially in refineries with multiple-train processing units.

Product and crude oil exchange arrangements, toll processing of crude oil, and other commercial arrangements could become more important in efficiently meeting emergency demands and in helping to maintain the economic viability of all segments of the refining industry. For example, two single-train refiners, each with a volume of crude oil equivalent to about 50 percent of rated capacity, might find a crude oil toll processing arrangement to be of mutual benefit. Any regulatory action which restricted such arrangements could adversely affect the ability of refiners to cope with the emergency. The design of standby allocation controls will have to take into account these various commercial arrangements, which may be far more extensive than in former, less severe oil supply emergencies.

To better understand the operational problems that might be typically encountered at low levels of capacity utilization, a special analysis was made for a small, single-train, high conversion refinery. The following conclusions were derived:

- The crude oil distillation unit could be turned down to as low as 55 percent of rated capacity assuming a constant crude oil mix, but about 60 percent of rated capacity was judged to be a more realistic minimum level. A minimum quantity of light crude oil was required to maintain acceptable distillation efficiency. Substitution of more heavy crude oil would require recycling of naphtha and distillate streams or periodic shutdowns to achieve higher onstream rates.

- Selectively reducing gasoline production required periodic shutdown of the reformer. Reductions in gasoline production could account for as much as 72 percent of total production cuts by extending reformer shutdowns.

- The hydrogen required for desulfurization and hydrocracking was available from a hydrogen plant. Relaxation of sulfur specifications would have been required if the refinery had no hydrogen plant. With the hydrogen plant, however, sulfur specifications are not critical, but their relaxation would still reduce refinery fuel consumption and increase product output. An additional allocation of natural gas would also be required to operate the hydrogen plant. A hydrogen source other than naphtha reforming clearly increases overall refinery flexibility. It should be pointed out, however, that most refineries in the United States do not have a hydrogen plant; therefore, most could be less flexible in meeting sulfur specifications, and waivers would likely be required or the ability to preferentially reduce gasoline yields would be limited.

- No other refinery units would require periodic shutdowns until crude oil rates dropped to 50 percent of rated capacity.

- With reduced crude oil runs, spare coking capacity was available. This capacity could be utilized to make higher priority products from heavy fuel oil by purchasing crude oil residuum from local refineries which lack coking capacity.

- Additional diesel fuel could be produced by relaxing the specifications for maximum distillation temperature at 90 volume percent and minimum cetane number. Additional jet fuel could be produced by relaxing the aromatic limit and flash specification.

- In order to minimize gasoline yield, relaxation of the current lead level restriction (0.5 grams of lead per gallon) would be desirable to permit extended shutdown of the reformer.

- Turndown of all refinery units would significantly reduce operating efficiency and result in increased energy consumption. Increased fuel consumption due to high turndown in a single-train refinery was estimated to increase by an amount equivalent to 2.4 percent of crude oil runs. Of course, multiple-train refineries could operate more efficiently at low throughputs by shutdown of processing units.

- In the refinery's particular geographic area, exchange of crude oils, intermediate feedstocks, and products would be essential to optimize utilization of available resources.

Although no two refineries are alike and each will have unique problems in coping with a major crude oil curtailment, this example illustrates the need for a regulatory environment which allows maximum operational and commercial flexibility. The importance of commercial arrangements in meeting emergency needs has also been demonstrated by experiences such as the 1973-1974 Arab oil embargo and the extremely cold winter of 1976-1977. Rapid negotiation of crude oil trades and spot product exchanges and purchases were critical in successfully avoiding customer runouts. During recent years, the number of companies engaged in petroleum trading has increased. Many small refiners, trading companies, and brokers have expertise in trading and logistics, thereby increasing the ability to quickly react to emergencies.

Crude Oil Substitution Flexibility

During the denial period, considerable adjustments would be required to rebalance refinery runs with suitable quality crude oil. East Coast refineries which are running 100 percent imported crude oil will have to make the largest adjustment. A logical and efficient step would be to divert Alaskan North Slope crude oil or other available imported crude oils to East Coast refineries. Available information suggests that this substitution should be practical with no major incompatibility with regard to crude oil quality. Data from the 1979 NPC petroleum refining capabilities survey show that in 1980 refineries in PAD I were designed to process the crude oil mix described in Table 43. The major constraints restricting the processing of higher sulfur crude oil in PAD I are environmental, as itemized in Table 44.

Thus, if necessary in an emergency, environmental restraints could be relaxed to substantially expand capability to refine high sulfur crude oil. It should be noted that the impact on the environment would be offset to an undetermined extent by the lower level of crude oil runs and the overall reduction in consumer burning of fuels due to the shortage.

A further consideration is the mix of the crude oil shortfall, as shown in Table 45. The denied crude oil is higher on the average in sulfur and slightly lighter than the estimated pre-denial imported crude oil slate. The largest volume of crude oil lost is in the high sulfur light category -- a quality level such as Arabian Light crude oil, for example. Alaskan North Slope crude

TABLE 43

Crude Oil Mix of PAD I Refineries

Crude Oil Type	Crude Oil Capacity (MB/D)	Percentage of Total Capacity
Sweet	910	47
Light Medium Sulfur	21	1
Heavy Medium Sulfur	51	3
Light High Sulfur	491	25
Heavy High Sulfur	379	20
Other Feedstocks	90	4
		100

TABLE 44

Restraints to Processing High Sulfur Crude Oil in PAD I

Restraint	Refineries Restrained	
	Number	Capacity (MB/D)
Sulfur Content of Products	13	1,251
Sulfur Content of Refinery	9	809
Air Emissions	8	882
Effluent Water Quality	1	42
Metallurgy	4	363

oil can usually be substituted for crude oil similar to Arabian Light without much difficulty. A comparison of the qualities of these crude oils is shown in Table 46.

Substitution of Alaskan North Slope crude oil would tend to help on sulfur restrictions and minimizing gasoline yield. Some 600 MB/D of additional Alaskan North Slope crude oil would be available to PADs I-IV to balance a 3,200 MB/D national shortfall. Redistribution of about half of this crude oil to East Coast refineries and the remainder to PAD II and PAD III refineries would achieve a geographic balance and appears to be feasible from an

TABLE 45

Emergency Crude Oil Mix

Crude Oil Type	Assumed Quality of Crude Oil Denied (%)	Estimated Quality of Pre-Denial Imported (%)
Low Sulfur	37	43
Medium Sulfur		
Light	7	7
Heavy	--	4
High Sulfur		
Light	45	32
Heavy	11	14
Total	100	100

TABLE 46

A Comparison of Arabian Light and Alaskan North Slope Crude Oils

	°API Gravity	Wt % Sulfur	% Naphtha C_5 to 350°F	% Bottoms Yield 1,050°F+
Arabian Light	32.36	1.5-1.8	28	11-14
Alaskan North Slope	27.6	1.02	18	17

operational perspective. Of course, a more complex redistribution of remaining imported crude oil, as well as Alaskan North Slope crude oil, could result in greater efficiencies and have other advantages. Overall, however, reasonable alternatives for rebalancing of crude oil supply to PAD I-IV refineries are available. A potential problem could be reducing heavy fuel oil yields if large potential demand savings for heavy fuel oil are realized. This could be handled through shipments of heavy fuel oil between refineries for further processing in spare coking capacity and by relaxing the sulfur specifications to allow withdrawal of distillate stocks from the heavy fuel oil blends.

Product Specifications

Distillate Fuel Specifications

Diesel engines vary widely in size and end-use application. Diesel fuels also vary in specific fuel characteristics. The American Society for Testing and Materials Committee D-2 for Petroleum Products and Lubricants has established specification ASTM

D975 to classify three grades of diesel fuels -- No. 1-D, No. 2-D, and No. 4-D. Specification ASTM D396 also classifies various grades of light and heavy fuel oils. These specifications are used as a guide by consumers to specify and purchase fuels with certain minimum qualities in order to ensure acceptable operation in their particular operating environment.

As illustrated in Table 47, if one compares the current average industry distillate quality based on Department of Energy surveys with the ASTM No. 2 Diesel and No. 2 heating oil specifications, it appears that many distillate suppliers are producing fuels at a higher quality than is required by the minimum ASTM specifications.

TABLE 47

Quality of Distillate Fuels

Test	ASTM Specifications	Actual Quality from DOE Surveys Minimum	Average	Maximum
		No. 2 Heating Oil		
Gravity (°API)		22.9	35.0	45.7
Flash Point (°F)	100 Min.	130	--	210
Pour (°F)	20 Max.	-40	--	10
90% Point (°F)	640 Max.	539	590	638
		No. 2 Diesel		
Gravity (°API)		29.8	36.0	46.8
Flash Point (°F)	125 Min.	125	--	212
90% Point (°F)	640 Max.	448	580	637
Cetane	40 Min.	40	49	66

Increased distillate volume would be available if actual quality levels more closely matched the appropriate "allowable" levels in the ASTM D975 and D396 specifications. In a state of severe product shortages for a limited period of one year or less, some relaxation of the distillate specifications is probably acceptable in the areas of flash, boiling range, viscosity, sulfur content, and cetane number. However, it should be noted that research results are limited as to the long-term engine effects of the lower quality.

Jet Fuel Specifications

A December 1977 study by Exxon that was presented to the ASTM showed that a significant increase in the volume of kerosine-type jet fuel is theoretically possible by lowering the flash point below 38°C (100°F), the present specification limit. The gain for Jet A fuel is 10 to 18 percent for 32°C (90°F) flash point and 22 to 30 percent for 27°C (80°F) flash point. Other fuel properties such as freezing point, aromatics, smoke point, sulfur content, and viscosity become less critical as the flash point is lowered and light hydrocarbons are included in the jet fuel. The desirability of reducing the flash point of Jet A below 100°F continues to receive attention in ASTM.

More flexible specifications are represented by Jet B (commercial equivalent to Military JP-4) which is a wide cut blend of naphthas and kerosine. Fuel of this type is in wide use by the military and has been used by commercial airlines when justified by economics or availability. Safety considerations related to low flash point, flammability, characteristic static electricity, crash hazard, etc., are well documented, with technology available for meeting safety requirements.

Establishment of Emergency Specifications

ASTM is the nation's primary management system for the development of voluntary specifications for petroleum products, as well as other materials, and is the appropriate organization to establish emergency specifications to help cope with a major petroleum shortage. The ASTM develops specifications through a full-participation procedure in which all parties, including producers and users, are fairly represented on the committee writing the specifications. Such specifications, written by representatives from all affected segments of society, are more likely to be used.

Representatives of the ASTM Technical Committee D-2 on Petroleum Products and Lubricants and its subcommittees on Burner, Diesel, and Gas Turbine Fuel Oils (Technical Division E) and Aviation Fuels (Technical Division J) have been briefed on the activities of the NPC Committee on Emergency Preparedness. The NPC has affirmed support for ASTM actions to draft emergency specifications on distillate fuel oils and jet fuel and to develop a rapid response mechanism for approval through balloting if the need arises. ASTM Technical Divisions E and J have responded favorably with documentation of plans to draft emergency specifications. Also, a rapid response arrangement has been approved which will allow balloting of emergency distillate fuel specifications within three to five weeks of a request instead of the 18 months required for the normal procedure.

It is noteworthy that emergency specifications for gasoline have already been approved by the Subcommittee on Gasoline (Technical Division A). These specifications raise the 90 percent maximum boiling point for leaded fuels from 374°F to 383°F, raise the maximum final boiling point from 437°F to 446°F, and generally raise the maximum Reid vapor pressure by 0.5 psi. Raising the gasoline end point would increase gasoline availability at the expense of jet fuel, which might be generally undesirable. In specific cases, however, such a move might provide important refiner flexibility. The important aspect of the emergency specifications for gasoline is the higher vapor pressure. One half pound in vapor pressure increases gasoline yield by 1 percent if normal butane is used for pressuring. If all refiners met the emergency vapor pressure specifications, gasoline availability could be increased by 120 MB/D, assuming gasoline production of 4 MMB/D. This would be especially significant if butane supplies become surplus as demand for gasoline blending decreases sharply while production from natural gas processing plants may slightly increase due to emergency gas production. All pipelines and many states have gasoline specifications including a vapor pressure specification. If an emergency gasoline specification is to have significance, pipelines and states should also adopt the emergency specification on a standby basis.

Environmental Sulfur Content Specifications

Air pollution legislation has been in effect for many years now and has evolved into specific sulfur limits on heavy fuel oil for small geographic areas. Appendix K, Exhibit 1, summarizes the current maximum allowable sulfur content. These limits are a part of the State Implementation Plans (SIP) that were required under the Clean Air Act. Under Section 110 of this act, in order to obtain emergency waivers it is possible for fuel users to petition the governor of a state to petition the President of the United States to declare a product supply emergency. If the President, in consultation with the Environmental Protection Agency (EPA) and DOE, agrees and acts, the governor of the state can waive the SIP and raise the maximum sulfur level within a given area for a specified period of no more than 120 days. This procedure has only been fully utilized once and has some potential for delay. Also, the emergency must be in existence before waivers can be granted and there is some question as to how to extend waivers if the emergency conditions persist longer than 120 days.

Based on work on emergency refining operations, it is anticipated that many refiners may have difficulty in producing adequate hydrogen for their desulfurization processes while severely curtailing gasoline production and would require sulfur content waivers for heavy fuel oil and perhaps distillate fuels. Where such problems can be anticipated in advance, it seems prudent to consider an appropriate rapid response contingency plan as a preparedness step.

The NPC has requested the assistance of the DOE in assessing the regulatory aspects of this problem, and a description of the sequential procedure for consideration of requests for emergency suspensions of State Implementation Plans under Section 110 of the Clean Air Act was developed (Appendix K, Exhibit 2). Based on consultation with the EPA, it appears that a response time of about three weeks would be required from the governor's notice and opportunity for public hearings to a Presidential declaration of a regional or national emergency of such severity that a temporary suspension of any part of a State Implementation Plan may be implemented. This response time for implementation may be lengthened by the time required for the affected owner or operator of a stationary source to make application requesting that his governor petition the President. Also, there are two factual findings which must be made by a governor before granting an application for a waiver:

- Whether an energy emergency in the vicinity of the source involves high levels of unemployment or loss of necessary energy supplies for residential dwellings
- Whether the proposed suspension would help mitigate the existing unemployment or loss.

These findings are restricted to the particular source which begins the waiver process with the submission of an application. It is the understanding of the NPC, however, that a governor's findings with respect to a particular source do not assist other sources regulated by the same SIP unless they too have joined in the application process. Should sources which have not made application for such a waiver seek to obtain similar relief after the President's decision, the governor must hold another hearing and make the two factual findings with respect to the new facility involved.

It would thus appear advantageous that as many source-specific waivers as possible be processed simultaneously utilizing joint public hearing procedures in order to minimize the various governors' time requirements with respect to multiple findings of fact.

The complexity of these procedures suggests that further consideration by government may be warranted to develop ways to reduce the overall response time in severe emergencies and to extend the waiver period should the emergency extend beyond 120 days.

Regulatory Sensitivities Affecting Hydrocarbon Utilization

In the NPC study of refinery flexibility, the benefit of easing restrictions on lead and MMT additives in motor gasoline were estimated for normal operations.[2] These estimates are indicative of the savings that might be realized under emergency conditions. The impact of the lead phasedown regulation was limited to 1982 because the decreasing fraction of leaded gasoline in the motor gasoline pool will gradually make this restriction less constraining. The study estimated the hydrocarbon savings that could be realized by eliminating the 0.5 grams/gallon (gm/gal) pool lead level restriction. The elimination of this regulation could result in a hydrocarbon saving of 35 MB/D, based on optimum lead usage of 0.8

---

[2] Refinery Flexibility, National Petroleum Council, December 1980.

gm/gal. If the addition of 3.0 gm/gal in the leaded grades were economical, the total gasoline pool would be at 1.09 gm/gal lead and process requirements would decrease by 0.7 clear octane (R+M/2). The hydrocarbon savings would then be about 70 percent greater than the calculated optimum case. The effects of allowing the use of MMT in unleaded gasoline were considered at a level of 1/16 gm/gal in unleaded gasoline, although this does not necessarily represent an economic optimum. The maximum savings range up to 80 MB/D of hydrocarbons.

Another sensitivity involves the potential energy savings that could be realized by a relaxation of environmental regulations on the sulfur content of fuel oils. The energy savings were estimated for several refineries processing crude oil of varying sulfur content. The analysis involves a number of considerations. First, some sulfur must be removed for metallurgical reasons to prevent equipment corrosion and to protect certain catalyst systems. Some sulfur is inherently removed in processes such as catalytic cracking and hydrocracking. On the other hand, energy is consumed in the process for final product desulfurization to meet environmental requirements. Although less significant, leaving more sulfur in the product also increases the volume of product output, but the relatively low heating value of sulfur reduces this impact on an equivalent energy basis. While the impact will vary considerably among refineries depending upon the sulfur content of the crude oil mix, it is estimated that a waiver of environmental sulfur specifications would allow U.S. refiners to increase their energy output by about 0.3 to 0.4 percent. Depending upon the level of emergency crude oil run, this is equivalent to an additional 30 to 60 MB/D of hydrocarbons.

Capability to Substitute High Sulfur Crude Oil for Low Sulfur Crude Oil

It is possible that some additional sources of heavy, high sulfur crude oil might be found, and refinery surveys indicate that substantial flexibility exists under emergency conditions to process such crude oil. The January 1979 NPC petroleum refining capabilities survey obtained data by PAD district and refinery size on the capability to substitute crude oil over 0.5 wt % sulfur for crude oil of 0.5 wt % sulfur or less in 1980 and 1982 under presently known environmental restraints and with emergency suspension of environmental restraints on product quality. The summary of results for the total United States for 1982 is shown in Table 48.

Emergency Capability to Make Heavy Fuel Oil

It appears that demand savings for heavy fuel oil will be adequate to offset the loss of imported product. If increases are required, however, refiners have substantial emergency capability provided appropriate increases in sulfur levels are allowed.

The January 1979 NPC petroleum refining capabilities survey obtained data by PAD district and refinery size on the capability

TABLE 48

Ability of U.S. Refiners to Substitute High Sulfur for Low Sulfur Crude Oil

Type of Substitute Crude	Present Environmental Restraints		Suspended Environmental Restraints	
	Substitute Crude (MB/D)	Sweet Crude Backed Out (MB/D)	Substitute Crude (MB/D)	Sweet Crude Backed Out (MB/D)
Light Medium Sulfur	957	991	3,079	3,100
Heavy Medium Sulfur	540	619	2,119	2,405
Light High Sulfur	577	664	2,246	2,331
Heavy High Sulfur	339	504	1,653	1,914

to maximize heavy fuel oil production, assuming that reductions in distillate and jet fuel volume not exceed 10 percent. The summary of results for the total United States for 1982 is shown in Table 49.

TABLE 49

Emergency Capability of U.S. Refiners to Produce Low Sulfur Heavy Fuel Oil

Sulfur Content of the Low Sulfur Grades (%)	Low Sulfur Fuel Oil Production (MB/D)	Balance of High Sulfur Grades (MB/D)	Reduction in Mogas Volume (MB/D)
0.3	842	496	339
0.5	1,339	394	394
0.7	1,610	340	444
1.0	2,048	336	536
2.0	2,658	103	599

Description of Refinery Model Used to Calculate Refinery Yield Flexibility

Methodology

The approach taken in this study on emergency refining operations was to utilize the U.S. refinery industry model developed by the NPC Committee on Refinery Flexibility. This model uses the

Bonner & Moore Refinery and Petrochemical Modeling System to build a composite LP model of the refining industry. Two separate models were developed, one for PADs I-IV and one for PAD V. This separation recognizes the processing differences between the two regions and the fact that there is limited interregional movement of product. In order to reduce over-optimization, each geographic model utilized a three-refinery configuration; however, results were reported on an aggregated basis. Only limited interrefinery transfer of feedstocks was allowed. This is more realistic than a single-refinery representation which implies unlimited access to all downstream capacity. For example, a simple refinery without catalytic cracking usually routes the catalytic cracking feedstock portion of the crude oil to residual fuel, unless it can sell it to another refiner.

All refineries and their corresponding capacities were divided into three classes of complexity. The first type is essentially a hydroskimming operation with topping units and may include naphtha reforming capability and distillate desulfurization; the second type adds catalytic cracking and alkylation; the third adds hydrocracking and bottoms processing (primarily coking). For reasons of confidentiality, the process capacity information in the January 1979 NPC petroleum refining capabilities survey was reported only in aggregates according to PAD district location, refinery size, and complexity index. This breakdown was insufficient by itself to provide the processing capacity detail by the refinery classes within the models. Also, the NPC survey did not receive a 100 percent response. Industry data from the *Oil & Gas Journal*'s March 26, 1979, Annual Refining Survey augmented the NPC data in development of the capacities for the model. The final breakdown of the U.S. crude oil capacity according to the model classification was 9 percent in the first type, 29 percent in the second, and 62 percent in the third.

The availability of process capacity and unit performance are affected by necessary downtime for unit maintenance, both scheduled and unscheduled; shipment irregularities; equipment or catalyst deterioration; and other uncontrollable factors. To represent the loss of capacity from scheduled downtime, a 5 percent discount was applied to the crude oil distillation stream-day capacity rating, and a 10 percent discount to other processes. A second discount of 7 percent, applied uniformly, represents the other types of losses and the fact that the model reflects modern technology, whereas the actual industry processing capacity is of varying vintage and efficiency. The net result is termed "effective capacity," which is the basis used in the models.

In attempting to validate the model using 1978 actual production data from the January 1979 NPC petroleum refining capabilities survey, various approaches were tried, including a single-refinery model, three-refinery model, demand-driven model, price-driven model, etc. A three-refinery model, essentially demand driven, was found to be most appropriate.

The model runs for determining future process capacity requirements were demand driven, except for LPG, coke, sulfur, and residual fuel, which were allowed to vary within limits. To the extent that optimization with price was involved, actual 1978 prices were used, derived from public sources, particularly from DOE Energy Information Administration publications and Platt's 1978 Oil Price Handbook and Oilmanac, 55th edition. In the supply disruption cases, assumed national priorities were reflected by changing relative product demand and prices. For cases wherein the model indicated that additional processing capacity was needed, optimizing runs with capital charges for new or debottlenecked capacity were made. This procedure selects the most economic way of meeting the refining requirements. Construction costs were based on 1978 Gulf Coast data adjusted for regional differences, ranging up to 15 percent. Debottlenecking costs were assumed to be applicable to expansion of up to 20 percent of original capacity, new unit costs to expansion of 60 percent or greater, and interpolated costs to the intermediate range. The new units were sized to suit the typical refinery in each complexity category. Debottlenecking costs were assumed to be 70 percent of new unit costs.

The crude oil supply distribution by geographic region was derived from the Oil & Gas Journal and DOE data. Alaskan North Slope crude oil surplus to the West Coast's needs was considered available to PADs I-IV. Crude oil properties were obtained from industry assay data and the crude oils were then classified according to the five quality category definitions listed on Page 42 of Volume I of the NPC's 1979 Refinery Flexibility, An Interim Report. In the studies of future situations crude oil supply variations were postulated in terms of varying proportions of the NPC-defined categories as composites.

The categories of crude oil were allocated to the three refinery classes according to 1978 data from the January 1979 NPC Survey of Petroleum Refining Capabilities, augmented by 1978 refinery data from the Oil & Gas Journal. The foreign crude oil allocation was derived from data in the Petroleum Import Data Book 1978, John G. Yeager and Associates, Inc. For future years, the distribution of crude oil categories across refinery classes was assumed to remain in proportion to the 1978 distribution.

As in previous attempts by others to model the refining industry, this model effort encountered difficulties and uncertainties. Oversimplification to keep the model to a manageable size is inherent in a simulation of an entire industry. Data inadequacies also impose practical limits. For example, utilization rates of downstream capacity indicated by the model validation runs could not be confirmed by actual 1978 experience because such data were not part of the January 1979 NPC petroleum refining capabilities survey. In this and other instances, qualitative judgments as to the reasonableness of results had to be applied. Considering the difficulties in matching the model to observed 1978 operations, predictions of future situations cannot be precise. However, the model should provide a reasonable estimate of the maximum flexibility to adjust product yields under various crude oil curtailment scenarios. Directionally, estimates through 1982 should be more accurate because they are based on processing capacities determined from survey data. Beyond 1982, the model assumed that additional processing capacity was built to meet projected demand.

Impact of Crude Oil Supply Disruption on Refinery Product Yield Flexibility

The impact upon major products (i.e., motor gasoline, distillate, and residual fuel oil) of various disruptions in foreign crude oil supply has been examined using the refinery industry model developed by the NPC Committee on Refinery Flexibility.

The types of disruptions considered were a 2,000 MB/D shortfall of foreign sweet crude oil, with and without replacement by other types, and a 5,000 MB/D shortfall of average quality foreign crude oil. As a point of reference for the cases studied, 2,000 MB/D for foreign sweet crude oil represents 13.8 percent of the total projected 1982 crude oil runs in the United States and 13.4 percent of the 1985 total, whereas 5,000 MB/D represents 34.4 percent of the 1982 total and 33.6 percent of the 1985 total. Thus, the cases adequately cover the range of scenarios developed for this study.

In the disruption cases an attempt was made to decrease production of gasoline only while maintaining production of the other major products to the extent feasible. If it was necessary to short other products, the allocation of the shortfall, by product, was set by economics. The remaining motor gasoline produced was required to be in the same proportion, by grade, as the base case. Because the disruptions are unpredictable in their timing and presumably too infrequent to justify refinery modifications, the process capacities are the same as in the respective base case. This approach provides an estimate of maximum refinery flexibility to take shortfalls as gasoline.

In the case of a 2,000 MB/D loss of foreign sweet crude oil in 1982, it was feasible to allow about 80 percent of the major product shortfall to show up as motor gasoline. This represents a 23 percent shortfall in the 1982 total projected motor gasoline pool. It was assumed that the 2,000 MB/D loss of foreign sweet crude oil would be allocated between PADs I-IV and PAD V in proportion to their normal dependence on such crude oil. PAD V, being less dependent on foreign supply sources, suffers relatively little on this basis.

If this crude oil reduction of 2,000 MB/D is allowed to be made up with the foreign light high sulfur crude oil assumed to be available, the total product shortfall is negligible with a necessary lower gasoline production offset by higher volumes of distillate and residual fuel oil. Also, if higher than normal values were placed on gasoline relative to distillate, the refinery could undoubtedly rebalance production between the two. It is noteworthy, however, that the average sulfur level of residual fuel oil has to rise in order to make possible the processing of the higher sulfur crude oil slate. In PADs I-IV, the residual sulfur level increases from 1.61 wt % to 2.00 wt % and in PAD V from 0.99 wt % to 1.03 wt %. This indicates that some relaxation of environmental restrictions may be necessary in an emergency.

The impact of a 5,000 MB/D loss of average quality foreign crude oil was studied to understand the impact of a more severe disruption. In this case, it was assumed that the government would allocate all available crude oil, including domestic, among the PAD districts in proportion to normal refinery runs, rather than to historical consumption of foreign crude oil. This requires PAD V to transfer about 800 MB/D of crude oil (e.g., Alaskan North Slope) to the other PAD districts. With a crude oil loss as large as 5,000 MB/D, the flexibility to take the bulk of the shortfall in motor gasoline is strained. However, the gasoline portion can approach 80 percent if sufficient value is attached to protecting distillate supply. This was done in the model, for example, by raising the relative price of distillate by 50 percent.

Based on these industry model studies, it seems reasonable to assume that there is sufficient flexibility in the U.S. refining system for 75 to 80 percent of a 2 to 5 MMB/D crude oil supply disruption to be reflected in gasoline production. However, two key assumptions in the models should be noted.

With substantial spare capacity in essentially all types of refining processing units, the major concern with regard to the accuracy of the model for the disruption cases is the hydrogen balances. The aggregate models assume that excess hydrogen in one facility can be used in any other facility when, in fact, transfer of hydrogen between refineries is essentially non-existent. Furthermore, experience suggests that about 25 percent of hydrogen production is typically lost to the refinery fuel systems for a variety of reasons. These factors would be difficult to model. In practice, one solution is to grant emergency waivers of sulfur specifications where hydrogen for desulfurization proves to be inadequate.

A second key assumption is complete flexibility to transfer crude oil and unfinished feedstocks within each of the aggregate refinery models, although some restraint was placed on transfer between the aggregate models. In practice, with low overall refinery capacity utilization, such transfers may be highly desirable to allow equipment shutdown to achieve operational efficiencies. For example, in the model studies, the percentage of the hydroskimming refinery's crude oil transferred to the other aggregate refineries as unfinished oil for further processing increased from 23 percent in the base case up to almost 50 percent in the most severe disruption case. However, the tendency of any computer model is to over-optimize and perhaps somewhat overestimate the flexibility that can be achieved in practice. Therefore, additional standby measures should be developed in areas in which the maximum calculated flexibility may be required to meet emergency needs.

Chapter Seven

EMERGENCY LOGISTICS OPERATIONS

INTRODUCTION

In the event of a disruption of petroleum imports to the United States, the ability of the existing crude oil and product logistics systems to adequately redistribute remaining supplies of petroleum will be crucial. Abnormal supply and demand patterns which could result from an interruption of petroleum imports may place severe strains on certain logistics systems.

The objective of this chapter is to assess the capabilities of the present overall U.S. logistics system and its ability to meet the requirements which would be placed on it in the event of a disruption of imports. In addition, this chapter will identify potential disruption bottlenecks within the logistics system, develop estimates of timing and investment required for their removal, and recommend government plans and procedures which could be implemented both prior to and during future emergency disruptions to minimize logistical inefficiencies.

SUMMARY

The results of the analysis of the U.S. logistics system indicate the following:

- Crude Oil Systems
  - The primary logistical constraint identified is the movement of PAD V crude oil through the Panama Canal to other areas of the United States. This bottleneck, which could lead to a restriction of PAD V production, could occur in 1981 in the event of an imports disruption, and possibly as early as 1982 or 1983 due to potential changes in normal supply and demand patterns. Construction of a pipeline across Panama is now under way and should relieve this constraint when completed in late 1982.
  - Generally, crude oil logistics systems in other areas of the United States appear adequate in the disruption cases studied.
  - Not all emergency crude oil production can be accommodated in 1981. Of the emergency production noted in Chapter Four, about 80 to 100 MB/D of Prudhoe Bay, all of the surge production from the Tom O'Connor and Yates fields, and some portion of the East Texas field can be handled.

- Logistics systems for the movement of natural gas liquids and unfinished materials appear adequate in the disruption cases studied.

- Maximum withdrawal rates from the SPR can be accommodated in 1981, but there may be logistical limitations in 1985 assuming that crude oil storage filling proceeds as planned. Further detailed investigation of SPR delivery system connections is recommended to fully assess their capabilities and limitations.

- Product Systems

  - No significant bottlenecks have been identified in the U.S. products logistics system, and there appears to be adequate flexibility to handle any reasonable redistribution of supply or demand resulting from the disruption cases studied.

- Storage and Inventories

  - There appears to be no significant spare capacity available in the existing U.S. petroleum logistics system for the long-term storage of emergency supplies.

  - For quality, flexibility, and efficiency considerations, storage of primary emergency inventories should be in crude oil rather than in particular products. This should not, however, preclude the buildup of product inventory reserves by petroleum end users.

  - A significant limitation in building emergency crude oil inventories is the availability and acquisition of crude oil and the resultant effects on crude oil markets.

  - Management of privately held crude oil and product inventories is best handled by suppliers and users even during periods of supply disruptions.

- Logistics Plans

  The government should consider initiating action in the following areas or utilizing the following concepts in future planning to ensure the continued efficient operation of the U.S. logistics system:

  - To protect against potential bottlenecks in west-to-east crude oil movements, give priority to completing government actions that are needed to allow the use of U.S.-subsidized tankers on a 12-month basis (subject to semiannual review) and the use of foreign flag tankers on short notice.

- Review tax and regulatory factors that act as disincentives to investments in major U.S. pipelines that may be needed in the longer term.

- Streamline the legislative authority and regulatory mechanisms required for the exchange of domestic crude oil from PAD V with contiguous and noncontiguous countries so that they may be implemented on short notice should the need arise.

- Ensure that the current crude oil exchange mechanisms with Canada are extended in order to provide additional flexibility in the U.S./Canadian logistics systems.

- Further investigate the delivery capability of crude oil from the SPR.

- Avoid placement of restrictions on the use of crude oil or product exchanges among companies.

- Do not control, restrict, or mandate the management of privately held inventories.

DISCUSSION AND ANALYSIS

Scope

This chapter focuses on the major elements of the logistics systems, including transportation facilities, inventories, and regulatory/legal constraints. The utilization and need for expansion of existing transportation systems is examined. Emphasis is placed on the transportation facilities required for inter-PAD district movements. Intradistrict requirements have been investigated where potential bottlenecks are indicated and where emergency production is involved. Comparisons are made of total movements vs. total capacity available to determine the adequacy of the transportation facilities. No attempt has been made to determine the movements through specific systems such as individual pipelines.

Secure sources of crude oil and product inventories are identified. The types of inventories considered are privately owned primary, secondary, and tertiary inventories, with emphasis on primary inventories. Also considered are inventories in the Strategic Petroleum Reserve and an estimate of inventories which may be available outside the United States.

Regulatory and legal limitations are identified where they may restrict operations of the logistics systems. Recommendations are made for government actions required to keep the U.S. logistics system operating efficently during an emergency.

Methodology

The supply/demand balances from Chapter Two and Appendix I of this study provide the basic volumetric data for the 1980-1985 pre-disruption forecast. A supply disruption scenario is imposed upon the pre-denial balances to develop the resulting supply/demand balances for the disruption scenario. These supply/demand balances for the total United States and for each PAD district provide the basis for projecting movements of raw materials and products.

The DOE Energy Data Report "Annual Petroleum Statement" for 1978 was used as a basis for projecting inter- and intradistrict movements of raw materials and products. These projected movements represent the requirements that will be placed on the crude oil and product transportation systems in the future and during periods of supply disruption.

A comparison of the required movements with the existing transportation capabilities provides an indication of the potential bottlenecks that may exist in the U.S. logistics system. The 1979 NPC study entitled Petroleum Storage and Transportation Capacities provides the basic data for this comparison. Changes in capacities of major systems and expected additions in the 1980-1985 time frame have been included. Where potential bottlenecks are identified in the transportation system, an investigation has been made to determine what steps can be taken for their removal.

Volume II ("Inventory and Storage") of the aforementioned 1979 NPC storage and transportation study is the primary source of data used in the identification of secure sources of crude oil and product inventories.

Assumptions

The following major assumptions were used in the development of this chapter:

- The demand reduction to be taken during a supply disruption is taken in each PAD district in direct proportion to the demand for each product in the district.
- Demand reductions required over and above those identified in Chapter Two are assumed to be gasoline and are distributed by PAD district in proportion to the gasoline demand in the district.
- The same relationship of refinery runs by PAD district is maintained in the disruption scenario as in the pre-disruption case.
- Commercial purchase, sale, processing, and/or exchange arrangements between companies is not assumed to be restricted.

This chapter includes an evaluation of supply disruption Scenarios 2, 3, 4A, 4B, and 4C for the years 1981 and 1985. The supply/demand balances developed for the five supply disruption cases are provided in Appendix L, Tables L-2 through L-10. The pre-disruption case is included in each disruption scenario for comparison. Crude oil from the SPR and from emergency surge production has not been included in the balances. Utilization of crude oil from these sources will be discussed in subsequent sections of the report.

Based on the projected supply/demand balances and resultant projected movements, an evaluation has been made of the transportation requirements for raw materials and products. An evaluation of these transportation requirements is presented in the sections of this chapter entitled "Crude Oil Logistics System" and "Product Logistic System."

Crude Oil Logistics System

The following is an assessment of the ability of the U.S. crude oil transportation system to meet projected movement requirements in 1981 and 1985 with and without supply disruption. Each PAD district is analyzed separately. Inter- and intradistrict flows are developed and compared with existing transportation capabilities. Other factors considered by PAD district are the sensitivity of movements to change in projected production rates within the district and the ability to move emergency surge production. The ability to handle crude oil from the SPR at projected withdrawal rates is considered in a separate section.

PAD District Assessments

PAD V. Shown in Figure 21 is the crude oil supply/demand balance for PAD V. As shown, the demand for crude oil is declining without a supply disruption. With a supply disruption, the demand would drop even more sharply in 1981 and 1985. The shaded areas indicate the various components of crude oil supply. Imports of foreign crude oil are to remain at about current levels in 1981, but are projected to be phased out by 1985. Prudhoe Bay production has been estimated at current levels of about 1,520 MB/D in 1981 and 1985. Other PAD V crude oil production increases significantly by 1985. Components of this increase are not identified but could come from several sources, including the Santa Barbara Channel, the North Slope of Alaska, new tertiary projects in California's heavy oil fields, and new discoveries.

Two sensitivities can be considered qualitatively on the supply side of the balance. These are the levels of imported crude oil and the levels of increase in other PAD V production.

While imports of foreign crude oil have been declining since North Slope crude oil came on production, they may not be phased out by 1985. DOE data for June 1980 indicate that PAD V imports are essentially all light low sulfur crude oil. Complete phase-out

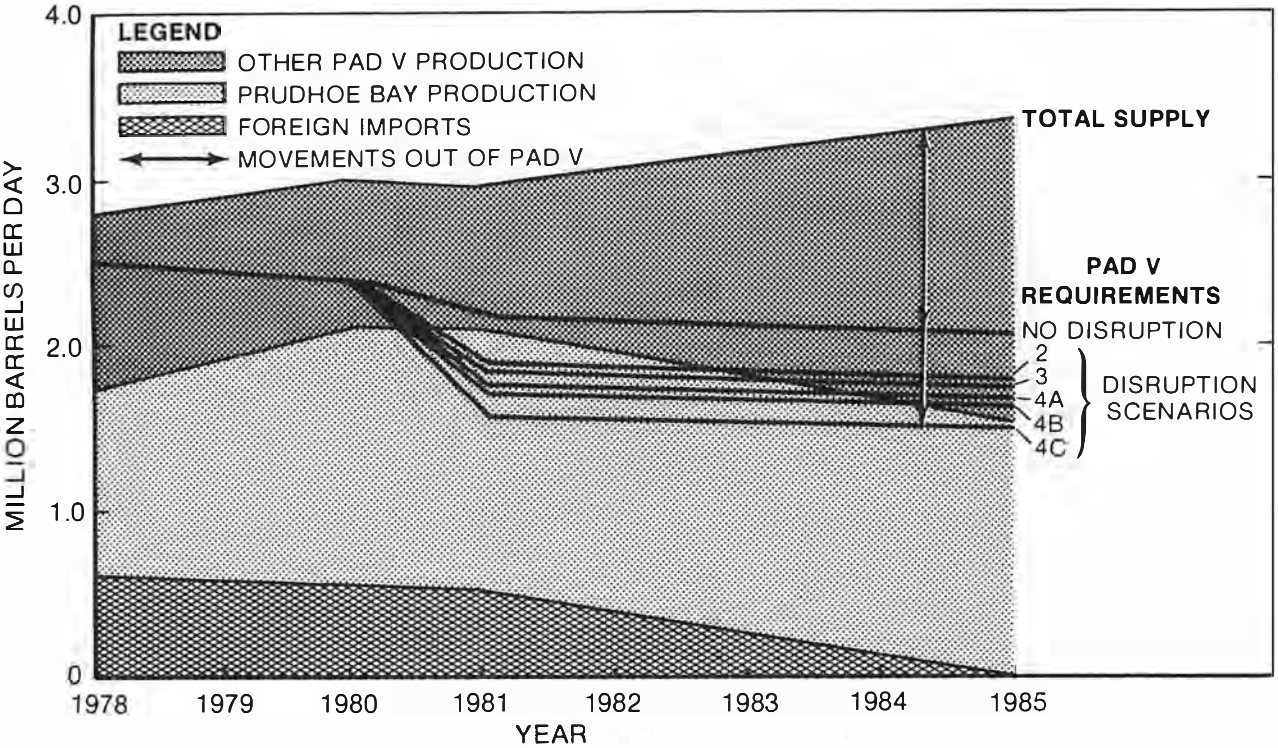


Figure 21. PAD V Crude Oil Supply/Demand Balance.

of these imports may require refinery processing modifications to meet product quality requirements. Such modifications require two to three years for completion after receiving the necessary permits. If imports are not phased out as indicated by 1985, total crude oil supplies in PAD V could increase over the level shown. With higher supplies, movements out of the area would increase.

Other PAD V production was 1,056 MB/D in June 1980 and is projected to increase by about 750 MB/D to 1,800 MB/D in 1985. With announced production increases of 80 to 100 MB/D in the Kuparuk field on the North Slope and 50 MB/D in the Santa Barbara Channel, new tertiary recovery projects and new discoveries could be in the range of 600 MB/D by 1985. This implies a very rapid expansion in thermal recovery projection and/or production from new discoveries. Should this production increase not materialize, total supply and movements out of the area in 1985 could be lower than shown.

Demand sensitivities also exist in these balances between 1981 and 1985. Further nuclear permit delays, reduced gas substitution, below average rainfall (for hydroelectric power), and less conservation could cause a flat or increasing oil demand pattern for PAD V. Higher demands, of course, could lead to lower west-to-east crude oil movements.

The difference between total supply and crude oil requirements is the crude oil that must be moved out of PAD V. These movements are shown in Figure 22. Movements out of PAD V are projected to increase from 800 MB/D in 1981 to 1,275 MB/D in 1985 with no supply disruptions. With supply disruptions, movements range from 1,025

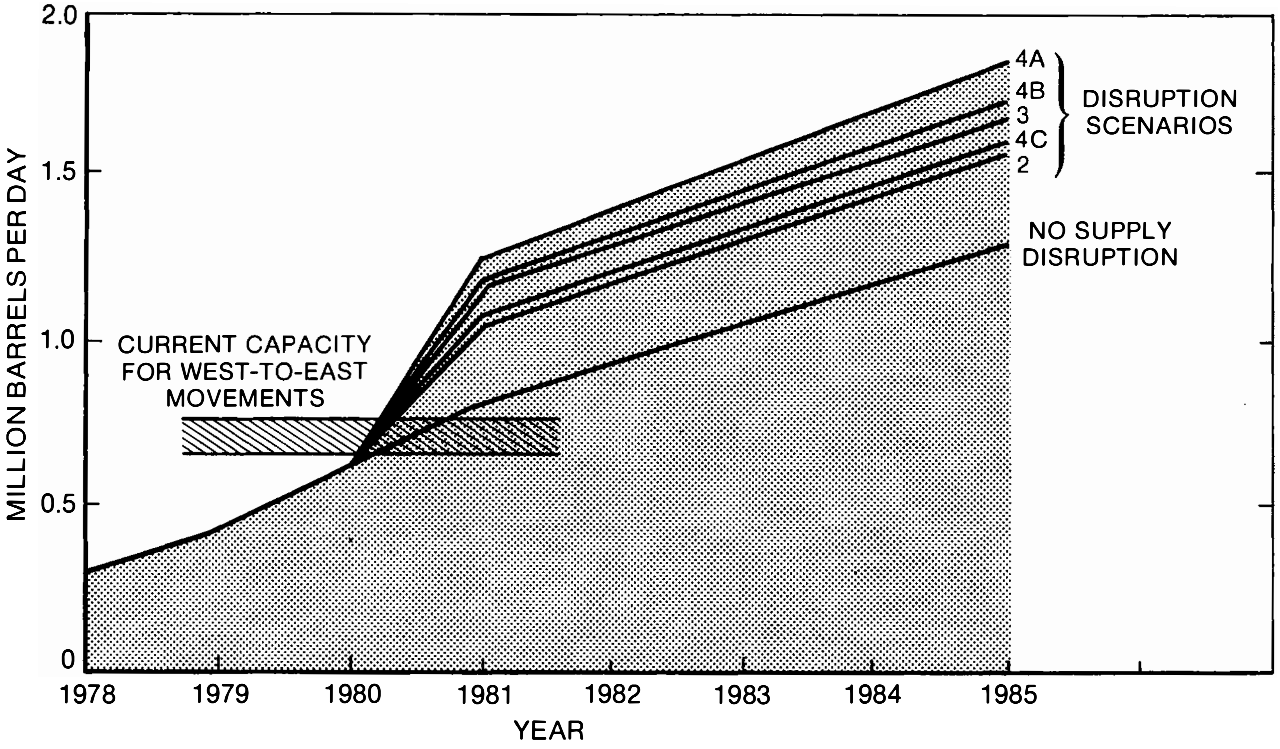


Figure 22. PAD V Crude Oil Movements.

to 1,220 MB/D in 1981 and from 1,545 to 1,835 MB/D in 1985. These projections could exceed the current logistics system capability of approximately 700 to 800 MB/D in 1981-1982 even in the absence of a disruption.

Table 50 summarizes the three primary routes currently used for movement of crude oil from PAD V to PADs I-IV and offers an estimate of the current capacity utilization of each component. There is only one small pipeline, the Four Corners and Texas-New Mexico system, which originates in Los Angeles and delivers crude oil into the West Texas pipeline center. This pipeline is full and is prorated at about 30 MB/D. Very large crude carriers (VLCCs) account for a total of about 120 MB/D. There is about 100 MB/D in foreign flag ships moving to the Virgin Islands. The availability of foreign flag VLCCs is largely due to the surplus of these tankers in the world marketplace. It is estimated that about 20 MB/D is moving around Cape Horn to the U.S. Gulf Coast in subsidized U.S. VLCCs. Eight of these VLCCs have been built with Construction Differential Subsidies (CDS) which are restricted by law to a maximum of six months in Jones Act service each year.

The majority of crude oil volumes move through the Panama Canal. Transits through the Canal are limited to tankers with a maximum beam of 106 feet, which is nominally a 50 to 60 thousand dead weight tons (MDWT) tanker. However, a limited number of tankers in the 70 to 90 MDWT range have been especially constructed for Canal service. At the current time, essentially all U.S. flag tankers are in service. About 10 MB/D moves directly through the

TABLE 50

PAD V Crude Oil Movements
Current Logistics System -- 1980

Logistics Component	Approximate Volume (MB/D)	Capacity Utilization
Non-Canal Movements		
Four Corners Pipeline	30	Full/Prorated
VLCCs Via Cape Horn		
Foreign Flag	100	Spare Foreign Flag Fleet
CDS to Gulf Coast	20	Waiver Limited
Subtotal	120	
Total Non-Canal	150	
Panama Canal Movements		
Direct	10	Vessel Limited
Transshipping	465	Approximately 80% Utilization
Total Panama Canal	475	Canal Approaching Capacity
Total	625	

Canal. The major volume going through the Panama Canal is via Petroterminal de Panama's transshipment terminal at Puerto Armuelles, Panama, which is handling about 465 MB/D, or about 80 percent of its estimated 600 MB/D maximum capacity. As will be discussed, the Canal appears to be rapidly approaching capacity.

Potential problems with the Panama Canal are summarized in Table 51. Built 65 years ago, the Panama Canal is narrow by today's standards, with the 106-foot beam limitation and a restriction to daylight transit for tankers with beams of greater than 90 feet. Thus, on a practical basis, crude oil ships carrying PAD V crude oil are limited to daylight transits of the Canal.

Under current conditions, 12 daylight transits can be handled per day. About seven or eight of the daylight transits are movements of dry cargoes and foreign petroleum which are subject to some fluctuation. This leaves a net of about four or five daily transits for PAD V crude oil. With one transit being about 150 MB/D, movements of PAD V crude oil through the Canal are limited to about 600 MB/D, depending on the tanker size. As transits through the Canal increase, delays are expected to increase, reducing the productivity of tankers using the Canal. In December 1980, tankers were experiencing an approximate two-day delay each way. Delays were even higher during a pilot's strike in October 1980, reaching four to five days each way. Another consideration is that more

TABLE 51

Potential Panama Canal Problems

Capacity

12 Clear Cut Daylight Transits (CCDL)
Estimated To Be Maximum

7-8 Other CCDLs Through Canal

Net = 600-750 MB/D for PAD V Crude Oil

Delays Increasing with Traffic

Improvement Options Limited

lights could be added, but they would provide only a marginal improvement. Major improvements would require large investments and time.

In summary, it appears in the near term (1981-1982) that the only west-to-east pipeline is full, the Panama Canal is approaching capacity, and the only large increment of additional capacity available is foreign flag tankers around Cape Horn.

The transportation options available to prevent interruption of movements of PAD V crude oil during the near term are summarized as follows:

- Twelve-month waivers (subject to semiannual review) for subsidized U.S. VLCCs
- Limited waiver of Jones Act to allow use of foreign flag tankers
- Exchanges with contiguous and noncontiguous countries.

Under current law, the eight subsidized U.S. VLCCs can be used only in U.S. service six months out of the year. Use of these tankers on a 12-month basis requires a legislative act which the Maritime Administration (MARAD) must initiate. If used on a 12-month basis, these VLCCs would add about 80 MB/D of additional capacity.

Beyond full employment of all Jones Act and CDS tankers, another step that could be taken would be action by the Secretary of the Treasury to waive the Jones Act to permit the use of foreign flag tankers in U.S. coastwise service. Legislative authority already exists for such actions if required in the national defense.

An additional option would be to exchange PAD V crude oil with contiguous or noncontiguous countries. Either form of exchange would require considerable time to obtain the necessary permits and the latter could also require additional legislation.

In the longer range (1983 and beyond), a number of facilities could be in place for the movement of PAD V crude oil. These facilities, their capacities, and the time they could be made available are shown in Table 52.

TABLE 52

Longer Range (1983-1985) Options For Movement of PAD V Crude Oil

Option	Capacity (MB/D)	Timing
Four Corners Pipeline Expansion	110	1984
Central American Pipeline	500-700	1983*
Construction of U.S. VLCCs	20/VLCC	1983
Major West-to-East Pipelines		
Northern Route	700-900	1986+†
Southern Route	500-700	1986+

---

*Construction has begun on a trans-Panama pipeline.

†Northern Tier Pipeline Company has projected a 1984 startup.

Expansion of the Four Corners Pipeline is a possibility. It could be on stream by 1984; however, it would provide only limited additional capacity of about 110 MB/D.

Two Central American pipeline projects have been proposed. Each project could provide 500 to 700 MB/D of capacity. One line would cross Panama from the Petroterminal de Panama, and the other would cross Costa Rica. The trans-Panama line is currently under construction. It is estimated that this pipeline could be available as soon as late 1982 due to the relatively short length of the line and fewer expected delays in permitting. The addition of 500 to 700 MB/D of capacity would handle a significant share of the PAD V crude oil movements which could occur in the 1985 supply disruption scenarios (see Figure 22).

Another possible source of capacity would be the construction of U.S. flag VLCCs with availability out of the shipyards beginning in late 1983-1984. These VLCCs would be 265 MDWT tankers, which are the largest that can call at Valdez. The trip around Cape Horn would require about 100 days, resulting in a carrying capacity of 20 MB/D per tanker.

The construction of major U.S. crude oil pipelines represents another approach. Two primary routes have been considered. The northern route serving the norther tier states and the Midwest is represented by the Northern Tier and Trans Mountain (via Canada) pipeline projects. Northern Tier Pipeline was selected by President Carter in January 1980 to receive expedited federal permitting. Since that time Northern Tier has been pursuing permits. If financing is not obtained by Northern Tier within the time schedule set by the President, its special procedures will be revoked, and Trans Mountain Pipeline will be given an opportunity to take advantage of the same expedited procedures. Because of the possibility of continuing regulatory delays, these projects may have difficulty in coming on stream within the time frame of this study. The southern route would serve the large Gulf Coast refining network and most of the Mid-Continent and Midwest via connecting pipeline networks; however, this route is not being actively pursued at this time.

Although practical considerations probably relegate a major U.S. pipeline to long-term consideration (not before the late 1980's), such would represent a secure project that is clearly in the national interest if PAD V movements continue to grow beyond 1985. With the potential for decline in North Slope production after 1985, the throughput for these pipelines will be heavily dependent upon the development of as yet undiscovered new reserves and on their location. In the event these discoveries materialize as projected, any new pipelines will require a multibillion dollar investment.

Finally, given the foregoing considerations, it is imperative that the route for a major U.S. pipeline be firmly supported by fundamental marketplace factors such as crude oil supply, demand, and refinery location, which will contribute to successful completion of a viable pipeline project.

In the past, unit trains have been proposed as an interim step for moving Alaskan North Slope crude oil off the West Coast until west-to-east pipelines could be constructed. Due to the magnitude of the volumes to be moved and the distances they must be moved, a large number of trains would be required. Tank cars and possibly locomotives would have to be built for these trains. There is also a possibility that sections of track on existing lines might have to be upgraded or additional tracks built. Large rail movements of crude oil eastward combined with increasing coal movements from the Rocky Mountain area could lead to congestion or overloading of the existing rail system. Aside from these considerations, perhaps the major problem would be siting the origin terminals on the West Coast. Experience to date has demonstrated that this can be a time-consuming process at best and is not always successful. Although unit trains have been and can be used efficiently for the transportation of crude oil, the use of unit trains to move large volumes of crude oil off the West Coast in an emergency does not appear to be practical.

Up to this point, only PAD V interdistrict movements have been considered. The discussion that follows will cover intradistrict movements and emergency surge production for PAD V.

Two fields in PAD V have been identified as having emergency surge production capacity which may be available during a supply disruption. These fields are the Prudhoe Bay field on the Alaskan North Slope and the Elk Hills field in the San Joaquin Valley of California.

The Prudhoe Bay field is estimated to have a surge capacity of 180 MB/D in 1981 and an average of 140 MB/D in 1985 (180 MB/D at the start of the year and 100 MB/D at the end of the year). The mechanical capacity of the Trans-Alaska Pipeline System is 1,420 MB/D, having been expanded in December 1980. With the addition of a drag reduction additive, the throughput capability can be increased. With a mechanical capacity of 1,360 MB/D and the use of DRA, TAPS throughput has been as high as 1,560 MB/D during 1980. It has been announced that the Kuparuk field will be on stream by 1982. Production is estimated to be in the 80 to 100 MB/D range during 1982-1985. With the startup of production in the Kuparuk field, the throughput capability of TAPS is expected to be fully utilized. Therefore, it appears that until 1982, approximately 80 to 100 MB/D of emergency surge production can be handled. After 1982, with the Kuparuk field production, no emergency surge production can be handled without the addition of mechanical pump horsepower. The addition of pumps would require in excess of one year for installation because of the long lead time for delivery of the pumps and construction. Therefore, additional throughput would not be available during a one-year disruption period without pre-investment.

Elk Hills is located in Naval Petroleum Reserve No. 1 west of Bakersfield, California. The field is currently producing at the rate of 167 MB/D. Expansion of facilities and initiation of further waterflood projects are expected to increase production to 190 MB/D by the end of 1981. During 1981, the emergency surge capacity is estimated to average 16 MB/D, but would decline to a 1985 average of 8 MB/D. It would require a waiver from Congress before Elk Hills could be produced at these surge rates. As indicated in Figure 21, production in other PAD V sectors is expected to increase dramatically. A portion of this increase can logically be expected to come from tertiary projects in the San Joaquin Valley where Elk Hills is located. Currently, it is understood that pipeline capacity out of the valley is tight. On this basis, it is estimated that it may be difficult to move surge production in 1981. By 1985, there could be expansions of pipeline systems out of the area. This, coupled with projected declines in the field, indicates that surge production probably could be handled.

Any surge production which may be available in 1981 and 1985 would be additive to the movements shown in Figure 22 and would add further to the need to move PAD V crude oil to the Gulf or East Coasts.

PAD IV. The crude oil supply/demand balance for PAD IV is shown in Figure 23. Imports of foreign crude oil and local PAD IV production are the principal sources of supply. Foreign crude oil is imported from Canada and obtained through exchanges. This imported crude oil is refined in Montana and is projected to be phased out by 1985. The phase-out of Canadian crude oil, which is light and sweet, implies a modification in processing facilities and/or a loss in ability to exchange for Canadian crude oil. Currently, exchanges are prevalent in the northern tier states. Local production is projected to remain constant at 650 MB/D, the same as in 1978.

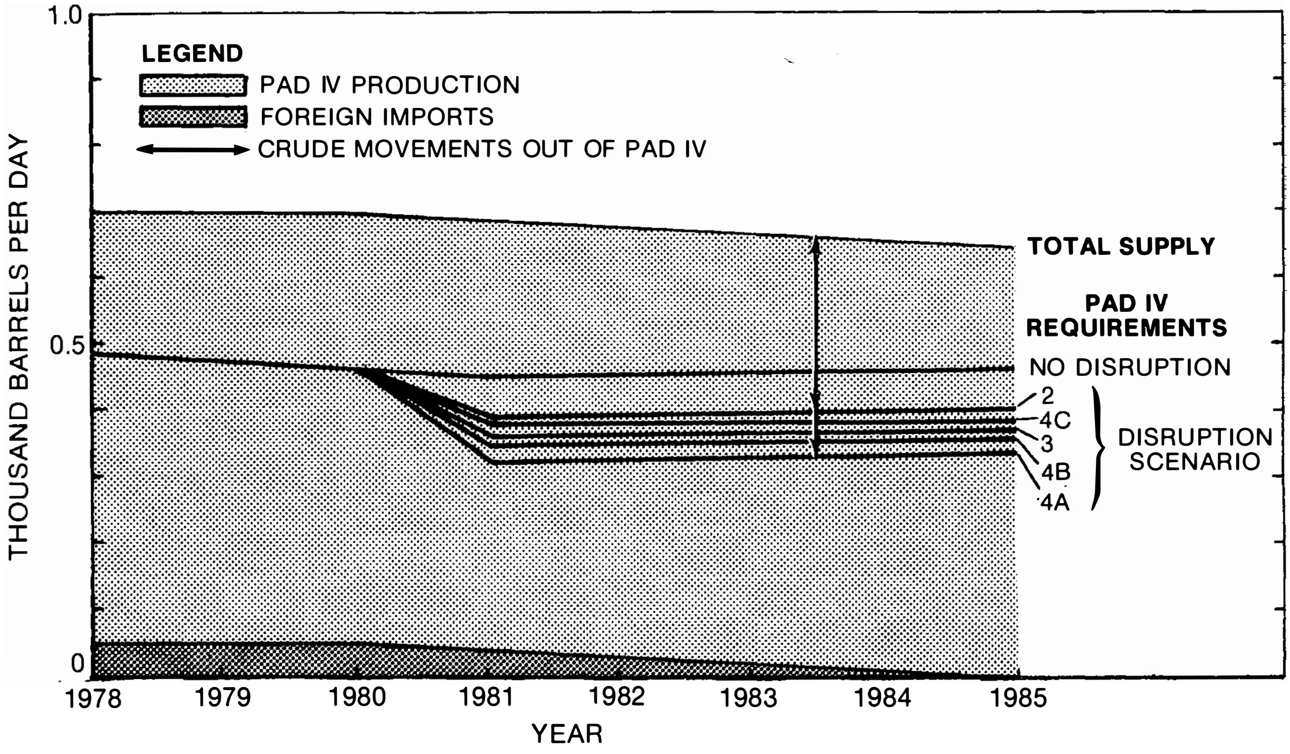


Figure 23. PAD IV Crude Oil Supply/Demand Balance.

PAD IV has historically been an exporter of crude oil, primarily to PAD II. The total movements out of the area are shown in Figure 24. With no supply disruption, crude oil movements reach a peak in 1980 and 1981 as crude oil requirements in the area decrease. After 1981, movements are projected to decline as imported crude oil is phased out. A supply disruption significantly increases the volume of crude oil that must be moved out of the area. Although other pipelines (Four Corners, Diamond Shamrock, and Portal) will probably handle a limited portion of the movements, it is estimated that the major portion will be handled by Amoco and Platte. Therefore, total movements out of PAD IV have been compared with the combined capacity of Amoco and Platte, which is 355 MB/D. This comparison indicates that adequate capacity is available in the most severe disruption scenario. Should Canadian exchange be continued through 1985, it is estimated that adequate capacity would be available to handle the 40 to 50 MB/D increase in

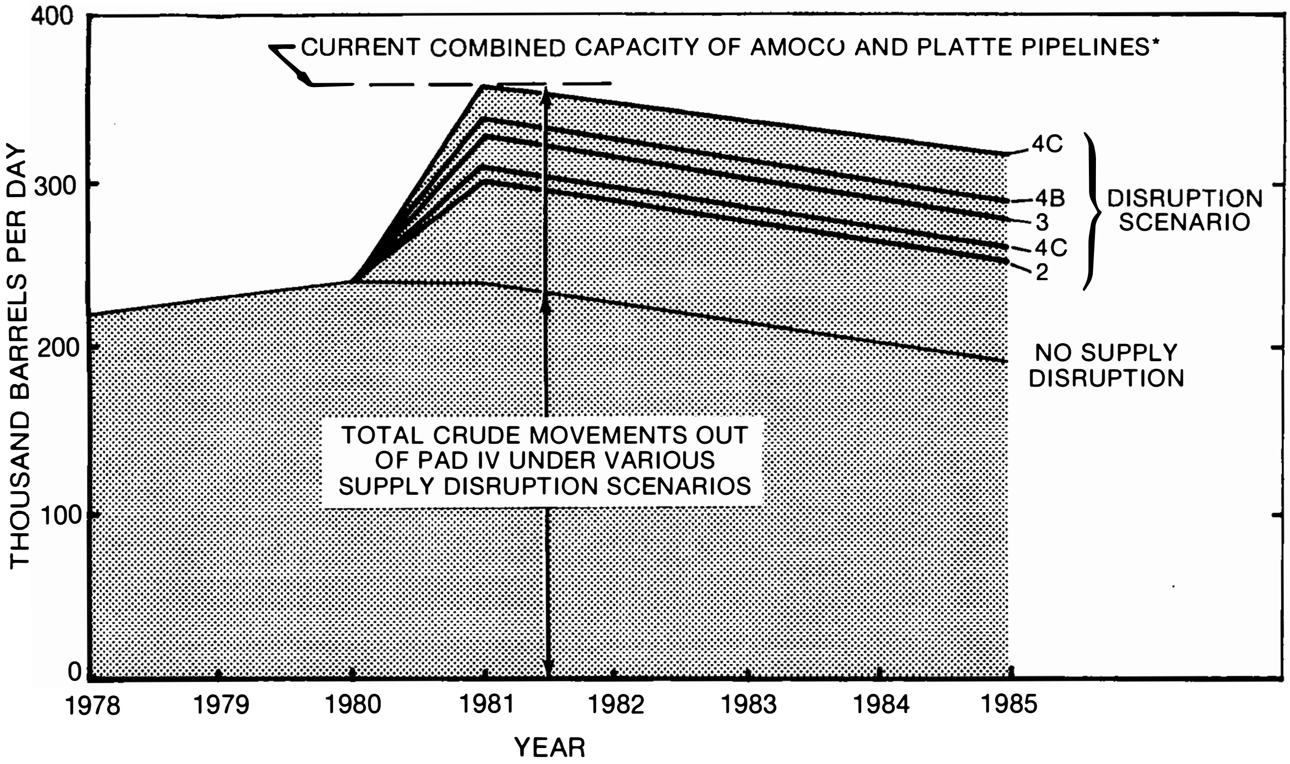


Figure 24. Crude Oil Movements Out of PAD IV.

*Although Amoco and Platte capacity is used to demonstrate adequacy a portion of PAD IV movements are by other pipelines.

movements out of PAD IV. Should PAD IV production be lower than shown in Figure 23, the movements out of the area would also be lower assuming demand remains constant.

The phase-out of Canadian exchanges could present a problem for Montana refiners in 1985. Statistics from the Montana Oil and Gas Statistical Bulletin for July 1980 indicated that of the 122 MB/D of crude oil refined in Montana, approximately 25 percent was Montana light medium sour crude oil, 45 percent was heavy sour crude oil from Wyoming, and 30 percent was light sweet crude oil from Canada. The Northern Tier Pipeline, if it is built, could provide an additional source of crude supplies for Montana refiners. However, there are presently no pipelines connecting these refiners to replacement crude oil supplies which could be made available in the Powder River and Williston Basins of PAD IV. Therefore, consideration should be given to ensuring that exchange mechanisms now in place are maintained in the future. An extension of this mechanism provides additional logistical flexibility to both countries in normal times as well as in emergencies.

As indicated previously, production in PAD IV has been projected to remain constant at 650 MB/D. Although no data are available on possible changes in the distribution of this production, the Overthrust area near Salt Lake City is indicated to have significant potential. Should production increase significantly in the Overthrust, the logistics system currently serving the Salt Lake area could be overloaded by 1985. However, there appears to be adequate time to resolve this problem should the situation arise.

PAD II, PAD III, and PAD I West. As indicated in Figure 25, there is an extensive pipeline network through the central portion of the United States that connects PAD II, PAD III, and the western portion of PAD I. This network moves domestic production (which is largely concentrated in PAD III) and foreign crude oil imports from the U.S. Gulf Coast to PAD II and PAD I West. For evaluation purposes, this area has been broken down into the areas shown in Figure 26.

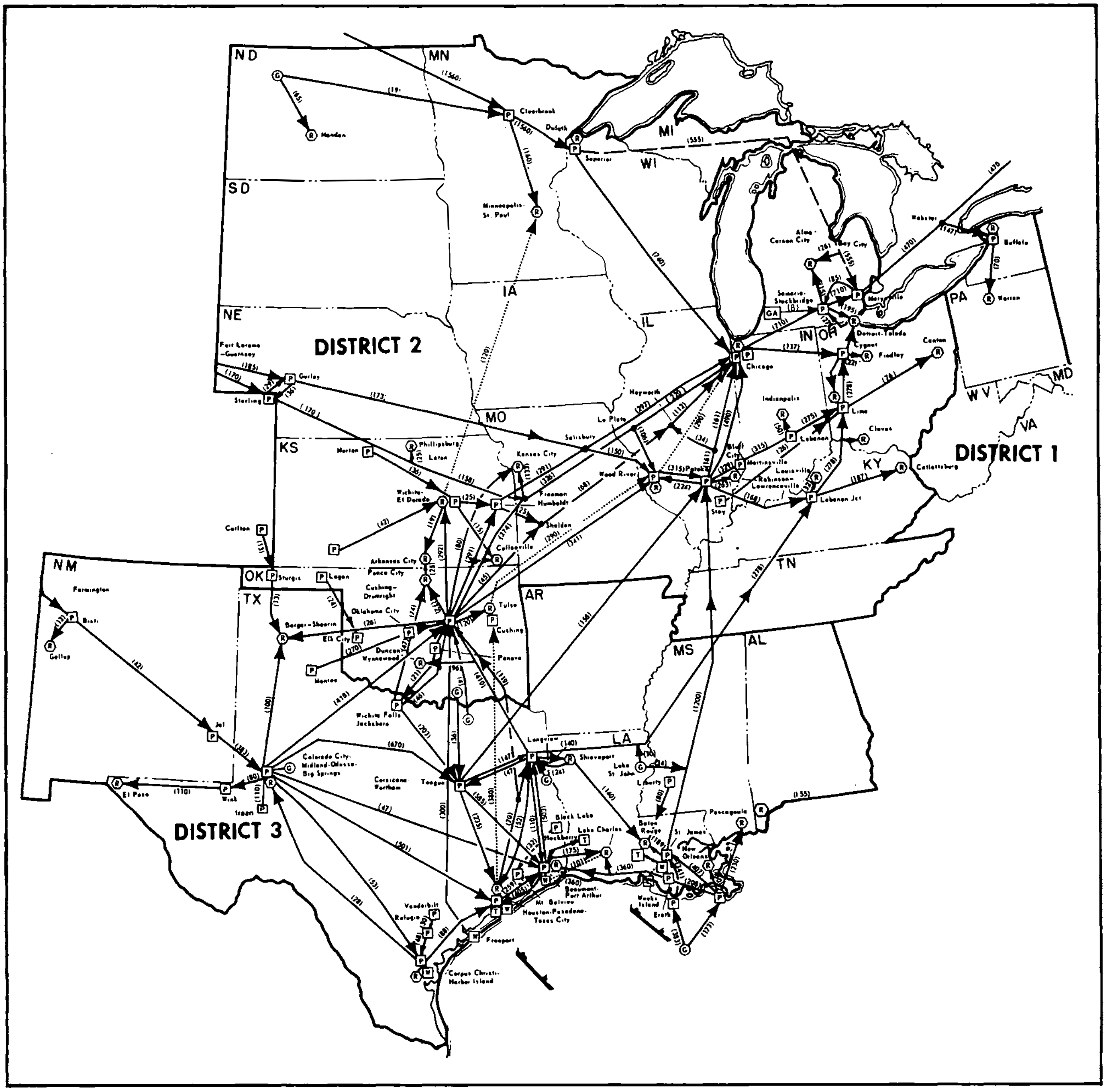


Figure 25. Crude Oil Pipeline Capacities as of December 31, 1978 (Thousand Barrels per Day).

PAD III has been broken into two subareas, PAD III West and PAD III East. The east/west division was made because the logistics

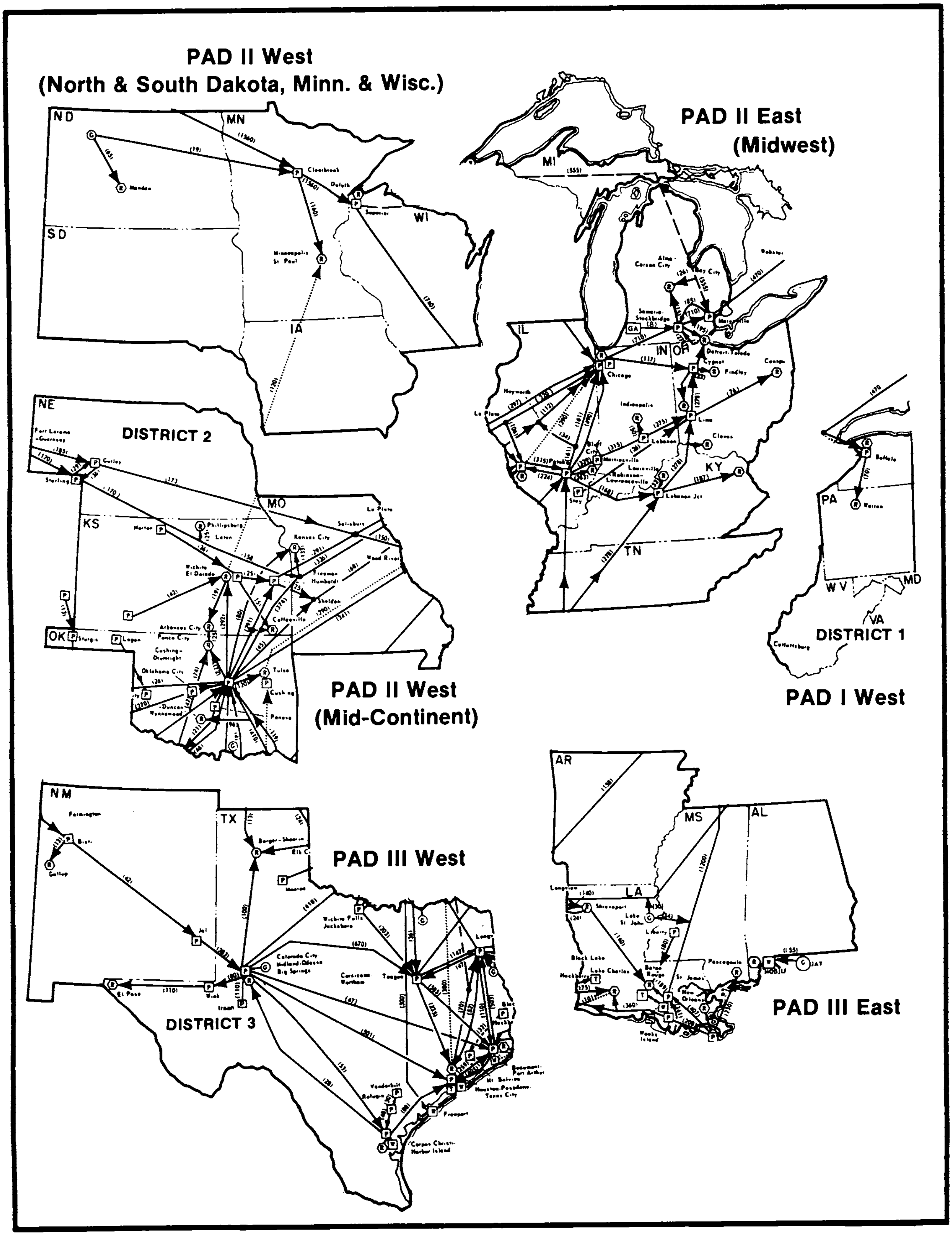


Figure 26. Crude Oil Pipeline Capacities by PAD District as of December 31, 1978 (Thousand Barrels per Day).

systems in PAD III run primarily in a north/south direction. Although the western and eastern portions of PAD III are interconnected with crude oil flowing in both directions, the major movements are in a north/south direction. PAD III West includes the states of New Mexico and Texas. Currently, crude oil production from these two states accounts for about 65 percent of the total production in PAD III. Crude oil production in PAD III West is concentrated along the northern portion of the area in New Mexico and West, North, and East Texas and accounts for about 80 percent of this western area. Production along the coast accounts for the remaining 20 percent.

