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# NSR 90-Day Review Background Paper

June 22, 2001

# Table of Contents

# List of Figures

# Introduction

In the National Energy Policy Report issued in May 2001, the National Energy Policy Development (NEPD) Group recommended that the Administrator of the Environmental Protection Agency (EPA), in consultation with the Secretary of Energy and other Federal agencies, examine the New Source Review (NSR) regulations, including administrative interpretations and implementation, and report to the President within 90 days on the impact of NSR on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection[1].

This document is the first step in fulfilling that responsibility. The purpose of this document is (1) to provide background on the NSR program and its implementation; (2) to provide an introduction to some of the information EPA is developing for the final report; and (3) to request comment upon the information in this document and additional information needed for the review. The data contained in this background document is based largely on a search of publicly available information. EPA recognizes that there are additional important data not readily available that would be helpful in undertaking the examination directed by the NEPD. Specifically, some of the additional information that would be useful includes: (1) the amount of time typically spent in pre-permit application activities; (2) any impact of NSR requirements on investment in expansions of or new utility and refinery generation capacity; (3) the significance of the cost of offsets in nonattainment areas related to the annualized cost of control; (4) the impact, if any, of minor NSR on investment in new utility and refinery generation capacity and energy efficiency; and (5) information on the impact of NSR on energy production and efficiency in other industries.

EPA also recognizes that much of the data in this report is related to the impact of the NSR program on the construction of new facilities. This does not reflect a lack of interest in existing facilities, but rather a lack of publicly available data regarding the impact of the NSR program on such facilities. The Agency is requesting data on how the NSR program may affect existing sources, including data on the extent to which the program has affected the ability of existing sources (1) to undertake pollution prevention or energy efficiency projects; (2) to switch to less polluting fuels or raw materials; (3) to maintain the reliability of production facilities; and (4) to effectively utilize and improve existing capacity. The public is invited to comment on the information contained in this document, and to provide EPA with any additional information that should be considered for inclusion in the final report that will be sent to the President in August. That final report, which will contain conclusions and recommendations, will be based in part on the information in this paper, as well as data and analysis both provided by the public and developed by EPA and its consulting agencies.

EPA's review of NSR will include not only examining how NSR is operating now with respect to the issues raised but also what kind of changes to the program might be desirable in light of these issues. The changes may include different administrative approaches, changes to rules, and legislative changes. EPA is seeking input on a broad range of potential approaches, not limited to pending regulatory revisions to the NSR program, nor to the various alternative approaches presented by the variety of stakeholder interest groups in EPA-led public forums over the past few years. Public input on alternatives, and their relative environmental impact, costs, and impact on power plant and refinery capacity and efficiency will be considered in the review.

[1] The National Energy Policy Report included a number of related recommendations which might influence the recommendations in the final report on NSR. Both the recommendation for this 90-day study and the related recommendations are included in Appendix A of this paper.

Section I of this document provides an overview of the NSR program. Sections II and III present basic data on the electric generation and refining industries, respectively, including any data specific to the impacts of NSR on investment in new capacity, energy efficiency, and the environment.

# I. Overview of the NSR Program

*Introduction*

The basic requirements of the NSR program are established in parts C and D of Title I of the Clean Air Act. The purpose of the program is to protect public health and welfare, as well as national parks and wilderness areas, even as new sources are built and existing sources expand. Specifically, its purpose is to ensure that (1) air quality does not worsen where the air is currently unhealthy to breathe, and (2) air quality is not significantly degraded where the air is currently clean. The fundamental philosophy underlying NSR is that a source should install modern pollution control equipment when it is built (for new sources) or when it makes a major modification that increases emissions significantly (for existing sources). Congress believed incorporating pollution controls into the design and construction when new units are built or when old ones are modified significantly is generally the most efficient way of controlling pollution from major sources.

NSR requires a source to obtain a permit and undertake other obligations prior to construction to control its emissions of air pollution. However, NSR only applies if the construction project results in the potential to emit air pollution in excess of certain threshold levels established in the NSR regulations. For a new source, NSR is triggered only if the potential emissions qualify as major. For an existing major source making a modification, NSR is triggered only if the modification will result in a significant increase in emissions[2].

In general, the NSR program is administered by state and local air pollution permitting authorities. Each state or local permitting authority is required to incorporate basic NSR program requirements into its state implementation plan (SIP), which is the state's plan to ensure progress toward, or maintenance of, attainment of all National Ambient Air Quality Standards (NAAQS)[3]. A state's NSR program may be approved, either by incorporation into a SIP, which is approved by EPA, or by delegation to the state by EPA. If the state designs its own program, EPA may approve it so long as it meets the criteria listed in federal regulations. Otherwise, the state may request delegation of the federal NSR program, as it is written in the federal NSR regulations[4].

*NSR vs. PSD: Nonattainment versus attainment areas*

[2] EPA regulations also require States to develop minor NSR programs to address emissions growth from sources that do not trigger major source cutoffs, and from modifications that do not increase emissions above the significance levels established in regulation. This paper does not address so-called minor NSR, nor will the Report to the President.

[3] NAAQS are ambient levels of pollution established by EPA and are set at levels which protect public health and welfare with an adequate margin of safety.

[4] As noted later, the NSR requirements are different for nonattainment areas. In nonattainment areas, a state's NSR program can only be a SIP-approved program meeting the criteria listed in federal NSR regulations for SIP approval.

Generally, the term NSR is used to refer to the Clean Air Act's construction permit program for major sources. However, the major NSR program is actually comprised of two separate programs: Nonattainment NSR and Prevention of Significant Deterioration (PSD)[5]. These two programs have separate requirements to address the differing air quality planning needs in the differing areas where they apply. Nonattainment NSR applies in areas where air is unhealthy to breathe – i.e., where the established NAAQS for a Clean Air Act pollutant is not being met. These areas are called nonattainment areas. Nonattainment NSR for major sources of certain pollutants also applies in the federally designated ozone transport region (OTR), which consists of eleven northeastern states[6]. PSD applies to major sources located in areas where air quality is currently acceptable – i.e. where the NAAQS for a Clean Air Act pollutant is being met. These are called attainment areas. Because nonattainment areas have poorer air quality, nonattainment NSR requirements are generally more stringent than PSD requirements.

*Determination of Major Sources and Significant Increases*

The first step in determining whether new construction or modification is subject to NSR is to define the source and determine its emissions. Next, the source's potential emissions are compared to the appropriate major source threshold defined by law or regulation. Major source thresholds are defined in terms of annual emissions (i.e., tons per year). For PSD, the major source threshold is generally 250 tons per year, but the PSD major source threshold is 100 tons per year if the stationary source belongs to a list of 28 source categories (i.e. industrial groupings)[7]. For nonattainment NSR, the major source threshold ranges from 100 tons per year down to 10 tons per year depending on the severity of the air quality problem where the source is located. To be a major source under nonattainment NSR, the source must emit or have a potential to emit above the major source level the specific pollutant (or its precursor) for which the area is designated nonattainment.

A source's potential emissions, or potential to emit, is defined as a source's capacity to emit a pollutant when operating at maximum design limits except as constrained by practicably enforceable permit conditions. Practicably enforceable permit conditions limit a source's potential to emit the maximum amount possible under its physical and operational design.

A new source under construction (sometimes referred to as a greenfield source) is subject to NSR if its potential emissions will exceed the major source threshold. Applicability of NSR to greenfield sources is relatively straightforward, because the emissions from the new source are relatively easy to determine.

The other type of change that can trigger NSR is a major modification at an existing major source. The Clean Air Act defines a modification as a physical change or change in the method of operation of a major stationary source that results in an increase in emissions, or emissions of a new pollutant. Examples are a new production line,

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[5] The term NSR usually refers to the overall program, but is sometimes also used as shorthand to refer to nonattainment NSR, which may be a source of confusion. In this document, we will use NSR to refer to the general program (both nonattainment NSR and PSD), and will use nonattainment NSR when referring specifically to NSR for nonattainment areas.

[6] Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Washington, D.C.

[7] The PSD major source size for petroleum refineries is 100 tons per year. The PSD major source size for large fossil fuel fired steam electric plants is also 100 tons per year, but there are some electric generation facilities that are not fossil fuel fired steam electric plants (e.g., certain simple cycle combustion turbines). For these sources, the threshold is 250 tons per year.

an equipment upgrade, or reconfiguration of a process. Implementing regulations exempt certain activities from the definition of physical or operational change. These include, for example: routine maintenance, repair or replacement of equipment, increases in hours of operation or production rate not involving physical and operational changes (unless the increase is prohibited under an existing permit), or changes in ownership. If there is no physical change or change in method of operation, or if the change falls under one of the exemptions just described, then NSR does not apply to the change, and emissions need not be determined.

A physical change or change in method of operation (i.e., a modification) is only subject to NSR if it results in a significant net emissions increase of any regulated pollutant under the Clean Air Act. Just like the definition of a major source, the NSR regulations establish levels that define major modifications, known as significance levels, which vary by pollutant and attainment status of the area. The provision allows for *net* emissions increases if the source can offer past or future emissions decreases at its other units to counterbalance the increase from the proposed change. The net emissions increase resulting from the netting calculation must result in an increase above the significance level for PSD or nonattainment NSR to apply.

For modifications at existing sources, the net *increase* in emissions is compared against the significance level, not the entire emissions for the modified unit(s). This means that the current emissions must be known, and the future increase must be determined. Current emissions are measured using actual emissions over the recent past, usually designated as the last two years. Future increases are generally determined using potential to emit (which, as described above, is the maximum capacity to emit, except as limited by a permit)[8]. The difference between the future potential and the past actual emissions is compared to the relevant significance level. An exception is the electric utility industry, which estimates future emissions using a special calculation that resulted from a federal rulemaking following a federal court opinion[9]. The utility calculation is established in a rule, commonly known as the "WEPCO rule", which EPA finalized on July 21, 1992. This rule provides that utilities compare past actual emissions to projected future actual emissions[10].

Both EPA and regulated entities agree that similar exceptions apply in the context of NSR. The regulated entities maintain, however, that in launching an NSR enforcement initiative in 1998, EPA significantly narrowed its historical view of what constitutes "routine maintenance." The consequence, in their view, is that many practices that have long been considered not to trigger either NSPS or NSR are now being viewed as triggering NSR. As a result, they maintain, this discourages utilities and refineries from making changes in the course of the ordinary life of a utility that would significantly improve efficiency and capacity (such as the potential replacement of turbine blades with more efficient ones considered by Detroit Edison, discussed elsewhere in this material.)

The second step in determining whether NSR applies to a change is to determine whether it has resulted in a significant net emissions increase of any regulated pollutant under the Clean Air Act. The question of what the baseline should be for current emissions and what it should be for future emissions is accordingly critical and likewise the subject of controversy. For most sources, EPA's current practice is to compare a facility's

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[8] This calculation is often referred to as the "actual-to-potential" test.

[9] See *Wisconsin Electric Power Co. vs. Reilly*, 893 F.2d 901 (7th Cir. 1990).

[10] This calculation is often referred to as the "actual-to-future-actual" test

current actual emissions to their post-change potential emissions.  For the electric utility industry, its 1992 "WEPCO  rule" calls for comparing current actual emissions to post-change projected actual emissions.

## The Permit Application Process

Once a source determines that NSR applies, it must then prepare and file a permit application. The basic steps associated with the permit application and issuance process include: (1) preparation of the permit application and participation in any associated pre-permit application meetings; (2) issuance of permit application completeness determination by the State; (3) development and negotiation of draft permit; (4) opportunity for public notice and comment on the draft permit; (5) response of permitting authority to public comments, if any; (6) possible administrative and judicial appeals.  In addition the source must address any state and local requirements associated with the project.  The time and resources expended on preparing and negotiating the content of the application and addressing the NSR or PSD requirements can vary depending on the quality of the information contained in the permit application and the nature, extent and environmental impact of the proposed project.  Additionally, the level of public participation can also impact the resources associated with the application process.  Sometimes sources will participate in meetings with the state permitting authority and other affected parties such as EPA, local government representatives, Federal Land Managers and citizens groups prior to filing the permit application to discuss these requirements. The following discussion describes the NSR or PSD requirements that must be addressed in the permit application process.

*Basic Nonattainment NSR Requirements*

The Nonattainment NSR requirements apply to sources that construct or modify in an area that is designated nonattainment for one or more pollutants. These provisions apply to the pollutants for which the area is in nonattainment.  If a source increases emissions of a nonattainment pollutant and increases emissions of an attainment pollutant the following provisions apply only to the nonattainment pollutant.  For the attainment pollutant(s), the PSD provisions, discussed later, would apply.

New major sources and existing major sources undertaking major modifications subject to nonattainment NSR must apply state of the art emission controls that meet the lowest achievable emissions rate (LAER).   LAER is based on the most stringent emission limitation in any State's SIP, or achieved in practice by the source category under review.

In order to get a nonattainment NSR permit, the applicant must also offset its emission increase by securing emission reductions from other sources in the area.  The amount of the offset must be as great or greater than the new increase, and is based on the severity of the area's nonattainment classification.  The more polluted the air is where the source is locating or expanding, the greater the emissions reductions required to offset the proposed increase. Offsets must be real reductions in emissions, not otherwise required by the Clean Air Act, must be enforceable by the EPA, result in a positive net air quality benefit and assure reasonable progress towards attaining the NAAQS.  In general, offsets must be secured for the entire life of the source. However, under EPA's Economic Incentives Program, a source does not need to have the full amount of the offsets necessary to cover the entire life of the source at the time the source begins operation.  Instead, the source can purchase additional offsets periodically to meet the offset requirement.

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Each applicant must also conduct an analysis of "alternative sites, sizes, production processes, and environmental control techniques...[that] demonstrates the benefits of the proposed source significantly outweigh the environmental and social costs of its location, construction, or modification." The applicant must also certify that all of its other sources operating within the state are in compliance with the Clean Air Act and SIP requirements. Finally, the public must be given adequate notice and opportunity to comment on each permit application.

In addition to the basic steps identified above, when preparing a permit application, the applicant must research and propose LAER for the source category at issue and secure valid offsets as a condition of the project's approval.

*Basic PSD Requirements*

New major sources and existing sources that undertake major modifications that are subject to PSD must apply best available control technology (BACT). When preparing a BACT analysis, the permit applicant must typically undertake the following steps: (1) identify available pollution control options; (2) eliminate the technically infeasible options; (3) rank the remaining control technologies by control effectiveness; (4) evaluate the most effective controls (considering energy, environmental, and economic impacts) and document the results; and (5) discuss the appropriate BACT selection with the permitting authority. The permitting authority then specifies an emission limit for the source that represents BACT.

Each PSD applicant must also perform an air quality analysis, which may include pre-application monitoring data, to demonstrate that the new emission increase will not cause or contribute to a violation of any applicable NAAQS or result in a significant deterioration of the air quality. Finally, each applicant must also conduct an analysis to ensure that the increase does not result in adverse impact on air quality related values, including visibility, that affect designated Class I areas, such as wilderness areas and national parks.

*Changes that do not trigger NSR*

There are a number of ways that sources can undertake new construction or modification without the need for a major NSR permit. First, as noted above, there are certain activities that are exempt from NSR because they are defined in the regulations as exclusions from the definition of a physical change or change in the method of operation. For example, a routine change is exempt from NSR. Certain pollution control projects are also exempt from NSR, even those that increase emissions, if they meet environmental safeguards established by EPA.

Even if a change does not qualify for one of these exemptions, a change at a major source does not trigger NSR if the emissions increase is below the level defined as significant. Many projects have emissions increases that are below these levels and never trigger NSR. Where a project's maximum capacity to emit would be above the significance levels, a source often uses a common NSR avoidance strategy -- a limit on potential to emit, or PTE limit. In a PTE limit, a source agrees to limit the size of the proposed project's emissions increase by taking a permit limit to keep emissions below the significance level. Such limitations can be accomplished by installing modern pollution controls, or by limiting some unit's operation (e.g., limiting fuel burned or hours operated)[11].

Furthermore, even if the proposed change would result in a significant increase and cannot be limited as just described, the source may offer past or future emissions decreases at other units to offset the increase from the proposed change. Many more sources rely on netting or PTE limits to avoid NSR than actually obtain NSR permits. These transactions can result in significant emissions reductions, but a full review of these benefits is beyond the scope of this report.

*General data on the NSR program's implementation*

Preliminary estimates based on EPA's most recent data indicate that approximately 250 facilities apply for a PSD or nonattainment NSR permits annually. There are approximately 20,000 sources that would be classified as major under the Clean Air Act, and many more stationary sources that are not large enough to be called major. Specific permitting data for utilities and refineries are presented in the sector-specific portions of this paper; the data in this section pertain to all source categories.

