Economic Impact Analysis of the Stationary Combustion Turbines NSPS: Final Report

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ECONOMIC IMPACT ANALYSIS (EIA) FOR THE STATIONARY COMBUSTION TURBINES NSPS

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SELECT LIST OF ACRONYMS AND ABBREVIATIONS

CAA:	Clean Air Act
CO:	Carbon Monoxide
COPD:	Chronic Obstructive Pulmonary Disease
CCCT:	Combined-Cycle Combustion Turbine
C/S:	Cost to Sales Ratio
DOE:	Department of Energy
EO:	Executive Order
EPA:	Environmental Protection Agency
EWG:	Exempt Wholesale Generators
GW:	Gigawatt
HAP:	Hazardous Air Pollutant
ICCR:	Industrial Combustion Coordinated Rulemaking
IPP:	Independent Power Producer
kWh:	Kilowatt Hour
lb:	Pound
mills/kWh:	Mills per Kilowatt Hour
mmBTU:	Millions of British Thermal Units
MACT:	Maximum Achievable Control Technology
MW:	Megawatts
Mwh:	Megawatt Hours
NAAQS:	National Ambient Air Quality Standards
NAICS:	North American Industrial Classification System
NESHAP:	National Emission Standards for Hazardous Air Pollutants
NPR:	Notice of Proposed Rulemaking

NSPS:	New Source Performance Standards
NSR:	New Source Review
OMB:	Office of Management and Budget
O&M:	Operation and Maintenance
P/E:	Partial Equilibrium
PM:	Particulate Matter
ppbdv:	Parts Per Billion, dry volume
ppm:	Parts Per Million
PRA:	Paperwork Reduction Act of 1995
RFA:	Regulatory Flexibility Act
SAB:	Science Advisory Board
SBA:	Small Business Administration
SBREFA:	Small Business Regulatory Enforcement Fairness Act of 1996
SCCT:	Simple-Cycle Combustion Turbine
SIC:	Standard Industrial Classification
SOA:	Secondary Organic Aerosols
TAC:	Total Annual Cost
tpd:	Tons Per Day
tpy:	Tons Per Year
UMRA:	Unfunded Mandates Reform Act
VOCs:	Volatile Organic Compounds

SECTION 1
INTRODUCTION

The U.S. Environmental Protection Agency (referred to as EPA or the Agency) is developing regulations under Section 111 of the Clean Air Act (CAA) for new stationary combustion turbines. The majority of stationary combustion turbines burn natural gas and are used in the electric power and natural gas industries. The regulations are designed to reduce emissions of nitrogen oxides (NO_x) and sulfur dioxide (SO_2) generated by the combustion of fossil fuels in new combustion turbines. To inform this rulemaking, the Air Benefits and Costs Group (ABCG) of EPA's Office of Air Quality Planning and Standards (OAQPS) has developed an economic impact analysis (EIA) to estimate the potential social costs of the regulation. This report presents the results of this analysis in which a market model was used to analyze the impacts of the air pollution rule on society.

1.1 Agency Requirements for an EIA

Congress and the Executive Office have imposed statutory and administrative requirements for conducting economic analyses to accompany regulatory actions. Section 317 of the CAA specifically requires estimation of the cost and economic impacts for specific regulations and standards proposed under the authority of the Act. In addition, Executive Order (EO) 12866 requires a more comprehensive analysis of benefits and costs for significant regulatory actions.[1] Other statutory and administrative requirements include examination of the composition and distribution of benefits and costs. For example, the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement and Fairness Act of 1996 (SBREFA), requires EPA to consider the economic impacts of regulatory actions on small entities. Also, Executive Order 13211 requires EPA to consider for particular rules the impacts on energy markets.

1.2 Scope and Purpose

The CAA's purpose is to protect and enhance the quality of the nation's air resources (Section 101(b)). Section 111 of the CAA establishes the authority of EPA to set new source performance standards (NSPS) for criteria pollutants. This report evaluates the economic impacts of pollution control requirements placed on stationary combustion turbines under these amendments. These control requirements are designed to reduce releases of NO_x and SO_2 from new sources into the atmosphere.