PAD III East includes four states, Alabama, Arkansas, Mississippi, and Louisiana, and provides about 35 percent of the crude oil production in PAD III. As opposed to the distribution of production in the western area, 80 percent of the production in this area is concentrated along the coast in southern Louisiana.

PAD II has also been divided into east and west areas. The western area, which produces about 75 percent of the total PAD II crude oil, has been further divided into two areas. The upper area includes the northern tier states of North and South Dakota, Minnesota, and Wisconsin. Except for Canadian imports and local production, crude oil must be moved up from the south. As can be noted, this area is not served by extensive pipeline systems as is the Mid-Continent area to the south.

The Mid-Continent area includes the states of Nebraska, Kansas, Oklahoma, and Missouri. Crude oil production in this area is about 83 percent of the western portion of PAD II and 63 percent of the total production in PAD II. Crude oil moves from PAD III west to satisfy Mid-Continent requirements as well as the requirements of the northern portion of PAD II West and the Midwest.

PAD II East is essentially the Midwest including states as far south as Tennessee. The Midwest is served by pipelines directly from PAD III East and PAD III West which, for purposes of this analysis, is considered one logistics system. It also receives crude oil from PAD III West via the Mid-Continent area. The Midwest can also be served by the Mississippi River.

PAD I West includes the western portions of the states of New York and Pennsylvania and the state of West Virginia. This area is served by pipelines which are an extension of the pipeline systems serving the Midwest and can also be served by the Mississippi and Ohio Rivers.

Using these areas for evaluation required that some assumptions be made concerning the distribution of crude oil demand and production within a PAD district. Distribution of crude oil requirements within a PAD district is based on 1978 DOE data. Crude oil production has been distributed based on June 1980 data published by DOE. The selection of the particular time period is not critical. A review of data for the years 1970-1979 indicates only minor variations. It has also been assumed that there are no restrictions on crude oil exchanges.

PAD II West. A supply and demand balance for PAD II West is shown in Figure 27. This balance is for both areas included in PAD II West. On the supply side of the balance is shown the PAD II West production that is retained in the area as well as crude oil receipts from PAD IV. This type of balance is used in order to indicate the amount of crude oil which must be moved into the area from the south. If total domestic production had been used as in the previous balances for PADs IV and V, movements would be understated. The movements from the south to PAD II West are shown on the lower portion of Figure 28.

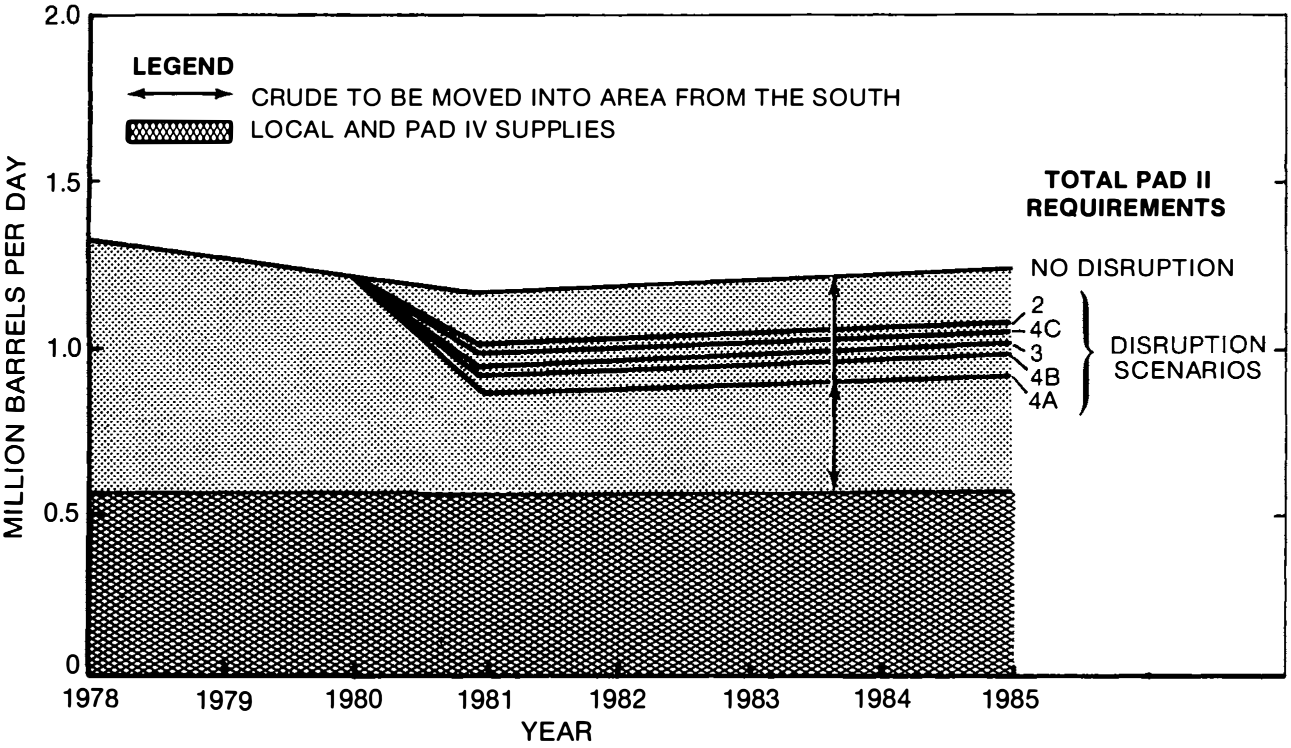


Figure 27. PAD II West Crude Oil Supply/Demand Balance.

The movements to PAD II West include domestic crude oil from Texas and New Mexico, the West Coast, and all foreign crude oils including Canadian. It is recognized that Canadian crude oil would not move from PAD III West to PAD II, so from this standpoint movements are overstated.

The movements over and above those required to satisfy the PAD II West requirements are the movements of Texas and New Mexico crude oil to the Midwest and PAD I West. It has been assumed that all Texas and New Mexico crude oil must move via the Mid-Continent. Only the "no disruption" case has been shown for these movements. The total of these two sets of movements should represent the maximum requirements on the pipeline systems connecting PAD III West

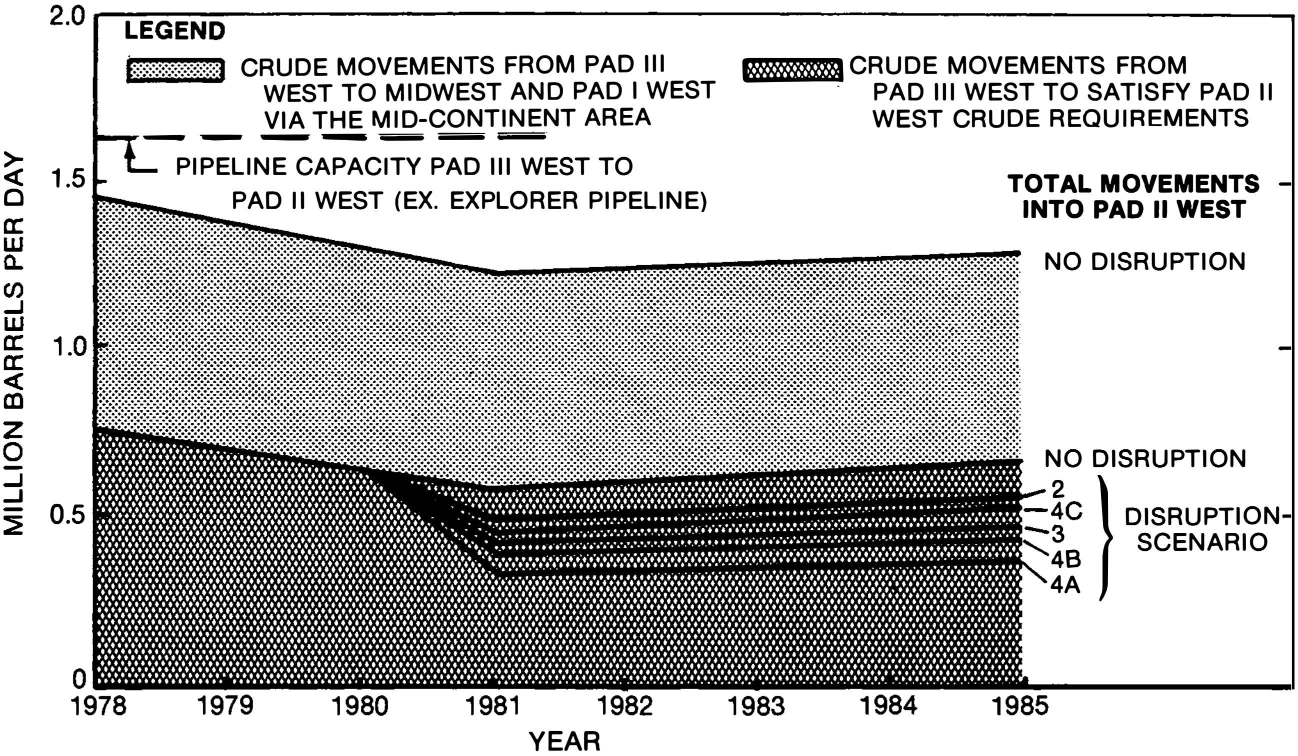


Figure 28. Crude Oil Movements into PAD II West from PAD III West.

with PAD II West. The combined pipeline capacity from Texas to Oklahoma of 1,625 MB/D is shown as a heavy broken line above the total movements. Explorer, which moves both crude oil and product, is not included in this capacity number. The comparison indicates that capacity in these systems should be adequate in 1981 and 1985 with or without a supply disruption.

Using this same approach, crude oil movements from the Mid-Continent area into North and South Dakota, Minnesota, and Wisconsin have been developed. These are shown in Figure 29. These movements include the total amount of foreign crude oil required in the area including Canadian. In 1981, some portions of this foreign crude oil requirement will be Canadian delivered by pipelines from the north. If Canadian exchanges are phased out by 1985, the movements shown are representative. The pipeline capacity shown is based on a capacity of 120 MB/D for the Williams Brothers Pipeline in 1980. The increase to 130 MB/D in 1981 is based on the announced capacity of the new system being constructed by Williams Brothers and Koch. This area can also be served by barges up the Mississippi River during part of the year.

Another movement out of the Mid-Continent area is the movement to the Midwest and PAD I West which is shown in Figure 30. These movements are assumed to consist of crude oil from PAD IV, North and South Dakota, Nebraska, and PAD III West. Very little variation is indicated for these movements with or without a supply disruption. Movements are slightly higher in the supply disruption cases because of the movements from PAD IV to the Midwest. The pipeline capacity available from the Mid-Continent to the Midwest

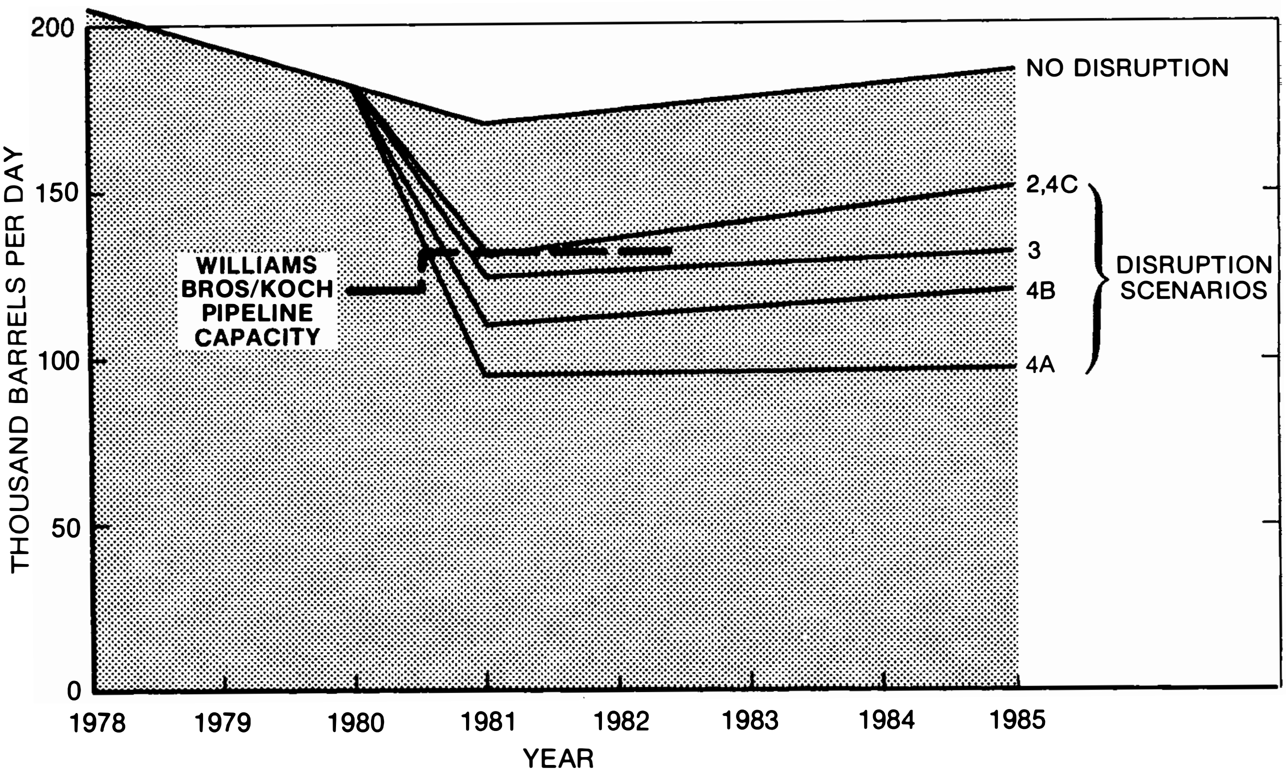


Figure 29. Crude Oil Movements from Mid-Continent to North and South Dakota and Minnesota and Wisconsin.

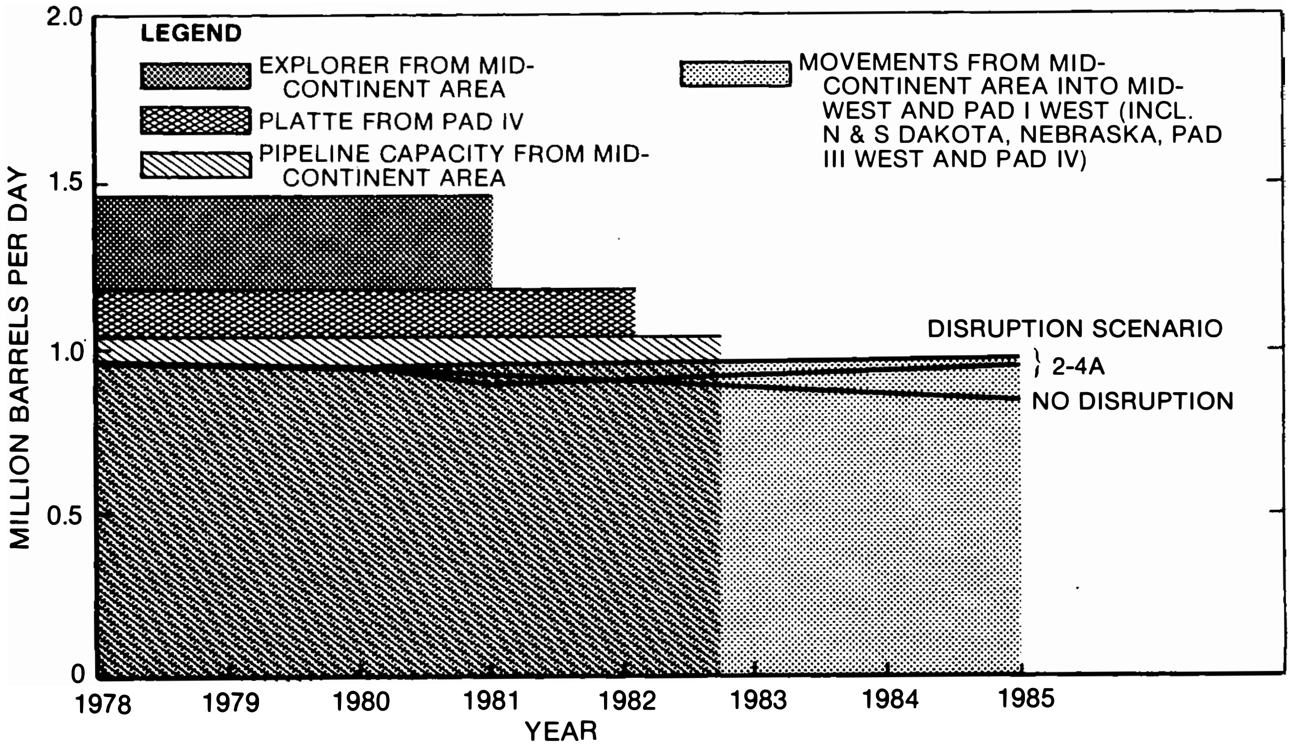


Figure 30. Crude Oil Movements from Mid-Continent Area to Midwest and PAD I West.

is shown in three increments. The lower line represents the combined capacity of pipelines out of the Oklahoma/Kansas area. The next increment is the capacity of Platte into Wood River which moves crude oil directly into the Midwest from PAD IV. The final increment is the capacity of the Explorer Pipeline from Tulsa to St. Louis. The comparison indicates that the loading on these systems will remain about constant with historical levels.

Midwest (PAD II East). The supply/demand balance for the Midwest shown in Figure 31 indicates that essentially all of the crude oil required must be moved into the area. This is due to limited amounts of production in the area and the movement of Midwest crude oil to PAD I West. In addition to movements from the Mid-Continent area, the Midwest receives crude oil from PAD III East. These movements are shown in Figure 32, and are assumed to include all domestic crude oil from PAD III East and the total foreign crude oil requirements of the Midwest. Again the foreign crude oil requirements include Canadian and to this extent are overstated. Two levels of pipeline capacity are shown.

The lower broken line represents the capacity of Capline. The next increment shown is the combined capacity of the Mid-Valley and Mobil Pipelines which originate in East Texas. Although it has been assumed in this analysis that these pipelines are only used to transport PAD III East and foreign crude oils to the Midwest, they also have access to crude oils from Texas, New Mexico, and PAD V. To the extent that these pipelines move these crude oils, the movements shown in Figures 28 and 30 would be reduced by a like amount. The Midwest can also be served by barge up the Mississippi on a year-round basis.

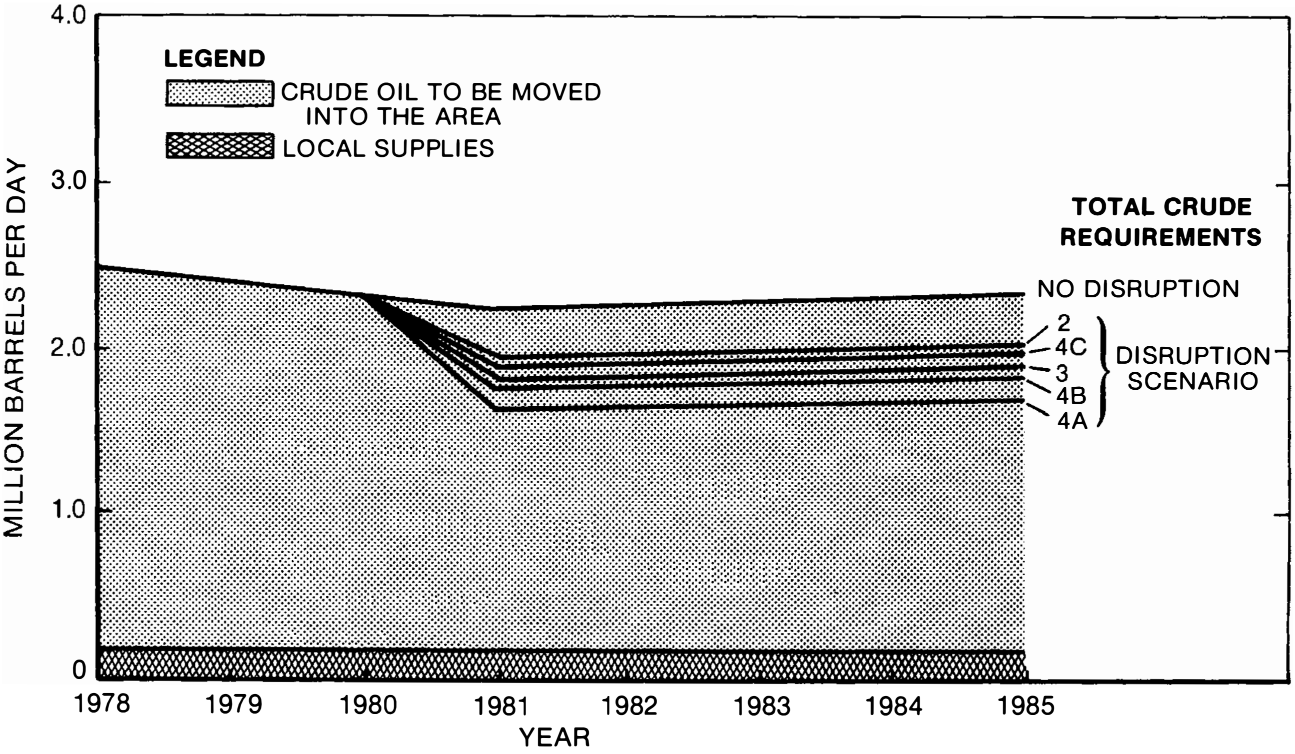


Figure 31. Midwest (PAD II East) Crude Oil Supply/Demand Balance.

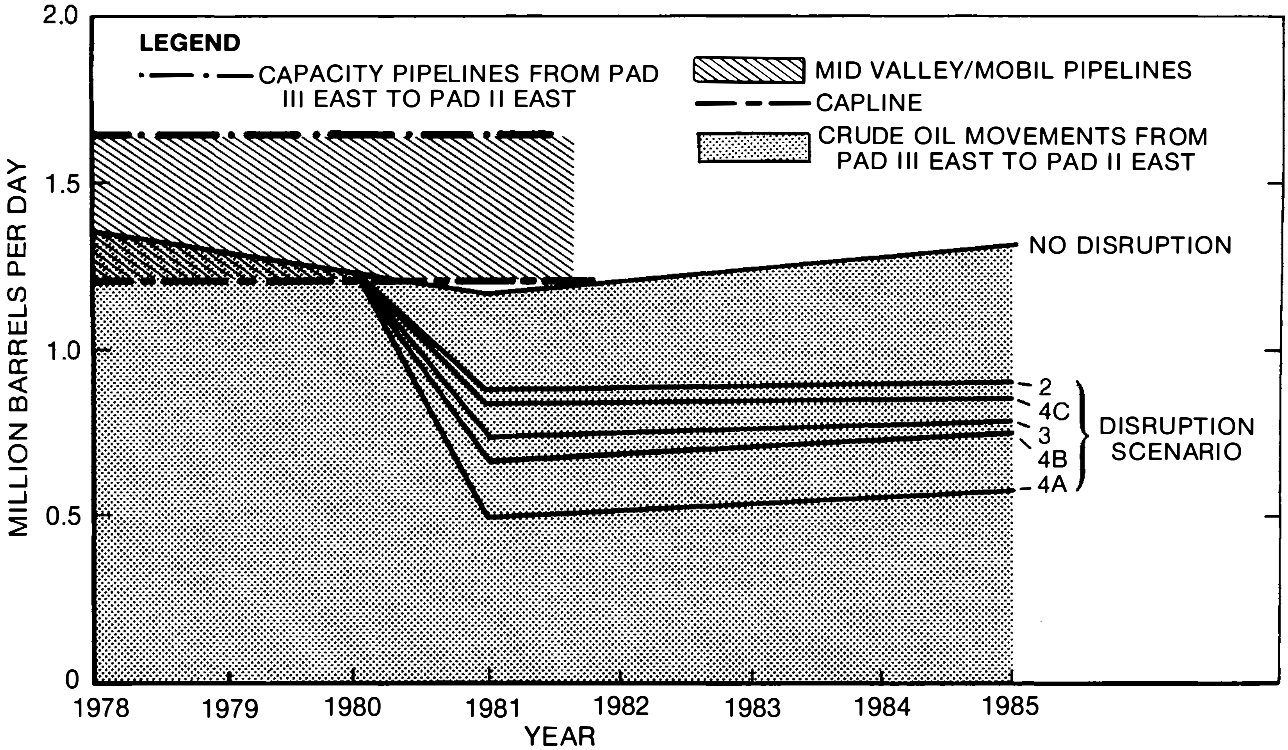


Figure 32. Crude Oil Movements from PAD III East to Midwest.

PAD I West. Movements of crude oil into PAD I West are shown in Figure 33. These movements are from the Midwest and include crude oil from all domestic producing areas except local production and all foreign crude oil requirements. Interprovincial is the primary pipeline serving the area.

In summary, it appears there are no significant bottlenecks in the transportation serving PAD II and PAD I West. As in PAD IV, there is an indication that continuation of Canadian exchanges could add additional flexibility to the system. The government should consider taking steps to ensure that this flexibility is maintained.

PAD III. Movements northward out of PAD III have been covered in previous discussions. There are no significant crude oil movements out of PAD III to the East Coast.

Currently, movements into PAD III are primarily by water. The major movements are of foreign imported crude oil and movements from PAD V destined for PAD III, PAD II, and PAD I West; these movements are shown in Figure 34. Movements show an increase of about 1 MMB/D by 1985 in the case of no supply disruption. This increase is due to the higher foreign imports required to replace declining domestic supplies and the increase in crude oil movements from PAD V. The movements shown include total foreign imports. The level of Canadian imports for 1978 through the first half of 1980 is shown for comparison.

With the completion of the Louisiana Offshore Oil Port (LOOP) in 1981, it appears that there should be adequate capacity to

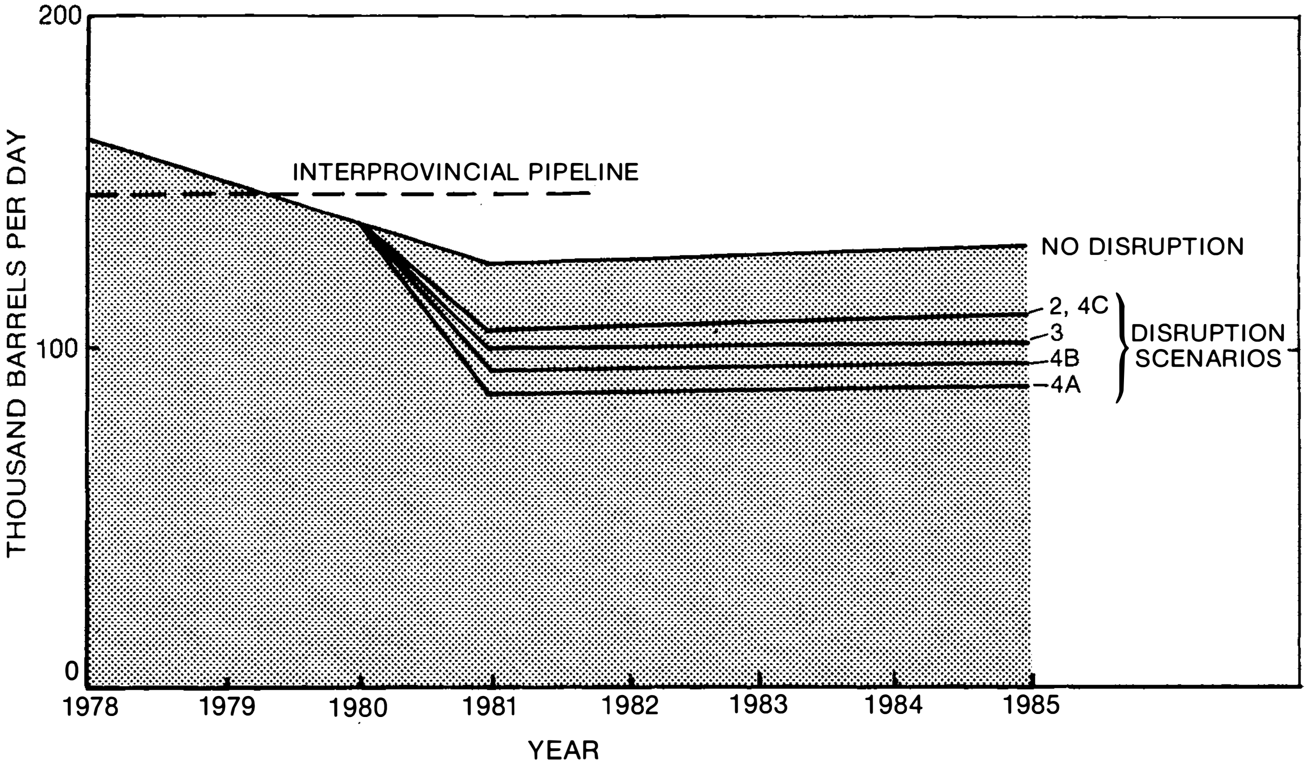


Figure 33. Crude Oil Movements to PAD I West.

handle this increase. LOOP will provide additional receipt capacity for Capline as well as refineries on the Texas and Louisiana coasts via pipeline systems being connected to LOOP. Several proposals for additional capacity along the Texas Gulf Coast are under consideration which could also add to the waterborne receipt capability.

Should Four Corners/Texas-New Mexico be expanded into the West Texas area, waterborne movements shown in Figure 34 would be decreased and an increased load placed on the pipeline systems out of West Texas. This could also occur if a southern route pipeline (PACTEX-type line) is constructed in the future, although it would not be on stream by 1985. Figure 35 indicates that by 1985 there could be a minimum of 400 MB/D of spare pipeline capacity out of West Texas. This would indicate that there should be no problems handling a Four Corners expansion and, in the longer range, a major southern-routed pipeline.

Within PAD III, three fields have been identified as having emergency surge capacity: Yates in West Texas, the East Texas field, and the Tom O'Connor field in South Texas.

The Yates field is indicated to have a surge capacity of 40 to 50 MB/D in 1981 but none in 1985 without significant investment. Spare capacity of 40 MB/D has been identified in two pipelines serving the field, leaving a maximum of 10 MB/D to be handled by the two remaining pipelines. On this basis, it appears that the emergency surge capacity could be handled.

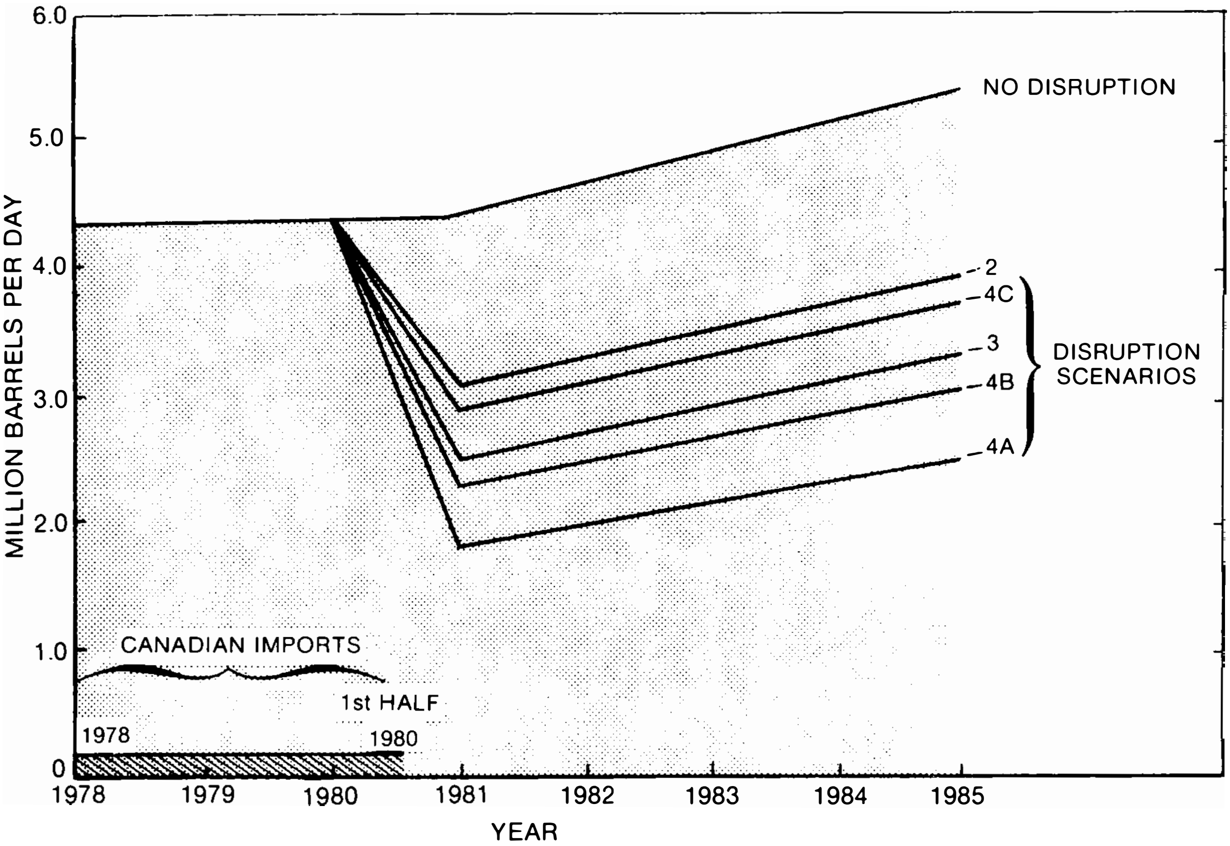


Figure 34. Major Waterborne Movements into PAD III.

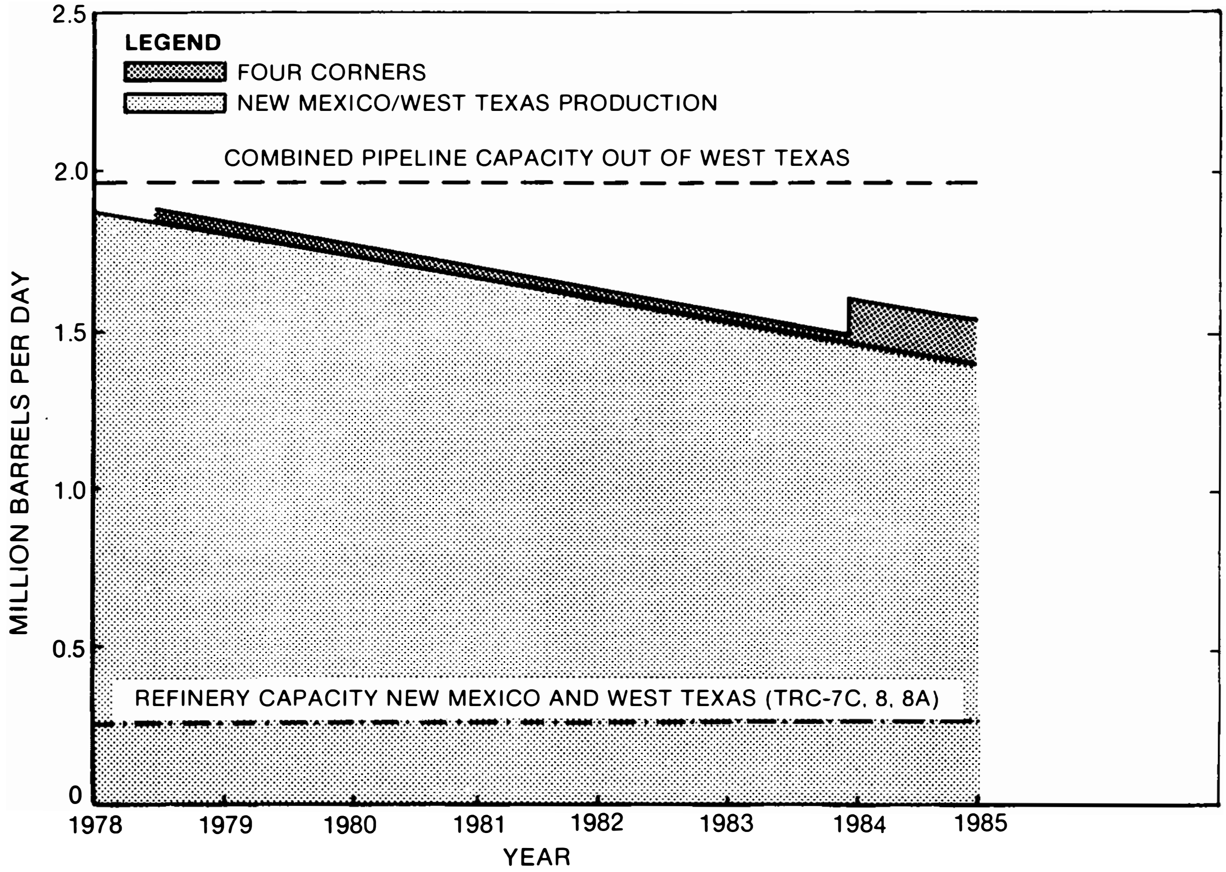


Figure 35. Pipeline Capacity Out of West Texas.

It is estimated that the surge capacity from the Tom O'Connor field would range between 3 and 7 MB/D in 1981, but due to declines in the field there would be no surge capacity by 1985. Existing pipeline capacity is indicated to be adequate to handle this level of surge production.

The East Texas field is currently producing 162 MB/D. Incremental surge capacity is estimated to be 154 MB/D in 1981 and 133 MB/D in 1985. At this time, no estimate is available on the ability of operators to move this increment of surge capacity. There are 21 operators who gather crude oil in the field and at least 10 to 12 pipelines which move crude oil out of the area. If the surge production is evenly distributed, movements of each operator would nearly double. It is unlikely that this total increment can be handled without additional pump horsepower assuming pipeline sizes are adequate.

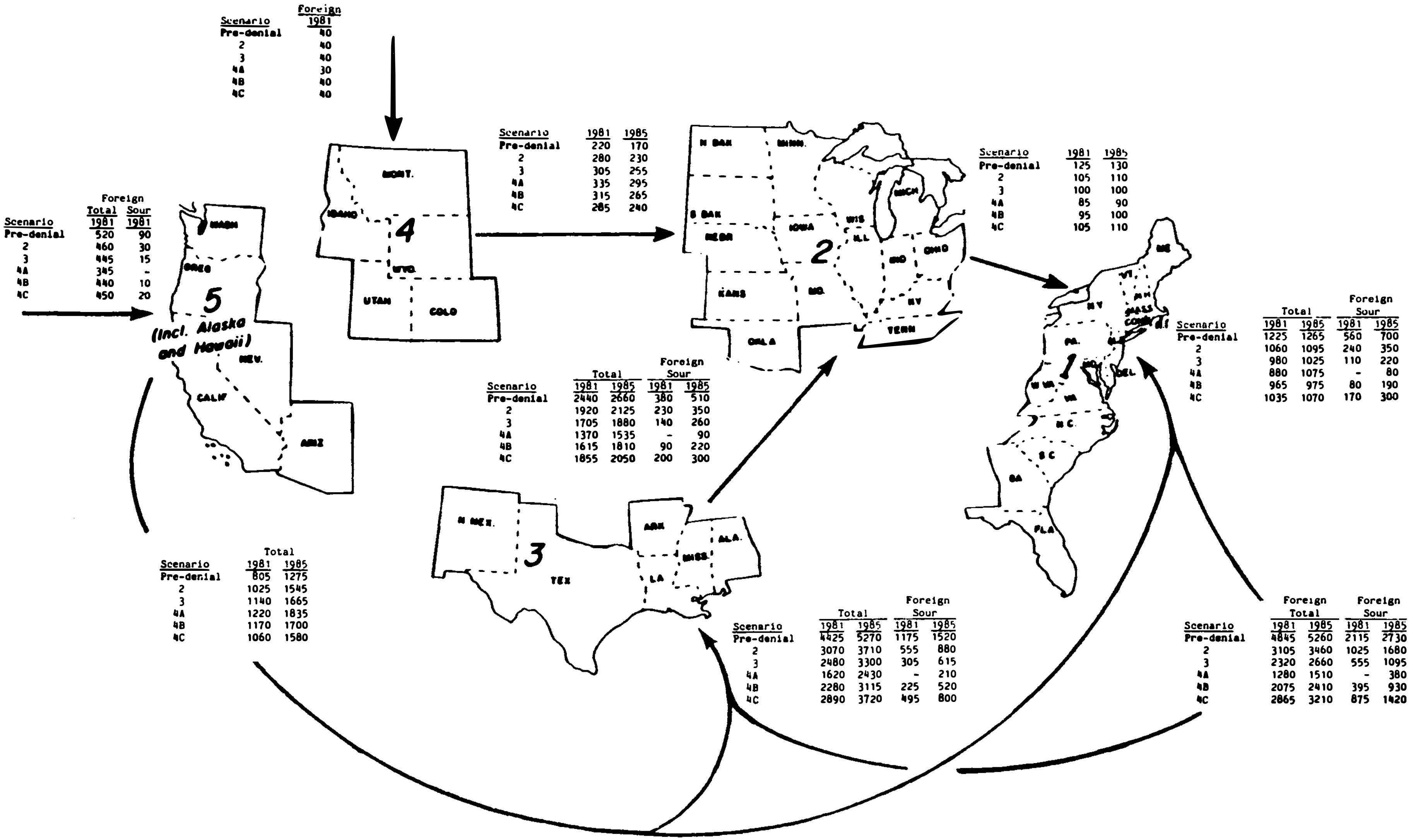
East Coast (PAD I East). The East Coast portion of PAD I receives all of its crude oil requirements by water. Crude oil requirements will be about 200 to 250 MB/D below the 1978 level with no supply disruption and significantly below the 1978 level in all the supply disruption cases. Therefore, it is anticipated that there will be no problems handling future crude oil requirements.

Crude oil from PAD V has been used as a supplement to East Coast foreign supplies where there is no supply disruption and as a replacement for foreign imports during periods of a supply disruption. PAD V movements to the East Coast range from 95 to 625 MB/D in 1981 and from 130 to 670 MB/D in 1985.

Summary of Crude Oil Movements. A summary of crude oil movements including foreign entry and inter-PAD district are shown in Figure 36. Pre-denial (no disruption) and Scenarios 2, 3, 4A, 4B, and 4C crude oil movement requirements for the years 1981 and 1985 are indicated, as well as the portions of these movements which are classified as sour crude oil. As can be noted in the increase in movements from PAD V to PADs I and III for all scenarios in 1981 and for all cases including the pre-denial case for 1985, the present crude oil logistics system will be unable to provide for the necessary redistribution of available crude oil supplies in the near future. The section of this chapter entitled "PAD V" provides further discussion on this subject.

Natural Gas Liquids and Unfinished Materials

Natural gas liquid production for 1981 taken from Chapter Two of this report is projected to be about 1,570 MB/D, which is approximately the same as for 1978. Movements between PAD districts are indicated to be the same. Therefore, it is concluded that the logistics systems handling these materials are adequate. By 1985, production is projected to decline to about 1,310 MB/D, which should reduce the load on the existing NGL systems. The distribution of NGL is indicated to be the same with or without a supply disruption.



Scenario	Foreign 1981
Pre-denial	40
2	40
3	40
4A	30
4B	40
4C	40

Scenario	Foreign Total 1981	Foreign Sour 1981
Pre-denial	520	90
2	460	30
3	445	15
4A	345	-
4B	440	10
4C	450	20

Scenario	1981	1985
Pre-denial	220	170
2	280	230
3	305	255
4A	335	295
4B	315	265
4C	285	240

Scenario	1981	1985
Pre-denial	125	130
2	105	110
3	100	100
4A	85	90
4B	95	100
4C	105	110

Scenario	Total 1981	Total 1985	Foreign Sour 1981	Foreign Sour 1985
Pre-denial	1225	1265	560	700
2	1060	1095	240	350
3	980	1025	110	220
4A	880	1075	-	80
4B	965	975	80	190
4C	1035	1070	170	300

Scenario	Total 1981	Total 1985	Foreign Sour 1981	Foreign Sour 1985
Pre-denial	2440	2660	380	510
2	1920	2125	230	350
3	1705	1880	140	260
4A	1370	1535	-	90
4B	1615	1810	90	220
4C	1855	2050	200	300

Scenario	Total 1981	Total 1985
Pre-denial	805	1275
2	1025	1545
3	1140	1665
4A	1220	1835
4B	1170	1700
4C	1060	1580

Scenario	Total 1981	Total 1985	Foreign Sour 1981	Foreign Sour 1985
Pre-denial	4425	5270	1175	1520
2	3070	3710	555	880
3	2480	3300	305	615
4A	1620	2430	-	210
4B	2280	3115	225	520
4C	2890	3720	495	800

Scenario	Foreign Total 1981	Foreign Total 1985	Foreign Sour 1981	Foreign Sour 1985
Pre-denial	4845	5260	2115	2730
2	3105	3460	1025	1680
3	2320	2660	555	1095
4A	1280	1510	-	380
4B	2075	2410	395	930
4C	2865	3210	875	1420

Figure 36. NPC Emergency Preparedness Study—Major Crude Oil Movements; Scenarios 2, 3, 4 (MB/D).

Total movements of unfinished oil (oils requiring further processing) in the United States are relatively small in volume and have fluctuated widely in the past. The 1978 total movements between districts averaged about 70 MB/D, while in June 1980 they were about 135 MB/D. The DOE Energy Data Reports "Annual Petroleum Statements" indicate that a portion of these movements is made by water and none are made by pipeline. This suggests that the remaining portion is made by rail tank car and tank truck. During periods of supply disruptions, it is anticipated that the same modes of transportation as are currently used would be available.

Strategic Petroleum Reserve Crude Oil Logistics

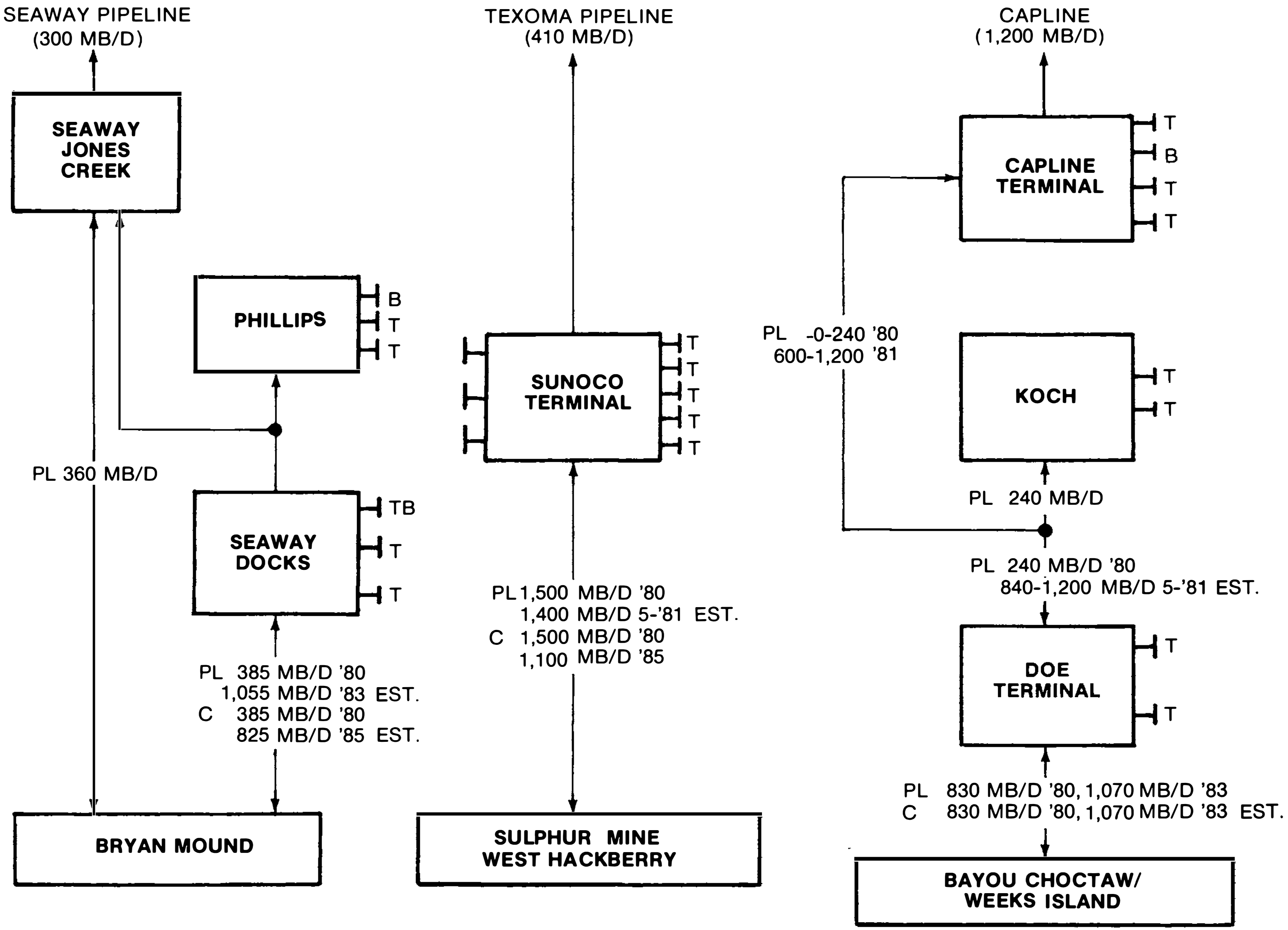
This section is an assessment of the capability of the U.S. logistics system to receive and distribute crude oil from the SPR assuming that current plans proceed as scheduled and that withdrawals are made at the maximum rates possible.

There are five SPR storage sites, all located in PAD III. Crude oil withdrawn from these five sites would enter the U.S. crude oil logistics system at three points, at which there are connections to major crude oil pipelines, Capline, Texoma, and Seaway. Figure 37 shows these three SPR delivery systems and the maximum rates at which crude oil could be delivered from SPR storage.

Capline System

Bayou Choctaw and Weeks Island are connected to the Capline system. Currently, crude oil from these storage sites can be delivered to the DOE's St. James Terminal at the rate of 830 MB/D. By 1983, this rate is expected to increase to 1,070 MB/D with an increase in the drawdown rate at Bayou Choctaw. Currently, the DOE's St. James Terminal can only deliver or receive from the Koch Terminal at the rate of 240 MB/D. By May 1981, a pipeline connection will be made to Capline with a maximum capacity of 1,200 MB/D. The delivery rate to Koch will remain unchanged. Koch has two tanker berths which can be used to move crude oil from the SPR, but deliveries would be limited by pipeline capacity of 240 MB/D. The connection to Capline will permit the movement of SPR crude oil out by pipeline. The amount of capacity available for SPR crude oil in Capline will depend upon other movements in the system.

Table 53 is an estimate of the amount of SPR crude oil that can be delivered out of the Capline system during a supply disruption in 1981 and 1985. Scenarios 2 and 4A have been shown only because they represent the extremes of the scenarios evaluated. The withdrawal rates shown are the maximum from Figure 37. These maximum withdrawal rates are compared with the capability of the connected transportation facilities to move SPR crude oil out of the area. The tanker docks at DOE's terminal are estimated to provide 415 MB/D of capacity to move out SPR crude oil. This movement is based on the use of 70 MDWT tankers limited to a draft of 39 feet, a turnaround time of 36 hours for each tanker reflecting congestion and transit of the Mississippi River, and a maximum dock occupancy



LEGEND

PL = PIPELINE CAPACITY
C = MAXIMUM CAVERN WITHDRAWAL RATE
CURRENT AND ESTIMATED PHASE II 1985
T = TANKER DOCK
B = BARGE DOCK

Figure 37. SPR Delivery Schematic.

TABLE 53

SPR Deliverability -- Capline System (Bayou Choctaw/Weeks Island)
(MB/D)

	1981		1985	
	Scenario		Scenario	
	2	4A	2	4A
Maximum Withdrawal Rate	830	830	1,070	1,070
Transportion Facilities				
DOE Docks	415	415	415	415
Capline Pipline (1,200 MB/D)	330	695	305	605
Cumulative	745	1,110	715	1,020
Koch Docks	240	240	240	240
Cumulative	985	1,350	955	1,260
Other Required	--	--	115	--

of 70 percent. It has been assumed that Capline would continue to move foreign and domestic crude oil available after a supply disruption from PAD III East to the Midwest as discussed previously, and any spare capacity would be used to move SPR crude oil. The spare capacity in Capline varies between scenarios with the availability of foreign crude oil and the amount of PAD V crude oil to be moved. The 1985 Capline spare is lower than in 1981 because the Midwest demand for crude oil is higher in 1985 than in 1981. Capacity of the Koch Terminal is limited to 240 MB/D.

It appears that the maximum SPR withdrawal rate can be handled in 1981 with the facilities described. In 1985, a maximum of 115 MB/D of additional facilities would be required to handle the maximum SPR rate in Scenario 2. These other facilities could be the utilization of Capline docks, delivery of crude oil into pipelines connected to the Capline Terminal other than the Capline Pipeline, expansion of delivery capability to Koch, and trucks. Capline Pipeline is indicated to have been expanded to its maximum capability without looping (laying additional pipeline).

Texoma System

The Sulphur Mines and West Hackberry storage facilities are connected to the Texoma Pipeline through the Sunoco Terminal. SPR withdrawal rates are currently about 500 MB/D. DOE pipeline capacity from these storage sites will be increased to 1.4 MMB/D in May of 1981. However, the withdrawal rates from storage will not reach 1.4 MMB/D until 1988 upon completion of Phase II of the fill program. It is estimated that the maximum withdrawal rate will be 1,100 MB/D by 1985 if the program proceeds as planned. At the

Sunoco Terminal, five tanker and three barge berths could be used for the movement of SPR crude oil as well as the pipeline connection to Texoma.

The capability to move SPR crude oil in the Texoma system is summarized in Table 54. The capacity of the five Sunoco tanker docks of 1,075 MB/D was developed using the same assumptions as for the DOE docks on the Capline system except that a limiting draft of 40 feet was used. The capacity of the barge docks is estimated at 170 MB/D assuming two 20-thousand-barrel barges could be loaded simultaneously, a turnaround time of 12 hours, and a maximum dock occupancy of 70 percent. Utilization of tanker dock capacity for movement of other than SPR crude oil has been estimated to be the sum of the capacity of the Texoma Pipeline (410 MB/D) plus 200 MB/D of additional crude oil, for a total of 610 MB/D. During a supply disruption, this throughput is reduced in relation to the reduction of foreign crude oil delivered into PAD III. For the barge docks, it has been assumed that only 50 percent of the capacity would be available for emergency purposes during a supply disruption. The capacity available in Texoma is based on the assumption that Texoma moves primarily foreign crude oil and that throughputs during a supply disruption would also be reduced directly with the delivery of foreign crude oil into PAD III. The difference between the capacity of Texoma (410 MB/D) and movements of foreign crude oil is the spare that could be used to move SPR crude oil.

TABLE 54

SPR Deliverability -- Texoma System (Sulphur Mines/West Hackberry)
(MB/D)

	1981		1985	
	Scenario		Scenario	
	2	4A	2	4A
Maximum Withdrawal Rate	500	500	1,100	1,100
Transportion Facilities				
Sunoco Docks Tanker	675	910	660	890
Barge	85	85	85	85
Cumulative	760	995	745	975
Texoma (410 MB/D)	140	295	130	285
Cumulative	900	1,290	875	1,260
Other Required	--	--	225	--

The capability of the Sunoco docks and Texoma Pipeline appears adequate during 1981 to move the SPR crude oil at the maximum withdrawal rates. In order to handle the maximum SPR rate in 1985, it is expected that other facilities would have to be utilized and that this requirement would be for a maximum of 225 MB/D of capacity. This additional capacity could come from pipelines, other than Texoma, which are tied into the Sunoco/Texoma systems. This area is a major pipeline interchange point and Beaumont/Port Arthur is a major refining center. Also, Texoma could be expanded to about 600 MB/D through the addition of pump horsepower.

Seaway System

Bryan Mound is the only storage facility connected to the Seaway system. The maximum withdrawal rate is currently about 385 MB/D. At the completion of Phase II of the DOE SPR program, the withdrawal rate is expected to be 1,055 MB/D by 1988, but by 1985, the maximum withdrawal rate is estimated to be only 835 MB/D. SPR crude oil withdrawn from storage can be moved over the Seaway docks or into the Seaway Pipeline.

Table 55 is a comparison of the maximum SPR withdrawal rates with the capacity available at the Seaway facilities. The capacity of the Seaway dock is estimated to be 540 MB/D assuming all three docks are used to load 50 MDWT tankers limited to a 38-foot draft, a turnaround time of 30 hours, and a maximum dock occupancy of 70 percent.

TABLE 55

SPR Deliverability -- Seaway System (Bryan Mound)
(MB/D)

	1981		1985	
	Scenario		Scenario	
	2	4A	2	4A
Maximum Withdrawal Rate	385	385	835	835
Transportion Facilities				
Seaway Docks	340	455	330	445
Seaway Pipeline (300 MB/D)	110	225	100	215
Total	450	680	430	660
Other Required	--	--	405	175

The capacity of Seaway Pipeline is assumed to remain constant at 30 MB/D. Utilization of this capacity for movement of other than SPR crude oil has been developed by the same method as used by Sunoco/Texoma. The resulting spare is assumed to be available for SPR movements.

Seaway facilities are adequate in 1981, but significant amounts of additional capacity are indicated to be required in 1985. SPR crude oil could probably be loaded over Phillips' docks by pumping to the Seaway docks and back up the lines to the Jones Creek tank farm. However, it may not be possible to load 50 MDWT tankers at this point. If 35 MDWT tankers are used, the maximum capacity available is estimated to be about 285 MB/D and this capacity would also have to be used for other than SPR movements. There is also the possibility that refineries in the area could be fed directly from the SPR, but this would require that supplies normally refined in this area be delivered to other areas. Another option for additional capacity is the expansion of the Seaway Pipeline to about 600 MB/D by the addition of pump horsepower.

As indicated in the discussion of each SPR delivery system, a number of simplifying assumptions have to be made. Therefore, the results can only be considered as an indication of how these systems might work with a supply disruption. These evaluations do have the advantage of focusing attention on the problems that can arise with the SPR delivery system. In all of the evaluations, it has been assumed that the largest tanker possible is used to make SPR deliveries. With a supply disruption, tankers could be freed up but they are likely to be in smaller size ranges, with any larger tankers being employed in the movement of PAD V crude oil. If smaller tankers (in the 35 to 40 MDWT range) are used to move crude oil away from the SPR delivery systems, the capacities of the tanker facilities would be lower than indicated in the analyses. Therefore, it may be necessary to utilize foreign flag vessels to maximize the capability of the SPR delivery facilities. This possibility supports the need for a standby mechanism which could permit use of foreign flag tankers in an emergency.

Also, it has been indicated that the capability exists to expand the Texoma and Seaway Pipelines to handle increased SPR movements. These expansions would require long lead times and substantial pre-investment. In order for these types of investments to be made, the current environment of uncertainty as to pipeline rates must be removed. Privately owned pipelines have been built in the past where and when needed. The climate for this same type of action in the future must be restored. Undoubtedly, any withdrawals from the SPR could be distributed to a large number of companies, and the volumes allocated to some could be extremely small. In order to maximize withdrawal rates from the SPR, maximum size tankers must be used. This would indicate that exchanges should not be restricted in any manner. Such exchanges could maximize SPR facility usage and provide flexibility in the remainder of the U.S. logistics system. The recent use of exchanges to move Elk Hills crude oil into SPR storage is an example of the manner in which the government can employ a mechanism which has been used in the petroleum industry for many years to reduce transportation costs and maximize the use of existing facilities.

It appears that additional investigation into the SPR delivery system should be made by DOE to ensure that there are no bottlenecks. Understandably, the emphasis has been on getting SPR facilities constructed and emergency crude oil reserves in place. In the event of a supply disruption, however, these reserves would be less than optimal if they cannot be retrieved and distributed where needed.

Product Logistics System

The capability of the U.S. petroleum industry's product logistics system to effectively respond to and handle the nation's product distribution needs after a major foreign supply interruption has been analyzed for the years 1981 and 1985. These studies were undertaken and completed in sufficient detail to describe the extent of changes in the use of distribution systems between PAD districts and to identify possible bottlenecks or other logistics problems that may arise as a result of changes in product flows. Logistic system capabilities described in the 1979 NPC study entitled Petroleum Storage and Transportation Capacities were used in these studies, with known changes identified in major systems only.

Logistics Background

The facilities currently available to transport, store, and distribute petroleum products are by definition adequate in 1980 to meet the nation's needs. Recent reductions in demand have, in fact, resulted in significant amounts of spare capacity in many commonly used and private industry product logistics facilities. In addition, a major Gulf-to-East Coast pipeline expansion that began in 1978 and will be completed by the end of 1980 has removed the one major product pipeline bottleneck between PAD III and PAD I that has existed since 1967. This expansion of almost 1.0 MMB/D origin capacity has permitted increased shipments to the East Coast of 350 MB/D, releasing product tankers for use in Alaskan North Slope crude oil service and transshipments of crude oil through the Panama Canal. However, Jones Act tanker availability will continue to be tight as additional Alaskan crude oil transshipments are required, scrappage of old tonnage occurs, and tanker capacity is lost due to implementation of the Port and Tanker Safety Act regulations on segregated ballast. The tight domestic tanker outlook will have limited impact on product logistics, as pipelines are now and will continue to be the dominant mode of product transportation in the future.

With the product logistics capability that exists today, only a major distortion of normal industry supply/demand patterns after a supply interruption would cause unmanageable problems in the distribution of products from refining source to marketing centers. The following analyses show that a uniform reduction in product supply after a severe supply interruption can be handled with the existing product logistics systems, and that additional spare capacity in the logistics systems caused by the supply reduction provides significant flexibility for reasonable departures from the logistics plan described.

Demand Reductions

Product demand forecasts for these logistics studies were provided in Chapter Two of this study. Reductions in forecast demands for 1981 and 1985, reflecting the loss of foreign supply ranging from 2.2 to 4.6 MMB/D, have been used in the development of logistics plans to identify major logistics problems, if any, and show the capability of product logistics systems to redistribute raw material and product supply in a conventional manner. Demand reductions corresponding to supply interruptions ranged from 13 to 28 percent of total 1981 and 1985 forecast demands. Product demand savings identified in demand management studies were used to offset 1.6 to 2.2 MMB/D of the supply losses. The additional reductions of up to 2.6 MMB/D, needed to provide total U.S. supply/demand balances, were assumed to be all gasoline in this study. Taking these additional reductions in all products rather than in gasoline only was shown to cause no significant changes in logistics system utilization. In addition, results from refining studies have shown that the product mix resulting from the demand reduction methodology used could be produced by refiners. These results show that, insofar as the logistic systems are concerned, there is a broad flexibility available to reduce existing product demand and change the remaining product demand mix as required to meet national objectives.

Demand reductions were taken regionally in direct proportion to the pre-denial demand forecasts by product and by PAD district. Tables L-11 and L-12 in Appendix L describe the resulting PAD district local demands by major product grade. This methodology resulted in total demand reductions exceeding the national average in districts where gasoline and heavy fuel oil demands are highest (PADs I and V) and below the national average in the other PAD districts. With uniform redistribution of refining in all districts, the above had the positive effect of reducing product shipments into PAD I and the negative effect of increasing crude oil shipments from PAD V relative to that resulting from a uniform percentage reduction in total volume by PAD district. The logistics system has the flexibility to handle either demand reduction approach.

Product Supply/Demand

Regional supply/demand balances by PAD district were completed for 1981 and 1985 before supply interruption and compared to similar balances based upon supply interruption Scenarios 2, 3, 4A, 4B, and 4C. Scenario 1 was excluded because of the relatively small impact on the logistics system. Included in these balances were total interdistrict shipments and receipts for each PAD district. These totals were then broken down into shipments and receipts between individual PAD districts based upon historical patterns. Minor shipments between PAD districts were reduced in direct proportion to the demand reduction in the receiving district. The major shipments were then calculated to establish the overall receipt/delivery balance across the nation. Tables L-13 and L-14 in Appendix L show the product shipment breakdowns by PAD district. The changes observed in these interdistrict shipments after a supply interruption are described for each PAD district below.

PAD I. Shipments into PAD I originate primarily in PAD III, with less than 2 percent originating in PAD II. Shipments from PAD III are made through Colonial and Plantation Pipelines and by tankers or barges from Gulf Coast refineries. Tanker supply will be at near minimum levels in 1981, as pipeline space becomes available through expansion and East Coast demand declines. In 1981, spare PAD III-to-PAD I pipeline capacity will be available and tankers will be used only to areas inaccessible to pipeline or for products that cannot be shipped by pipeline; i.e., heavy fuel oil and specialty products. Figure 38 shows the effects of supply interruptions ranging from 2.2 to 4.6 MMB/D on PAD III-to-PAD I pipeline utilization.

Figure 38 describes total Gulf/East Coast shipment requirements by transportation mode and a comparison of 'pipeline capacity with maximum pipeline shipment requirements from PAD III to PAD I. Spare pipeline capacity described in the screened area ranges from 15 percent for a 2.2 MMB/D supply interruption (Scenario 2) to 25 percent for a 4.6 MB/D supply interruption (Scenario 4A). When spare capacity approaches the latter, product transit times may become a problem. During a 4.6 MMB/D supply interruption, Gulf-to-East Coast pipeline transit time is increased by 40 percent vs. the pre-denial operation. Taking a shipment reduction of this size instantaneously would create an immediate shortage of product at primary terminals and in the secondary distribution system. These

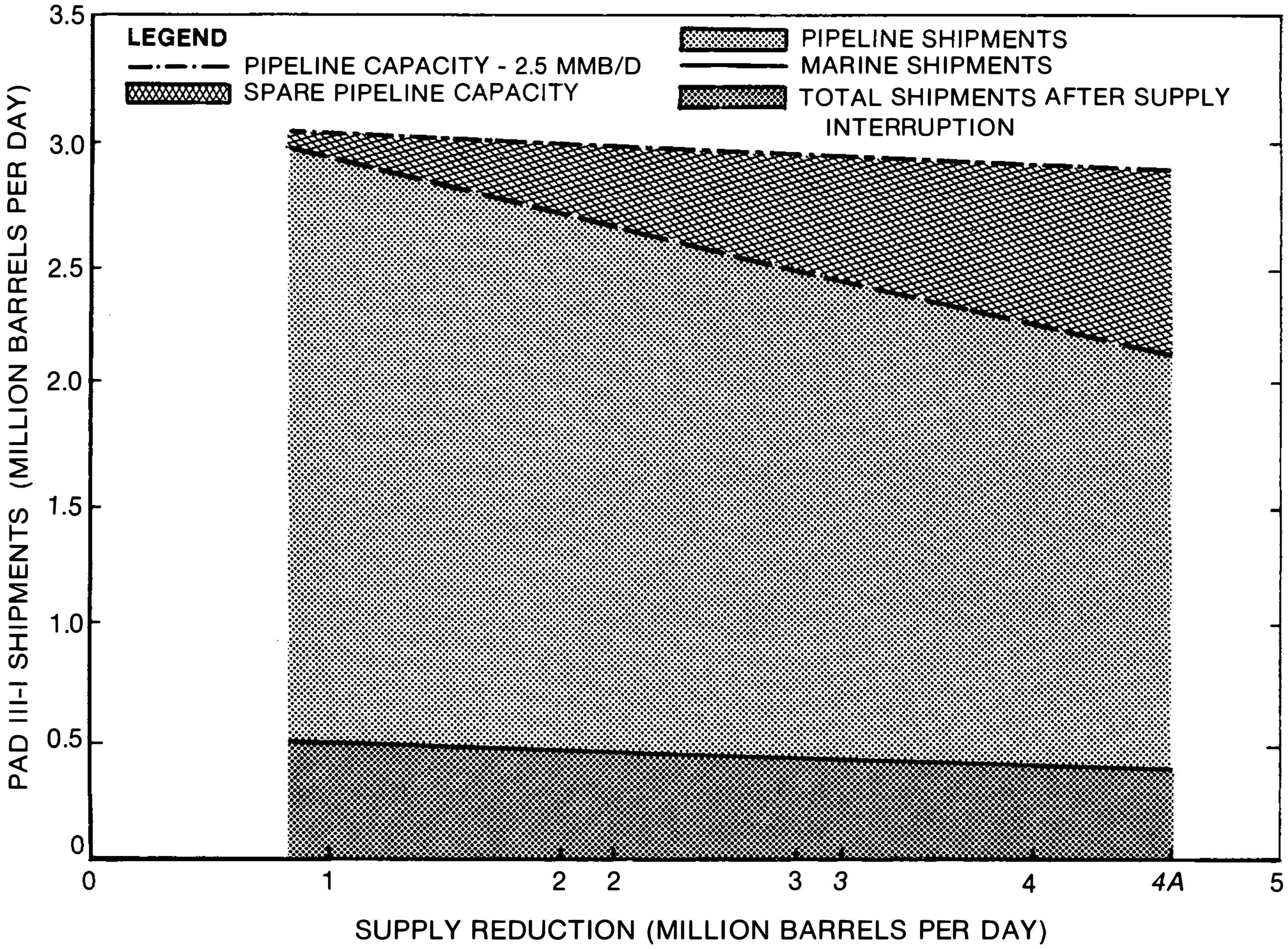


Figure 38. Product Shipments, PAD III to PAD I.

NOTE: Scenario numbers shown in italics.

conditions could be avoided if pipeline shipments were phased down gradually in all regions until all demand reduction steps are in place. Once steady-state operations are attained at the lower shipment level, the increased transit time should be manageable; however, if operating problems caused by increased transit times are encountered when making seasonal product changes, the capability exists in the Gulf-to-East Coast pipelines to shut down part of the system and restore pipeline velocities to historical rates.

PAD II. Products are shipped into PAD II by barge from the Gulf Coast and by pipelines from PADs I, III, and IV. Shipments through these logistics systems into PAD II are broken down historically as shown in Table 56.

TABLE 56

Shipments to PAD II

	% of Total Receipts			
	PAD I	PAD III	PAD IV	Total (%)
Barge	--	15	--	15
Pipelines				
Products	25	32	3	60
NGL	--	24	1	25
Total (%)	25	71	4	100

Total shipments into PAD II exceeded 1,000 MB/D in 1978; however, forecasts for 1981 and 1985 indicate reductions of 25 percent from 1978 shipment levels. Barge shipments are expected to bear a higher share of these reductions than pipelines.

A major supply interruption and corresponding demand reductions will increase the spare capacity in pipelines supplying PAD II by up to 40 percent of shipment levels before the emergency. Some of these pipelines could be forced to operate at less than 50 percent of capacity under these conditions. This shortage of throughput will result in excessive transit times and major scheduling difficulties in some pipelines between the Gulf Coast and upper Midwest. To avoid this problem, a number of possible solutions are indicated, the use of which would depend upon the circumstances at the time.

- Divert crude oil moving to the same destination from the Gulf into product pipelines going to the Midwest.
- Divert products from barges to pipeline through exchange arrangements.
- Combine parallel pipeline operations and shut down one system; balance supplies through exchange arrangements.

- Redistribute crude oil runs to bring pipeline throughput up to operable levels.

Any one of or a combination of these steps is physically possible and could be used to resolve this problem.

Shipments from PAD I into PAD II originate from both the East Coast and Gulf Coast. East Coast refineries deliver small volumes into western Ohio as a balancing mechanism. Both Colonial and Plantation Pipelines supply products into Tennessee and Kentucky from lateral lines originating in PAD I but carrying PAD III supplies. Reduced deliveries into these areas should create no logistics problems.

PADs III, IV, V. Products are supplied in these PAD districts primarily from local refineries and pipelines, with only small shipments between districts. Major efficiencies in the existing supply systems have historically been gained by broad use of product exchange arrangements, particularly in PAD IV and PAD V. Physical facilities for long distance distribution of products either within or between PAD districts are not as prevalent as in the Gulf/East Coast circuit.

Continuation of exchange arrangements as a primary method of product distribution in these districts is essential in a supply emergency. With such capability, no logistics problems should be encountered.

Product Mix Effects

To determine if the changed product mix caused by a major supply interruption would create problems in the logistics system, a detailed product-by-product supply/demand balance was developed for Scenario 3. Refinery make, shown in Table L-15 of Appendix L for 1981, was established by product in each PAD district initially in direct proportion to actual 1978 operations, then adjusted by an equal percentage in each PAD district to match the reduced demand level. Product imports and exports were adjusted to the reduced levels and distributed in a historical pattern based upon 1978 actual results. Interdistrict shipments by product were then calculated to provide the overall supply/demand balance. Details of these supply/demand balances are shown for each PAD district and the total United States in Tables L-16 through L-21 of Appendix L.