Based on an EPA review of about 900 permits since 1997, the average time needed to obtain a major NSR or PSD permit, across all industries, is approximately 7 months from receipt of the complete permit application. Specific data for the electric generation and refining industries are reported in the sector-specific sections of this paper. In recent years, permitting times have been reduced for all source types.

**Figure 1: Average Permitting Time for PSD permits***

| Permitting Time 1997 - 1998 | Permitting Time 1999 - early 2001 | Overall Average Time 1997 - 2001 |
|---|---|---|
| Average: 8 - 9 months<br>Range: 1.5 – 35 months | Average: 6 - 7 months<br>Range: 3 - 12 months | 7.2 months |

*These times are based on a total of 391 PSD sources for which sufficient data were available to calculate permitting time. Permitting time is defined to include the time period from the date on which the permit application is filed through the date on which the final permit is issued.

Improved permitting time can be explained in part by permit applicants having more pre-application meetings with the permitting agency and submitting applications with what is believed to be current BACT. Based on experience, the most common sources of delay in permit issuance are the submittal of an incomplete application, the selection of a BACT option that the permitting authority believes to be less stringent than required, and public opposition to the permitting authority's draft BACT determination. Over time, as permit engineers from the industrial sector, the permitting authority, and EPA become familiar with specific issues, permitting can be done faster, as has recently been the case with turbines. Finally, recent emphasis by EPA, state, and local permitting authorities on permitting for new electric generating capacity and refining capacity appears to be resulting in shorter permitting processes.

[11] In addition to limiting the PTE of a project to stay below the significance levels for a major modification, some sources limit their entire facility PTE to levels that keep the source from being classified as a major source.

*General environmental impacts of NSR*

Recent work by EPA indicates that over the period from 1997-1999, the BACT component of the PSD program has resulted in emissions reductions of over 4 million tons (or an annual average of about 1.4 million tons) compared to what emissions would have been if the controls otherwise required in the absence of PSD had been applied instead[12]. These data are based on a thorough review of approximately 900 PSD permits issued since 1997. Figure 2 summarizes these data by pollutant.

**Figure 2: Estimated Emissions Avoided Due to PSD BACT Permitting (1997 – 1999) (short tons)**

| | |
|---|---|
| PM/PM10 | 180,000 |
| SO2 | 1,260,000 |
| NOx | 2,540,000 |
| CO | 65,000 |
| VOC | 25,000 |
| **TOTAL** | **4,100,000** |
| ***Annual average over time period*** | ***1.4 million tons per year*** |

The review on which these numbers are based included only PSD permits. Therefore, these emissions reductions estimates do not include emissions reductions for control technology and offsets in nonattainment areas.

The emissions reductions that result from pollution control required under NSR are not the only way that the NSR program keeps pollution out of the air. Each year many companies make modifications to existing facilities, and even construct entirely new facilities, without obtaining and NSR permit by keeping emissions lower than the amounts for which permits are required. This process is sometimes referred to as "netting out" of NSR. [13] Because EPA is usually not involved when companies make changes that do not require NSR permits, we do not have data on the amount of pollution avoided as a result.

***Benefits Associated with Electricity Generating Emissions Reductions Realized Under the NSR Program***

[12] Typically, in the absence of BACT, the controls required would be a federal New Source Performance Standard (NSPS), and/or a limit from an applicable State Implementation Plan (SIP).

[13] For example, if a power plant located in an attainment area makes a change that would increase its emissions of NOx by 50 tons per year but at the same time installs pollution control technology that would reduce its NOx emissions by 35 tons per year, the plant would not have to obtain an NSR permit because its net emissions increase (15 tons per year) would be less than the 40 tons per year that makes a change a major modification.

Based on the estimated emissions avoided due to PSD BACT permitting as reported in the table above, EPA estimated the magnitude of the benefits associated with this program. This estimate is lower than the actual benefits of the NSR program because not all the health and environmental benefits are captured, nor are all the benefits of nonattainment NSR captured. Also, the estimate does not capture the benefits of the reductions in emissions of pollutants other than SO2 or NOx.

Based on the figure above, roughly 400,000 tons of SO2 and 822,000 tons of NOx emissions are avoided annually as a result of the PSD program. Ninety percent of these reductions are thought to be from electricity generating facilities. Based on previous EPA analyses (Hubbell 2001), the average health-related benefits per ton of NOx reduced are around $1,300, and the average benefits per ton of SO2 reduced are around $7,300 for electricity generating units of this type and proximity to population. For simplicity, estimates are provided only for health impacts that generally account for over 90 percent of monetary benefits in previous analyses.

# II. Electric Power Industry

## 1. Historical NSR Permitting Data

This section presents a summary of the available data for NSR permitting for the electric generation industry. Most of the available information comes from the EPA regional offices. Because states issue the vast majority of nonattainment NSR and PSD permits, they are the best source for historical permitting data. EPA Regional offices work with the states to track various program data. However, states are generally not required to submit permitting data to EPA. Recent tracking has focused on PSD permitting for combustion turbines. Limited PSD data are also available for coal-fired power plants and for the broader electric generating sector. The summaries in this section do not include nonattainment NSR or minor source permits because of the limited availability of data.

Since 1995, 274 PSD permits have been issued nationally for new and modified electric generation facilities. Most of these have been for gas turbines, but some PSD permits have been issued for other electric generators as well. The combined new generating capacity for these PSD-permitted facilities is approximately 150,000 MW.

For coal-fired electric generation, there have been at least 10 PSD permits issued nationally, reflecting a combined generating capacity of approximately 5,600 MW. The average permitting time for these units was approximately 10 months[14]. For gas turbines, there have been over 250 PSD permits issued nationally, reflecting a combined generating capacity of about 138,000 MW. The average permitting time for these units was approximately 7 ½ months. However, more recent data indicate that, for turbines, the average time is decreasing, most likely because the process for determining BACT is accelerating as applicants and permit writers become more familiar with emerging $NO_x$ control technology.

**Electric Power Industry Enforcement Actions**

[14] One anomalous case is an appealed PSD permit that became a subject of Federal litigation, which significantly lengthened its issuance time. If this case is removed, the average permitting time is 8 months.

EPA and several states have taken enforcement actions against owners and operators of several coal-fired plants, alleging that a number of facilities had been modified without NSR permits. In connection with all of the notices of violation filed on the coal-fired plants for the types of modifications noted above, EPA is unaware of any minor NSR permits issued for the activities in question. These modifications tended to fall within four general categories:

(1) Construction without a permit: EPA has identified instances where sources completed construction of entire coal-fired steam generating units without incorporating modern pollution controls. In these cases, the source argues that construction permits issued in 1974 exempt those sources from the 1977 regulations, notwithstanding the 18-month limitation in the regulations governing the life of construction permits.

(2) Expansion of capacity: EPA has identified a number of instances where the hourly capacity of the unit was increased. An example of such a modification is a company that increased the amount of coal being fed into the boiler by 5 tons per hour.

(3) Redesign of existing units: Between the 1950s and 1970s, the size of power plant units increased from 50 MW to over 1000 MW units. Not all of these large units were immediately successful. EPA identified a number of instances where, in the first few years after installation, relatively new installations were redesigned and modified to eliminate or mitigate original design defects, and such modifications led to significant increases in emissions.

(4) Life Extension Projects: EPA has identified a number of projects undertaken by power plants that extend the useful life of the boilers beyond that contemplated when the facilities were built. For example, some power plants replaced major components (e.g., economizers, super heaters) after 30 years of use and in a manner that resulted in an emission increase from the unit. EPA's position is that these types of physical changes trigger NSR/PSD under existing law and regulations.

Following on these investigations. EPA engaged the operators of the investigated facilities in discussions aimed at resolving the alleged violations. EPA has reached a final settlement with one operator, Tampa Electric, and has reached agreements in principle with Cinergy, Inc. and Virginia Power. Those settlements provide for a total emissions reduction of approximately 305,000 tons per year of NOx and 641,000 tons per year of SO2 over a period of time that extends to December 31, 2012.

EPA currently is engaged in settlement discussions with a number of other utilities. These discussions are aimed at reaching agreements that provide flexibility in the operation and modification of utility systems and substantial reductions in emissions.

# 2. Factors Affecting Investment in New Capacity

This section examines those factors that are considered by power sector decision-makers when building and siting a new plant, and when deciding to expand an existing plant. It is based on a review and analysis of available literature performed for EPA by ICF Consulting. Although the review found limited data, some information was available that shed light on considerations important to developers.

A decision to invest in a new power plant or expand an existing one requires simultaneous evaluation of strategic and siting considerations and permitting issues. Company officials and developers do not typically enumerate the relative importance of different factors in evaluating projects. Rather they seek to identify the impact of all the different elements on the rate of return (ROR) of each potential investment option. An investment's ROR is the most common metric by which investors organize, standardize and evaluate all pertinent information in order to make an informed investment decision. Although decision makers often rely on ROR projections to make investment decisions, whether for new plant construction or expansion of existing facilities, they remain sensitive to intangibles such as public opinion.

In general, there are three primary considerations in project development:

1. Strategic Considerations: whether a market for power generation is likely to be the most profitable among those a firm wants to locate in;

2. Siting Considerations: access to the power transmission grid, reliability of natural gas and coal delivery systems, water availability, as well as local environmental and zoning issues.

3. Permitting Issues: time and cost of obtaining various permits, including air and operating permits.

***Strategic considerations***. Factors like capital outlay, power prices, and fuel costs generally have the most impact on ROR. In addition, uncertainty about power prices and fuel costs introduce risk into the investment decision. The other notable component of the strategic considerations of interest in this report is environmental costs, primarily pollution control equipment. These usually have a small to moderate impact on ROR. If the spread between fuel and power prices is sufficiently high, environmental cost may not affect a decision about whether or not to construct. However, in some instances where the facility minimally meets the required ROR, pollution control requirements can change the investment decision of a plant. Environmental cost, as with any other cost component, only matters to the extent that it impacts the ROR. Generally, environmental costs are one of many cost components under consideration, and not necessarily the deciding factor.

***Siting considerations***. These factors have important implications for decisions to invest in a new plant in one location versus another, or to expand at an existing facility. Recently, the difficulty in finding acceptable sites has more important in the decision calculation.

The importance of siting is perhaps most obvious in the decision to invest in a new facility or to expand an existing facility. An existing site provides numerous beneficial advantages – an existing access to transmission lines, a ready supply of fuel sources, appropriate zoning laws, and water sources. Furthermore, expansion of existing facilities may not always require significant additional permitting time if the definition of the source does not change. However, expansion of an existing facility may be limited by its physical capabilities, and new construction then may be necessary.

***Permitting issues***. These issues have become an integral part of the project development process. Permitting can be a costly process that negatively impacts ROR. Most developers describe permitting as an extremely complex and time-consuming process. The financial impacts from permitting (including NSR) can change the economic feasibility of the project. Permitting (including required public hearings and comment processes) can be costly not only because of the time and human resources involved, but also because of uncertainty and delay. Delay, for example, can cause a developer to miss advantageous financial circumstances when interest and equity costs are low.

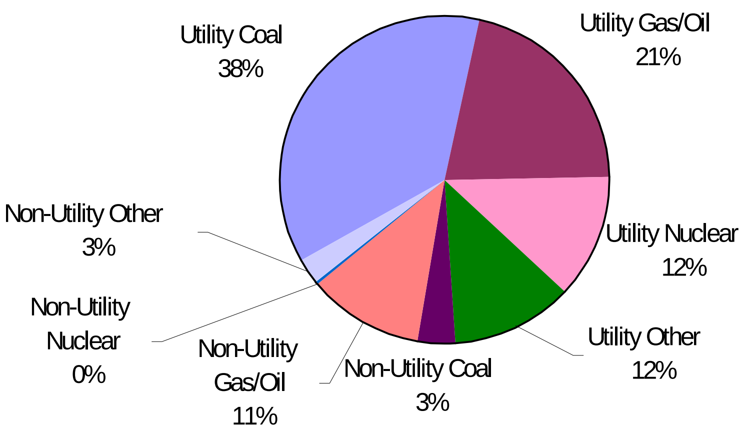
This cost of financing can have a large and negative impact on ROR.

# 3. Trends in Electric Capacity and Utilization

This section summarizes the trends in electric capacity utilization over the last 20 years, particularly the last decade. Any examination of the trends in electric capacity and utilization over the last 20 years must be placed within the context of deregulation in the electric generation industry. Three seminal laws – the Public Utility Regulatory Policies Act (PURPA) in 1978, the Energy Policy Act (EPACT) in 1992, and Federal Energy Regulatory Commission (FERC) Order 888 in 1996 – set into motion various measures to increase competition in the electric generation industry and to enhance transmission access for sources other than utilities. Deregulation in electric generation not only has reshaped the market for electricity, but has fundamentally altered the strategies that generating companies use in managing their portfolio of assets.

In 1999, total U.S. electric generating capacity was 781 GW, of which utilities accounted for approximately 83 percent. In 1992, non-utilities accounted for less than 7 percent of total electric capacity, compared to 17 percent in 1999. The emergence of non-utilities as a more significant component of the electric generation industry is the direct result of deregulation activities that created a more vibrant generation market and improved access to transmission lines. Figure 3 below highlights utility and non-utility electric capacity in 1999.

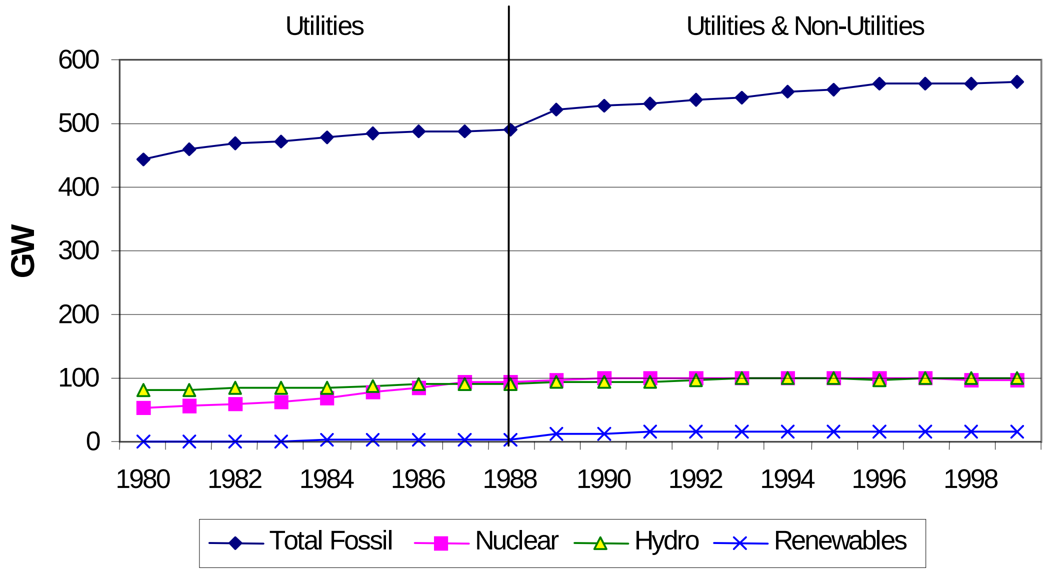
**Figure 3: Utility and Non-Utility Capacity in 1999**




Source: Annual Energy Review, EIA

Non- utilities have increased their share of total electric capacity through new capacity additions and by acquiring divested utility assets. In 1997, for instance, 53 GW of utility assets were for sale; in 1998 an additional 77 GW of utility assets were made available for auction. By April 2000, 156 GW of utility capacity, or 22 percent of total capacity, had been sold, transferred to unregulated subsidiaries, or were for sale. Many of these assets were acquired by non-utilities seeking to penetrate generation markets. Similarly, between 1998 and 1999 non-utilities installed approximately 12 GW of capacity, outstripping the net capacity additions by utilities. Figure 4 shows the trend in total U.S. capacity between 1980 and 1999.