The regulation affects new stationary combustion turbines over 1 megawatt (MW). To estimate the economic impacts associated with the regulation, new stationary combustion turbines are projected through the fifth year after promulgation.

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[1]Office of Management and Budget (OMB) guidance under EO 12866 stipulates that a full benefit-cost analysis is required only when the regulatory action has an annual effect on the economy of $100 million or more.

1.3 Organization of the Report

The remainder of this report is divided into six sections that describe the methodology and present results of this analysis:

- Section 2 provides background information on combustion turbine technologies and compares the equipment, installation, and operating costs of simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs).
- Section 3 provides background information on the regulatory alternatives examined, information on the emission reductions associated with the rule, and health effects from exposure to the NO_x emitted by combustion turbines.
- Section 4 provides projections of new stationary combustion turbines through the fifth year after promulgation. This section also profiles the population of existing turbines.
- Section 5 profiles the electric service industry (NAICS 221).
- Section 6 presents the methodology for assessing the economic impacts of the NSPS and describes the computerized market model used to estimate the social cost impacts and to disaggregate impacts into changes in producer and consumer surplus.
- Section 7 presents the economic impact estimates for the NSPS . This section also discusses the regulation’s impact on energy supply, distribution, and use.
- Section 8 provides the Agency’s analysis of the regulation’s impact on small entities.

In addition to these sections, Appendix A details the market model approach used to predict the economic impacts of the NSPS. Appendix B describes the limitations of the data and market model and presents sensitivity analyses associated with key assumptions.

SECTION 2

COMBUSTION TURBINE TECHNOLOGIES AND COSTS

This section provides background information on combustion turbine technologies. Included is a discussion of simple-cycle combustion turbines (SCCTs) and combined-cycle combustion turbines (CCCTs), along with a comparison of fuel efficiency and capital costs between the two classes of turbines.

2.1 Simple-Cycle Combustion Turbine Technologies

Most stationary combustion turbines use natural gas to generate shaft power that is converted into electricity.[2] Combustion turbines have four basic components, as shown in Figure 2-1.

1. The compressor raises the air pressure up to thirty times atmospheric.

2. A fuel compressor is used to pressurize the fuel.

3. The compressed air is heated in the combustion chamber at which point fuel is added and ignited.

4. The hot, high pressure gases are then expanded through a power turbine, producing shaft power, which is used to drive the air and fluid compressors and a generator or other mechanical drive device. Approximately one-third of the power developed by the power turbine can be required by the compressors.

Electric utilities primarily use simple-cycle combustion turbines as peaking or backup units. Their relatively low capital costs and quick start-up capabilities make them ideal for partial operation to generate power at periods of high demand or to provide ancillary services, such as spinning reserves or black-start back-up capacity.[3] The disadvantage of simple-cycle

[2]Combustion turbine technology used for aircraft engines is virtually the same except the energy is used to generate thrust.

[3]Spinning reserves are unloaded generating capacity that is synchronized to the grid that can begin to respond immediately to correct for generation/load imbalances caused by generation and transmission outages and that is fully available within 10 minutes. Black-start capacity refers to generating capacity that can be made fully available within 30 to 60 minutes to back up operating reserves and for commercial purposes.