These individual product balances revealed no product distribution problems resulting from product mix. Gasoline and heavy fuel oil yields on crude oil were reduced significantly and distillate yields increased. Shipments in logistics systems were also more heavily weighted towards distillate; however, the increased gravity of the shipments should create no problems with the large amount of spare capacity available. Production and redistribution of heavy fuel oil supplies at the extremely low demand levels imposed after a supply interruption may cause problems that did not show up in this analysis.

Conclusions

These logistics analyses have shown that a supply interruption and corresponding demand reduction of any magnitude will in general reduce utilization of product logistics facilities, assuming that reductions in refining and demands occur relatively uniformly across the entire nation.

Potential problems with low utilization of pipeline capacity may occur in some areas causing unusually long transit times from supply source to destination. A number of possible steps to reduce transit time have been identified, all of which are physically possible but which may require government actions in the form of exceptions to transportation regulations or legislative changes to implement.

Inventory and Storage

Storage

Volume II ("Inventory and Storage") of the 1979 NPC study entitled Petroleum Storage and Transportation Capacities indicated that about 1,500 million barrels of storage capacity exists for crude oil and the major petroleum products in the U.S. primary system. Inventory in the primary system has averaged over 50 percent of storage capacity for the past 30 years. Based on these findings, it was concluded that there is no significant storage capacity available for handling emergency supplies.

It was estimated that the secondary and tertiary storage capacity for gasoline and distillate is over 500 million barrels. Although not much is known about the secondary and tertiary systems, it is reasonable to assume that the ratio of inventory to storage capacity should be similar to that for the primary system. The same competitive pressures to keep costs low would apply particularly at the secondary level and may also apply at the tertiary level. This would suggest that there would be no significant capacity available in secondary and tertiary storage for emergency supplies. This same type of reasoning can be extended to storage capacity available in U.S. possessions and territories and transshipment facilities in foreign countries adjacent to the United States which are estimated to have storage capacities of 45 and 50 million barrels, respectively.

The Strategic Petroleum Reserve currently has storage capacity of about 250 million barrels and is projected to reach about 400 million barrels by 1985. At the current time, there are about 110 million barrels of crude oil in storage. The availability of crude oil has been one of the major problems faced by this project. This would indicate that even if crude oil storage capacity were available in the U.S. primary system and in areas outside of the United States, the availability of crude oil could also be a major problem in utilizing this capacity for emergency storage.

The decision to store crude oil rather than products in the SPR was based on quality and flexibility considerations. Deterioration, weathering, and possible contamination could be a problem with product storage. Storage of crude oil would provide a full slate of products when refined and avoid the necessity of deciding the quantities of each type, grade, and specification of product for storage. In view of the different demand reduction steps available and the uncertainty of the duration of a supply disruption, it would appear that crude oil storage is still preferable to product storage.

Inventories

The 1979 NPC storage and transportation capacities study provides a complete analysis of inventories in the primary storage system as well as limitations on their use. The study also identified other sources of inventory which included the SPR, crude oil and product inventories located in U.S. possessions and territories, transshipment facilities in foreign countries adjacent to the United States, foreign crude oil and product in transit to the United States by tanker, and Alaskan North Slope crude oil in transit by tanker to refineries in PADs I-IV.

The following is a brief discussion concerning each of these inventories as a source of supply during a disruption. The SPR inventories are not a normal part of the U.S. logistics system and are discussed in detail in Chapter Three of this study. It is anticipated that inventories in U.S. possessions and territories will be required for continued operation in these areas. The transshipment terminals are not committed exclusively to the U.S. market. With a reduction in crude oil demand in the United States and completion of LOOP near, some portion of this capacity may be underutilized. However, as production in Mexico increases, some of this spare capacity could be used to transship crude oil from Mexico to other parts of the world. Sailing time from the Persian Gulf area is 30 to 35 days which represents 30 to 35 days of supply in tankers that would be available in the case of a supply disruption in this area. These supplies could provide a buffer during the 30 to 60 days required to implement emergency preparedness plans.

It was pointed out in the 1979 NPC study that responses to the questionnaires on storage and inventories indicated that an operator's inventory control is a function of many factors, including the level and location of demand, location of supply, availability of transportation and refining facilities, availability and location of tankage, and the cost of capital. With these factors varying from operator to operator, it would be difficult to establish an inventory control system to be used during supply disruption periods which would be universally applicable to all operators in every situation that might arise. Each operator is in the best position to control his inventory situation. This has been effective in the past and should also apply in the future. Any effort to control inventory could further add to the confusion of an emergency.

Proposed Logistics Plans

Based on the above analyses, it is recommended that the government consider initiating action in a number of areas, follow some primary concepts in developing plans to ensure continued efficient operation of the U.S. logistics system, and be prepared to adjust quickly in the event of a supply disruption.

With the indication of a potential near-term problem in PAD V, this situation should be closely monitored. A survey of Alaska and California crude oil reserve holders could be made to obtain an updated perspective on future PAD V production. Priority should be placed on completing governmental action that would facilitate prompt use of U.S.-subsidized and foreign flag tankers should the need arise. Negotiations with Canada could be initiated if this step appears necessary for the continuation of the current exchange mechanisms. In the case of a supply disruption, consideration could be given to delivery of foreign crude oil on the east or west coasts of Canada for Canadian crude oil delivered into the northern tier states. Currently, there are no exchanges of West Coast crude oils with contiguous countries. A regulatory mechanism should be considered which would facilitate such exchanges without delay so that they would be in place when needed. An investigation should be made of ways to encourage investment in west-to-east pipeline systems. Further investigation is required in order to ensure that withdrawals can be made from the SPR at maximum rates. This involves the operation of individual segments of the U.S. logistics systems. Restrictions should not be placed on the exchange of crude oil and products between companies because this would also reduce the flexibility of the logistics systems. Such exchanges may be required in the redistribution of crude oil and products during a supply disruption and may be necessary to ensure maximum withdrawal rates from the SPR.

Government, of course, should monitor inventories. But control of inventories is best left to the individual decisions of the thousands of individual operators. Action to pre-determine levels of inventory is not recommended. Such action could seriously reduce the flexibility of the logistics system.

Chapter Eight

INTERNATIONAL CONSIDERATIONS

INTRODUCTION

The preceding chapters of this study discussed in considerable detail possible policies and plans for the U.S. government to apply in a major interruption of petroleum imports. The United States also has international commitments as a signatory of the Agreement on an International Energy Program (IEP) and a member of the International Energy Agency. The IEA's emergency allocation system would involve the United States in a system in which the 21 member countries would share available oil supplies. In the event of an IEA general oil shortage, U.S. companies might be required to divert supplies to other countries more dependent on imports than the United States; in the event the United States experienced a disproportionately severe supply disruption, others would provide supplies to the United States.

This part of the study focuses on the coordination of U.S. plans with the IEP. Its purpose is to examine the interactions, to discuss the relationship of U.S. plans to its IEA commitments, and to comment on the IEA system in practice. For the reader unfamiliar with the IEA, a description of the emergency system and a glossary of terms and abbreviations used in this report are provided in Appendix M.

It is not the purpose of this study to evaluate the current IEA system or the wisdom of U.S. participation in it. It does not assess the ability of other member nations to participate in the sharing system and, therefore, does not comment on how effectively the IEA system would function in an emergency.

SUMMARY

The following pages focus on two types of concerns: the U.S. government's preparations to meet its IEA obligations and certain improvements the U.S. government might suggest that the IEA consider undertaking. The recommendations for the U.S. government to consider are several, but three key steps are suggested which would apply to U.S. participation in the IEA before as well as during an emergency.

A forum is needed to inform reporting companies serving on IEA industry advisory groups of positions the United States will be taking on emergency preparedness issues that come before the IEA governments. It is suggested that if it is possible within the existing legal framework, these companies be consulted as positions are being developed. This would become particularly important if the IEA were to consider revisions to the IEP Agreement itself in light of past performance and experience. The broad question of advisory groups for overall U.S. emergency planning and for managing an emergency is addressed in Chapter Nine of this study. It is suggested here that IEA issues receive appropriate consideration if such a group is formed.

A separate but related step would be the designation of a government advisory panel to assist the President in determining whether an IEP emergency should be declared. Such a panel as discussed here relates to the workings of the IEA's trigger mechanisms and the Secretariat's "findings," and should have access to industry advice. This function could be filled by the government energy contingency planning entity discussed in Chapter Nine.

The third key step is coordinating U.S. representation on the various IEA bodies. The United States should consider being represented in the IEA by a single government agency. Multiple agency involvement with the IEA in Paris may result in an uncoordinated view of U.S. positions. Other interested agencies should, of course, continue to play appropriate roles within the U.S. government on IEA matters.

In addition to these overall concerns, several points are raised for the U.S. government to consider when formulating its emergency plans.

- Emergency standby measures in the United States should take into account potential international emergency oil allocation.
- Antitrust clearances are needed if the IEA emergency allocation measures are triggered and effective cooperation among companies is required.
- The government energy contingency planning entity discussed in Chapter Nine should make preparations to handle the administrative tasks involved in the international emergency program, including in particular monitoring company supply positions, evaluating IEA data and recommendations, and implementing emergency allocations as necessary.
- Experience during emergency tests has pointed to the need for personnel both in Paris and in the NESO to be familiar with the details of the IEA system. Attention to training, perhaps in conjunction with IEA tests, would be one step to consider.
- Information should be provided to the U.S. public on the IEA and its activities. Plans should be considered for a public information program during an emergency to explain cooperative international efforts under way.
- Nonreporting U.S. companies should also be informed of and be involved in IEA plans and activities.
- New legislation may be necessary to facilitate the export of Alaskan crude oil in an emergency should such exports be required to provide logistical efficiency. Similarly, new regulations would be required for the export of other indigenous crudes in a timely fashion.

The United States should develop its demand restraint program and encourage other members in developing their programs. The United States should encourage the IEA to address the means of pricing internationally mandated sales on a commercial basis in its emergency procedures, as price is frequently mentioned as an unresolved problem in the IEA system.

Two procedural revisions to the IEA are suggested to reflect recent experience. There should be some consideration given to establishing an estimate of "current demand" or "normal supply" for use in determining the true effects of an interruption in oil imports. This would reduce both the distortion of the base period concept in a period of declining demand and the effect of actual seasonal demand vs. an annual base. It would also return the trigger threshold closer to the level envisaged when the IEA was formed.

Recognizing the desirability of keeping informed on international supply problems that may be encountered below the formal activation threshold, a rapid response consultation procedure should be encouraged as a means of addressing lower level disruptions, replacing undefined or ad hoc procedures. This may involve international consultations as needed to understand developments and identify problems. If, as a result of these consultations, national governments propose new measures, they should be well defined and the principles on which such measures are based should be spelled out and agreed to in advance. It should be recognized, however, that provision of a flexible informal system of consulting and communicating among participating governments will be an effective role for the IEA in most lower level supply interruption situations. This view is based on past experiences with rigid, formalized allocation systems that cannot easily keep up with changes in the marketplace, especially one that is as vast and complex as the international petroleum market.

U.S. INTERFACE WITH THE IEA IN AN EMERGENCY

The declaration of an emergency would involve the United States in a highly complex international emergency sharing program. Membership in the IEA involves a significant commitment on the part of all members in that the sharing program has serious impact on their domestic energy policies and emergency plans. All participating countries must be able to meet these commitments in order for the allocation program to work. While it is beyond the scope of this study to evaluate the policies and programs of each member, it is important to do so in the case of the United States.

Legislation and Decision-Making Authority

In order to participate in the sharing system, member governments need the enabling authority for the necessary domestic actions and standby emergency programs. The United States has provided the former under the Energy Policy and Conservation Act of 1975. The President has the authority to declare an emergency and to take the steps necessary to meet U.S. obligations to the IEP. This Presidential declaration is also required before any U.S.-based companies can participate in the sharing program without risk of antitrust violations. Even though the IEA may decide to trigger international emergency sharing, the President must make a comparable finding in order to activate U.S. participation.

Thus, a Presidential decision is the key to U.S. participation in the IEA sharing program. To this end, the U.S. government should have in place an advisory panel consisting of high level government employees with access to the information necessary to evaluate the situation. This panel should also have access as needed to advice from industry experts knowledgeable in the workings of industry. This function could be filled by the government energy contingency planning entity discussed in Chapter Nine.

The case of a selective shortfall in the United States may be more complex. The U.S. government must decide whether to seek IEA assistance when the United States is experiencing a selective shortfall. Scenario 1A is an example. The assumed shortfall equal to 10 percent of exports from OAPEC and Iran would be directed at the United States alone. This U.S. shortfall of 2 MMB/D would be sufficient to activate the IEA allocation system through a selective trigger. In that case, the United States would be assumed to have reduced demand by 7 percent, depending on the details of the allocation calculation some of the remainder of the shortage would be supplied proportionately by other IEA members. In the NPC scenario, however, it has been assumed that the IEA system would not be activated. Such a decision -- whether to seek IEA assistance or not -- would be a serious one for a government panel to consider.

Most importantly, the U.S. government should re-examine its decision-making authority when it comes to issues raised within the various IEA bodies. Several parts of the Executive Branch have been involved in U.S. relationships with the IEA, including the DOE, the State Department, the Justice Department, and the Federal Trade Commission. While the decision-making process no doubt functions best with some variety of input, the representation in Paris should be well defined and limited. As an example, over a dozen people were involved in speaking for the United States during the recent emergency test.

Since each agency speaks from its own viewpoint, the United States has not taken a consistent posture in the IEA. This is in sharp contrast to some other countries which present a coordinated government policy and, in some cases, have developed this posture in consultation with their oil industry. This is the case in routine deliberations of the IEA as much as in an emergency. Too often an observer would be left with the impression that legal issues and antitrust enforcement were the primary concerns of the United States in the IEA, to the neglect of energy policy and emergency management.

The United States represents a large part of the IEA in terms of the volumes involved and the size and numbers of companies. Its best people should be involved with the IEA in Paris both to protect its interests and to oversee U.S. cooperation with the IEA. Given the large role the United States plays, such a commitment is also necessary to the efficient operation of the entire allocation system.

Administration of the Emergency: The NESO

Each IEA member must designate a National Emergency Sharing Organization (NESO) to oversee its participation in the emergency program. This is a vital part of the IEA system since each NESO plays such a key role both domestically and internationally. In the United States, the Department of Energy would serve as the NESO. In an emergency, the DOE would be the point of contact with the IEA Emergency Management Organization; it would submit data to the IEA and receive data back on the supply position of each country, and it would oversee fulfillment of the IEA obligations communicated to it.

Demand Restraint

Perhaps the first step the DOE must take is to implement emergency measures to achieve a significant reduction in demand -- 7 or 10 percent of consumption, or more if the Emergency Reserve Drawdown Obligation (ERDO) requirement is to be met in part by demand restraint. As discussed in an earlier chapter, there are a variety of measures that can be considered. Since the U.S. supply right will be determined assuming demand restraint of this order, failure to meet these targets would result in unsatisfied demand and the consequent market pressures.

Allocation

A more complex task for the NESO involves the allocation of supplies where coordination between international obligations and domestic allocation is involved. Two aspects of allocation are important -- meeting the IEA allocation right or obligation and the interaction with any emergency standby distribution program in the United States.

With respect to the international aspects of this problem, the IEA emergency tests and the DOE in its preparations have tended to focus on U.S. allocation obligations. However, the United States must also be capable of working additional supplies into its domestic plans. At the extreme, the DOE has the authority to mandate allocation steps which are needed to balance international allocation rights and obligations but which have not been achieved through voluntary measures. Such steps would be identified by the Industry Supply Advisory Board, recommended by the Allocation Coordinator, and approved by the Standing Group on Emergency Questions and the Governing Board.

A second major function of the DOE relates to the role of the reporting companies. The allocation system will function best if the necessary reallocations can be achieved as much as possible on a voluntary basis. Realistically it might be assumed that during the process of cycling data through the appropriate channels, the DOE might approach companies informally. However, in doing so the DOE should be sensitive to the conflicting demands being placed on international companies by their domestic customers, by other IEA members, and by non-IEA countries. And the DOE should be aware that each company's supply picture will change. The monthly reports can only provide a snapshot of a constantly evolving supply situation. The DOE should monitor offers to remain on top of the situation and to be able to evaluate suggested steps.

It is particularly important that the DOE be able to evaluate the reallocation recommendations from the IEA in light of the domestic situation. The IEA receives detailed information on international flows but does not follow domestic supply patterns or distribution programs. Therefore, its recommendation may not be the most efficient in terms of the domestic situation.

A particular point of coordination involves what the IEA terms "fair sharing" of domestically available supplies, whether imported or locally produced, among companies, and in the case of the United States, among regions. A company diverting a U.S.-destined cargo should be reasonably confident that it and its customers will not thereby suffer a disproportionate disadvantage in its U.S. markets. Emergency standby measures should be available in the United States if needed to distribute available supplies, particularly if international companies are to be encouraged to make voluntary international reallocations. In addition, geographic adjustments may be necessary. If, for example, imports to the East Coast are severely reduced, other domestic supplies may have to be shifted to these areas.

To ensure maximum flexibility to meet the international allocation obligations, exemptions should be provided in an emergency to allow the export of indigenous crude oils to provide logistical efficiency. In some cases it may prove most efficient, both from an international and a domestic standpoint, to meet a U.S. obligation using Alaskan crude oil, for example, rather than international supplies destined for the East Coast. Such a step might also simplify the task of balancing supplies among regions in the United States since otherwise the Alaskan crude oil might have to be transported to the East Coast to replace international supplies and equalize the regional impact of the shortage. (This also serves to emphasize the point that the DOE must be able to evaluate IEA recommendations and company offers in terms of efficiency in the U.S. market.)

It should be noted that while the IEA will calculate the U.S. share of IEA imports monthly, the patterns of deliveries from month to month will deviate from the target levels. Thus, some degree of flexibility must be built into both the domestic and international aspects of emergency allocation. The IEA has built such flexibility into its program in that it is not expected that members can balance allocation rights and obligations month by month but rather cumulatively over time. The DOE must be able to audit the U.S. position with respect to supply rights and obligations as they develop over time and to identify the most efficient course of action to satisfy such obligations.

Other Responsibilities

The NESO in each country would be responsible for relating to NESOs in other countries as necessary. In particular, the DOE must establish a close working relationship with its counterpart in Canada because of the extensive links between the logistics systems of these two countries. Exchanges or other cooperative steps may become desirable to facilitate meeting IEA allocation obligations. The level of government-controlled stocks and the regulations governing them would be an integral part of the DOE or NESO function. This is discussed further in the next section.

A selective trigger could cause particular problems which the DOE must be able to address. A selective trigger implemented for a country or group of countries may call upon the United States to divert some supplies to those countries. It can be assumed that these diversions would not be sufficient to activate the U.S. emergency measures. Yet some oil demand reduction or inventory draw may be required to absorb the shortfall. In this case a full domestic oil sharing program would not be justified.

The above points list the major functions expected from the DOE in terms of IEA obligations. A key element that is less tangible but no less important is the ease and speed of communications between the NESO, the IEA, and the companies. These relationships are apt to prove vital to facilitating voluntary reallocation and hence the smooth functioning of the entire IEA system. This can only emphasize the importance of assigning high quality and well trained personnel in the DOE to interact with the IEA in Paris and with the companies in the United States.

Emergency Reserve Drawdown Obligation

Each country's ERDO -- the difference between permissible consumption and the supply right -- can be met by drawing emergency reserves or by any other means the member may choose. The U.S. emergency authorities must have plans for meeting this portion of the shortfall by drawing inventories, demand restraint beyond the 7 or 10 percent requirement, fuel substitution, or additional domestic production. Current emergency reserve levels are not adequate to meet a U.S. ERDO except in a very limited disruption scenario.

The IEA requires that member countries hold emergency reserves equal to 90 days of the previous year's imports (but not below 1979 levels). For this purpose, the IEA counts total stocks (except naphtha and bunker fuel) less 10 percent for "unavailable oil." (The IEA is currently considering the question of whether to add naphtha to the definition of emergency reserves.) Minimum operating stocks and other commercial inventories are included in this

IEP definition of emergency reserves. Thus, while in theory nearly all countries currently meet the 90-day target, their ability to draw on these emergency reserves varies greatly.

In the United States, the emergency reserve requirement is about 790 million barrels (based on 1979 imports averaging 7.9 MMB/D). While U.S. inventory levels on October 1, 1980, were twice that at 1.4 to 1.5 billion barrels, the 790 million barrel requirement is below estimated minimum operating levels (stocks required to operate the distribution system without significant disruptions), currently about 900 to 1,000 million barrels. Thus, for the United States or for any country with substantial indigenous production, the IEA reserve requirement does not increase supply protection beyond the level routinely expected to be available. The commercial stocks held by industry above the minimum operating level may provide some protection in an emergency but the size of these inventories does vary. While they currently provide inventory protection above what might normally be expected, there is no assurance this will be the case when the supplies are needed.

Data Systems

The IEA emergency procedures include specific report formats and timing to be used by "reporting companies" and "participating governments." These reports focus on international supply data but do include domestic supplies. These data allow the IEA to calculate "allocation rights" and "obligations." To minimize confusion and duplication of effort, the data on international supplies required by the U.S. government in an emergency should, to the extent possible, be consistent with the IEA requirements in timing, content, and definition of terms. The potential for confusion is great if two sets of similar but not identical data need to be handled.

The different conventions for reporting units -- volume vs. weight -- present a problem in particular for the United States where volume measures (barrels) are used, while Europe, Japan, and the IEA use measures of weight (tons). The DOE should coordinate closely with the IEA Secretariat and the reporting companies to ensure that the IEA is familiar with the appropriate conversion conventions for U.S. data in order to minimize conflicting data series. And the IEA Secretariat for its part should state the conversions it has applied in each report it issues.

Problems of definition may be more of a concern. For example, stock data required by the DOE relate to crude oil and product within U.S. borders. The IEA requests company reports which include oil in transshipment terminals destined for IEA countries. Thus, if a company complied with both regulations it would report one volume to the DOE -- excluding, for example, Caribbean transshipment facilities -- and a second, larger volume to the IEA. A similar example arises in the definition of indigenous production where the DOE asks companies to include lease purchases and the IEA does not. While country totals for indigenous production should be identical, the IEA definitions would suggest it would be looking at a somewhat different company profile. The DOE must at minimum be aware of these problems or, preferably, work with one consistent set of data.

To illustrate the potential importance of data consistency and accuracy among all IEA countries, a problem arose in the recent test of the emergency system. According to the U.S. government, the case concerned data from other member countries which were not consistent with U.S. reports. This discrepancy amounted to a difference of 40 to 850 MB/D in U.S. supplies. This example serves to emphasize the point that the United States should strive for consistency with IEA terms and procedures. It also suggests the need to work with the IEA to encourage such consistency on the part of other members.

U.S. Companies

A large number of the reporting companies in the IEA system are U.S.-based companies, including several large international companies. These companies must be prepared to cooperate with the IEA, and the U.S. government must facilitiate that cooperation. At the same time, these companies will be subject to a complex series of domestic regulations. The potential conflicts between the domestic and international commitments may represent serious problems. Some simple mechanism for companies to resolve these conflicts can facilitate the emergency management task of the regulatory authorities. One potential solution is to designate a company contact within the NESO who would be familiar with that company's position during the emergency and would maintain close communication with that company.

One major area where the companies would experience a problem involves the antitrust laws. The need is clear for the proper antitrust authorities to provide in-advance clearances or safeguards for the types of activities the oil companies can participate in, including the details of reporting and monitoring requirements. Some balance must be achieved between the need of the regulators to monitor company activities and the potential reporting burden. The documentation requirements should not impede a company's ability to cope with an emergency and cooperate with the IEA. Most importantly, until a plan of action as required by the Energy Policy and Conservation Act is provided detailing emergency activities, U.S. companies cannot participate in the IEA sharing system without risking charges of antitrust violations, not only by governments but also by allegedly injured private parties.

Some forum may be appropriate to allow regular consultations between the companies and the United States on key international issues the United States confronts in the IEA. The U.S. government has not developed formal procedures for consulting with U.S.-based companies on IEA activities. The DOE may have had informal discussions with individual companies prior to making a policy decision on an international issue before the IEA, but no regular procedure has been developed.

It is also desirable to have "nonreporting companies" integrally involved in the emergency system. The distinction between reporting and nonreporting companies involves submission of data directly to the IEA Secretariat. More broadly, the reporting companies have been involved in the development of the emergency system and, for the most part, are familiar with the IEA and its procedures. However, nonreporting companies in the United States are also significant to the U.S. market and should be involved in the international allocation system. Their understanding of the IEA system and how it affects them would facilitate their cooperation in an emergency.

Public Acceptance of IEA Obligations

The DOE and the U.S. government must be able to defend participation in the allocation system in the public arena. The government must be able to present its reasons for participation -- the balance of the advantages and disadvantages derived from cooperation with our allies in a crisis, the possibility of receiving additional supplies if the United States is affected disproportionately by a shortage, and the need to divert some U.S. imports if other members are more severely affected. If the government has not laid the groundwork in advance, it will be difficult during an emergency to explain why oil should be rerouted away from the United States. The current lack of public awareness of the IEA and its procedures will make this task more difficult.

Thus, as a first step, the U.S. government should consider doing more to inform the public now, particularly those who would be affected by the IEA (such as major consumers and state governments). It should also give some thought to a public information program during an emergency. For example, public understanding of demand restraint measures in other countries and the severity of the impact on consumers outside the United States could aid in the general acceptance of our IEA obligations. The IEA could help by informing all governments of measures being taken in each country as rapidly as possible. Member governments could use this information with their legislatures and the public to document the cooperative effort of other IEA members.

Note on the European Economic Community

It should be pointed out that France is not a member of the IEA but would participate in an EEC sharing system if it were activated. The EEC system parallels the IEA in some ways, including the trigger level, but also contains some major differences. In the event both the EEC and the IEA emergency systems were activated, any EEC supply reallocation to France would be kept separate from the IEA system; i.e., country data on anticipated supplies would not reflect any diversions to France. From a legal standpoint, it is important that France, or other non-IEA members, be kept out of the sharing system because U.S.-based companies are not afforded an antitrust defense for actions taken relative to nonmembers.

One important difference between the two systems is that the EEC sharing formulas take into account a country's ability to draw on non-oil sources of energy. This moves them closer to an "energy sharing" scheme than the IEA's oil sharing program.

THE IEA SYSTEM IN PRACTICE

The IEA emergency system has not been activated to date. However, the process of dialogue and consultations in creating and refining the IEA information systems and the emergency procedure has been beneficial in several ways.

Frequent communication among industrialized nations on energy policies serves an important function. For one, it can act as an incentive for governments' conservation efforts, and it is a mechanism for keeping international and national attention focused on the energy issue. To a certain extent, such communication and consultation has encouraged consumer/government cooperation in periods of market disruption (e.g., the 1978 Iranian revolution; the Iraq-Iran war; Swedish and Italian applications for a selective trigger). The experience with "competitive bilateralism" in earlier periods, such as 1973-1974, suggests that cooperation is the better approach.

Data collection and analysis have provided governments with better information, facilitating an increased understanding of the oil market. And consultations and exchanges with the industry have proven beneficial in keeping governments informed.

Finally, encouraging high reserves through the commitment to 90 days of import reserves may have helped some importing countries in adjusting to temporary supply disruptions.

The importance of consumer/government cooperation and data collection should not be underestimated. In the course of discussions in response to a potential emergency, understanding of the problem can be increased and ill advised steps avoided. However, several serious problem areas can be identified. The IEA is an outgrowth of the 1973 oil embargo and reflects the structure of the oil market and the experiences of governments at that time. There are several places where the influence of the 1973-1974 events can be seen.

- The trigger mechanism was designed for an environment in which oil demands and imports were growing. When demand is growing, a 7 percent reduction from historical levels reflects a real shortfall in excess of 7 percent; the expected demand reductions (7 or 10 percent vs. base period) represent significant responses to the supply emergency. However, when demand is falling, as it is at present, the significance of a 7 percent shortfall vs. historical demand is lessened.

- At the time of the Arab oil embargo, most crude oil traded internationally was under the control of large oil companies headquartered in IEA countries. It was assumed that a large portion of international reallocations would be managed by rebalancing within these large company systems and the rest would be handled by voluntary arrangements facilitated by the Industry Supply Advisory Group. Today this assumption may no longer be valid. Recent studies indicated that in 1973 over 92 percent of international crude oil was oil under the direct control of private companies. By 1979, this percentage was down to about 55 percent; direct sales by producing governments had increased fivefold. This puts more of the reallocation burden on smaller companies and governments, particularly those which are direct purchasers of crude oil and/or products from producing countries. While this may or may not alter the ability of the IEA to reallocate supplies, it is nevertheless true that the importance of these entities --nonreporting companies and governments -- must be recognized.

- An additional consequence of this changed market structure is that more companies, or different companies, are importing oil into the IEA countries. The percentage of IEA imports handled by reporting companies had been declining from the 75 percent coverage provided by the original list of companies. In response to this, the IEA recently increased the number of reporting companies to 45, which returned the coverage to about 75 percent.

- The assumption that the flexibility of company logistics systems would accomplish much of the task of apportioning oil equitably within the IEA is also being challenged by the increasing use of destination restrictions in producing government transactions. Such restrictions at the point of sale reduce the amount of crude oil that can be reallocated within the IEA. This suggests that indigenous crude oils may become important to the allocation system in exchanges for supplies where destinations for international crude oils are restricted.

These changes in world oil markets are clearly identifiable -- they can be documented and to some extent quantified. In addition, there are other potential weaknesses in the IEA emergency system. The scope of IEA activities is limited and problems outside its purview could impede its ability to deal effectively with a serious crisis. Commentators, member countries, and IEA personnel have speculated on possible shortcomings which could impede the effectiveness of the IEA in an emergency. Some of the frequently mentioned items include antitrust restrictions, actions of producers and consumers outside the IEA, and the extent of member countries' commitment to the IEA.

Antitrust regulations may impede the speed and effectiveness of the system. Regulations required by U.S. law have yet to be issued; their impact would depend on the nature of the requirements imposed. In addition, the authorities who administer the Treaty of Rome have not provided protection against suits by private parties.

The U.S. government and the IEA need to take the necessary steps to allow full cooperation by companies.

Producers might choose to redirect supplies themselves, as for example reducing or terminating contract commitments or imposing additional destination or resale restrictions. There are examples of this including designated sales and the restrictions imposed during the 1973 Arab boycott by some OPEC producers. However, there is little the IEA can do here beyond accommodating these shifts in its reporting system and allocation calculations. The use of indigenous crude oils might facilitate the balancing of rights and obligations in spite of the producer restrictions.

Countries outside the IEA would be affected by any general shortage. IEA countries represent 70 to 75 percent of 1980 world demand (excluding the Soviet Union, eastern Europe, and China). Many of the non-IEA nations have only limited ability to bid for premium priced supplies. However, even limited spot market activity on their part could have significant market effects in a severe shortfall. In addition, some of these countries may receive favored treatment from producers. For its part, the IEA showed its awareness of the interests of non-IEA countries by adopting the principle that IEA actions are not to be at the expense of non-IEA consumers. The extent to which cooperation between IEA and non-IEA consumers will materialize in a supply disruption is not clear.

Effective demand restraint measures are essential to the efficient functioning of the system. Orderly demand reductions would lessen price pressures on the domestic market, reduce the incentives for noncompliance, and alleviate the political pressures to somehow meet unfilled demand. Yet many members still do not have strong emergency programs. The IEA should continue to receive updates on countries' progress in this area and urge members to have emergency measures designed in advance of a shortfall.

Compliance with the emergency system is an international obligation which depends on the commitment of individual members. As the shortage increases, the rewards for "beating the system" are apt to increase. The IEA does not have the authority to enforce compliance and probably should not. Intergovernmental bodies such as the IEA work best without enforcement authority reflecting the political reality that they are only as strong as the commitment among members allows. Member governments could, however, do more to detail the measures they would take to mandate compliance by entities within their jurisdiction. IEA coordination of these national steps could be useful.

To its credit, the IEA has itself identified many of these problems or potential problems in the emergency area and has taken steps to correct them. It expanded the number of reporting companies; it has tested and monitored its data procedures which should facilitate its ability to work with this data in an emergency; it has made revisions to the emergency system procedures based on experience in tests of the system; it is looking into the way in which synthetic fuels should be treated in its system; and it is considering additional procedures to facilitate flows of indigenous crude oil in the system. Thus many of the technical problems are already being addressed by the IEA itself. A few outstanding issues do need closer attention: the price issue, cooperation in a non-emergency environment, and the trigger mechanism itself.

Price

The IEA has never fully resolved the question of pricing in its emergency system. However, price remains an unresolved issue and is frequently cited by critics as the reason the IEA may not work.

Voluntary reallocations, that is, offers and acceptances, carry with them a price. This pricing piece of the offers has never been tested. Antitrust concerns would make a practical test of the price mechanism difficult. However, IEA emergency procedures should be in clear accord with the principle set out in the IEP Agreement -- that prices for allocated oil should be based on those prices prevailing for comparable commercial transactions.

The issue of member government pricing policies is also a key to the functioning of the IEA system. Members' price regulations -- or the lack of them -- can provide incentives or disincentives for companies in a position to help meet a country's allocation right or obligation. A company's position in any domestic crude oil distribution program in the United States is such a factor. Not only does this reinforce the need for a carefully thought out interface between domestic and international programs, it also points out the role price can play. If the domestic price for a buyer of crude oil is more attractive, he may not wish to accept an offer of international crude oil. Or a seller in the U.S. program may find a price incentive to offer the crude oil to another IEA member rather than bringing it into the United States.

The problem of dampening price pressures while providing market incentives to allow voluntary reallocation and demand reduction to work has no obvious solution. Certainly the U.S. government needs to be aware of these linkages.

Non-Emergency Cooperation

In recent years the IEA has become concerned with the effect of market disruptions below the 7 percent threshold level. Unfortunately, the proposed responses do not reflect the same kind of thorough analysis and careful thinking that went into the emergency system. The established emergency system has explicitly defined its role as relating to shortfalls above the 7 percent level. Proposed plans for ad hoc intervention into supply disruption situations below the 7 percent level have tended to ignore the earlier precedent of carefully thinking out the bases for intervention and sharing. In addition, such plans seem to represent a serious divergence from two basic principles implicit in the IEP agreement: that market mechanisms and company rebalancing steps should be relied on for smaller disruptions and that a supply emergency requires immediate and severe demand restraint as a first step.

As an alternative, the IEA might find it useful to consider a formal rapid response consultation status to facilitate information flows and consultations among governments in an environment where an emergency trigger may become necessary or where a significant change in supply patterns signals a potential problem. To date, such environments have been handled on an ad hoc basis. Instead, the IEA could, given an early sign of a potential crisis, implement its emergency reporting systems, dissuade countries from unusual reliance on the spot market, encourage early attention to demand restraint plans, convene monthly or bimonthly Governing Board meetings, hold frequent consultations with industry, and generally intensify its efforts to keep abreast of the oil market. The information and understanding gained from these measures should enhance the decision-making ability of national governments. It would also allow careful consideration of the trigger decision in advance and hopefully better prepare members for implementation if it became necessary. Such status would not differ significantly from the activities today to keep abreast of the situation arising from the Iraq-Iran war. However, regularizing such procedures could better facilitate rapid intergovernmental communication to avoid the confused crisis atmosphere that has at times been seen.

There are potential dangers in implementing sharing procedures below the trigger threshold. Some of these dangers have already been discussed in the IEA. In general, ad hoc measures are not as well planned as existing procedures. Frequently the details of implementation are not spelled out and lead to new problems. For example, in past supply problems which are certainly within the IEA's purview, the issue on occasion has been turned into one of the availability of supplies at a favorable price for a member country rather than the availability of commercially priced supplies. This can be a legitimate foreign policy or foreign aid concern of governments, but it should not be the subject of IEA sharing procedures.

The Trigger

One significant potential shortcoming is the danger that the emergency system may be triggered when the situation does not warrant such a cumbersome measure. While there have been pressures to activate the system at such points in the past, consultations among member governments in the IEA context have served as an effective restraint and undue haste has been avoided. In these cases, the market mechanism and actions of individual companies were sufficient to allow a roughly equitable redistribution of supplies among countries. It would seem that the IEA's established allocation procedures were designed for and would be needed most in a major disruption or boycott. To refocus these procedures on preparing only for such major crises, an adjustment of the trigger threshold may prove sufficient. This could be done in several ways.

- Elimination of the Base Period Final Consumption (BPFC) in favor of an estimate of current or forecast demand as the basis for calculating the size of the shortfall is one solution. In a period of declining demand, BPFC exaggerates the size of the shortfall as a percentage of demand or normal supplies. Each member's national statistics could be drawn on to maintain an estimate of current demand for use in an emergency.

- The voting procedures for declaring a shortfall at the 7 to 11 percent level could be redefined. Requiring a smaller number of votes to overturn a positive finding by the Secretariat would make it more difficult to activate the system at these lower shortfall levels. It is at these levels that members are more apt to disagree as to the seriousness of the shortfall or the ability of the market to sort things out. As a practical matter, such disagreement would reduce the incentive to cooperate and should be avoided if possible. The voting procedure for the 12 percent trigger could remain unchanged recognizing that disagreement at this level is apt to be less of a problem.

- The trigger level could be increased above 7 percent to avoid declaring an emergency unless the shortage is very severe. Declining demand where BPFC overstates needed supplies makes the 7 percent threshold lower in today's environment than envisaged when the IEP agreement was signed.

These alternatives would require a revision to the IEP agreement which established the IEA. The IEA agreement as a whole should be reexamined with this in mind. The problem of obtaining agreement by all IEA member governments to new procedures could be significant, however.

Note on International Obligation to Non-IEA Countries in an Emergency

The preceding discussion has focused on the mechanics of IEA interactions. The U.S. government is well aware of the full scope of its other international obligations and it is not the role of the NPC to advise on these matters. It need only be mentioned that in an emergency the requirements of non-IEA allies may become a matter of U.S. foreign policy concern and could affect domestic plans and the IEA system. While the IEA allocation system assumes supplies will not be diverted from non-IEA countries, many IEA nations are apt to be subject to pressures for assistance in meeting supply needs. This has not been built into IEA procedures but will need to be part of domestic decisions. In particular, the United States will have defense commitments to NATO in a military crisis and may have specific commitments to other countries as well. It is assumed that these considerations will be built into U.S. strategic plans.

Chapter Nine

EMERGENCY INDUSTRY/GOVERNMENT OPERATIONS

INTRODUCTION

The petroleum allocation and price controls used during the two supply interruptions in the 1970's and the organization for administering the operations of the controls have been the subjects of numerous post-appraisals.

Many economic researchers now contend that these price and allocation controls were fundamentally flawed in concept, and their operations fostered costly inefficiencies that far outweighed their transitory benefits. Over time, administration of the controls became institutionalized in a tangle of regulations that were often contradictory and long outlived their usefulness. These observers conclude that normal market competition should be the dominant theme of future measures to cope with supply disruptions. They contend that the market offers a proven, nonbureaucratic mechanism for rapidly and efficiently equating oil demand with a suddenly reduced oil supply. Others hold the view that varying degrees of government intervention in the operations of the marketplace are required in time of a supply emergency.

While this report recommends that the competitive market system be relied on to provide the primary response to an oil import disruption, it recognizes that individual consumers and petroleum refiners and marketers will very likely be affected disproportionately in a severe disruption. Political pressures on the government to take some operational role in dealing with the crisis will be intense. For planning policy responses to an extremely severe disruption, there is probably no realistic choice between complete market freedom and some degree of market intervention. Broadly, the choice appears to lie between temporary, limited market intervention only to the extent necessary to deal with critical political and equity considerations or essentially complete control of the petroleum industry through the imposition of a comprehensive fabric of price and distribution controls which are likely to lead to constraints on individual end users as well. The measures outlined in this study focus on the first of these two choices.

It is not the purpose of this portion of the study to define or recommend what policy responses are appropriate to the various potential interruptions of oil imports under consideration. Instead, it offers an overview of the kind of cooperative industry/government/public efforts that can provide constructive input to the process of contingency planning before an emergency occurs and effective management of the supply crisis itself. In this context, it is useful to briefly review the history of emergency energy management in the United States over the past 40 years. The intent here is to provide perspective, not to describe a model to be copied in the future. A more complete discussion of the past programs for energy emergency management is provided in Appendix N. The energy emergency preparedness problems confronting the nation in the 1980's and 1990's are vastly different from those which were faced in the 1940's and 1950's, and even different from those of the 1960's and 1970's.

PREVIOUS ENERGY EMERGENCY ORGANIZATIONS

The most recent organizational structure and regulations to deal with an emergency supply disruption date back to the Arab oil embargo of 1973-1974. This regulatory system was assembled in the crisis atmosphere of the embargo and built on top of a system of price controls that had been in place for more than two years prior to the emergency. This complex system of controls has been staffed and run entirely by government employees. It has never made provision in its structure to use personnel and expertise from private industry, even in a very severe emergency.

The fundamental structure of this regulatory system changed little after the embargo of 1973-1974. The system was used again to deal with the Iranian crisis in 1979 with generally unsatisfactory results.

Prior to the Arab oil embargo, the United States had responded to two wartime oil emergencies, one during World War II and the other during the Korean War. Both of these efforts made extensive use of industry personnel and expertise in dealing with the crisis. In World War II, the Petroleum Administration for War included industry personnel in its ranks, as well as relying heavily on industry committees for advice, coordination, and implementation. During the Korean War, the Petroleum Administration for Defense drew the majority of its staff from industry, but with little duplication in the form of industry committees.

The principal objectives of PAW and PAD were to increase domestic oil production and to deliver petroleum to the war effort while meeting essential civilian petroleum needs. In addition, PAW and PAD were heavily involved in the allocation of controlled materials (steel, etc.) to the petroleum industry. Both PAW and PAD were organized on a functional basis and were staffed with experts for each function. Price controls and rationing were administered by separate agencies.

The threat of a direct nuclear attack on the United States and its disruption of the oil system led in 1963 to the development of an organization to deal with this type of an oil crisis. The organization, called the Emergency Petroleum and Gas Administration, is similar to PAW and especially to PAD in its purpose, role, and organization. It relies heavily on regional headquarters as it is designed to deal with the possibility of a nuclear attack wherein the national headquarters office may not be functional. Most EPGA personnel are executive reservists, drawn from the specialist ranks of industry, who would serve only during an emergency. Additional personnel are drawn from other government organizations, the petroleum industry, and other private sector groups.

The EPGA has never been used to deal with an actual emergency, but there have been several practice sessions to test its effectiveness. An extensive roster of personnel to staff each of the designated positions was kept until 1976 but has not been updated since then. Appendix N provides a brief history of the various organizations that deal with energy emergencies starting from World War II, including organization charts for each one.

None of these organizations appears suitable for the type of major energy supply interruption visualized in this study. Assembled in a wartime emergency, PAW and PAD were primarily concerned with maximizing output from the existing refining and distribution system in a situation in which domestic crude oil supplies were adequate and the United States was a major oil exporter. The focus was on providing additional facilities to produce and distribute the oil product needs for expanded civilian and defense purposes, both in this country and abroad. In the case of the EPGA, emphasis was also to be placed on operating and rebuilding a war-damaged energy system. In contrast, the potential crisis envisioned in this NPC study involves a standby system for coping with a suddenly reduced supply of oil imports, but where the domestic refinery and distribution system presents few, if any, physical limitations. For example, in such a future crisis, the primary concern would be minimizing damage to the civilian economy rather than mobilizing manpower and material to increase manufacturing and logistic capability. It is also more difficult for petroleum industry personnel to become directly involved with the government than was the case 20 years ago because of restraints imposed by conflict of interest, financial disclosure, and antitrust laws. An analysis of the restraints imposed by the conflict of interest and financial disclosure laws, as well as the DOE Organization Act, is contained in Appendix O.

GOVERNMENT ORGANIZATION FOR ENERGY EMERGENCIES

A government entity charged with planning as well as coordinating and administering implementation of overall response to a major interruption in petroleum imports is essential to the effectiveness of emergency preparedness plans. While this agency could logically fit into the current DOE, the NPC recognizes that different government reporting relationships for such an energy emergency agency are possible. Obviously, it should not become locked into a structure that is inappropriate to its mission. For the purposes of the present discussion, it is assumed that this agency would operate directly under the Secretary of Energy. The energy emergency agency should be given overall responsibility for:

- Pre-emergency planning

- Assisting the Secretary of Energy and the President in assessing threatened or actual disruptions of petroleum imports into the United States

- Developing appropriate response options to deal with an ongoing emergency and assisting the President and/or the Secretary of Energy in selecting options for implementation and termination

- Providing the basic organizational framework for coordinating emergency measures during the time they are operational

- Developing plans to educate the public well in advance of an emergency and to provide effective public communications during the emergency.

It is not visualized that this agency would require a large, full-time staff. Its ongoing activities would entail its emergency planning function and its monitoring and assessment function. Maintaining a large standby operations staff is not consistent with the policy thrust emphasized in this study which involves relatively simple, temporary interventions in the marketplace to mitigate major problems. The agency should, however, receive adequate resources and have access to senior Administration officials.

The importance of the government's role in providing effective communications to the public during an emergency should not be underestimated. The flexible approach recommended in this study for dealing with supply disruptions relies heavily on market mechanisms and voluntary responses. In order for this approach to be effective, public confidence and cooperation are crucial. The early stage of an actual or threatened crisis when the situation and outlook may be least clear is a particularly important period when actions which could exacerbate the problem, such as panic buying by consumers and unwarranted restraint by suppliers in drawing down inventories, should be avoided. Energy suppliers and consumers should be provided with timely information so that their actions can be based on the best available assessment of the situation. Petroleum industry advice could be very helpful to the government in making these early assessments of potential disruptions.

PRIVATE SECTOR ADVISORY ROLE

As noted in an earlier section, the petroleum price and allocation system that evolved in the 1970's operated without any formal mechanism for directly utilizing petroleum industry technical expertise. Many have since thought that this emphasis on maintaining a distance discreet enough to doubly satisfy the most suspicious observer was counterproductive. It led to bad decisions that were based not on malice but on simple misunderstanding of a complex industry. These problems are now widely recognized. However, it is also now recognized that both legal constraints and public attitudes have evolved over the past two decades to demand scrupulous regard for the public interest/private interest interface.

As a suitable vehicle for providing private sector input to the government energy emergency agency, this study recommends that a federal advisory committee of representatives from the private sector be formed to provide continuing advice and assistance to the Secretary of Energy on questions of energy emergency preparedness both prior to and during an emergency. This federal advisory committee should be formed as soon as practical. The Secretary of Energy would choose the members of such a private sector advisory committee primarily to provide him direct access to the experience, expertise, and counsel of energy industry executives, but a wide spectrum of other constituencies such as consumers, labor, research, public interest, and academic organizations should also be represented.

In assisting the Secretary of Energy, the advisory committee which this study proposes could provide a variety of useful inputs. At the pre-emergency planning stage, it would be a logical source of comprehensive understanding of the workings of the petroleum industry, both in this country and overseas. During the difficult period when a potential disruption in the normal flow of petroleum exports and imports is developing, its counsel would provide a useful mechanism in assessing the often conflicting and fragmentary data that emerge. In this regard, it would supplement but not replace the various other situation assessments available to the government and would not involve an exchange of proprietary information. During a supply emergency, it could provide evaluations and technical guidance on the policy responses available to the Secretary and the President and on the operational implementation of the policies chosen. It could also provide industry information and counsel that the Secretary may desire in fulfilling U.S. commitments to the IEA. Its role would not include actually recommending government policies or response options for implementation. However, the committee could provide rapid and valuable feedback on the effectiveness of the response options selected.

The meetings and agenda of the advisory committee would be at the discretion of the Secretary and would be made public unless the Secretary deemed it necessary to close them for national security or other reasons cited in the Federal Advisory Committee Act. The committee might have a small administrative staff but no permanent technical staff.

In instances in which the Secretary of Energy requests specialized technical guidance from the advisory committee, the committee could (with the Secretary's concurrence) set up temporary, professional subcommittees to assist the advisory committee in responding to the Secretary. Subcommittee membership would be determined by the advisory committee and would be open to individuals from the private sector with special technical competence, appropriate government personnel, and any members of the advisory committee who wished to participate. The role of the subcommittees would be strictly limited to providing specific technical advice and performing studies for the main advisory committee, such as alternative schemes for wheeling electric power or routing emergency natural gas supplies, etc. The subcommittee would report their recommendations to the advisory committee; it would not be the prerogative of any subcommittee to make recommendations directly to the Secretary of Energy or other government officials. While the advisory committee would be free to modify the assignments given to technical subcommittees, it is not intended that the subcommittees become permanent groups.

It does not appear that the private sector activity recommended herein would require changes in the antitrust laws. However, such activities should be carried out pursuant to guidelines provided by antitrust counsel.

APPENDICES

APPENDIX A

Request Letter and Description of the National Petroleum Council

THE SECRETARY OF ENERGY
WASHINGTON, D.C. 20585

June 3, 1980

Mr. C. H. Murphy, Jr.
Chairman
National Petroleum Council
1625 K Street, N.W.
Washington, D.C. 20006

Dear Mr. Murphy:

The Nation continues to depend on imported crude oil and petroleum products to satisfy its energy needs. Associated with this dependence is the high risk to the Nation's well-being and security in the event that these imported energy supplies are interrupted. Thus, we must strive to improve our national emergency preparedness program.

The Council has provided the Federal Government in the past with many outstanding studies that have contributed significantly to the Nation's readiness for an energy emergency. My attention has been directed recently to the Council's reports titled, Emergency Preparedness for Interruption of Petroleum Imports into the United States, September 1974, and Petroleum Storage for National Security, August 1975. These studies furnished necessary information for the 1970's. To prepare for the 1980's a similar effort is required.

Accordingly, I request the National Petroleum Council to undertake a new study addressing issues bearing on emergency preparedness planning. Three areas of particular concern are: 1) the ability of the Nation's supply and distribution system to operate under constrained conditions; 2) the regulatory and statutory climate needed to minimize damage to the Nation; and 3) the organization and method of operation of the industry - government relationship under emergency conditions.

For purposes of this study, I designate Barton R. House, Deputy Administrator, Operations and Emergency Management, Economic Regulatory Administration, to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

John C. Sawhill
Deputy Secretary

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- Petroleum Resources Under the Ocean Floor (1969, 1971)
  Law of the Sea (1973)
  Ocean Petroleum Resources (1974, 1975)

- Environmental Conservation -- The Oil and Gas Industries (1971, 1972)

- U.S. Energy Outlook (1971, 1972)

- Emergency Preparedness for Interruption of Petroleum Imports into the United States (1973, 1974)

- Petroleum Storage for National Security (1975)

- Potential for Energy Conservation in the United States: 1974-1978 (1974)
  Potential for Energy Conservation in the United States: 1979-1985 (1975)

- Enhanced Oil Recovery (1976)

- Materials and Manpower Requirements (1979)
- Petroleum Storage & Transportation Capacities (1979)
- Refinery Flexibility (1980)
- Unconventional Gas Sources (1980).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

NATIONAL PETROLEUM COUNCIL
MEMBERSHIP

1981

ABERNATHY, Jack H.
Vice Chairman
Entex, Inc.

ALLEN, Jack M., President
Alpar Resources, Inc.

ANDERSON, Robert O.
Chairman of the Board
Atlantic Richfield Company

BAILEY, R. E.
Chairman and
Chief Executive Officer
Conoco Inc.

BASS, Sid R., President
Bass Brothers Enterprises, Inc.

BAUER, R. F.
Chairman of the Board
Global Marine Inc.

BELFER, Robert A., President
Belco Petroleum Corporation

BOOKOUT, John F.
President and
Chief Executive Officer
Shell Oil Company

BOWEN, W. J.
Chairman of the Board
and President
Transco Companies Inc.

BRUMLEY, I. Jon
President and
Chief Executive Officer
Southland Royalty Company

BUFKIN, I. David
Chairman and
Chief Executive Officer
Texas Eastern Corporation

BURTIS, Theodore A.
Chairman, President and
Chief Executive Officer
Sun Company, Inc.

CALAWAY, James C., President
Southwest Minerals, Inc.

CARL, William E., President
Carl Oil and Gas, Inc.

CARVER, John A., Jr.
Director of the Natural
Resources Program
College of Law
University of Denver

CHAMBERS, C. Fred, President
C & K Petroleum, Inc.

CHANDLER, Collis P., Jr.
President
Chandler & Associates, Inc.

CHENAULT, James E., Jr.
President
Lone Star Steel

CLARK, E. H., Jr.
Chairman of the Board
President and
Chief Executive Officer
Baker International

COX, Edwin L.
Oil and Gas Producer
Dallas, Texas

DORN, David F., President
Forest Oil Corporation

DURST, Roy T.
Consulting Engineer
Fort Worth, Texas

EMISON, James W., President
Western Petroleum Company

EVANS, James H., Chairman
Union Pacific Corporation

FAHERTY, John E., President
Crown Oil and Chemical Company

FITZSIMMONS, Frank E.
General President
International Brotherhood
of Teamsters

FOSTER, John S., Jr.
Vice President
Science and Technology
TRW Inc.

GALLAND, R. I.
Chairman of the Board
American Petrofina, Incorporated

GARVIN, C. C., Jr.
Chairman of the Board
Exxon Corporation

GARY, James F.
Chairman and
Chief Executive Officer
Pacific Resources, Inc.

GARY, Joe F., President
Sooner Petroleum Company

GERTZ, Melvin H., President
Guam Oil & Refining Company, Inc.

GLANVILLE, James W.
General Partner
Lazard Freres & Company

GONZALEZ, Richard J.
Energy Economics Consultant
Houston, Texas

GOSS, Robert F., President
Oil, Chemical and Atomic Workers
International Union

GOTTWALD, F. D., Jr.
Chief Executive Officer,
Chairman of the Board and
Chairman of Executive Committee
Ethyl Corporation

GRAHAM, David B.
Deputy General Counsel
Velsicol Chemical Corporation

HAMILTON, Frederic C., President
Hamilton Brothers Oil Company

HAMMER, Armand
Chairman of the Board and
Chief Executive Officer
Occidental Petroleum Corporation

HAMON, Jake L.
Oil and Gas Producer
Dallas, Texas

HARBIN, John P.
Chairman of the Board and
Chief Executive Officer
Halliburton Company

HARTLEY, Fred L.
Chairman and President
Union Oil Company of California

HAUN, John D.
Immediate Past President
American Association
of Petroleum Geologists

HAYES, Denis
Executive Director
Solar Energy Research Institute

HAYNES, H. J.
Chairman of the Board
Standard Oil Company
of California

HEFNER, Robert A. III
Managing Partner
The GHK Company

HERRING, Robert R.
Chairman of the Board and
Chief Executive Officer
Houston Natural Gas Corporation

HESS, Leon
Chairman of the Board and
Chief Executive Officer
Amerada Hess Corporation

HINERFELD, Ruth J., President
League of Women Voters
of the United States

HOOPMAN, H. D.
President and
Chief Executive Officer
Marathon Oil Company

HUDSON, Mary, President
Hudson Oil Company

HUTCHISON, William L.
Chairman of the Board and
Chief Executive Officer
Texas Oil and Gas Corporation

JACOBY, Professor Henry D.
Director, Center for Energy
Policy Research
Massachusetts Institute
of Technology
Sloan School of Management

JONES, A. V., Jr.
Partner
Jones Company

KANEB, John A., President
Northeast Petroleum
Industries, Inc.

KETELSEN, James L.
Chairman and
Chief Executive Officer
Tenneco Inc.

KIMBALL, Thomas L.
Executive Vice President
National Wildlife Federation

KLINKEFUS, John T., President
Berwell Energy, Inc.

KOCH, Charles G.
Chairman and
Chief Executive Officer
Koch Industries, Inc.

LICHTBLAU, John H.
Executive Director
Petroleum Industry
Research Foundation, Inc.

LIEDTKE, J. Hugh
Chairman of the Board
Chief Executive Officer
Pennzoil Company

McAFEE, Jerry
Chairman of the Board
Gulf Oil Corporation

MacAVOY, Paul W.
The Milton Steinbach Professor of
Organization and Management
and Economics
The Yale School of Organization
and Management
Yale University

MacDONALD, Peter, Chairman
Council of Energy Resource Tribes

McGEE, D. A., Chairman
Kerr-McGee Corporation

McKINLEY, John K.
Chairman of the Board
Texaco Inc.

McMILLIAN, John G.
Chairman and
Chief Executive Officer
Northwest Alaskan
Pipeline Company

McWILLIAMS, W. K., Jr.
President
W. K. M. Investments, Inc.

MAGUIRE, Cary M., President
Maguire Oil Company

MARSH, C. E., II
President
Mallard Oil & Gas Company

MARTIN, W. F.
Chairman of the Board
Phillips Petroleum Company

MASSELLI, David C.
Antaeus: Resources Consulting

MAYER, F. R.
Chairman of the Board
Exeter Company

MEDDERS, Thomas B., Jr.
Partner
Medders Oil Company

MOFFETT, James R.
Chairman and President
McMoRan Exploration Company

MONTGOMERY, Jeff
Chairman of the Board
Kirby Exploration Company

MORAN, R. J.
Chairman and
Chief Executive Officer
Moran Energy Inc.

MOSBACHER, Robert
Oil and Gas Producer
Houston, Texas

MURPHY, C. H., Jr.
Chairman of the Board
Murphy Oil Corporation

MURRELL, John H.
Chief Executive Officer
DeGolyer and MacNaughton

NORDLICHT, Ira S., Esquire
Holtzmann, Wise & Shepard

O'SHIELDS, R. L.
Chairman and
Chief Executive Officer
Panhandle Eastern
Pipe Line Company

PETERSEN, Sidney R.
Chairman of the Board and
Chief Executive Officer
Getty Oil Company

PETTY, Travis H.
Chairman of the Board
The El Paso Company

PHILLIPS, John G.
Chairman of the Board and
Chief Executive Officer
The Louisiana Land
& Exploration Company

PICKENS, T. Boone, Jr.
President and
Chairman of the Board
Mesa Petroleum Company

PITTS, L. Frank, Owner
Pitts Oil Company

POOLER, Rosemary S.
Chairwoman and
Executive Director
New York State
Consumer Protection Board

RICE, Donald B., President
Rand Corporation

ROBERTSON, Corbin J.
Chairman of the Board
Quintana Petroleum Corporation

ROSAPEPE, James C., President
Rosapepe, Powers & Associates

ROSENBERG, Henry A., Jr.
Chairman of the Board and
Chief Executive Officer
Crown Central Petroleum
Corporation

RUSSO, Ned C.
Consultant of Public Relations
PRC Services, Inc.

SELLERS, Robert V.
Chairman of the Board
Cities Service Company

SNYDER, Theodore, Jr.
Immediate Past President
Sierra Club

SWEARINGEN, John E.
Chairman of the Board
Standard Oil Company (Indiana)

THOMAS, Robert E.
Chairman of the Board
MAPCO Inc.

TRIMBLE, George E.
Chairman of the Board and
Chief Executive Officer
Aminoil U.S.A., Inc.

TRUE, H. A., Jr.
Partner
True Oil Company

WARD, Martin, President
United Association of Journeymen
and Apprentices of the
Plumbing and Pipe Fitting
Industry of the United States
and Canada

WARNER, Rawleigh, Jr.
Chairman of the Board
Mobil Corporation

WARREN, John F.
Independent Oil Operator/Producer
Austin, Texas

WARREN, J. N.
Chairman of the Board
Goldrus Drilling Co.

WHITEHOUSE, Alton W., Jr.
Chairman of the Board and
Chief Executive Officer
The Standard Oil Company (Ohio)

WILLIAMS, Joseph H.
Chairman of the Board and
Chief Executive Officer
The Williams Companies

WRIGHT, M. A.
President and
Chairman of the Board
Cameron Iron Works, Inc.

YANCEY, Robert E., President
Ashland Oil, Inc.

ZEPPA, Keating V., President
Delta Drilling Company

APPENDIX B

Committee Rosters

NATIONAL PETROLEUM COUNCIL

COMMITTEE ON EMERGENCY PREPAREDNESS

CHAIRMAN

C. C. Garvin, Jr.
Chairman of the Board
Exxon Corporation

GOVERNMENT COCHAIRMAN*

John C. Sawhill
Deputy Secretary
U.S. Department of Energy

EX OFFICIO

C. H. Murphy, Jr.
Chairman
National Petroleum Council

EX OFFICIO

H. J. Haynes
Vice Chairman
National Petroleum Council

SECRETARY

Marshall W. Nichols
Executive Director
National Petroleum Council

* * *

W. J. Bowen
Chairman of the Board
and President
Transco Companies Inc.

Edwin L. Cox
Oil and Gas Producer
Dallas, Texas

Dr. John S. Foster, Jr.
Vice President
Science and Technology
TRW Inc.

James F. Gary
Chairman and
Chief Executive Officer
Pacific Resources, Inc.

Robert F. Goss, President
Oil, Chemical and Atomic Workers
International Union

Leon Hess
Chairman of the Board and
Chief Executive Officer
Amerada Hess Corporation

Ruth J. Hinerfeld, President
League of Women Voters
of the United States

Mary Hudson, President
Hudson Oil Company

William L. Hutchison
Chairman of the Board and
Chief Executive Officer
Texas Oil and Gas Corporation

Professor Henry D. Jacoby
Director, Center for Energy
Policy Research
Massachusetts Institute
of Technology
Sloan School of Management

John A. Kaneb, President
Northeast Petroleum
Industries, Inc.

---

*Served until leaving DOE to become Chairman of the Synthetic Fuels Corporation in October 1980. Barton R. House represented DOE thereafter.

EMERGENCY PREPAREDNESS

Charles G. Koch
Chairman and
Chief Executive Officer
Koch Industries, Inc.

John H. Lichtblau
Executive Director
Petroleum Industry
Research Foundation, Inc.

Cary M. Maguire, President
Maguire Oil Company

W. F. Martin
Chairman of the Board
Phillips Petroleum Company

Thomas B. Medders, Jr.
Partner
Medders Oil Company

Jeff Montgomery
Chairman of the Board
Kirby Exploration Company

Ira S. Nordlicht, Esquire
Holtzmann, Wise & Shepard

R. L. O'Shields
Chairman and
Chief Executive Officer
Panhandle Eastern
Pipe Line Company

Sidney R. Petersen
Chairman of the Board and
Chief Executive Officer
Getty Oil Company

T. Boone Pickens, Jr.
President and
Chairman of the Board
Mesa Petroleum Company

Donald B. Rice, President
Rand Corporation

James C. Rosapepe, President
Rosapepe, Powers & Associates

Robert V. Sellers
Chairman of the Board
Cities Service Company

John E. Swearingen
Chairman of the Board
Standard Oil Company (Indiana)

John F. Warren
Independent Oil Operator/Producer
Austin, Texas

Joseph H. Williams
Chairman of the Board and
Chief Executive Officer
The Williams Companies

NATIONAL PETROLEUM COUNCIL

COORDINATING SUBCOMMITTEE OF THE COMMITTEE ON EMERGENCY PREPAREDNESS

CHAIRMAN

Edward T. DiCorcia
Vice President
Supply Department
Exxon Company, U.S.A.

GOVERNMENT COCHAIRMAN

Barton R. House
Deputy Administrator
Operations and Emergency Management
Economic Regulatory Administration
U.S. Department of Energy

ASSISTANT TO THE CHAIRMAN

Donald L. Corl
Senior Staff Planning Advisor
Corporate Planning Department
Exxon Company, U.S.A.

SECRETARY

John H. Guy, IV
Deputy Executive Director
National Petroleum Council

* * *

John C. Boehm
Senior Vice President
Transcontinental Gas Pipeline

H. Kent Bowden
Vice President
Logistics and Downstream Planning
Conoco Inc.

John G. Buckley
Vice President
Northeast Petroleum Industries, Inc.

Warren E. Burch
Senior Vice President
Resources and Strategy
Sun Petroleum Products Company

William P. Bush, President
Marathon Pipe Line Company
Marathon Oil Company

Dr. Frank Collins, Consultant
Oil, Chemical and Atomic Workers International Union

James H. DeNike
Vice President - Oil Products
Shell Oil Company

Richard R. Dickinson
Vice President
Texaco Inc.

John Dunbar
Manager - Energy Projects
Corporate Planning Department
The Williams Companies

Edward H. Forgotson, Attorney
Texas Oil and Gas Corporation

Lawrence J. Goldstein
Senior Economist
Petroleum Industry Research Foundation, Inc.

Fred S. Hoffman
Senior Economist
Rand Corporation

COORDINATING SUBCOMMITTEE

Professor Henry D. Jacoby
Director, Center for Energy Policy Research
Massachusetts Institute of Technology
Sloan School of Management

William H. Magee
Vice President - Planning and Control
Arco Petroleum Products

Terence B. Redmond
Vice President - Planning and Economics
Standard Oil Company (Indiana)

John Dee Roper
Executive Vice President
Koch Refining Company

Frederick C. Spreyer
Director, Federal Affairs
Pacific Resources, Inc.

Isabelle P. Weber, Director
Energy Department
League of Women Voters Education Fund

L. E. Williams
Vice President
Supply and Marine
Cities Service Company

SPECIAL ASSISTANTS

Stephen D. Bojack
Director of Economic Studies
Standard Oil Company (Indiana)

William R. Carter
Coordinator of Industry and Government Analysis
Supply Department
Exxon Company, U.S.A.

Richard B. Guerin
Senior Staff Planner
Energy Planning and Economics
Corporate Planning Department
Shell Oil Company

Jerry D. Harrison
Manager of Supply and Logistics
Planning Department
Cities Service Company

Clement B. Malin
Director of Coordination/Energy Regulations
Texaco Inc.

L. C. Mihaly
Coordinating Manager
Supply and Marine Transportation
Marathon Oil Company

J. M. Morgan
Senior Staff Specialist Policy Development
Public Affairs - Oil Products
Shell Oil Company

Julia Nanay
Assistant to the Vice President
Northeast Petroleum Industries Inc.

Thomas L. Neff
Energy Laboratory
Massachusetts Institute of Technology

George G. Persyn
Supply Advisor
Exxon Company, U.S.A.

William C. Rusnack
Manager of Planning and Analysis
Arco Petroleum Products

David Solberg
Manager of Downstream Financial Analysis
Conoco Inc.

COORDINATING SUBCOMMITTEE

Ernest J. Turocy
Manager of Functional Analysis
Arco Petroleum Products

R. Eric Vige
Director of Federal Agencies
Cities Service Company

Wilford Webb
Assistant to the Chairman
of the Board
Texas Oil & Gas Corporation

Ralph Zaayenga
Operations Economic Consultant
Sun Petroleum Products Company

* * *

The National Petroleum Council would like to acknowledge the following scholars for the presentations of their views on emergency preparedness for the benefit of the study participants:

Alvin L. Alm
Kennedy School of Government
Harvard University

David A. Deese
Kennedy School of Government
Harvard University

William C. Lane, Jr.
Attorney
Kaye, Scholer, Fierman, Hayes & Handler

Henry S. Rowen
Graduate School of Business
Stanford University

Philip K. Verleger, Jr.
The Yale School of Organization and Management
Yale University

APPENDIX C

Bibliography: Emergency Preparedness for Oil Import Disruptions

BIBLIOGRAPHY:

EMERGENCY PREPAREDNESS FOR OIL IMPORT DISRUPTIONS

Alm, Alvin L., "Energy Supply Interruptions and National Security," Science, March 27, 1981.

Aspen Institute for Humanistic Studies, Summary Findings, Conference on Petroleum Interruptions and National Security, Wye Plantation, Md., May 9-11, 1980. Alvin L. Alm, Chairman.

Committee on Energy and Natural Resources, United States Senate, The Economic Impact of Oil Import Reductions, U.S. Government Printing Office, December 1978.

Committee on Energy and Natural Resources, United States Senate, The Geopolitics of Oil, Staff Report, U.S. Government Printing Office, December 1980.

Congressional Budget Office, "Policy Options to Mitigate the Negative Impacts of Oil Import Reductions," Staff Memorandum, November 6, 1980.

Deese, David A., and Nye, Joseph S., Energy and Security, A Report of Harvard's Energy and Security Research Project, Ballinger Publishing Co., 1981.

Hogan, William W., "Import Management and Oil Emergencies," Discussion Paper Series, John Fitzgerald Kennedy School of Government, Harvard University, September 1980.

Jacobs, Allen, "The Economic Effects of Implementing the Standby Gasoline Rationing Plan," presented at the conference on New Strategies for Managing U.S. Oil Disruptions, School of Organization and Management, Yale University, November 7, 1980.

Lane, William C., Jr., "Dealing With Oil Supply Disruptions: Meeting Commitments under the IEA," presented at the conference on New Strategies for Managing U.S. Oil Disruptions, School of Organization and Management, Yale University, November 7, 1980.

Lane, William, C., Jr., "Free Markets and Full Stockpiles," paper presented to the National Petroleum Council Coordinating Subcommittee on Emergency Preparedness, December 16, 1980.

Nordhaus, William, "Planning for Petroleum Shortages," prepared for the Senate Finance Committee, November 11, 1980.

Oppenheimer, Ernest J., A Realistic Approach to U.S. Energy Independence, Pen and Podium Production, 1980.

Pan Heuristics, A Division of R & D Associates, "Report on Persian Gulf Oil and Western Security," November 4, 1980.

Rivlin, Alice M., Statement for the Committee on Finance, United States Senate, November 11, 1980.

Rowen, Henry S., "Energy Vulnerability and Energy Taxes," presented to the Committee on Finance, United States Senate, November 11, 1980.

Sawhill, John C., Statement for Hearing on Emergency Preparedness before the Permanent Subcommittee on Investigations, Committee on Governmental Affairs, United States Senate, September 22, 1980.

Telson, Michael L., "Managing Oil Contingencies: The U.S. Experience and Choices for the Future," presented at the Second Annual Conference of the International Association of Energy Economists, Churchill College, Cambridge, U.K., June 24, 1980.

U.S. Department of Energy and U.S. Department of Treasury, "Allocating Petroleum Products During Oil Supply Disruptions: A Comparison of Four Alternative Plans," Preliminary Staff Analysis, September 1980.

U.S. Department of Energy, "Decision Summary for Post-decontrol Petroleum Policies," Draft Paper by the Office of Oil and Gas, Policy and Evaluation, December 24, 1980.

U.S. Department of Energy, "Reducing U.S. Oil Vulnerability: Energy Policy for the 1980's," An Analytical Report to the Secretary of Energy, November 10, 1980.

U.S. Department of Energy, "The Federal Government's Role in a Petroleum Supply Shortage: A Sampling of Opinion," prepared by the Post EPAA Task Force, Economic Regulatory Administration, February 3, 1981.

Verleger, Philip K., Jr., "Alternatives Available to Reduce Impacts of a Supply Interruption on Transportation--Lesson from the Crises of the 70's," paper presented at the Aspen Institute's program on Options for Fueling America's Transportation, 1980.

Verleger, Philip K., Jr., "Petroleum Price and Allocation Regulations During the 70's: History and Economic Analysis," paper presented at the conference on New Strategies for Managing U.S. Oil Disruptions, School of Organization and Management, Yale University, November 7, 1980.

Verleger, Philip K., Jr., "The Relationship Between Spot and Contract Crude Oil Prices," Yale University, October 1980.

Wright, Brian D., "The Roles of Public and Private Storage in Managing Oil Import Disruptions," presented at the conference on New Strategies for Managing U.S. Oil Disruptions, School of Organization and Management, Yale University, November 7, 1980.

APPENDIX D

Existing Authorities for Emergency Management of Oil Import Disruptions

EXISTING AUTHORITIES FOR EMERGENCY MANAGEMENT OF OIL IMPORT DISRUPTIONS

EXISTING STANDBY AUTHORITIES FOR EMERGENCY MANAGEMENT DURING A SUPPLY DISRUPTION

Emergency Crude Oil Allocation, Price Controls, and Refinery Yield Controls

Emergency Petroleum Allocation Act of 1973 (EPAA) provides for existing DOE standby regulations to be triggered by either IEA shortfall of 7 percent or discretionary Administration judgment. Allows for distribution of crude oil to refiners based on prior actual runs. Allocated sales based on actual cost of sellers. Exception provisions for small and independent refiners. DOE has discretionary authority to control refiner product mix output. Expires September 30, 1981.

Energy Policy and Conservation Act of 1975 (EPCA) provides limited Presidential authority, subject to Congress, to allocate and control crude oil prices to meet obligations of IEA. Also establishes limited authority for conservation contingency programs, subject to Congressional approval, which may not include rationing, fees/taxes, rebates, or other mechanisms affecting price of crude oil or products. Expires June 30, 1985.

Defense Production Act provides broad Presidential authority to allocate and divert supplies for military and related purposes. Expires December 31, 1984.

Emergency Product Allocation and Price Controls

EPAA provides for existing standby DOE regulations with implementation triggers identical to crude oil. Broad DOE discretion for allocation and price control of all products, geographic areas, base period adjustments, exceptions for classes of refiners, etc. Expires September 30, 1981.