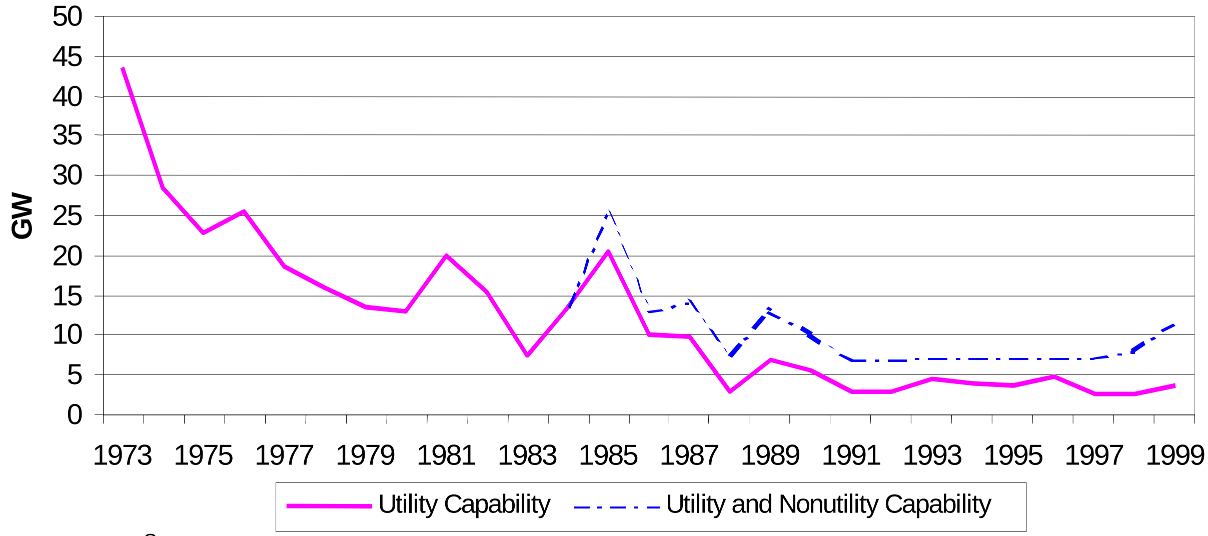
**Figure 4: Total U.S. Electric Capacity (1980-1999)**




Source : Annual Energy Review, EIA, Table 8.5

Between 1989 and 1999 electric capacity grew by 8 percent from 725 GW to 781 GW. This is in sharp contrast to the pace of new capacity between 1980-1988, when the generating capacity of electric utilities alone grew by 17 percent from 579 GW to 677 GW. (Data on non-utilities are not available for the years prior to 1989.) Figure 5 highlights the trend in net capacity additions. The capacity data in Figure 5 reflect summer dependable capacity, which is a measure of a unit's capacity during the summer months.

**Figure 5: Annual Net Capacity Additions (Net Summer Dependable Capacity) (1973-1999)**



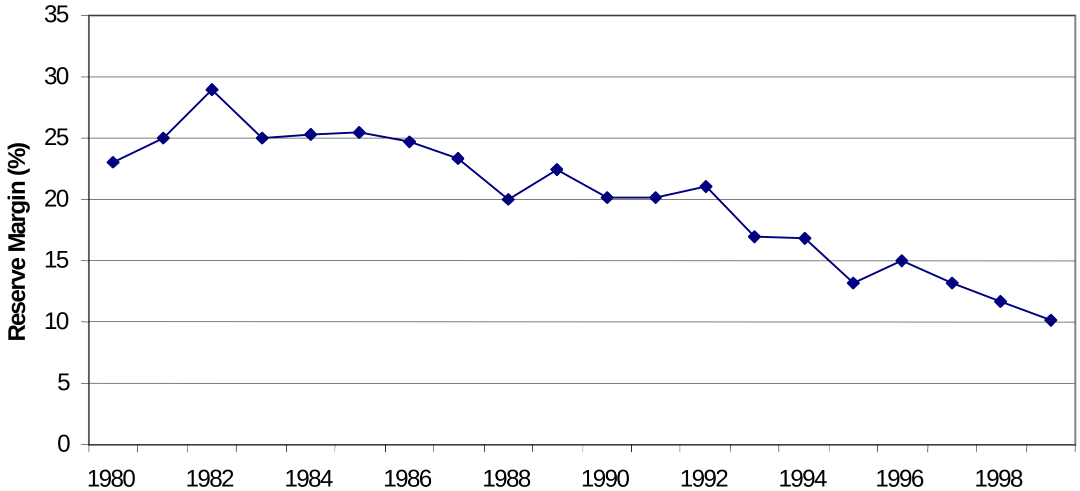

Sources:
Data from 1973 through 1993: EIA, *Annual Energy Review*
Data for utilities from 1994 onwards: EIA, *Inventory of Power Plants*
Data for non-utilities from 1994 through 1997: EIA, *Electric Power Annual Vol. II*
Data for non-utilities from 1998 and 1999: EIA, *Inventory of Non-utility Power Plants*

While the growth in capacity during the 1980s was driven largely by reliability concerns and consistent overestimates of future peak demand, the decline in the rate of capacity growth during the 1990s has been attributed largely to deregulation and the emergence of non-utilities. During the 1970s and through 1983, peak demand forecasts were consistently high. Since utilities based their capacity planning on expected future peak demand, there was significant investments in additional capacity, mostly coal-fired and nuclear facilities. Additionally, the northeastern blackouts of 1965 and the formation of the North American Reliability Council (NERC) put added emphasis on the reliability of electric bulk power systems. The economic and regulatory climate during the 1980s also helped spur investments in new generation capacity. Since utilities were regulated, they were guaranteed some level of return on their investment. Fuel prices also dropped sharply during that time. Average coal prices, after peaking in 1978 at $45 per short ton (real 1996 dollars), had dropped to $25 (real 1996 dollars) by the end of the 1980s.

The construction boom in capacity during the 1980s subsided during the 1990s as EPACT and FERC Order 888 initiated deregulation. Utilities were reluctant to make major investments in new plant capacity because of uncertainty about how the costs would be recovered and the risk of capital investments being stranded under deregulation. Declines in utility capacity additions, however, were offset by non-utility investments in new capacity. While EPACT made it easier for exempt wholesale generators to come online, FERC Order 888 ensured that non-utilities would be able to compete fairly against utilities through equal access to transmission lines. Thus, by the late 1990s pure non-utility plants were being built and operated.

The advent of deregulation and the emergence of non-utilities in electric generation has had significant impacts on reliability planning and investments in new capacity during the 1990s. Reserve margins, the percent of capacity over peak demand, is the most frequently used metric for reliability. Figure 6 highlights the trend in total U.S. reserve margins over the period 1980-1997.

**Figure 6: Reserve Margins (Percent Capacity Over Peak Demand) (1980- 1997)**



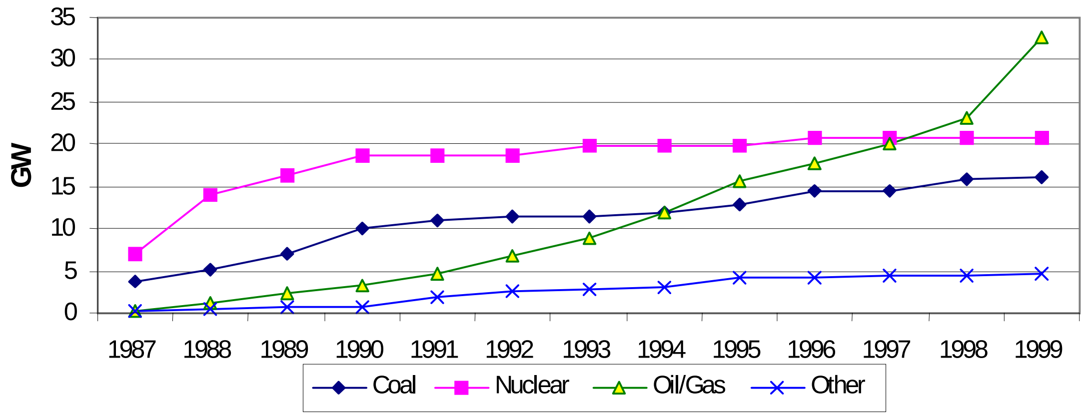

Source: EEI, *Statistical Yearbook of Electric Utility Industry*
Note: Reserve Margin is calculated as: (Capability - Peak Load)/Capability * 100

After peaking in the early 1980s at 33 percent, reserve margins declined rapidly and are currently at 12 percent. This drop in reserve margins coincides with the emergence of non-utilities and deregulation. Forecasted peak demand also was consistently lower than actual peak demand during the years after 1983. [15] Collectively, the risk of stranded investment, deregulation, and the emergence of non-utilities reduced the construction boom in new electric capacity during the 1990s.

During the 1990s coal-fired and nuclear plant construction declined, while the construction of natural gas-fired units increased. Some utility and power plant owner have contended that existing and potential future environmental regulations limit the economic possibilities for new coal-fired plants. Additionally, public opposition to the construction of new coal-fired and nuclear plants has increased. Another reason for the shift in construction from coal and nuclear to gas may be the fact that deregulation favors construction of less capital-intensive projects. The decline in coal and nuclear construction, however, was offset by non-utility investment in natural gas-fired combined cycle and combustion turbines. Figure 7 highlights cumulative capacity additions by energy source for 1987 - 1999. Figure 8 highlights the additions and retirements of coal-fired capacity between 1989 and 1997.

[15] EIA, Performance Issues for Changing Power Industry, January 1995 (Appendix, p.31)

**Figure 7: Cumulative Capacity Additions by Energy Source (1987-1999)**

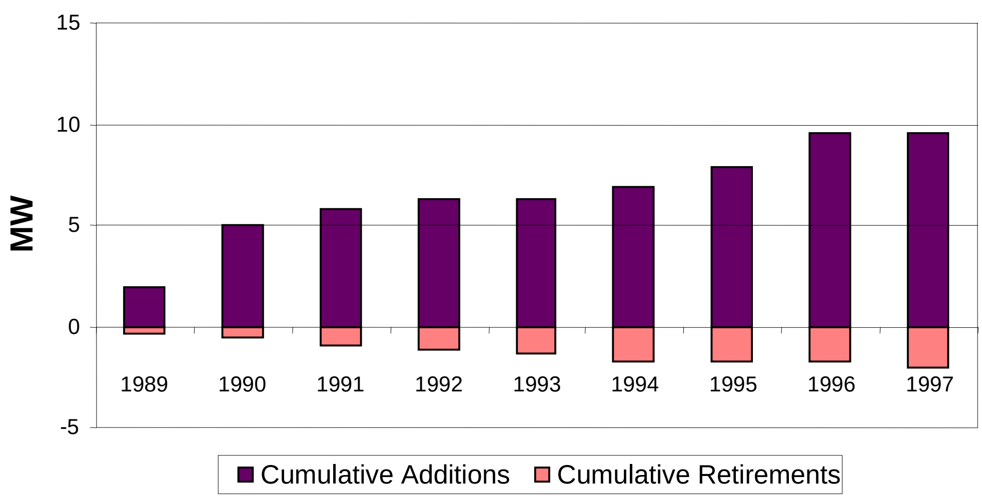



Sources: EIA, *Inventory of Power Plants* , 1990, 1992, 1993, 1996, 1997, 1998, 1999,

EIA, *Inventory of Non-Utility Power Plants* , 1998, 1999.

Note: Capacity additions in 1998 and 1999 include non-utilities; prior to that only utility information was available.

**Figure 8: Cumulative Additions and Retirements of Coal-Fired Capacity (1989- 1997)**

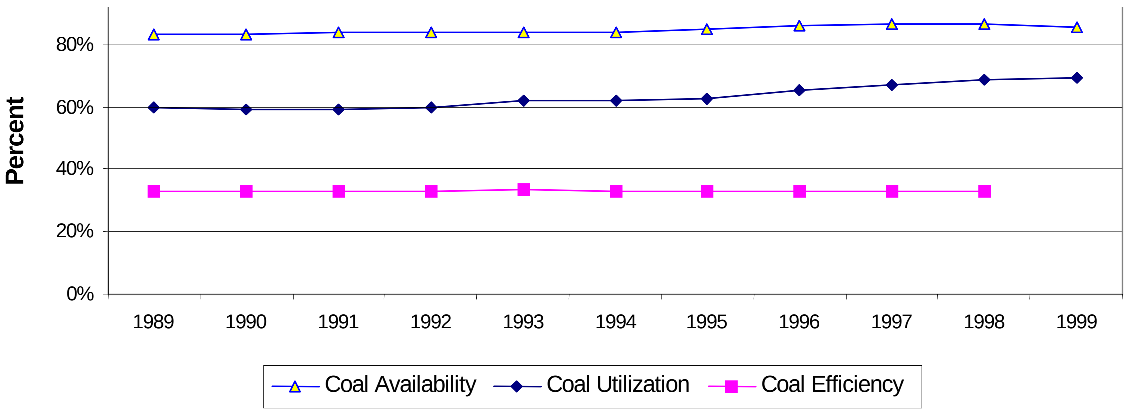



Technological innovations in the performance of gas turbines also contributed to growth in new gas-fired capacity. Throughout the 1990s the efficiency of gas turbines improved significantly, providing generators with an effective strategy for penetrating markets. Rather than compete against base load units, non-utilities wanted to compete against the less efficient, older oil/gas steam units that provided electricity during peak loads. Non-utilities with their efficient gas units could penetrate those markets successfully.

The increased utilization of coal-fired capacity during the 1990s stemmed from the decline in capacity addition and reserve margins over that same period in time. Since fewer new units were being added, increased utilization of the existing units was necessary to satisfy increasing electricity demand. Deregulation and a decline in fuel prices were also important factors in increased utilization. Between 1989 and 1999 average real coal prices dropped by 34 percent from $26 per short ton (real 1996 dollars) to $17 per short ton (real 1996 dollars)[16]. Natural gas prices declined similarly, as did operation and maintenance costs. Between 1989 and 1997, total non-fuel expenditures for coal steam units decreased by 13 percent while generation increased by 14 percent. As a result, average operation and maintenance cost for coal generation declined from $5.22 mill/kWh (1997 dollars) in 1989 to $3.96 mill/kWh (1997 dollars) in 1997[17].

In addition to putting downward pressure on operation and maintenance costs, deregulation also pressured existing plant owners to reduce both scheduled outages (planned plant shutdowns for maintenance and repair) and forced outages (unplanned plant shutdowns). Between 1989 and 1999, both scheduled and forced outage rates for coal-fired plants declined, scheduled outages by 13 percent and forced outages by 19 percent. Figure 9 highlights the trends in availability for coal-fired capacity. The average efficiency of coal-fired capacity, however, remained relatively unchanged.

**Figure 9: Availability, Utilization, and Efficiency for Coal-Fired Plants (1989-1999)**

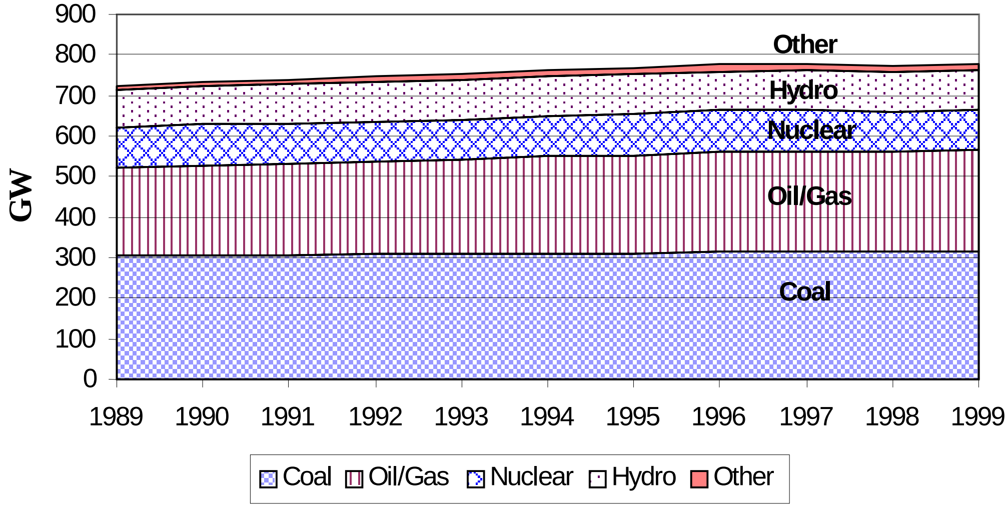



Source: Coal efficiency: Parker, Larry B. and Blodgett, John E., "Air Quality and Electricity: Enforcing New Source Review,", January 31, 2000.
*Coal availability: 1999 Generating Availability Report* (GADS), NERC
Coal utilization: EIA, *Annual Energy Review,* Tables 8.2 and 8.5

The capacity mix of existing units over the last decade has remained fairly stable. Figure 10 highlights electric generation by different types of fuel for the period 1989-1999. Coal-fired capacity has remained at around 40 percent, oil/gas at around 30 percent, and nuclear and hydro power at about 13 percent each. The remaining capacity consists of renewable fuels and others. Significant nuclear capacity was added during the 1980s. The mix of capacity additions, however, is significantly different from the mix of existing capacity during the 1980s. (Note for Figure VIII: Data on non-utility additions by energy source were available only for 1998 and 1999.)