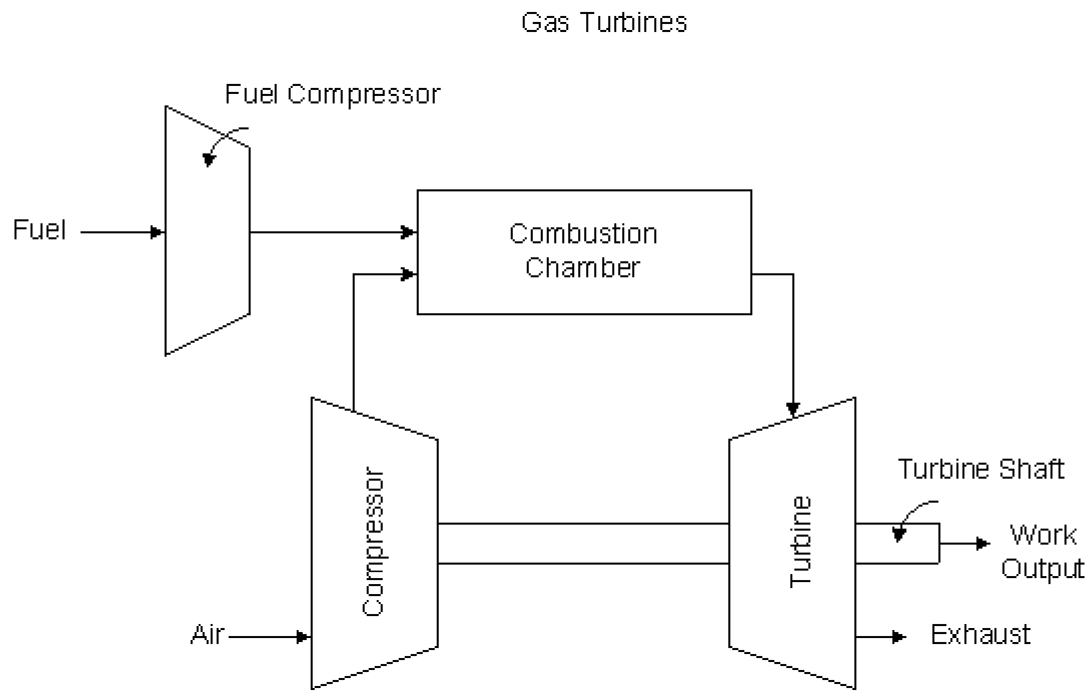

Figure 2-1. Simple-Cycle Gas Turbine

Source: Hay, Nelson E., ed. 1988. *Guide to Natural Gas Cogeneration*. Lilburn, GA: The Fairmont Press, Inc.

systems is that they are relatively inefficient, thus making them less attractive as base load generating units.

2.2 Combined-Cycle Combustion Turbines Technologies

The combined-cycle system incorporates two simple-cycle systems into one generation unit to maximize energy efficiency. Energy is produced in the first cycle using a gas turbine; then the heat that remains is used to create steam, which is run through a steam turbine. Thus, two single units, gas and steam, are put together to minimize lost potential energy.

The second cycle is a steam turbine. In a CCCT, the waste heat remaining from the gas turbine cycle is used in a boiler to produce steam. The steam is then put through a steam turbine, producing power. The remaining steam is recondensed and either returned to the boiler where it is sent through the process again or sold to a nearby industrial site to be used in a production process. Figure 2-2 shows a gas-fired CCCT.