EPCA and Defense Production Act provide authority as outlined above for crude oil controls.

Import/Export of Petroleum

Trade Expansion Act authorizes President to adjust imports that threaten national security. No expiration.

International Emergency Economic Powers Act (IEEPA) authorizes President upon declaration of national emergency to regulate import or export of any property in which a foreign or national country has any interest.

Utilization of SPR

EPCA provided authority to establish plans for utilization of SPR during emergency conditions. Congress approved DOE plan (November 15, 1979) which provides authority to Secretary of Energy to distribute SPR crude oil during national or regional supply disruptions.

Control of Private Inventories

EPAA provides DOE authority, in supply shortage situation, to adjust crude oil and product inventories by persons engaged in petroleum industry. Also prohibits hoarding of petroleum in supply emergency. Expires September 30, 1981.

Emergency Production Rates

EPCA authorizes President to require emergency production on federal lands during severe supply interruption. Expires June 30, 1985. Where states set temporary emergency production rates, President may order that rate during an emergency.

Emergency Conservation

Emergency Energy Conservation Act (EECA) provides that the President establish and implement emergency conservation targets for nation and states upon declaration of emergency. Plans and targets may include employer-based efforts, speed limit enforcement, vehicle sticker plans, compressed work weeks. Final plan not approved. Expires July 1, 1983.

Gasoline Rationing

EPCA provided authority to establish rationing plan.

EECA amended EPCA to require President to establish a plan. Approved plan on standby status and can be implemented by President in event of a 20 percent shortfall in gasoline and middle distillates. Congress can approve implementation at lesser shortfalls. Expires September 30, 1981.

Natural Gas

Natural Gas Policy Act and Public Utilities Regulatory Policies Act (PURPA) give President authority in severe gas shortage with respect to purchases, use prohibition, and allocation.

FERC also has authority in emergencies to take extraordinary actions.

Electricity

Federal Power Act permits DOE to order connections of electrical transmission lines and generation to facilitate "power wheeling" during an emergency.

PURPA provides FERC authority to allocate electricity on exception basis (individual utility request).

Fuel Switching and Petroleum Product Specifications

The Power Plant and Industrial Fuel Use Act (FUA) provides emergency authorities to President to allocate coal and/or prohibit use of natural gas or liquid petroleum as a prime energy source.

Clean Air Act provides for limited waivers of provisions through state application, public hearings, and findings of President that emergency requires temporary remedial actions. Findings must show either high level of unemployment or loss of energy supplies to residential dwellings for locality.

CURRENT ACTIVE EMERGENCY MANAGEMENT AUTHORITIES

Crude Oil Price and Allocation Controls

EPAA provides authority for allocation and price controls on crude oil and products. Executive order signed by the President on January 28, 1981, eliminated implementation of these controls.

Product Price and Allocation Controls

EPAA provides authority for control of all products. Executive order signed by the President on January 28, 1981, eliminated current implementation of these controls.

Petroleum Marketing Practices Act (PMPA) protects motor fuel supply relation of distributors and dealers. No expiration.

Strategic Petroleum Reserve

EPCA provided authority to establish SPR up to 1 billion barrels.

Energy Security Act (ESA) provides that SPR be filled at minimum 100 MB/D until 1 billion barrels are in reserve. Further amended by Interior Appropriations bill to "seek to" fill SPR at 300 MB/D.

Industrial Petroleum Reserve

EPCA provides authority to establish an Industrial Reserve and require importers and refiners to store up to 3 percent of previous year's imported or refined products. Expires June 30, 1985.

Federal Purchasing Authority

EPCA provides authority to establish Federal Purchasing agency to exclusively import and purchase for resale all or any part of crude oil or products of foreign origin. Expires September 30, 1981.

Import/Export Controls

Mandatory Oil Import Program (MOIP) levies custom duty on imported crude oil and products to discourage their use. Currently in effect.

Trade Expansion Act enables levy of import fee on crude oil and product imports to protect U.S. economy from adverse impacts. Presently not in effect.

Export Administration Act precludes exports of crude oil and products in an emergency. Subject to limited exceptions, including an exception to meet U.S. obligations under the IEA program.

EPCA authorizes President, by rule, to limit exports of crude oil, products, natural gas, and petroleum feedstocks. Expires June 30, 1985.

International Considerations

EPCA authorizes President allocation control of crude oil and products to meet obligations of IEA agreement. Also provides authority for procedures to implement IEA response plans and antitrust defense for participating U.S. companies. Expires June 30, 1985.

Emergency Management Contingency Plans

EPCA provides authority to establish emergency conservation contingency plans including rationing plan.

EECA provides for establishment of state conservation targets through a federal conservation plan (not complete as yet).

APPENDIX E

Distribution of Incremental Revenue from Crude Oil Price Increases for Oil Produced by Integrated Corporations

DISTRIBUTION OF INCREMENTAL REVENUE FROM CRUDE OIL PRICE INCREASES FOR OIL PRODUCED BY INTEGRATED CORPORATIONS

The discussion in Chapter One indicates that 80 to 90 percent of the incremental revenue resulting from increases in domestic crude oil prices would accrue to government. The principal sources of government participation in incremental revenue are as follows:

- Direct government ownership of royalty and Naval Petroleum Reserve Oil
- State severance taxes
- "Windfall profit" tax
- State income taxes
- Federal income taxes on producers, private royalty owners, and dividends paid to shareholders.

INTEGRATED CORPORATIONS

Details of the estimated distribution of incremental revenue which would result from increases in domestic crude oil prices for oil produced by a typical integrated corporation are shown in Table E-1 for 1981 and 1985. The revenue distributions are based on the following assumptions.

- The initial revenue distribution is based on estimated net interests in production of 5 percent for federal, state, and local governments, 10 percent for private royalty owners, and 85 percent for the corporations.

- Severance taxes vary from none for oil produced from federal offshore leases to an effective rate of about 11.5 percent in Alaska and 12.5 percent in Louisiana. Calculations in Table E-1 assume an average rate of 6.5 percent, which is consistent with recent estimates by the Joint Committee on Taxation of 11.5 percent for Alaska and an average of 5.4 percent for other states.

- The average "windfall profit" tax rates for a typical integrated corporation were estimated to be 64 percent in 1981, decreasing to 57 percent in 1985. These rates apply to incremental revenue less incremental severance tax. These estimated rates are based on the applicable tax rates for the three "windfall profit" tax tiers and recent estimates by the Joint Committee on Taxation of the distribution of total U.S. oil production by tax tiers for 1981 and 1985, as shown in Table E-2.

TABLE E-1

Distribution of Incremental Revenue Dollar From Crude Oil Price Increase for Oil Produced by Typical Integrated Corporation

(U.S. Dollars)

	Corporation	Private Royalty Owner	Shareholder	Government
		1981		
Revenue	0.85	0.10	--	0.05
Severance Tax	(0.05)	(0.01)	--	0.06
"Windfall Profit" Tax	(0.51)	(0.06)	--	0.57
Net Income Before Income Taxes	0.29	0.03	--	0.68
State Income Taxes	(0.02)	--	--	0.02
Federal Income Tax	(0.12)	(0.01)	--	0.13
Net Income Before Dividends	0.15	0.02	--	0.83
Dividends	(0.06)	--	0.06	--
Income Tax on Dividends	--	--	(0.02)	0.02
Net Income After Dividends and Taxes	0.09	0.02	0.04	0.85*
		1985		
Revenue	0.85	0.10	--	0.05
Severance Tax	(0.05)	(0.01)	--	0.06
"Windfall Profit" Tax	(0.46)	(0.05)	--	0.51
Net Income Before Income Taxes	0.34	0.04	--	0.62
State Income Taxes	(0.03)	--	--	0.03
Federal Income Tax	(0.14)	(0.02)	--	0.16
Net Income Before Dividends	0.17	0.02	--	0.81
Dividends	(0.07)	--	0.07	--
Income Tax on Dividends	--	--	(0.03)	0.03
Net Income After Dividends and Taxes	0.10	0.02	0.04	0.84†

---

*Of the government total, the federal government's share is 0.74 and the state governments' share is 0.11.

†Of the government total, the federal government's share is 0.72 and the state governments' share is 0.12.

TABLE E-2

Percentage of U.S. Oil Production by "Windfall Profit" Tax Tiers

	Tax Rate (%)	1981	1985
Tier 1	70	73	56
Tier 2	60	16	16
Tier 3	30	11	28
		100	100

Tax Tier 3 includes newly discovered oil, incremental tertiary oil, and heavy oil (16°API or less). Tier 3 oil is currently a relatively small percentage of total production but is expected to increase with time. Tier 2 production is primarily stripper oil and is expected to remain relatively constant over the next several years. Most current produced oil, including current Alaskan North Slope production, is taxed in Tier 1. The volume of oil in Tier 1 will decline with time, as present reserves approach depletion.

- State income taxes, except for Alaska, are estimated to average 5 percent of net income before income taxes. For Alaska, the applicable rate is 9.4 percent, and the "windfall profit" tax is not deductible for Alaskan state income tax purposes.

- Federal income taxes were calculated using a marginal tax rate of 46 percent for corporations and an estimated 40 percent for private royalty owners. It could be argued that price increases will encourage additional expenditures which would result in income tax credits, reducing the effective tax rate below the 46 percent marginal corporate tax rate. However, the marginal rate is the appropriate rate in determining the portion of incremental revenue available to the corporations. The tax consequences of any expenditures of these funds should be considered only with respect to the income attributable to those expenditures.

- It was assumed that the typical corporation would pass on 40 percent of its after-tax income to shareholders as dividends. Dividend policies would probably vary among corporations. A marginal income tax rate of 40 percent was assumed for the average shareholder.

The revenue distribution changes with time primarily because of changes in the relative distribution of oil production among "windfall profit" tax tiers. As indicated above, however, although there is a reduction in the estimated average "windfall profit" tax rate for the typical integrated corporation from 64 percent in 1981 to 57 percent in 1985, the government share of revenue after dividends and taxes is only reduced from 85 percent to 84 percent as a result of offsetting increases in income taxes.

The distribution will also vary among corporations due to differences in the relative proportions of the individual corporation's production from government leases, production from the various states, and production of oil in the three "windfall profit" tax tiers, as well as differences in individual corporate dividend policies. As an illustration of the effect that different "windfall profit" tax rates and different state tax rates and royalty interests can have, the government share of Tier 1 Alaskan North Slope oil would be about 93 percent. On the other hand, Tier 3 production from the lower 48 states would yield governments a 71 percent share.

The distributions in Table E-1 do not include the effects of any increases in costs of oil producing operations and assume that all increases in raw material costs and other costs of refining, marketing, and transporting crude oil and products can be recovered in higher product prices. To the extent any increases in these costs cannot be recovered due to market conditions or regulation, the corporation's net income before income tax would be reduced and hence the fraction of incremental revenue retained by the corporation and by the government would also be reduced.

INDEPENDENT PRODUCERS

The revenue distribution of incremental revenue will be different for oil produced by those who qualify as independent producers because of the more favorable "windfall profit" tax rates provided for a portion of their production and varying income tax rates applicable to independent producers. Special "windfall profit" tax rates of 50 percent for Tier 1 and 30 percent for Tier 2 are provided for a qualified independent producer, up to a combined production limit of 1 MB/D in Tiers 1 and 2. The effect of these special rates is not included in Table E-1, as this table is for oil produced by integrated corporations. There is no special treatment for independent producers' oil in Tier 3.

For a hypothetical small independent producing corporation with all of its production qualifying for the percentage depletion allowance (which is not available on crude oil to integrated producers) and the lowest 30 percent "windfall profit" tax rate, the government share of incremental revenue could be as low as 62 percent in 1981. For larger independent producing corporations, the government share may approach that for oil produced by integrated corporations due to limits on the amounts of oil eligible for percentage depletion and special "windfall profit" tax rates.

APPENDIX F

Emergency Crude Oil Distribution

EMERGENCY CRUDE OIL DISTRIBUTION

INTRODUCTION

As discussed in Chapter One of this report, in very large crude oil disruptions to the United States (generally in excess of 2 to 3 MMB/D), the competitive market should be relied upon to the extent possible, supplemented by voluntary and mandatory steps of demand restraint, fuel switching, diversion of current SPR fill, possible distribution of SPR stocks, and emergency oil and gas production.

However, crude oil access may be expected to be a serious refiner concern during such a major crude oil imports disruption. Individual refiners' crude oil supplies may be affected disproportionately due to loss of the disrupted imported crude oil source or due to assignments received as a result of U.S. participation in the IEA crude oil sharing agreement. Most refiners have product supply contracts with the jobbers, dealers, and commercial consumers they serve. Through this contract structure, the disproportionate impacts of a disruption on individual refiners could be transmitted downstream to the respective customers and regions of the country they serve. While these disproportionate product shortfalls could be mitigated and buffered by market mechanisms supplemented by fuel switching, demand restraint, and drawdown of private stocks during less severe crude oil import disruptions, this study suggests that these steps may not be sufficient to ensure effective petroleum operations during interruptions of petroleum imports in excess of approximately 2 to 3 MMB/D.

In the event of a severe oil imports disruption, the disproportionate impacts might be further mitigated through the use of a standby federal crude oil distribution program designed to distribute available crude oil among all domestic refiners on a common national crude oil run ratio. This conclusion is reached even with the knowledge, based on prior experience, of the distortions created and the difficulties of administering such programs in an efficient manner. Such a program should normally be contemplated in the context of a national emergency due to a sudden cutoff in excess of approximately 2 to 3 MMB/D of petroleum imports into the United States.

The pricing basis mandated for crude oil transactions among refiners required to achieve the common crude oil run ratio should not provide unwarranted benefits either to buyers or sellers. Such a program would provide for a reasonably uniform geographic distribution of the available crude oil and allow each active domestic refiner an opportunity to continue serving its customers.

Any mandated crude oil distribution program would require an extensive bureaucracy to monitor and maintain the data and compliance systems necessary for successful operation and will quickly attract constituencies against its deactivation. In fact, such constituencies for a government crude oil sharing program existed even before consideration of need in emergency planning existed.

Thus, implementation of a standby crude oil distribution program should be taken only after a clear assessment that a U.S. imports disruption of major proportions has occurred. The program should include a sunset clause providing for discontinuation within a set period of time, probably three months. The program should also exclude provisions for distribution of initial stocks held by refiners to avoid disincentives to private stockbuilding.

Finally, a distribution method based on historical crude oil runs in a base period appears to be most appropriate for the emergency program described herein. This last conclusion was reached by means of the following study procedure:

- Identification of several approaches that might be suitable for use as a distribution method (see Exhibit 1 on page F-12). The approaches identified for examination were:
  - Historical crude oil run/capacity method
  - Refinery efficiency method -- a highly regulated approach optimizing critical product output
  - Competitive purchase method -- a free-market-oriented method
- Analysis of these approaches against a set of criteria related to the presumed goals of government emergency management policy
- Choice of a method based on this analysis.

For historical perspective, a review and critique of past and present allocation controls is included as Exhibit 2 (page F-16).

The principal assumptions used are as follows:

- The crude oil to be distributed will be defined as "currently available crude oil," that crude oil which becomes currently available following introduction of the program. This means that initial stocks of companies would be interpreted as working stocks and would be excluded. Any company that stored crude oil would be allowed to retain the advantage of having that crude oil. Thus, currently available crude oil would consist of current domestic production plus landed imports plus any drawdown of the Strategic Petroleum Reserve less any necessary exports.
- A governmental body to oversee the program will exist. Within the existing government organization this would be administered by the DOE.
- The focus of attention in the crude oil distribution system proposed is on the specific question of efficient functioning of the petroleum supply system during an emergency interruption of imports. The related economic burdens of individual refiners suffering opportunity losses due to a

crude oil shortfall are alluded to, but any attempts to redress these and all other burdens in the emergency would be handled separately (if required) by government.

GOALS OF THE EMERGENCY CRUDE OIL DISTRIBUTION PROGRAM

This section attempts to specify what the goals of government policy for the emergency crude oil distribution program would be. The goals, in turn, are translated into a set of evaluation criteria against which any proposed method can be examined.

The basic premise is that there is a severe interruption of petroleum imports; the country's national security, its economic and industrial viability, and the health and safety of its citizens are in serious jeopardy. In this situation the primary goal of the program may be stated as follows:

> To maximize the availability of the products for vital defense and human needs and minimize losses to the economy until such time as total reliance on the competitive market is restored.

In the emergency allocation program, this goal is referred to by using the term "distributional efficiency." It is useful to subdivide this goal into three subsidiary concepts: product mix efficiency, logistical efficiency, and cost efficiency.

Product mix efficiency refers to the production of those petroleum products most critically needed by the nation in the emergency -- whether jet fuel, heating oil, gasoline, lubricants, petrochemical feedstocks, etc.

Logistical efficiency refers to how conveniently a refinery is located in terms of its physical accessibility to a crude oil supply and its capability to distribute products to the nation's critical consumption areas via pipelines or other transportation systems.

After product mix and logistical efficiency, the last facet of distribution efficiency is cost efficiency. This is determined by a refinery's cost of producing a particular product and the transportation cost of supplying crude oil to the refinery and distributing the product to ultimate users.

A secondary objective of a distribution program would be to distribute the available supply of crude oil among all refiners as equitably as possible. This concept of equity embraces not only the physical barrels that are distributed but also the price that each refiner/buyer pays. Note that there is a potential conflict between the primary goal of distributional efficiency and the secondary objective of equity. A program that perfectly attained distributional efficiency would probably not enable the attainment of complete equity among all refiners. As either is maximized, the other may be diminished.

In addition, a number of other objectives related to the mechanics of the program would be important. Simplicity is the first objective. In order for a distribution program to be workable, it must necessarily be simple to implement. It must be relatively simple to gather needed information and the reporting requirements should not be intolerably burdensome. Basically, the more variables which must be controlled in a distribution program, the less simple it becomes.

Flexibility is another desirable characteristic of a distribution program. Flexibility is judged by how readily a program can adjust to varying crude oil supplies as well as changing product demand patterns. A flexible sharing program will be able to adapt quickly and smoothly to changes in the environment and the severity of the crisis.

Finally, susceptibility to abuse is an important consideration. The distribution program should minimize the opportunities for the parties involved in the program, sellers or buyers, to illegally take advantage of the rules to benefit themselves. The program should be structured so that no one can deviate from its purposes or rules without detection. The program's intentions should be capable of explicit definition, with adequate provisions for proper reporting and audits.

In the analysis section of this appendix, therefore, the recommended emergency program is evaluated on the basis of how well it measures up against the following criteria:

- Distribution efficiency
- Equity
- Simplicity
- Flexibility
- Nonsusceptibility to abuses.

It is believed that a competitive market would best achieve the goals of efficiency, simplicity, flexibility, and freedom from abuse. However, some members of the public may perceive problems of equity, and for the purposes of this analysis, it is assumed that competitive markets are suddenly, temporarily, and severely disrupted by a major interruption in U.S. petroleum imports.

RECOMMENDED GOVERNMENT EMERGENCY CRUDE OIL SHARING PROGRAM

The following paragraphs describe the recommended government standby crude oil sharing scheme given the assumption of a severe crude oil shortfall. Within this section are three subsections which provide (1) a description of the method; (2) a comparison of the method to recent past DOE programs; and (3) an evaluation of the method based on the pre-determined performance criteria. Issues associated with this method are described in Exhibit 1.

Description of Method

The emergency crude oil sharing program described in this appendix is very similar to one of several DOE standby crude oil allocation systems. This was not the consequence of a special effort to pattern the method after its DOE counterpart. Rather, similarities can be attributed to inherent strengths in one of the DOE programs and a rejection of the others. The net result is that the method can be regarded as an extension of that standby system, incorporating certain features to improve it.

The standby distribution procedure developed uses crude oil runs over a base period as the sharing parameter. In general, this system would take the following form:

- Upon program startup, refiners would submit to a central body an estimate of their currently available crude oil, excluding any prior required distribution.

- When aggregated, the individual availabilities would yield a total U.S. crude oil availability. This total U.S. crude oil availability compared with total U.S. base period crude oil runs would yield a National Utilization Rate (NUR). The NUR multiplied by each individual firm's base period crude oil runs would determine the company's allowable run level for the following period. The difference between this allowable run level and the firm's previously submitted availability estimate would determine its buy rights or sales obligations for that period.

- In order to provide incentives for refiners to seek secure crude oil supplies in advance, the above calculation of crude oil buy rights or sales obligations would be adjusted by reducing it to 95 percent of the amount needed to bring all refiners to the NUR. Thus,

  $$\begin{array}{l}\text{Crude oil entitled}\\ \text{to be purchased,}\\ \text{or sales obligation}\end{array} = \Big[\,[(C/R) \text{ x } r] - c\,\Big] \text{ x } \Big[\,0.95\,\Big]$$

  where

  $$\left.\begin{array}{l}C = \text{U.S. crude oil availability}\\ R = \text{U.S. base period crude oil runs}\end{array}\right\} \; C/R = \text{NUR}$$

  r = Individual refiner base period crude oil runs[1]
  c = Individual refiner currently available crude oil

- The procedure would be repeated each period with adjustments being made in later periods for errors in prior crude oil availability estimates.

---

[1] Adjustments should be considered for additions to refinery capacity affected after the base period.

- Buyers would make supply arrangements with sellers on their own (the price-setting concept is described elsewhere).

- The crude oil acquisition rights would not be freely negotiable. That is, those firms provided the right to purchase crude oil could not outright sell the right to other refiners. A refiner receiving these government rights would be obligated to run the crude oil provided by the buy rights and supply his customers, or have the crude oil processed by another refiner with the same end result. In this latter instance, the crude oil buy right could be sold but equivalent products to supply customers would have to be repurchased.

Under this crude oil run system, each refiner, regardless of size, would suffer the same percentage decline in crude oil runs relative to the base period, except for the small extra amount that sellers would be allowed to retain as a premium for having been adequately prepared. Two points concerning this must be mentioned. First, there are no special provisions for small or independent refiners under this approach. Second, there is no distribution of additional crude oil to the more efficient refiners.

As stated previously, equity or hardship issues should be handled by government through separate financial programs.

It would seem advantageous for the national well being to have more efficient refiners operate at a higher percentage of base period crude oil runs. Under the proposed system, this would occur automatically to the extent that less efficient refiners had some or all of their crude oil processed by their more efficient counterparts. An incentive for both parties to make such transactions would theoretically exist as both could seek to improve their economic performance.

The price that sellers will be allowed to charge refiner/buyers for crude oil is another critical aspect of the government distribution plan. The system described in the following paragraphs utilizes a cost basis for this price.

The first element of the price-setting mechanism is the recommended treatment of crude oils of differing quality (e.g., sulfur content and gravity). Several quality groupings for crude oils would be developed -- perhaps as few as six groupings based on three gravity categories and two sulfur categories. The number of such groupings and fine tuning the boundaries between them may need to be studied further. The resultant groupings would provide the basis for price determinations.

The second element of the price-setting mechanism is the actual costs that sellers incur to acquire the crude oil in each of the aforementioned quality categories. At the time a sale of a given quality of crude oil is negotiated, the seller and buyer would agree upon a provisional price based on the highest cost fraction (tentatively set at one third) of the crude oil of that quality acquired by the seller. In other words, the seller would rank his expected crude oil avails within a quality group according to anticipated acquisition cost. He would then segregate out the costliest one third of these volumes and calculate their average cost. This cost, plus a reasonable handling charge and finder's fee, would represent his allowable sales price; the sales price would be subject to later adjustment to reflect actual acquisition costs.

The handling charge, which remains to be determined, would be a cents-per-barrel charge intended to compensate the seller for any extra cost incurred in moving and storing the crude oil sold under the program. The finder's fee, which also remains to be determined, would compensate the seller in acknowledgement of the fact that in seeking out secure supplies, he has taken risks and likely incurred costs. The costs may have stemmed from investments required or perhaps from paying term prices which were higher than spot prices during times of adequate supplies. Other refiners may have made the decision to be in the spot market only in times of adequate supplies. The refiner who has incurred costs to secure crude oil should be compensated to some extent if he is required to share that crude oil.

The recommended pricing mechanism incorporated in the suggested crude oil distribution plan would reduce pressure on the spot market by limiting the price a seller may charge to the average of the costliest one third of the seller's crude oil acquisitions within a pre-determined crude oil quality range and set time period. The last barrel purchased (incremental or marginal barrel) by a seller would almost always be sold at a price less than the actual acquisition cost under the suggested plan, thus providing incentive for sellers to negotiate for lowest possible spot prices. A buyer of shared crude oil would almost always pay somewhat less than a seller's incremental spot price, thus reducing incentive to acquire incremental barrels in the spot market. Both sellers and buyers would have incentives to refrain from spot purchases, thereby reducing upward price pressure by reducing overall spot demand.

In addition to reducing spot market pressures, the recommended pricing mechanism should also tend to encourage both potential sellers and buyers to seek long-term supply commitments under the program, because term prices historically have been lower than spot prices during a shortage. A seller who seeks and attains long-term supplies may be able to price sales closer to his average of crude oil costs to buyers under the recommended program by virtue of more stable pricing of long-term supplies. A buyer who attains a term contract can possibly negotiate a lower price than the spot market price during normal periods and possibly lower than a seller's average upper one third cost during supply disruption periods.

A constituency of buyers who would be in favor of continuing the suggested pricing mechanism during periods of nondisrupted supply is unlikely to develop because buyers would be required to pay a price equal to or above a seller's average acquisition cost plus handling and finder's fees. More attractive crude oil prices could be available in the marketplace.

Alternative approaches were considered in the process of arriving at the pricing scheme just described. These are discussed in Exhibit 1.

Data Requirements of the Method

In order for the government to be in a position to implement an emergency crude oil distribution plan in the event of a major supply disruption, an adequate mechanism must be in existence for capturing all the necessary data from U.S. refiners prior to the need for implementing such crude oil sharing. The rationale for maintaining a data source mechanism is that it:

- Ensures continuity and quality of data over time
- Provides a functional ongoing means of gathering data
- Eliminates the startup time and inherent problems with initiating any new reporting system in the heat of a supply disruption
- Ensures that all parties understand the mechanics of the crude oil sharing mechanism before necessity requires its implementation.

Basic data requirements for effecting the suggested emergency crude oil distribution plan would include actual crude oil runs to stills by refinery for all U.S. refiners and an estimate of currently available crude oil by refinery for all U.S. refiners. The estimate of crude oil avails would represent a projection of a refiner's crude oil availability in a future period, usually by month. Refining data would be required to be reported in a timely manner, enabling the government to aggregate and determine the relative position (buyer or seller) of each refiner under the emergency crude oil sharing program. Cost and quality data of crude oil actually being purchased and/or sold under the program would need to be reported to the government for auditing purposes and SPR pricing (in the event of drawdown during crude oil sharing). Developing this cost data on comparable bases among companies will be a complex task.

In order to fully implement the suggested crude oil distribution plan, a task force of industry and government personnel might be formed to develop a proper reporting mechanism with attention to tailoring the system to the need, including actual data requirements, most efficient method of acquiring data, simplicity, timeliness of reporting, and a consistent method of developing or "constructing" actual crude oil acquisition costs.

Comparison of Method With Present DOE Standby Program

The basic structure of this program of crude oil distribution based upon crude oil runs during a base period is, as already noted, close to the current DOE emergency crude oil sharing method. However, the DOE system differs from the one proposed here in three ways.

First, the DOE system does not permit the sale of buy rights. This detracts from the efficiency of the system as it limits the movement of crude oil from less efficient to more efficient refiners. In addition, in the case of a severe reduction in crude oil availabilities, it is possible that some refiners would be allocated insufficient crude oil to maintain continuous operation. The ability to sell buy rights would allow an accommodation of this circumstance, but in all cases, only when equivalent products are repurchased to supply the rights seller's customers.

Second, the current DOE program offers special treatment to those refiners with capacity under 50 MB/D. These refiners are exempt from any sales obligation under the DOE program under certain circumstances. The conditions necessary to trigger the distribution program detailed in the text, however, would be severe enough so that this exemption under the DOE rules would not exist.

Third, the pricing provisions differ under the two programs. Under the DOE program, refiner/buyers with aggregate capacities of over 50 MB/D are charged the refiner/seller's incremental crude oil cost plus a $0.25 per barrel handling fee. Allowing refiner/sellers to charge incremental crude oil costs in this way is undesirable as it provides no incentive to hold down costs at the margin. The pricing structure suggested alleviates this problem somewhat by restricting the passthrough to the average of the highest cost crude oil fraction, a level below the seller's incremental cost.

Under the DOE program, those refiners with less than 50 MB/D of refinery capacity are charged the refiner/seller's average imported crude oil costs. Such a subsidized pricing structure provides little incentive for these refiner/buyers to seek out their own outside crude oil sources and thereby lengthens the time these buyers will maintain their dependence on sellers. The pricing structure suggested here reduces the economic subsidy to the buyer and therefore does not unnecessarily prolong buyer/seller relationships.

Analysis of Method Based On Evaluation Criteria

How well the proposed method meets the previously discussed performance criteria is examined in this section.

Distribution Efficiency

The degree of distribution efficiency of this method depends upon the extent to which buy rights would be sold by less efficient refiners to more efficient refiners. In addition, large amounts of energy could be conserved if some refineries operated at a high level of capacity and others shut down and repurchased products for their customers, as was discussed earlier. This factor is not controllable and difficult to predict. It would depend upon each refiner's particular situation; i.e., how economic his post-allocation run level would be. In any case, however, this method is superior on an efficiency basis to a distribution program which does not permit selling of buy rights or one which gives special preference to certain refiners.

Equity

The program should best be described as moderately equitable in terms of the definition offered earlier. Most importantly, the procedure treats all refiners equally in terms of crude oil availability. All refiners have access to the same crude oil availability expressed in relation to base period crude oil runs, except for a 95 percent reduction factor incorporated in the method. The choice of the base period for measurement of historical runs may put some refiners in an unusual position due to events peculiar to their own operations. As in all mandatory systems, an appeals board would have to be available to review and resolve such problems. This appeals board must be intended to function without yielding concessions that undermine the basic integrity of the emergency program.

A refiner/buyer's cost of crude oil will depend upon the actual cost of that crude oil to the refiner/seller (or sellers) he deals with. As a result, two buyers may pay a different price for the same quality crude oil.

Simplicity

No program of this type dealing with a complex industry and a necessarily large government bureaucracy is simple. However, the program as proposed should be a relatively simple program to set up and administer as compared to more draconian systems. Refinery run and pricing data should both be relatively accessible.

Flexibility

This program is flexible in the sense that the distribution mechanism automatically handles varying crude oil availabilities. On the other hand, there is no provision for altering the sharing procedure as a result of a change in the environment, as for example, if there were a shift in the mix of products required by the nation. As indicated in Chapter Six, however, the refining industry has the flexibility to respond to a relatively broad range of product mix demands.

Susceptibility to Abuse

This system does not appear to offer significant opportunities for manipulation by companies for individual gain. However, two sources of possible abuse need to be pointed out. First, there exists the possibility of companies attempting to avoid their crude oil sales obligations under this program by refining some of their available crude oil abroad and bringing the products, instead of the crude oil, into the United States. To avoid this, monitoring of individual firm crude oil and product imports by the program's governing body should be conducted. Second, since underestimates of crude oil availabilities by individual refiners can only be corrected for after some time delay (probably about two reporting periods), some abuses may arise from refiners' intentionally underestimating crude oil availabilities in order to operate at a crude oil run level higher than the one assigned to them. This could be motivated by the belief that a crisis would be short and that they could avoid ever having to pay recompense, or simply by a time-value-of-money consideration. Since abuses such as this could undermine the effectiveness of the program, it would be necessary for the responsible government entity to have authority to impose appropriate penalties for any company found to be deliberately acting in this manner.

EXHIBIT 1

ALTERNATIVE EMERGENCY METHODS CONSIDERED FOR A STANDBY CRUDE OIL DISTRIBUTION MECHANISM

ALTERNATIVE EMERGENCY METHODS CONSIDERED

Two emergency distribution procedures besides the one chosen were examined and rejected by the study participants. A brief description of each, along with its reasons for rejection, follows.

Refinery Efficiency Method

This method of distributing crude oil assumes that the nation's interests are best served if its most efficient refineries are utilized during a crisis. The method envisions a centralized decision-making body which would be responsible for distributing the available supply of crude oil to individual refineries. An integral part of the committee's decision-making process under this method would be a computer model utilizing linear programming techniques to optimize the distribution of crude oil to individual refineries. The information base for this model would be technical specifications of all U.S. refineries, including distillation, cracking, and reforming capabilities and capacities, heavy ends upgrading capabilities, refined product mix, etc. This technical information would be used to rank the product mix efficiency of particular refineries. Layered on top of this ranking would be geographic supply patterns for each refinery; i.e., identifying the regional product demand areas it traditionally served. Combining this supply pattern information with the product mix optimization would yield the best distribution of crude oil for all U.S. refineries.

This method was rejected for two reasons. First, it is too complicated. It is doubtful that such a system could be developed and implemented. The system requires the gathering, analyzing, disseminating, and monitoring of large amounts of data on a continuing basis. Second, the system is not equitable. Many refiners would be forced to shut down purely because of government fiat, while others would be allowed to operate at or near capacity.

National Auction Method

The basis of this approach is that a market mechanism for allocating scarce resources is preferable and its characteristics should be retained even in the most severe of imports disruptions. This method assumes that economic market forces will cause crude oil to tend to flow to the more efficient refiners.

The focus of this method would be on those private companies participating in the national crude oil supply network. However, a central administrative body would assist market forces by supervising a national auction for those volumes that individual companies desired to sell, by monitoring the resulting crude oil distribution to ensure that regional defense and other critical needs were adequately served, and by responding to those refiners requesting relief from hardships.

The primary reasons for rejection of the competitive purchase method is that, in a crisis which is perceived to be of short duration, the method may be lacking in efficiency. Less efficient refiners may ignore the economic incentives of the system (i.e., increased short-term profit by selling rather than running crude oil), preferring to try to "weather the storm" rather than sell their supplies to more efficient refiners. A secondary weakness of the system is that, because it would not result in a uniform sharing of the crude oil shortage among all refiners, its implementation might be politically unfeasible in a severe emergency as some regions and some petroleum products customers may suffer severely disproportionate impacts of the shortage.

ALTERNATIVE FEATURES CONSIDERED FOR THE EMERGENCY DISTRIBUTION METHOD CHOSEN

The following paragraphs discuss significant issues that were debated in arriving at the suggested program.

Determination of the Allocation Parameter

As previously noted, the study concludes that historical crude oil runs is the preferred distribution parameter. There has been some sentiment expressed for using refinery capacity instead. The main reason for choosing crude oil runs is that this measure, for the most part, represents an economic decision made by the refiner in the free market. Using this as the basis for distribution keeps the system closer to a free market orientation. On the negative side, there exists the problem of choosing an acceptable base period by which to judge historical run levels. Almost any period chosen would result in an anomaly for some refiner. Any refiner who acquired an operating refinery since the base period would also take title to the base period runs in the calculation of rights.

Efficiency Function

As stated in the text, it would be desirable in a crisis of the magnitude considered to have the more efficient refiners -- refiners both in a position to produce the products needed most and well located relative to markets -- operate at a higher than average percentage of base period crude oil runs. While the provision for the saleability of buy rights is a step in this direction, the possibility of explicitly modifying the sharing formula to transfer additional crude oil to more efficient refiners was considered. Such a modification could take the following form:

$$\begin{array}{l}\text{Crude oil entitled}\\ \text{to be purchased,}\\ \text{or sales obligation}\end{array} = \Big[[(C/R) \times r \times Q] - c \Big] \times \Big[0.95 \Big]$$

In the above equation the new term, Q, would be a function of refinery efficiency such that it would be greater than 1 for more efficient refiners and less than 1 for less efficient refiners.

While conceptually appealing, the complexity of developing a workable efficiency measure is great. In the end, it was decided to refrain from including such an efficiency function in the distribution equation based on a belief that any benefit that such an inclusion would bring to the program would be outweighed by the complexity it would add.

Pricing

Pricing of crude oil under this distribution program can take many possible forms. Consequently, several issues arise in association with the suggested pricing system.

The first issue is whether there should be different prices for different qualities of crude oil (e.g., sulfur content and gravity). Although such an option would add complexity to the program, its inclusion would be desirable. Two methods were considered for adjusting prices for differing crude oil qualities. The first was a simple cents-per-barrel quality differential adjustment to the refiner/buyer's crude oil cost; an increment would be added for higher than average quality crude oil or subtracted for lower than average quality crude oil. This increment would vary depending upon the crude oil's relative quality. Although the method sounds simple, the determination of reasonable quality differentials is quite difficult. As such, this method suffers from the risk of large possible pricing distortions resulting from the use of inappropriate differentials. To reduce the possibility of these large distortions, a method employing quality groupings was chosen instead. Under this system, there would be an as yet unspecified number of quality categories. This method also will have some pricing distortions, with the size of these distortions being inversely related to the number of quality groupings. It is hoped that appropriate groupings can be established to minimize distortions while at the same time not overburdening the system with added complexities.

The second issue is the price which the refiner/seller should be allowed to charge for crude oil of a specific quality. There are several options here: the replacement cost of this crude oil, his actual cost for the crude oil, his average cost, or some combination of these three options. Note that under any option the seller would be allowed an as yet unspecified handling fee plus a finder's fee on the sale.

The replacement cost represents the cost of going out on the open market and reacquiring those volumes distributed under the program. Thus, the seller is being compensated for the true market value of his crude oil. The main problem with this method is defining what this replacement cost would be. In a market that is disrupted to the extent necessary to activate this distribution procedure, it is doubtful if the crude oil could be replaced. The replacement-cost basis was therefore rejected.

The actual cost, which undoubtedly would be taken to be equivalent to the seller's highest crude oil cost, approximates the replacement value of this crude oil and may thus promote the acquisition of additional volumes. However, such a pricing system would provide no incentive to hold down crude oil acquisition costs and thus, if adopted, would tend to inflate world spot prices. Alternatively, if a seller were required to charge his average crude oil cost, the crude oil would be sold for less than the cost of the "incremental" barrel. This would result in both a subsidy for the refiner/buyer and a disincentive for the refiner/seller to purchase high cost spot crude oil. This disincentive may not represent a significant problem in practice because with the IEP in effect it is questionable how much additional spot crude oil could be brought into the country. However, the subsidization of the refiner/buyer would tend to prolong buyers' relationships of dependence on sellers. It is believed that this is undesirable as there should be an incentive for buyers to seek out their own outside crude oil sources rather than becoming dependent upon other refiners.

Because of the weaknesses in each of the latter two pricing methods, the compromise approach of allowing refiner/sellers to charge the average cost of their top one third costliest volumes for each crude oil type (the approach dealt with in the text) was settled on. This pricing method, when compared to the average cost methods, reduces the disincentive for sellers to acquire incremental crude oil in world markets. However, by requiring refiner/sellers to charge something less than their actual cost, this method provides some incentive for them to hold down crude oil acquisition costs. In addition, since the cost refiner/sellers can pass through is, for most sellers, substantially above their average cost, there is a considerable reduction in the economic subsidy for refiner/buyers, thereby creating some incentive for these buyers to seek out their own crude oil sources.

The final issue relating to pricing is whether there should be a cost equalization program for refiner/buyers. Because sellers will have different costs, allowed prices for given quality of crude oil will be different depending upon who the seller is. All buyers will naturally want to purchase from the lowest cost seller. To prevent the creation of "winners" and "losers," the program could calculate and use an average highest cost fraction for each quality category. In order to make sellers indifferent in this program, a sales price equalization pool would have to be established to eliminate losses and gains for the sellers. It was felt, however, that the inclusion of such provisions would provide only marginal benefits to the nation while adding a layer of additional bureaucracy and complication to the distribution program. Perverse disincentives to acquire oil at the lowest price would be created exactly at the time the nation is struggling to minimize disruptive increases in crude oil costs. As such, the idea of cost equalization was therefore not incorporated in the proposed emergency program.

EXHIBIT 2

SUMMARY AND CRITIQUE OF PAST AND PRESENT DISTRIBUTION CONTROLS

The Emergency Petroleum Allocation Act, which authorized federal distribution programs, was passed during the Arab oil embargo of late 1973 and early 1974. It gave the Federal Energy Office, the Federal Energy Administration, and ultimately the DOE's Economic Regulatory Administration broad and extensive authority over the oil industry. Since the EPAA's passage, there have been three basic sharing programs instituted in the United States to distribute crude oil: supplier/purchaser restrictions, buy/sell programs, and standby provisions. These programs are described in the following paragraphs.

SUPPLIER/PURCHASER RESTRICTIONS

The first crude oil distribution program was issued in January 1974. It used a limited distribution concept in that it attempted only to maintain the previous supply patterns. Its purposes were to preserve access to low cost domestic crude oil for small independent refiners and to establish a basis from which the distribution of supplies during shortages could begin. Basically, this program prevented crude oil producers/suppliers from switching customers without the customers' consent.

As originally adopted, this program froze supplier/purchaser relationships that were under contract on December 1, 1973. This base date was later changed to January 1, 1976, when upper tier oil came under price controls. In addition, if a producer/supplier with excess crude oil entered into a contractual relationship with a purchaser after the base date, the relationship was also frozen as if it were in existence on January 1, 1976.

The supplier/purchaser rule was amended effective October 1, 1980, to narrow its scope. All price-decontrolled crude oil and all price-controlled crude oil not sold to a reseller, small refiner, or independent refiner was eliminated from the scope of the rule. Thus, supplier/purchaser relationships for price-controlled crude oil not sold to a major refiner remained in effect under the amended rule. Effective with President Reagan's order of January 28, 1981, all remaining crude oil price and allocation controls were eliminated -- including the supplier/purchaser rule.

Such a program by itself would be undesirable during a time of substantial crude oil import interruptions. In terms of the main evaluation criteria developed in this report, the program placed virtually all of its emphasis on equity, with essentially no attention to distribution efficiency. It was a complex system to set up and follow and inherently inflexible in that it froze supplier relationships. The use of such a rule in a future supply disruption is unnecessary if crude oil prices are not controlled.

BUY/SELL PROGRAM

The buy/sell program, also instituted as a result of the EPAA, provides a basis for distributing crude oil to small refiners from certain large refiners. The DOE defines a small refiner as one whose total refining capacity does not exceed 175 MB/D. It was originally developed to permit small refiners with supplies below the national average to purchase crude oil from major refiners with supplies in excess of the national average; this was to eliminate the advantage the latter had by virtue of their better access to imported crude oil.

In August 1977, following a period of increased crude oil availability, the program was amended and its scope limited to refiners that had actually exercised their purchase opportunities from September 1, 1976, through August 31, 1977, and did not have access to imported crude oil. Those not included in the program could be added if they experienced or expected a 25 percent reduction in their supplies.

Toward the end of 1978, world crude oil supplies once again tightened up. The Economic Regulatory Administration amended the program in April 1979, changing the reference period for determining the refiner's level of supply reduction and establishing a 95 percent allocation limit. Fifteen U.S. refiners were compelled to sell crude oil to eligible refiners, the volume of which was based on the seller's proportionate share of the total refining capacity of all sellers. Under President Reagan's decontrol order, the buy/sell program was eliminated effective March 31, 1981.

To the extent that the goal of equity is judged to be a form of assistance to small refiners, the buy/sell program has worked to a degree in that it promotes some sharing of supply coverage between small and large refiners. It totally ignores, however, the actual supply positions of various refiners. Thus, in a supply disruption it may be completely inequitable depending on how the impact of the shortfall affects individual refiners. Preferential treatment for some refiners is pre-ordained in this system.

STANDBY CRUDE OIL DISTRIBUTION PROGRAMS

In the international arena, the United States is a member of the International Energy Agency, which was established to administer the International Energy Program. Through the IEP, the 21 member nations have agreed to equitably distribute world crude oil supplies in the event of a serious worldwide shortage. Each member's distributed share is to be based on consumption during the previous year. The program can be triggered when at least one country has a shortfall of 7 percent compared to the previous year.

The domestic standby crude oil allocation program was adopted in January 1979. Its rules are put into effect either when the IEP is activated (unless overridden by the Secretary of Energy), or by the Economic Regulatory Administration based on its own judgment that a crisis situation has been reached. If activated, this program will distribute crude oil supplies among refiners by means of a buy/sell list that would permit each refiner to operate at a national utilization rate.

A bias in favor of small refiners remains in the standby allocation program. This takes two forms. First, the DOE has flexibility as to which size refiners will be buyers or sellers; depending upon the severity of the shortage, small refiners may or may not be included on the sell list. Second, the provision for purchase price of the buy/sell volumes allows actual costs or imputed landed costs to be used when volumes are sold to refiners whose capacity exceeds 50 MB/D; weighted average costs are to be used when volumes are sold to refiners whose capacity is less than 50 MB/D.

This program is similar to the current buy/sell program. In terms of equity, there continue to be provisions in the program which may result in preference for small refineries. Since the DOE has the option of placing any refiner, regardless of size, on the sell list, this preference may not be applied; on the other hand, however, is the fact that vaguely defined, discretionary rules of this kind can cause the DOE to be exposed to heavy political pressure to make suboptimal decisions. Like the buy/sell program, this programs's effectiveness in time of a severe shortage of crude oil would be less than total because it makes no allowance for refinery efficiency. The terms of this standby program were not affected by President Reagan's decontrol order and remain in place until expiration of EPAA on September 30, 1981.

APPENDIX G

Emergency Products Distribution

EMERGENCY PRODUCTS DISTRIBUTION

STANDBY EMERGENCY PRODUCT DISTRIBUTION SYSTEM

As discussed in Chapter One of this report, in large crude oil disruptions to the United States (generally in excess of approximately 2 to 3 MMB/D), the competitive market should be relied upon to the extent possible, supplemented by voluntary and mandatory steps of demand restraint, fuel switching, discontinuation of the SPR fill, possible distribution of SPR stocks, and emergency oil and gas production.

Under emergency imported crude oil supply disruption conditions, a standby crude oil distribution program to bring all domestic refiners to a common crude oil run ratio may be implemented. Such a program would provide for a reasonably uniform geographic distribution of the available crude oil and provide each active U.S. refiner an opportunity to continue serving its customers. This conclusion is drawn even with the knowledge, based on prior experience, of the distortions created and the difficulties of administering such a problem in an efficient manner.

Standby Priority User Designations

In the event of a large and sustained imported crude oil supply disruption to the United States, available petroleum product supplies will be restricted to levels well below pre-disruption availability. Under these circumstances, there should be available a standby program of limited priority user designations. The priority user classifications should be designated by the federal government and should be limited to the protection of national security, health, and safety interests. Priority user classifications and designations should be held to a minimum because volumes supplied preferentially to an end-user group would differentially reduce the remaining volumes available to all other consumers. Under such a program, priority users should only be assured of volumes available under their supply contracts or of volumes approximately equivalent to their liftings during an immediately prior period. Priority user programs should avoid terms that provide current requirements. Such terms are subject to abuse, as has been experienced in prior efforts to distribute current requirements on a priority basis.

The priority user program should be complemented by a state set-aside program to provide limited volumes for distribution at each state's discretion in meeting additional priority and essential needs. Distribution of state set-aside volumes should be restricted to consumers and marketers particularly hard hit by the shortage. The state set-aside volumes should not exceed approximately 3 percent of each refiner's total motor gasoline and middle distillate sales volume within each state. Other product lines, such as residual fuels, could also be included in the state set-aside programs if severe dislocations occur in the emergency. However, motor gasoline and middle distillates will likely be the products of greatest concern in the emergency.

It is important that the state set-aside volumes not be set too high because these volumes are automatically deducted from the product volumes that suppliers have available for distribution to their customers. It is also important that the states release any unused state set-aside to the product suppliers for distribution as quickly as possible. Delay in returning unused state set-aside to suppliers can unnecessarily worsen product shortages.

Product Supplier/Purchaser Relationships

In the event of less severe imported crude oil supply disruptions generally not exceeding approximately 2 to 3 MMB/D to the United States, existing product supplier/purchaser contracts and supplier assurances should normally accomodate product distribution concerns in most situations. The existing product supplier/ purchaser contract structure is backed by an extensive body of contract and antitrust law. The Petroleum Marketing Practices Act generally prohibits arbitrary termination of contracts with branded motor fuel jobbers/dealers and deals with some aspects of market withdrawal. The Uniform Commercial Code requires fair and reasonable distribution of available volumes where inadequate to meet contract obligations. The antitrust laws prohibit attempted monopolization (Sherman Act); price discrimination (Robinson Patman Act); and unfair methods of competition (Federal Trade Commission Act). This body of contract and antitrust law provides aggrieved purchasers ample opportunity to contest their grievances through the courts, should that become necessary. It has been reported that many suppliers voluntarily distributed middle distillates among their customers pursuant to their contracts with generally favorable experience during the supply disruption in 1979 following the Iranian revolution.

In more severe crude oil import disruptions (generally exceeding about 2 to 3 MMB/D to the United States), implementation of a standby crude oil distribution program would allow each domestic refiner the opportunity to continue serving its customers as should be expected. However, pressures for implementation of federal product distribution guidelines are likely to build from fear of market withdrawals and nonrenewals of jobber/dealer or commercial account contracts.

Despite generally unfavorable experience with measures of this type in the past, a federal program of standby product distribution guidelines should be available to address these concerns. These guidelines should provide for a continuation of supplier/purchaser relations for the duration of the disruption in crude oil imports to the United States. These guidelines should prohibit unilateral supplier contract termination or market withdrawal during a severe supply disruption. Since the existing body of contract law will require fair and reasonable distribution of volumes available under the standby mandate, there is essentially no need for further mandatory provisions dealing with the volumes to be made available by a supplier to its accounts. The standby product distribution guidelines should include on an exception basis provisions for establishing buyer volume rights in those cases in which a contract does not exist between the supplier and purchaser. The standby product distribution guidelines should also address the unique needs of certain consumer accounts whose needs could be expected to move geographically over time. An example would be a construction contractor whose needs would move geographically from one contract location to another.

The standby product distribution guidelines should be designed to specifically avoid special interest provisions such as special adjustments, upward certifications, and new business provisions. Avoiding such special interest provisions would simplify administration and minimize the building of constituencies against deactivation of the emergency standby program.

During a large petroleum imports disruption to the United States, there is some possibility that product importers might be disproportionately affected relative to product purchasers supplied by domestic refiners. This possibility would appear remote since most U.S. product imports are from Caribbean refiners and over the years the Caribbean refiners have proven to be a reliable product supply source. However, if product importers suffer a disproportionate shortfall in imported supplies of major proportions relative to a determined percentage of available supplies just prior to the disruption, the shortfall should be partially made up through a standby product distribution system which directs sales of refined products to them. This percentage could be determined by the government, based on the total availability of products. Once established, the supply rights of product importers could be satisfied by both domestic refiners and offshore suppliers.

Termination Provisions

The standby product distribution guidelines, when implemented, should be accompanied by a sunset clause providing for discontinuation of the guidelines within a set period of time -- probably three or six months. Continuation of the mandated guidelines beyond the time frame specified in the sunset clause should require review and approval by either the President or the Congress.

State and Local Preemption

The federal standby emergency product distribution measures should be accompanied by specific provisions that the terms of these programs preempt any state or local programs to the extent that they conflict with federal programs.

It is recognized that product distribution measures cannot adequately replace the dynamics of a competitive market, and will inevitably create distortions and inequities. This may be true, for example, for end uses such as petrochemical feedstocks, which may be experiencing significant growth. Concerns for these types of problems reinforce the recommendations of this study that emergency product distribution measures only be implemented in very severe supply disruptions and that they be accompanied by specific termination provisions.

STANDBY EMERGENCY PETROLEUM PRODUCT MARGIN LIMITATIONS

As discussed in Chapter One of this study, in the event of a severe crude oil import disruption to the United States (generally in excess of approximately 2 to 3 MMB/D), the market should be relied upon to the extent possible supplemented by voluntary and mandatory steps of demand restraint, fuel switching, discontinuation of the SPR fill, possible distribution of SPR stocks, and emergency oil and gas production.

It is assumed that a fundamental government policy in support of maximum reliance on market mechanisms during crude oil import disruptions to the United States will include market pricing of domestic crude oil. This policy should encourage conservation and fuel switching and thus make possible the protection from vulnerability that these actions potentially afford. Importantly, market pricing of domestic crude oil during an emergency crude oil import disruption would allow crude oil prices to rise to clear the products market as efficiently as possible. It is estimated that the crude oil excise tax (the "windfall profit" tax) and other existing taxes would divert about 80 to 90 percent of the domestic crude oil price increases to government.

Petroleum Product Margin Limits

During a severe crude oil imports disruption, even though market pricing of domestic crude oil would tend to clear the downstream market, there is still likely to be considerable potential for public concern over windfalls downstream of the wellhead in petroleum product manufacturing, distribution, and marketing. This concern may be most widely evident immediately following an imports disruption if there were a time lag before crude oil prices rose sufficiently to clear the market. Public concern may also be voiced over the actions of individual refiners or marketers during a supply disruption that may be perceived as generating windfalls. To address these concerns, and as an alternate to a downstream windfall profits tax overkill measure, a simple structure of standby refiner and marketer product margin limits should be available.

The refiner margin limitation should include sufficient flexibility to allow refiners to respond to changes in fuel costs, crude oil quality, and product demands or output guidelines while continuing to generate an adequate return on their refining investments. To accomplish this objective, the refiner margin limitation should consider fuel as a cost of input; consider as fixed the monthly average margin (less fuel costs) earned by each refiner in the year prior to the disruption and allow the dollar amount to escalate with a recognized and relevant inflation index; and permit a standard increase/decrease in margin for increased/decreased processing of heavier, higher sulfur crude oils.

Jobber and dealer product margins should be limited to generous fixed cents-per-gallon levels that escalate with a recognized and relevant inflation index.

A downstream windfall profits tax would be a highly unsatisfactory alternative to a limited program of standby refiner and marketer product margin limits. Public concerns would not be as adequately addressed, and furthermore, a downstream windfall profits tax would likely be administratively ineffective due to massive reporting and enforcement difficulties.

Petroleum Products Tax

At the outset of a petroleum imports disruption, a petroleum products excise tax could be implemented immediately to reduce demand for various products and reduce the opportunity for refiner and marketer windfalls early in a disruption. The advantages and disadvantages of the use of a product excise tax are discussed in Chapter One of this study.

Special Interest Provisions

The use of special interest provisions or interference with the downstream refiner or marketer margin structure beyond the scope outlined in the foregoing comments should be avoided. Such provisions, although well intended, may be expected to introduce distortions and disincentives into the downstream product margin structure. Results can range from unwarranted disincentives that could worsen product shortages to the building of constituencies against the termination of standby measures such as margin limitations after the emergency is over.

Termination Provisions

The standby emergency refiner and marketer product margin limits, when implemented, should be accompanied by a sunset clause providing for discontinuation of the controls within a set period of time -- probably three to six months. Continuation of the controls beyond the time frame specified in the sunset clause should require review and approval by either the President or the Congress.

GAS PLANT PRODUCTS

The standby measures discussed in this appendix deal with the emergency distribution of products from crude oil. It should be recognized that the supply conditions which create the need for standby emergency crude oil and petroleum product distribution or margin measures may, or may not, create a similar need for emergency distribution of gas plant products. Any decision on the need for emergency distribution of gas plant products should be made separately, taking into consideration the supply/demand balance for these products. Emergency distribution measures affecting propane, in particular, should be developed with the recognition that this product is derived in significant quantities both from natural gas and from crude oil.

It should also be noted that this study has not specifically addressed the implications of a disruption of LPG imports. Some energy analysts project an increasing U.S. dependence on LPG imports over the next ten years. Even though there appears to be significant flexibility on the part of petrochemical users of LPG imports to switch to other feedstocks, a disruption of imported LPG supplies could adversely affect the nation. Thus, government contingency planning should include additional study of this potential area of vulnerability.

APPENDIX H

Emergency Supply/Demand Management Scenarios

EMERGENCY SUPPLY/DEMAND MANAGEMENT SCENARIOS

USE OF SCENARIO ANALYSES

The use of scenarios in contingency planning is a convenience to test the appropriateness and the effectiveness of particular responses to meet a given situation. The several scenarios involving increased levels of supply disruption in terms of crude oil available to the United States are admittedly arbitrary and do not necessarily reflect any particular situation or event, political or economic, deliberate or accidental, that may in fact occur which would affect the availability of crude oil to the United States. Similarly, in developing the various responses to meet the imports disruptions, it is necessary to make arbitrary assumptions about the effectiveness of particular programs. It is recognized that the response in a dynamic market economy is never altogether predictable.

Once having performed the analytical exercise of scenario assessment and response development, it is necessary to view from a slightly different perspective the identification of policy strategies. In an actual emergency situation, an assessment of the anticipated disruption in crude oil imports will be plagued with uncertainty, with respect to both the intensity and the duration of the interruption. It is also possible that an initial assessment of one level of supply disruption may of necessity be adjusted to reflect an increasing or decreasing level of imports disruption over time. In short, as the nation experiences an imports disruption it must be viewed as a continuum with a gradual increase or decrease in the level of expected duration and intensity.

In developing responses, the policymaker is faced with a similar problem. His view of the supply situation is a snapshot which, before it can be developed and viewed, is overcome by events. No specific program or package of programs, therefore, is appropriate to meet any given level of imports disruption at any particular time. When one appreciates fully the uncertainty of the assessment in the first instance and the uncertainty surrounding the effectiveness and timeliness of the particular program in advance of its implementation, it may suggest inaction on the part of the responsible body attempting to alleviate the impact of the disruption. It may be argued, however, that it simply underlines the necessity of having both an ongoing assessment and a flexible response capability in the system that is devised to provide management of emergencies.

Anticipation of an interruption in crude oil imports to the United States will not be an overnight event. There will be sufficient lead time both to assess the intensity and duration and to evaluate the appropriateness of particular responses. What would be inappropriate would be a sterile calculation of some figure which would then be used to trigger one plan or another. It is imperative that the industry and the government effect an appropriate response to meet a particular situation. Pre-planning is also imperative to ensure that the range of responses available is sufficient to deal with the widest range of disruption possibilities. An ongoing government and industry assessment capability would seem to meet the needs of the nation in this respect.

While the United States is almost certain to experience many situations during the next decade that pose an imminent risk of severe oil supply disruptions, past experience suggests that most of these crises will pass without a cumulative loss of production sufficient to create conditions of severe national emergency. In general, however, we will not know this until after the crisis has been resolved (or displaced by the next crisis). Past experience also suggests, however, that crises falling well short of severe national emergency may result in price increases sufficient to inflict widespread hardship and some legitimate demands for relief from such hardship. Government cannot completely insulate the U.S. society from the effects of a significant supply reduction; it will have to respond to the claims of those faced with extraordinary hardship, and it may have to mobilize such response early in a crisis to avoid more extreme intervention in market processes.

Among the most difficult problems associated with managing an energy crisis is that of assessing the seriousness of the crisis while it is in progress. This study points out that no simple or mechanistic trigger mechanism to govern our responses will deal adequately with the uncertainty and complexity of a serious energy crisis. The factors that will affect judgment about the severity and duration of the crisis and that will govern the timing and nature of crisis response measures include assessment of the nature of and motivation for the disruption, its coupling with international, political, or national security issues, the impact on other countries, the nature of their response, and the prospects for coordination of U.S. responses with those of other countries. The development of a suitable crisis assessment process is among the most important government tasks in preparing to deal with energy crises. While several hypothetical crises of varying severity have been used to assist in this analysis, we do not believe that crisis response measures can usefully be graded in terms of crisis severity, except in very general and qualitative terms.

ILLUSTRATIVE DISCUSSION OF APPROACH TO EMERGENCY SUPPLY/DEMAND MANAGEMENT

Supply disruptions may range from very minor to quite severe. An effective emergency preparedness plan should be flexible and should be designed to deal differently with varying degrees of gross imports reduction and net shortfall. Table H-1 is a matrix which may be helpful in understanding the sequence of actions which should be considered when dealing with supply disruptions. In developing the matrix, the actions are guided by market forces to the maximum degree practicable. Over the last several years the results of interfering with the market mechanism have demonstrated that allocation and price controls often exacerbate shortages. It should be realized that higher prices are likely in a shortfall

TABLE H-1

ILLUSTRATION OF APPROACH TO EMERGENCY PREPAREDNESS - SEQUENCE OF EVENTS DISRUPTION OF IMPORTS TO U.S.

Gross Denial	(0-1 MMB/D - (0-6%))	(2-3 MMB/D - 12%)	(≥4.5 MMB/D ≥ 27%)	
			Implementation Sequence	
			Initially	Later
o Demand Management Difficulty of Implementation				
- Low	X	X	X	
- Moderate	X	X	X	
- Major			X	
o Fuel Switching				
- Partial	X	X	X	
- All			X	
o Emergency Production (Oil & Gas)		X	X	
o Diversion of SPR Fill		X	X	
Resulting Net Shortfall	(0-.25 MMB/D - (1.5%))	(.5-1.5 MMB/D - 3%)	(2 MMB/D - 12%)	
o Private Stocks Drawdown	X	X	X	
o Priority Users - Guidelines			← — — X	
o Crude Distribution Program			← — — X	
o Product Distribution Program				X
o Consumption Tax/Rebate (Coupon Rationing)				X
o SPR Draw		X	X	

situation; however, it is believed that a competitive market would be an efficient method to distribute available supplies. Sharp price increases may create some hardship which should properly be addressed by the government.

Two different types of crude oil denial are displayed in the matrix: gross denial, which refers to the actual amount of crude oil that is denied the United States; and net denial, which reflects the amount of shortfall with must be dealt with through mechanisms other than demand management, fuel switching, or emergency production. This net shortage can certainly be affected greatly by destocking in the private sector. A key issue is the circumstances under which the destocking decision is made. Arguments can be made that the decision to destock will be made under competitive market conditions because of concerns that if it is not made, more onerous control programs (crude oil or product allocation) would be likely. Another reason a corporation will choose to use available inventories is to avoid the sudden shock of a step function supply change to its customers. By using inventories, supply changes can be phased in gradually, giving the customer valuable planning time. Upon examination of the matrix, it is apparent that some possible options have been excluded; the reasons basically fall into the category of concerns about workability.

During imports disruptions, the nation must utilize the available supplies as efficiently as possible. For reasons of maximizing available supplies, efficiency concerns should be considered relatively more important than equity issues. However, the controlling concern is that the entire public, while sharing the pain, be served in the most efficient manner.

The sequencing of actions becomes critical after arriving at the net denial quantification because proceeding beyond the priority user guideline step significantly burdens the market mechanism. One mechanism to ensure the proper sequencing is to utilize expert opinion from many sectors of the economy.

This critical element of an emergency preparedness plan is best accomplished by utilizing the expertise of various groups, including but not limited to the oil industry, consumers, and academia. Often in shortage situations, the precise level of shortfall is difficult to determine because inventory changes are occurring, some producers may actually increase production, and demand may be restrained because of escalating prices. The advisory group expertise can help define the situation and, as a result, recommend appropriate action. Expert advice need not be limited to the group forum. It can also be called for by the government in private one-on-one sessions.

If at all possible, the meetings should be open to the public; however, the meetings should be closed to the public if national security concerns or foreign policy sensitivities are discussed. Throughout the process, if technical advice is needed, advisory groups with particular expertise could be convened. In the preplanning stage, an argument can be made for periodic meetings of the advisory group to fully develop the emergency preparedness plan, update it, and provide timely advice to government. The disengagement, or sunset stage, must be followed when the emergency is over or the credibility of the emergency plan will suffer.

EMERGENCY SUPPLY/DEMAND MANAGEMENT SCENARIOS

Figures H-1 through H-5 illustrate the potential effects of emergency preparedness actions described within this study relative to the supply disruption scenarios also provided herein. The quantitative effects of the various emergency options should be considered as no better than "order of magnitude" quality. It is impossible to project the actual magnitude or duration of the supply disruption with which the United States may be faced or to project the effectiveness of the specific emergency management options which may be selected to reduce the effects of the disruption. The following assumptions were used in development of the emergency supply/demand management scenarios presented in Figures H-1 through H-5:

- Levels of demand reduction and fuel substitution are based on potentials provided in Chapter Two of this report.
- Announcement of disruption of import supplies occurs 45 days prior to actual impact in the United States and normal supplies are re-established 45 days after resolution of interruption. For the case study, disruption announcement begins October 1985.
- Minimal increases in demand occur at the outset of announced disruption due to consumer fear and tendency to build stocks.
- Nationwide appeals for voluntary conservation are implemented within the first two weeks of the announced disruption and assessment of potential impact. Efficient personal energy consumption patterns are urged.
- The federal government diverts NPR crude oil production from SPR fill to marketplace at 100 MB/D -- immediately upon announcement of a disruption of 2 MMB/D or greater.
- Beginning within 30 days after a disruption of 2 MMB/D or greater, state and federal process is begun to remove or amend existing legal constraints on energy conservation and initiate new laws encouraging or mandating increased conservation and supplies. The assumed process requires an additional 30 days for enactment; such measures have a .50 percent effectiveness during the third month and near or at 100 percent by the fourth or fifth month.
- Assumed price increases and consumer inconvenience begin to have a growing impact on the effectiveness of voluntary conservation measures beginning in the second month of disruption. Effectiveness level and timing are accelerated with the perceived magnitude of shortfall disruption.

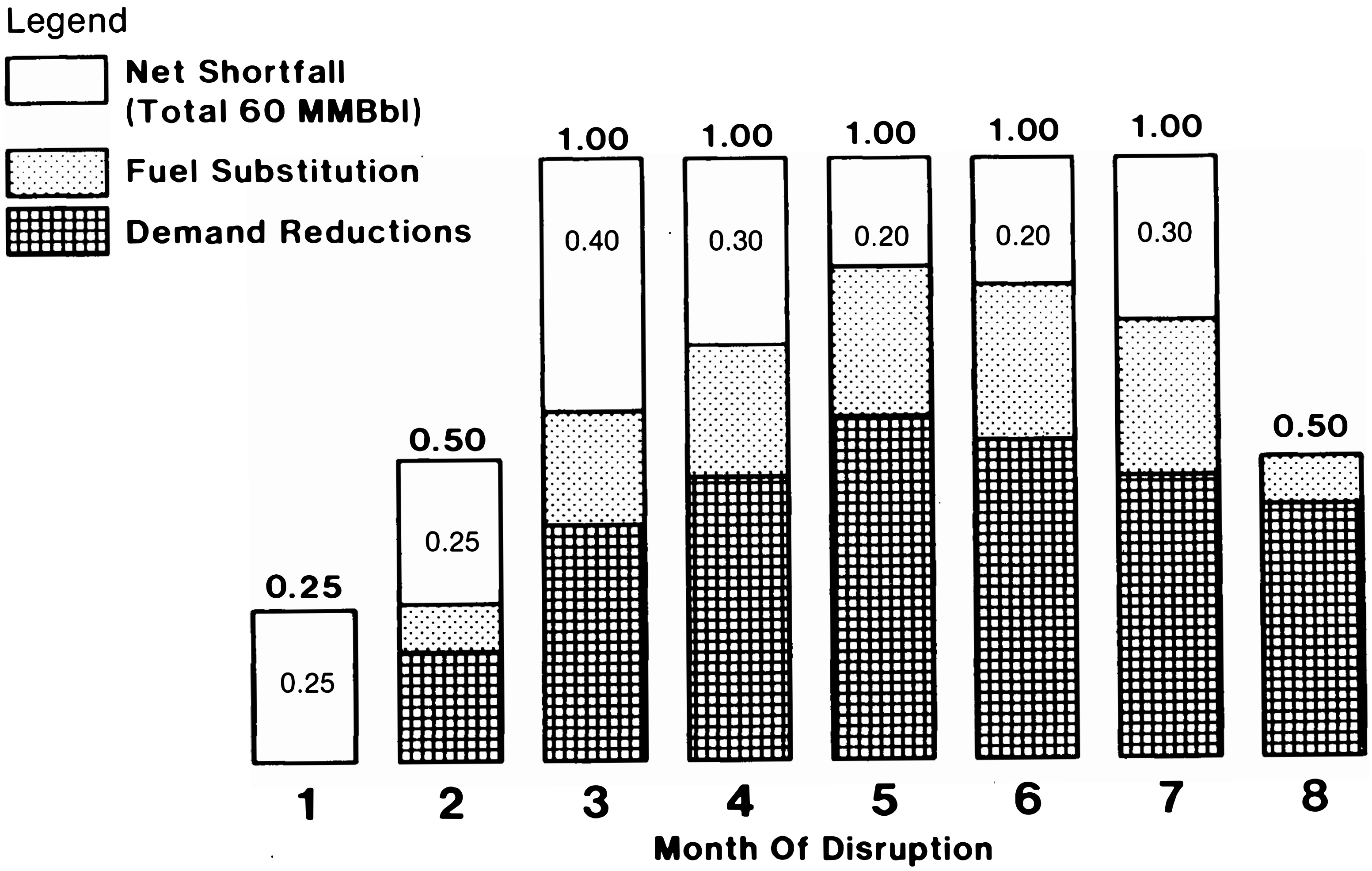


Figure H-1. Emergency Supply Demand Management; Scenario 1—1985 (MMB/D).

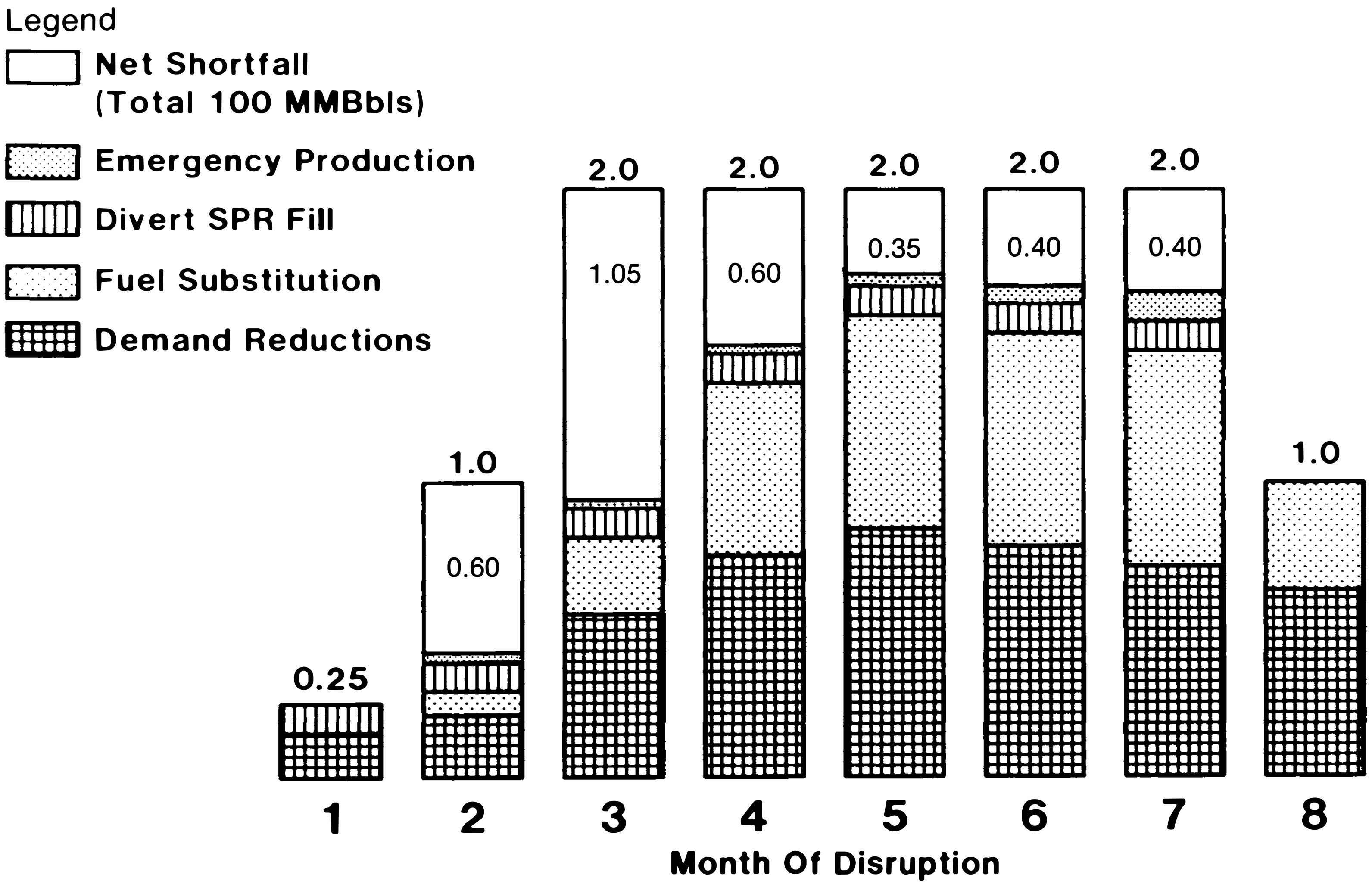


Figure H-2. Emergency Supply Demand Management; Scenario 1A—1985 (MMB/D).