[16] EIA, Annual Energy Review 1999, Table 7.8.
[17] Beamon, Alan J. and Leckey, Thomas J., "Trends in Power Plant Operating Costs," EIA, 1999.

**Figure 10: Total Capacity (GW) – Utilities and Non-Utilities (1989-1999)**




Source: EIA, *Annual Energy Review*, Table 8.5

In the future non-utilities are likely to command more of the capacity and generation share. The Energy Information Administration (EIA) projects that generation from coal and natural gas will continue to increase to offset the projected retirement of nuclear capacity. EIA also forecasts that since deregulation favors less capital-intensive plants, new gas capacity will continue to be added. However, the recent surge in natural gas prices has reinvigorated the interest in coal plants. While the trends over the last 10 years are likely to continue, particularly for new natural gas capacity, competitive markets made facility owners extremely sensitive to cost pressures. Significant changes in the relative cost of coal and gas, for example, could lead to investments in significant new coal-fired capacity. Additionally, the recent California experience and concerns about similar shortages in the northeast again has made reliability an important concern.

# 4. Data on Costs of Pollution Controls[18]

In general, capital expenditures for air pollution control as a percentage of total capital expenditures on new plant construction are significantly lower than those expenditures on existing plants. Pollution control equipment retrofitted to existing units are subject to physical and engineering constraints (including the availability of needed space, removal of existing equipment, additional engineering required to fit new equipment into the existing site, etc.) that add to the cost. In a new plant, on the other hand, optimal configurations of generating units and all necessary pollution control equipment can be built in at the design phase.

[18] The control technology cost estimates were obtained from various sources. Therefore the cost estimates may not be consistent in terms of their assumptions or estimation methodology. The range of pollution control costs, therefore, should only be considered illustrative and not as upper or lower bound of actual pollution control costs that will be incurred by generating units. For a more complete information concerning the cost estimates please refer to Exhibit 1 in the Draft Report of the "Review of Data on the Impact of New Source Review on Investment Decisions- Power Generation and Refinery Sectors" prepared for EPA by ICF Incorporated.

The ratio of pollution control capital expenditures to the total capital expenditures differs according to the size of the units. In general, over a certain range of generating capacities, larger units tend to have lower costs on a unit-cost basis ($/kW) due to economies of scale. In addition, total pollution control costs differ depending on the location of the generating units, whether they are new or modified. Furthermore, these costs depend on whether the generating unit is to be located in an attainment or non-attainment area.

***Attainment Areas:*** In attainment areas, pollution control costs are limited solely to the costs of control equipment. These costs, however, depend on the location of the plant, plant characteristics, and the amount of plant emissions. These factors determine the stringency of required BACT controls.

***Non-Attainment Areas:*** In nonattainment areas, pollution control costs consist of control equipment costs plus the costs of offsetting new emissions of pollutants for which the area is in non-attainment. In this paper the costs of offsets have not been included in the pollution control expenditures, since the costs of offsets vary widely by specific location and the pollutant being controlled. An analysis by ICF Consulting [19] (hereafter called the "ICF report") provides illustrative cost shares of pollution control expenditures. Exhibit 1 in the ICF report indicates that the pollution control expenditures are highest for new coal-fired units and lowest for new combined cycle units. [20] Further, the pollution controls cost shares are higher in nonattainment areas than in attainment areas. Other conclusions that can be drawn from Exhibit 1 include:

**Attainment Areas**

- For new coal-fired units, pollution control capital expenditures account for about 20 to 27 percent of total construction capital costs.
- For new coal-fired units, annual pollution control expenditures account for about 23 to 31 percent of total annual generating unit costs.
- For new combined cycle units, however, pollution control capital expenditures account for only about 2 to 5 percent of total unit construction capital costs.
- For new combined cycle units, annual pollution control expenditures account for about 5 to 14 percent of total annual generating unit costs.
- For repowered combined cycle units, pollution control capital expenditures account for only about 5 to 6 percent of total construction capital costs.

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[19] ICF, Inc. "Review of Data on the Impact of New Source Review on Investment Decisions." Prepared for the U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. Research Triangle Park, NC. June 22, 2001.

[20] The control technology cost estimates were obtained from various sources. Therefore the cost estimates may not be consistent in terms of their assumptions or estimation methodology. The range of pollution control costs, therefore, should only be considered illustrative and not as upper or lower bound of actual pollution control costs that will be incurred by generating units. For a more complete information concerning the cost estimates please refer to Exhibit 1 in the Draft Report of the "Review of Data on the Impact of New Source Review on Investment Decisions- Power Generation and Refinery Sectors" prepared for EPA by ICF Incorporated.

- For repowered combined cycle units, annual pollution control expenditures account for about 5 to 15 percent of total annual generating unit costs.

**Nonattainment Areas**

- For new coal-fired units, pollution control capital expenditures account for about 24 to 27 percent of total construction capital costs.

- For new coal-fired units, annual pollution control expenditures account for about 27 to 31 percent of total annual costs.

- For new combined cycle units, however, pollution control capital expenditures account for only about one to 14 percent of total construction capital costs.

- For new combined cycle units, the annual pollution control expenditures account for about 5 to 17 percent of the total annual generating unit costs.

- For repowered combined cycle units, pollution control capital expenditures account for only about 2 to 15 percent of the total construction capital costs.

- For repowered combined cycle units, annual pollution control expenditures account for about 5 to 29 percent of total annual costs.

<u>Costs of Offsets:</u>

As noted earlier, in nonattainment areas newly constructed or modified plants are required to purchase offsets at a one-to-one or greater ratio (depending on the SIP requirements) to offset projected emissions increases of those pollutants for which the area is in non-attainment. Figure 11 (taken from the ICF report) illustrates the average costs of ERCs for specific pollutants.

**Figure 11: ERC Bid and Offer Prices for Specific Criteria Pollutants ( May 2001)**

(current $ per ton per year)

| **Location** | **$SO_2$** | **$NO_x$** | **$PM_{10}$** | **VOC** | **CO** |
|---|---|---|---|---|---|
| *Highest Offset Price (Nation-wide)* | $ 7,667 | $ 104,000 | $ 75,693 | $ 52,500 | $ 35,381 |
| *Average Offset Price (Nation-wide)* | $ 6,834 | $ 14,644 | $ 27,243 | $ 6,253 | $ 15,710 |
| *Lowest Offset Price (Nation-wide)* | $ 6,000 | $ 475 | $ 4,500 | $ 300 | $ 3,750 |
| *Highest Offset Price (Excl. California)* | $ - | $ 12,000 | $ 4,500 | $ 10,000 | $ 8,000 |
| *Average Offset Price (Excl. California)* | $ - | $ 5,531 | $ 4,500 | $ 3,642 | $ 8,000 |
| *Lowest Offset Price (Excl. California)* | $ - | $ 475 | $ 4,500 | $ 300 | $ 8,000 |

# 5. NSR Impacts on Capacity Additions

The purpose of this section is to summarize data from relevant studies or articles on topics related to NSR and investment in new generating capacity. This section is based on a literature search about the impact of NSR on new power plants. Though numerous articles discussed legal aspects of NSR, only a small number directly discussed the impacts of NSR on the location of new utility plants.

In summarizing the literature on the impacts of NSR on new construction, the primary question was whether or not NSR had affected the economic behavior of new plant owners or developers. In other words, did NSR change the course of new plant construction, or would the same new plants have been built with or without NSR? No studies nor could be found that answer this question. Consequently, three sub-questions were developed, and, taken sequentially, they provide indicators for the primary question. The sub-questions include:

*Do the requirements of NSR affect the cost of new plants?*

In order for NSR to have an impact on the location of new plants, it must affect the cost or revenues of new plants.

*Has NSR changed the economics of new plants?*

If NSR influenced either the cost or revenues of new plants, was it sufficient to change the economics or financial outlook for new plants?

*Have utilities and developers responded to the changes in economics of new plants resulting from NSR?*

If NSR changed the economics or financial outlook for new plants, did power plant owners and developers fully internalize the changes and then adjust their decision process?

<u>Do the requirements of NSR affect the cost of new plants?</u>

Based on the literature survey, NSR has affected the cost of new plants in a formal and informal way. Formal impacts include the quantifiable costs of pollution control and the direct costs associated with permitting. Informal impacts include intangible elements such as real or perceived regulatory barriers, public opinion about the new plant, and permitting delay cost.

The cost of building a new plant is dependent, among other things, on pollution control equipment mandated by NSR requirements. Major new sources in attainment areas, for instance, are required to install Best Achievable Control Technology (BACT) and satisfy Prevention of Significant Deterioration (PSD) requirements. Although state agencies can determine BACT taking into account energy, environmental, and economic impacts, BACT cannot be less stringent than NSPS requirements. In non-attainment areas, major new sources need to install Lowest Achievable Emissions Rate (LAER) technology and provide offsets for the emissions from the new source[21]. Whether in attainment or non-attainment areas, new coal-fired plants at a minimum must include pollution control

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[21] Parker, Larry and Blodgett, John, "Electricity Restructuring: The implications for Air Quality," Congressional Research Service Report for Congress, Updated January 2001.

equipment for $SO_2$ and $NO_x$. Estimates of pollution control costs have been varied. The Congressional Research Services (CRS) estimated that pollution controls for $SO_2$ cost 0.53 cents/kWh (1995 dollars), while controls for $NO_x$ cost 0.17 cents/kWh.[22] A study by $E^3$ Ventures, Inc. estimated environmental costs for new coal-fired plants to be about 0.5 cents/kWh.[23]

Some reports have discussed the costs associated with NSR permitting. One author concluded that it would be "prudent to involve environmental managers, operations personnel, management, consultants, and legal counsel in process".[24] Although the article does not provide any indication of what the costs might be, it can be inferred that time spent by some or all of the suggested personnel would imply some cost, albeit a small fraction of the total project cost.

Many reports have discussed the informal impacts of NSR on the costs of new plants, although these costs are generally difficult to quantify. Perhaps the most visible of these impacts is the involvement of the public in the permitting process. NSR is an example of a program that explicitly calls for public involvement, including a right to contest permitting decisions. In an article discussing public participation in the review process, one author wrote that "opposition is widespread…a significant movement of grass root activists".[25] This article provides summaries of case studies on how public involvement terminated or changed the proposed project.

Alliant was so sensitive to public opinion that, even before considering a new coal-fired plant in Iowa, the company surveyed its customers to assess their receptiveness to a coal-fired plant, indicating that a survey was necessary because "the industry in general has been battle scarred."[26] The Alliance of Energy Suppliers[27] suggested that public relations and education be explicitly included in the project development budget for a new plant. In New York, Heritage Power LLC negotiated siting and operation permits for an 800 MW natural gas-fired combined cycle facility with approval conditions that included the source providing public benefits to the county.[28]

A few reports also discuss legislative barriers to new plants, although it is unclear whether these barriers were real or perceived. In announcing a new gas-fired plant in Mississippi, a spokesperson for Duke Energy concluded that the Clean Air Act restricted the construction of new coal-fired plants.[29] On the other hand, a recent

[22] Ibid., Table 5.

[23] $E^3$ Ventures, Inc., "Plain Language Guide to Power Investments", March 2001.

[24] Belden, Roy S., "Navigating the Permit Process," Independent Energy, May/June 1995, pages 56-59.

[25] Deisinger, Chris, "The Backlash Against Merchant Plants and the Need for a New Regulatory Model," Electricity Journal, December 2000.

[26] "Alliant Gets Ahead of the Curve in Coal Plant Strategy," Coal Week, April 23, 2001.

[27] Picardi, Al, Hodges, Mark and Tarr, Nancy, "Fast-Track Development Strategies," Electric Perspectives', March/April 2001. Posted on Alliance of Energy Suppliers website, URL:// www.eei.org/alliance.

[28] Fitting, Beth, "State Oks Building New Power Plant," Business Journal, February 9, 2001, page 1.

[29] Gillette, Becky, "Power Plant Construction in Mississippi Has Major Economic Impact," Mississippi Business Journal.

news report indicated that 34 new coal-fired plants totaling 20,000 MW had been proposed.[30] It is difficult to determine if NSR is a perceived or real regulatory barrier to the construction of a new coal-fired plant, since the recent announcements of proposed plants may have been motivated by high gas prices and electricity shortages.

Some of the available literature asserts that the NSR process is long and can be cumbersome. For example, after evaluating NSR and NSPS, the National Coal Council concluded that "permitting is a lengthy process" that can last years.[31] Some literature suggests that the lengthy permitting process might have an important informal impact on the cost of new power plants, since it often leads to some loss in flexibility. The Alliance of Energy Suppliers warns its members that "unexpected delays or unforeseen permitting difficulties are almost always costly and, at the extreme, can kill a project." This article adds that lengthening the permitting time from a few months to a year not only increases the cost of the project several times but also implies lost sales revenues.[32]

Has NSR changed the economics of new plants?

To answer this question, the literature was searched for data indicating change in the relative costs of different types of new plants due to NSR. If, for example, coal was the preferable fuel before NSR, is there any evidence that NSR changed that preference? In summary, the available literature is inconclusive. The search suggested that more data are needed to quantify the impacts of NSR on the economics of new plants.

In 1998, Resources Data International (RDI) released a study naming the top ten utility winners and losers due to the impacts of the Clean Air Act. RDI reported that the winners would incur no new costs and losers would incur high costs in meeting new regulations.[33] Although the study targeted existing utilities, it concluded that clean air requirements could penetrate through to the bottom line – revenues and asset values.

A more recent article evaluates the potential for new plants in California. Based on rates of return on investment, the author concluded that there are sufficient returns to attract new power plants to California despite the many inherent risks. The author wrote that "environmental constraints and/or opposition to power plant siting are the only serious impediments to new power plant construction in California".[34] In a similar vein, the National Coal Council reported that the cost of new pulverized coal-fired plants fully equipped with NSR required control technology is lower than the cost of existing coal-fired plants, and NSR plants can be more utilized much more fully than existing coal-fired plants.[35]

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[30] Reuters News Agency, June 5, 2001.

[31] "Increasing Electric Availability From Coal-Fired Generation in the Near-Term," The National Coal Council, May 2001, Page 27.

[32] Picardi, Al, Hodges, Mark and Tarr, Nancy, "Fast-Track Development Strategies," Electric Perspectives', March/April 2001. Posted on Alliance of Energy Suppliers web-site: URL://www.eie.org/alliance.

[33] Lobsensz, George, "A New Top 10 List Names Utility Winners, Losers from Clean Air Impacts," Energy Daily, October 27, 1998.

[34] Schmidt, Michael, "California's Power Gamble: Long Term Contracts," Public Utilities Fortnightly, page 40.

[35] The National Coal Council, "Increasing Electricity Availability From Coal-Fired Generation in the Near-Term," May 2001.

Some of the surveyed literature attributed the decline in new construction to non-NSR impacts. In a recent news release, Reuters reported that 34 new coal-fired plants totaling over 20,000 MW have been announced.[36] This observation from Reuters is interesting because it marks a sharp departure from the past decade, when very few new coal-fired plants have been built. At the same time, it must be noted that this observation was made in the context of historically high prices for natural gas. A report by the CRS suggested that the smaller number of new coal-fired plant construction over the past decade may be due to the fact that natural gas-fired plants were the technology of choice in deregulated electricity markets. The CRS report contended that the decline in new coal-fired capacity, operated as base load capacity, also may have been due to the current surplus in base load capacity. Furthermore, the report contended that current average capacity margins of 15 percent (ranging from 13 to 18 percent) could increase to 15.6 percent by 2008 if announced new non-utility plants come online as anticipated.[37]

In evaluating whether NSR has had an impact on the location of new power plants, it is important to consider whether the formal or informal impacts of NSR have realigned the cost economics of new power plants. One article reviewing the broader impacts of environmental regulation argued that emissions control projects were as much a response to competitive pressures as to environmental regulations. Quoting a project manager at Connectiv, the article stated that long-term commitments with environmental equipment suppliers were important to overall project execution.[38] Similarly, the New York State attorney general said low demand and not environmental regulations had led to few plants being built. He urged the Senate Environment and Public Works Clean Air subcommittee to hold hearings to "reject the spurious claim that environmental protections are the cause of the energy squeeze we see today."[39] Along similar lines, a comment received by the National Coal Council for their report indicated that there were no environmental barriers to installing clean coal technologies. Rather, the comment added that "economic issues are the major barriers, since these technologies are not competitive with either the existing plants/technologies or the combined cycle natural gas-fired plants."[40]

Some studies also challenged the notion that the informal impacts of NSR were distorting the economics of new power plants**.** Testimony by David Hawkins, Natural Resources Defense Council to the House Committee on Science disputed industry claims that either EPA's interpretation of its NSR rules had changed or that such interpretation will prevent expansion of electricity or gasoline production at existing plants. Mr. Hawkins presented a detailed chronology of industry activities which he concluded proved these claims were false.[41] In

[36] "New US Coal Plants to Power 20 Million Homes," Reuters, June 5, 2001.