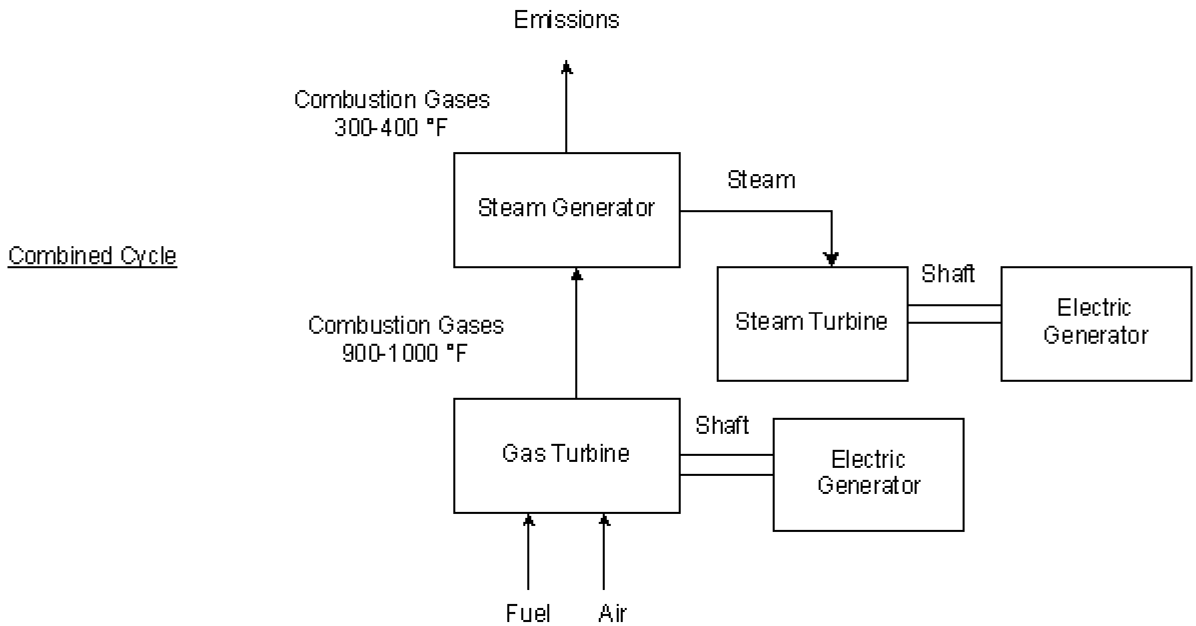

Figure 2-2. Combined-Cycle Gas Turbine

Source: Siemens Westinghouse. August 31, 1999. Presentation.

There are significant efficiency gains in using a combined-cycle turbine compared to simple-cycle systems. With SCCTs, adding a second stage allows for heat that otherwise would have been emitted and completely wasted to be used to create additional power or steam for industrial purposes. For example, a SCCT with an efficiency of 38.5 percent, adding a second stage increases the efficiency to 58 percent, a 20 percent increase in efficiency (Siemens, 1999). General Electric (1999) has recently developed a 480 MW system that will operate at 60 percent net combined-cycle efficiency.

In addition to energy efficiency gains, CCCTs also offer environmental efficiency gains compared to existing coal plants. In addition, efficiency gains associated with the CCCT lead to lower emissions compared to SCCTs. As Table 2-1 shows, the 58 percent efficiency turbine decreases NO_x emissions by 14 percent over simple-cycle combustion turbines and 89 percent over existing coal electricity generation plants. In addition, CO_2 emissions will be 5 percent lower than emissions from SCCTs and 64 percent lower than existing coal plants.

Table 2-1. Comparison of Emissions from Coal-Fired and Simple-Cycle Turbines and Combined-Cycle Turbines

	NO_x (lb/MW-hr)	CO_2 (lb/MW-hr)
Coal electricity generation	5.7	2,190
Simple-cycle turbines	0.7	825
Combined-cycle turbines	0.6	780

Source: Siemens Westinghouse. August 31, 1999. Presentation.

2.3 Capital and Installation Costs

CCCT capital and installation costs are approximately 30 percent less ($/MW) than a conventional coal or oil steam power plant's capital and installation costs, and CCCT costs are likely to decrease over the next 10 years. Gas turbine combined-cycle plants range from approximately $300 per kW installed for very large utility-scale plants to $1,000 per kW ($1998) for small industrial cogeneration installation (*GTW Handbook*, 1999). However, the prices of construction can vary as a result of local labor market conditions and the geographic conditions of the site (*GTW Handbook*, 1999). SCCTs are approximately half the cost of CCCT units.

Table 2-2 breaks down the budgeted construction costs of a gas-fired 107 MW combined-cycle cogenerating station at John F. Kennedy International Airport that was installed several years ago. As shown in Table 2-2, the construction price can range dramatically. This job finished near the top of the budget, close to $133,600,000. According to *Gas Turbine World*, the typical budget price for a 168 MW plant is $80,600,000, ($480/kW) for a plant with net efficiency of 50.9 percent (*GTW Handbook*, 1999).

2.4 O&M Costs Including Fuel

Fuel accounts for one-half to two-thirds of total production costs (annualized capital, operation and maintenance, fuel costs) associated with generating power using combustion turbines. Table 2-3 compares the percentage of costs spent on annualized capital, operation and maintenance, and fuel for both simple turbines and CCCTs.