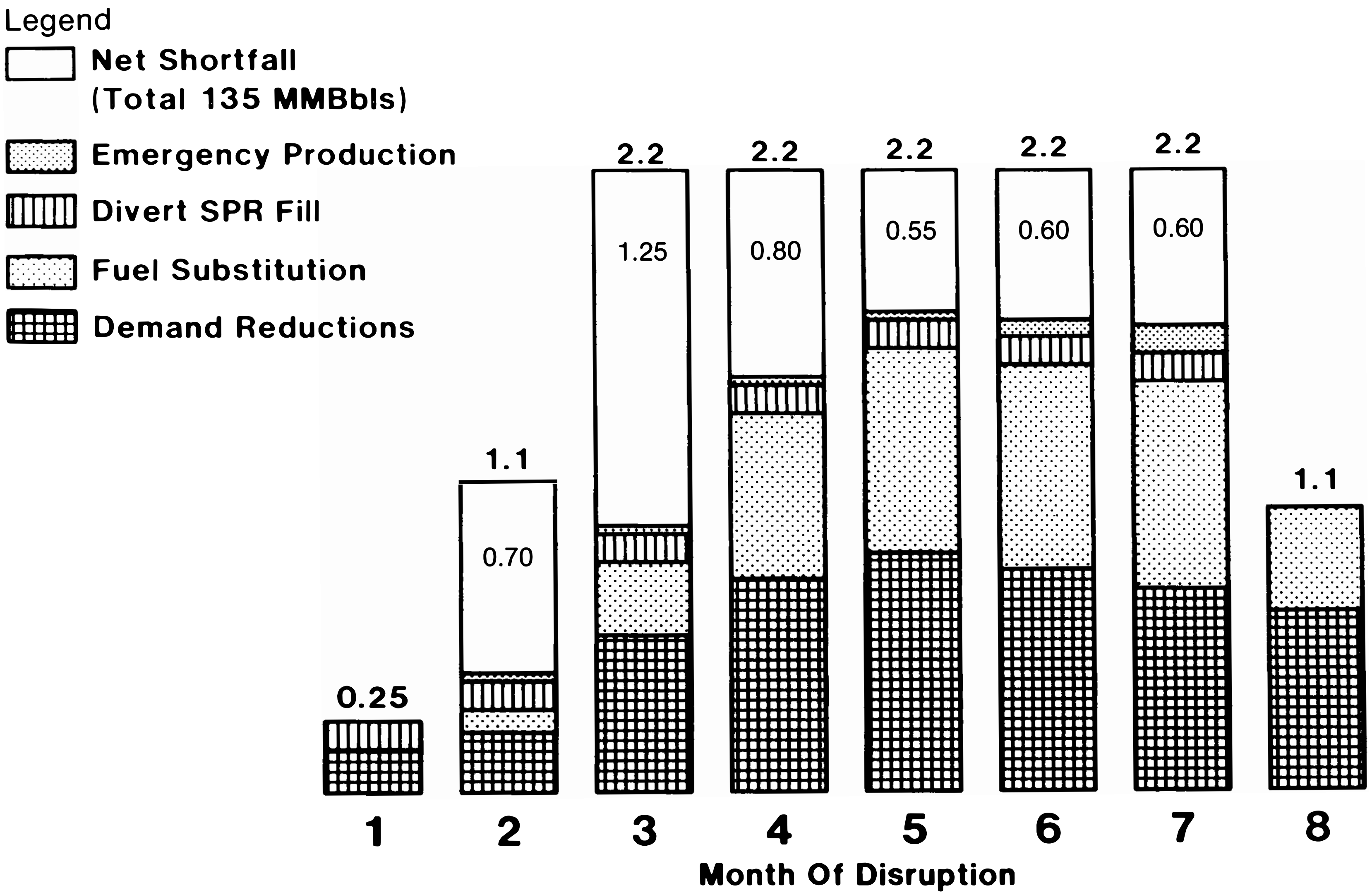


Figure H-3. Emergency Supply Demand Management; Scenario 2—1985 (MMB/D).

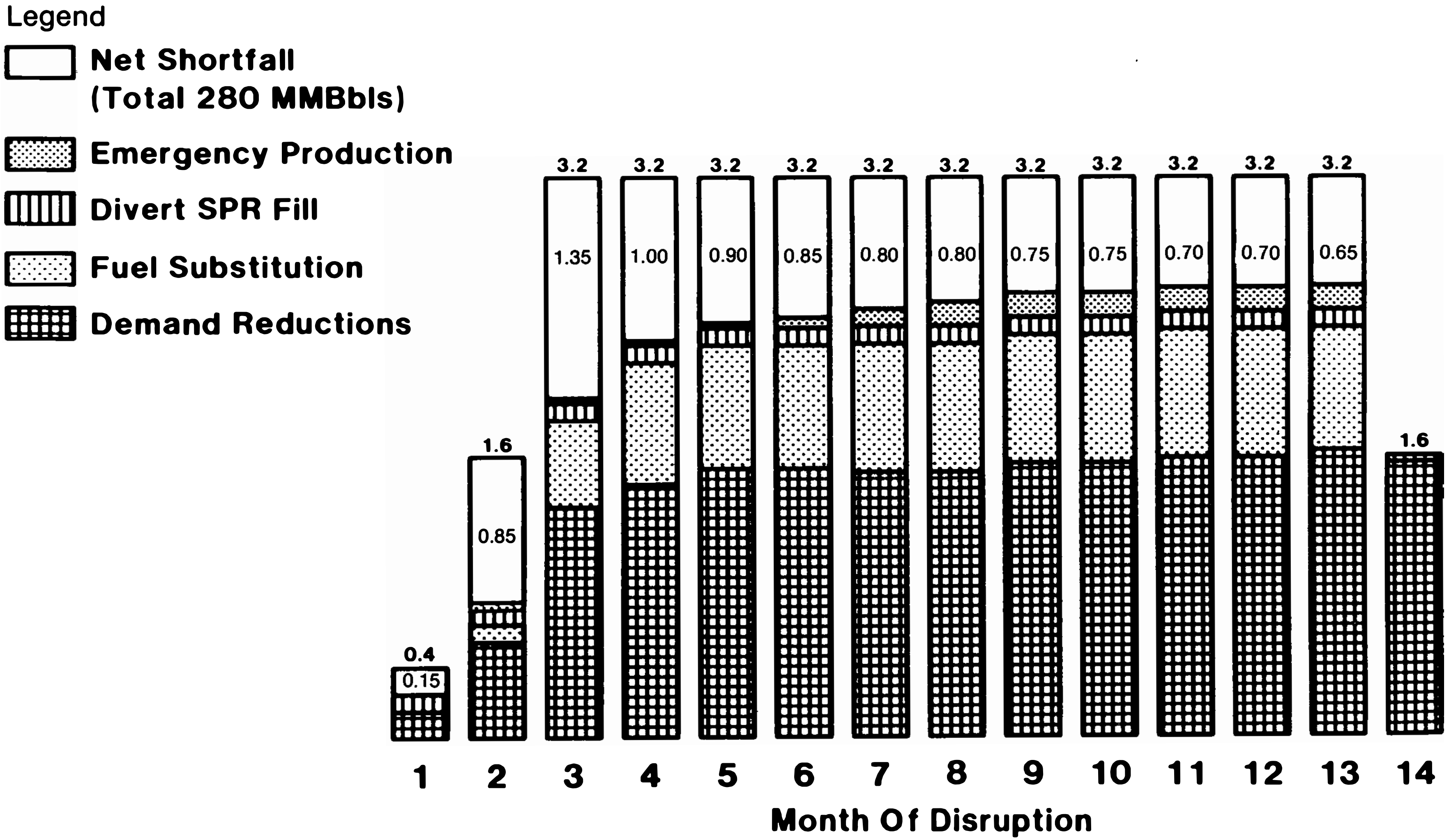


Figure H-4. Emergency Supply Demand Management; Scenario 3—1985 (MMB/D).

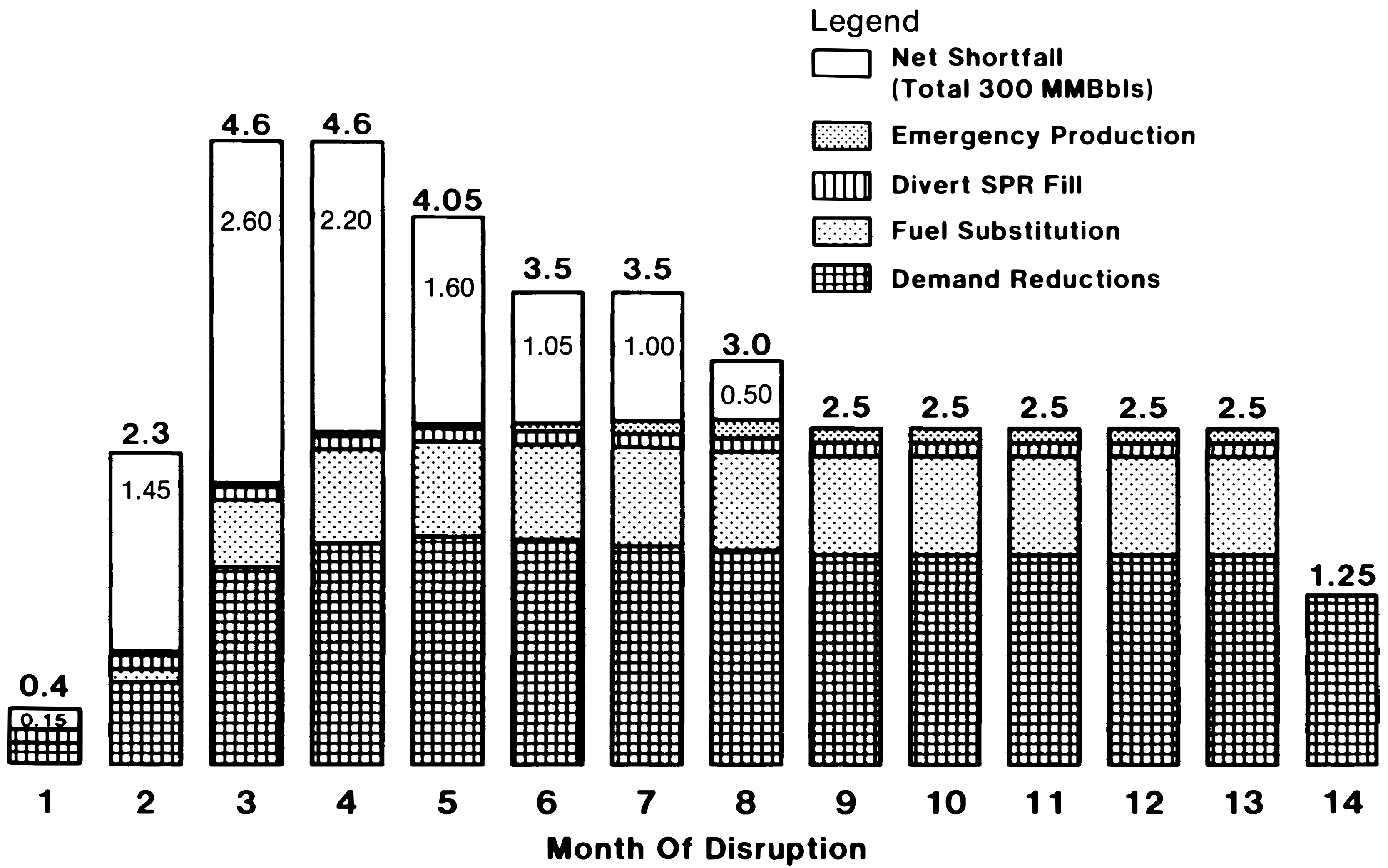


Figure H-5. Emergency Supply Demand Management; Scenario 4—1985 (MMB/D).

- Emergency oil production levels assume a 30-day delay beyond estimates provided in Chapter Four for moderate and severe supply interruption scenarios.

- The potential effects of private and public inventory drawdown, high energy prices, price controls, distribution mechanisms including tax/rebate, allocation, and rationing have not been incorporated into scenario studies.

Sensitivities which must be recognized in evaluating the potential effectiveness of the emergency supply/demand management options include the following:

- Government pricing and allocation strategies could severely affect the effectiveness of conservation actions, especially voluntary steps.

- Public sympathies toward cause and degree of interruption and effect on national security could affect effectiveness to support conservation efforts.

- The impact of diverting crude oil supplies from SPR fill to the marketplace is dependent upon the fill rate at the time of disruption.

- Potential effectivenss of private and SPR inventories will be a direct function of availability.

- Federal management of interruption under pressure of crisis could have a significant effect on implementation of demand restraint measures and alternate supply sources.

EMERGENCY PRODUCT DEMAND MANAGEMENT AND REFINING OPERATIONS

Figure H-6 illustrates the effects on products supplies which could occur under Scenario 4, for 1985, based on the emergency response steps identified in the report and illustrated in Figure H-5. The product shortfalls or overages for different products would result as shown should refinery yield patterns not be adjusted beyond normal seasonal changes and all refined product output is reduced proportionally by the shortfall. The shortfall or overage of different products results from lesser or greater effectiveness of demand reduction and fuel substitution response steps identified for particular products.

Figure H-7 illustrates the effects on product supplies under Scenario 4, for 1985, where refinery yield patterns are adjusted so that the total shortfall which results from a disruption of supplies is reflected entirely in motor gasoline output. Figure H-8 illustrates the associated reduction in refining product output for Scenario 4, for 1985, vs. normal levels as well as the percentage change in product mix output which would be required to reflect the entire shortfall in motor gasoline. The flexibility of U.S. refineries to make these adjustments is discussed in Chapter Six.

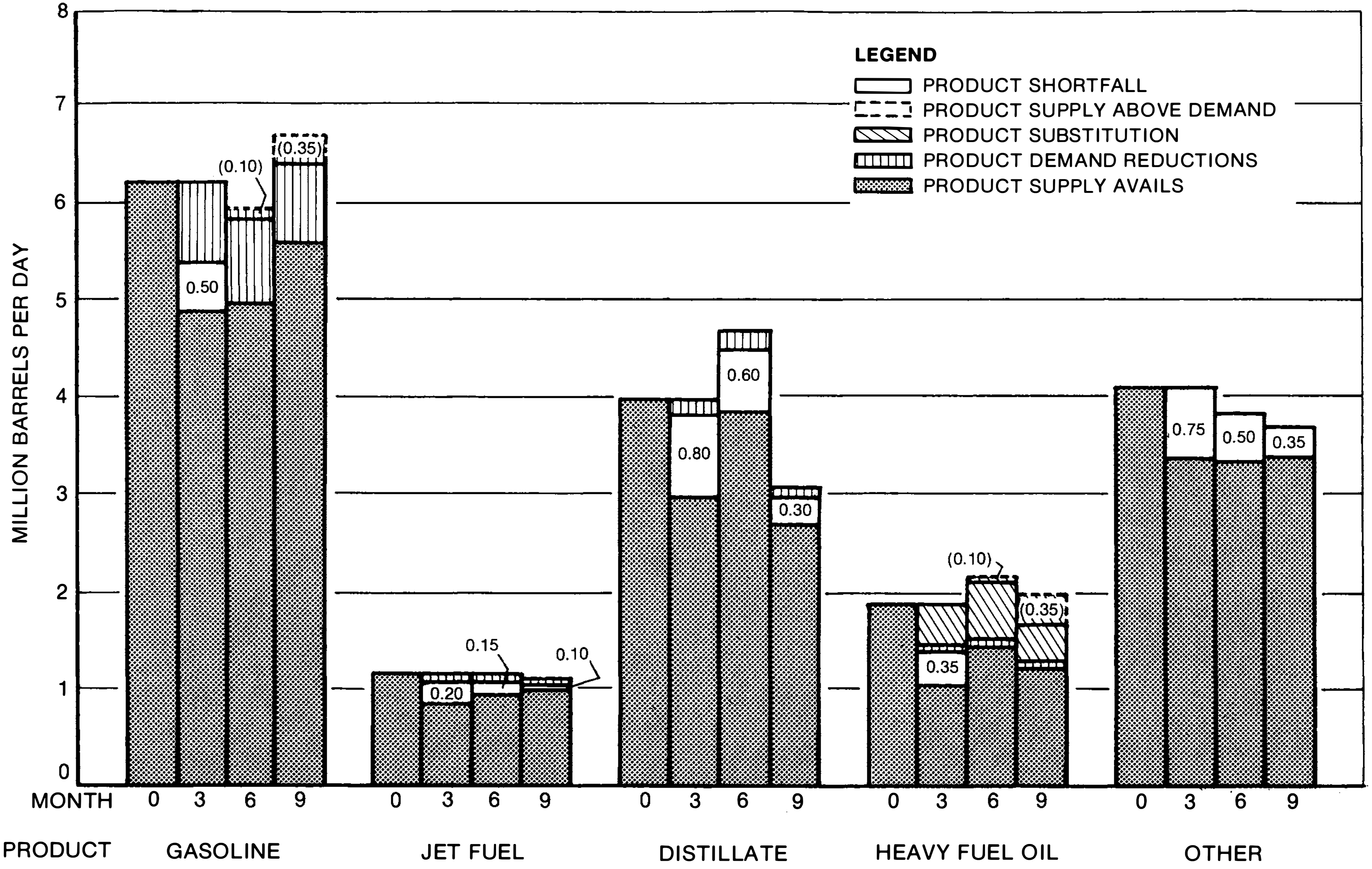


Figure H-6. Emergency Product Demand Management; Scenario 4—1985.
Without Change in Normal Refinery Yield Patterns.

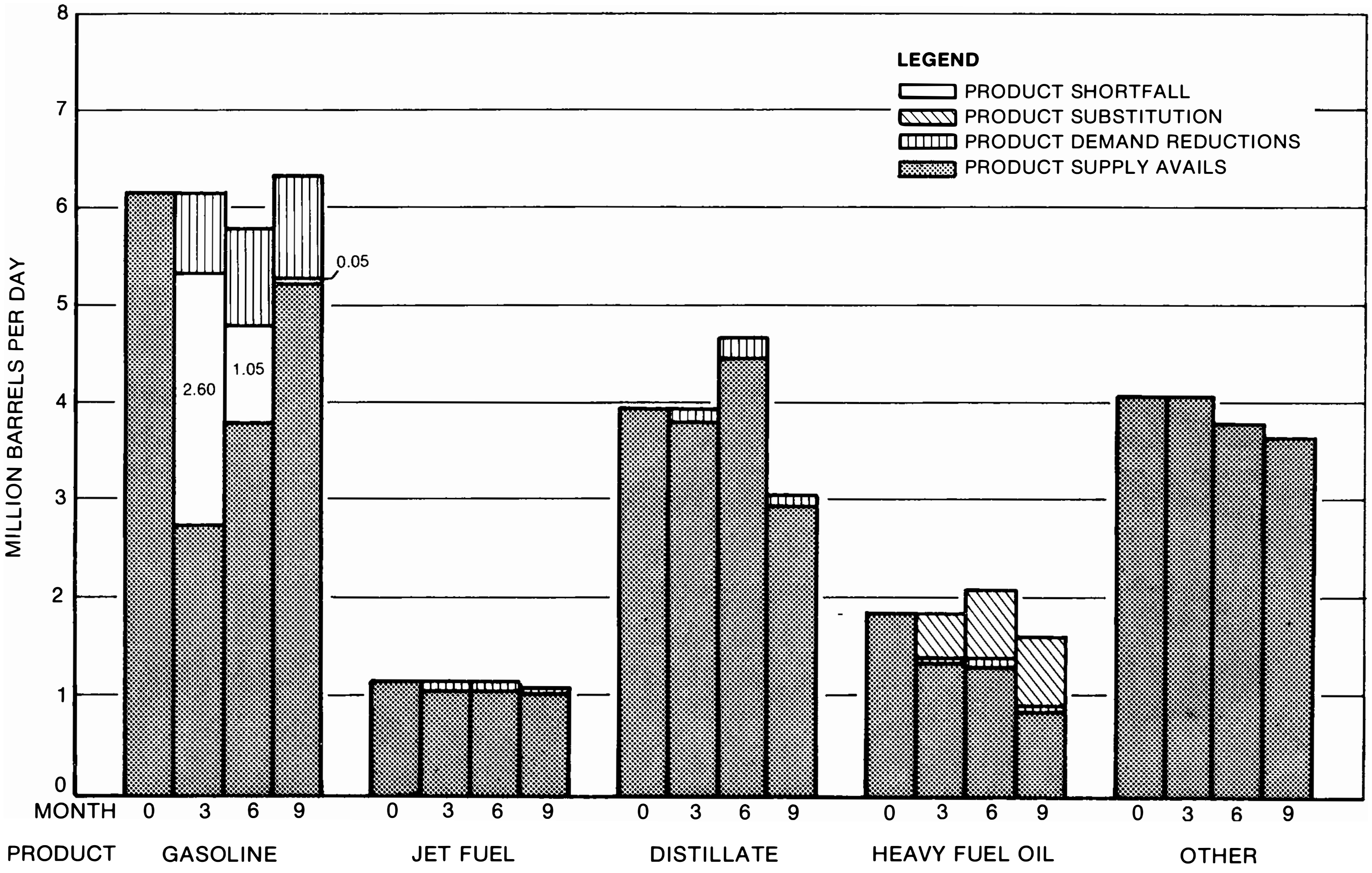


Figure H-7. Emergency Product Demand Management; Scenario 4—1985.
Refinery Yield Patterns Reflect Shortfall Entirely in Gasoline.

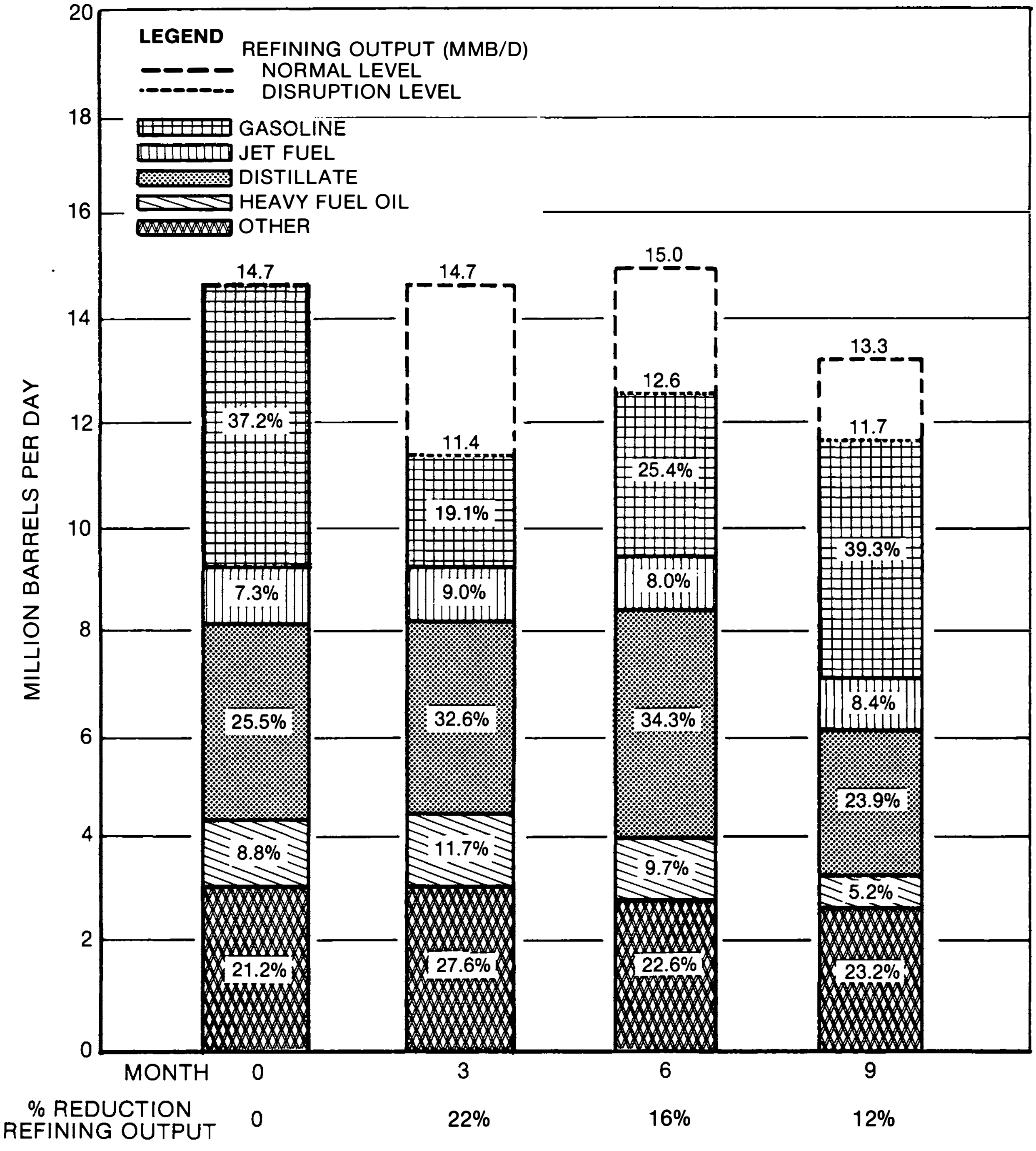


Figure H-8. Emergency Refining Operations; Scenario 4—1985. Shortfall Reflected Entirely in Gasoline.

APPENDIX I

Scenario Supply/Demand Balances and Pre-Disruption Supply/Demand Outlook

EXHIBIT 1

SCENARIO SUPPLY/DEMAND BALANCES

TABLE I-1

CASE 1

DENIAL PERIOD: SUMMER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	500	85	40		625			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			75	75	150	20	115	10
Electric Utilities			-	280	280	-	235	30
NET TOTAL	500	85	150	355	1090	(20)	250	40

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	500	85	190*	400*	1175
Product Denial	25	10	25	115	175
Net	(475)	(75)	(165)	(285)	(1000)
Crude Denial(3)	410	45	190	205	850
BALANCE(2)	(65)	(30)	25	(80)	(150)

(*)Adjusted for refinery throughput energy reduction savings of 40 M B/D Dist., 45 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-2

CASE 1A

DENIAL PERIOD: SUMMER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	500	85	40		625			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			75	75	150	20	115	10
Electric Utilities			-	280	280	-	235	30
NET TOTAL	500	85	150	355	1090	(20)	250	40

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	500	85	225*	440*	1250
Product Denial	45	20	50	235	350
Net	(455)	(65)	(175)	(205)	(900)
Crude Denial(3)	815	90	385	415	1705
BALANCE(2)	360	25	210	210	805

(*)Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-3

CASE 2

DENIAL PERIOD: SUMMER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	500	85	40		625			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			75	75	150	20	115	10
Electric Utilities			-	280	280	-	235	30
NET TOTAL	500	85	150	355	1090	(20)	250	40

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	500	85	225 *	440*	1250
Product Denial	50	20	55	275	400
Net	(450)	(65)	(170)	(165)	(850)
Crude Denial(3)	890	100	420	450	1860
BALANCE(2)	440	35	250	285	1010

(*) Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-4

CASE 3

DENIAL PERIOD: SUMMER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	405	405	-	235	30
NET TOTAL	1055	85	225	555	1920	(10)	335	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	335*	680*	2155
Product Denial	80	30	85	405	600
Net	(975)	(55)	(250)	(275)	(1555)
Crude Denial(3)	1285	145	605	650	2685
BALANCE(2)	310	90	355	375	1130

(*) Adjusted for refinery throughput energy reduction savings of 110 M B/D Dist., 125 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-5

CASE 4A

DENIAL PERIOD: SUMMER 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	405	405	-	235	30
NET TOTAL	1055	85	225	555	1920	(10)	335	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	390 *	745*	2275
Product Denial	110	40	120	580	850
Net	(945)	(45)	(270)	(165)	(1425)
Crude Denial(3)	1855	205	870	940	3870
BALANCE(2)	910	160	600	775	2445

(*) Adjusted for refinery throughput energy reduction savings of 165 M B/D Dist., 190 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-6

CASE 4B

DENIAL PERIOD: SUMMER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	405	405	-	235	30
NET TOTAL	1055	85	225	555	1920	(10)	335	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	350*	700*	2190
Product Denial	85	30	90	445	650
Net	(970)	(55)	(260)	(255)	(1540)
Crude Denial(3)	1410	155	660	715	2940
BALANCE(2)	440	100	400	460	1400

(*)Adjusted for refinery throughput energy reduction savings of 125 M B/D Dist., 145 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-7

CASE 4C

DENIAL PERIOD: SUMMER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			-	-	-	(5)	(10)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	405	405	-	235	30
NET TOTAL	1055	85	225	555	1920	(10)	335	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	315*	655*	2110
Product Denial	60	20	65	305	450
Net	(995)	(65)	(250)	(350)	(1660)
Crude Denial(3)	1015	115	475	510	2115
BALANCE(2)	20	50	225	160	455

(*) Adjusted for refinery throughput energy reduction savings of 90 M B/D Dist., 100 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-8

CASE 1

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	480	85	40		605			
Residential			70		70	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			75	75	150	20	115	10
Electric Utilities			-	300	300	-	255	30
NET TOTAL	480	85	200	425	1190	(55)	50	40

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	480	85	240 *	470*	1275
Product Denial	25	10	25	115	175
Net	(455)	(75)	(215)	(355)	(1100)
Crude Denial(3)	410	45	190	205	850
BALANCE(2)	(45)	(30)	(25)	(150)	(250)

(*) Adjusted for refinery throughput energy reduction savings of 40 M B/D Dist., 45 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-9

CASE 1A

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	480	85	40		605			
Residential			70		70	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			75	75	150	20	115	10
Electric Utilities			-	300	300	-	255	30
NET TOTAL	480	85	200	425	1190	(55)	50	40

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	480	85	275*	510*	1350
Product Denial	45	20	50	235	350
Net	(435)	(65)	(225)	(275)	(1000)
Crude Denial(3)	815	90	385	415	1705
BALANCE(2)	380	25	160	140	705

(*) Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-10

CASE 2

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	480	85	40		605			
Residential			70		70	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			75	75	150	20	115	10
Electric Utilities			-	300	300	-	255	30
NET TOTAL	480	85	200	425	1190	(55)	50	40

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	480	85	275*	510*	1350
Product Denial	50	20	55	275	400
Net	(430)	(65)	(220)	(235)	(950)
Crude Denial(3)	890	100	420	450	1860
BALANCE(2)	460	35	200	215	910

(*) Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-11

CASF 3

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	290	600	1985	(45)	135	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	400 *	725*	2220
Product Denial	80	30	85	405	600
Net	(930)	(55)	(315)	320	(1620)
Crude Denial(3)	1285	145	605	650	2685
BALANCE(2)	355	90	290	330	1065

(*) Adjusted for refinery throughput energy reduction savings of 110 M B/D Dist., 125 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-12

CASE 4A

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	290	600	1985	(45)	135	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	455*	790*	2340
Product Denial	110	40	120	580	850
Net	(900)	(45)	(335)	(210)	(1490)
Crude Denial(3)	1855	205	870	940	3870
BALANCE(2)	955	160	535	730	2380

(*) Adjusted for refinery throughput energy reduction savings of 165 M B/D Dist., 190 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-13

CASE 4B

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	290	600	1985	(45)	135	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	415 *	745*	2255
Product Denial	85	30	90	445	650
Net	(925)	(55)	(325)	(300)	(1605)
Crude Denial(3)	1410	155	660	715	2940
BALANCE(2)	485	100	335	415	1335

(*) Adjusted for refinery throughput energy reduction savings of 125 M B/D Dist., 145 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-14

CASE 4C

DENIAL PERIOD: WINTER, 1981

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			150	150	300	30	200	20
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	290	600	1985	(45)	135	50

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	380*	700*	2175
Product Denial	60	20	65	305	450
Net	(950)	(65)	(315)	(395)	(1725)
Crude Denial(3)	1015	115	475	510	2115
BALANCE(2)	65	50	160	115	390

(*) Adjusted for refinery throughput energy reduction savings of 90 M B/D Dist., 100 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation)	23.2
Heavy fuel oil and all others	25.0
	103.2

TABLE I-15

CASF 1

DENIAL PERIOD SUMMER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	500	85	40		625			
Residential			35		35	(35)	(90)	
Commercial			---	---	---	(5)	(10)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			---	280	280	---	235	30
NET TOTAL	500	85	280	495	1360	---	395	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	500	85	320 *	540*	1445
Product Denial	25	10	25	115	175
Net	(475)	(75)	(295)	(425)	(1270)
Crude Denial(3)	410	45	190	205	850
BALANCE(2)	(65)	(30)	(105)	(220)	(420)

(*) Adjusted for refinery throughput energy reduction savings of 40 M B/D Dist., 45 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-16

CASF 1A

DENIAL PERIOD SUMMER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	500	85	40	X	625			X
Residential	X	X	35	X	35	(35)	(90)	X
Commercial	X	X	--	--	--	(5)	(10)	X
Industrial Fuel	X	X	205	215	420	40	260	50
Electric Utilities	X	X	--	280	280	--	235	30
NET TOTAL	500	85	280	495	1360	--	395	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	500	85	355*	580*	1520
Product Denial	45	20	50	235	350
Net	(455)	(65)	(305)	(345)	(1170)
Crude Denial(3)	815	90	385	415	1705
BALANCE(2)	360	25	80	70	535

(*)Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
  diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-17

CASE 2

DENIAL PERIOD Summer, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	500	85	40		625			
Residential			35		35	(35)	(90)	
Commercial			--	--	--	(5)	(10)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			--	280	280	--	235	30
NET TOTAL	500	85	280	495	1360	--	395	30

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	500	85	355*	580*	1520
Product Denial	50	20	55	275	400
Net	(450)	(65)	(300)	(305)	(1120)
Crude Denial(3)	890	100	420	450	1860
BALANCE(2)	440	35	120	145	740

(*)Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-18

CASE 3

DENIAL PERIOD Summer, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			---	---	---	(5)	(10)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			---	405	405	---	235	30
NET TOTAL	1055	85	280	620	2040	---	395	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	390*	745*	2275
Product Denial	80	30	85	405	600
Net	(975)	(55)	(305)	(340)	(1675)
Crude Denial(3)	1285	145	605	650	2685
BALANCE(2)	310	90	300	310	1010

(*)Adjusted for refinery throughput energy reduction savings of 110 M B/D Dist., 125 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-19

CASF 4A

DENIAL PERIOD Summer, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			--	--	--	(5)	(10)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			--	405	405	--	235	30
NET TOTAL	1055	85	280	620	2040	--	395	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	445*	810*	2395
Product Denial	110	40	120	580	850
Net	(945)	(45)	(325)	(230)	(1545)
Crude Denial(3)	1855	205	870	940	3870
BALANCE(2)	910	160	545	710	2325

(*)Adjusted for refinery throughput energy reduction savings of 165 M B/D Dist., 190 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-20

CASF 4B

DENIAL PERIOD Summer, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			--	--	--	(5)	(10)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			--	405	405	--	235	30
NET TOTAL	1055	85	280	620	2040	--	395	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	405*	765*	2310
Product Denial	85	30	90	445	650
Net	(970)	(55)	(315)	(320)	(1660)
Crude Denial(3)	1410	155	660	715	2940
BALANCE(2)	440	100	345	395	1280

(*) Adjusted for refinery throughput energy reduction savings of 125 M B/D Dist., 145 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-21

CASE 4C

DENIAL PERIOD Summer, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1055	85	40		1180			
Residential			35		35	(35)	(90)	
Commercial			--	--	--	(5)	(10)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			--	405	405	--	235	30
NET TOTAL	1055	85	280	620	2040	--	395	30

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1055	85	370*	720*	2230
Product Denial	60	20	65	305	450
Net	(995)	(65)	(305)	(415)	(1780)
Crude Denial(3)	1015	115	475	510	2115
BALANCE(2)	20	50	170	95	335

(*)Adjusted for refinery throughput energy reduction savings of 90 M B/D Dist., 100 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-22

CASE 1

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	480	85	40		605			
Residential			70		70	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	300	300	-	255	30
NET TOTAL	480	85	330	565	1460	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	480	85	370*	610*	1545
Product Denial	25	10	25	115	175
Net	(455)	(75)	(345)	(495)	(1370)
Crude Denial(3)	410	45	190	205	850
BALANCE(2)	(45)	(30)	(155)	(290)	(520)

(*) Adjusted for refinery throughput energy reduction savings of 40 M B/D Dist., 45 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-23

CASE 1A

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	480	85	40		605			
Residential			70		70	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	300	300	-	255	30
NET TOTAL	480	85	330	565	1460	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	480	85	405*	650*	1620
Product Denial	45	20	50	235	350
Net	(435)	(65)	(355)	(415)	(1270)
Crude Denial(3)	815	90	385	415	1705
BALANCE(2)	380	25	30	(0)	435

(*)Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF -------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-24

CASE 2

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	480	85	40		605			
Residential			70		70	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	300	300	-	255	30
NET TOTAL	480	85	330	565	1460	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	480	85	405*	650*	1620
Product Denial	50	20	55	275	400
Net	(430)	(65)	(350)	(375)	(1220)
Crude Denial(3)	890	100	420	450	1860
BALANCE(2)	460	35	70	75	640

(*) Adjusted for refinery throughput energy reduction savings of 75 M B/D Dist., 85 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
  diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-25

CASE 3

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	345	665	2105	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	455*	790*	2340
Product Denial	80	30	85	405	600
Net	(930)	(55)	(370)	(385)	(1740)
Crude Denial(3)	1285	145	605	650	2685
BALANCE(2)	355	90	235	265	945

(*)Adjusted for refinery throughput energy reduction savings of 110 M B/D Dist., 125 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-26

CASE 4A

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	345	665	2105	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	510*	855*	2460
Product Denial	110	40	120	580	850
Net	(900)	(45)	(390)	(275)	(1610)
Crude Denial(3)	1855	205	870	940	3870
BALANCE(2)	955	160	480	665	2260

(*)Adjusted for refinery throughput energy reduction savings of 165 M B/D Dist., 190 M B/D H.F.O

---

(1)20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2)Energy saved = ( ).

(3)Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF ---------------	55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4, diesel fuel, kero (not aviation) -	23.2
Heavy fuel oil and all others ------	25.0
	103.2

TABLE I-27

CASE 4B

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS(1)

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	400	400	-	255	30
NET TOTAL	1010	85	345	665	2105	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	470*	810*	2375
Product Denial	85	30	90	445	650
Net	(925)	(55)	(380)	(365)	(1725)
Crude Denial(3)	1410	155	660	715	2940
BALANCE(2)	485	100	280	350	1215

(*) Adjusted for refinery throughput energy reduction savings of 125 M B/D Dist., 145 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
  diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

TABLE I-28

CASE 4C

DENIAL PERIOD: WINTER, 1985

ESTIMATED SAVINGS SUMMARY THROUGH VOLUNTARY & MANDATORY PROGRAMS[1]

	OIL SAVINGS (M B/D)					SUPPLY CHANGES (M B/D COE)		
	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total	Elect.	Gas	Coal
Transport	1010	85	40		1135			
Residential			85		85	(40)	(160)	
Commercial			15	50	65	(35)	(160)	
Industrial Fuel			205	215	420	40	260	50
Electric Utilities			-	400	400		255	30
NET TOTAL	1010	85	345	665	2105	(35)	195	80

SCENARIO BALANCES

(M B/D)

	Gasoline	Jet Fuel	Middle Dist.	Heavy Fuel Oil	Total
Demand Savings	1010	85	435*	765*	2295
Product Denial	60	20	65	305	450
Net	(950)	(65)	(370)	(460)	1845)
Crude Denial[3]	1015	115	475	510	2115
BALANCE[2]	65	50	105	50	270

(*) Adjusted for refinery throughput energy reduction savings of 90 M B/D Dist., 100 M B/D H.F.O

---

(1) 20 to 60 days' implementation, no tax, rationing or allocation programs included. Refer to the specific demand sections of this report for a detailed explanation of each sector savings.

(2) Energy saved = ( ).

(3) Crude denial product proration based on 1978 refinery runs as follows:

Mogas, naphthas, ATF --------------- 55.0% (Jet fuel assumed to be 10% of this total.)
Middle distillates are #1, #2, #4,
diesel fuel, kero (not aviation) - 23.2
Heavy fuel oil and all others ------ 25.0
103.2

EXHIBIT 2

PRE-DISRUPTION SUPPLY/DEMAND OUTLOOK

NPC FORECAST DEVELOPMENT

In the preparation of the following forecast, three recent projections of domestic energy demand by fuel source and total petroleum supply and demand by product were assembled and arithmetically averaged. These projections were derived from studies developed by industry consultants and government.[1]

A projection from the oil industry was not included because the detail required (e.g., product demands and regionalization) is not publicly available.

The forecasts of energy demands by fuel from these reports have been converted to crude oil equivalent barrels using 5.8×10^6 Btu per barrel of crude oil. In several cases, the data were adjusted if there were differences among forecasts in definitions, conversion factors, or accounting techniques.

All oil product demands were allocated to the five Petroleum Administration for Defense districts (PADs) using historical share data. For each product and market, 1978 regional factors were computed and applied to the national forecast data. Demands in each market were then summed by region to develop regional product demands.

The 1978 DOE annual petroleum statements were used as the basis for regionalization of the oil supply forecast. The same patterns of demand and supply were maintained for each scenario for each year.

NOTES AND SOURCES OF HISTORICAL DATA

Historical energy balances shown in Table I-29 are drawn from a variety of data sources published by the Energy Information Administration. The following "Energy Data Reports" were used to compile regional energy and oil data for the 1978 base year:

- LPG Sales, Annual
- Fuel Oil Sales, Annual

---

[1] The forecasts used were: Data Resources, Inc., DRI Energy Review, August 1980; Energy Information Administration, Annual Report to Congress (1979) and Short-Term Energy Outlook, May 1980; S. H. Clark Associates, Memo 80-2, Comparison of Energy and Economic Projections and Short-Term Outlook Revised, June 1980.

- Petroleum Statement, Annual
- U.S. Oil Supply/Demand by PAD Districts, Annual
- Natural Gas, Annual
- Bituminous Coal and Lignite Distribution, Annual
- Power Production, Fuel Consumption, and Installed Capacity Data for 1978
- 1978 Statistical Yearbook of the Electric Utility Industry (published by the Edison Electric Institute).

Regional data for 1979 are estimated from preliminary data and are subject to revision.

All data are reported in physical units and then converted to Btus using the conversion factors found in DOE's Monthly Energy Review. In this report, crude oil is assumed to contain 5.8 million Btu per barrel. Thus, daily crude oil equivalent barrels are computed by multiplying the Btu content (10^{12} Btu) of each fuel source by 0.472 $\left(\text{or } \frac{1}{2.117} = \frac{1}{0.365} \times \frac{1}{5.8}\right)$.

Historical market breakdowns are generally consistent with definitions used in the "Energy Consumption" chapters of the Monthly Energy Review with some key exceptions:

- In this report, consumption by end-use market (residential/commercial, transportation, industrial) does not include utility conversion losses. In the Monthly Energy Review these volumes are allocated to consuming sectors based upon electricity sales.
- In the Monthly Energy Review, asphalt and road oil are included in the residential/commercial sector, while in this report it is a part of industrial raw material oil consumption.
- Pipeline use of natural gas is included in the industrial fuels sector in this report, while it is shown as a transportation demand in the Monthly Energy Review.
- Industrial consumption in the Monthly Energy Review includes fuel and power, petrochemical, and raw material use. In this study, these three sectors are treated separately.

TABLE I-29

Summary Totals of U.S. Energy Consumption by Fuels and by Consuming Sectors

(MB/D COE)

	OIL	NATURAL GAS	COAL	NUCLEAR	HYDRO & OTHER	TOTAL PRIMARY ENERGY	ELECTRICITY	ENERGY CONSUMPTION
Residential/ Commercial:								
1978	2785.1	3674.4	117.3			6576.8	1984.7	8561.5
1979	2661.9	3592.2	103.6			6357.7	2031.9	8389.6
1980	2222.5	3543.4	114.5			5880.4	2121.9	8002.4
1981	2362.2	3603.5	122.7			6088.4	2129.9	8218.3
1985	1996.3	3829.7	135.4			5961.4	2449.2	8410.6
Transportation:								
1978	9570.2					9570.2	7.0	9577.2
1979	9222.9					9222.9	7.2	9230.1
1980	9011.4					9011.4	7.3	9018.7
1981	8955.9					8955.9	7.4	8963.3
1985	8837.3					8837.3	10.9	8848.3
Industrial Fuel and Power:								
1978	2065.3	3987.6	1553.7			7606.7	1260.7	8867.3
1979	2085.4	3856.8	1577.8			7520.0	1305.9	8825.8
1980	1694.7	3782.0	1518.3			6995.1	1271.8	8266.9
1981	1550.9	3867.7	1586.5			7005.1	1266.5	8271.6
1985	1786.9	3491.0	2073.6			7351.5	1562.2	8913.6
Electric Utility:								
1978	1638.6	1491.9	4975.0	1362.0	1399.0	10866.5	(3252.4)	7614.2
1979	1457.7	1658.0	5575.7	1258.0	1401.0	11350.4	(3345.0)	8005.4
1980	1340.6	1627.3	5779.9	1260.0	1533.0	11540.8	(3401.1)	8139.7
1981	1230.0	1587.9	5732.1	1413.0	1587.0	11549.9	(3403.8)	8146.2
1985	838.8	1315.3	7321.7	2433.0	1740.0	13648.8	(4022.3)	9626.5
Industrial Raw Materials and Chem. Feedstocks:								
1978	1856.7	311.0				2167.7		2167.7
1979	2030.1	318.0				2348.1		2348.1
1980	1953.7	317.4	14.3			2285.4		2285.4
1981	2056.1	324.0	14.7			2394.6		2394.6
1985	2173.7	356.9	132.4			2663.0		2663.0
Total:								
1978	17916.0	9465.0	6646.0	1362.0	1399.0	36788.0		36788.0
1979	17458.0	9425.0	7257.0	1258.0	1401.0	36799.0		36799.0
1980	16223.0	9270.0	7427.0	1260.0	1533.0	35713.0		35713.0
1981	16155.0	9383.0	7456.0	1413.0	1587.0	35994.0		35994.0
1985	15633.0	8993.0	9663.0	2433.0	1740.0	38462.0		38462.0

TABLE I-30

Summary of Pre-Denial U.S. Oil Supplies
(MB/D)

	1978	1980	1981	1985
Total Domestic Production	10,280	10,030	9,860	9,800
Crude & Condensate	8,710	8,460	8,290	8,490
NGL's	1,570	1,570	1,570	1,310
Total Imports	8,320	6,890	6,985	6,470
Total Crude	6,360	5,500	5,405	5,260
Canadian	250	---	---	---
Other	6,110	5,500	5,405	5,260
Total Products	1,960	1,390	1,580	1,210
Total Crude & Products	18,600	16,920	16,845	16,270
Processing Gain, etc., Unaccounted	500	540	410	440
Adjustments	110	50(1)	205(1)	120(1)
Total Required Supply	19,210	17,510	17,460	16,830
Exports	(360)	(360)	(360)	(250)
Total Domestic Supply(2)	18,850	17,150	17,100	16,580

(1) Small adjustments required since average figures derived from reference forecasts did not balance exactly.

(2) Synfuel contributions are expected to be minor by 1985 and have not been included.

TABLE I-31

Oil Supply/Demand Balance for 1978 -- Pre-Denial

(MB/D)

	PAD					Inter-District Adjusts	Total U.S.
	I	II	III	IV	V		
DEMANDS							
Local Demand	6660	5240	3800	560	2590	--	18850
Interdist Ship-Prod	220	170	3640	90	10	4130	--
Exports	10	90	100	--	160	--	360
Total Req'd Supply	6890	5500	7540	650	2760	(4130)	19210
SUPPLY							
Interdist Recp. Prod.	3080	760	70	80	140	4130	--
Interdist Recp. (Net) Crude	50	1500	(1030)	(220)	(300)	--	--
Interdist Recp. (Net) NGL	90	190	(270)	(20)	10	--	--
Crude Production	150	870	4860	650	2180	--	8710
NGL Production	40	280	1170	60	20	--	1570
Processing Gain	70	140	180	10	100	--	500
Adjustments	240	280	(330)	30	(110)	--	110
Total Domestic Supply	3720	4020	4650	590	2040	(4130)	10890
Imports							
Crude	1490	1350	2870	50	600	--	6360
Products	1680	130	20	10	120	--	1960
Total Imports	3170	1480	2890	60	720	--	8320
Total Supply	6890	5500	7540	650	2760	(4130)	19210
Total Crude	2130	4610	7450	560	2500	--	17250
Total Products	4760	890	90	90	260	(4130)	1960

TABLE I-32

Oil Supply/Demand Balance for 1980 -- Pre-Denial
(MB/D)

	PAD						
	I	II	III	IV	V	Inter-District Adjust.	TOTAL U.S.
DEMANDS							
Local Demand	5780	4790	3690	510	2380	---	17150
Interdist. Ship.-Prod.	220	170	3640	90	10	4130	---
Exports	10	90	100	---	160	---	360
Total Required Supply	6010	5050	7430	600	2550	(4130)	17510
SUPPLY							
Interdist. Recpt. Prod.	3080	760	70	80	140	4130	---
Interdist. Recpt. (Net) Crude	150	1480	(550)	(240)	(840)	---	---
Interdist. Recpt. (Net) NGL	90	190	(270)	(20)	10	---	---
Crude Production	150	870	4360	650	2430	---	8460
NGL Production	40	280	1170	60	20	---	1570
Processing Gain	70	150	200	10	110	---	540
Adjustments	50	---	---	---	---	---	50
Total Domestic Supply	3630	3730	4980	540	1870	(4130)	10620
Imports							
Crude	1270	1190	2430	50	560	---	5500
Products	1110	130	20	10	120	---	1390
Total Imports	2380	1320	2450	60	680	---	6890
Total Supply	6010	5050	7430	600	2550	(4130)	17510
Total Crude	1820	4160	7340	510	2290	---	16120
Total Products	4190	890	90	90	260	(4130)	1390

TABLE I-33

Oil Supply/Demand Balance for 1981 -- Pre-Denial

(MB/D)

	PAD					Inter-District Adjust.	TOTAL U.S.
	I	II	III	IV	V		
DEMANDS							
Local Demand	5730	4790	3730	500	2350	-	17100
Interdist. Ship.-Prod.	220	170	3640	90	10	4130	-
Exports	10	90	100	-	160	-	360
Total Required Supply	5960	5050	7470	590	2520	(4130)	17460
SUPPLY							
Interdist. Recpt. Prod.	3080	760	70	80	140	4130	---
Interdist. Recpt. (Net) Crude	55	1335	(350)	(240)	(800)	-	-
Interdist. Recpt. (Net) NGL	90	190	(270)	(20)	10	-	-
Crude Production	150	870	4190	650	2430	-	8290
NGL Production	40	280	1170	60	20	-	1570
Processing Gain	50	110	160	10	80		410
Adjustments	-	205	-	-	-	-	205
Total Domestic Supply	3465	3750	4970	540	1880	(4130)	10475
Imports							
Crude	1195	1170	2480	40	520	-	5405
Products	1300	130	20	10	120	-	1580
Total Imports	2495	1300	2500	50	640	-	6985
Total Supply	5960	5050	7470	590	2520	(4130)	17460
Total Crude	1580	4160	7380	500	2260	-	15880
Total Products	4380	890	90	90	260	(4130)	1580

TABLE I-34

Oil Supply/Demand Balance for 1985 -- Pre-Denial

(MB/D)

	PAD						
	I	II	III	IV	V	Inter-District Adjust.	TOTAL U.S.
DEMANDS							
Local Demand	5320	4700	3770	510	2280	-	16580
Interdist. Ship.-Prod.	220	170	3720	90	10	4210	-
Exports	10	50	50	-	140	-	250
Total Required Supply	5550	4920	7540	600	2430	(4210)	16830
SUPPLY							
Interdist. Recpt. Prod.	3080	840	70	80	140	4210	-
Interdist. Recpt. (Net) Crude	90	1500	(130)	(190)	(1270)	-	---
Interdist. Recpt. (Net) NGL	10	10	(10)	(20)	10	-	---
Crude Production	150	870	3500	650	3320	-	8490
NGL Production	40	280	910	60	20	-	1310
Processing Gain	50	120	170	10	90	-	440
Adjustments	-	-	120	-	-	-	120
Total Domestic Supply	3420	3620	4630	590	2310	(4210)	10360
Imports							
Crude	1200	1170	2890	-	-	-	5260
Products	930	130	20	10	120	-	1210
Total Imports	2130	1300	2910	10	120	-	6470
Total Supply	5550	4920	7540	600	2430	(4210)	16830
↑ Total Crude	1540	3950	7450	510	2170	-	15620
Total Products	4010	970	90	90	260	(4210)	1210

TABLE I-35

U.S. Crude Oil, Condensate, and NGL Supplies for 1978

(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V	TOTAL
Sweet Crude	730	830	1280	50	480	3370
Algeria	235	125	275	--	--	635
Libya	100	325	210	--	--	635
Others	395	380	795	50	480	2100
Sour Crude	760	520	1590*	--	120	2990
Egypt	10	--	10	--	--	20
Iran	240	70	250	--	--	560
Iraq	--	5	55	--	--	60
Kuwait	--	--	5	--	--	5
Qatar	5	30	20	--	10	65
Saudi Arabia	325	140	660	--	15	1140
Syria	--	5	--	--	--	5
UAE	30	40	240	--	80	390
Others	150	230	350	--	15	745
Total Crude Imports	1490	1350	2870	50	600	6360
Domestic						
Production Crude & Condensate	150	870	4860	650	2180	8710
Transferred to/(from)	50	1500	(1030)	(220)	(300)	--
Total Domestic Crude	200	2370	3830	430	1880	8710
NGL's Domestic Production	40	280	1170	60	20	1570
Transfers to/(from)	90	190	(270)	(20)	10	--
Total NGL's	130	470	900	40	30	1570
Total Domestic Crude	330	2840	4730	470	1910	10280
TOTAL CRUDE**	1820	4190	7600	520	2510	16640

*Includes 160 to SPR.
**Excludes processing gain and adjustments.

TABLE I-36

Imported Crude Oil Slate for 1980
(MB/D)

		SCENARIO CASES						
	BASE	1	1A	2	3	4 100%	4 75%	4 50%
PAD I	1270	1040	820	780	570	330	510	700
Sweet*- OAPEC	300	220	140	130	50	----	20	100
Others	410	410	410	410	410	330	410	410
Sour - OAPEC	390	240	100	70	----	----	----	20
Others	170	170	170	170	110	----	80	170
PAD II	1190	1010	840	810	610	320	540	760
Sweet - OAPEC	400	290	190	170	60	----	30	140
Others	410	410	410	410	410	320	410	410
Sour - OAPEC	180	110	40	30	----	----	----	10
Others	200	200	200	200	140	----	100	200
PAD III	2430	2040	1630	1560	1185	660	1070	1450
Sweet - OAPEC	440	330	210	190	65	----	40	160
Others	820	820	820	820	820	660	820	820
Sour - OAPEC	730	450	160	110	----	----	----	30
Others	440	440	440	440	300	----	210	440
PAD IV	50	50	50	50	50	40	50	50
Sweet - OAPEC	----	----	----	----	----	----	----	----
Others	50	50	50	50	50	40	50	50
Sour - OAPEC	----	----	----	----	----	----	----	----
Others	----	----	----	----	----	----	----	----
PAD V	560	535	510	500	485	400	480	490
Sweet - OAPEC	----	----	----	----	----	----	----	----
Others	470	470	470	470	470	400	470	470
Sour - OAPEC	70	45	20	10	----	----	----	----
Others	20	20	20	20	15	----	10	20
TOTAL U.S.	5500	4675	3850	3700	2900	1750	2650	3450
Sweet - OAPEC	1140	840	540	490	175	----	90	400
Others	2160	2160	2160	2160	2160	1750	2160	2160
Sour - OAPEC	1370	845	320	220	----	----	----	60
Others	830	830	830	830	565	----	400	830

*Sweet is less than 0.5% sulfur content.

TABLE I-37

Imported Crude Oil Slate for 1981
(MB/D)

		SCENARIO CASES						
	BASE	1	1A	2	3	4 100%	4 75%	4 50%
PAD I	1195	965	745	705	495	270	435	615
Sweet*- OAPEC	300	220	140	130	50	----	20	100
Others	335	335	335	335	335	270	335	335
Sour - OAPEC	390	240	100	70	----	----	----	10
Others	170	170	170	170	110	----	80	170
PAD II	1170	990	820	790	590	310	510	730
Sweet - OAPEC	400	290	190	170	60	----	30	140
Others	390	390	390	390	390	310	390	390
Sour - OAPEC	180	110	40	30	----	----	----	----
Others	200	200	200	200	140	----	90	200
PAD III	2480	2090	1680	1610	1235	700	1130	1520
Sweet - OAPEC	440	330	210	190	65	----	40	160
Others	865	865	865	865	865	700	865	865
Sour - OAPEC	700	420	130	80	----	----	----	20
Others	475	475	475	475	305	----	225	475
PAD IV	40	40	40	40	40	40	40	40
Sweet - OAPEC	----	----	----	----	----	----	----	----
Others	40	40	40	40	40	40	40	40
Sour - OAPEC	----	----	----	----	----	----	----	----
Others	----	----	----	----	----	----	----	----
PAD V	520	495	470	460	445	345	440	450
Sweet - OAPEC	----	----	----	----	----	----	----	----
Others	430	430	430	430	430	345	430	430
Sour - OAPEC	70	45	20	10	----	----	----	----
Others	20	20	20	20	15	----	10	20
TOTAL U.S.	5405	4580	3755	3605	2805	1665	2555	3355
Sweet - OAPEC	1140	840	540	490	175	----	90	400
Others	2060	2060	2060	2060	2060	1665	2060	2060
Sour - OAPEC	1340	815	290	190	----	----	----	30
Others	865	865	865	865	570	----	405	865

*Sweet is less than 0.5% sulfur content.

TABLE I-38

Imported Crude Oil Slate for 1985
(MB/D)

		SCENARIO CASES						
	BASE	I	1A	2	3	4 100%	4 75%	4 50%
PAD I	1200	960	720	680	475	260	430	610
Sweet*- OAPEC	230	150	70	60	----	----	----	40
Others	270	270	270	270	255	180	240	270
Sour - OAPEC	450	290	130	100	----	----	----	50
Others	250	250	250	250	220	80	190	250
PAD II	1170	985	810	780	590	330	530	720
Sweet - OAPEC	310	200	100	80	----	----	----	50
Others	350	350	350	350	330	240	310	350
Sour - OAPEC	210	135	60	50	----	----	----	20
Others	300	300	300	300	260	90	220	300
PAD III	2890	2490	2080	2000	1595	920	1450	1880
Sweet - OAPEC	340	230	110	90	----	----	----	50
Others	1030	1030	1030	1030	980	710	930	1030
Sour - OAPEC	820	530	240	180	----	----	----	100
Others	700	700	700	700	615	210	520	700
PAD IV	----	----	----	----	----	----	----	----
Sweet - OAPEC	----	----	----	----	----	----	----	----
Others	----	----	----	----	----	----	----	----
Sour - OAPEC	----	----	----	----	----	----	----	----
Others	----	----	----	----	----	----	----	----
PAD V	----	----	----	----	----	----	----	----
Sweet - OAPEC	----	----	----	----	----	----	----	----
Others	----	----	----	----	----	----	----	----
Sour - OAPEC	----	----	----	----	----	----	----	----
Others	----	----	----	----	----	----	----	----
TOTAL U.S.	5260	4435	3610	3460	2660	1510	2410	3210
Sweet - OAPEC	880	580	280	230	----	----	----	140
Others	1650	1650	1650	1650	1565	1130	1480	1650
Sour - OAPEC	1480	955	430	330	----	----	----	170
Others	1250	1250	1250	1250	1095	380	930	1250

*Sweet is less than 0.5% sulfur content.

TABLE I-39

Oil Supply/Demand Balance for 1980
Adjusted for Denials
(MB/D)

	PAD							
	I	II	III	IV	V	U.S.		
SCENARIO 1								
Gross Denial								
Crude	230	180	390	---	25	825		
Products	125	20	---	---	30	175		
TOTAL	355	200	390	---	55	1,000		
Adjusted Supplies								
Crude	1,590	3,980	6,950	510	2,265	15,295		
Products	4,065	870	90	90	230	1,215*		
TOTAL	5,655	4,850	7,040	600	2,495	16,510*		
SCENARIO 1A								
Gross Denial								
Crude	450	350	800	---	50	1,650		
Products	265	40	10	---	35	350		
TOTAL	715	390	810	---	85	2,000		
Adjusted Supplies								
Crude	1,370	3,810	6,540	510	2,240	14,470		
Products	3,925	850	80	90	225	1,040*		
TOTAL	5,295	4,660	6,620	600	2,465	15,510*		
SCENARIO 2								
Gross Denial								
Crude	490	380	870	---	60	1,800		
Products	300	40	10	---	50	400		
TOTAL	790	420	880	---	110	2,200		
Adjusted Supplies								
Crude	1,330	3,780	6,470	510	2,230	14,320		
Products	3,890	850	80	90	210	990*		
TOTAL	5,220	4,630	6,550	600	2,440	15,310*		
SCENARIO 3								
Gross Denial								
Crude	700	580	1,245	---	75	2,600		
Products	465	40	20	---	75	600		
TOTAL	1,165	620	1,265	---	150	3,200		
Adjusted Supplies								
Crude	1,120	3,580	6,095	510	2,215	13,520		
Products	3,725	850	70	90	185	790*		
TOTAL	4,845	4,430	6,165	600	2,400	14,310*		

*Excludes inter-district transfers of products of 4,130 M B/D.

TABLE I-39 (Continued)

	PAD							
	I	II	III	IV	V	U.S.		
SCENARIO 4A (100%)								
Gross Denial								
Crude	940	870	1,770	10	160	3,750		
Products	700	50	20	---	80	850		
TOTAL	1,640	920	1,790	10	240	4,600		
Adjusted Supplies								
Crude	880	3,290	5,570	500	2,130	12,370		
Products	3,490	840	70	90	180	540*		
TOTAL	4,370	4,130	5,640	590	2,310	12,910*		
SCENARIO 4B (75%)								
Gross Denial								
Crude	760	650	1,360	---	80	2,850		
Products	505	50	20	---	75	650		
TOTAL	1,265	700	1,380	---	155	3,500		
Adjusted Supplies								
Crude	1,060	3,510	5,980	510	2,210	13,270		
Products	3,685	840	70	90	185	740*		
TOTAL	4,745	4,350	6,050	600	2,395	14,010*		
SCENARIO 4C (50%)								
Gross Denial								
Crude	570	430	980	---	70	2,050		
Products	350	30	20	---	50	450		
TOTAL	920	460	1,000	---	120	2,500		
Adjusted Supplies								
Crude	1,250	3,730	6,360	510	2,220	14,070		
Products	3,840	860	70	90	210	940*		
TOTAL	5,090	4,590	6,430	600	2,430	15,010*		

*Excludes inter-district transfers of products of 4,130 M B/D.

TABLE I-40

Oil Supply/Demand Balance for 1981 Adjusted for Denials

(MB/D)

	PAD							
	I	II	III	IV	V	U.S.		
SCENARIO 1								
Gross Denial								
Crude	230	180	390	---	25	825		
Products	125	20	---	---	30	175		
TOTAL	355	200	390	---	55	1,000		
Adjusted Supplies								
Crude	1,350	3,980	6,990	500	2,235	15,055		
Products	4,255	870	90	90	230	1,405*		
TOTAL	5,605	4,850	7,080	590	2,465	16,460*		
SCENARIO 1A								
Gross Denial								
Crude	450	350	800	---	50	1,650		
Products	265	40	10	---	35	350		
TOTAL	715	390	810	---	85	2,000		
Adjusted Supplies								
Crude	1,130	3,810	6,580	500	2,210	14,230		
Products	4,115	850	80	90	225	1,230*		
TOTAL	5,245	4,660	6,660	590	2,435	15,460*		
SCENARIO 2								
Gross Denial								
Crude	490	380	870	---	60	1,800		
Products	300	40	10	---	50	400		
TOTAL	790	420	880	---	110	2,200		
Adjusted Supplies								
Crude	1,090	3,780	6,510	500	2,200	14,080		
Products	4,080	850	80	90	210	1,180*		
TOTAL	5,170	4,630	6,590	590	2,410	15,260*		
SCENARIO 3								
Gross Denial								
Crude	700	580	1,245	---	75	2,600		
Products	465	40	20	---	75	600		
TOTAL	1,165	620	1,265	---	150	3,200		
Adjusted Supplies								
Crude	880	3,580	6,135	500	2,185	13,280		
Products	3,915	850	70	90	185	980*		
TOTAL	4,795	4,430	6,205	590	2,370	14,260*		

*Excludes inter-district transfers of 4,130 M B/D.

TABLE I-40 (Continued)

	PAD					
	I	II	III	IV	V	U.S.
SCENARIO 4A (100%)						
Gross Denial						
Crude	925	860	1,780	10	175	3,750
Products	700	50	20	---	80	850
TOTAL	1,625	910	1,800	10	255	4,600
Adjusted Supplies						
Crude	655	3,300	5,600	490	2,085	12,130
Products	3,680	840	70	90	180	730*
TOTAL	4,335	4,140	5,670	580	2,265	12,860*
SCENARIO 4B (75%)						
Gross Denial						
Crude	760	660	1,350	---	80	2,850
Products	505	50	20	---	75	650
TOTAL	1,265	710	1,370	---	155	3,500
Adjusted Supplies						
Crude	820	3,500	6,030	500	2,180	13,030
Products	3,875	840	70	90	185	930*
TOTAL	4,695	4,340	6,100	590	2,365	13,960*
SCENARIO 4C (50%)						
Gross Denial						
Crude	580	440	960	---	70	2,050
Products	350	30	20	---	50	450
TOTAL	930	470	980	---	120	2,500
Adjusted Supplies						
Crude	1,000	3,720	6,420	500	2,190	13,830
Products	4,030	860	70	90	210	1,130*
TOTAL	5,030	4,580	6,490	590	2,400	14,960*

*Excludes inter-district transfers of 4,130 M B/D.

TABLE I-41

Oil Supply/Demand Balance for 1985 Adjusted for Denials

(MB/D)

	PAD							
	I	II	III	IV	V	U.S.		
SCENARIO 1								
Gross Denial								
Crude	240	185	400	---	---	825		
Products	125	20	---	---	30	175		
TOTAL	365	205	400	---	30	1,000		
Adjusted Supplies								
Crude	1,300	3,765	7,050	510	2,170	14,795		
Products	3,885	950	90	90	230	1,035*		
TOTAL	5,185	4,715	7,140	600	2,400	15,830*		
SCENARIO 1A								
Gross Denial								
Crude	480	360	810	---	---	1,650		
Products	265	40	10	---	35	350		
TOTAL	745	400	820	---	35	2,000		
Adjusted Supplies								
Crude	1,060	3,590	6,640	510	2,170	13,970		
Products	3,745	930	80	90	225	860*		
TOTAL	4,805	4,520	6,720	600	2,395	14,830*		
SCENARIO 2								
Gross Denial								
Crude	520	390	890	---	---	1,800		
Products	300	40	10	---	50	400		
TOTAL	820	430	900	---	50	2,200		
Adjusted Supplies								
Crude	1,020	3,560	6,560	510	2,170	13,820		
Products	3,710	930	80	90	210	810*		
TOTAL	4,730	4,490	6,640	600	2,380	14,630*		
SCENARIO 3								
Gross Denial								
Crude	725	580	1,295	---	---	2,600		
Products	465	40	20	---	75	600		
TOTAL	1,190	620	1,315	---	75	3,200		
Adjusted Supplies								
Crude	815	3,370	6,155	510	2,170	13,020		
Products	3,545	930	70	90	185	610*		
TOTAL	4,360	4,300	6,225	600	2,355	13,630*		

*Excludes inter-district transfers of 4,210 M B/D.

TABLE I-41 (Continued)

	PAD					
	I	II	III	IV	V	U.S.
SCENARIO 4A (100%)						
Gross Denial						
Crude	940	840	1,970	---	---	3,750
Products	700	50	20	---	80	850
TOTAL	1,640	890	1,990	---	80	4,600
Adjusted Supplies						
Crude	600	3,110	5,480	510	2,170	11,870
Products	3,310	920	70	90	180	360*
TOTAL	3,910	4,030	5,550	600	2,350	12,230*
SCENARIO 4B (75%)						
Gross Denial						
Crude	770	640	1,440	---	---	2,850
Product	505	50	20	---	75	650
TOTAL	1,275	690	1,460	---	75	3,500
Adjusted Supplies						
Crude	770	3,310	6,010	510	2,170	12,770
Products	3,505	920	70	90	185	560*
TOTAL	4,275	4,230	6,080	600	2,355	13,330*
SCENARIO 4C (50%)						
Gross Denial						
Crude	590	450	1,010	---	---	2,050
Products	350	30	20	---	50	450
TOTAL	940	480	1,030	---	50	2,500
Adjusted Supplies						
Crude	950	3,500	6,440	510	2,170	13,570
Products	3,660	940	70	90	210	760*
TOTAL	4,610	4,440	6,510	600	2,380	14,330*

*Excludes inter-district transfers of 4,210 M B/D.