[37] Parker, Larry and Blodgett, John, "Electricity Restructuring: The implications for Air Quality," Congressional Research Service Report for Congress, Updated January 2001.

[38] Schimoller, Brian K., "Balancing Compliance with Competition," Power Engineering, October 1999, page 22-28.

[39] Karey, Gerald, "Environment Should Remain Energy Issue: Protections do not lead to market glitches: Testimony," Platts Oilgram News, April 6, 2001.

[40] "Increasing Electric Availability From Coal-Fired Generation in the Near-Term," The National Coal Council, May 2001. Comment from Manoj Guha (mkugha@aep.com), page 71.

[41] Testimony to the House Committee on Science, May 23, 2001

another hearing, the Executive Vice President of TVA stated that he believed the implementation of NSR programs had not discouraged improvements in efficiency.[42]

Have utilities and developers responded to the changes in economics of new plants brought about by NSR?

The survey of the available literature on NSR, which is sparse, does not conclusively indicate whether power plants responded to changes in the economics of new plants caused by NSR. There is some evidence that power plant owners have internalized the impacts, but whether that led to changes in economic behavior is unclear.

One study examining the interplay between environmental regulations and deregulation concluded that as power plant owners gained experience in complying with environmental regulations, business acumen was being sharpened. Using the Big Bend power plant owned by Tampa Electric Company as a case study, the report argued that successful power plant owners had skillfully adapted the requirements of environmental regulations to deregulated electricity markets.[43]

Most trade press reports announcing new construction quote power plant managers as being attentive to the physical issues (e.g. zoning restrictions, fuel supply source, grid access, water availability) related to new plants.[44] At the same time, most companies announcing new power plants normally include a statement about how the plant provides an environmentally superior source of electricity. In some instances, like with the Athens power plant in New York, plant owners have responded to public opposition by making physical or site adjustments to the design of power plants.

## Review of Public Statement and Reports

### Background

This section examines the extent of planned capacity expansion in the electric generating sector. ICF Consulting reviewed public statements made by electric generating companies regarding plans for capacity expansion over the next 5 years. SEC filings (10-Ks), annual reports, company press releases, and newspaper, magazine, and specialized journal articles also were examined. To provide context and background, projections of capacity requirements and summary information on planned additions also were reviewed.

With electricity demand increasing, increased generating capacity is needed to maintain the balance between supply and demand. The National Energy Policy report states that U.S. electricity demand is projected to grow 1.8 percent a year over the next 20 years, requiring an addition of 393,000 MW of capacity.[45] To meet this projected demand, the report states that between 1,300 and 1,900 new power plants must be built over the next two

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[42] Testimony to the Senate Environmental and Public Works Subcommittee on Clean Air, Wetlands, Private Property and Nuclear Safety, February 28, 2000.

[43] Schimmoler, Brian K., "Balancing Compliance with Competition," Power Engineering, October 1999, page 22-28.

[44] Numerous trade press reports. One good source is: Gillete, Becky, "Power Plant Construction in Mississippi Has Major Economic Impact," Mississippi Business Journal, January 31, 2001, page 12.

[45] National Energy Policy Development Group. "National Energy Policy", May 16, 2001, p 1-4.

decades.[46]The U.S. Energy Information Administration (EIA) also projects a need for an additional 96,000 MW by 2005 and 231,000 MW (cumulative) by 2010.[47]

Estimates on planned electric generation expansion vary greatly by source and change over time as corporate plans change. Aggregate expansion estimates vary; indeed, reports and press statements from the same company can change over time. The ICF report presents findings on an aggregate national level and for a selection of individual companies and specific fuels. A study performed by MSB Energy Associates on behalf of the Clean Air Task Force estimated proposed new gas-fired capacity by 2004 to range from 158,000 MW to 165,000 MW for the area covered by the study, which included projects within the Eastern Interconnect[48] and ERCOT [49]. Duke Energy states in its *Year 2000 Overview* that U.S. consumers will demand more than 200,000 additional MW of capacity – nearly a 25 percent increase – within the next decade.[50]

**Summary of Selected Announcements of Expansion Plans**

A review of public statements in journals, press releases, and corporate annual reports revealed expansion plans on the part of many major U.S. electric generating companies. Data were not readily available for all major generators, but the data for many companies are summarized and presented in this section. Companies give forward looking corporate plans in varying levels of detail (e.g., some by subsidiary, some only for the holding company, with and without indications of time frames). Where available, current generating capacity data are provided. A summary of findings is summarized below in Figure 12.

**Figure 12: Summary of Selected Planned Development Activities Based on Public Statements**

| Parent Company | Subsidiary | Current Capacity (MW) | Capacity Under Development (MW) |
|---|---|---|---|
| Calpine Corp | | 5,850 | 29,000 |
| Duke | North American Wholesale Energy | 9,000 | 23,000 |
| PSE&G | | 10,000 | 14,000 |
| PG& E Corp | National Generating Group | 7,000 | 10,000 |

[46] National Energy Policy Development Group. "National Energy Policy", May 16, 2001, p.xi.

[47] US Energy Information Administration (EIA). Annual Energy Outlook 2001 with Projections to 2020, Table A9 Electric Generating Capability. http://www.eia.doe.gov/oiaf/aeo/pdf/aeo_base.pdf

[48] Deisinger, Chris. "The Current Surge of Independent Power Development", MSB Energy Associates, July 10, 2000. http://www.msbnrg.com/MSB-_PEC_White_Paper.html#AppendixA.

[49] The North American bulk power system includes three major transmission interconnections or grids: ERCOT (which encompasses a large part of Texas), the Western Interconnect (which includes most of the Western States), and the Eastern Interconnect (which includes the Midwest, Southern, and Eastern States, and parts of Canada).

[50] Duke Energy Year 2000 Overview. http://media.corporate-ir.net/media_files/NYS/DUK/reports/2000ar/overview.htm

| | | | |
|---|---|---|---|
| Mirant | | 20,000* | 9,000 |
| Dominion | | 19,000 | 9,000 |
| Constellation Energy Group | Constellation Energy Services | 9,000 | 9,000 |
| FPL Group | FPL Company | 17,700 | 6,000 |
| FPL Group | FPL Energy | 4,100 | 2,700 |
| NRG Energy, Inc. | | 15,000 | 5,515 |
| AES Corp | | 10,500 | 3,500 |
| Reliant Energy | | 9,231 | 2,766 |
| Cinergy | Cincinnati Gas & Electric Company and PSI Energy, Inc | 21,000 | 1,700 |
| Note: This table is not exhaustive but illustrates the expansion plans of selected companies based on public statements. | | | |
| *Global capacity | | | |

**Fuel Types and New Capacity**

Planned new facilities are predominantly natural gas-fired plants, but some new coal-fired capacity expansion also has been announced. The companies cited in the previous section of this report made expansion announcements predominantly about new gas-fired units. However, a recent article reported that 34 new coal-fired plants, amounting to approximately 20,000 MW, are being planned for construction over the next 12 years.[51] Many of these plants are reportedly planned for large coal mining states, particularly Wyoming and Kentucky.

According to EPA's Office of Air Quality Planning and Standards, a PSD permit has been granted for 2 new coal-fired boilers as part of a 1000-1600 MW plant in Arkansas scheduled to come on line in the near future. EnviroPower of Indiana, LLC has two permit applications under review for 2 250 MW coal-fired boilers. Kentucky has 5 coal-fired boilers, ranging in capacity from 110 MW to 1,500 MW, for which permit applications are under review.[52]

As noted in the background section at the beginning of this document, if a major modification occurs at an existing power plant, that plant becomes subject to NSR. The regulations governing which actions at

[51] "New U.S. Coal Plants to Power 20 Million Homes". Reuters, June 5, 2001.

[52] Response to STAPPA/ALAPCO Questions to State and Local Officials on Mercury Utility Boiler Emissions Test Data, STAPPA/ALAPCO, May 15, 2001.

existing sources trigger new source review requirements are complex, and involve making distinctions between routine and non-routine maintenance, and in calculation of emissions prior to and after changes are to be made. As a result, it may be appropriate to examine whether repairs that restore lost capacity and component upgrades that improve efficiency may be discouraged by NSR. It may also be appropriate to examine the extent to which NSR rules concerning the modification of existing facilities promote or deter investment in new utility and refinery generation capacity, energy efficiency, and environmental protection. Some have argued that the modification rule deters modifications at existing plants, especially where the emissions increase is significant, but the increase in generating capacity is not.

In a report to the Secretary of Energy[53], the National Coal Council (NCC) examined data in the North American Electric Reliability Council's GADS database, and found that coal-fired units over 20 years of age (approximately two-thirds of total coal-fired generating capacity) had been substantially derated, compared to units less than 20 years of age. The NCC concluded that: "If all existing conditions resulting in a derating could be addressed, approximately 20,000 MWs of increased capacity could be obtained from regaining lost capacity due to unit deratings." The NCC further stated that: "These approaches and techniques could only be logically pursued by the facility owners if it was clearly understood that the increased availability and/or electrical output would not trigger New Source Review (NSR) and if repowering or construction of new clean coal technologies would be subject to the streamlined permitting authorized by the 1990 CAA Amendments."

# 6. NSR Impacts on Energy Efficiency Improvements

Electricity generators often have opportunities to improve their generating efficiency. One measure of such efficiency is the amount of electricity generated per amount of fuel consumed. The reduced cost of fuel per megawatt generated provides a strong economic incentive to make such improvements. On a megawatt basis, such changes also reduce pollution (though if a generator uses the more economical, upgraded unit more often as a result, total emissions can still increase). Another measure of efficiency is the amount of electricity generated per unit of emissions. EPA did not find any research specifically addressing how the NSR program impacts generators' ability to make these types of changes. However, a number of issues have been raised recently by industry in the context of specific projects.

One example is a case raised by Detroit Edison. The company proposed to replace and reconfigure the high-pressure section of two steam turbines at its Monroe Power Plant. The purpose of this proposed project was to upgrade energy efficiency. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Yet because this proposed project would result in substantially improved efficiency compared to the original design, EPA considered it a physical change under its NSR regulations, and if it were to result in a significant increase in emissions, the units would be subject to NSR. It has been asserted that this decision will lead to less investment in efficiency improvements as opposed to the normal replacement of the damaged blades. However, no specific information is available on how the costs of NSR (e.g.,

[53] National Coal Council, Increased Electricity Availability From Coal-fired Generation in the Near-Term, p.9, May 2001.

control technology, permitting expense, etc.) alter the economics of the project, or whether they make the project no longer economically attractive. Nor is information available regarding the extent to which this kind of project would or would not increase emissions.

Another example is combined heat and power (CHP) units, which can be used to replace existing industrial boilers. They can provide both steam to the industrial facility and electricity to the public. They emit significantly fewer emissions than the existing boilers they replace. Because of how NSR regulations define a single source, power companies assert that these facilities are not being brought on line in greater numbers. There is also the assertion that NSR may cause CHP operation for small plants (e.g., 15 MW or less capacity) to be uneconomic.. Absent the complicated NSR requirements, the companies claim that many older, higher emitting boilers would be replaced by these more efficient units. Again, no specific information is available on the relative effect of NSR on the overall viability of such projects.

The final example of how NSR allegedly hinders efficiency improvements in electrical generation is the use of foggers. Duke Power proposed a project that involved the installation of inlet air foggers on combustion turbines (CTs) at the Duke Power Lincoln Combustion Turbine Facility. Duke Power, which operates 16 simple cycle CTs at the Lincoln facility, proposed to install inlet air foggers on each CT to increase power output during periods of high ambient temperatures. Use of foggers allows combustion of additional fuel and, thus, greater power output at the same ambient temperature. Despite more fuel combustion, the possibility exists that nitrogen oxides emissions actually decrease when foggers are turned on. The project was considered a physical change under NSR regulations, and appropriate safeguards were required to ensure that the emissions did not significantly increase as a result of the change. It is claimed that this decision makes it harder to use the foggers and increase the output of existing units.

A May 2001 report by the National Coal Council [54]discussed the impact of regulatory policy on efficiency improvements at existing coal-fired power plants. The report stated, "EPA has further indicated that it will treat innovative component upgrades that increase efficiency or reliability without increasing a unit's pollution producing capacity as modifications as well. EPA's current approach to these projects strongly discourages utilities from undertaking them, due to the significant permitting delay and expense involved, along with the retrofit of expensive emission controls that are intended for new facilities. This is the greatest current barrier to increased efficiency at existing units." To support this conclusion, the NCC identified two EPA determinations, one involving Detroit Edison Company in May 2000 (discussed above), the other involving Sunflower Corporation in 1998, in which EPA ruled that improved, higher efficiency turbine blades could not be used to replace less efficient blades that had broken, without invoking new source review and associated costs for additional pollution controls.

# III. Petroleum Refining Industry

## 1. Historical NSR Permitting Data

[54] National Coal Council, Increased Electricity Availability From Coal-fired Generation in the Near-Term, p.9, May 2001.

This section presents a summary of the available data for NSR permitting for the refining industry. As described above for the utility sector, most of the available information about NSR permitting comes from the EPA Regional Offices. Limited data are available for refineries, because only a small number of permits have been issued for this sector. For this report, only PSD data were used, because sufficient nonattainment NSR information is not available. A review of PSD permit data found that there have been 11 PSD permits issued involving refineries since 1997. All of these permits were for modifications at existing refineries. The average permitting time from application to issuance was 5.2 months. Information is not available to determine the increase in refining capacity as a result of these PSD permits. However, information presented later in this section discusses overall capacity trends in the refining industry.

**Refinery Enforcement Actions**

Based on investigations conducted over the past 4 years, EPA and several states have taken enforcement actions against owners and operators of several refineries alleging that modifications were made at a number of U.S. refineries that should have undergone NSR permitting.

For example, refineries have undertaken a variety of projects to increase the capacity of fluid catalytic cracking units (FCCUs):

Increasing or modifying the air flow to the FCCU regenerator, resulting in an increased coke burn rate and increased emissions;

- Modifying slide valves to increase catalyst circulation and throughput, but also increasing coke burn and emissions;

- Increasing wet gas compressor capacity;

- Modifying risers and/or feed distribution systems;

- Installing more/larger cyclones and/or overhead gas coolers; and

- Rebuilding/replacing the FCCU regenerator or the reactor.

EPA has gathered data from 13 companies with 48 plants. EPA filed notices of violation of NSR for eight refineries. For five of the refineries, the refinery obtained a minor NSR permit based on what EPA believes were incorrect estimates that concluded there were no emissions increase resulting from changes at the refinery for at least one of the actions cited in the notice of violation. EPA brought enforcement actions against owners and operators of new units based upon the failure to go through NSR (e.g., for the construction of new crude and vacuum distillation units or the reuse of a sulfur recovery unit from another refinery), improper netting analyses, and the provision of erroneous emissions information.

To date, EPA has reached four company-wide settlements with the following companies: Koch, BP-Amoco, Motiva/Equilon/Shell, and Marathon Ashland Petroleum. These settlements involve 27 refineries and approximately 29 percent of domestic refining capacity (4,760,000 barrels per day). The estimated cost of implementing the control equipment aspects of all of the consent decrees is $1.3 billion. EPA estimates that these settled cases alone will reduce NOx emissions by 43,200 tons per year (tpy) and SO2 emissions by 88,250 tpy. EPA also is engaged in company-wide settlement negotiations with additional companies.

# 2. Factors Affecting Investment in New Capacity

This section summarizes available data on how executives in the refining industry make decisions on whether or not to invest in new refining capacity. These data are the result of a literature search, conducted by ICF Consulting, Inc., of 35 sources of information from 19 industry, trade, and financial publications from 1971 to 2001. ICF then summarized factors affecting corporate decisions, which are presented here in order of relative importance according to the literature.

A decision to invest in new refining capacity or expand an existing refinery requires simultaneous evaluation of strategic and siting considerations and permitting issues. Refining company executives in general are responsible for ensuring the financial health of the corporation and providing a rate of return (ROR) on investment that is acceptable to investors. Company officials and developers typically do not enumerate the relative importance of different factors in evaluating projects. Rather they seek to identify the impact of all the different elements on the ROR of each potential investment option. An investment's ROR is the most common metric by which investors organize, standardize, and evaluate all pertinent information in order to make an informed investment decision. Although decision makers often rely on ROR projections to make investment decisions for a new plant or for expansion of existing facilities, they remain sensitive to intangibles such as public opinion.