Table 2-2. Overall Installation Costs

Construction costs can vary dramatically. This table shows the budgeted cost for a gas-fired 107 MW combined-cycle cogenerating station at John F. Kennedy International Airport in Brooklyn, New York. The power plant uses two 40 MW Stewart & Stevenson LM6000 gas turbine generators each exhausting into a triple pressure heat recovery steam generator raising steam for processes and to power a nominal 27 MW steam turbine generator. Budgeted prices are in 1995–1996 U.S. dollars.

Budget Equipment Pricing	**$ Amount**
Gas turbine generators	$24,000,000
Heat recovery steam generators	10,000,000
Steam turbine generator set	4,000,000
Condenser	300,000
Cooling towers	800,000
Transformer and switchgear	8,000,000
Balance of plant equipment	7,500,000
Subtotal, equipment	$54,600,000
Budget Services and Labor	
Mechanical and electrical construction	$20-75,000,000
Engineering	4,000,000
Subtotal, services	$24-79,000,000
Total Capital Cost	**$78,600,000-133,600,000**

Source: *1998–99 GTW Handbook*. "Turnkey Combined Cycle Plant Budget Price Levels." Fairfield, CT: Pequot Pub. Pgs. 16–26.

Table 2-3. Comparison of Percentage of Costs[a]

	Simple Cycle	**Combined Cycle**
% Capital costs	50	25
% Operation and maintenance	10	10
% Fuel	40	65

[a] Based on a review of marketing information from turbine manufacturers and the *GTW Handbook*.

The fuel costs may vary depending on the plant's location. In areas where gas costs are high, for a base-load CCCT power plant, fuel costs can account for up to 70 percent of total plant costs—including acquisition, owning and operating costs, and debt service

(*GTW Handbook*, 1999). General Electric's "H" design goals for future CCCT systems are to reduce power plant operating costs by at least 10 percent compared to today's technology as a direct result of using less fuel. The higher efficiency allows more power to be generated with the same amount of fuel, resulting in a substantial fuel cost savings for the plant owner (General Electric, 1999).

SECTION 3

BACKGROUND ON HEALTH AFFECTS AND REGULATORY ALTERNATIVES

3.1 Background

Section 111 of the CAA requires EPA to establish NSPS for major and area sources within various source categories.

3.1.1 Summary of the Stationary Combustion Turbines NSPS

Does the rule apply to me?

The standards would apply to new stationary combustion turbines with a heat input at peak load greater than or equal to 10.7 GJ (10 MMBtu) per hour that commerce construction, modification, or reconstruction after February 18, 2005. The applicability of the rule is similar to that of existing 40 CFR part 60, subpart GG, except that the rule would apply to new, modified, and reconstructed stationary combustion turbines, and their associated heat recovery steam generators (HRSG) and duct burners. A new stationary combustion turbine is defined as all equipment, including but not limited to the combustion turbine, the fuel, air, lubrication and exhaust gas systems, control systems (except emissions control equipment), heat recovery system, and any ancillary components and sub-components comprising any simple cycle stationary combustion turbine, any regenerative/recuperative cycle stationary combustion turbine, any combined cycle combustion turbine, and any combined heat and power combustion turbine based system. The new stationary combustion turbines subject to the standards are exempt from the requirements of 40 CFR part 60, subpart GG. Heat recovery steam generators and duct burners subject to subpart KKKK are exempt from the requirements of 40 CFR part 60, subparts Da, Db, and Dc.

What pollutants would be regulated?

The pollutants to be regulated by the standards are NOx and SO2.

What is the affected source?

The affected source for the stationary combustion turbine NSPS is each stationary combustion turbine with a power output at peak load greater than or equal to 1 MW, that commences construction, modification, or reconstruction after proposal. Integrated gasification combined cycle (IGCC) combustion turbine facilities covered by subpart Da of 40 CFR part 60 (the Utility NSPS) are exempt from the requirements of the rule.