TABLE I-42

U.S. Oil Product Demand by Year

(MB/D)

	TOTAL U.S.							
		ACTUAL 1978		PREL. 1979		1980	1981	1985
Gasolines		7450.8		7069.2		6735.1	6608.8	6181.8
Jet Fuel		1058.0		1073.0		1027.0	1048.0	1130.0
Special Naphtha		104.2		114.7		93.1	97.1	93.7
Kerosine		176.8		182.7		188.1	193.7	174.7
Distillate		3432.0		3307.0		3025.0	3112.0	3336.0
Residual		3023.0		2822.0		2412.0	2245.0	1799.0
Liquefied Gases		1554.3		1610.9		1570.7	1598.9	1572.5
Petrochemical Feed		603.0		708.1		640.7	693.8	818.6
Lubricants and Waxes		183.0		186.2		192.2	202.0	200.3
Coke		249.3		252.0		240.9	247.8	243.9
Asphalt and Road Oil		482.7		499.5		502.7	521.5	524.6
Still Gas		535.0		564.4		527.7	536.2	504.6
Total		18852.1		18389.7		17155.2	17104.8	16579.7

	1978							
		PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
Gasolines		2518.4	2518.4	1028.2	253.3	1132.5		7450.8
Jet Fuel		386.2	211.6	120.6	36.0	303.6		1058.0
Special Naphtha		20.3	28.4	39.4	0.7	15.4		104.2
Kerosine		73.2	49.4	40.0	1.6	12.6		176.8
Distillate		1434.9	1077.2	454.6	122.0	343.3		3432.0
Residual		1725.4	324.7	458.5	45.1	469.3		3023.0
Liquefied Gases		217.0	533.1	695.4	45.5	63.3		1554.3
Petrochemical Feed		27.1	45.2	520.4	0.6	9.7		603.0
Lubricants and Waxes		63.2	42.1	56.4	2.2	19.1		183.0
Coke		29.9	93.3	78.2	7.9	40.0		249.3
Asphalt and Road Oil		107.6	187.3	82.1	26.1	79.6		482.7
Still Gas		62.1	126.3	232.7	15.0	98.9		535.0
Total		6665.3	5237.0	3806.5	556.0	2587.3		18852.1

	1979							
		PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
Gasolines		2389.4	2389.4	975.5	240.4	1074.5		7069.2
Jet Fuel		391.6	214.6	122.3	36.5	308.0		1073.0
Special Naphtha		22.4	31.3	43.4	0.8	16.8		114.7
Kerosine		76.0	51.5	40.8	1.6	12.8		182.7
Distillate		1368.0	1040.7	444.7	118.5	335.1		3307.0
Residual		1592.6	308.1	439.3	44.6	437.4		2822.0
Liquefied Gases		220.7	543.9	735.9	46.2	64.2		1610.9
Petrochemical Feed		31.9	53.1	611.1	0.7	11.3		708.1
Lubricants and Waxes		64.2	42.9	57.4	2.2	19.5		186.2
Coke		30.2	94.5	78.9	8.0	40.4		252.0
Asphalt and Road Oil		111.4	193.8	84.9	27.0	82.4		499.5
Still Gas		65.5	133.2	245.5	15.8	104.4		564.4
Total		6363.9	5097.0	3879.7	542.3	2506.8		18389.7

TABLE I-42 (Continued)

	1980							
		PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
Motor Gasoline		2276.5	2276.5	929.4	229.0	1023.7		6735.1
Jet Fuel		374.9	205.4	117.1	34.9	294.7		1027.0
Special Naphtha		18.2	25.4	35.2	0.7	13.6		93.1
Kerosine		78.6	53.5	41.3	1.6	13.1		188.1
Distillate		1192.5	961.9	431.9	111.9	326.8		3025.0
Residual		1337.0	243.9	396.7	32.8	401.6		2412.0
Liquefied Gases		208.8	522.1	735.8	45.5	58.5		1570.7
Petrochemical Feed		28.8	48.1	553.0	0.6	10.2		640.7
Lubricants and Waxes		66.4	44.2	59.2	2.3	20.1		192.2
Coke		28.8	92.0	73.8	7.6	38.7		240.9
Asphalt and Road Oil		112.1	195.0	85.5	27.1	83.0		502.7
Still Gas		61.2	124.5	229.5	14.8	97.7		527.7
Total		5783.8	4792.5	3688.4	508.8	2381.7		17155.2

	1981							
		PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
Motor Gasoline		2233.8	2233.8	912.0	224.7	1004.5		6608.8
Jet Fuel		382.5	209.6	119.5	35.6	300.8		1048.0
Special Naphtha		18.9	26.5	36.7	0.7	14.3		97.1
Kerosine		81.2	55.5	42.1	1.6	13.3		193.7
Distillate		1246.3	990.1	433.3	112.5	329.8		3112.0
Residual		1246.4	225.3	369.1	29.6	374.6		2245.0
Liquefied Gases		209.5	527.3	757.7	46.4	58.0		1598.9
Petrochemical Feed		31.2	52.0	598.7	0.7	11.2		693.8
Lubricants and Waxes		69.7	46.4	62.2	2.5	21.2		202.6
Coke		29.7	95.3	75.3	7.8	39.7		247.8
Asphalt and Road Oil		116.3	202.3	88.7	28.2	86.0		521.5
Still Gas		62.2	126.5	233.2	15.0	99.3		536.2
Total		5727.7	4790.6	3728.5	505.3	2352.7		17104.8

	1985							
		PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
Motor Gasoline		2089.4	2089.4	853.1	210.2	939.7		6181.8
Jet Fuel		412.5	226.0	128.8	38.4	324.3		1130.0
Special Naphtha		18.3	25.6	35.4	0.7	13.7		93.7
Kerosine		72.4	48.8	39.6	1.6	12.3		174.7
Distillate		1241.3	1063.6	512.6	131.0	387.5		3336.0
Residual		964.9	196.8	314.0	31.1	292.2		1799.0
Liquefied Gases		211.2	522.4	733.1	44.4	61.4		1572.5
Petrochemical Feed		36.8	61.4	706.5	0.8	13.1		818.6
Lubricants and Waxes		69.1	46.0	61.7	2.4	21.1		200.3
Coke		29.1	96.0	72.0	7.7	39.1		243.9
Asphalt and Road Oil		117.0	203.5	89.2	28.3	86.6		524.6
Still Gas		58.5	119.1	219.5	14.1	93.4		504.6
Total		5320.5	4698.6	3765.5	510.7	2284.4		16579.7

TABLE I-43

Regional Oil Product Demand by Year

(MB/D)

		PAD I						
		ACTUAL 1978		PREL. 1979		1980	1981	1985
Gasolines		2518.4		2389.4		2276.5	2233.8	2089.4
Jet Fuel		386.2		391.6		374.9	382.5	412.5
Special Naphtha		20.3		22.4		18.2	18.9	18.3
Kerosine		73.2		76.0		78.6	81.2	72.4
Distillate		1434.9		1368.0		1192.5	1246.3	1241.3
Residual		1725.4		1592.6		1337.0	1246.4	964.9
Liquefied Gases		217.0		220.7		208.8	209.5	211.2
Petrochemical Feed		27.1		31.9		28.8	31.2	36.8
Lubricants and Waxes		63.2		64.2		66.4	69.7	69.1
Coke		29.9		30.2		28.8	29.7	29.1
Asphalt and Road Oil		107.6		111.4		112.1	116.3	117.0
Still Gas		62.1		65.5		61.2	62.2	58.5
Total		6665.3		6363.9		5783.8	5727.7	5320.5

		PAD II						
		ACTUAL 1978		PREL. 1979		1980	1981	1985
Gasolines		2518.4		2389.4		2276.5	2233.8	2089.4
Jet Fuel		211.6		214.6		205.4	209.6	226.0
Special Naphtha		28.4		31.3		25.4	26.5	25.6
Kerosine		49.4		51.5		53.5	55.5	48.8
Distillate		1077.2		1040.7		961.9	990.1	1063.6
Residual		324.7		308.1		243.9	225.3	196.8
Liquefied Gases		533.1		543.9		522.1	527.3	522.4
Petrochemical Feed		45.2		53.1		48.1	52.0	61.4
Lubricants and Waxes		42.1		42.9		44.2	46.4	46.0
Coke		93.3		94.5		92.0	95.3	96.0
Asphalt and Road Oil		187.3		193.8		195.0	202.3	203.5
Still Gas		126.3		133.2		124.5	126.5	119.1
Total		5237.0		5097.0		4792.5	4790.6	4698.6

TABLE I-43 (Continued)

	PAD III							
		ACTUAL 1978		PREL. 1979		1980	1981	1985
Gasolines		1028.2		975.5		929.4	912.0	853.1
Jet Fuel		120.6		122.3		117.1	119.5	128.8
Special Naphtha		39.4		43.4		35.2	36.7	35.4
Kerosine		40.0		40.8		41.3	42.1	39.6
Distillate		454.6		444.7		431.9	433.3	512.6
Residual		458.5		439.3		396.7	369.1	314.0
Liquefied Gases		695.4		735.9		735.8	757.7	733.1
Petrochemical Feed		520.4		611.1		553.0	598.7	706.5
Lubricants and Waxes		56.4		57.4		59.2	62.2	61.7
Coke		78.2		78.9		73.8	75.3	72.0
Asphalt and Road Oil		82.1		84.9		85.5	88.7	89.2
Still Gas		232.7		245.5		229.5	233.2	219.5
Total		3806.5		3879.7		3688.4	3728.5	3765.5

	PAD IV							
		ACTUAL 1978		PREL. 1979		1980	1981	1985
Gasolines		253.3		240.4		229.0	224.7	210.2
Jet Fuel		36.0		36.5		34.9	35.6	38.4
Special Naphtha		0.7		0.8		0.7	0.7	0.7
Kerosine		1.6		1.6		1.6	1.6	1.6
Distillate		122.0		118.5		111.9	112.5	131.0
Residual		45.1		44.6		32.8	29.6	31.1
Liquefied Gases		45.5		46.2		45.5	46.4	44.4
Petrochemical Feed		0.6		0.7		0.6	0.7	0.8
Lubricants and Waxes		2.2		2.2		2.3	2.5	2.4
Coke		7.9		8.0		7.6	7.8	7.7
Asphalt and Road Oil		26.1		27.0		27.1	28.2	28.3
Still Gas		15.0		15.8		14.8	15.0	14.1
Total		556.0		542.3		508.8	505.3	510.7

	PAD V							
		ACTUAL 1978		PREL. 1979		1980	1981	1985
Gasolines		1132.5		1074.5		1023.7	1004.5	939.7
Jet Fuel		303.6		308.0		294.7	300.8	324.3
Special Naphtha		15.4		16.8		13.6	14.3	13.7
Kerosine		12.6		12.8		13.1	13.3	12.3
Distillate		343.3		335.1		326.8	329.8	387.5
Residual		469.3		437.4		401.6	374.6	292.2
Liquefied Gases		63.3		64.2		58.5	58.0	61.4
Petrochemical Feed		9.7		11.3		10.2	11.2	13.1
Lubricants and Waxes		19.1		19.5		20.1	21.2	21.1
Coke		40.0		40.4		38.7	39.7	39.1
Asphalt and Road Oil		79.6		82.4		83.0	86.0	86.6
Still Gas		98.9		104.4		97.7	99.3	93.4
Total		2587.3		2506.8		2381.7	2352.7	2284.4

TABLE I-44

U.S. Oil Product Demand by Region

(MB/D)

		PAD		1978(A)	1979(P)	1980	1981	1985
Gasoline		I		2518.4	2389.4	2276.5	2233.8	2089.4
		II		2518.4	2389.4	2276.5	2233.8	2089.4
		III		1028.2	975.5	929.4	912.0	853.1
		IV		253.3	240.4	229.0	224.7	210.2
		V		1132.5	1074.5	1023.7	1004.5	939.7
				7450.8	7069.2	6735.1	6608.8	6181.8
Jet Fuel		I		386.2	391.6	374.9	382.5	412.5
		II		211.6	214.6	205.4	209.6	226.0
		III		120.6	122.3	117.1	119.5	128.8
		IV		36.0	36.5	34.9	35.6	38.4
		V		303.6	308.0	294.7	300.8	324.3
				1058.0	1073.0	1027.0	1048.0	1130.0
Special Naphtha		I		20.3	22.4	18.2	18.9	18.3
		II		28.4	31.3	25.4	26.5	25.6
		III		39.4	43.4	35.2	36.7	35.4
		IV		0.7	0.8	0.7	0.7	0.7
		V		15.4	16.8	13.6	14.3	13.7
				104.2	114.7	93.1	97.1	93.7
Kerosine		I		73.2	76.0	78.6	81.2	72.4
		II		49.4	51.5	53.5	55.5	48.8
		III		40.0	40.8	41.3	42.1	39.6
		IV		1.6	1.6	1.6	1.6	1.6
		V		12.6	12.8	13.1	13.3	12.3
				176.8	182.7	188.1	193.7	174.7
Distillate		I		1434.9	1368.0	1192.5	1246.3	1241.3
		II		1077.2	1040.7	961.9	990.1	1063.6
		III		454.6	444.7	431.9	433.3	512.6
		IV		122.0	118.5	111.9	112.5	131.0
		V		343.3	335.1	326.8	329.8	387.5
				3432.0	3307.0	3025.0	3112.0	3336.0
Residual		I		1725.4	1592.6	1337.0	1246.4	964.9
		II		324.7	308.1	243.9	225.3	196.8
		III		458.5	439.3	396.7	369.1	314.0
		IV		45.1	44.6	32.8	29.6	31.1
		V		469.3	437.4	401.6	374.6	292.2
				3023.0	2822.0	2412.0	2245.0	1799.0
Liquefied Gases		I		217.0	220.7	208.8	209.5	211.2
		II		533.1	543.9	522.1	527.3	522.4
		III		695.4	735.9	735.8	757.7	733.1
		IV		45.5	46.2	45.5	46.4	44.4
		V		63.3	64.2	58.5	58.0	61.4
				1554.3	1610.9	1570.7	1598.9	1572.5
Petrochemical Feed		I		27.1	31.9	28.8	31.2	36.8
		II		45.2	53.1	48.1	52.0	61.4
		III		520.4	611.1	553.0	598.7	706.5
		IV		0.6	0.7	0.6	0.7	0.8
		V		9.7	11.3	10.2	11.2	13.1
				603.0	708.1	640.7	693.8	818.6
Lubricants and Waxes		I		63.2	64.2	66.4	69.7	69.1
		II		42.1	42.9	44.2	46.4	46.0
		III		56.4	57.4	59.2	62.2	61.7
		IV		2.2	2.2	2.3	2.5	2.4
		V		19.1	19.5	20.1	21.2	21.1
				183.0	186.2	192.2	202.0	200.3

TABLE I-44 (Continued)

		PAD		1978(A)	1979(P)	1980	1981	1985
Coke		I		29.9	30.2	28.8	29.7	29.1
		II		93.3	94.5	92.0	95.3	96.0
		III		78.2	78.9	73.8	75.3	72.0
		IV		7.9	8.0	7.6	7.8	7.7
		V		40.0	40.4	38.7	39.7	39.1
				249.3	252.0	240.9	247.8	243.9
Asphalt and Road Oil		I		107.6	111.4	112.1	116.3	117.0
		II		187.3	193.8	195.0	202.3	203.5
		III		82.1	84.9	85.5	88.7	89.2
		IV		26.1	27.0	27.1	28.2	28.3
		V		79.6	82.4	83.0	86.0	86.6
				482.7	499.5	502.7	521.5	524.6
Still Gas		I		62.1	65.5	61.2	62.2	58.5
		II		126.3	133.2	124.5	126.5	119.1
		III		232.7	245.5	229.5	233.2	219.5
		IV		15.0	15.8	14.8	15.0	14.1
		V		98.9	104.4	97.7	99.3	93.4
				535.0	564.4	527.7	536.2	504.6
Total		I		6665.3	6363.9	5783.8	5727.7	5320.5
		II		5237.0	5097.0	4792.5	4790.6	4698.6
		III		3806.5	3879.7	3688.4	3728.5	3765.5
		IV		556.0	542.3	508.8	505.3	510.7
		V		2587.3	2506.8	2381.7	2352.7	2284.4
				18852.1	18389.7	17155.2	17104.8	16579.7

TABLE I-45

U.S. Oil Product Demand by Region and by Consuming Sector

(MB/D)

		Total U.S.						
		Actual 1978		Prel. 1979		1980	1981	1985
Residential & Commer.		2946.6		2829.3		2406.2	2551.4	2175.0
Transportation		10299.7		9911.3		9669.5	9605.9	9457.0
Industrial H&P		2052.0		2071.9		1680.1	1537.3	1785.2
Electric Utilities		1521.3		1355.7		1248.9	1145.9	785.3
Petrochemical Feed		1259.7		1418.6		1360.2	1439.4	1537.8
Raw Material		772.8		802.9		790.3	824.9	839.4
TOTAL		18852.1		18389.7		17155.2	17104.8	16579.7

		1978						
		PAD I	PAD II	PAD III	PAD IV	PAD V		TOTAL
Residential & Commer.		1550.7	950.2	247.1	77.4	121.2		2946.6
Transportation		3343.1	3172.4	1638.4	351.5	1794.3		10299.7
Industrial H&P		586.9	537.6	557.0	87.0	283.5		2052.0
Electric Utilities		951.5	153.0	164.2	2.1	250.5		1521.3
Petrochemical Feed		59.3	137.1	1036.6	7.8	18.9		1259.7
Raw Material		173.8	286.7	163.2	30.2	118.9		772.8
TOTAL		6665.3	5237.0	3806.5	556.0	2587.3		18852.1

		1979						
		PAD I	PAD II	PAD III	PAD IV	PAD V		TOTAL
Residential & Commer.		1473.8	919.5	244.0	75.2	116.8		2829.3
Transportation		3214.9	3038.9	1581.3	337.9	1738.3		9911.3
Industrial H&P		588.0	542.5	567.2	87.2	287.0		2071.9
Electric Utilities		840.2	146.2	147.0	2.3	220.0		1355.7
Petrochemical Feed		66.7	152.6	1169.6	8.5	21.2		1418.6
Raw Material		180.3	297.3	170.6	31.2	123.5		802.9
TOTAL		6363.9	5097.0	3879.7	542.3	2506.8		18389.7

TABLE I-45 (Continued)

	1980							
		PAD I	PAD II	PAD III	PAD IV	PAD V		TOTAL
Residential & Commer.		1200.4	810.8	227.8	66.4	100.8		2406.2
Transportation		3121.5	2959.3	1558.7	330.9	1699.1		9669.5
Industrial H&P		450.5	437.8	483.1	69.1	239.6		1680.1
Electric Utilities		768.8	141.3	135.9	2.5	200.4		1248.9
Petrochemical Feed		64.1	148.8	1118.5	8.5	20.3		1360.2
Raw Material		178.5	294.5	164.4	31.4	121.5		790.3
TOTAL		5783.8	4792.5	3688.4	508.8	2381.7		17155.2

	1981							
		PAD I	PAD II	PAD III	PAD IV	PAD V		TOTAL
Residential & Commer.		1280.6	855.7	238.5	69.8	106.8		2551.4
Transportation		3097.7	2937.6	1550.0	329.8	1690.8		9605.9
Industrial H&P		392.5	400.7	458.4	61.7	224.0		1537.3
Electric Utilities		702.7	133.0	125.0	2.4	182.8		1145.9
Petrochemical Feed		67.7	156.4	1184.7	8.9	21.7		1439.4
Raw Material		186.5	307.2	171.9	32.7	126.6		824.9
TOTAL		5727.7	4790.6	3728.5	505.3	2352.7		17104.8

	1985							
		PAD I	PAD II	PAD III	PAD IV	PAD V		TOTAL
Residential & Commer.		1069.8	743.8	209.4	60.6	91.4		2175.0
Transportation		3035.3	2896.5	1525.7	331.0	1668.5		9457.0
Industrial H&P		484.3	475.9	497.3	74.8	252.9		1785.2
Electric Utilities		468.8	107.3	86.8	2.5	119.9		785.3
Petrochemical Feed		72.0	162.1	1271.8	8.7	23.2		1537.8
Raw Material		190.3	313.0	174.5	33.1	128.5		839.4
TOTAL		5320.5	4698.6	3765.5	510.7	2284.4		16579.7

TABLE I-46

Regional Oil Product Demand in the Transportation Sector
(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
1978							
Gasoline	2518.4	2518.4	1028.2	253.3	1132.5		7450.8
Jet Fuel	386.2	211.6	120.6	36.0	303.6		1058.0
Distillate	309.2	398.3	245.5	57.8	192.4		1203.2
Residual	92.8	5.6	180.4	----	152.8		431.6
LPG	10.6	21.2	40.6	3.5	5.2		81.1
Lubes & Waxes	25.9	17.3	23.1	0.9	7.8		75.0
TOTAL	3343.1	3172.4	1638.4	351.5	1794.3		10299.7
1979							
Gasoline	2389.4	2389.4	975.5	240.4	1074.5		7069.2
Jet Fuel	391.6	214.6	122.3	36.5	308.0		1073.0
Distillate	304.6	392.3	241.8	56.9	189.7		1185.3
Residual	93.1	5.6	181.0	----	153.4		433.1
LPG	9.7	19.3	37.0	3.2	4.7		73.9
Lubes & Waxes	26.5	17.7	23.7	0.9	8.0		76.8
TOTAL	3214.9	3038.9	1581.3	337.9	1738.3		9911.3
1980							
Gasoline	2276.5	2276.5	929.4	229.0	1023.7		6735.1
Jet Fuel	374.9	205.4	117.1	34.9	294.7		1027.0
Distillate	338.5	436.0	268.7	63.2	210.8		1317.2
Residual	95.6	5.8	185.8	----	157.3		444.5
LPG	8.8	17.5	33.5	2.9	4.3		67.0
Lubes & Waxes	27.2	18.1	24.2	0.9	8.3		78.7
TOTAL	3121.5	2959.3	1558.7	330.9	1699.1		9669.5
1981							
Gasoline	2233.8	2233.8	912.0	224.7	1004.5		6608.8
Jet Fuel	382.5	209.6	119.5	35.6	300.8		1048.0
Distillate	351.6	452.8	279.1	65.7	218.9		1368.1
Residual	93.3	5.6	181.5	----	153.7		434.1
LPG	8.6	17.2	33.0	2.8	4.3		65.9
Lubes & Waxes	27.9	18.6	24.9	1.0	8.6		81.0
TOTAL	3097.7	2937.6	1550.0	329.8	1690.8		9605.9
1985							
Gasoline	2089.4	2089.4	853.1	210.2	939.7		6181.8
Jet Fuel	412.5	226.0	128.8	38.4	324.3		1130.0
Distillate	421.2	542.4	334.3	78.7	262.2		1638.8
Residual	79.1	4.8	153.8	----	130.3		368.0
LPG	8.9	17.8	34.1	2.9	4.5		68.2
Lubes & Waxes	24.2	16.1	21.6	0.8	7.5		70.2
TOTAL	3035.3	2896.5	1525.7	331.0	1668.5		9457.0

TABLE I-47

Regional Oil Product Demand in the Residential/Commercial Sector

(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
1978							
Distillate	948.6	483.9	75.3	30.4	64.1		1602.3
Residual	412.7	99.0	22.8	14.8	20.0		569.3
LPG	123.8	321.6	118.2	31.1	27.3		622.0
Kerosene	65.6	45.7	30.8	1.1	9.8		153.0
TOTAL	1550.7	950.2	247.1	77.4	121.2		2946.6
1979							
Distillate	883.6	450.8	70.2	28.4	59.6		1492.6
Residual	395.9	95.0	21.8	14.2	19.1		546.0
LPG	125.3	325.6	119.7	31.5	27.7		629.8
Kerosene	69.0	48.1	32.3	1.1	10.4		160.9
TOTAL	1473.8	919.5	244.0	75.2	116.8		2829.3
1980							
Distillate	699.2	356.7	55.5	22.4	47.2		1181.0
Residual	301.2	72.3	16.6	10.8	14.6		415.5
LPG	127.5	331.2	121.7	32.0	28.2		640.6
Kerosene	72.5	50.6	34.0	1.2	10.8		169.1
TOTAL	1200.4	810.8	227.8	66.4	100.8		2406.2
1981							
Distillate	755.2	385.2	60.0	24.2	51.0		1275.6
Residual	318.2	76.3	17.6	11.4	15.4		438.9
LPG	131.4	341.3	125.4	33.0	29.0		660.1
Kerosene	75.8	52.9	35.5	1.2	11.4		176.8
TOTAL	1280.6	855.7	238.5	69.8	106.8		2551.4
1985							
Distillate	644.8	328.9	51.2	20.7	43.6		1089.2
Residual	240.1	57.6	13.2	8.6	11.7		331.2
LPG	120.2	312.2	114.7	30.2	26.6		603.9
Kerosene	64.7	45.1	30.3	1.1	9.5		150.7
TOTAL	1069.8	743.8	209.4	60.6	91.4		2175.0

TABLE I-48

Regional Oil Product Demand in the Industrial Sector
(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
1978							
Distillate	126.3	142.1	116.9	31.7	78.2		495.2
Residual	319.2	120.0	108.0	30.3	54.6		632.1
LPG	50.4	98.4	20.4	3.7	21.6		194.5
Kerosene	7.6	3.7	9.2	0.5	2.8		23.8
Still Gas	62.1	126.3	232.7	15.0	98.9		535.0
Petroleum Coke	21.3	47.1	69.8	5.8	27.4		171.4
TOTAL	586.9	537.6	557.0	87.0	283.5		2052.0
1979							
Distillate	123.0	138.4	113.8	30.9	76.2		482.3
Residual	320.2	120.5	108.4	30.4	54.5		634.0
LPG	50.9	99.5	20.7	3.7	21.9		196.7
Kerosene	7.0	3.4	8.5	0.5	2.4		21.8
Still Gas	65.5	133.2	245.5	15.8	104.4		564.4
Petroleum Coke	21.4	47.5	70.3	5.9	27.6		172.7
TOTAL	588.0	542.5	567.2	87.2	287.0		2071.9
1980							
Distillate	94.7	106.6	87.7	23.8	58.7		371.5
Residual	231.5	87.1	78.4	22.0	39.4		458.4
LPG	37.2	72.7	15.1	2.7	15.9		143.6
Kerosene	6.1	2.9	7.3	0.4	2.3		19.0
Still Gas	61.2	124.5	229.5	14.8	97.7		527.7
Petroleum Coke	19.8	44.0	65.1	5.4	25.6		159.9
TOTAL	450.5	437.8	483.1	69.1	239.6		1680.1
1981							
Distillate	80.5	90.6	74.5	20.2	50.0		315.8
Residual	191.2	71.9	64.7	18.2	32.6		378.6
LPG	33.0	64.4	13.3	2.4	14.2		127.3
Kerosene	5.4	2.6	6.6	0.4	1.9		16.9
Still Gas	62.2	126.5	233.2	15.0	99.3		536.2
Petroleum Coke	20.2	44.7	66.1	5.5	26.0		162.5
TOTAL	392.5	400.7	458.4	61.7	224.0		1537.3
1985							
Distillate	115.9	130.5	107.3	29.1	71.8		454.6
Residual	236.3	88.9	80.0	22.5	40.2		467.9
LPG	46.9	91.7	19.0	3.4	20.2		181.2
Kerosene	7.7	3.7	9.3	0.5	2.8		24.0
Still Gas	58.5	119.1	219.5	14.1	93.4		504.6
Petroleum Coke	19.0	42.0	62.2	5.2	24.5		152.9
TOTAL	484.3	475.9	497.3	74.8	252.9		1785.2

TABLE I-49

Regional Oil Product Demand in the Raw Material Sector

(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
1978							
Petroleum Coke	8.6	46.2	8.4	2.1	12.6		77.9
Special Naphthas	20.3	28.4	39.4	0.7	15.4		104.2
Lubes & Waxes	37.3	24.8	33.3	1.3	11.3		108.0
Asphalt & Road Oil	107.6	187.3	82.1	26.1	79.6		482.7
TOTAL	173.8	286.7	163.2	30.2	118.9		772.8
1979							
Petroleum Coke	8.8	47.0	8.6	2.1	12.8		79.3
Special Naphthas	22.4	31.3	43.4	0.8	16.8		114.7
Lubes & Waxes	37.7	25.2	33.7	1.3	11.5		109.4
Asphalt & Road Oil	111.4	193.8	84.9	27.0	82.4		499.5
TOTAL	180.3	297.3	170.6	31.2	123.5		802.9
1980							
Petroleum Coke	9.0	48.0	8.7	2.2	13.1		81.0
Special Naphthas	18.2	25.4	35.2	0.7	13.6		93.1
Lubes & Waxes	39.2	26.1	35.0	1.4	11.8		113.5
Asphalt & Road Oil	112.1	195.0	85.5	27.1	83.0		502.7
TOTAL	178.5	294.5	164.4	31.4	121.5		790.3
1981							
Petroleum Coke	9.5	50.6	9.2	2.3	13.7		85.3
Special Naphthas	18.9	26.5	36.7	0.7	14.3		97.1
Lubes & Waxes	41.8	27.8	37.3	1.5	12.6		121.0
Asphalt & Road Oil	116.3	202.3	88.7	28.2	86.0		521.5
TOTAL	186.5	307.2	171.9	32.7	126.6		824.9
1985							
Petroleum Coke	10.1	54.0	9.8	2.5	14.6		91.0
Special Naphthas	18.3	25.6	35.4	0.7	13.7		93.7
Lubes & Waxes	44.9	29.9	40.1	1.6	13.6		130.1
Asphalt & Road Oil	117.0	203.5	89.2	28.3	86.6		524.6
TOTAL	190.3	313.0	174.5	33.1	128.5		839.4

TABLE I-50

Regional Oil Product Demand in the Petrochemical Feedstock Sector

(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
1978							
LPG	32.2	91.9	516.2	7.2	9.2		656.7
Petrochemicals*	27.1	45.2	520.4	0.6	9.7		603.0
TOTAL	59.3	137.1	1036.6	7.8	18.9		1259.7
1979							
LPG	34.8	99.5	558.5	7.8	9.9		710.5
Petrochemicals*	31.9	53.1	611.1	0.7	11.3		708.1
TOTAL	66.7	152.6	1169.6	8.5	21.2		1418.6
1980							
LPG	35.3	100.7	565.5	7.9	10.1		719.5
Petrochemicals*	28.8	48.1	553.0	0.6	10.2		640.7
TOTAL	64.1	148.8	1118.5	8.5	20.3		1360.2
1981							
LPG	36.5	104.4	586.0	8.2	10.5		745.6
Petrochemicals*	31.2	52.0	598.7	0.7	11.2		693.8
TOTAL	67.7	156.4	1184.7	8.9	21.7		1439.4
1985							
LPG	35.2	100.7	565.3	7.9	10.1		719.2
Petrochemicals*	36.8	61.4	706.5	0.8	13.1		818.6
TOTAL	72.0	162.1	1271.8	8.7	23.2		1537.8

*Includes still gas, naphthas (+400°F), and miscellaneous products.

TABLE I-51

Regional Oil Product Demand in the Electric Utility Sector

(MB/D)

	PAD I	PAD II	PAD III	PAD IV	PAD V		U.S.
1978							
Distillate	50.8	52.9	16.9	2.1	8.6		131.3
Residual	900.7	100.1	147.3	---	241.9		1390.0
TOTAL	951.5	153.0	164.2	2.1	250.5		1521.3
1979							
Distillate	56.8	59.2	18.9	2.3	9.6		146.8
Residual	783.4	87.0	128.1	---	210.4		1208.9
TOTAL	840.2	146.2	147.0	2.3	220.0		1355.7
1980							
Distillate	60.1	62.6	20.0	2.5	10.1		155.3
Residual	708.7	78.7	115.9	---	190.3		1093.6
TOTAL	768.8	141.3	135.9	2.5	200.4		1248.9
1981							
Distillate	59.0	61.5	19.7	2.4	9.9		152.5
Residual	643.7	71.5	105.3	---	172.9		993.4
TOTAL	702.7	133.0	125.0	2.4	182.8		1145.9
1985							
Distillate	59.4	61.8	19.8	2.5	9.9		153.4
Residual	409.4	45.5	67.0	---	110.0		631.9
TOTAL	468.8	107.3	86.8	2.5	119.9		785.3

TABLE I-52

Regional Energy Demand in the Electric Utility Sector
(MB/D)

1978	I	II	III	IV	V	U.S.
Oil	995	128	118	3	395	1639
Gas	124	248	858	16	246	1492
Coal	1602	2450	512	244	167	4975
Nuclear	709	424	139	-	90	1362
Other	258	175	82	112	772	1399
Total	3688	3425	1709	375	1670	10867
1979						
Oil	884	114	105	3	352	1458
Gas	137	275	953	18	275	1658
Coal	1796	2745	574	273	188	5576
Nuclear	655	391	128	-	84	1258
Other	258	175	82	113	773	1401
Total	3730	3700	1842	407	1672	11351
1980						
Oil	826	115	113	-	287	1341
Gas	95	278	983	12	259	1627
Coal	1902	2751	665	260	202	5780
Nuclear	684	366	122	4	84	1260
Hydro	265	190	80	141	857	1533
Total	3772	3700	1963	417	1689	11541
1981						
Oil	727	92	97	-	314	1230
Gas	99	267	955	11	256	1588
Coal	1880	2701	664	275	212	5732
Nuclear	762	404	140	8	99	1413
Hydro	274	195	87	146	885	1587
Total	3742	3659	1943	440	1766	11550
1985						
Oil	459	35	84	-	262	840
Gas	72	221	758	8	256	1315
Coal	2416	3112	1069	381	344	7322
Nuclear	1096	814	313	10	200	2433
Hydro	287	204	89	167	993	1740
Total	4330	4386	2313	566	2055	13650

TABLE I-53

Electric Utilities Installed Capacity -- 1979

(10^3 Megawatts)

	I	II	III	IV	V	TOTAL
Coal	62.3	96.8	23.3	7.9	6.9	197.2
Coal/Gas	1.0	14.7	2.3	1.4	-	19.4
Coal/Oil	11.8	8.6	1.8	0.8	0.1	23.1
Oil	33.8	6.1	3.0	-	1.3	44.2
Gas	0.1	4.6	9.7	-	0.7	15.1
Oil/Gas	18.9	8.3	45.5	0.3	24.4	97.4
Coal/Oil/Gas	2.6	7.5	-	0.3	-	10.4
Waste	1.2	2.0	-	-	1.6	4.8
Nuclear	28.6	15.4	5.8	0.3	2.7	52.8
Total	160.3	164.0	91.4	11.0	37.7	464.4

TABLE I-54

U.S. Oil Demand by Product and Consuming Sector
(MB/D)

	1978 (A)							
		R&C	TRANS.	INDUST.	CHEMICAL FEED	R.M.	ELECTRIC UTIL.	TOTAL
Gasolines		--	7450.8	--	--	--	--	7450.8
Jet Fuel		--	1058.0	--	--	--	--	1058.0
Special Naphtha		--	--	--	--	104.2	--	104.2
Kerosine		153.0	--	23.8	--	--	--	176.8
Distillate		1602.3	1203.2	495.2	--	--	131.3	3432.0
Residual		569.3	431.6	632.1	--	--	1390.0	3023.0
Liquefied Gases		622.0	81.1	194.5	656.7	--	--	1554.3
Petrochemical Feed		--	--	--	603.0	--	--	603.0
Lubricants and Waxes		--	75.0	--	--	108.0	--	183.0
Coke		--	--	171.4	--	77.9	--	249.3
Asphalt and Road Oil		--	--	--	--	482.7	--	482.7
Still Gas		--	--	535.0	--	--	--	535.0
TOTAL		2946.6	10299.7	2052.0	1259.7	772.8	1521.3	18852.1

	1979 (P)							
		R&C	TRANS.	INDUST.	CHEMICAL FEED	R.M.	ELECTRIC UTIL.	TOTAL
Gasolines		--	7069.2	--	--	--	--	7069.2
Jet Fuel		--	1073.0	--	--	--	--	1073.0
Special Naphtha		--	--	--	--	114.7	--	114.7
Kerosine		160.9	--	21.8	--	--	--	182.7
Distillate		1492.6	1185.3	482.3	--	--	146.8	3307.0
Residual		546.0	433.1	634.0	--	--	1208.9	2822.0
Liquefied Gases		629.8	73.9	196.7	710.5	--	--	1610.9
Petrochemical Feed		--	--	--	708.1	--	--	708.1
Lubricants and Waxes		--	76.8	--	--	109.4	--	186.2
Coke		--	--	172.7	--	79.3	--	252.0
Asphalt and Road Oil		--	--	--	--	499.5	--	499.5
Still Gas		--	--	564.4	--	--	--	564.4
TOTAL		2829.3	9911.3	2071.9	1418.6	802.9	1355.7	18389.7

	1980							
		R&C	TRANS.	INDUST.	CHEMICAL FEED	R.M.	ELECTRIC UTIL.	TOTAL
Gasolines		--	6735.1	--	--	--	--	6735.1
Jet Fuel		--	1027.0	--	--	--	--	1027.0
Special Naphtha		--	--	--	--	93.1	--	93.1
Kerosine		169.1	--	19.0	--	--	--	188.1
Distillate		1181.0	1317.2	371.5	--	--	155.3	3025.0
Residual		415.5	444.5	458.4	--	--	1093.6	2412.0
Liquefied Gases		640.6	67.0	143.6	719.5	--	--	1570.7
Petrochemical Feed		--	--	--	640.7	--	--	640.7
Lubricants and Waxes		--	78.7	--	--	113.5	--	192.2
Coke		--	--	159.9	--	81.0	--	240.9
Asphalt and Road Oil		--	--	--	--	502.7	--	502.7
Still Gas		--	--	527.7	--	--	--	527.7
TOTAL		2406.2	9669.5	1680.1	1360.2	790.3	1248.9	17155.2

TABLE I-54 (Continued)

	1981							
		R&C	TRANS.	INDUST.	CHEMICAL FEED	R.M.	ELECTRIC UTIL.	TOTAL
Gasolines		--	6608.8	--	--	--	--	6608.8
Jet Fuel		--	1048.0	--	--	--	--	1048.0
Special Naphtha		--	--	--	--	97.1	--	97.1
Kerosine		176.8	--	16.9	--	--	--	193.7
Distillate		1275.6	1368.1	315.8	--	--	152.5	3112.0
Residual		438.9	434.1	378.6	--	--	993.4	2245.0
Liquefied Gases		660.1	65.9	127.3	745.6	--	--	1598.9
Petrochemical Feed		--	--	--	693.8	--	--	693.8
Lubricants and Waxes		--	81.0	--	--	121.0	--	202.0
Coke		--	--	162.5	--	85.3	--	247.8
Asphalt and Road Oil		--	--	--	--	521.5	--	521.5
Still Gas		--	--	536.2	--	--	--	536.2
TOTAL		2551.4	9605.9	1537.3	1439.4	824.9	1145.9	17104.8

	1985							
		R&C	TRANS.	INDUST.	CHEMICAL FEED	R.M.	ELECTRIC UTIL.	TOTAL
Gasolines		--	6181.8	--	--	--	--	6181.8
Jet Fuel		--	1130.0	--	--	--	--	1130.0
Special Naphtha		--	--	--	--	93.7	--	93.7
Kerosine		150.7	--	24.0	--	--	--	174.7
Distillate		1089.2	1638.8	454.6	--	--	153.4	3336.0
Residual		331.2	368.0	467.9	--	--	631.9	1799.0
Liquefied Gases		603.9	68.2	181.2	719.2	--	--	1572.5
Petrochemical Feed		--	--	--	818.6	--	--	818.6
Lubricants and Waxes		--	70.2	--	--	130.1	--	200.3
Coke		--	--	152.9	--	91.0	--	243.9
Asphalt and Road Oil		--	--	--	--	524.6	--	524.6
Still Gas		--	--	504.6	--	--	--	504.6
TOTAL		2175.0	9457.0	1785.2	1537.8	839.4	785.3	16579.7

TABLE I-55

Oil Supply/Demand Balance for 1981, First Quarter
Pre-Denial

	PAD					INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	6,610	4,990	3,700	455	2,315		18,070
Interdistrict Ship.	205	165	3,760	90	10	(4,230)	-
Exports	10	50	100	-	150		310
SUPPLY REQUIRED	6,825	5,205	7,560	545	2,475	(4,230)	18,380
SUPPLY							
Interdistrict Receipts							
Products	3,275	740	65	75	145	(4,300)	-
Crude (Net)	60	1,300	(325)	(225)	(820)	10	-
NGL (Net)	95	185	(255)	(20)	10	(15)	-
Crude Production	140	875	4,235	655	2,350		8,255
NGL Production	40	280	1,180	55	20		1,575
Processing Gain	50	105	160	10	70		395
Adjustments	540	430	(95)	(60)	75	75	965
Domestic - Total	4,200	3,915	4,965	490	1,850	(4,230)	11,190
Imports							
Crude	1,095	1,145	2,580	40	500		5,360
Products	1,530	145	15	15	125		1,830
Imports - Total	2,625	1,290	2,595	55	625		7,190
SUPPLY AVAILABLE	6,825	5,205	7,560	545	2,475	(4,230)	18,380

TABLE I-56

Oil Supply/Demand Balance for 1981, Second Quarter
Pre-Denial

	PAD					INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	5,245	4,650	3,615	495	2,325		16,330
Interdistrict Ship.	220	165	3,540	90	10	(4,025)	-
Exports	10	95	100	-	165		370
SUPPLY REQUIRED	5,475	4,910	7,255	585	2,500	(4,025)	16,700
SUPPLY							
Interdistrict Receipts							
Products	3,010	740	70	75	150	(4,045)	-
Crude (Net)	55	1,300	(345)	(225)	(850)	65	-
NGL (Net)	90	185	(265)	(20)	10	-	-
Crude Production	150	875	4,230	655	2,380		8,290
NGL Production	35	275	1,175	60	20		1,565
Processing Gain	45	105	150	10	75		385
Adjustments	(265)	235	(295)	(10)	80	(45)	(300)
Domestic - Total	3,120	3,715	4,720	545	1,865	(4,025)	9,940
Imports							
Crude	1,190	1,080	2,515	35	520		5,340
Products	1,165	115	20	5	115		1,420
Imports - Total	2,355	1,195	2,535	40	635		6,760
SUPPLY AVAILABLE	5,475	4,910	7,255	585	2,500	(4,025)	16,700

TABLE I-57

Oil Supply/Demand Balance for 1981, Third Quarter
Pre-Denial

			PAD			INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	5,130	4,585	3,715	560	2,390		16,380
Interdistrict Ship.	230	170	3,565	95	10	(4,070)	-
Exports	10	110	95	-	155		370
SUPPLY REQUIRED	5,370	4,865	7,375	655	2,555	(4,070)	16,750
SUPPLY							
Interdistrict Receipts							
Products	2,940	785	70	85	130	(4,010)	-
Crude (Net)	50	1,375	(355)	(255)	(755)	(60)	-
NGL (Net)	85	195	(275)	(20)	10	5	-
Crude Production	155	870	4,150	650	2,465		8,290
NGL Production	40	275	1,155	60	20		1,550
Processing Gain	55	115	155	10	85		420
Adjustments	(415)	(40)	70	75	(60)	(5)	(375)
Domestic - Total	2,910	3,575	4,970	605	1,895	(4,070)	9,885
Imports							
Crude	1,260	1,175	2,380	40	540		5,395
Products	1,200	115	25	10	120		1,470
Imports - Total	2,460	1,290	2,405	50	660		6,865
SUPPLY AVAILABLE	5,370	4,865	7,375	655	2,555	(4,070)	16,750

TABLE I-58

Oil Supply/Demand Balance for 1981, Fourth Quarter
Pre-Denial

			PAD			INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	5,935	4,935	3,880	510	2,375		17,635
Interdistrict Ship.	230	180	3,690	85	10	(4,195)	-
Exports	10	110	105	-	175		400
SUPPLY REQUIRED	6,175	5,225	7,675	595	2,560	(4,195)	18,035
SUPPLY							
Interdistrict Receipts							
Products	3,105	775	75	85	135	(4,175)	-
Crude (Net)	55	1,360	(375)	(255)	(775)	(10)	-
NGL (Net)	90	195	(290)	(20)	10	15	-
Crude Production	160	860	4,145	645	2,520		8,330
NGL Production	45	290	1,165	65	20		1,585
Processing Gain	50	115	170	10	90		435
Adjustments	125	205	320	10	(85)	(25)	550
Domestic - Total	3,630	3,800	5,210	540	1,915	(4,195)	10,900
Imports							
Crude	1,235	1,275	2,445	45	525		5,525
Products	1,310	150	20	10	120		1,610
Imports - Total	2,545	1,425	2,465	55	645		7,135
SUPPLY AVAILABLE	6,175	5,225	7,675	595	2,560	(4,195)	18,035

TABLE I-59

Oil Supply/Demand Balance for 1985, First Quarter
Pre-Denial

	PAD					INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	6,140	4,840	3,740	460	2,250		17,430
Interdistrict Ship.	205	165	3,845	90	10	(4,315)	-
Exports	10	25	50	-	130		215
SUPPLY REQUIRED	6,355	5,030	7,635	550	2,390	(4,315)	17,645
SUPPLY							
Interdistrict Receipts							
Products	3,275	820	65	75	145	(4,380)	-
Crude (Net)	95	1,460	(120)	(175)	(1,305)	45	-
NGL (Net)	10	10	(10)	(20)	10		-
Crude Production	140	875	3,540	655	3,215		8,425
NGL Production	40	280	920	55	20		1,315
Processing Gain	50	115	175	10	80		430
Adjustments	550	180	40	(65)	100	20	825
Domestic - Total	4,160	3,740	4,610	535	2,265	(4,315)	10,995
Imports							
Crude	1,100	1,145	3,010	-	-		5,255
Products	1,095	145	15	15	125		1,395
Imports - Total	2,195	1,290	3,025	15	125		6,650
SUPPLY AVAILABLE	6,355	5,030	7,635	550	2,390	(4,315)	17,645

TABLE I-60

Oil Supply/Demand Balance for 1985, Second Quarter
Pre-Denial

	PAD					INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	4,875	4,495	3,655	500	2,230		15,755
Interdistrict Ship.	220	165	3,620	90	10	(4,105)	-
Exports	10	50	50	-	145		255
SUPPLY REQUIRED	5,105	4,710	7,325	590	2,385	(4,105)	16,010
SUPPLY							
Interdistrict Receipts							
Products	3,010	820	70	75	150	(4,125)	-
Crude (Net)	90	1,460	(130)	(180)	(1,345)	105	-
NGL (Net)	10	10	(10)	(20)	10	-	-
Crude Production	150	875	3,530	655	3,255		8,465
NGL Production	35	275	915	60	20		1,305
Processing Gain	45	115	160	10	85		415
Adjustments	(260)	(40)	(165)	(15)	95	(85)	(470)
Domestic - Total	3,080	3,515	4,370	585	2,270	(4,105)	9,715
Imports							
Crude	1,195	1,080	2,935	-	-	-	5,210
Products	830	115	20	5	115		1,085
Imports - Total	2,025	1,195	2,955	5	115		6,295
SUPPLY AVAILABLE	5,105	4,710	7,325	590	2,385	(4,105)	16,010

TABLE I-61

Oil Supply/Demand Balance for 1985, Third Quarter

Pre-Denial

	PAD					INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	4,765	4,560	3,750	565	2,305		15,945
Interdistrict Ship.	230	170	3,645	95	10	(4,150)	-
Exports	10	60	50	-	150		270
SUPPLY REQUIRED	5,005	4,790	7,445	660	2,465	(4,150)	16,215
SUPPLY							
Interdistrict Receipts							
Products	2,940	865	70	85	135	(4,095)	-
Crude (Net)	85	1,545	(130)	(200)	(1,230)	(70)	-
NGL (Net)	10	10	(10)	(20)	10	-	-
Crude Production	155	870	3,470	650	3,440	-	8,585
NGL Production	40	275	900	60	20		1,295
Processing Gain	55	125	165	10	100		455
Adjustments	(405)	(190)	185	65	(130)	15	(460)
Domestic - Total	2,880	3,500	4,650	650	2,345	(4,150)	9,875
Imports							
Crude	1,265	1,175	2,770	-	-		5,210
Products	860	115	25	10	120		1,130
Imports - Total	2,125	1,290	2,795	10	120		6,340
SUPPLY AVAILABLE	5,005	4,790	7,445	660	2,465	(4,150)	16,215

TABLE I-62

Oil Supply/Demand Balance for 1985, Fourth Quarter

Pre-Denial

	PAD					INTER-DISTRICT ADJ.	TOTAL U.S.
	I	II	III	IV	V		
DEMAND							
Local Demand	5,510	4,895	3,290	515	2,305		16,515
Interdistrict Ship.	230	180	3,770	85	10	(4,275)	
Exports	10	60	50	-	150		270
SUPPLY REQUIRED	5,750	5,135	7,110	600	2,465	(4,275)	16,785
SUPPLY							
Interdistrict Receipts							
Products	3,105	855	75	85	135	(4,255)	-
Crude (Net)	90	1,530	(140)	(200)	(1,230)	(50)	-
NGL (Net)	10	10	(10)	(20)	10	-	-
Crude Production	160	860	3,460	645	3,440		8,565
NGL Production	45	290	905	65	20		1,325
Processing Gain	50	125	180	10	100		465
Adjustments	115	40	(230)	5	(130)	30	(170)
Domestic - Total	3,575	3,710	4,240	590	2,345	(4,275)	10,185
Imports							
Crude	1,240	1,275	2,850	-	-		5,365
Products	935	150	20	10	120		1,235
Imports - Total	2,175	1,425	2,870	10	120		6,600
SUPPLY AVAILABLE	5,750	5,135	7,110	600	2,465	(4,275)	16,785

TABLE I-63

U.S. Regional Oil Product Demand by Quarter -- 1980

(MB/D)

PAD: I
YEAR: 1980

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	2,172	2,311	2,347	2,274	2,277
Jet Fuel	382	359	371	384	375
Special Naphtha	19	16	18	17	18
Kerosene	130	44	49	93	79
Distillate	1,794	926	714	1,345	1,193
Residual	1,601	1,200	1,211	1,339	1,337
LPG	267	151	173	243	209
Petrochemical Feedstocks	31	27	29	28	29
Lubricants & Wax	62	69	66	64	66
Coke	29	27	30	28	29
Asphalt & Road Oil	48	128	158	109	112
Still Gas	58	62	64	58	61
TOTAL	6,593	5,320	5,230	5,982	5,784

PAD: II
YEAR: 1980

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	2,101	2,358	2,363	2,281	2,277
Jet Fuel	205	200	209	204	205
Special Naphtha	24	26	24	24	25
Kerosene	82	33	35	64	54
Distillate	1,175	848	767	1,059	962
Residual	320	206	191	258	244
LPG	687	364	392	648	522
Petrochemical Feedstocks	46	47	49	48	48
Lubricants & Wax	42	46	43	43	44
Coke	92	88	95	92	92
Asphalt & Road Oil	64	211	213	17	195
Still Gas	123	122	130	123	125
TOTAL	4,961	4,549	4,511	4,861	4,793

TABLE I-63 (Continued)

PAD: III
YEAR: 1980

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	890	954	932	939	929
Jet Fuel	106	122	123	115	117
Special Naphtha	32	36	34	36	35
Kerosene	45	33	36	47	41
Distillate	423	402	457	443	432
Residual	415	357	382	431	397
LPG	804	659	664	815	736
Petrochemical Feedstocks	522	535	561	591	553
Lubricants & Wax	55	60	60	59	59
Coke	73	71	75	75	74
Asphalt & Road Oil	64	95	103	80	86
Still Gas	222	232	239	225	230
TOTAL	3,651	3,556	3,666	3,856	3,688

PAD: IV
YEAR: 1980

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	199	233	261	221	229
Jet Fuel	32	33	36	37	35
Special Naphtha	-	-	-	-	1
Kerosene	3	1	1	2	2
Distillate	107	109	113	117	112
Residual	44	28	27	37	33
LPG	55	37	36	55	46
Petrochemical Feedstocks	-	-	-	-	1
Lubricants & Wax	1	2	1	2	2
Coke	7	7	8	8	8
Asphalt & Road Oil	5	29	52	20	27
Still Gas	15	14	15	14	15
TOTAL	468	493	550	513	509

TABLE I-63 (Continued)

PAD: V
YEAR: 1980

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	964	1,025	1,075	1,016	1,024
Jet Fuel	293	289	304	292	295
Special Naphtha	13	15	13	13	14
Kerosene	14	13	11	13	13
Distillate	336	316	308	346	327
Residual	451	371	362	424	402
LPG	59	58	57	60	59
Petrochemical Feedstocks	9	9	11	9	10
Lubricants & Wax	19	18	21	20	20
Coke	40	36	35	39	39
Asphalt & Road Oil	48	87	116	79	83
Still Gas	93	98	102	97	98
TOTAL	2,339	2,335	2,415	2,408	2,384

PAD: U.S.
YEAR: 1980

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	6,330	6,896	6,977	6,728	6,735
Jet Fuel	1,022	1,003	1,046	1,034	1,027
Special Naphtha	91	95	93	92	93
Kerosene	276	123	132	220	188
Distillate	3,920	2,574	2,289	3,330	3,025
Residual	2,831	2,178	2,182	2,462	2,412
LPG	1,847	1,291	1,341	1,805	1,571
Petrochemical Feedstocks	612	621	657	671	641
Lubricants & Wax	182	198	195	190	192
Coke	241	229	249	243	241
Asphalt & Road Oil	228	554	763	460	503
Still Gas	512	529	551	519	528
TOTAL	18,092	16,291	16,475	17,755	17,155

TABLE I-64

U.S. Regional Oil Product Demand by Quarter -- 1981

(MB/D)

PAD: I
YEAR: 1981

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	2,131	2,268	2,303	2,232	2,234
Jet Fuel	391	368	380	393	383
Special Naphtha	21	17	20	18	19
Kerosene	133	45	51	95	81
Distillate	1,874	1,118	746	1,405	1,246
Residual	1,493	221	1,129	1,248	1,246
LPG	269	152	175	245	210
Petrochemical Feedstocks	33	30	28	31	31
Lubricants & Wax	67	74	71	69	70
Coke	30	28	32	29	30
Asphalt & Road Oil	51	133	166	114	116
Still Gas	59	63	65	60	62
TOTAL	6,552	5,264	5,166	5,921	5,728

PAD: II
YEAR: 1981

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	2,062	2,314	2,319	2,238	2,234
Jet Fuel	211	205	215	209	210
Special Naphtha	27	28	27	26	27
Kerosene	86	34	37	67	56
Distillate	1,210	873	790	1,090	990
Residual	296	190	176	239	225
LPG	694	365	396	655	527
Petrochemical Feedstocks	50	51	54	53	52
Lubricants & Wax	44	48	45	45	46
Coke	95	91	98	95	95
Asphalt & Road Oil	67	219	343	177	202
Still Gas	125	125	133	126	127
TOTAL	4,967	4,543	4,633	5,020	4,791

TABLE I-64 (Continued)

PAD: III
YEAR: 1981

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	874	936	915	922	912
Jet Fuel	109	125	127	118	120
Special Naphtha	34	38	36	38	37
Kerosene	46	34	37	48	42
Distillate	424	403	458	444	433
Residual	386	332	355	401	369
LPG	832	679	684	839	758
Petrochemical Feedstocks	566	580	608	640	599
Lubricants & Wax	57	63	63	62	62
Coke	74	72	76	76	75
Asphalt & Road Oil	66	98	107	83	89
Still Gas	225	235	242	228	233
TOTAL	3,693	3,595	3,708	3,899	3,729

PAD: IV
YEAR: 1981

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	195	229	256	217	225
Jet Fuel	33	34	37	38	36
Special Naphtha	-	-	-	-	1
Kerosene	3	1	0	2	2
Distillate	108	110	114	118	113
Residual	34	25	25	34	30
LPG	55	37	36	55	46
Petrochemical Feedstocks	-	-	-	-	1
Lubricants & Wax	1	2	1	2	2
Coke	7	7	8	8	8
Asphalt & Road Oil	5	30	54	20	28
Still Gas	15	14	15	14	15
TOTAL	456	489	546	508	505

TABLE I-64 (Continued)

PAD: V
YEAR: 1981

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	946	1,020	1,507	997	1,005
Jet Fuel	299	295	310	298	301
Special Naphtha	13	15	13	13	14
Kerosene	14	13	11	13	13
Distillate	339	319	311	349	330
Residual	421	346	337	395	375
LPG	58	57	56	59	58
Petrochemical Feedstocks	10	10	12	9	11
Lubricants & Wax	20	19	22	21	21
Coke	41	36	41	40	40
Asphalt & Road Oil	50	90	120	81	86
Still Gas	94	99	103	98	99
TOTAL	2,305	2,319	2,843	2,373	2,353

PAD: U.S.
YEAR: 1981

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	6,212	6,768	6,847	6,602	6,609
Jet Fuel	1,044	1,024	1,068	1,056	1,048
Special Naphtha	96	99	98	96	97
Kerosene	285	127	137	228	194
Distillate	4,033	2,648	2,355	3,426	3,112
Residual	2,635	2,028	2,032	2,293	2,245
LPG	1,880	1,315	1,366	1,837	1,599
Petrochemical Feedstocks	663	673	711	727	694
Lubricants & Wax	192	209	206	201	202
Coke	249	236	257	250	248
Asphalt & Road Oil	237	575	793	508	522
Still Gas	519	538	559	527	536
TOTAL	18,045	16,240	16,429	17,751	17,105

TABLE I-65

U.S. Regional Oil Product Demand by Quarter -- 1985

(MB/D)

PAD: I
YEAR: 1985

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	1,992	2,120	2,153	2,086	2,089
Jet Fuel	421	396	410	423	413
Special Naphtha	19	16	18	17	18
Kerosene	118	40	44	84	72
Distillate	1,866	964	743	1,399	1,241
Residual	1,156	866	874	966	965
LPG	270	152	175	245	211
Petrochemical Feedstocks	39	35	37	35	37
Lubricants & Wax	65	72	69	67	69
Coke	29	27	30	28	29
Asphalt & Road Oil	51	134	167	114	117
Still Gas	56	60	62	56	59
TOTAL	6,082	4,882	4,782	5,520	5,321

PAD: II
YEAR: 1985

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	1,928	2,164	2,168	2,093	2,089
Jet Fuel	226	220	230	225	226
Special Naphtha	25	26	25	25	26
Kerosene	74	29	32	58	49
Distillate	1,300	938	849	1,171	1,064
Residual	257	166	154	208	197
LPG	687	361	392	648	522
Petrochemical Feedstocks	59	59	63	61	61
Lubricants & Wax	44	48	45	45	46
Coke	96	91	99	96	96
Asphalt & Road Oil	67	240	346	178	204
Still Gas	115	116	124	117	119
TOTAL	4,878	4,458	4,527	4,925	4,699

TABLE I-65 (Continued)

PAD: III
YEAR: 1985

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	818	876	856	862	853
Jet Fuel	117	134	136	126	129
Special Naphtha	32	36	34	36	35
Kerosene	44	33	36	46	40
Distillate	503	478	542	526	513
Residual	328	282	302	341	314
LPG	804	656	661	812	733
Petrochemical Feedstocks	668	685	718	755	707
Lubricants & Wax	57	63	63	62	62
Coke	71	69	73	73	72
Asphalt & Road Oil	66	98	107	83	89
Still Gas	212	221	228	216	220
TOTAL	3,720	3,631	3,756	3,938	3,766

PAD: IV
YEAR: 1985

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	182	213	239	202	210
Jet Fuel	35	35	39	40	38
Special Naphtha	-	-	-	-	1
Kerosene	3	1	1	2	2
Distillate	126	128	132	136	131
Residual	36	26	26	35	31
LPG	53	79	34	52	44
Petrochemical Feedstocks	-	-	-	-	1
Lubricants & Wax	1	2	1	2	2
Coke	7	7	8	8	8
Asphalt & Road Oil	5	30	54	20	28
Still Gas	14	13	14	13	14
TOTAL	462	534	548	510	511

TABLE I-65 (Continued)

PAD: V
YEAR: 1985

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	885	954	987	933	940
Jet Fuel	323	318	334	321	324
Special Naphtha	13	16	14	13	14
Kerosene	13	12	11	12	12
Distillate	400	376	366	411	388
Residual	328	270	263	308	292
LPG	61	60	59	63	61
Petrochemical Feedstocks	13	13	15	12	13
Lubricants & Wax	21	20	22	21	21
Coke	41	36	40	40	39
Asphalt & Road Oil	51	91	123	83	87
Still Gas	89	93	97	93	93
TOTAL	2,238	2,259	2,331	2,310	2,284

PAD: U.S.
YEAR: 1985

	QUARTERS				
	I	II	III	IV	YEAR
Gasoline	5,811	6,330	6,404	6,175	6,182
Jet Fuel	1,125	1,104	1,151	1,137	1,130
Special Naphtha	92	96	94	93	94
Kerosene	257	114	123	195	175
Distillate	4,323	2,838	2,525	3,672	3,336
Residual	2,112	1,624	1,628	1,836	1,799
LPG	1,849	1,344	1,293	1,807	1,573
Petrochemical Feedstocks	782	794	839	857	819
Lubricants & Wax	190	206	204	198	200
Coke	244	232	252	246	244
Asphalt & Road Oil	238	578	796	480	525
Still Gas	489	506	527	496	505
TOTAL	17,512	15,766	15,836	17,192	16,582

APPENDIX J

Strategic Petroleum Reserve Development Plans

STRATEGIC PETROLEUM RESERVE DEVELOPMENT PLANS

PHASE I

Phase I consists of five underground storage complexes in salt domes and the construction of a marine terminal. Construction of Phase I facilities began in May 1977 with the installation of temporary facilities for early oil fill. Major construction commenced in 1978 and, as of October 1980, is fully complete at all five sites. These storage sites are identified in Table J-1.

TABLE J-1

SPR Phase I Facilities

Storage Site	Location	Storage Capacity (Million Barrels)
Bryan Mound	Brazoria County, TX	60
West Hackberry	Cameron Parish, LA	51
Bayou Choctaw	Iberville Parish, LA	36
Weeks Island	Iberia Parish, LA	75
Sulphur Mines	Calcasieu Parish, LA	22
Subtotal		244
Tanks and Pipelines		4
Total		248

In 1977, the Department of Energy acquired approximately 150 acres of land at St. James, Louisiana, for the construction of a marine terminal. The terminal consists of above-ground storage of 2 million barrels and two tanker docks for the discharging and loading of crude oil. Construction of the terminal facility began in 1978 and is essentially complete. In August 1979, the facility was tested with the docking of a fully loaded tanker. The St. James Terminal is located adjacent to the Capline Terminal on the Mississippi River and is designed to permit distribution of oil from Bayou Choctaw and Weeks Island by pipeline or tanker.

Figure J-1 illustrates the location of Phase I sites and their links with the distribution system. SPR connecting pipelines and their general description are provided in Table J-2.

Deliveries of crude oil to some Phase I sites began in 1978 but was halted in August 1979 due to the reduction of Iranian production and the resulting tight supply situation. Table J-3 details the current inventory of oil in the SPR by site as of December 31, 1980.

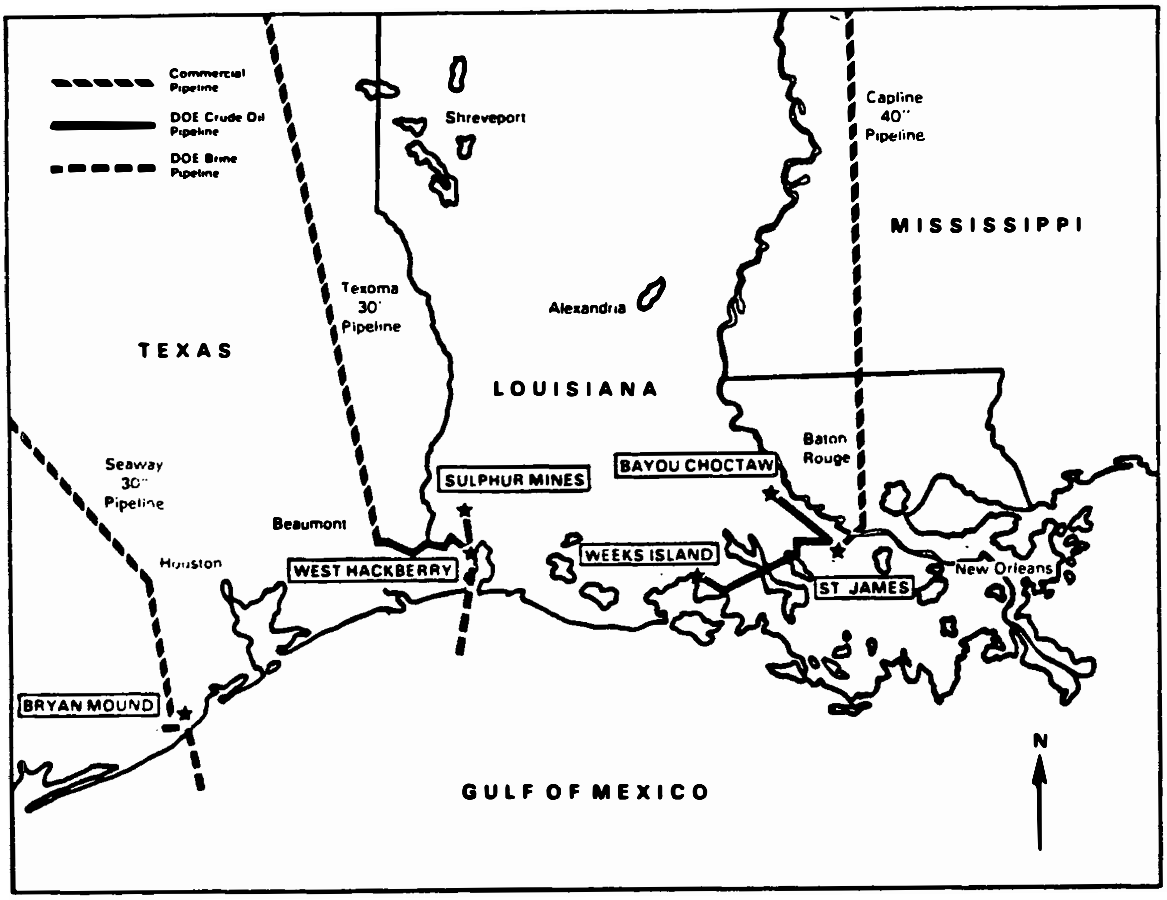


Figure J-1. Strategic Petroleum Reserve System Site Complexes and Pipeline Connections.

TABLE J-2

Pipeline Statistics

Pipeline Size (In.)	Pipeline Type	From	To	Distance (Miles)
30	Crude Oil	Bryan Mound	Seaway Docks	3.6
30	Crude Oil	Bryan Mound	Seaway Pipeline	4.6
36	Brine	Bryan Mound	Gulf of Mexico	14.6
42	Crude Oil	W. Hackberry	Sunoco Terminal	41.5
36	Brine	W. Hackberry	Gulf of Mexico	27.0
16	Crude Oil	Sulphur Mines	W. Hackberry Line	17.0
36	Crude Oil	Bayou Choctaw	St. James Terminal	39.0
36	Crude Oil	Weeks Island	St. James Terminal	69.0
			Total	216.3

TABLE J-3

SPR Crude Oil Inventory
(December 1980)

Storage Site	Location	Storage Capacity (Million Barrels)	1980 Cumulative Crude Oil Inventory (Million Barrels)		
			Sour*	Sweet†	Total
Bryan Mound	Brazoria County, TX	60	--	38.4	38.4
West Hackberry	Cameron Parish, LA	51	27.5	10.5	38.0
Bayou Choctaw	Iberville Parish, LA	36	25.2	--	25.2
Weeks Island	Iberia Parish, LA	75	4.3	--	4.3
Sulphur Mines	Calcasieu Parish, LA	22	--	--	--
Subtotal		244	57.0	48.9	105.9
Tanks and Pipelines		4	1.2	0.7	1.9
Total		248	58.2	49.6	107.8

---

*High sulfur content.
†Low sulfur content.

The SPR drawdown capability as of December 1980 is detailed in Table J-4. The drawdown capability of Bryan Mound, West Hackberry, and Bayou Choctaw are operational and have undergone at least one unannounced drawdown test. These three sites are capable of a combined drawdown rate of greater than 1 MMB/D. The Weeks Island and Sulphur Mines sites each have drawdown facilities in place. However, since no crude oil has been delivered to these sites to date, their drawdown capability has not been tested under actual conditions. Table J-4 also identifies the distribution system and drawdown capabilities for each of the Phase I sites.

PHASE II

Phase II development consists of expansion of the Bryan Mound and West Hackberry sites via the leaching of new salt dome caverns and the acquisition of an additional existing cavern at Bayou Choctaw. This development is shown in Table J-5.

Phase II development is currently well under way with all major facilities installed at Bryan Mound, and leaching is under way there. At the West Hackberry site, construction is progressing and facilities are scheduled for completion in mid-1981 with leaching of storage to begin shortly thereafter.

Although the major physical facilities for Phase II will be completed by mid-1981, due to the rather long lead time necessary

TABLE J-4

SPR Drawdown Capability
(December 1980)

Storage Site	Distribution System Inland Pipeline	Tanker Terminal	Type Oil	Drawdown Rate (MB/D)
Bryan Mound	Seaway	Seaway	Sweet	387
West Hackberry	Texoma	Sunoco	Sour/Sweet	402
Bayou Choctaw	Capline	DOE/St. James	Sour	240
Total Tested				1,029
Weeks Island	Capline	DOE/St. James	Sour (ANS)	590
Sulphur Mines	Spur to W. Hackberry Line	Sunoco	--	100
Total Drawdown Capability				1,719*

---

*Realization of this increased drawdown rate dependent upon oil fill in all five sites.

TABLE J-5

SPR Phase II Facilities

Storage Site	Million Barrels Phase I Capacity	Phase II Capacity	Cumulative Capacity
Bryan Mound	60	120	180
West Hackberry	51	160	211
Bayou Choctaw	36	10	46
Weeks Island	75	--	75
Sulphur Mines	22	--	22
Subtotal	244	290	534
Tanks and Pipelines	4	--	4
Total	248	290	538

to leach new caverns, it is estimated that the full capacity potential of 290 million barrels of new additional storage will not be attained until 1988. As new caverns are leached and become available, however, they can be filled with oil so that Phase II capacity is expected to come on stream in time-phased increments.

Initial Phase II storage is projected to be available the second quarter of 1982 and to continue on a phased-in basis as new caverns are completed through the first quarter of 1988.

The acquisition of an additional 10-million-barrel cavern at Bayou Choctaw is currently under way and is expected to be acquired in the near future. This cavern is existing and currently being used by Allied Chemical for ethylene storage. A 4-million-barrel replacement cavern is being developed for Allied Chemical; upon completion and transfer to Allied, the 10-million-barrel cavern will be acquired and added to SPR capacity.

Upon completion of installation of hardware for Phase II in 1981, systems will be in place to draw down up to 3.5 MMB/D as indicated in Table J-6. As the Phase II expansion of storage at Bryan Mound and West Hackberry progresses between 1980 and 1988, the sustained drawdown rate that can be achieved will increase on a phased-in basis, as the caverns are filled, from 1.7 to 3.5 MMB/D. Table J-6 lists the drawdown capabilities upon the completion of Phase II.

TABLE J-6

Drawdown Capabilities
(Cumulative -- Phase I and Phase II)

Storage Site	Drawdown Rate (MB/D)
Bryan Mound	1,054
West Hackberry	1,402
Bayou Choctaw	480
Weeks Island	590
Sulphur Mines	*
Total	3,526

---

*Combined drawdown rate of West Hackberry and Sulphur Mines is 1.4 MMB/D.

PHASE III

The Phase III development program as currently envisioned consists of the acquisition and development of a new site, and the further expansion of the Bryan Mound and West Hackberry sites. Currently, funding for Phase III provides monies in fiscal year 1982 to begin site acquisition and construction at an as yet undetermined new site plus further expansion of two existing sites. Phase III development is shown in Table J-7.

TABLE J-7

SPR Phase III Facilities

Storage Site	Million Barrels Phase I Capacity	Phase II Capacity	Phase III Capacity	Cumulative Capacity
Bryan Mound	60	120	40	220
West Hackberry	51	160	30	241
Bayou Choctaw	36	10	--	46
Weeks Island	75	--	--	75
Sulphur Mines	22	--	--	22
New Site	--	--	140	140
Subtotal	244	290	210	744
Tanks and Pipelines	4	--	--	4
Total	248	290	212*	750*

---

*Rounded up; expected total Phase III addition to be 212 million barrels.

Total capacity addition is projected to be 212 million barrels of additional storage capacity which will complete the authorized SPR capacity of 750 million barrels as summarized in Table J-8. Phase III storage is scheduled to begin accepting fill during the third quarter of 1985 and to continue on a phased-in schedule until completed in the second quarter of 1989. Phase III drawdown capacity will be 935 MB/D, all at the new Phase III site. This will bring the total SPR drawdown rate to approximately 4.5 MMB/D in 1989.

CURRENT SPR CRUDE OIL SPECIFICATIONS

Table J-9 provides a description of SPR crude oil characteristics and specification limits as they currently exist for acceptable receipt and storage in the SPR. Acceptable grades of crude oil which meet the specifications of an SPR crude oil type are stored in separate storage caverns.

TABLE J-8

SPR Storage Availability

	Cumulative Storage Capacity (Million Barrels)			
Quarter/Year	Total SPR	Phase I	Phase II	Phase III
4Q 1980	248.0	248.0	--	--
1Q 1981			--	--
2Q			--	--
3Q			--	--
4Q			--	--
1Q 1982			--	--
2Q	249.9		1.9	--
3Q	261.1		13.1	--
4Q	272.4		24.4	--
1Q 1983	286.2		38.2	--
2Q	307.7		59.7	--
3Q	330.7		82.7	--
4Q	356.2		108.2	--
1Q 1984	369.0		121.0	--
2Q	394.7		146.7	--
3Q	398.0		150.0	--
4Q	398.0			--
1Q 1985	398.0			--
2Q	398.0			--
3Q	409.2		156.7	4.5
4Q	420.5		163.5	9.0
1Q 1986	431.7		170.2	13.5
2Q	453.0		184.3	20.7
3Q	480.9		202.5	30.4
4Q	508.8		220.7	40.1
1Q 1987	536.6		238.9	49.8
2Q	564.5		257.1	59.4
3Q	605.4		274.5	82.9
4Q	636.3		286.0	102.3
1Q 1988	656.9		290.0	118.9
2Q	672.0			134.0
3Q	687.1			149.1
4Q	705.3			167.3
1Q 1989	730.5			192.5
2Q	750.0			212.0
Total System	750.0	248.0	290.0	212.0

TABLE J-9

Current SPR Crude Oil Specifications

	SPR Crude Oil Types						Appropriate ASTM Test Method
Characteristic	I	II	III	IV	V	VI*	
API Gravity (°API)	30-36	40-45	30-36	34-40	36-41	26-30	D 1298
Total Sulfur (Wt %), Max.	1.99	0.25	0.50	0.25	0.50	1.25	D 129, D 1552, or D 2662
Pour Point (°F), Max.	50	50	50	50	50	50	D 97
Salt Content (lb/1,000 bbl), Max.	50	50	50	50	50	50	D 3230
Viscosity (SUS @ 60°F), Max.	150	150	150	150	150	200	D 445 & D 2161
Reid Vapor Pressure (psig @ 100°F), Max.	11	11	11	11	11	11	D 323
Mercaptans (ppm in 375°-500°F Fraction), Max.	No Limit	12	12	12	No Limit	No Limit	D 1323
Water and Sediment (Vol %), Max.	1.0	1.0	1.0	1.0	1.0	1.0	D 95, D 473
Yields (Vol %)							
Naphtha (<375°F)	24-30	35-42	21-29	29-36	30-38	15-20	
Distillate (375°-620°F)	17-31	21-35	23-37	31-45	19-33	24-27	
Gas Oil (620°-1,050°F)	26-38	20-34	28-42	20-34	23-37	38-42	
Residuum (>1,050°F)	10-19	4-9	7-14	0-5	7-14	15-20	

---

*Type VI crude oil added to list of acceptable fill grades October 1980. Prior to this time, it met SPR specifications but was not allowed as a fill grade.