In general, there are three primary considerations in project investment decisions:

1. Strategic Considerations: whether a market that a refinery will furnish products to is likely to be most profitable for operations.

2. Siting Considerations: proximity to a pipeline system for transporting products, water availability, as well as local environmental and zoning issues.

3. Permitting Issues: time and cost of obtaining various permits, including air and operating permits, and the impact of public opinion on the permitting process for the new or expanded facility.

***Strategic considerations***. Strategic factors generally have the most impact on ROR. Capital outlay, energy prices, and production costs all have a large impact on ROR; in addition, uncertainty about prices and costs introduce risk in the investment decision. The other notable component of strategic considerations is environmental costs, primarily pollution control equipment. Such usually have a small to moderate impact on ROR.

Changes in fuel specifications (for example, as a result of government regulation of fuel or to meet voluntary industry standards) can trigger investment in new refining capacity. While refinery changes required to meet new fuel specifications generally do not increase capacity, they often can lead to voluntary decisions to increase capacity at the same time, because costs are lowered when capacity expansions are undertaken at the same time as other changes.

Similarly, investment in new capacity at petroleum refineries always has depended upon on the costs of crude oil and moving refined products to markets. Over the past 10 to 20 years, national and worldwide crude oil production centers have changed. Thus, proximity to foreign oil sources has a more pronounced role in product distribution decisions. For example, in one of the few cases where serious consideration was given to building a green field refinery (Williams Company's 18-month study of a possible Phoenix, AZ, refinery), one key factor that adversely impacted the project was the announcement of a new refined product pipeline that would link major refining centers in the California Bay area, San Joaquin Valley, and Los Angeles with Arizona and southern Nevada markets.

The relatively low cost of pipeline product movement favors large-scale refining centers over smaller niche market refineries, because the distant competitors' advantage in lower-cost production is not significantly reduced by the cost of product movement.

An additional factor influencing investment decisions is technology. Petroleum refining is one of the most technology-intensive industries, and refining technology is becoming more intensive and more expensive. Technology upgrades are economically difficult to recover in a flat marketplace. However, expansion of capacity and increased market share enhance the economics of technology conversions, because it leads to increased revenues.

Still another factor influencing investment decisions is the changing cost of expanding capacity. Many factors influence expansion costs, but the literature reveals one particularly interesting change – the availability of used refinery assets. As financially weaker refineries close, they sell their assets at from 3 - 10 percent of the cost of a new refinery. Furthermore, a closing refinery tends to enjoy local advantages – e.g., nearby support industries, skilled workers, and tax subsidies – that a green field location would not necessarily have. Buying and selling refineries and refinery assets has emerged as a very cost-effective way to enter or remain viable in the refining business.

A minor factor affecting the cost side of the investment decision is the cost of compliance with environmental regulations. All refineries are subject to nearly the same requirements, although their generally fixed costs tend to be smaller for a large refinery than for a small one. Pollution control costs are passed along in the price of the products. The literature search revealed only 5 references to pollution abatement issues, and no specific references to NSR, as factors influencing decisions to invest in new capacity.

***Siting considerations***. The literature search discovered only one decision that addressed siting a new greenfield refinery. The key factors in this decision appeared to be based on economics, product movements, and alternative options to buy an existing refinery. Similarly, decisions on whether to expand refinery capacity were clearly tied to the prospect of future profitability in the market.

According to the literature review, many refineries have closed since 1990 for various reasons, e.g., limited operating flexibility, inability to meet demand shifts, lack of capital needed to comply with environmental and anti-dumping rules, and low market demand for heavy oil products. Other factors that have affected profitability include: unusually warm winters, which dampened the heating oil market; low demand in 1991 due to economic recession; and decreasing gross margins. However, these factors continue to change over time. For example, refining margins were at record highs last summer, and high margins are continuing. Furthermore, refinery closures open product markets for larger, more profitable refineries. These newly opened markets create an incentive to increase capital intensity if there is an increase in profit per unit of output.

***Permitting Issues***. The literature search revealed only 5 references to pollution abatement issues, and no specific references to NSR, as factors influencing the decision to invest in new capacity.

# 3. Trends in Capacity and Utilization

This section summarizes the available data on trends in refinery capacity expansion and utilization. Existing data reveal that no new refineries[55] have been built in the United States in the past 20 years, and the number of existing refineries has fallen from 324 in 1981 to 149 in 2000. The decline in refineries in the early 1980s is due largely to removal of economic regulations that had previously had the effect of supporting small refineries. Between January 1, 1981, and January 1, 1984, 111 small refineries shut down. (Of these 111 refineries, 52 had operated for less than 10 years, many of them for only one to two years.) These data appear to support the argument that price controls and supply allocation resulted in the proliferation of small inefficient refineries. These refineries were unable to survive following deregulation, and probably would not have been built if regulations had not been in place.

Apart from the deregulation of the early 1980s, the data reveal a slower decline in the number of refineries. However, as the data show, total refinery capacity has increased over this period. Figure 13 provides data on the number and capacity of U.S. refineries from 1986-1999. The remainder of this section focuses on data from this time period, so that the effects of deregulation do not drive the results.

Figure 13: Number and Capacity of Total U.S. Operating Refineries (1986 – 1999)

| Year | Number of Operating Refineries* | Atmospheric Distillation Capacity for Operating Refineries (MMbpcd) | Mean of Atmospheric Distillation Capacity for Operating Refineries (Bpcd) | Median of Atmospheric Distillation Capacity for Operating Refineries (Bpcd) |
|---|---|---|---|---|
| 1986 | 189 | 14.94 | 79,050 | 46,200 |
| 1987 | 190 | 15.02 | 79,042 | 46,100 |
| 1988 | 186 | 15.01 | 80,709 | 48,250 |
| 1989 | 188 | 15.06 | 80,120 | 48,000 |
| 1990 | 178 | 14.96 | 84,038 | 53,500 |
| 1991 | 177 | 14.97 | 84,551 | 55,000 |
| 1992 | 168 | 14.78 | 87,958 | 56,750 |
| 1993 | 164 | 14.70 | 89,663 | 57,750 |
| 1994 | 159 | 15.08 | 94,853 | 62,500 |
| 1996 | 152 | 15.17 | 99,789 | 65,000 |
| 1998 | 149 | 16.06 | 107,795 | 72,500 |
| 1999 | 149 | 16.31 | 109,496 | 73,000 |

*The number of refineries column only accounts for those refineries with operating capacity on each given year. All subsequent graphs presenting number of refineries use this data.

Source: Energy Information Administration

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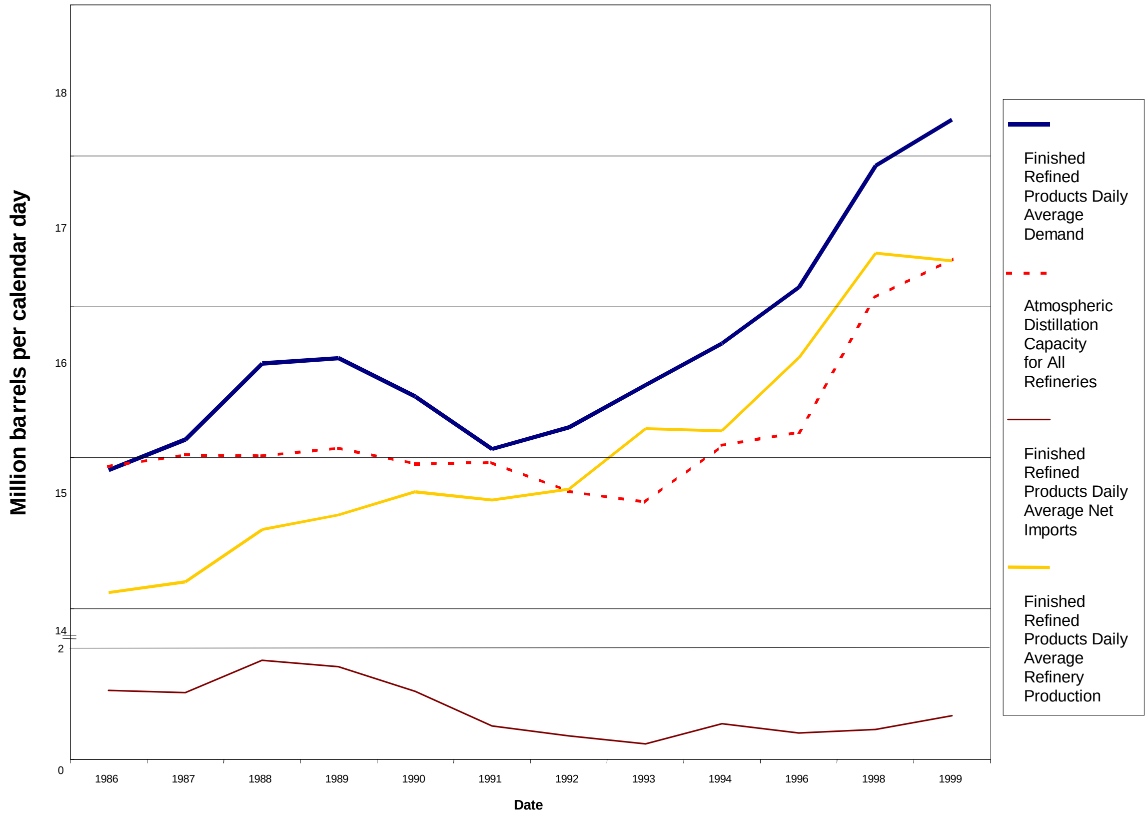
[55] Although no new greenfield refineries were built in the U.S. during this period all surviving U.S. refineries have been substantially rebuilt and revamped.

From 1986 to 1999 the number of U.S. refineries continued to decline, but the atmospheric distillation capacity (and other downstream capacities) continued to increase. Capacity creep maintained and increased overall capacity, despite the closures[56]. Large, efficient Gulf Coast refineries were able to take advantage of technological economies of scale to expand capacity while other refineries shut down. Between 1984 and 1999, 64 refineries shut down, 29 of them between 1990 and 1996. Most of the plants that shut down were smaller, simpler plants. Many of them filled a niche market or depended on the market for heavy fuel oil. Unfortunately, they were entering a period when growth was occurring in the demand for light products, and especially those with stringent specifications. In addition, in the latter part of the period many of the smaller refineries came under increasing pressure and competition from the large, efficient Gulf Coast refiners.

As shown in Figures 13 and 14, during the time period 1986 – 1999 the overall atmospheric distillation capacity of U.S. refineries grew. The increase in the closures and the temporary fall in capacity in the early 1990s were due to steadily decreasing prices, worldwide recession, and the resulting fall in demand. However, 1994 saw the recovery of demand and the steady growth of capacity additions. The remaining data in Figure 13 show the impact of economies of scale on the industry, driven in part by technological innovations. The average size of U.S. refineries grew steadily over this period, from approximately 79,000 barrels per day in 1986 to nearly 110,000 barrels per day in 1999. The median size also increased from about 46,000 barrels per day to 73,000.

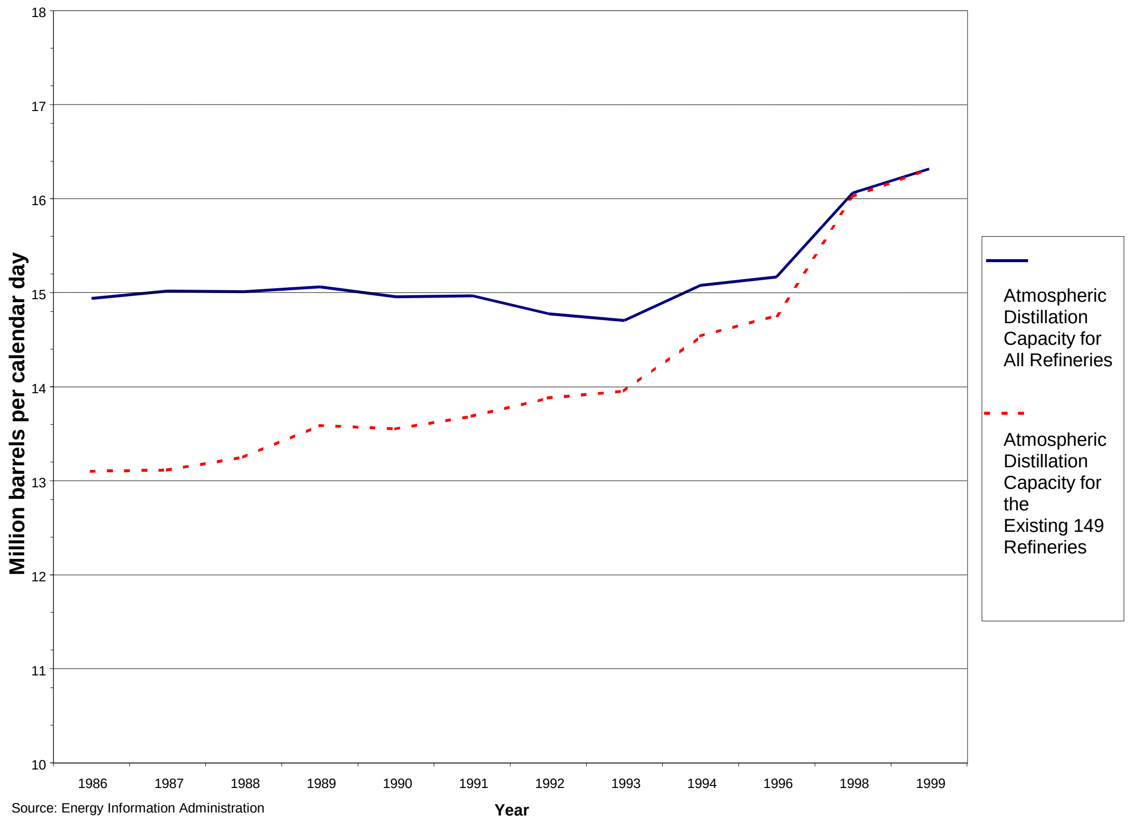
[56] Capacity creep is the accumulation of incremental capacity increases from normal optimization of refinery facilities and processes (e.g., installing bypass piping where flow bottlenecks exist).

**Figure 14: Total U.S. Atmospheric Distillation Capacity and Daily Average Supply and Demand of Finished Products (1986 to Present)**




Source: Energy Information Administration

**Figure 15: Atmospheric Distillation Capacity for Total U.S. Refineries and Surviving 149 Refineries (1986 to Present)**



Finally, Figure 16 shows the annual average capacity utilization for all U.S. refineries over the period. Utilization is measured by EIA as the atmospheric distillation capacity. There are some data available on the utilization of the downstream processing units, and that typically is also very high. Capacity utilization generally has increased during this time. The early years on the figure reflect some excess capacity and decreases in demand driven by economic downturns. However, the figure also clearly shows the effect of growing demand in the later years driven by increased economic growth.