What emission limits must I meet?

The format of the standards for NO_x is allow the turbine owner or operator the choice of a concentration-based or an output-based emission limit. The concentration-based limit is in units of parts per million by volume (ppmv) at 15 percent oxygen. The output-based emission limit is in in units of emissions mass per unit useful recovered energy, nanograms/Joule (ng/J) or pounds per megawatt-hour (lb/MW-hr). The Nox limits differ based on the fuel input at peak load, fuel, application, and location of the turbine. The fuel input of the turbine does not include any supplemental fuel input to the heat recovery system and refers to the rating of the combustion turbine itself. The 50 mmBTU/hr category peak heat input is based on the fuel input to a 23 percent efficient 3.5 MW combustion turbine. The 850 mmBTU/hr category peak heat input is based on the fuel input to a 44 percent efficient 110 MW combustion turbine. The 30 MW category for turbines located north of the Arctic Circle, turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 degress Fahrenheit is based on the categories in the original NSPS for combustion turbines, subpart GG. These are presented in Table 3-1.

Table 3-1. NO_x Emission Standards (ng/J)

Combustion Turbine Type	Combustion Turbine Heat Input at Peak Load (HHV)	NOx Emission Standard
New turbine firing natural gas, electric generating	<= 50 mmBTU/hr	42 ppm at 15 percent oxygen (O_2) or 290 ng/J of useful output (2.3 lb/MWh)
New turbine firing natural gas, mechanical drive	<= 50 mmBTU/hr	100 ppm at 15 percent O2 or 690 ng/J of useful output (5.5 lb/MWh)
New turbine firing natural gas	> 50 mmBTU/hr and <=850 mmBTU/hr	25 ppm at 15 percent oxygen (O_2) or 150 ng/J of useful output (0.43 lb/MWh)
New turbine firing fuels other than natural gas, electric generating	<= 50 mmBTU/hr	96 ppm at 15 percent oxygen (O_2) or 700 ng/J of useful output (2.3 lb/MWh)

New turbine firing fuels other than natural gas, mechanical drive	<= 50 MMBTU/hr	150 ppm at 15 percent oxygen (O_2) or 1,100 ng/J of useful output (8.7 lb/MWh)
New turbine firing fuels other than natural gas	> 50 mmBTU/hr and <=850 mmBTU/hr	74 ppm at 15 percent oxygen (O_2) or 460 ng/J of useful output (2.3 lb/MWh)
New turbine firing natural gas, electric generating	<= 50 mmBTU/hr	42 ppm at 15 percent oxygen (O_2) or 290 ng/J of useful output (2.3 lb/MWh)
New, modified, or reconstructed turbine firing fuels other than natural gas	> 850 mmBTU/hr	42 ppm at 15 percent oxygen (O_2) or 160 ng/J of useful output (1.3 lb/MWh)
Modified or reconstructed turbines	<= 50 mmBTU/hr	150 ppm at 15 percent oxygen (O_2) or 1,100 ng/J of useful output (8.7 lb/MWh)
Modified or reconstructed turbine firing natural gas	> 50 mmBTU/hr and <= 850 mmBTU/hr	42 ppm at 15 percent oxygen (O_2) or 250 ng/J of useful output (2.0 lb/MWh)
Modified or reconstructed turbine firing fuels other than natural gas	>50 mmBTU/hr and <= 850 mmBTU/hr	96 ppm at 15 percent oxygen (O_2) or 590 ng/J of useful output (4.7 lb/MWh)
Turbines located north of the Arctic Circle (latitude 66.5 north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 degree Fahrenheit	<= 30 MW output	150 ppm at 15 percent oxygen (O_2) or 1,100 ng/J of useful output (8.7 lb/MWh)

Turbines located north of the Arctic Circle (latitude 66.5 north), turbines operating at less than 75 percent of peak load, modified and reconstructed offshore turbines, and turbines operating at temperatures less than 0 degree Fahrenheit	> 30 MW output	96 ppm at 15 percent O2 or 590 ng/J of useful output (4.7 lb/MW-hr)
Heat recovery units operating independent of the combustion turbine	All sizes	54 ppm at 15 percent O2 or 110 ng/J of useful output (0.86 lb/MW-hr)