APPENDIX K

Clean Air Act Waivers of Heavy Fuel Oil Sulfur Content Specifications

EXHIBIT 1

STATE SULFUR REGULATIONS FOR HEAVY FUEL OIL AS OF MAY 1980

	Current Sulfur Maximums (Wt %)
Alabama	
Jackson County	
TVA Willow Creek Plant	1.11
Other	1.66
Jefferson and Mobile Counties	1.66
Remainder	3.7
Arkansas	None*
California	
North Coast Air Basin	1.9
San Francisco Bay Area Air Basin	0.60
North Central Coast Air Basin	0.5
South Central Coast Air Basin	0.5
South Coast Air Basin	0.25
San Diego Air Basin	0.5
Northeast Plateau Air Basin	
Lassen and Modoc Counties	0.5
Eastern Shasta County	3.48
Siskiyou County	4.52
Sacramento Valley Air Basin	
Tehama County	0.5
Plumas and Western Shasta Counties	2.39
Other Counties	4.52
San Joaquin Valley and Great Basin Valleys Air Basins	4.52
Southeast Desert Air Basin	
Imperial, Northeast San Bernardino, and Eastern Riverside Counties	0.5
Northeast San Bernardino Co.	0.5
Kern County	3.6
Eastern San Diego County	
Steam Generators >0.25 MM lb/hr	0.5
Connecticut	0.5
Delaware	
New Castle County	1.0
Remainder	0.3
Florida	
Duval County, Hillsborough County and Crist Steam Plant and Monsanto Facility in Escambia County	1.0
Remainder	2.5

EXHIBIT 1 (Continued)

	Current Sulfur Maximums (Wt %)
Georgia	
<100 MBtu/hr	2.5
>100 MBtu/hr	3.0
Illinois	0.93
Indiana	
East Chicago	1.66
Hammond	1.5
Remainder	1.03-1.9[†]
Kentucky	
New	0.74-2.31[†]
Evansville, Huntington, Louisville, Cincinnati, and Paducah AQCR[§]	1.85-2.31
Appalachian, Bluegrass, and North Central Kentucky AQCR	1.39-2.31
South Central Kentucky AQCR	0.74-2.31
Louisiana	3.64[¶]
Maine	
Metropolitan Portland	1.5
Other	2.5
Maryland/DC	
Metropolitan Baltimore	1.0
District of Columbia	1.0
Montgomery and Prince Georges Counties	1.0
Alleghany, Garrett, and Washington Counties	2.0
Remainder	2.0
Massachusetts	
Boston Metro Region	
Inner Core	0.52
Outer Core	1.0
Central Mass. AQCR	2.2
Except -	
Worcester	1.0
Fitchburg (Winter)	1.0
(Summer)	2.2
Merrimack Valley	
Except - Lawrence, Andover, N. Andover, and Methuen	1.0
Mississippi	
New >250 MMBtu/hr	2.2
Other	4.4

EXHIBIT 1 (Continued)

	Current Sulfur Maximums (Wt %)
Missouri	
St. Louis AQCR	
>2,000 MMBtu/hr	2.13
Other	2.0
Greene County	
New	0.9
Existing	3.6
Other	None*
New Hampshire	
Androscoggin AQCR	2.2
Remainder	1.5
New Jersey	
Counties of: Atlantic, Cape May, Cumberland, Ocean...	2.0
Salem	0.7
Burlington, Camden, Gloucester, Mercer (Excluding Pine Barrens)	0.5
New York	
New York City	0.3**
Nassau, Rockland, and Westchester Counties	0.37
Suffolk County	1.0
Erie and Niagara Counties	1.1
Remainder	2.0
North Carolina	
Existing	2.1
New	1.5††
Ohio	0.95
Pennsylvania	
Air Basins of: Erie, Harrisburg, York, Lancaster, Scranton, Wilkes-Barre	2.8
Allentown, Bethlehem, Easton, Reading, Johnston	2.0
Southeast Pennsylvania:	
Inner Zone	0.5
Outer Zone	1.0
Philadelphia	0.3
Rhode Island	1.0
South Carolina	
Charleston County >10 MMBtu/hr	2.11§§
Aiken and Anderson Counties >1,000 MMBtu/hr	2.1
Other	3.2

EXHIBIT 1 (Continued)

	Current Sulfur Maximums (Wt %)
Tennessee	
Polk County	
>1,000 MMBtu/hr	1.1
<1,000 MMBtu/hr	1.5
Humphreys, Maury, and Roane Counties	
>1,000 MMBtu/hr	1.1
<1,000 MMBtu/hr	4.6
Sullivan County - All	2.2
Shelby County	
In Operation After 4/3/72	3.7
Others	2.5
Anderson, Davidson, Hamilton, Hawkins, Krok, and Rhea Counties - All	3.7
Other Counties	4.6
Texas	0.7¶¶
Vermont	1.0
Virginia	
National Capital AQCR	1.0
Remainder	2.4
West Virginia	
Steubenville, Cumberland, and Parkersburg AQCR	
Steam Generators >10 MMBtu/hr	2.5
Other Units >10 MMBtu/hr	2.9
All Other AQCRs	
Steam Generators >10 MMBtu/hr	3.1
Other Units >10 MMBtu/hr	3.0

---

*No limits if ground level SO_2 concentrations are not excessive.

†Function of burner capacity, number of stacks, stack height, etc.

§AQCR = Air Quality Control Region.

¶Permits to burn liquid fuel must be obtained from the Louisiana Air Control Commission which will only issue permits for 0.7 wt % sulfur fuels. Temporary exceptions may be granted if 0.7 wt % fuels are not available and emissions will not be detrimental to achieving or maintaining ambient air standards.

**Lower levels may be required if present secondary air quality standards are to be met.

††Effective July 1980. Current state environmental policy is to direct new facilities to burn 1.5 wt % sulfur.

§§Opacity requirement is twenty percent (20%), not to be exceeded more than three (3) minutes in any one hour or fifteen (15) minutes in a twenty-four (24) hour period.

¶¶SO_2 emissions at the stack allow use of a 0.9 wt % sulfur fuel; however, consumers must also demonstrate that ground level SO_2 requirements are met and this can generally only be done with 0.7 wt % sulfur fuel.

EXHIBIT 2

PROCEDURAL STEPS AND INFORMATION REQUIREMENTS UNDER THE CLEAN AIR ACT FOR WAIVERS ON SULFUR CONTENT OF HEAVY FUEL OIL

PROCEDURAL STEPS

Section 110(f) provides that emergency SIP (State Implementation Plan) suspensions may be grated by a Governor in accordance with the following steps:

1.0 <u>Owner/Operator Petition</u>

1.1 Owner/Operator of a fuel-burning stationary installation source applies to the state for relief from the fuel requirements of the SIP.

1.2 Governor specifies application procedures.

2.0 <u>Governor's Notice for Public Hearing</u>

2.1 Following receipt of the application, the Governor gives notice and provides an opportunity for a public hearing on the proposed petition to discuss the issues involved.

3.0 <u>Public Hearing</u>

3.1 Governor determines after the public hearing:

- Whether an energy emergency in the vicinity of the source involves high levels of unemployment or loss of necessary energy supplies for residential dwellings
- Whether the proposed suspension would help mitigate the existing unemployment or loss
- Whether suspension of air quality standards will have severe environmental consequences.

4.0 <u>Governor's Petition to the President</u>

4.1 The Governor petitions the President to declare that a natural or regional energy emergency exists of such severity that:

- A temporary suspension of any part of the applicable implementation plan may be necessary
- Other means of responding to the energy emergency may be inadequate.

4.1.1 Appropriate personnel at DOE and EPA are made aware of the request.

4.1.2 DOE and EPA staff investigate the site-specific situation and confer on a joint recommendation to the President that an energy emergency does/does not exist.

5.0 Presidential Declaration

5.1 The President determines that a national or regional energy emergency exists. (This authority may not be redelegated.)

5.2 Formal declaration of the President's determination is published.

6.0 Governor Issues Suspension

6.1 The Governor issues an emergency suspension to the source which may take effect immediately.

6.1.1 Usual suspensions are for 30 or 60 days.

6.1.2 The suspension may be extended for a maximum period of 120 days or for the duration of the energy emergency, whichever is shorter.

6.1.3 Not more than one such suspension may be issued to a source based on the same set of circumstances or on the basis of the same emergency.

6.1.4 Suspensions may be limited by any time restrictions the President makes in his formal declaration.

6.2 The governor has the option of granting waivers first to those installations having the least potential for adverse environmental impacts in the event that multiple applications are involved.

6.3 The Governor may request a fuel burning installation to keep mechanical controls over emissions in operation which may reduce particulate pollution up to 75 percent.

7.0 EPA Administrator Review

7.1 The EPA Administrator may review each suspension to ascertain:

- Whether the energy emergency does indeed exist in the vicinity of the source

- Whether the emergency involves high levels of unemployment or loss of necessary energy supplies for residential dwellings

- Whether such unemployment or loss can be totally or partially alleviated by an emergency suspension of SIP requirements applicable to the source.

7.2 If the EPA Administrator determines that the Governor's action does not satisfy the above three conditions, he will issue a disapproval order reinstating improperly suspended provisions of the SIP.

7.2.1 The EPA Administrator will specify in the disapproval order the date on which the Governor's suspension shall no longer be effective.

EPA INFORMATION REQUIREMENTS

Primary responsibility for developing the following information rests with the state and the source. Most of the information requirements may be gathered prior to the onset of an energy emergency. The following guidelines are provided by the EPA.

1.0 Identify the affected or potentially affected parties, including:

1.1 Parties claiming a fuel shortage or otherwise petitioning for an SIP suspension, together with the basis of their claims

1.2 Affected customer

1.3 Suppliers (potential or actual) to parties experiencing shortages or cutbacks.

2.0 Provide information concerning the nature, magnitude, and duration of an expected emergency, including:

2.1 Monthly demand for fuel by type for two calendar quarters before and projected for after an SIP suspension

2.2 Projected shortfall of conforming fuel for the period, if appropriate

2.3 Any circumstances affecting fuel needs such as abnormal weather conditions, changes in production levels, etc.

2.4 Unanticipated changes in supply/demand, or availability of transportation.

3.0 Summarize the current fuel inventories of the various parties affected, including:

  3.1 Fuels by type and sulfur content

  3.2 Storage capacity/blending capacity

  3.3 A historical comparison of fuel supplies/inventory over last two years

  3.4 Details of the desulfurization or other fuel processing capacity of the source of fuel supply and a historical summary of such capability, including any recent (3 year) changes.

4.0 Information on alternative supplies of available SIP conforming fuels, including natural gas and a documentation of those steps taken to locate such fuels. Adequate documentation includes a list of all suppliers contacted (including date and mode of contact), the response of each supplier contacted, copies of correspondence with the suppliers (including telephone logs), and any other memoranda, notes, or reports evidencing the availability or unavailability of fuels. Where applicable, the firm will be expected to apply to DOE/ERA for a temporary public interest exemption to burn gas, and to FERC for "self help gas."

5.0 Information on alternate fuel supplies that may be available, including coal, natural gas, wood, etc.

6.0 Information on the availability of other fuel supplies which, though not SIP conforming, represent a minimal increase in sulfur or ash levels (i.e., 1 percent sulfur content vs. 0.3 percent sulfur content).

7.0 A summary of the contractual arrangements between various parties, suppliers, and users and a description of the available options in the event of a fuel shortage.

8.0 Actions that have been taken or considered to mitigate the environmental, energy, and employment impacts of the shortage situation or to conserve conforming fuel (mandatory or voluntary). Examples of such measures may be conservation measures, voltage reduction, thermostat reductions, wheeling, and the substituion of natural gas for oil. The amount of fuel saved by each measure should be detailed, as well as the consequences of these strategies on unemployment and necessary residential energy supplies.

9.0 Current and projected loss of necessary residential energy supplies associated with the energy emergency, including the magnitude of losses, the number of people affected, and their location.

10.0 Facilities that may have to close down as a result of the shortages. Current and projected impact on employment associated solely with the energy emergency in the area.

11.0 Which facilities can convert to alternate fuels, and the lead time necessary for these facilities to convert. Other obstacles to conversion that may exist, including other environmental regulations, access to capital, availability of trained operators, equipment availability, etc. Whether conversion would be permanent or temporary.

12.0 How SIP suspensions might alleviate the shortage.

  12.1 The present SIP limitations on fuel use.

  12.2 The new requirements if the SIP were suspended.

  12.3 How much conforming fuel would be saved.

  12.4 Other alternatives within the existing SIP that might wholly or partially alleviate the shortage.

  12.5 Pollutant emissions levels both before and after the proposed temporary suspension of portions of the SIP.

  12.6 Preliminary assessment of the air quality and health effects of the proposed SIP suspensions.

  12.7 Steps the state will undertake to mitigate environmental impacts.

  12.8 Whether the fuel user might blend conforming and nonconforming fuels to minimize any local environmental impact of using nonconforming fuels.

13.0 Documentation of which sources would violate NAAQS (National Ambient Air Quality Standards) if the emissions limitations were suspended, and the present air quality attainment status of the affected areas.

APPENDIX L

Crude Oil and Product Logistics Supply/Demand Balances

TABLE L-1

OIL SUPPLY/DEMAND BALANCES

1981 Scenario 2

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	17,100	14,945	5,730	4,885	4,790	4,195	3,730	3,415	500	440	2,350	2,010
Crude Exports	155	135	-	-	75	65	-	-	-	-	80	70
Product Exports	205	180	10	10	15	15	100	85	-	-	80	70
Total	17,460	15,260	5,740	4,895	4,880	4,275	3,830	3,500	500	440	2,510	2,150
Shipments			220	190	170	155	3,640	3,125	90	80	10	10
Total	17,460	15,260	5,960	5,085	5,050	4,430	7,470	6,625	590	520	2,520	2,160
SUPPLY												
Product Receipts	-	-	3,080	2,690	760	625	70	65	80	70	140	110
NGL Receipts (net)	-	-	90	90	190	190	(270)	(270)	(20)	(20)	10	10
NGL Production	1,570	1,570	40	40	280	280	1,170	1,170	60	60	20	20
Adjustments	205	205	-	-	205	205	-	-	-	-	-	-
Product Imports	1,580	1,180	1,300	1,000	130	90	20	10	10	10	120	70
Total Products	3,355	2,955	4,510	3,820	1,565	1,390	990	975	130	120	290	210
Crude Receipts (net)	-	-	55	360	1,335	1,270	(350)	(310)	(240)	(300)	(800)	(1,020)
Crude Production	8,290	8,290	150	150	870	870	4,190	4,190	650	650	2,430	2,430
Crude Imports	5,405	3,605	1,195	705	1,170	790	2,480	1,610	40	40	520	460
Total Crude	13,695	11,895	1,400	1,215	3,375	2,930	6,320	5,490	450	390	2,150	1,870
Process Gain	410	410	50	50	110	110	160	160	10	10	80	80
Total	14,105	12,305	1,450	1,265	3,485	3,040	6,480	5,650	460	400	2,230	1,950
Total Supply	17,460	15,260	5,960	5,085	5,050	4,430	7,470	6,625	590	520	2,520	2,160
Total Crude	13,695	11,895	1,400	1,215	3,375	2,930	6,320	5,490	450	390	2,150	1,870
Crude Exports	(155)	(135)	-	-	(75)	(65)	-	-	-	-	(80)	(70)
Crude Runs	13,540	11,760	1,400	1,215	3,300	2,865	6,320	5,490	450	390	2,070	1,800

TABLE L-2

OIL SUPPLY/DEMAND BALANCES

1981 Scenario 3

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	17,100	13,985	5,730	4,495	4,790	3,925	3,730	3,280	500	415	2,350	1,870
Crude Exports	155	125	-	-	75	60	-	-	-	-	80	65
Product Exports	205	150	10	10	15	10	100	70	-	-	80	60
Total	17,460	14,260	5,740	4,505	4,880	3,995	3,830	3,350	500	415	2,510	1,990
Shipments			220	180	170	140	3,640	2,985	90	70	10	10
Total	17,460	14,260	5,960	4,685	5,050	4,135	7,470	6,335	590	485	2,520	2,005
SUPPLY												
Product Receipts	-	-	3,080	2,530	760	620	70	65	80	55	140	115
NGL Receipts (net)	-	-	90	95	190	95	(270)	(180)	(20)	(15)	10	5
NGL Production	1,570	1,570	40	40	280	280	1,170	1,170	60	60	20	20
Adjustments	205	205	-	-	205	205	-	-	-	-	-	-
Product Imports	1,580	980	1,300	835	130	90	20	-	10	10	120	45
Total Products	3,355	2,755	4,510	3,500	1,565	1,290	990	1,055	130	110	290	185
Crude Receipts (net)	-	-	55	490	1,335	1,275	(350)	(305)	(240)	(325)	(800)	(1,135)
Crude Production	8,290	8,290	150	150	870	870	4,190	4,190	650	650	2,430	2,430
Crude Imports	5,405	2,805	1,195	495	1,170	590	2,480	1,235	40	40	520	445
Total Crude	13,695	11,095	1,400	1,135	3,375	2,735	6,320	5,120	450	365	2,150	1,740
Process Gain	410	410	50	50	110	110	160	160	10	10	80	80
Total	14,105	11,505	1,450	1,185	3,485	2,845	6,480	5,280	460	375	2,230	1,820
Total Supply	17,460	14,260	5,960	4,685	5,050	4,135	7,470	6,335	590	485	2,520	2,005
Total Crude	13,695	11,095	1,400	1,135	3,375	2,735	6,320	5,120	450	365	2,150	1,740
Crude Exports	(155)	(125)	-	-	(75)	(60)	-	-	-	-	(80)	(65)
Crude Runs	13,540	10,970	1,400	1,135	3,300	2,675	6,320	5,120	450	365	2,070	1,675

TABLE L-3

OIL SUPPLY/DEMAND BALANCES

1981 Scenario 4a

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	17,100	12,600	5,730	3,910	4,790	3,575	3,730	3,085	500	370	2,350	1,660
Crude Exports	155	110	-	-	75	55	-	-	-	-	80	55
Product Exports	205	150	10	10	15	10	100	70	-	-	80	60
Total	17,460	12,860	5,740	3,920	4,880	3,640	3,830	3,155	500	370	2,510	1,775
Shipments			220	165	170	125	3,640	2,550	90	65	10	10
Total	17,460	12,860	5,960	4,085	5,050	3,765	7,470	5,705	590	435	2,520	1,785
SUPPLY												
Product Receipts	-	-	3,080	2,290	760	445	70	55	80	50	140	75
NGL Receipts (net)	-	-	90	90	190	190	(270)	(270)	(20)	(20)	10	10
NGL Production	1,570	1,570	40	40	280	280	1,170	1,170	60	60	20	20
Adjustments	205	205	-	-	205	205	-	-	-	-	-	-
Product Imports	1,580	730	1,300	600	130	80	20	-	10	10	120	40
Total Products	3,355	2,505	4,510	3,020	1,565	1,200	990	955	130	100	290	145
Crude Receipts (net)	-	-	55	595	1,335	1,275	(350)	(300)	(240)	(355)	(800)	(1,215)
Crude Production	8,290	8,290	150	150	870	870	4,190	4,190	650	650	2,430	2,430
Crude Imports	5,405	1,655	1,195	270	1,170	310	2,480	700	40	30	520	345
Total Crude	13,695	9,945	1,400	1,015	3,375	2,455	6,320	4,590	450	325	2,150	1,560
Process Gain	410	410	50	50	110	110	160	160	10	10	80	80
Total	14,105	10,355	1,450	1,065	3,485	2,565	6,480	4,750	460	335	2,230	1,640
Total Supply	17,460	12,860	5,960	4,085	5,050	3,765	7,470	5,705	590	435	2,520	1,785
Total Crude	13,695	9,945	1,400	1,015	3,375	2,455	6,320	4,590	450	325	2,150	1,560
Crude Exports	(155)	(110)	-	-	(75)	(55)	-	-	-	-	(80)	(55)
Crude Runs	13,540	9,835	1,400	1,015	3,300	2,400	6,320	4,590	450	325	2,070	1,505

TABLE L-4

OIL SUPPLY/DEMAND BALANCES

1981 Scenario 4b

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	17,100	13,670	5,730	4,320	4,790	3,885	3,730	3,240	500	410	2,350	1,815
Crude Exports	155	125	-	-	75	60	-	-	-	-	80	65
Product Exports	205	165	10	10	15	15	100	75	-	-	80	65
Total	17,460	13,960	5,740	4,330	4,880	3,960	3,830	3,315	500	410	2,510	1,945
Shipments			220	175	170	135	3,640	2,805	90	70	10	10
Total	17,460	13,960	5,960	4,505	5,050	4,095	7,470	6,120	590	480	2,520	1,955
SUPPLY												
Product Receipts	-	-	3,080	2,420	760	560	70	55	80	65	140	95
NGL Receipts (net)	-	-	90	90	190	190	(270)	(270)	(20)	(20)	10	10
NGL Production	1,570	1,570	40	40	280	280	1,170	1,170	60	60	20	20
Adjustments	205	205	-	-	205	205	-	-	-	-	-	-
Product Imports	1,580	930	1,300	795	130	80	20	-	10	10	120	45
Total Products	3,355	2,705	4,510	3,345	1,565	1,315	990	955	130	115	290	170
Crude Receipts (net)	-	-	55	525	1,335	1,290	(350)	(315)	(240)	(335)	(800)	(1,165)
Crude Production	8,290	8,290	150	150	870	870	4,190	4,190	650	650	2,430	2,430
Crude Imports	5,405	2,555	1,195	435	1,170	510	2,480	1,130	40	40	520	440
Total Crude	13,695	10,845	1,400	1,110	3,375	2,670	6,320	5,005	450	355	2,150	1,705
Process Gain	410	410	50	50	110	110	160	160	10	10	80	80
Total	14,105	11,255	1,450	1,160	3,485	2,780	6,480	5,165	460	365	2,230	1,785
Total Supply	17,460	13,960	5,960	4,505	5,050	4,095	7,470	6,120	590	480	2,520	1,955
Total Crude	13,695	10,845	1,400	1,110	3,375	2,670	6,320	5,005	450	355	2,150	1,705
Crude Exports	(155)	(125)	-	-	(75)	(60)	-	-	-	-	(80)	(65)
Crude Runs	13,540	10,720	1,400	1,110	3,300	2,610	6,320	5,005	450	355	2,070	1,640

TABLE L-5

OIL SUPPLY/DEMAND BALANCES

1981 Scenario 4c

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	17,100	14,655	5,730	4,730	4,790	4,145	3,730	3,375	500	440	2,350	1,965
Crude Exports	155	130	-	-	75	65	-	-	-	-	80	65
Product Exports	205	175	10	10	15	15	100	80	-	-	80	70
Total	17,460	14,960	5,740	4,740	4,880	4,225	3,830	3,455	500	440	2,510	2,100
Shipments			220	190	170	145	3,640	3,040	90	75	10	10
Total	17,460	14,960	5,960	4,930	5,050	4,370	7,470	6,495	590	515	2,520	2,110
SUPPLY												
Product Receipts	-	-	3,080	2,610	760	615	70	60	80	70	140	105
NGL Receipts (net)	-	-	90	90	190	190	(270)	(270)	(20)	(20)	10	10
NGL Production	1,570	1,570	40	40	280	280	1,170	1,170	60	60	20	20
Adjustments	205	205	-	-	205	205	-	-	-	-	-	-
Product Imports	1,580	1,130	1,300	950	130	100	20	-	10	10	120	70
Total Products	3,355	2,905	4,510	3,690	1,565	1,390	990	960	130	120	290	205
Crude Receipts (net)	-	-	55	425	1,335	1,270	(350)	(335)	(240)	(305)	(800)	(1,055)
Crude Production	8,290	8,290	150	150	870	870	4,190	4,190	650	650	2,430	2,430
Crude Imports	5,405	3,355	1,195	615	1,170	730	2,480	1,520	40	40	520	450
Total Crude	13,695	11,645	1,400	1,190	3,375	2,870	6,320	5,375	450	385	2,150	1,825
Process Gain	410	410	50	50	110	110	160	160	10	10	80	80
Total	14,105	12,055	1,450	1,240	3,485	2,980	6,480	5,535	460	395	2,230	1,905
Total Supply	17,460	14,960	5,960	4,930	5,050	4,370	7,470	6,495	590	515	2,520	2,110
Total Crude	13,695	11,645	1,400	1,190	3,375	2,870	6,320	5,375	450	385	2,150	1,825
Crude Exports	(155)	(130)	-	-	(75)	(65)	-	-	-	-	(80)	(65)
Crude Runs	13,540	11,515	1,400	1,190	3,300	2,805	6,320	5,375	450	385	2,070	1,760

TABLE L-6

OIL SUPPLY/DEMAND BALANCES

1985 Scenario 2

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	16,580	14,415	5,320	4,450	4,700	4,135	3,770	3,435	510	445	2,280	1,950
Crude Exports	110	95	-	-	40	35	-	-	-	-	70	60
Product Exports	140	120	10	10	10	10	50	40	-	-	70	60
Total	16,830	14,630	5,330	4,460	4,750	4,180	3,820	3,475	510	445	2,420	2,070
Shipments			220	190	170	150	3,720	3,230	90	80	10	10
Total	16,830	14,630	5,550	4,650	4,920	4,330	7,540	6,705	600	525	2,430	2,080
SUPPLY												
Product Receipts	-	-	3,080	2,670	840	750	70	65	80	65	140	110
NGL Receipts (net)	-	-	10	10	10	10	(10)	(10)	(20)	(20)	10	10
NGL Production	1,310	1,310	40	40	280	280	910	910	60	60	20	20
Adjustments	120	120	-	-	-	-	120	120	-	-	-	-
Product Imports	1,210	810	930	630	130	90	20	10	10	10	120	70
Total Products	2,640	2,240	4,060	3,350	1,260	1,130	1,110	1,095	130	115	290	210
Crude Receipts (net)	-	-	90	420	1,500	1,430	(130)	(60)	(190)	(250)	(1,270)	(1,540)
Crude Production	8,490	8,490	150	150	870	870	3,500	3,500	650	650	3,320	3,320
Crude Imports	5,260	3,460	1,200	680	1,170	780	2,890	2,000	-	-	-	-
Total Crude	13,750	11,950	1,440	1,250	3,540	3,080	6,260	5,440	460	400	2,050	1,780
Process Gain	440	440	50	50	120	120	170	170	10	10	90	90
Total	14,190	12,390	1,490	1,300	3,660	3,200	6,430	5,610	470	410	2,140	1,870
Total Supply	16,830	14,630	5,550	4,650	4,920	4,330	7,540	6,705	600	525	2,430	2,080
Total Crude	13,750	11,950	1,440	1,250	3,540	3,080	6,260	5,440	460	400	2,050	1,780
Crude Exports	(110)	(95)	-	-	(40)	(35)	-	-	-	-	(70)	(60)
Crude Runs	13,640	11,855	1,440	1,250	3,500	3,045	6,260	5,440	460	400	1,980	1,720

TABLE L-7

OIL SUPPLY/DEMAND BALANCES

1985 Scenario 3

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	16,580	13,440	5,320	4,085	4,700	3,840	3,770	3,295	510	420	2,280	1,800
Crude Exports	110	80	-	-	40	30	-	-	-	-	70	50
Product Exports	140	110	10	5	10	10	50	40	-	-	70	55
Total	16,830	13,630	5,330	4,090	4,750	3,880	3,820	3,335	510	420	2,420	1,905
Shipments			220	180	170	140	3,720	2,990	90	80	10	10
Total	16,830	13,630	5,550	4,270	4,920	4,020	7,540	6,325	600	500	2,430	1,915
SUPPLY												
Product Receipts	-	-	3,080	2,535	840	650	70	60	80	65	140	90
NGL Receipts (net)	-	-	10	10	10	10	(10)	(10)	(20)	(20)	10	10
NGL Production	1,310	1,310	40	40	280	280	910	910	60	60	20	20
Adjustments	120	120	-	-	-	-	120	120	-	-	-	-
Product Imports	1,210	610	930	465	130	90	20	-	10	10	120	45
Total Products	2,640	2,040	4,060	3,050	1,260	1,030	1,110	1,080	130	115	290	165
Crude Receipts (net)	-	-	90	545	1,500	1,410	(130)	(20)	(190)	(275)	(1,270)	(1,660)
Crude Production	8,490	8,490	150	150	870	870	3,500	3,500	650	650	3,320	3,320
Crude Imports	5,260	2,660	1,200	475	1,170	590	2,890	1,595	-	-	-	-
Total Crude	13,750	11,150	1,440	1,170	3,540	2,870	6,260	5,075	460	375	2,050	1,660
Process Gain	440	440	50	50	120	120	170	170	10	10	90	90
Total	14,190	11,590	1,490	1,220	3,660	2,990	6,430	5,245	470	385	2,140	1,750
Total Supply	16,830	13,630	5,550	4,270	4,920	4,020	7,540	6,325	600	500	2,430	1,915
Total Crude	13,750	11,150	1,440	1,170	3,540	2,870	6,260	5,075	460	375	2,050	1,660
Crude Exports	(110)	(80)	-	-	(40)	(30)	-	-	-	-	(70)	(50)
Crude Runs	13,640	11,070	1,440	1,170	3,500	2,840	6,260	5,075	460	375	1,980	1,610

TABLE L-8

OIL SUPPLY/DEMAND BALANCES

1985 Scenario 4a

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	16,580	12,050	5,320	3,540	4,700	3,455	3,770	3,090	510	385	2,280	1,580
Crude Exports	110	80	-	-	40	30	-	-	-	-	70	50
Product Exports	140	100	10	5	10	5	50	40	-	-	70	50
Total	16,830	12,230	5,330	3,545	4,750	3,490	3,820	3,130	510	385	2,420	1,680
Shipments			220	170	170	130	3,720	2,675	90	65	10	10
Total	16,830	12,230	5,550	3,715	4,920	3,620	7,540	5,805	600	450	2,430	1,690
SUPPLY												
Product Receipts	-	-	3,080	2,335	840	555	70	65	80	55	140	40
NGL Receipts (net)	-	-	10	10	10	10	(10)	(10)	(20)	(20)	10	10
NGL Production	1,310	1,310	40	40	280	280	910	910	60	60	20	20
Adjustments	120	120	-	-	-	-	120	120	-	-	-	-
Product Imports	1,210	360	930	230	130	80	20	-	10	10	120	40
Total Products	2,640	1,790	4,060	2,615	1,260	925	1,110	1,085	130	105	290	110
Crude Receipts (net)	-	-	90	640	1,500	1,375	(130)	130	(190)	(315)	(1,270)	(1,830)
Crude Production	8,490	8,490	150	150	870	870	3,500	3,500	650	650	3,320	3,320
Crude Imports	5,260	1,510	1,200	260	1,170	330	2,890	920	-	-	-	-
Total Crude	13,750	10,000	1,440	1,050	3,540	2,575	6,260	4,550	460	335	2,050	1,490
Process Gain	440	440	50	50	120	120	170	170	10	10	90	90
Total	14,190	10,440	1,490	1,100	3,660	2,695	6,430	4,720	470	345	2,140	1,580
Total Supply	16,830	12,230	5,550	3,715	4,920	3,620	7,540	5,805	600	450	2,430	1,690
Total Crude	13,750	10,000	1,440	1,050	3,540	2,575	6,260	4,550	460	335	2,050	1,490
Crude Exports	(110)	(80)	-	-	(40)	(30)	-	-	-	-	(70)	(50)
Crude Runs	13,640	9,920	1,440	1,050	3,500	2,545	6,260	4,550	460	335	1,980	1,440

TABLE L-9

OIL SUPPLY/DEMAND BALANCES

1985 Scenario 4b

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	16,580	13,130	5,320	3,945	4,700	3,790	3,770	3,250	510	400	2,280	1,745
Crude Exports	110	90	-	-	40	35	-	-	-	-	70	55
Product Exports	140	110	10	5	10	5	50	40	-	-	70	60
Total	16,830	13,330	5,330	3,950	4,750	3,830	3,820	3,290	510	400	2,420	1,860
Shipments			220	170	170	135	3,720	2,930	90	70	10	10
Total	16,830	13,330	5,550	4,120	4,920	3,965	7,540	6,220	600	470	2,430	1,870
SUPPLY												
Product Receipts	-	-	3,080	2,455	840	665	70	70	80	45	140	80
NGL Receipts (net)	-	-	10	10	10	10	(10)	(10)	(20)	(20)	10	10
NGL Production	1,310	1,310	40	40	280	280	910	910	60	60	20	20
Adjustments	120	120	-	-	-	-	120	120	-	-	-	-
Product Imports	1,210	560	930	425	130	80	20	-	10	10	120	45
Total Products	2,640	1,990	4,060	2,930	1,260	1,035	1,110	1,090	130	95	290	155
Crude Receipts (net)	-	-	90	560	1,500	1,410	(130)	10	(190)	(285)	(1,270)	(1,695)
Crude Production	8,490	8,490	150	150	870	870	3,500	3,500	650	650	3,320	3,320
Crude Imports	5,260	2,410	1,200	430	1,170	530	2,890	1,450	-	-	-	-
Total Crude	13,750	10,900	1,440	1,140	3,540	2,810	6,260	4,960	460	365	2,050	1,625
Process Gain	440	440	50	50	120	120	170	170	10	10	90	90
Total	14,190	11,340	1,490	1,190	3,660	2,930	6,430	5,130	470	375	2,140	1,715
Total Supply	16,830	13,330	5,550	4,120	4,920	3,965	7,540	6,220	600	470	2,430	1,870
Total Crude	13,750	10,900	1,440	1,140	3,540	2,810	6,260	4,960	460	365	2,050	1,625
Crude Exports	(110)	(90)	-	-	(40)	(35)	-	-	-	-	(70)	(55)
Crude Runs	13,640	10,810	1,440	1,140	3,500	2,775	6,260	4,960	460	365	1,980	1,570

TABLE L-10

OIL SUPPLY/DEMAND BALANCES

1985 Scenario 4c

MB/D

	Total U.S.		PAD I		PAD II		PAD III		PAD IV		PAD V	
	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial	Pre Denial	Post Denial
DEMAND												
Local	16,580	14,115	5,320	4,320	4,700	4,065	3,770	3,395	510	435	2,280	1,900
Crude Exports	110	95	-	-	40	35	-	-	-	-	70	60
Product Exports	140	120	10	10	10	10	50	40	-	-	70	60
Total	16,830	14,330	5,330	4,330	4,750	4,110	3,820	3,435	510	435	2,420	2,020
Shipments			220	190	170	140	3,720	3,140	90	75	10	10
Total	16,830	14,330	5,550	4,520	4,920	4,250	7,540	6,575	600	510	2,430	2,030
SUPPLY												
Product Receipts	-	-	3,080	2,615	840	725	70	60	80	60	140	95
NGL Receipts (net)	-	-	10	10	10	10	(10)	(10)	(20)	(20)	10	10
NGL Production	1,310	1,310	40	40	280	280	910	910	60	60	20	20
Adjustments	120	120	-	-	-	-	120	120	-	-	-	-
Product Imports	1,210	760	930	580	130	100	20	-	10	10	120	70
Total Products	2,640	2,190	4,060	3,245	1,260	1,115	1,110	1,080	130	110	290	195
Crude Receipts (net)	-	-	90	465	1,500	1,425	(130)	(55)	(190)	(260)	(1,270)	(1,575)
Crude Production	8,490	8,490	150	150	870	870	3,500	3,500	650	650	3,320	3,320
Crude Imports	5,260	3,210	1,200	610	1,170	720	2,890	1,880	-	-	-	-
Total Crude	13,750	11,700	1,440	1,225	3,540	3,015	6,260	5,325	460	390	2,050	1,745
Process Gain	440	440	50	50	120	120	170	170	10	10	90	90
Total	14,190	12,140	1,490	1,275	3,660	3,135	6,430	5,495	470	400	2,140	1,835
Total Supply	16,830	14,330	5,550	4,520	4,920	4,250	7,540	6,575	600	510	2,430	2,030
Total Crude	13,750	11,700	1,440	1,225	3,540	3,015	6,260	5,325	460	390	2,050	1,745
Crude Exports	(110)	(95)	-	-	(40)	(35)	-	-	-	-	(70)	(60)
Crude Runs	13,640	11,605	1,440	1,225	3,500	2,980	6,260	5,325	460	390	1,980	1,685

TABLE L-11

1981 PRODUCT DEMANDS - PAD DISTRICTS

MB/D

1981 Pre-Denial	I	II	III	IV	V	Total
Gasoline	2,230	2,230	915	225	1,005	6,605
Jet Fuel	385	210	120	35	300	1,050
Kerosene	80	55	45	-	15	195
Distillates	1,245	990	430	115	335	3,115
HFO	1,245	225	370	30	385	2,255
NGL	210	525	760	45	60	1,600
Other	335	555	1,090	50	250	2,280
Total	5,730	4,790	3,730	500	2,350	17,100
1981 Scenario 2						
Gasoline	1,780	1,780	720	180	800	5,260
Jet Fuel	350	200	110	30	275	965
Kerosene	80	55	45	-	15	195
Distillates	1,150	905	400	105	305	2,865
HFO	985	180	290	25	300	1,780
NGL	210	525	760	45	60	1,600
Other	330	550	1,090	55	255	2,280
Total	4,885	4,195	3,415	440	2,010	14,945
1981 Scenario 3						
Gasoline	1,570	1,565	640	160	710	4,645
Jet Fuel	350	200	110	30	275	965
Kerosene	80	55	45	-	15	195
Distillates	1,090	870	385	105	295	2,745
HFO	860	155	250	25	265	1,555
NGL	210	525	760	45	60	1,600
Other	335	555	1,090	50	250	2,280
Total	4,495	3,925	3,280	415	1,870	13,985

TABLE L-11 (Continued)

1981 PRODUCT DEMANDS - PAD DISTRICTS

MB/D

	I	II	III	IV	V	Total
1981 Scenario 4a						
Gasoline	1,505	1,500	615	150	680	4,450
Jet Fuel	275	160	85	25	220	765
Kerosene	80	55	45	-	15	195
Distillates	835	665	295	80	225	2,100
HFO	670	120	195	15	210	1,210
NGL	210	525	760	45	60	1,600
Other	335	550	1,090	55	250	2,280
Total	3,910	3,575	3,085	370	1,660	12,600
1981 Scenario 4b						
Gasoline	1,690	1,685	685	170	760	4,990
Jet Fuel	305	175	95	30	245	850
Kerosene	80	55	45	-	15	195
Distillates	950	755	335	90	255	2,385
HFO	750	140	230	20	230	1,370
NGL	210	525	760	45	60	1,600
Other	335	550	1,090	55	250	2,280
Total	4,320	3,885	3,240	410	1,815	13,670
1981 Scenario 4c						
Gasoline	1,780	1,780	725	185	800	5,270
Jet Fuel	350	195	110	30	280	965
Kerosene	80	55	45	-	15	195
Distillates	1,105	880	385	100	295	2,765
HFO	870	160	260	25	265	1,580
NGL	210	525	760	45	60	1,600
Other	335	550	1,090	55	250	2,280
Total	4,730	4,145	3,375	440	1,965	14,655

TABLE L-12

1985 PRODUCT DEMANDS - PAD DISTRICTS

MB/D

1985 Pre-Denial	I	II	III	IV	V	Total
Gasoline	2,090	2,090	850	210	940	6,180
Jet Fuel	410	225	130	40	325	1,130
Kerosene	70	50	40	-	15	175
Distillates	1,245	1,065	515	130	385	3,340
HFO	965	200	315	30	290	1,800
NGL	210	520	735	45	60	1,570
Other	330	550	1,185	55	265	2,385
Total	5,320	4,700	3,770	510	2,280	16,580
1985 Scenario 2						
Gasoline	1,725	1,725	700	175	770	5,095
Jet Fuel	380	215	120	35	295	1,045
Kerosene	70	50	40	-	15	175
Distillates	1,100	945	450	115	345	2,955
HFO	635	125	210	20	195	1,185
NGL	210	525	735	45	60	1,575
Other	330	550	1,185	55	265	2,385
Total	4,450	4,135	3,440	445	1,945	14,415
1985 Scenario 3						
Gasoline	1,460	1,460	595	145	655	4,315
Jet Fuel	380	210	120	35	300	1,045
Kerosene	70	50	40	-	15	175
Distillates	1,085	930	445	120	340	2,920
HFO	550	115	175	20	165	1,025
NGL	210	525	735	45	60	1,575
Other	330	550	1,185	55	265	2,385
Total	4,085	3,840	3,295	420	1,800	13,440

TABLE L-12 (Continued)

1985 PRODUCT DEMANDS - PAD DISTRICTS

MB/D

	I	II	III	IV	V	Total
1985 Scenario 4a						
Gasoline	1,390	1,385	565	145	630	4,115
Jet Fuel	290	165	90	30	225	800
Kerosene	70	50	40	-	15	175
Distillates	815	695	335	90	255	2,190
HFO	435	85	140	20	130	810
NGL	210	525	735	45	60	1,575
Other	330	550	1,185	55	265	2,385
Total	3,540	3,455	3,090	385	1,580	12,050
1985 Scenario 4b						
Gasoline	1,580	1,575	645	160	705	4,665
Jet Fuel	330	185	100	30	260	905
Kerosene	70	50	40	-	15	175
Distillates	930	805	385	95	290	2,505
HFO	495	100	160	15	150	920
NGL	210	525	735	45	60	1,575
Other	330	550	1,185	55	265	2,385
Total	3,945	3,790	3,250	400	1,745	13,130
1985 Scenario 4c						
Gasoline	1,670	1,670	680	170	750	4,940
Jet Fuel	380	215	120	35	295	1,045
Kerosene	70	50	40	-	15	175
Distillates	1,090	940	450	115	340	2,935
HFO	570	115	185	15	175	1,060
NGL	210	525	735	45	60	1,575
Other	330	550	1,185	55	265	2,385
Total	4,320	4,065	3,395	435	1,900	14,115

TABLE L-13

INTER-DISTRICT PRODUCT SHIPMENTS - 1981

MB/D

1981, Pre-Denial

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	3,050			3,080
II	220		510	30		760
III		70				70
IV		70			10	80
V			80	60		140
Total	220	170	3,640	90	10	4,130

1981, Scenario 2 (Denial = 2,200 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	2,660			2,690
II	190		410	25		625
III		65				65
IV		60			10	70
V			55	55		110
	190	155	3,125	80	10	3,560

1981, Scenario 3 (Denial = 3,200 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	2,500			2,530
II	180		415	25		620
III		65				65
IV		45			10	55
V			70	45		115
Total	180	140	2,985	70	10	3,385

1981, Scenario 4a (Denial = 4,600 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	2,260			2,290
II	165		260	20		445
III		55				55
IV		40			10	50
V			30	45		75
	165	125	2,550	65	10	2,915

TABLE L-13 (Continued)

INTER-DISTRICT PRODUCT SHIPMENTS - 1981

MB/D

	1981, Scenario 4b (Denial = 3,500 MB/D)					
	Shipments					Receipts
	I	II	III	IV	V	Total
I		25	2,395			2,420
II	175		360	25		560
III		55				55
IV		55			10	65
V			50	45		95
Total	175	135	2,805	70	10	3,195

	1981, Scenario 4c (Denial = 2,500 MB/D)					
	Shipments					Receipts
	I	II	III	IV	V	Total
I		25	2,585			2,610
II	190		400	25		615
III		60				60
IV		60			10	70
V			55	50		105
Total	190	145	3,040	75	10	3,460

TABLE L-14

INTER-DISTRICT PRODUCT SHIPMENTS - 1985

MB/D

1985 Pre-Denial

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	3,050			3,080
II	220		590	30		840
III		70				70
IV		70			10	80
V			80	60		140
Total	220	170	3,720	90	10	4,210

1985, Scenario 2 (Denial = 2,200 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	2,640			2,670
II	190		535	25		750
III		65				65
IV		55			10	65
V			55	55		110
Total	190	150	3,230	80	10	3,660

1985, Scenario 3 (Denial = 3,200 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		25	2,510			2,535
II	180		445	25		650
III		60				60
IV		55			10	65
V			35	55		90
Total	180	140	2,990	80	10	3,400

1985, Scenario 4a (Denial = 4,600 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		20	2,315			2,335
II	170		360	25		555
III		65				65
IV		45			10	55
V				40		40
Total	170	130	2,675	65	10	3,050

TABLE L-14 (Continued)

INTER-DISTRICT PRODUCT SHIPMENTS - 1985

MB/D

1985 Scenario 4b (Denial = 3,500 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	2,425			2,455
II	170		470	25		665
III		70				70
IV		35			10	45
V			35	45		80
Total	170	135	2,930	70	10	3,315

1985, Scenario 4c, (Denial = 2,500 MB/D)

	Shipments					Receipts
	I	II	III	IV	V	Total
I		30	2,585			2,615
II	190		510	25		725
III		60				60
IV		50			10	60
V			45	50		95
Total	190	140	3,140	75	10	3,555

TABLE L-15

1981 REFINERY MAKE
PRE-DENIAL vs. SCENARIO 3 COMPARISON

MB/D

	MB/D								
Pre-Denial	Mogas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
PAD I	620	50	10	360	1,040	65	130	215	1,450
II	1,695	155	30	765	2,645	70	165	530	3,410
III	2,490	500	130	1,380	4,500	165	530	1,285	6,480
IV	205	25	-	135	365	5	35	55	460
V	930	230	15	300	1,475	35	335	305	2,150
TOTAL	5,940	960	185	2940	10,025	340	1,195	2,390	13,950
Avg. Yield %	42.6	6.9	1.3	21.1	71.9	2.4	8.6	17.1	100.0
Scenario 3									
I	395	45	10	335	785	65	125	210	1,185
II	1,190	145	30	710	2,075	70	120	520	2,785
III	1,680	455	130	1,210	3,475	165	365	1,275	5,280
IV	140	25	-	120	285	5	30	55	375
V	680	235	15	275	1,205	35	225	290	1,755
TOTAL	4,085	905	185	2,650	7,825	340	865	2,350	11,380
Avg. Yield %	35.9	8.0	1.6	23.3	68.8	3.0	7.6	20.6	100.0
Yield Change	(6.7)	1.1	.3	2.2	(3.1)	.6	(1.0)	3.5	-

TABLE L-16

PAD DISTRICT I
PRODUCT SUPPLY/DEMAND BALANCE
1981, SCENARIO 3

MB/D

	Case: Pre-Denial									Case: Post Denial								
	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
Local Demand	2230	385	80	1245	3940	210	1245	335	5730	1,570	350	80	1,090	3,090	210	860	335	4,495
Ship: PAD I																		
II	160	10	-	50	220	-	-	-	220	135	5	-	40	180	-	-	-	180
III																		
IV																		
V																		
Total	160	10	-	50	220	-	-	-	220	135	5	-	40	180	-	-	-	180
Exports	-	-	-	-	-	-	-	15	15	-	-	-	-	-	-	-	10	10
Total	2390	395	80	1295	4160	210	1245	350	5965	1705	355	80	1130	3270	210	860	345	4685
Receipts PAD I																		
II	25	-	-	5	30	30	-	-	60	20	-	-	5	25	30	-	-	55
III	1620	315	60	805	2800	65	125	125	3115	1225	280	60	740	2305	65	75	125	2570
IV																		
V																		
Total	1645	315	60	810	2830	95	125	125	3175	1245	280	60	745	2330	95	75	125	2625
NGL						40			40						40			40
Ref. Make	620	50	10	360	1040	65	130	215	1450	395	45	10	335	785	65	125	210	1185
Imports	125	30	10	125	290	10	990	10	1,300	65	30	10	50	155	10	660	10	835
Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	2390	395	80	1295	4160	210	1245	350	5965	1705	355	80	1130	3270	210	860	345	4,685

TABLE L-17

PAD DISTRICT II
PRODUCT SUPPLY/DEMAND BALANCE
1981, SCENARIO 3

MB/D

	Case: Pre-Denial									Case: Post Denial								
	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
Local Demand	2230	210	55	990	3485	525	225	555	4790	1565	200	55	870	2690	525	155	555	3925
Ship: PAD I	25	-	-	5	30	30	-	-	60	20	-	-	5	25	30	-	-	55
II																		
III	55	-	-	15	70	60	-	-	130	45	-	-	15	60	60	-	-	120
IV	50	15	-	5	70	5	-	-	75	40	10	-	5	55	5	-	-	60
V																		
Total	130	15	-	25	170	95	-	-	265	105	10	-	25	140	95	-	-	235
Exports	-	-	-	-	-	-	-	15	15	-	-	-	-	-	-	-	10	10
Total	2360	225	55	1015	3655	620	225	570	5070	1670	210	55	895	2830	620	155	565	4170
Receipts PAD I	160	10	-	50	220	-	-	-	220	135	5	-	40	180	-	-	-	180
II																		
III	400	45	25	140	610	170	-	-	780	240	45	25	90	400	175	10	5	590
IV	15	-	-	15	30	15	-	-	45	15	-	-	10	25	15	-	-	40
V																		
Total	575	55	25	205	860	185	-	-	1045	390	50	25	140	605	190	10	5	810
NGL						280			280						280			280
Ref. Make	1695	155	30	765	2645	70	165	530	3410	1190	145	30	710	2075	70	120	520	2785
Imports	-	-	-	-	-	75	50	5	130	-	-	-	-	-	70	15	5	90
Adjustment	90	15	-	45	150	10	10	35	205	90	15	-	45	150	10	10	35	205
Total	2360	225	55	1015	3655	620	225	570	5070	1670	210	55	895	2830	620	155	565	4170

TABLE L-18

PAD DISTRICT III
PRODUCT SUPPLY/DEMAND BALANCE
1981, SCENARIO 3

	Case: Pre-Denial									Case: Post Denial								
	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
Local Demand	915	120	45	430	1510	760	370	1090	3730	640	110	45	385	1180	760	250	1090	3280
Ship: PAD I	1620	315	60	805	2800	65	125	125	3115	1225	280	60	740	2305	65	75	125	2570
II	400	45	25	140	610	170	-	-	780	240	45	25	90	400	175	10	5	590
III																		
IV																		
V	10	20	-	20	50	-	35	-	85	5	20	-	10	35	-	30	-	65
Total	2030	380	85	965	3460	235	160	125	3980	1470	345	85	840	2740	240	115	130	3225
Exports						15		75	90						10		60	70
Total	2945	500	130	1395	4970	1010	530	1290	7800	2110	455	130	1225	3920	1010	365	1280	6575
Receipts PAD I																		
II	55	-	-	15	70	60	-	-	130	45	-	-	15	60	60	-	-	120
III																		
IV																		
V																		
Total	55	-	-	15	70	60	-	-	130	45	-	-	15	60	60	-	-	120
NGL	395				395	775			1170	385				385	785			1170
Ref. Make	2490	500	130	1380	4500	165	530	1285	6480	1680	455	130	1210	3475	165	365	1280	5285
Imports	5	-	-	-	5	10	-	5	20									
Adjustment																		
Total	2945	500	130	1395	4970	1010	530	1290	7800	2110	455	130	1225	3920	1010	365	1280	6575

TABLE L-19

PAD DISTRICT IV
PRODUCT SUPPLY/DEMAND BALANCE
1981, SCENARIO 3

MB/D

	Case: Pre-Denial									Case: Post Denial								
	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
Local Demand	225	35	-	115	375	45	30	50	500	160	30	-	105	295	45	25	50	415
Ship: PAD I																		
II	15	-	-	15	30	15	-	-	45	15	-	-	10	25	15	-	-	40
III																		
IV																		
V	30	5	-	15	50	10	5	5	70	20	5	-	10	35	5	5	5	50
Total	45	5	-	30	80	25	5	5	115	35	5	-	20	60	20	5	5	90
Exports																		
Total	270	40	-	145	455	70	35	55	615	195	35	-	125	355	65	30	55	505
Receipts PAD I																		
II	50	15	-	5	70	5	-	-	75	40	10	-	5	55	5	-	-	60
III																		
IV																		
V	5	-	-	5	10	-	-	-	10	5	-	-	-	5	-	-	-	5
Total	55	15	-	10	80	5	-	-	85	45	10	-	5	60	5	-	-	65
NGL	10				10	55			65	10				10	55			65
Ref. Make	205	25	-	135	365	5	35	55	460	140	25	-	120	285	5	30	55	375
Imports						5			5									
Adjustment																		
Total	270	40	-	145	455	70	35	55	615	195	35	-	125	355	65	30	55	505

TABLE L-20

PAD DISTRICT V
PRODUCT SUPPLY/DEMAND BALANCE
1981, SCENARIO 3

	Case: Pre-Denial									Case: Post Denial								
	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
Local Demand.	1005	300	15	335	1655	60	385	250	2350	710	275	15	295	1295	60	265	250	1870
Ship: PAD I																		
II																		
III																		
IV	5	-	-	5	10	-	-	-	10	5	-	-	-	5	-	-	-	5
V																		
Total	5	-	-	5	10	-	-	-	10	5	-	-	-	5	-	-	-	5
Exports	-	-	-	5	5	5	10	65	85	-	-	-	-	-	5	5	50	60
Total	1010	300	15	345	1670	65	395	315	2445	715	275	15	295	1300	65	270	300	1935
Receipts PAD I																		
II																		
III	10	20	-	20	50	-	35	-	85	5	20	-	10	35	-	30	-	65
IV	30	5	-	15	50	10	5	5	70	20	5	-	10	35	5	5	5	50
V																		
Total	40	25	-	35	100	10	40	5	155	25	25	-	20	70	5	35	5	115
NGL	15	-	-	-	15	5	-	-	20	-	-	-	-	-	20	-	-	20
Ref. Make	930	230	15	300	1475	35	335	305	2150	680	235	15	275	1205	35	225	290	1755
Imports	25	45	-	10	80	15	20	5	120	10	15	-	-	25	5	10	5	45
Adjustment																		
Total	1010	300	15	345	1670	65	395	315	2445	715	275	15	295	1300	65	270	300	1935

TABLE L-21

TOTAL U.S.
PRODUCT SUPPLY/DEMAND BALANCE
1981, SCENARIO 3

MB/D

	Pre-Denial									Post Denial								
	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total	Gas	Jet	Kero	Dist	Total	NGL	Resid	Other	Total
Local Demand	6605	1050	195	3115	10965	1600	2255	2280	17100	4645	965	195	2745	8550	1600	1555	2280	13985
Ship: PAD I																		
II																		
III																		
IV																		
V																		
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Exports	-	-	-	5	5	20	10	170	205	-	-	-	-	-	15	5	130	150
Total	6605	1050	195	3120	10970	1620	2265	2450	17305	4645	965	195	2745	8550	1615	1560	2410	14135
Receipts PAD I																		
II																		
III																		
IV																		
V																		
Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NGL	410	-	-	-	410	1160	-	-	1570	390	-	-	-	390	1180	-	-	1570
Ref. Make	5950	960	185	2940	10035	340	1185	2390	13950	4085	905	185	2650	7825	340	860	2355	11380
Imports	155	75	10	135	375	120	1060	25	1580	75	45	10	50	180	95	685	20	980
Adjustment	90	-	0	45	150	-	20	35	205	95	15	-	45	155	-	15	35	205
Total	6605	1050	195	3120	10970	1620	2265	2450	17305	4645	965	195	2745	8550	1615	1560	2410	14135

APPENDIX M

The International Energy Agency

THE INTERNATIONAL ENERGY AGENCY

THE IEA ORGANIZATION

This appendix presents a description of the full IEA organization and the sharing system. The Agreement on an International Energy Program came about as a result of the events of 1973-1974 including an embargo of some crude oil supplies to a few countries, among them the United States, and the ensuing competition among consumer countries for supplies. As a result of this experience, and in part at the urging of the United States, 16 industrialized nations signed the Agreement on an International Energy Program in November of 1974. Their purpose was to cooperate on energy policies and to decrease their vulnerability to supply interruptions through a program for sharing supplies in the event of another disruption; the International Energy Agency is the body that was formed to implement those goals. Since the IEA was established, five members have been added. France, Finland, and Iceland are the only OECD countries that are not members.

The IEA is an intergovernmental organization -- its membership is made up of national governments or, in its terminology, "participating countries." While the IEA has no enforcement powers, the IEP does involve a binding commitment by each signatory. Changes to the basic agreement, including the structure of the emergency system, would presumably require an amendment to that treaty.

The Secretariat, or IEA staff, is an autonomous unit within the OECD. The IEA's supreme decision-making body is the Governing Board, which is made up of representatives of each member government. However, much of the work of the IEA is done by four "standing groups" consisting of senior personnel from members' energy departments. The Standing Group on Emergency Questions is the group most closely involved with the sharing program and is discussed in more detail below. The Standing Group on the Oil Market (SOM) is responsible for following developments in international oil markets. Several data reporting systems and periodic consultations with individual oil companies have been instituted to assist the SOM in this regard. For example, after agreement among several IEA members at the Tokyo summit in June of 1979 that a crude oil transaction register should be established, the SOM, working with advice from industry, instituted a reporting system for this purpose. Governments discuss long-term energy policies and plans in the Standing Group on Long Term Cooperation (SLT). This group works in long-term energy goals and reviews members' energy policies as they relate to those goals. The final group, the Standing Group on Relations with Producer and Other Consumer Countries (SPC), addresses producer/consumer relations, but to date it has not been very active. In addition, there is a high level Committee on Energy to coordinate research and development efforts among members.

Apart from emergency activities, industry participates in the IEA through two formally constituted advisory bodies and through consultations. The latter are discussions between a company and the IEA Standing Groups or the Secretariat and occur at the invitation of the IEA. The Standing Group on the Oil Market has received advice on its information systems from the Industry Working Party (IWP), a body of representatives from 13 oil companies. The Industry Advisory Board (IAB) is a larger group (18 companies) which has helped in the development and testing of the emergency system through advice and recommendations to the Standing Group on Emergency Questions. In refining the mechanisms for implementing the sharing system outlined in the IEP, the IAB has played an important role by advising the SEQ. The SEQ and the Governing Board have made the final decisions on these mechanisms. (There are no industry groups to advise the SLT or the SPC).

In the event of an emergency, the sharing system would be administered by the Allocation Coordinator (the Executive Director of the IEA) assisted by the Secretariat, the SEQ, the IAB, and several other organizations activated when an emergency is declared. These bodies together constitute the Emergency Management Organization. Specifically, the Industry Supply Advisory Group (ISAG), made up of representatives from some of the reporting companies, would work with the Secretariat and under the supervision of the Allocation Coordinator to advise on the reallocation of supplies. A National Emergency Sharing Organization (NESO) within each member government would be responsible for coordinating that country's interaction with the Emergency Management Organization. It would also have to oversee the fair distribution of available supplies within its own country, particularly keeping in mind the position of companies receiving or diverting supplies to meet the countries' IEA commitments. Each NESO must have a clear, well organized domestic emergency program to enable the member country to implement its allocation obligation or accommodate its allocation right. Finally, it must oversee demand restraint and emergency reserve management. These organizations and their interrelationships are shown on the diagram of the Emergency Management Organization (Figure M-1). The companies directly involved in this system are termed Reporting Companies and represent large oil companies in each participating country. A list of these companies is provided in Table M-1.

In the period since the IEP was signed, the emergency system has never been activated. In two instances individual countries (Sweden and Italy) did request emergency sharing for selective problems they were experiencing. The IEA did not agree that the shortfall in either case warranted activation of the sharing procedures. In 1979, when domestic political unrest in Iran led to a temporary interruption of exports from that country, the general shortfall to the group was not considered sufficient to warrant implementation of emergency sharing. However, since January 1979 the Secretariat has been receiving the monthly reports that would be required in an emergency. It has used these reports to monitor estimated supplies vs. historical consumption in each country.

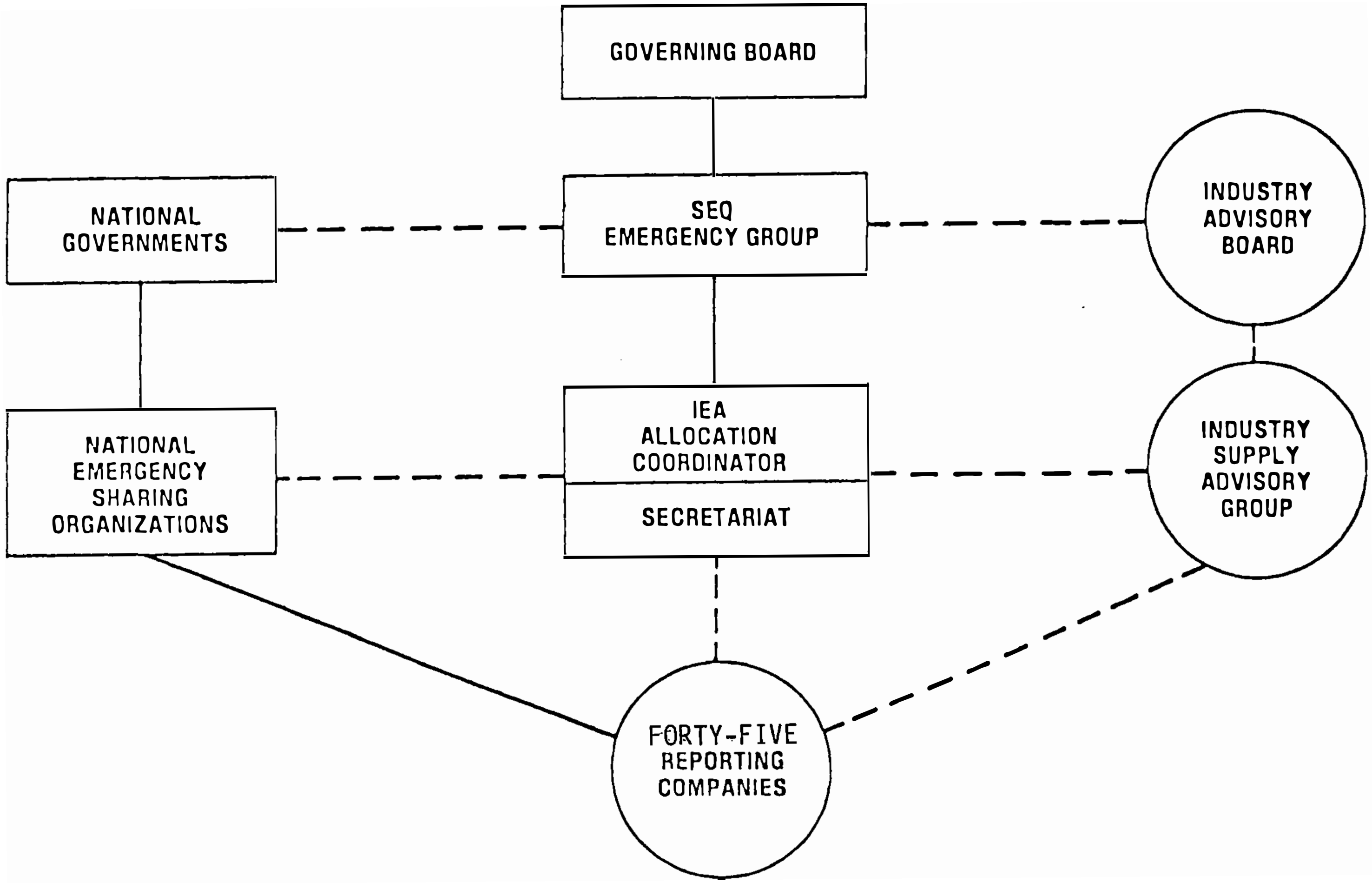


Figure M-1. International Energy Agency Emergency Management Organization.

TABLE M-1

IEA Reporting Companies

United States Companies
- Amerada Hess Corp.
- Ashland Oil, Inc.
- Atlantic Richfield Co.
- Axel Johnson & Co., Inc.
- Caltex Petroleum Corp.
- Cities Service Co.
- Conoco Inc.
- Exxon Corporation
- Getty Oil Co.
- Gulf Oil Corp.
- Mobil Oil Co.
- Occidental Petroleum Corp.
- Phillips Petroleum Co.
- Shell Oil Co.
- Standard Oil Co. of California
- Standard Oil Co. (Indiana)
- Standard Oil Co. of Ohio
- Sun Oil Co.
- Texaco Inc.
- Union Oil Co. of California

Canadian Companies
- Petro-Canada

European Companies
- Anonima Petroli Italiana (Italy)
- British National Oil (U.K.)
- British Petroleum (U.K.)
- Compania Espanola de Petrolios, S.A. (Spain)
- Ente Naziole Idrocarbure (Italy)
- Hispanoil, S.A. (Spain)
- Mabanaft GMBH (Germany)
- Montedison (Italy)
- OEMV (Austria)
- Petrofina (Belgium)
- Petroliber (Spain)
- Petronor (Spain)
- Saarberowerke (Germany)
- Shell International Co. (U.K.)
- Statoil (Norway)
- Svenska Petroleum (Sweden)
- Union Kraftstoff (Germany)
- Veba Oel (Germany)
- Wintershall A.G. (Germany)

Japanese Companies
- Daikyo Oil Co., Ltd.
- Idemitsu Kosan Co., Ltd.
- Maruzen Oil Co.
- Mitsubishi Oil Co., Ltd.
- Nippon Mining Co., Ltd

THE IEA EMERGENCY MANAGEMENT SYSTEM

Declaring an Emergency

The IEP provides a specific calculation procedure to define a general emergency and activate the sharing procedures. If the Secretariat believes that anticipated supplies of the IEA as a group can reasonably be expected to fall below historical consumption by 7 percent or more, it can trigger the sharing system. Consumption for this purpose is Base Period Final Consumption (BPFC) measured over the four quarters prior to the most recently completed quarter. (It is assumed that data for the most recent quarter are incomplete.) The Secretariat must make a "finding" that an emergency does in fact exist. It should be noted that the emergency relates to the size of a supply shortfall irrespective of its cause. To assess the supply situation, the Secretariat uses quarterly oil supply and demand forecasts for two quarters (the current quarter and one forward quarter) as provided by governments and some companies; it must also hold consultations with oil companies before making a finding. The Secretariat finding is presented to the Governing Board and the system is activated unless the Board votes to override the finding.

In addition to the general trigger designed for an overall supply shortfall, a selective trigger can also activate the sharing system. In this case, a single country experiencing a supply shortfall of greater than 7 percent can request implementation of the sharing formulas. Again the Secretariat presents a formal finding to the Governing Board. The sharing formulas are similar to those used in a general shortage but the administrative procedures need not be fully implemented. The remainder of this discussion will focus on a general shortage emergency.

The IEP defines the voting procedures for an emergency. The voting system is a combination of an equal vote for each country and a system based on oil consumption. The voting weights are detailed in Table M-2. The Secretariat's emergency finding is implemented unless the Governing Board overrides that decision. A special majority of 60 percent of the combined voting weights and 45 of the general votes would be required to override the Secretariat's finding. Thus, if all countries were voting it would take at least 15 members to override a general trigger finding. While the United States has nearly one third of the combined voting weights, this provision limits the voting power derived from oil consumption alone. In the case of a selective trigger, 51 general voting weights or 17 countries are required to override the finding.

While there are formulas and guidelines for arriving at a trigger decision, the process is not totally rigid. There is a considerable amount of judgment involved and, inevitably, the political situation at the time may influence the outcome. As an example, the Secretariat receives an array of quarterly oil forecasts for consideration in arriving at the assumptions and forecasts it uses in the formulas. It must make judgments in assessing and weighing these conflicting forecasts.

TABLE M-2

IEA Membership and Voting Rights

Participating Countries*	General Voting Weights	Oil Consumption Voting Weights	Combined Voting Weights
Australia	3	1	4
Austria	3	1	4
Belgium	3	2	5
Canada	3	5	8
Denmark	3	1	4
Greece	3	1	4
Germany	3	8	11
Ireland	3	0	3
Italy	3	5	8
Japan	3	15	18
Luxembourg	3	0	3
Netherlands	3	2	5
New Zealand	3	0	3
Portugal	3	0	3
Spain	3	2	5
Sweden	3	2	5
Switzerland	3	1	4
Turkey	3	1	4
United Kingdom	3	6	9
United States	3	47	50
Total	60	100	160

---

*Norway is also an IEA member but does not participate in votes.

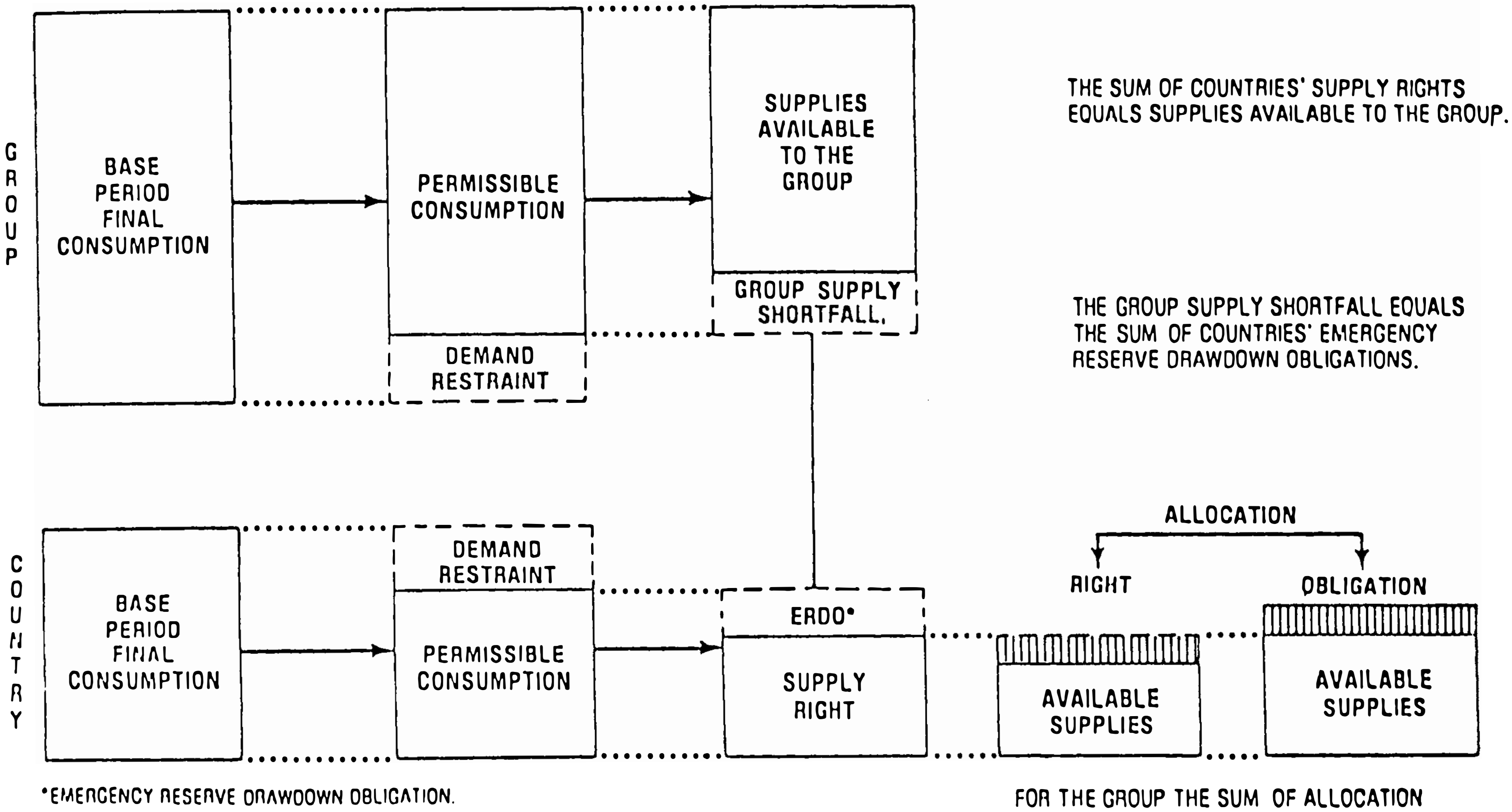
Managing the Emergency

The declaration of an emergency activates a series of rapid response reports in which the reporting companies estimate the supplies they will have available for each member country in the reporting month, two forward months, and two historical months. Governments provide similar data for the country as a whole; that is, the sum of both reporting and nonreporting company data. In an emergency, the data are used to calculate each participating country's "supply right" which is then compared with forecast supplies to arrive at an "allocation right" or an "allocation obligation." The allocation right or obligation is the difference between the country's supply right and its forecast supplies. This is the basis for sharing available supplies. The calculation is performed for each month and the position of each member is reassessed monthly.

The supply right calculation involves a forecast of available supplies, an assumed demand reduction, and a calculated Emergency Reserve Drawdown Obligation (ERDO).