**Figure 16: Total U.S. Refinery Utilization (1986 to Present)**

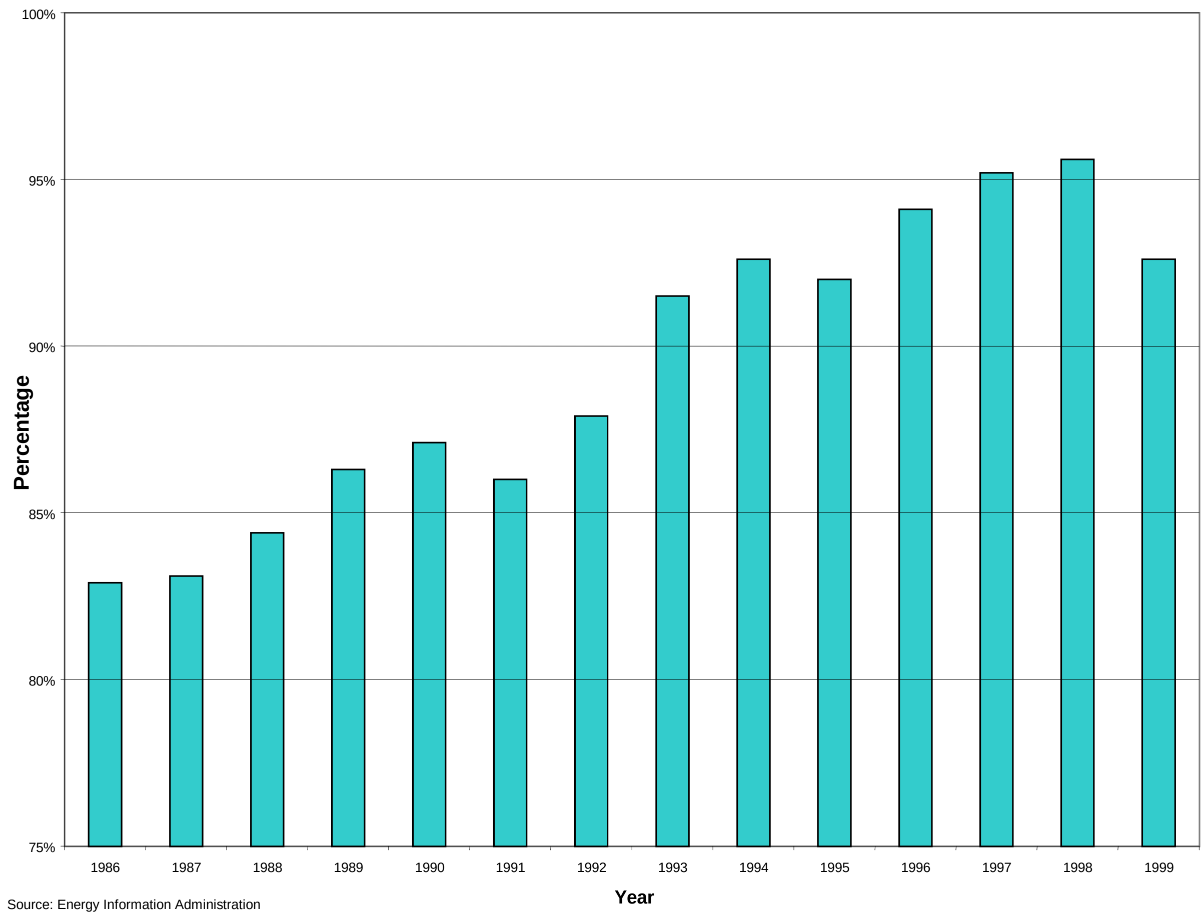
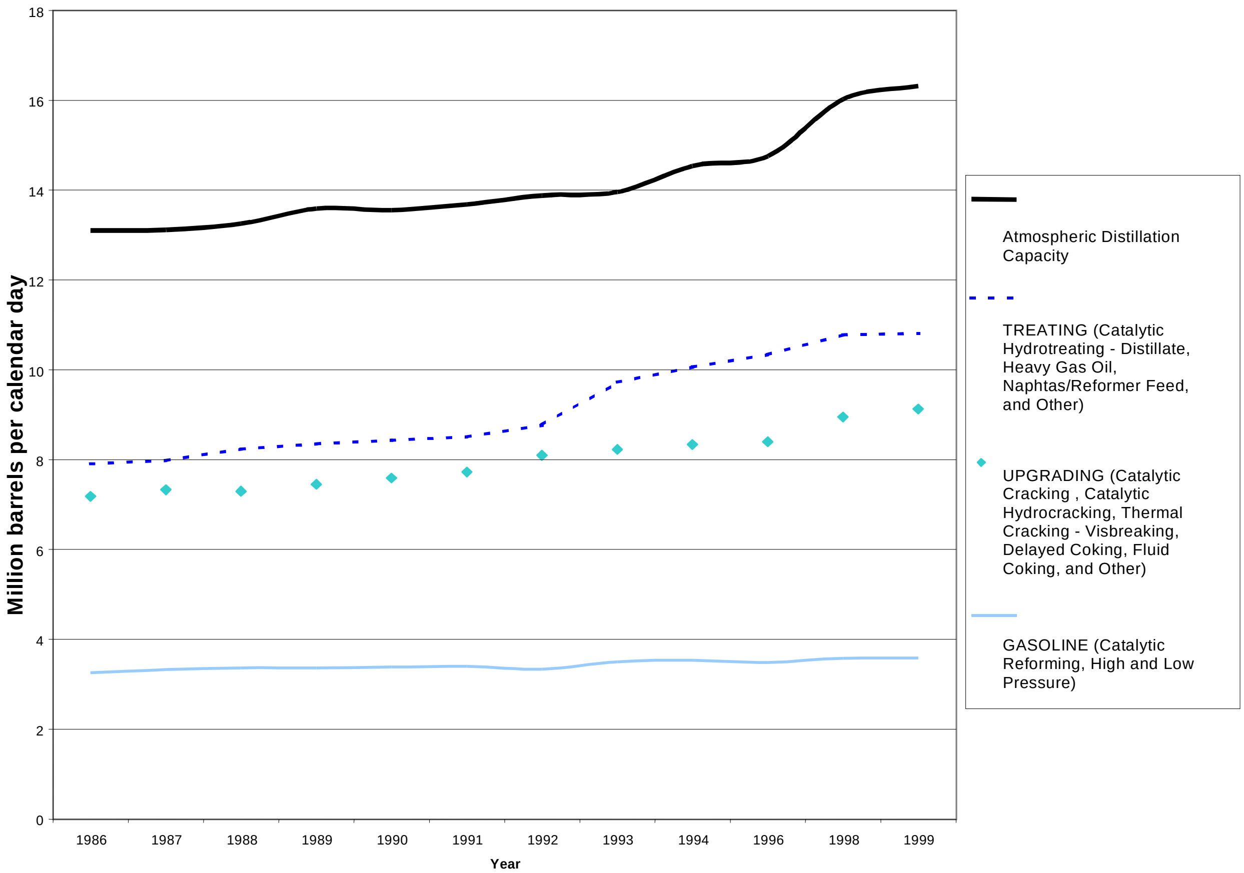


**Figure 17: Downstream Processes Capacity for 149 Refineries in Continuous Operation from 1986 to Present**

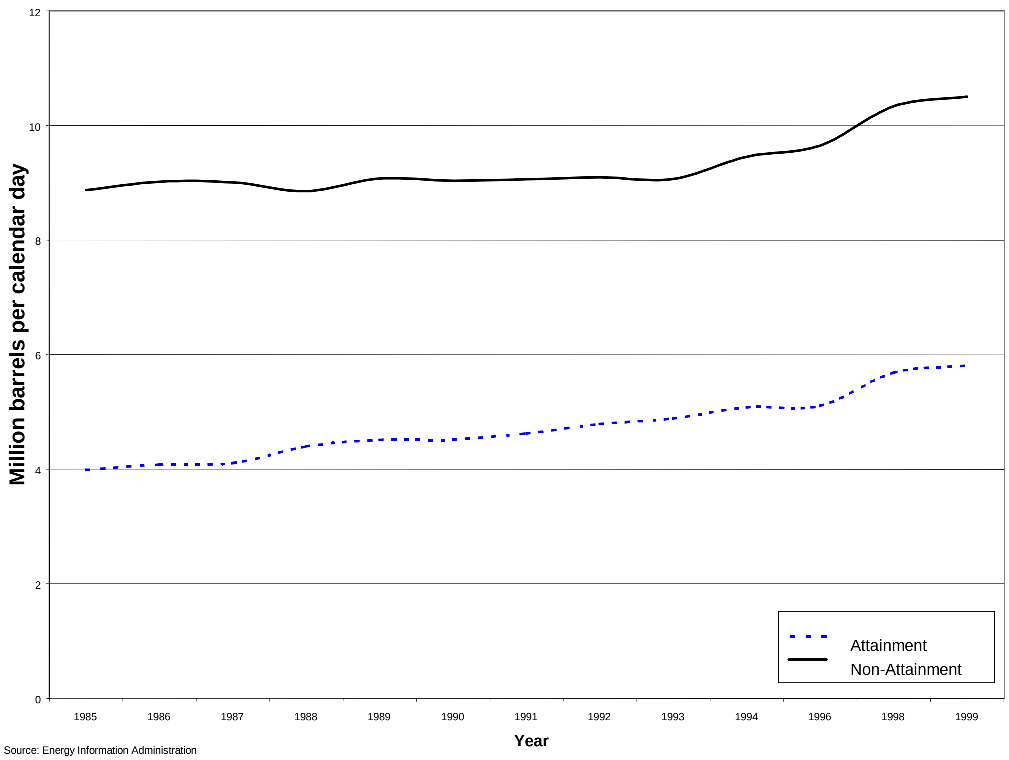



Source: Energy Information Administration

Figure 15 compares the atmospheric distillation capacity for all operating U.S. refineries to that of the surviving 149. As can be seen, the capacity of the 149 surviving refineries increased steadily over time. Figure 17 shows the growth of downstream processing capacity over time for these same 149 refineries. As Figure 17 shows, capacity, particularly for sulfur treating processes, has increased along with the overall increase in atmospheric distillation capacity. Capacity for upgrading heavy products (i.e., fuel oil) to light products (i.e., gasoline) continues to increase.

Figure 18 shows capacity for the 149 refineries divided between those located in attainment and non-attainment regions. Capacity is higher in nonattainment areas, as refineries tend to be clustered in high-population, industrialized areas with poor air quality. However, the rate of incremental growth is approximately the same whether in attainment or nonattainment areas, indicating that this is not a determining factor in investment in new capacity.

**Figure 18: Atmospheric Distillation Capacity for Attainment and Non-Attainment Regions for 149 Refineries in Continuous Operation from 1986 to Present**




Source: Energy Information Administration

# 4. Data on Costs of Pollution Controls

The purpose of this section is to provide an understanding of the relative importance of air pollution control costs relative to the cost of new refineries[57] and to the cost of capacity expansion at existing refineries. A review by ICF found data and information sources related to this issue to be limited. The Bureau of the Census collects data on pollution abatement expenditures whose primary purpose is environmental protection. (Some expenditures, such as investments in a catalytic process, have pollution abatement benefits but their primary purpose is to increase the yield and quality of a refined product).[58] Air pollution control costs are included here, but so are other pollution abatement expenditures, such as research and development and operating, maintenance, and direct administrative expenditures for legal fees, operating permits, restoration of sites, and Superfund taxes. The American Petroleum Institute (API) collects similar information – although it does not include the primary purpose qualifier – in a voluntary survey known as the Environmental Expenditures Survey (EES)[59] No data were available on the specific costs of compliance with NSR.

With respect to overall capital costs in the petroleum refining industry, there are two sources of data: the Bureau of the Census' 1997 Economic Census on Petroleum Refineries, and the Energy Information Administration's Financial Reporting System (FRS). The Economic Census collects data on total capital expenditures (new and used) for (1) permanent addition and major alterations to manufacturing establishments, and (2) machinery and equipment used for replacement and additions to plant capacity if they are of the type for which depreciation accounts are ordinarily maintained.[60] Exhibit 16 of the ICF report has a detailed listing of this data for annual estimates prepared for the years 1190 –1999.

The EIA's FRS is an annual survey that collects financial and associated operating information from the top 24 U.S.-based major energy-producing companies. The data are reported on a line-of-business basis, including the U.S. petroleum refining and marketing line of business. The FRS companies make up a major part of the U.S. refining industry. For example, from 1990 to 1995, the FRS companies' share of U.S. crude distillation capacity has ranged from 66 percent to 69 percent.[61]

An EIA report entitled *The Impact of Environmental Compliance Costs on U.S. Refining Profitability* ( October, 1997) incorporated FRS capital expenditures and the API and Census pollution abatement data into one

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[57] Although no new green field refineries were built in the U.S. during this period all surviving U.S. refineries have been substantially rebuilt and revamped; therefore, this section will focus entirely upon capacity expansion.

[58] If a technology's primary purpose is for the reduction of air pollutants, then it is listed as an air pollution abatement expenditure. But not all pollution abatement technologies are classified as abating a particular pollution category, like water, air, and solid/contained waste. Because of these difficulties, an analysis of pollution control technologies and their costs relative to particular air pollutants using census data has some limitations.

[59] American Petroleum Institute, Comparison Between the 1990-1993 API's Environmental Expenditures Survey and The Bureau of the Census' MA-200, Hazem Arafa, July 5, 1995.

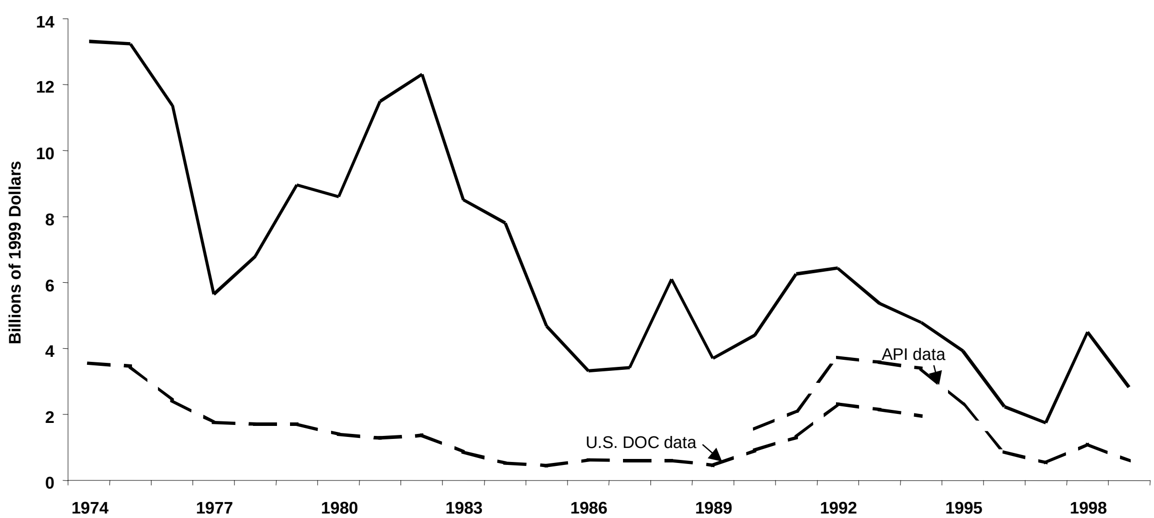
[60] U.S. Department of Commerce, Economics and Statistics Administration, The Bureau of the Census, *1997 Economic Census, Manufacturing, Petroleum Refineries*, September, 1999.

[61] The U.S. Department of Energy, Energy Information Administration, Office of Energy Markets and End Use, *The Impact of Environmental Compliance Costs on U.S. Refining Profitability*, October, 1997.

complete analysis of this question. This report concluded that approximately 7.6 cents of the $1.52 ($1995) per barrel decline in refining and marketing net cash margins between 1988 and 1995 was due to increased operating costs traceable to pollution abatement. Further, EIA concluded that of the 12 percentage point decline in the return on investment to major U.S. refining/marketing operations, slightly over one percentage point can be attributed to increased capital expenditures and operating costs for pollution abatement.[62]

Figure 19 shows the FRS companies' capital expenditures adjusted for inflation. The data show that, over time, capital expenditures for pollution abatement have accounted for a varying share of total capital investment, which was highest after the Clean Air Act amendments of 1990, but has diminished noticeably in recent years. The data also show that, despite varying pollution abatement expenses, a significant portion of capital investment is attributable to other areas, such as capacity expansion.

**Figure 19: Refining Capital Expenditures and Pollution-Related Capital Expenditures**




Sources: Overall refining capital expenditures: Energy Information Administration, Form EIA-28 (Financial Reporting System)

Pollution-related capital expenditures: 1974-1994: U.S. Department of Commerce; 1990-1999: American Petroleum Institute, *U.S. Petroleum Industry's Environmental Expenditures, 1990-1999* (Washington, DC, January 19, 2001).

Figure 20 shows a similar picture using a bar graph and total capital expenditure data from the Oil and Gas Journal.[63] The same conclusions can be drawn from this exhibit, which shows increased pollution abatement expenditures in the early to mid-1990s. It must be noted that API's pollution abatement spending is greater than the Census' pollution abatement spending in all years for which data were available for both sources (1990-1994). Therefore, the shaded API areas are represented as the difference between total API data and U.S. Census data.