- Available supplies are estimated based on the reports from governments and companies.
- "Permissible consumption" equals consumption in the base period less an assumed demand restraint of 7 percent in an emergency where the supply shortfall is from 7 percent up to 12 percent and 10 percent where the shortage is 12 percent or more. The difference between the permissible consumption of the members as a group and available supplies is the "group supply shortfall."
- Each member assumes a portion of the group supply shortfall based on its share of IEA imports. This is termed the Emergency Reserve Drawdown Obligation, which represents an allowable inventory draw. However, a country may meet its ERDO through any method it may choose, including additional demand restraint, increased use of non-oil energies, or standby production. The ERDO is only a means of defining maximum allowable supplies. (The sum of the ERDOs of each member is equal to the group supply shortfall.)
- Permissible consumption less the ERDO is the member's supply right.

After completing the above calculations, the Secretariat compares the supply right with total oil supplies forecast to be available to that country. If the right is more than estimated supplies, the country has a right to receive oil from the group (an allocation right); if the supply right is less than the quantity of oil estimated to be available to the country, it has an obligation to give up oil to the group (an allocation obligation). Figures M-2 and M-3 depict these calculations and terms in graph form; they are also explained for each scenario later in this appendix.



THE SUM OF COUNTRIES' SUPPLY RIGHTS EQUALS SUPPLIES AVAILABLE TO THE GROUP.

THE GROUP SUPPLY SHORTFALL EQUALS THE SUM OF COUNTRIES' EMERGENCY RESERVE DRAWDOWN OBLIGATIONS.

FOR THE GROUP THE SUM OF ALLOCATION RIGHTS AND OBLIGATIONS IS ZERO.

*EMERGENCY RESERVE DRAWDOWN OBLIGATION.

Figure M-2. Outline of IEA System of Emergency Oil Allocation

Reference: Article 7 of the Agreement on an Internation Energy Program.

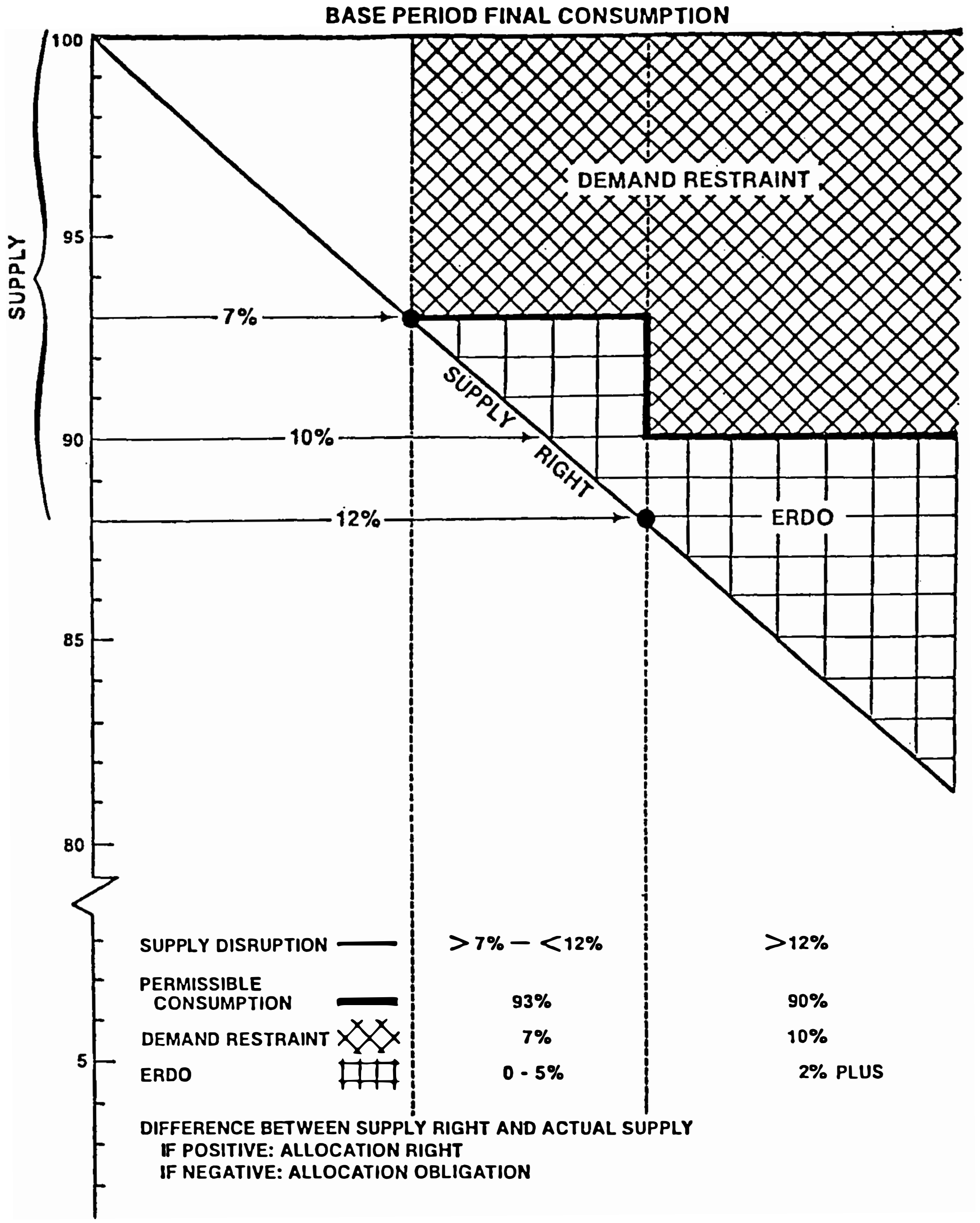


Figure M-3. Illustration of Demand Restraint and Emergency Reserve Drawdown Obligation (ERDO) in an IEA Emergency.

The two threshold levels of emergency (7 percent vs. 12 percent) involve changing the proportion of sharing based on consumption vs. imports. As the shortfall becomes larger, the import basis becomes relatively more important and the sharing based on oil demand becomes less so. Table M-3 illustrates how this works at various shortfall levels.

TABLE M-3

Basis for Sharing Shortfall

	Percentage of Supply Reduction			
	7	11	12	30
Sharing Based on Consumption	7	7	10	10
Sharing Based on Net Imports	-	4	2	20

Once the allocation right or allocation obligation has been determined, this information is provided to the SEQ, national governments, reporting companies, and the Industry Supply Advisory Group (ISAG). There are then three levels in the allocation process. Type 1 reallocations involve a company's individual business activities -- scheduled supplies are shifted among affiliates, or sales or exchanges are arranged with other companies to meet affiliate demands. Such activities are an ongoing process which of necessity take many factors into account, one of which may be the Secretariat calculation of rights and obligations. It should be emphasized here that the reporting system can only represent a picture of this process at one point in time and cannot capture the dynamics of the company's market activities. The second level (Type 2 transactions) involves agreement between companies to reallocate supplies; for example, a U.S. company offering a cargo for delivery to Japan. The Allocation Coordinator plays a key role here in recommending which offers should be implemented. The primary function of the ISAG is to facilitate these Type 2 transfers. If these voluntary steps by companies fail to balance allocation rights and obligations, Type 3 or mandatory allocations can be implemented. The Allocation Coordinator would recommend mandatory measures with the SEQ having final approval and then working with the NESOs on implementation. The NESO in each country would mandate reallocation steps by companies under its jurisdiction.

This brief description of how the allocation system works cannot portray the complexities of the interactions necessary in an emergency. Communications would have to be rapid and company representatives on the ISAG would be involved in identifying and coordinating sales, exchanges, or other transfers of supplies among two or more companies. In some cases, as with U.S.-based companies, such intercompany activities present an antitrust problem.

Member Government Obligations

Each IEA member government must have a few key elements of national emergency plans and policies in place to enable it to participate fully in this sharing procedure. To begin with, legislation may be necessary for participation in the sharing program. Governments must also have the authority to allocate international supplies, draw on emergency reserves as needed, and restrict demand. Since the IEA system allocates international supplies only, countries need to have some domestic procedures in place to ensure fair sharing of available supplies.

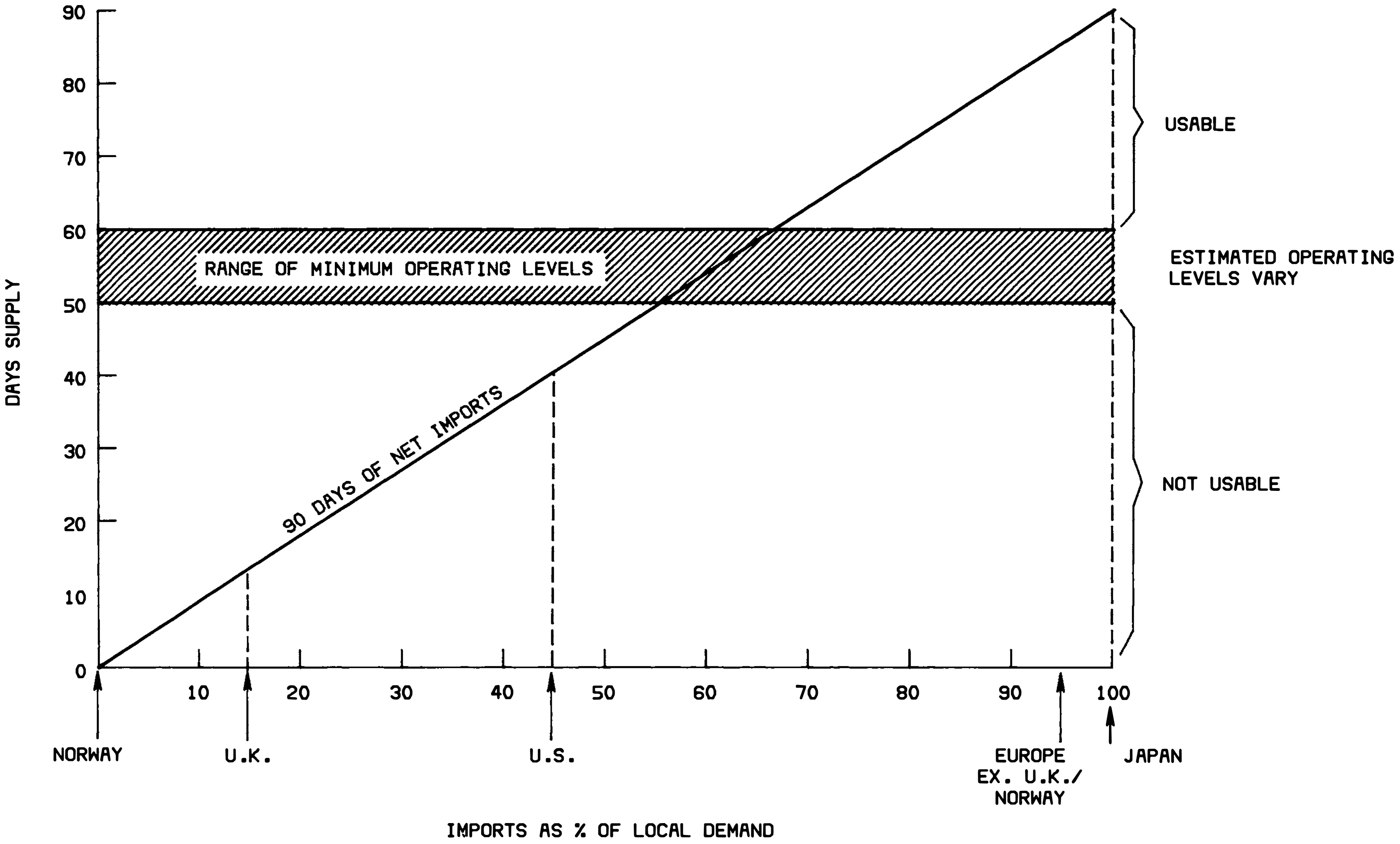
Two key elements in the IEA program require national government actions -- demand restraint and emergency reserves. In an emergency where a supply shortfall of from 7 to 12 percent is experienced, countries are assumed to restrain demand by 7 percent below the Base Period Final Consumption. With a shortage of 12 percent or more, demand restraint of 10 percent is assumed. Thus, each member government should have an effective emergency demand restraint program ready to be implemented.

Any supply shortfall below the permissible consumption level after reallocation is to be met by the Emergency Reserve Drawdown Obligation. However, members are not actually required to draw reserves at this rate. The shortfall between permissible consumption and supplies could be met by additional demand restraint in lieu of drawing reserves. In either case, governments are assumed to maintain the required reserve level and must be ready to use it or provide alternate coverage as necessary. For this purpose, IEA members must maintain emergency reserves equal to 90 days of petroleum imports (not to fall below the level calculated for 1979). This reserve obligation is written into the IEP Agreement and is, therefore, part of the commitment each member made when it signed the treaty.

The IEA reserve requirement of 90 days of imports is not a factor in the case of the United States or other countries with significant indigenous production. The reserve definition covers all primary stocks including operating stocks and commercial inventories. In the United States, the requirement is less than minimum operating or working stocks; thus the United States would meet this target at all times. A schematic representation of the impact of a reserve requirement defined by import levels is given in Figure M-4. The figure shows that 90 days of imports translates into only 40 to 45 days of consumption. This is below the estimated minimum level held by industry of 50 to 60 days needed to operate the logistics system efficiently. The reserve requirement would have to exceed the 50 to 60 day level in order to provide usable or drawable inventory coverage.

IEA Reallocation in the NPC Scenarios

Perhaps the easiest way to explain the IEA calculation is to use the scenarios developed by the DOE for this report. For purposes of illustration, the calculation will be explained for Scenario 2. A summary of the other scenarios is also provided.



EXAMPLE: IN THE US, 90 DAYS OF IMPORT REQUIREMENTS EQUAL ABOUT 41 DAYS OF SUPPLY, THIS IS BELOW THE OPERATING LEVEL NEEDED BY INDUSTRY AND THIS PROVIDES NO ADDITIONAL SUPPLY COVERAGE.

Figure M-4. Effective Supply Coverage Provided by IEA Import Target.

Scenario 2

Scenario 2 postulates an interruption of 25 percent of the imports from OAPEC and Iran for a period of six months beginning in the first quarter of 1981. The scenario further assumes that the IEA nations are targeted by OAPEC and Iran to receive the full impact of the disruption. Thus the IEA shortfall is equal to the total world supply shortfall, or 4.9 MMB/D. The following calculation is used to derive the U.S. shortfall.

- The shortfall of 4.9 MMB/D represents 13 percent of Base Period Final Consumption. While the shortfall is given in this scenario, in a real emergency the Secretariat would use forecast reports and consultations to form its judgment. This shortfall is above 12 percent, triggering more severe demand restraint. (Note: the base period for a shortfall occurring in the first quarter of 1981 should be the fourth quarter 1979 through third quarter 1980. Since these data were not available, the DOE used the previous period; i.e., third quarter 1979 through second quarter 1980.)
- In an emergency, available supplies would be estimated by the IEA. In this scenario, supplies available to the IEA are assumed to be 32.4 MMB/D.
- Permissible consumption for the IEA would be 33.6 MMB/D, 10 percent below the base period.
- The gap between permissible consumption (33.6 MMB/D) and supplies available to the IEA (32.4 MMB/D) is the group supply shortfall (1.2 MMB/D).
- The Emergency Reserve Drawdown Obligation in the United States is the U.S. share of the group supply shortfall. For the period used in this scenario, the U.S. represents 38 percent of IEA imports and assumes 38 percent of the group shortfall, or 0.5 MMB/D.
- Permissible consumption in the United States would be 10 percent below the base period, or a reduction of 1.7 MMB/D to 15.8 MMB/D.
- The U.S. supply right would be 15.3 MMB/D, representing its shortfall of 1.7 MMB/D (demand restraint) and 0.5 MMB/D (ERDO) vs. the base period.

This supply right would be compared to supplies estimated to be available to the United States, based on company and government reports. If supplies were above 15.3 MMB/D, the difference would be the allocation obligation; if below 15.3 MMB/D the United States would have an allocation right.

Scenarios 3 and 4

The calculations for the remaining two scenarios are similar and are shown on Table M-4. Scenario 3 assumes that 40 percent of exports from OAPEC and Iran to the IEA are halted. Scenario 4 assumes that all exports from the Persian Gulf cease for three months and are gradually resumed thereafter. In this scenario, the shortage is assumed to affect all consumers, and non-IEA supplies are assumed to be a consumption weighted share of the shortfall.

TABLE M-4

Supply Calculations for NPC Scenarios
(MMB/D)

	25% OAPEC Plus Iran	40% OAPEC Plus Iran	Persian Gulf Exports Halted 100%	Persian Gulf Exports Halted 75%	Persian Gulf Exports Halted 50%
International Energy Agency					
Available Supplies	32.4	29.5	25.8	28.8	31.5
Permissible Consumption					
Base Period Final Consumption	37.3	37.3	37.3	37.3	37.3
Less 10% Demand Restraint	3.7	3.7	3.7	3.7	3.7
	33.6	33.6	33.6	33.6	33.6
Group Supply Shortfall					
Permissible Consumption	33.6	33.6	33.6	33.6	33.6
Less Available Supplies	32.4	29.5	25.8	28.8	31.5
	1.2	4.1	7.8	4.8	2.1
United States					
Emergency Reserve Drawdown Obligation 38% of Group Supply Shortfall	0.5	1.5	2.9	1.8	0.8
Permissible Consumption					
Base Period Final Consumption	17.5	17.5	17.5	17.5	17.5
Less 10% Demand Restraint	1.7	1.7	1.7	1.7	1.7
	15.8	15.8	15.8	15.8	15.8
Supply Right					
Permissible Consumption	15.8	15.8	15.8	15.8	15.8
Less ERDO	0.5	1.5	2.9	1.8	0.8
	15.3	14.3	12.9	14.0	15.0

GLOSSARY OF IEA TERMINOLOGY

Allocation Coordinator: The Executive Director of the IEA serves as the allocation coordinator in an emergency. This individual supervises the allocation system; he reports to the Standing Group on Emergency Questions and interacts with the Industry Supply Advisory Group.

Allocation Right/Allocation Obligation (AR/AO): The amount by which estimated supplies for a country exceed (AO) or fall short of (AR) the country's supply right. The volume of oil which must be diverted to (AR) or from (AO) a country to achieve the IEA's allocation.

AST: Allocation System Test, of which there have been three to date. (AST-3, the most recent, was held in October and November 1980.)

Base Period Final Consumption (BPFC): The reference demand level for use in calculating the extent of a supply shortfall, the required demand reduction, and hence a country's supply right. BPFC is domestic consumption in the four most recent quarters for which data are available (thus excluding the previous quarter).

Demand Restraint: The first tranche of a shortfall is managed by implementation of demand restraint measures to lower demand by 7 percent of BPFC for shortfalls between 7 and 12 percent or by 10 percent for shortfalls in excess of 12 percent.

Emergency Reserve Drawdown Obligation (ERDO): A country's share of the group supply shortfall calculated based on import share. (A country which imported 23 percent of the IEA's total imports would be allocated 23 percent of the group's shortfall.)

Finding: A finding from the Secretariat to the Governing Board that an emergency, as defined by the IEA procedures, exists or is expected to exist. A finding automatically results in the initiation of the emergency sharing procedures unless the Governing Board overrides the finding.

Governing Board: The plenary body of the IEA comprised solely of government representatives. The Secretary of Energy has represented the United States when meetings were held on a ministerial level.

Group Supply Shortfall: The difference between permissible consumption and available supply for the IEA as a whole.

Industry Advisory Board (IAB): A group representing 18 reporting companies. The IAB helped design the implementation procedures for the allocation system and continues to advise the Standing Group on Emergency Questions.

Industry Supply Advisory Board (ISAG): A group of representatives from reporting companies responsible for communications with reporting companies, expertise on supply matters, and coordination of voluntary actions undertaken to implement the IEA emergency allocation program.

Industry Working Party (IWP): A group of 13 oil companies which advises the Standing Group on the Oil Market.

International Energy Agency (IEA): The organization set up to implement the Agreement on an International Energy Program.

International Energy Program (IEP): The Agreement on an International Energy Program was signed by 16 nations in November 1974. The purpose of the agreement and of the IEA is to coordinate energy policies, reduce vulnerability of member nations to supply disruptions, and facilitate cooperation on long-term energy issues. There are currently 21 member nations.

National Emergency Sharing Organization (NESO): An organization within each member government responsible for interaction with the IEA in the implementation of the emergency sharing procedures.

Permissible Consumption: Base Period Final Consumption less the required demand restraint.

Plan of Action: U.S. regulations required in the Energy Policy and Conservation Act detailing reporting and monitoring requirements necessary for an antitrust defense in an emergency.

Questionnaires A & B: These questionnaires are the IEA's primary sources of data for use in implementing the allocation system. Questionnaire A is supplied by reporting companies to the IEA and contains oil imports, exports, production, and inventory by country for two historical months, the current month, and two forward months. Questionnaire B is supplied by member governments and provides similar information for all companies operating in that country.

Reporting Company: 45 oil companies designated by the IEA which would, in an emergency, submit data on their current supply situation and forecast supply plans directly to the IEA. They also cooperate voluntarily in actions intended to implement the IEA allocation system.

Secretariat: The autonomous staff group which performs the ongoing activities of the IEA. The Secretariat is headed by an Executive Director who reports to the Governing Board.

Supply Right: The amount of oil a country is entitled to receive. The supply right of a country is equal to the base period final consumption less the required demand restraint and the Emergency Reserve Drawdown Obligation.

Standing Groups: The IEA has four bodies of government representatives that address specific aspects of energy cooperation. Every member country is represented in each of these groups.

- Standing Group on the Oil Market (SOM): Monitors developments in international oil markets. The SOM maintains a crude oil transaction register to monitor market activity. (Advised by the IWP.)
- Standing Group on Emergency Questions (SEQ): Oversees the preparation of and, if activated, the operation of the oil-sharing procedures. (Advised by the IAB.)
- Standing Group on Long Term Cooperation (SLT): Coordinates long-term energy goals and reviews member nations' progress in achieving them.
- Standing Group on Relations with Producer and Other Consumer Countries (SPC): Concerned with relations between producers and consumers.

Trigger: The percentage shortfall of estimated supplies against Base Period Final Consumption compared against a minimum 7 percent for invoking emergency procedures.

- General Trigger: A shortfall experienced by the full IEA. There are two shortfall levels (7 percent and 12 percent) which activate different levels of demand restraint.
- Selective Trigger: A shortfall in excess of 7 percent experienced by any single country (or countries). Any country may apply to the Secretariat if it believes it is in a selective trigger position.

Voting Weights: The designated voting shares of each member: 60 votes are divided equally among all members; 100 votes are assigned according to shares of total IEA oil consumption.

APPENDIX N

History of U.S. Oil Emergency Organizations

HISTORY OF U.S. OIL EMERGENCY ORGANIZATIONS[1]

The history of U.S. government response to emergency oil situations includes emergency situations in World War II, the Korean War, the 1973-1974 Arab oil embargo, and the 1979 Iran crisis. In the 1960's the government also responded to a potential direct war threat. The organization for the response to each emergency was unique for each emergency. Each reflected the political and economic climates as well as the petroleum industry situation of the time.

The wartime efforts included extensive industry participation. In World War II, the Petroleum Administration for War included industry personnel in its ranks as well as relying heavily upon industry committees for advice, coordination, and implementation. During the Korean War, the Petroleum Administration for Defense drew the majority of its staff from industry. In PAD there was little duplication in the form of industry committees. The Emergency Petroleum and Gas Administration was created in 1963 in response to the threat of direct nuclear attack on the United States. The EPGA is patterned after PAD but is unique in its regional organization and would be able to function initially without a national headquarters.

The principal objectives of PAW and PAD were to increase oil production and to deliver petroleum to the war effort while meeting essential civilian petroleum needs. PAW and PAD were heavily involved in the allocation of controlled materials (steel, etc.) to the petroleum industry. Both PAW and PAD worked as claimants to and extensions of a defense mobilization agency. Both agencies were organized on a functional basis. They were staffed with experts for each function. (For organization charts of these agencies see Figures N-1 and N-2.) Price controls and rationing were administered by separate agencies. The goal in each case was to win the war.

The designed purpose, role, and organization of EPGA is similar to PAW and especially PAD. It relies heavily on its regional headquarters because in the event of a nuclear attack the national headquarters may not be functional. Most EPGA personnel are Executive Reservists and serve only during an emergency. Personnel are drawn from other government organizations, from the petroleum industry, and from other areas of the private sector. EPGA's organization is shown in Figures N-3 and N-4.

Use of EPGA was considered during the Arab oil embargo. For the reasons noted elsewhere in this appendix and Chapter Nine, it was not used and has since been dormant. EPGA has not been tested since 1972. Its personnel roster has not been updated since 1976.

---

[1] This history of U.S. oil emergency organizations is summarized from a number of sources, some of which are listed at the end of this appendix.

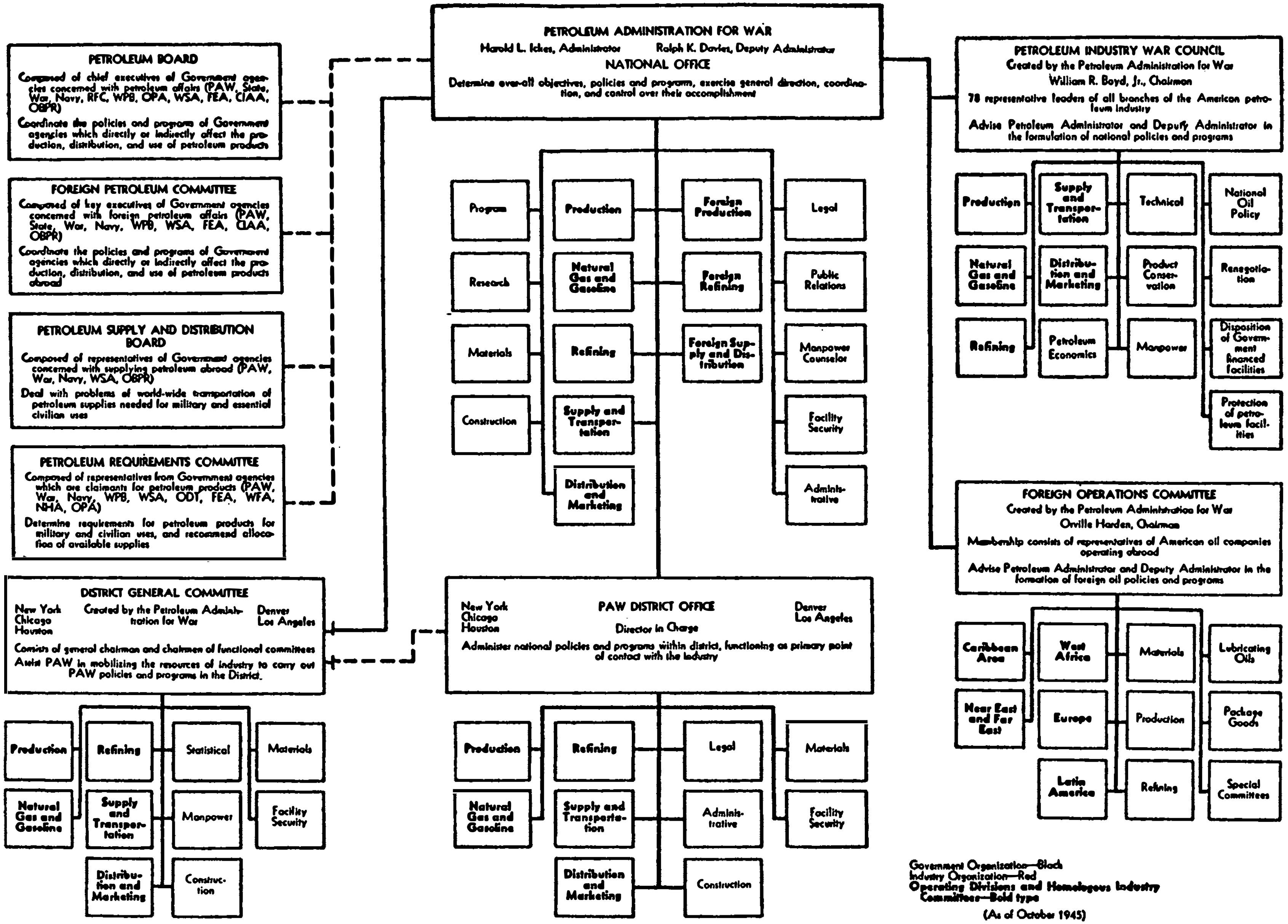


Figure N-1. Petroleum War Team.

SOURCE: Petroleum Administration for War, *A History of the Petroleum Administration for War, 1941-1945*, U.S. Government Printing Office, 1946.

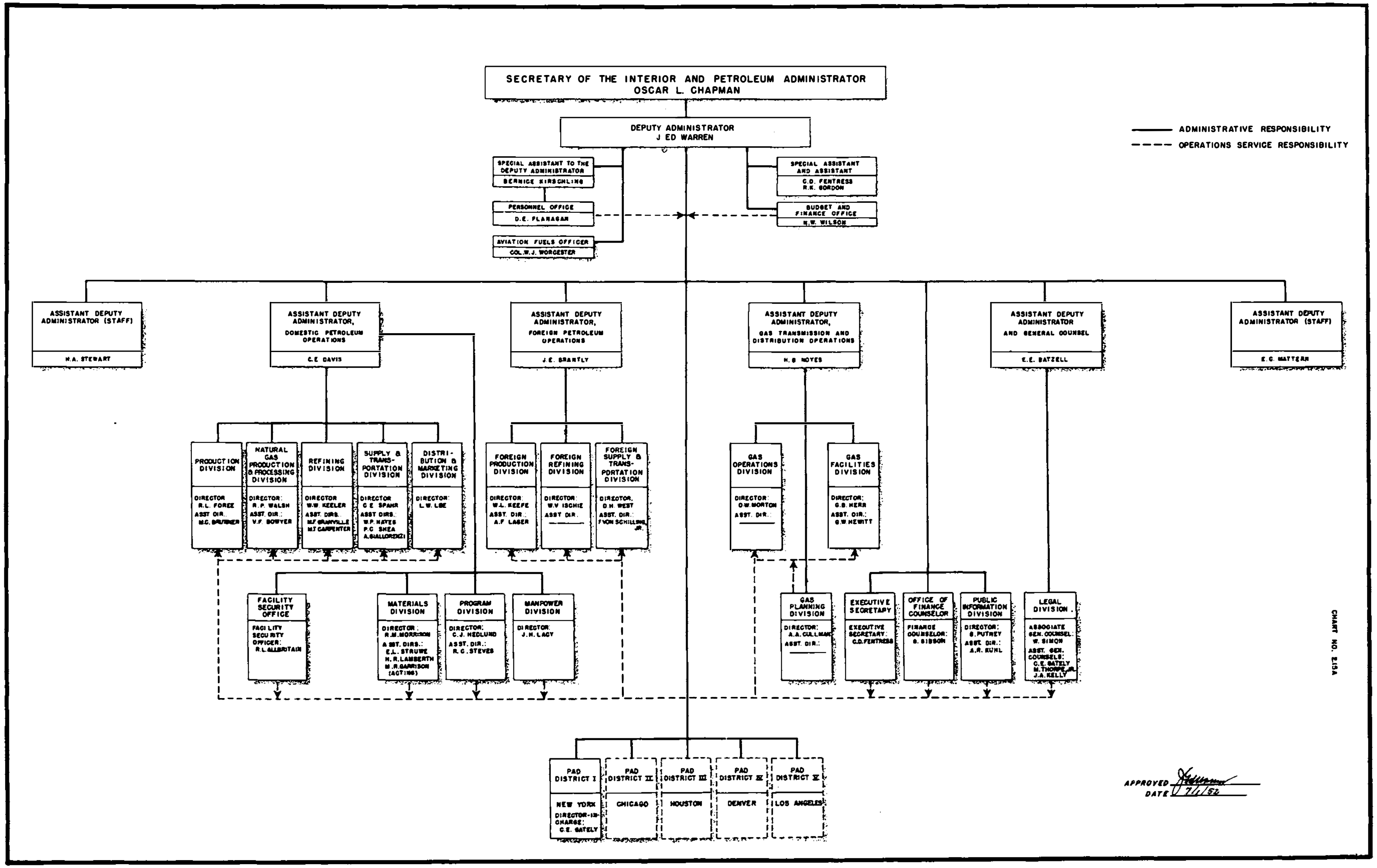


Figure N-2. Petroleum Administration for Defense.

SOURCE: "Petroleum Administration for Defense Plan of Organization," U.S. Department of the Interior, 1951.

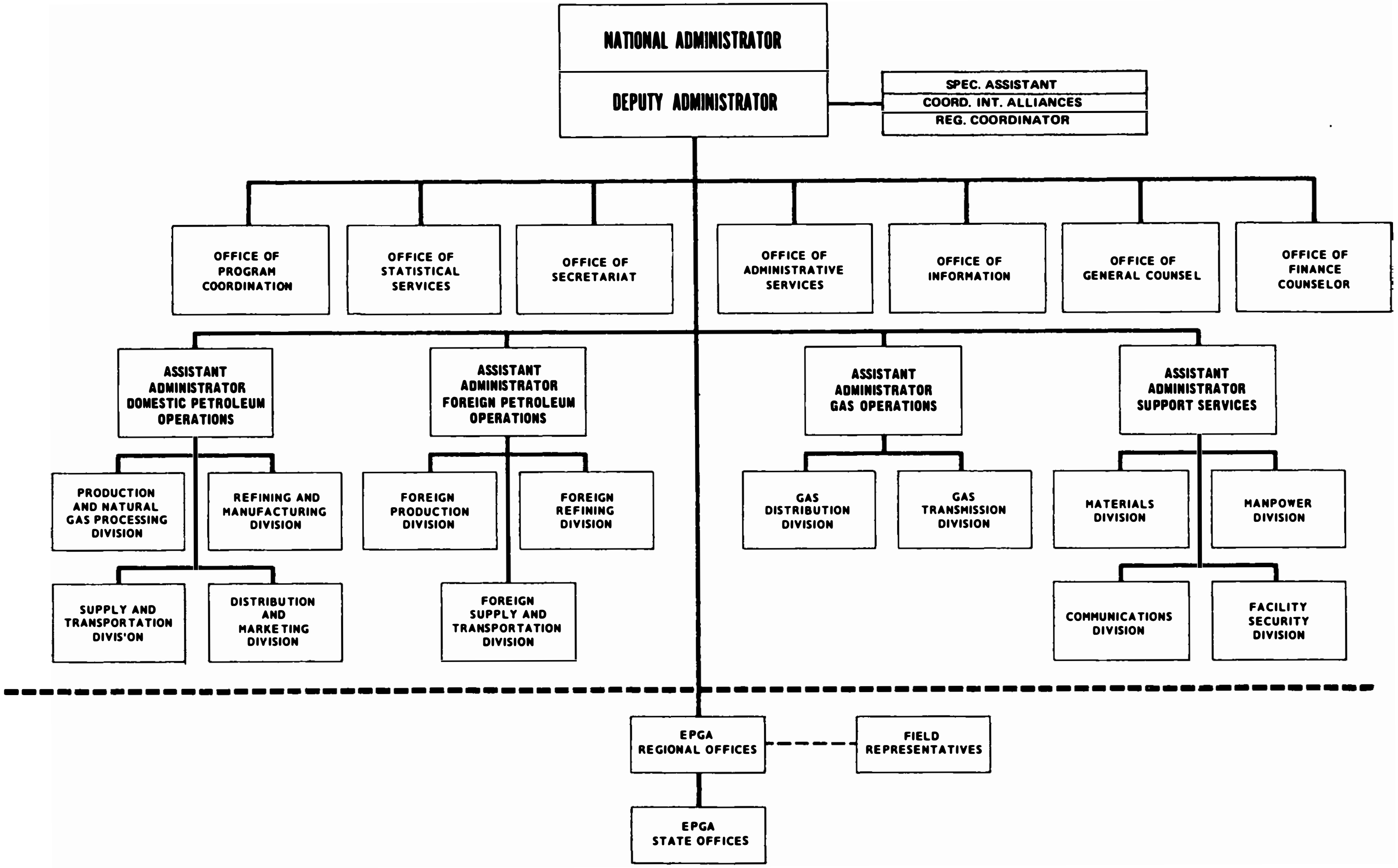


Figure N -3. National Headquarters Organization—Emergency Petroleum and Gas Administration.

SOURCE: National Petroleum Council, *What is the Emergency Petroleum and Gas Administration?*, revised by the Office of Oil and Gas, U.S. Department of the Interior, 1972.

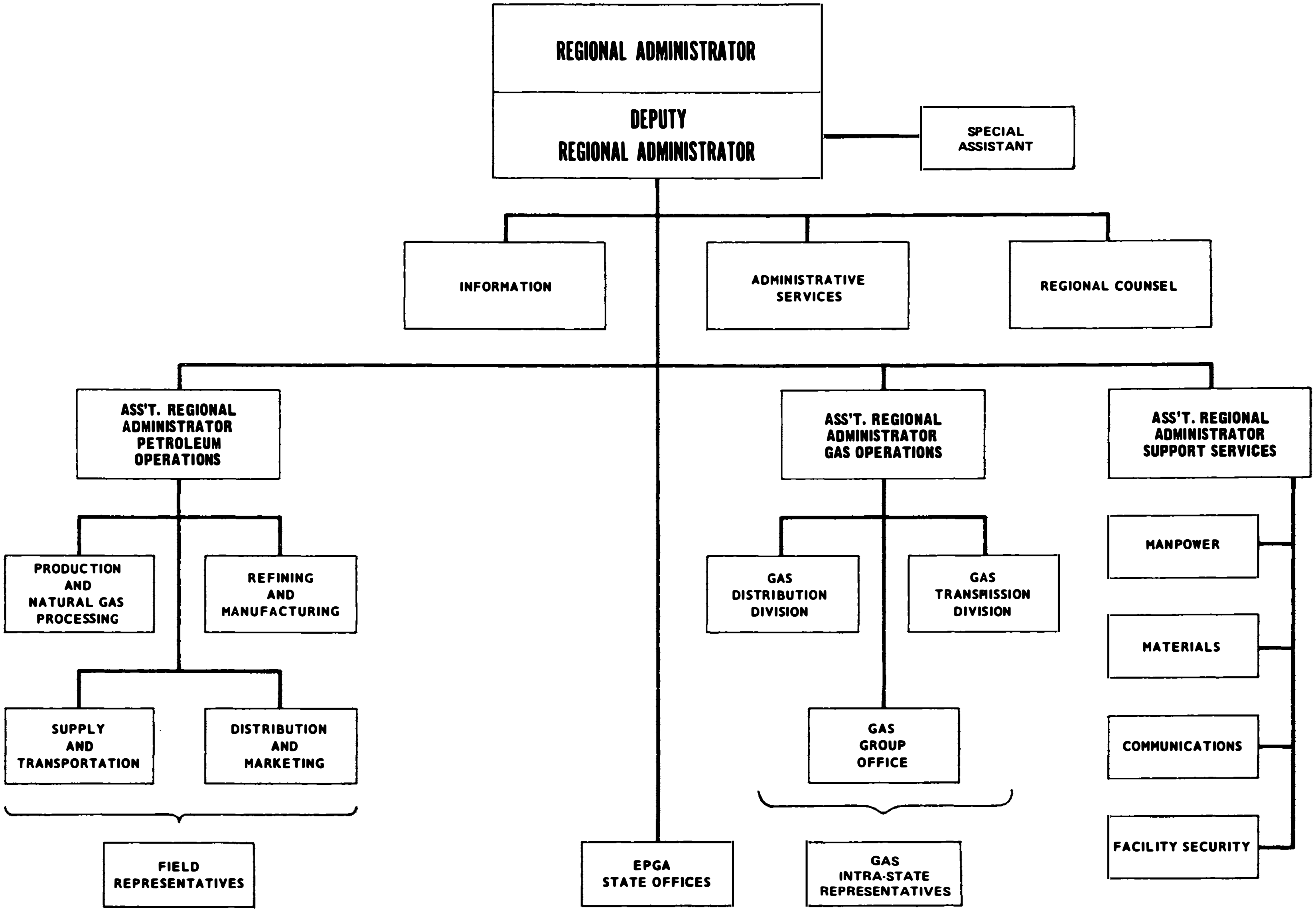


Figure N-4. Pro Forma Regional Organization—Emergency Petroleum and Gas Administration.
(Activated as required and staffed to the depth necessary in each region)

SOURCE: National Petroleum Council, *What is the Emergency Petroleum and Gas Administration?*, revised by the Office of Oil and Gas, U.S. Department of the Interior, 1972.

The federal organization that met the emergency of the Arab oil embargo was a series of wholly government administrations that grew out of a price control administration in place at the time of the emergency. The common goal of the chain of administrations was to minimize the economic impact of rising oil prices. Oil price and allocation regulations expanded to spread the benefits of controls, to avoid unjust enrichment, and to maintain historical industry relationships. For oil there were no end-user allocation mechanisms other than the inconvenience of gasoline lines and distribution system red tape. Gas distribution companies based their allocations on priority formulas approved by the Federal Power Commission. Efforts to reduce petroleum consumption were restricted to an advertising campaign, reduced speed limits, and customer inconvenience. Oil and gas production increases were discouraged by price controls.

By the time of the Iranian interruption, the government oil emergency organization had been consolidated in the Department of Energy. Its goals were little different from those of government during the Arab oil embargo, and its tools for handling the emergency were essentially the same. New consumption restraint features added during the Iranian interruption included mandatory temperature limits in public buildings and mandatory fuel switching in electrical generation.

The International Energy Agency was formed in 1974 as a result of the Arab oil embargo. Its membership now totals 21 nations, including the United States. The organization has many energy-related purposes, but one of its primary purposes is to share among its members the shortage resulting from a major oil supply interruption. IEA oil sharing responsibility stops at the border of each country. Each government deals with its internal situation.

The IEA's emergency organization is a combination of its full-time Secretariat, member government committees, and industry. Industry participates by directly reporting oil supply positions, by participating on various advisory committees, and by manning an oil sharing implementation group that is convened during an emergency. Oil supply reports are individually provided by 40 to 50 companies during potential shortage periods. The advisory role deals primarily with oil sharing mechanics and to some extent with oil markets. The implementation group coordinates the details of oil sharing between countries within policies and procedures of the Secretariat and the government committees. Industry participation is made possible by antitrust clearances of the U.S. government and the European Economic Community. All activity is closely monitored and procedures are closely followed. (An IEA oil sharing organization chart is shown in Figure N-5.)

The IEA oil sharing operation has not been used in an actual emergency. However, its system has been tested approximately every three years. The latest test was conducted in 1980.

A central issue of each oil supply emergency has been the role of industry personnel in government administration. At the heart

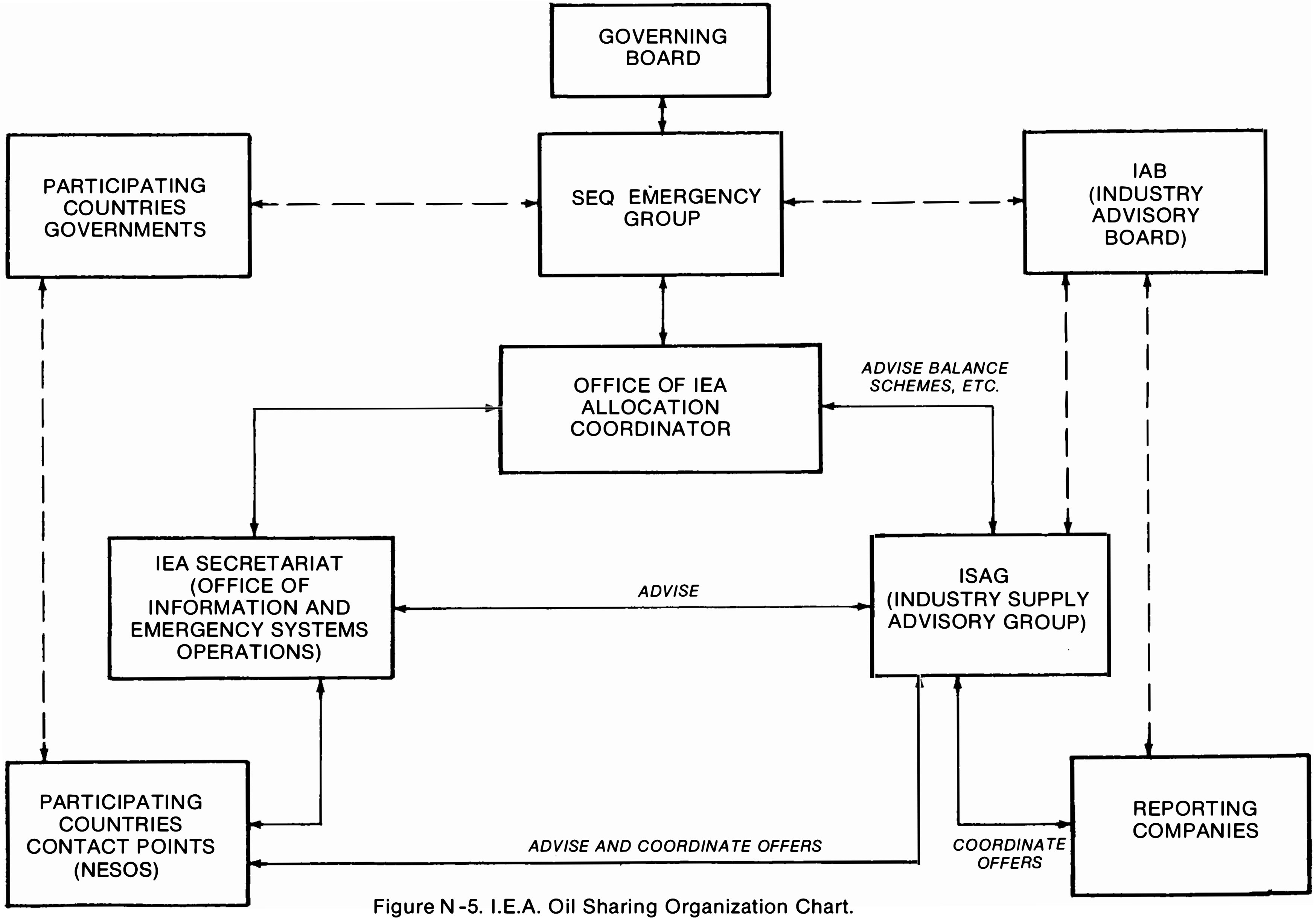


Figure N-5. I.E.A. Oil Sharing Organization Chart.

of the argument is the benefit of coordinated efforts of knowledgeable people vs. the threat to free market principles. The decision has been most influenced by the degree of the emergency. Where the emergency has been perceived as severe and mobilization time deemed short, industry personnel have been used.

A severe emergency was the case in both World War II and the Korean War. Such is the expected case in which either the EPGA or the IEA sharing organization would be mobilized.

The Arab oil embargo and the Iranian interruption were threats to the economy and to the nation's political position. In both cases, industry free market operations outside the United States promised to provide some degree of relief to the nation's supply problems. The primary concern in each interruption was the economic impact of higher oil prices. A government price control agency was in operation at the time of each interruption. At the time of the Arab oil embargo, there was a price-related public mistrust of the petroleum industry. Industry personnel were not used in the government organizations that dealt with the effects of these two supply interruptions.

Currently, the Secretary of Energy is the President's Energy Crisis Manager for the federal government, serving as chairman of the Energy Coordinating Committee (ECC). The ECC is a Cabinet-level body which coordinates policy formulation and decision-making for energy matters. ECC membership includes virtually all the Cabinet officers and key Presidential assistants.

During an energy interruption, the ECC is charged with formulating and coordinating an integrated federal, state, and public sector response. The ECC will review the assessments of the domestic and international energy situation and develop a Cabinet-level recommendation for the President as to the appropriate course of action. The recommendation will contain a set of objectives to be achieved during the emergency and response actions to be implemented by the government. Once Presidential approval has been obtained, the ECC will coordinate implementation through each executive agency.

The energy emergency organization includes several DOE offices as well as the Federal Emergency Management Agency. The Office of Energy Contingency Planning, reporting directly to the Secretary of Energy, has primary responsibility for preparing energy interruption response plans. DOE program offices contribute to the planning process and will operate the approved program during an emergency. An Energy Liaison center has been established to communicate with state and local governments. The Energy Information Agency maintains a system of energy-related information for use during an emergency. The Federal Emergency Management Agency will provide field staff services for DOE in an emergency. Current government emergency planning does not include use of industry personnel.

REFERENCES

PAW: A History of the Petroleum Administration for War 1941-1945; John W. Frey and H. Chandler Ide; U.S. Government Printing Office; 1946.

PAD: Oil Men in Washington . . . An Informal Account of the Organization and Activities of the Petroleum Administration for Defense During the Korean War 1950-1952; Bruce K. Brown; Evanil Press; 1965.

EPGA: "What is the Emergency Petroleum and Gas Administration?"; Office of Oil and Gas, U.S. Department of the Interior; 1972.

Arab Oil Embargo to Present: "A Record of Petroleum Industry Regulation Since 1971;" American Petroleum Institute; August 1979.

Current Government Oil Emergency Organization: Statement of John C. Sawhill, Deputy Secretary, Department of Energy, Before the Permanent Subcommittee on Investigations, Committee on Government Affairs, United States Senate; September 22, 1980.

APPENDIX O

Legal Constraints on Utilization of Oil Industry Personnel in a Supply Emergency

LEGAL CONSTRAINTS ON UTILIZATION OF OIL INDUSTRY PERSONNEL IN A SUPPLY EMERGENCY

The question has been presented whether, and under what legal constraints, oil industry personnel could be mobilized to handle emergency management functions in the event of a serious disruption in petroleum supplies. This appendix will review the legal constraints on three alternative methods of mobilization:

- Industry personnel volunteer in advance to become government employees in the event of a serious supply disruption
- Industry personnel become consultants without compensation to provide advice to government decision-makers (the "buddy" system)
- Industry personnel function as part of an advisory committee.

Each alternative presents legal problems for both the companies and the individuals involved. Table O-1, Statutes Affecting Government Employment, briefly outlines the legal constraints to the first alternative. The second alternative avoids the legal problems under the Department of Energy Organization Act (DOEOA) and Executive Personnel Financial Disclosure Requirements, but it may violate the Federal Advisory Committee Act. The third alternative requires adherence to procedural rules which may increase response time.

INDUSTRY PERSONNEL VOLUNTEER IN ADVANCE TO BECOME GOVERNMENT EMPLOYEES IN THE EVENT OF A SERIOUS SUPPLY DISRUPTION

This alternative is best analyzed in the context of existing statutory authority for establishing and maintaining a National Defense Executive Reserve under the Defense Production Act of 1950 (DPA). 50 U.S.C. App. § 2061 et seq. The DPA authorizes:

> [T]he President to provide for the establishment and training of a nucleus executive reserve for employment in executive positions in government during periods of emergency.... The President is authorized to provide by regulation for the exemption of such persons who are not full-time government employees from the operations of [certain conflict of interest statutes].

50 U.S.C. App. § 2160(e).

Executive Order 11179 established "a National Defense Executive Reserve composed of persons selected from various segments of the civilian economy and from the government for training for employment in executive positions in the federal government in the event

TABLE O-1

Statutes Affecting Government Employees

	Conflict of Interest Laws		Department of Energy Organization Act		Financial Disclosure Requirements
CITATIONS	18 U.S.C. § 201 *et seq.*		42 U.S.C. § 7211 *et seqe*		5 U.S.C. App. § 201 *et seq.*
APPLICABILITY	Regular Government Employees	Special Government Employees (fewer than 130 days out of 365)	Regular Government Employees	Supervisory Employees 1) More than 90 days a year and 2) Paid more than GS-16 minimum or designated by Secretary	All Government Employees, if 1) Paid more than GS-16 minimum and 2) Employed more than 60 days a year Waiver available for special government employees.
REQUIREMENTS	§ 205 Complete prohibition of any representation of others before government.	Prohibition limited to matters participated in as government employee or pending before employing agency.	§ 205 applies	§ 7216 -- 1 year prohibition against particpation where former company employer involved, or for which had responsibility while employed by company. Waiver available from Secretary.	
	§ 207 Limitations on post-employment contact. Most onerous provisions apply to GS-17 and above.		§ 207 applies	§ 7215 Prohibits post-employment contact with agency for 1 year.	

TABLE O-1 (Continued)

Conflict of Interest Laws		Department of Energy Organization Act		Financial Disclosure Requirements
Regular Government Employees	Special Government Employees	Regular Government Employees	Supervisory Employees	
§ 208 prohibits participation in matter in which current or future nongovernment employer has a financial interest.		§ 208 applies	§ 7212 requires divestiture of energy holdings. Waiver available for pensions.	
§ 209 prohibits payment of salary by anyone but government.	Not applicable to special government employees or persons serving without compensation.	§ 209 applies	§ 7212 prohibits receipt of any compensation from any energy company.	
		§ 7213 requires disclosure of assets held in any energy concern. Exemptions available for GS-12 and below.		Requires full disclosure of income, assets, liabilities, property or securities transactions, employment (including agreements for future employment), and participation in pension, health, or other benefit plans.
			§ 7214 requires report on prior employment by any energy concern.	

TABLE O-1 (Continued)

	Conflict of Interest Laws		Department of Energy Organization Act		Financial Disclosure Requirements
	Regular Government Employees	Special Government Employees	Regular Government employees	Supervisory Employees	
				§ 7215 requires employment reports for 2 years following termination of government employment.	
				§ 7216 requires that reports and waivers be publicly available.	Reports and waivers available to the public.
SANCTIONS	§§ 205, 207, 208: Criminal penalty of $10,000 fine and/or 2 years in prison. § 209: Criminal penalty of $5,000 fine and/or 1 year in prison.		Civil penalty of $10,000 per violation. § 7213: Criminal penalty of $2,500 fine and/or 1 year in prison.		Civil penalty of $5,000.

of the occurrence of an emergency that requires such employment." Executive Order 12148 assigned administration of the executive reserve program to the Director of the Federal Emergency Management Agency. Ex. Ord. No. 11179, September 22, 1964, 29 Fed. Reg. 13239, as amended by Ex. Ord. No. 12148, July 20, 1979, 44 Fed. Reg. 43239.

Amendments to the Defense Production Act by the Energy Security Act of 1980 make it clear that one of the purposes for which the National Defense Executive Reserve may be established is an energy supply emergency. The declaration of policy, as amended, reads as follows:

> In view of the present international situation and in order to provide for the national defense and national security, our mobilization effort continues to require some diversion of certain materials and facilities from civilian use to military and related purposes. It also requires the development of preparedness programs and the extension of productive capacity and supply beyond the levels needed to meet the civilian demand, in order to reduce the time required for full mobilization in the event of an attack on the United States or to respond to actions occurring outside of the United States which could result in the termination or reduction of the availability of strategic and critical materials, including energy, and which would adversely affect the national defense preparedness of the United States. In order to ensure the national defense preparedness which is essential to national security, it is also necessary and appropriate to assure domestic energy supplies for national defense needs.

50 U.S.C. App. § 2062.

If an executive reserve is established to cope with energy supply emergencies, what are the legal constraints on reservists activated to become government employees? 50 U.S.C. App. § 2160(e) authorizes the President to exempt national executive reservists from 18 U.S.C. §§ 281, 283, 284, 434, 1914, and 5 U.S.C. § 99. However, these statutes were superseded by 18 U.S.C. 203, 205, 207, 208, and 209. The superseding statute provided for the continuation of all existing exemptions from the provisions of the conflict of interest laws, "except to the extent that they affect officers or employees of the executive branch of the United States government, of any independent agency of the United States,...as to whom they are no longer applicable." Act October 23, 1962, P.L. 87-849, § 2, 76 Stat. 1126. Congress continued to extend the Defense Production Act of 1950 on a biannual basis without either eliminating the reference to possible exemption or conforming the citations to the current conflict of interest statutes. Under the circumstances, the 1962 statute superseding the old conflict of interest laws must be read as terminating the exemption authority contained in 50 U.S.C. App. § 2160(e).[1] Therefore, a careful review of applicable conflict of interest provisions is necessary.

Conflict of Interest Laws

Any discussion of conflict of interest laws requires a distinction between a "special government employee" and any other government employee. A special government employee is an employee who is retained for not more than 130 days in any period of 365 consecutive days, with or without compensation. 18 U.S.C. Section 202(a). The severity of conflict of interest prohibitions varies with the employee's status.

18 U.S.C. § 205 prohibits an officer or employee of the United States from acting as an agent for anyone "before any department, agency,...in connection with any proceeding, application, request for a ruling or other determination, contract, claim, controversy,. ...or other particular matter in which the United States is a party or has a direct and substantial interest...." For a special government employee the prohibitions of 18 U.S.C. § 205 apply only in relation "to a particular matter involving a specific party or parties (1) in which he has at any time participated personally and substantially as a Government employee or as a special government employee...or (2) which is pending in the department or agency of the Government in which he is serving." Clause (2) does not apply to a special government employee who has served in the department for no more than 60 days during the immediately preceding period of 365 consecutive days.

18 U.S.C. § 207 limits post-employment contact with the agency and is expressly applicable to a special government employee. Section 207(a) contains a lifetime prohibition on any formal or informal appearance before or communication to any agency in connection with any "particular matter involving a specific party...in which the U.S...is a party or has a direct and substantial interest" and in which the former special government employee participated personally and substantially while working for the government.

Section 207(b) is a two-year prohibition of any personal appearance before or communication to any agency in connection with any particular matter involving a specific party in which the United States is a party or has a direct and substantial interest, and (1) which was actually under the employee's official responsibility or (2) in which he participated personally and substantially as a government employee. "Official responsibility" means direct administrative or operating authority to approve, disapprove, or otherwise direct government action. 18 U.S.C. § 202. Section 207(b) also prohibits certain high level employees from aiding, counseling, advising, consulting, or assisting "any other person...by personal presence at any formal or informal appearance."

---

[1] In any event, the President has not exercised this exemption authority, nor is the exemption available to "full-time government employees."

Section 207(c) is the broadest provision. For one year after leaving the government, a high level employee may not represent anyone in any formal or informal appearance before, or make any written or oral communication on behalf of anyone to, the agency in which he served in connection with any proceeding (including rule-making) pending before the agency or in which the agency has a direct and substantial interest. This section applies to persons employed "at a rate of pay specified in or fixed according to [Executive Schedule pay rates], or a comparable or greater rate of pay under other authority...."[2] The prohibition also applies to persons paid at a rate equal to or greater than that for GS-17, if they are in positions with significant decision-making or supervisory responsibility as designated by the Director of the Office of Government Ethics in consultation with the agency concerned. Section 207(c) does not apply to special government employees who serve for less than 60 days in a calendar year.

18 U.S.C. § 208 prohibits participation in any proceeding in which the government employee, an organization by which he is employed, or an organization with whom he has any arrangement concerning prospective employment has a financial interest, unless he first makes full disclosure to the government official appointing him and receives an advance written determination from the official that the interest is not "so substantial as to be deemed likely to affect the integrity of the services which the government may expect from him."

> Violations of the prohibitions of 18 U.S.C. §§ 205, 207, or 208 are subject to fines of up to $10,000 and up to two years' imprisonment, or both.

18 U.S.C. § 209 prohibits any government employee from accepting, and any individual, partnership, corporation, or other organization from paying, any supplement to the salary of the officer or employee. This section expressly permits employees of the government to continue to participate in a bona fide pension, retirement, group life, health or accident insurance, profit sharing, stock bonus, or other employee welfare or benefit plan maintained by a former employer. This section does not apply to a special government employee or to a government employee serving without compensation (whether or not he is a special government employee) or to any organization paying, contributing to, or supplementing his salary as such. Violations of this section are subject to a fine of 00 $5,000 or imprisonment of up to one year, or both.

---

[2] Executive Schedule pay rates have been frozen by Executive Order No. 12087, as amended by Executive Order No. 12165. For Level V employees on the Executive Schedule that rate is now approximately $54,000.

Department of Energy Organization Act

If an executive reserve is organized so that, in the event of mobilization, reservists become employees of the Department of Energy, then activated executives could be subject to the restrictions of the Department of Energy Organization Act on "supervisory employees." The definition of supervisory employees includes experts or consultants who are (1) employed for more than 90 days in any calendar year, and (2) paid at an annual rate equal to or greater than the minimum rate for GS-16.[3] 42 U.S.C. § 7211. If activation results in the executive entering the employment of the Department of Energy, and he falls within this definition, then he must comply with the following restrictions:

1. Divestiture of energy holdings. 42 U.S.C. § 7212.

A supervisory employee may not willingly receive compensation from, have any official relationship with, or own any stock in any energy concern. The Secretary may waive divestiture requirements to avoid exceptional hardship to the employee or if the interest is a pension, insurance, or other similarly vested interest. The waiver must be published in the Federal Register, contain a finding of exceptional hardship or that a vested interest exists, state the period of the waiver, and "indicate the actions taken to minimize or eliminate the conflict of interest." In the absence of a waiver by the Secretary, the requirements of this section may not be met by transferring the interest to a spouse or a dependent or by placing it in a trust. 42 U.S.C. § 7211(d).

2. Disclosure of energy assets. 42 U.S.C. § 7213.

Each person who serves as an employee of the DOE at any time during the calendar year must disclose (1) the amount and the source of income received by the individual, a spouse, or dependent from any energy concern, and (2) the identity and value of any interest held in any energy concern during the calendar year. The Secretary may exempt nonregulatory or nonpolicy-making positions at GS-12 or below from the disclosure requirements.

3. Report on prior employment. 42 U.S.C. § 7214.

A supervisory employee of the Department must file a report identifying any energy concern which paid him more than $2,500 in any of the previous five calendar years. The report must include: (1) the name and address of each source of compensation, (2) the period during which the consultant received compensation from each source, (3) the title of each position the consultant held with each compensating source, and (4) a description of his job duties in each position.

---

[3] As of October 1, 1980, the minimum rate for GS-16 was approximately $52,000.

4. Post-employment prohibitions and reporting requirements. 42 U.S.C. § 7215.

The statute contains a one-year post-employment prohibition of appearances or communications with the DOE relating to "any particular matter" pending before the DOE. According to the House Conference Report No. 95-539, 1977 U.S. Code Cong. and Administrative News, at 961, the intent of this provision is to prohibit any contact for one year after leaving the DOE:

> The prohibitions extend to both oral and written communications and extend to new matters that arise after the employee leaves service as well as to matters which were before the Department while the individual was employed there. The prohibitions extend to any particular matter or issue with which the Department is concerned; there is no requirement that there be a formal proceeding in the Department before the prohibitions apply.

In the first and second calendar years following departure from the DOE, a former supervisory employee must file a report describing any employment with any energy concern, unless he has an agreement for future employment before he leaves the DOE and files a report describing the agreement within 30 days of departure. This report must be amended if he accepts employment with another energy concern during the next two years.

5. Participation prohibitions. 42 U.S.C. § 7216.

For one year after terminating employment with any energy concern, a supervisory employee may not participate in any DOE proceeding in which his former employer is substantially, directly, or materially involved, other than a rule-making proceeding which has a substantial effect on numerous energy concerns. For one year after commencing service in the Department a supervisory employee is also prohibited from participating in any DOE proceeding for which the employee had direct responsibility or in which he participated substantially or personally while employed by any energy concern in the previous five years. The Secretary may waive these requirements if he makes a written finding that the prohibitions would work an exceptional hardship on the supervisory employee or would be contrary to the national interest.

6. Procedures applicable to reports. 42 U.S.C. § 7217.

The reports disclosing energy assets and prior and subsequent employment with energy concerns must be retained for six years and must be made available to the public. Any waivers of the divestiture or other requirements must also be made available to the public.

7. Sanctions. 42 U.S.C. § 7218.

Violations of the conflict of interest provisions are subject to a civil penalty of up to $10,000 for each violation. Failure to disclose energy assets is subject to a criminal penalty of $2,500 fine, one year in prison, or both. Violation of the one-year prohibition on post-employment contact will be considered in deciding the outcome of the DOE proceeding in connection with which the prohibited contact was made.

Financial Disclosure Requirements

In addition to the extensive conflict of interest provisions contained in the general criminal statutes and in the Department of Energy Organization Act, government employees are subject to substantial financial disclosure requirements. Each officer or employee in the Executive Branch, including a special government employee, whose position is compensated at a rate equal to or greater than the minimum rate of basic pay fixed for GS-16 (which is now approximately $52,000) and who is employed by the government for more than 60 days in a calendar year must comply with Executive Personnel Financial Disclosure Requirements, 5 U.S.C. App. § 201 *et seq*. If the individual is employed for fewer than 130 days in a calendar year, the Director of the Office of Government Ethics may grant a publicly available request for a waiver of any reporting requirement under 5 U.S.C. § 201, but only if the director determines that (1) such individual is not a full-time government employee, (2) the individual is able to provide services specially needed by the government, (3) it is unlikely that the individual's outside employment or financial interest will create a conflict of interest, and (4) public disclosure by the individual is not necessary in the circumstances.

An employee subject to the disclosure requirements must report for the preceding calendar year the source, type, and amount of income from any source; the source and a brief description of any reimbursement received; the identity and value of any interest in property held for investment or the production of income; the identity and category of liabilities owed to any creditor exceeding $10,000 (excluding liabilities on a personal residence or automobile); a brief description, date, and value of any purchase, sale, or exchange of real property (other than a personal residence) or securities; identity of all positions held as an officer, director, employee, or consultant of any firm, nonprofit organization, or any educational or other institution; a description of the duties performed for any source compensating the employee more than $5,000 in the prior two calendar years; and a description of the date, parties to, and terms of any agreement with respect to future employment, a leave of absence during the period of government service, continuation of payments by a former employer, or continuing participation in an employee welfare or benefit plan maintained by a former employer. Certain information must also be reported regarding the individual's spouse or dependent child. This description of the reporting requirements is very brief and is provided merely to give an outline of the categories of information required.

Failure to file or filing a false report is subject to a civil penalty of $5,000. 5 U.S.C. App. § 204. The reports will be made available to the public. 5 U.S.C. App. § 205.

Summary

All industry employees who are activated to serve as government employees during an oil supply disruption will face severe problems under conflict of interest and financial disclosure provisions, even if they do not become employees of the Department of Energy subject to the additional provisions of the Department of Energy Organization Act. Because of the unpredictable duration of any energy supply emergency, it would be difficult to guarantee that these individuals could retain the status of special government employees. Special government employee status is crucial both under the conflict of interest statute and for purposes of obtaining a waiver from financial disclosure requirements. It may be possible to structure the plan to limit "tours of duty" to fewer than 130 days, or to fewer than 90 days if activated executives will become DOE employees.

These legal constraints could be mitigated by amending the Defense Production Act to exempt company executives employed by the government during an emergency from the statutes affecting government employees. Such an exemption could be accompanied by special conflict of interest provisions tailored to the circumstances. For example, participation prohibitions should be limited to matters involving the former employer, post-employment contact prohibitions should be limited to specific matters handled while working for the government, and disclosure requirements should be limited to identification of the former employer and other major financial interests. Provisions tailored to the emergency circumstances will help protect the executive by defining the parameters of permissible conduct and it will help avoid the appearance of impropriety in the program.

INDUSTRY PERSONNEL BECOME CONSULTANTS WITHOUT COMPENSATION TO PROVIDE ADVICE TO GOVERNMENT DECISION-MAKERS (THE "BUDDY" SYSTEM)

The Defense Production Act of 1950 specifically authorizes the President "to employ persons of outstanding experience and ability without compensation." The statute further provides at 50 U.S.C. App. § 2160(b)(2):

> The President shall be guided in the exercise of the authority provided in this subsection by the following policies:
>
> (i) So far as possible, operations under the act shall be carried out by full time, salaried employees of the government, and appointments under this authority shall be to advisory or consultative positions only.
>
> (ii) Appointments to positions other than advisory or consultative may be made

under this authority only when the requirements of the position are such that the incumbent must personally possess outstanding experience and ability not obtainable on a full time, salaried basis.

(iii) In the appointment of personnel and in assignment of their duties, the head of the department or agency involved shall take steps to avoid, to as great an extent as possible, any conflict between the governmental duties and the private interests of such personnel.

Persons appointed under this authority may not make policy decisions, but are limited to advising full-time salaried government officials who are responsible for making policy decisions.

50 U.S.C. App. § 2160(b)(4) also purports to exempt individuals employed pursuant to this authority from certain provisions of the conflict of interest statutes. However, the exemption cites the conflict of interest statutes in existence before January 21, 1962. As noted above, Congress terminated exemptions from conflict of interest statutes given to officers or employees of the Executive Branch of the United States government or of any independent agency of the United States when it repealed the old conflict of interest provisions and replaced them with 18 U.S.C. § 201 et seq.[4]

The Defense Production Act further requires that notice of appointments be published in the Federal Register stating the name of the appointee, the employing department or agency, the title of his position, the name of his private employer, the names of any corporations of which the appointee is an officer or director or in which he owns stocks, bonds, or other financial interests, the names of any partnerships in which he is a partner, and the names of any other businesses which he owns. Every six months, the appointee must file for publication in the Federal Register a statement showing any changes in such interests during the period.

---

[4] The exemptions available under 2160(b)(4) were limited to exclude the following matters: (1) negotiations of government contracts with the private employer of the appointee or any other entity in which the appointee has any direct or indirect interest; (2) applications to the government for relief or assistance made by the private employer of the appointee or any entity in which the appointee has any direct or indirect interest; (3) the participation by the appointee in any fashion in the prosecution of any claims against the government involving any matter concerning which the appointee had any responsibility during his employment by the government, during the period of such employment, and for two years following termination of government employment; (4) the receipt of salary in connection with the appointee's government service from any source other than the private employer of the appointee at the time of his appointment.

Since coverage under Executive Personnel Financial Disclosure Requirements is based on the government employees' pay grade (GS-16 or higher), executives serving without compensation should be exempt. Moreover, the more onerous provisions of the Department of Energy Organization Act should not apply to executives serving without compensation since automatic coverage is based on pay grade GS-16 or higher.[5] This conclusion is supported by the legislative history of DOEOA. The original Senate version of the Department of Energy Organization bill contained a section expressly bringing volunteers within the conflict of interest provisions of the DOEOA. See Senate Report No. 95-164, 1977 U.S. Code Cong. and Administrative News, at 908-909. The conference deleted this provision. House Conference Report No. 95-539, Id. at 971. The general conflict of interest provisions contained in Title 18 continue to apply to executives serving without compensation, so the special government employee status remains crucial.

Establishing a group of industry persons to serve without compensation to provide a "buddy system" for government policy-makers could run afoul of the Federal Advisory Committee Act and the requirements of the Federal Energy Administration Act of 1974, 15 U.S.C. § 776, which are incorporated in the DOE Organization Act by reference. 42 U.S.C. § 7234. The FEAA provides:

> Whenever the Administrator shall establish or utilize any board, task force, commission, committee, or similar group not composed entirely of full-time government employees, to advise with respect to...any...plan of action affecting any industry or segment thereof, the Administrator shall endeavor to ensure that each such group is reasonably representative of the various points of view....

The FEAA also provides that the Federal Advisory Committee Act, 5 U.S.C. App. § 1 et seq. shall govern. That statute (at § 2) defines an "advisory committee" to be:

> [A]ny committee, board, commission, counsel, conference, panel, task force, or other similar group...established or utilized by one or more agencies in the interest of obtaining advice or recommendations....

Given the breadth of these definitions, any group of industry executives brought in to advise government decision-makers could be an advisory committee, whether or not they are given that formal

---

[5] However, 42 U.S.C. § 7211(a) also permits the Secretary to designate as a "supervisory employee" any employee who "exercises sufficient decision-making or regulatory authority" so that DOEOA conflict of interest provisions should apply.

title.[6] Then the FEAA requirement of broad representation of different points of view and the Federal Advisory Committee Act's procedural requirements governing an advisory committee would apply.

INDUSTRY PERSONNEL FUNCTION AS PART OF AN ADVISORY COMMITTEE

This alternative avoids the conflict of interest and financial disclosure problems. The advisory committee must include representatives of the various points of view of the industry and consumers. 15 U.S.C. § 776. The Federal Advisory Committee Act established procedures for chartering advisory committees and expressly limited their function to advice. 5 U.S.C. App. § 8. Meetings must be open to the public, unless the Secretary determines that the meeting may be closed to protect national security, foreign policy, or trade secrets (or other specified matters not relevant here). 5 U.S.C. § 5526 and 5 U.S.C. App. § 10. The committee cannot meet in the absence of the federal employee designated to attend its meetings. All meetings must be called by a federal employee who has authority over the agenda. All advisory committee materials must be made available to the public, unless they are exempt (e.g., national security information or trade secrets). 5 U.S.C. App. § 10.

---

[6] As Judge Gesell noted in Nader v. Baroody, 396 F. Supp. 1231 (D.C.D.C., 1975): "The very vagueness and sweeping character of the definition permits a reading which could include...any...conference of two or more non-government persons who advise the President." Judge Gesell refused to read the definition that broadly and concluded that biweekly meetings of various groups at the White House did not violate the act. In contrast, another court held that one meeting with a group of doctors did fall under the act where the agency sought and relied on the advice received. National Nutritional Foods Association v. Califano, 603 F. 2d 327 (2d Cir., 1979).