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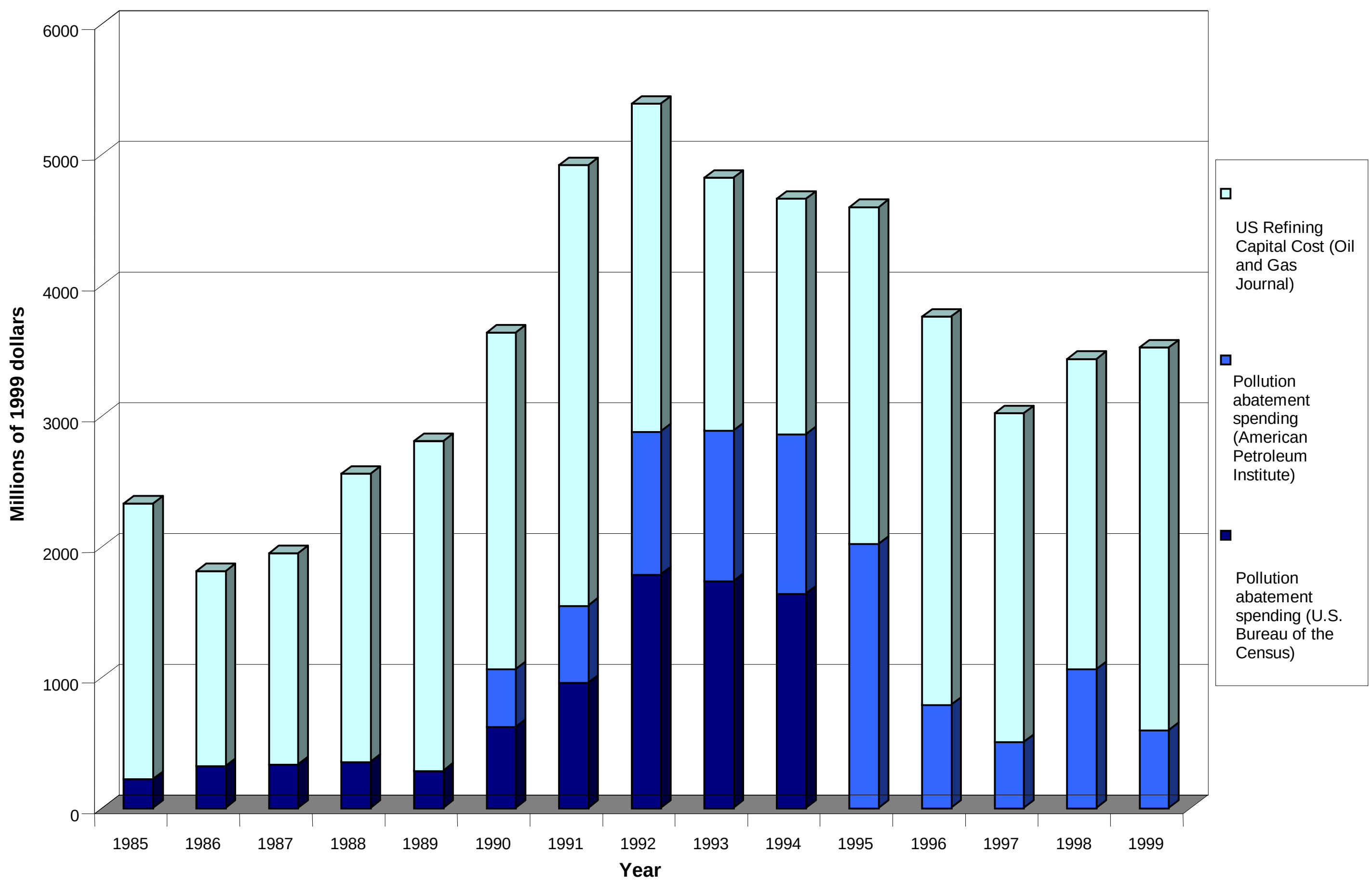
[62] Ibid.

[63] Oil and Gas Journal, *Capital Spending Outlook*, various issues.

# Figure 20: Historical U.S. Refining and Market Investments




<u>Sources</u>: Oil and Gas Journal - *Capital Spending Outlook*, U.S. Bureau of the Census - *MA-200*, American Petroleum Institute - *Environmental Expenditures Survey* .

Note: The shaded API areas in 1990-1994 are represented as the difference between total API data and U.S. Census data. Therefore, API data is greater in all common years.

# 5. Data on Refinery Profitability

The last two decades have seen considerable volatility in refinery profit margins. The gross margin peaked in 1980; since deregulation, it has generally decreased, as have operating costs. Net margins have followed the same pattern, with the mean net margin being $1 per barrel in 1999 dollars (from Exhibit 19 of the ICF report). NPC data, which cover a longer period, show net margin as negative in the mid-1980s.

**Figure 21: U.S. Refined Product Margins and Costs per Barrel of Petroleum Product Sold for FRS Companies (1990-1999)**

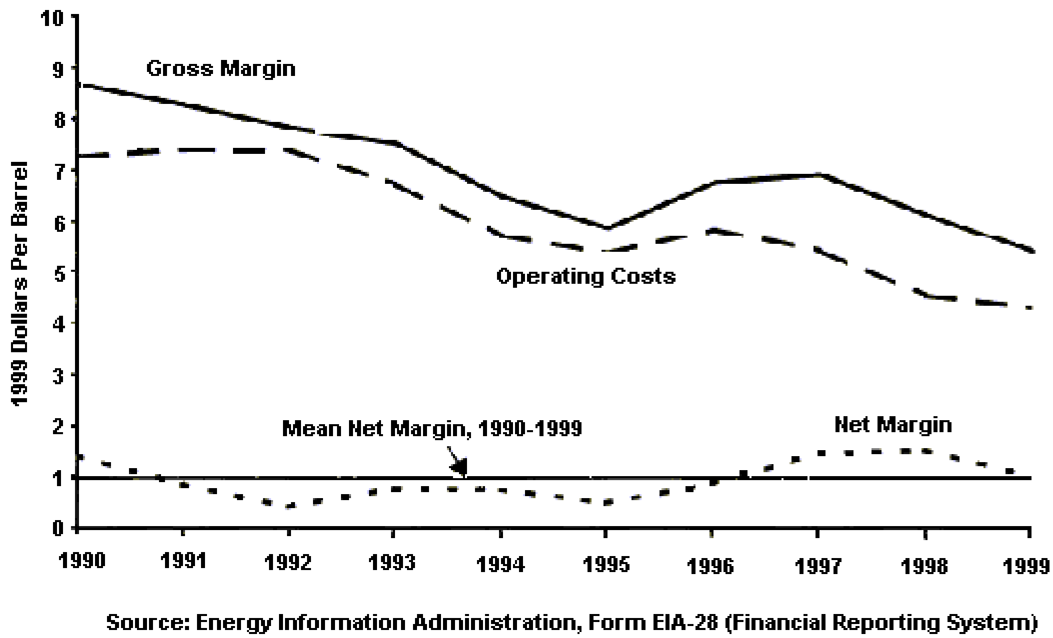



Figure 21 does not reflect the most recent data on margins, which are likely to increase substantially over 1999 data. Exxon-Mobil profits in the first quarter of 2001 were up over 51percent to $5.1 billion, Conoco was up 58 percent to $616 million, Chevron was up 53 percent to $1.6 billion, Texaco reported a 45 percent increase to $833 million in profits, and Phillips Petroleum was up 86 percent to $504 million

# 6. NSR Impacts on Capacity Additions

ICF conducted a series of directed literature searches seeking information on the impacts of NSR on refinery capacity. The review included approximately two dozen sources.

No studies were found specifically mentioning NSR's impact upon refinery expansion. However, many articles discussed NSR's impact on related issues that directly affect the expansion or changes at refineries, in particular, costs and technologies employed. Another group of studies either mentioned general regulatory effects on factors directly affecting capacity expansion, or that related to NSR but with no mention of capacity expansion.

The National Petroleum Council (NPC) reported in June 2000 on the ability of the Nation's petroleum refining and distribution infrastructure to deliver adequate petroleum supplies to consumers, given a number of recent regulatory initiatives requiring cleaner or better performing transportation fuels.[64] The NPC concluded: "The most critical factor in the U.S. refining industry's ability to meet new fuel requirements in a timely manner is the ability to obtain permits." Moreover, the NPC report noted the lengthy process for obtaining such permits and explained how that process could conflict with the relatively near-term need for improved, cleaner transportation fuels. The permitting steps outlined by NPC included:

- 3-6 months to prepare a permit application
- 1-3 months for the permitting authority to deem the application complete
- 3-6 months for the development and negotiation of a draft permit
- An unstated period for public notice and the opportunity to receive public comment on the draft permit
- An unstated period of time for the permitting authority to respond to public comments and take final action on the permit

Public statements by some oil company executives and organizations assert that NSR impedes U.S. capacity expansion. Generally, these statements express concern about NSR and other regulations on refinery expansions. Some general concern about recent NSR enforcement actions and their potential impact on expansion also is voiced in the literature. Moreover, specific cost or other decision-making data related to permitting are not directly addressed in the available literature. The search also revealed one positive statement from an environmental interest group about the environmental benefits of NSR at refineries.

ICF also looked at available public statements made by refinery companies regarding plans for capacity expansion over the next five years. Sources included SEC filings (10-Ks), Annual Reports, company press releases, and newspaper, magazine, and trade journal articles.

As a result of time constraints, the literature review focused primarily on a cross-section of the refining companies. 10Ks and annual reports were reviewed for a large integrated (Exxon-Mobil), an independent (Tosco), a medium (Sunoco), and a small (Murphy Oil) publicly owned refining company. Relevant press releases were collected for the largest refining companies, including Exxon-Mobil, BP Amoco, Chevron, Valero, Phillips, Marathon Ashland, Conoco, and Citgo. Article searches on the all-inclusive news database Lexis-Nexis and the Oil & Gas Journal complemented these refinery-specific searches. Other online sources included the Department of Energy's Energy Information Administration and the American Petroleum Institute.

Several companies, through their press releases and 10Ks, have expressed their plans to expand refining capacity:

*Citgo, a subsidiary of Venezuela's PDVSA, is studying investments of up to $300 million to expand capacity by 100 Mbbl/d at its Lake Charles, Louisiana, refinery.[65] Furthermore, Venezuela's President Hugo Chafes, during a visit to Texas, announced that Citgo's Corpus*

[64] National Petroleum Council, U.S. Petroleum Refining - Assessing the Adequacy and Affordability of Cleaner Fuels, June 2000.

[65] "Citgo to Invest Up to US $300 Million to Increase Refining Capacity." Business News America S.A., April 30, 2001.

*Christi refinery, while having plenty of room to grow, has no plans for expansion at this time. Texas State representative Jaime Capelo urged the Corpus Christi and Nueces County community to "see what [it] can do to include Corpus Christi in Citgo's expansion process."*[66]

*Alon USA, recent acquirer of TotalFinaElf's U.S. assets, reported that it has immediate plans to expand its refineries. Its first goal is to expand the Big Spring, Texas, refinery's crude distillation unit to 75 Mbbl/d. The company plans on reaching the 65 Mbbl/d-stage in 2002.*[67]

*After recently acquiring UDS, Valero expects to improve its profits by $195 million in the first year after the merger and $240 million in the second year. CEO Bill Greehey mentioned that these additional profits could be used to expand refineries.*[68] *Additionally, Valero is planning to expand FCC capacity by 12 Mbbl/d by 2004 at its Krotz Springs, Louisiana, refinery.*[69]

*TotalFinaElf's ongoing construction of a steam cracker near its Port Arthur, Texas, refinery, and the need for naphtha as a feedstock for a planned acrylic plant in Atofina's Bayport, Texas, polyethylene plant, will eventually "result in a sizable increase in the size of the [Port Arthur] refinery." According to refinery manager Dale Emanuel, while gasoline is highly profitable, the refinery will focus its attention to the production of feedstock for chemicals and the meshing of the refinery with the nearly completed steam cracker. Additionally, TotalFinaElf recently added a condensate splitter to its refinery, ultimately increasing capacity to around 220 Mbbl/d.*[70]

*Phillips allocated $246 million of its capital budget to Refining, Marketing, and Transportation. Funds will be used to complete a low-sulfur gasoline demonstration unit (beginning in 2001), a 20 Mbbl/d crude oil capacity expansion (beginning in 2002), and manufacturing automation at its Borger, Texas, refinery. Funds will also be used for environmental projects related to state-mandated emissions reductions at its Sweeney, Texas, refinery.*[71] *Furthermore, Tosco's refinery in Ferndale, Washington, will add a 30 Mbbl/d FCC unit to its facilities. This project will be completed in January, 2003.*[72]

*Murphy Oil's planned refining, marketing, and transportation capital expenditures in the U.S. for 2001 amount to $145 million. This includes spending on "greener fuel" projects at the Meraux refinery. The main component of the projects is the construction of a hydrocracker and its associated facilities. Furthermore, the company plans to enhance the refinery's crude unit to expand crude throughput capacity from 100 Mbbl/d to 125 Mbbl/d. Completion of this project is expected by mid-2003. Additionally, future plans include investing $25 million to expand sulfur recovery capacity by late 2002.*[73]

*Chevron plans to invest $600 million in its U.S. refining and marketing sectors. The company "will continue to make investments to improve safety, reliability and profitability in its refining segment."*[74]

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[66] "Chavez Denies Dictator Rumors; Venezuelan Chief Also Says Refinery Isn't Due Increase." Corpus Christi Caller-Times., June 3, 2001.

[67] "Alon USA – A Counterflow in Investment and Technology." Petroleum Economist Limited., March 31, 2001.

[68] "Aiming for No. 1 Valero's Growth Plan Goes Beyond its UDS Purchase." The Corpus Christi Caller-Times., May 13, 2001.

[69] *"Worldwide Construction Update."* Oil & Gas Journal., April 16, 2001.

[70] "Picking Up a Head of Steam; Construction of Huge Plant Nearly Done." The Houston Chronicle., June 8, 2001.

[71] *"Phillips' Board of Directors Approves 2001 Capital Budget."* Phillips Newsroom., December 12, 2000.
*"Phillips Plans Improvement Project at Borger, Texas, Refinery."* Phillips Newsroom., June 6, 2000.
"Phillips to Build Low-Sulfur Gasoline Facility at Borger Refinery." Phillips Newsroom., October 21, 1999.

[72] *"Worldwide Construction Update."* Oil & Gas Journal., April 16, 2001.

[73] Murphy Oil, 10K, Filed March 22, 2001, for Period Ending December 31, 2000.

[74] "Chevron Announces $6 Billion Capital Spending Program for 2001." Chevron Press Releases., January 18, 2001.

*Equiva Services LLC is planning to expand hydrocracking and hydrotreating capacity at its refineries in Los Angeles, California; Puget Sound, Washington; Port Arthur, Texas; Deer Park, Texas; Norco, Louisiana; and Convent, Louisiana. While the added capacity at each site is still unknown, the company expects completion of the projects by 2003.*[75]

*ExxonMobil has entered the engineering phase of their project to revamp hydro-desulfurization units at the company's Baytown, Texas, refinery. The project, which is expected to be completed by 2002, will add 133.5 Mbbl/d capacity to the units.*[76]

While several refineries are expanding now, and others will expand in the future, the construction of new refineries in the United States seems unlikely. According to several industry observers in one report, a new plant will not be built due to unattractive profit margins and environmental questions.[77] Before the Senate Subcommittee on Clean Air, Wetlands, Private Property and Nuclear Safety, the general counsel of the National Petrochemical and Refiners Association (NPRA) stressed the point that "rates of return for refineries have averaged about 5 percent in the last decade, roughly equivalent to the return from a passbook savings account – but with much greater risk." From this type of information, industry observers have concluded that new plants in new sites are highly unlikely to be built. Any future added capacity most likely would come from the expansion of existing refineries, because the construction of new refineries at new sites, and the necessary attraction of local support services, facilities, and skilled manpower, remain unattractive to the industry.

[75] "*Worldwide Construction Update.*" Oil & Gas Journal., April 16, 2001.

[76] "*Worldwide Construction Update.*" Oil & Gas Journal., April 16, 2001.

[77] "Refining Report: Future US Regulations, Product Demand." Oil & Gas Journal., March 19, 2001.

# APPENDIX A

**National Energy Policy Recommendations Related To NSR**

Recommendation for a 90-day study of NSR

The NEPD Group recommends that the President to direct the Administrator of the Environmental Protection Agency, in consultation with the Secretary of Energy and other relevant agencies, to review New Source Review regulations, including administrative interpretation and implementation, and report to the President within 90 days on the impact of the regulations on investment in new utility and refinery generation capacity, energy efficiency, and environmental protection.

Related NEP Recommendations

The NEPD Group recommends that the President direct the Administrator of the Environmental Protection Agency and the Secretary of Energy to take steps to ensure America has adequate refining capacity to meet the needs of consumers.

- Provide more regulatory certainty to refinery owners and streamline the permitting process where possible to ensure that regulatory overlap is limited.
- Adopt comprehensive regulations (covering more than one pollutant and requirement) and consider the rules' cumulative impacts and benefits.

The NEPD Group recommends that the President direct the Attorney General to review existing enforcement actions regarding New Source Review to ensure that the enforcement actions are consistent with the Clean Air Act and its regulations.

The NEPD Group recommends that the President direct federal agencies to provide greater regulatory certainty relating to coal electricity generation through clear policies that are easily applied to business decisions.