We have determined that it is appropriate to exempt emergency combustion turbines from the NO_x limit. We have defined these units as turbines that operate in emergency situations. For example, turbines used to supply electric power when the local utility service is interrupted are considered to fall under this definition. In addition, we are proposing that combustion turbines used by manufacturers in research and development of equipment for both combustion turbine emission control techniques and combustion turbine efficiency improvements be exempted from the NO_x limit. Given the small number of turbines that are expected to fall under this category and since there is not one definition that can provide an all-inclusive description of the type of research and development work that qualifies for the exemption from the NOx limit, we have decided that it is appropriate to make these exemption determinations on case by case basis only.

The proposed standard for SO2 is the same for all turbines regardless of size and fuel type. You may not cause to be discharged into the atmosphere from the subject stationary combustion turbine any gases which contain SO_2 in excess of 110 ng/J (0.90 lb/MW-hr) gross energy output for turbines located in continental areas, and 780 ng/J (6.2 lb/MW-hr) gross energy output for turbines located elsewhere. You can choose to comply with the SO_2 limit itself or with a limit on the sulfur content of the fuel. The fuel sulfur content is 26 ng SO2/J (0.060 lb SO2/mmBTU) heat input for turbines in continental areas and 180 ng SO2/J (0.42 lb SO2/mmBTU) heat input for turbines in noncontinental areas.

If I modify or reconstruct my existing turbine, does the rule apply to me?

The standards apply to stationary combustion turbines that are modified or reconstructed after proposal. The guidelines for determining whether a source is modified or reconstructed are given in 40 CFR 60.14 and 60.15, respectively. A turbine that is overhauled as part of a maintenance program is not considered a modification if there is no increase in emissions.

How do I demonstrate compliance?

In order to demonstrate compliance with the NO_x limit, an initial performance test is required. If you are using water or steam injection, you must continuously monitor your water or steam to fuel ratio in order to demonstrate compliance and you are not required to perform annual stack testing to demonstrate compliance. If you are not using water or steam injection, you would conduct performance tests annually following the initial performance test in order to demonstrate compliance. Alternatively, you may choose to demonstrate continuous compliance with the use of a continuous emission monitoring system (CEMS) or parametric monitoring; if you choose this option, you are not required to conduct subsequent annual performance tests.

If you are using a NO_x CEMS, the initial performance test required under 40 CFR 60.8 may, alternatively, coincide with the relative accuracy test audit (RATA). If you choose this as your initial performance test, you must perform a minimum of nine reference method runs, with a minimum time per run of 21 minutes, at a single load level, between 90 and 100 percent of peak (or the highest achievable) load. You must use the test data both to demonstrate compliance with the applicable NO_x emission limit and to provide the required reference method data for the RATA of the CEMS.

What monitoring requirements must I meet?

If you are using water or steam injection to control NO_x emissions, you must install and operate a continuous monitoring system to monitor and record the fuel consumption and the ratio of water or steam to fuel being fired in the turbine. Alternatively, you could use a CEMS consisting of NO_x and oxygen (O_2) or carbon dioxide (CO_2) monitors. During each full unit operating hour, each monitor would complete a minimum of one cycle of operation for each 15-minute quadrant of the hour. For partial unit operating hours, at least one valid data point would be obtained for each quadrant of the hour in which the unit operates.

If you operate any new turbine which does not use water or steam injection to control NO_x emissions, you would have to perform annual stack testing to demonstrate continuous compliance with the NO_x limit. Alternatively, you could elect either to use a NO_x CEMS or perform continuous parameter monitoring as follows:

(1) For a diffusion flame turbine without add-on selective catalytic reduction (SCR) controls, you would define at least four parameters indicative of the unit's NO_x formation characteristics, and you would monitor these parameters continuously.

(2) For any lean premix stationary combustion turbine, you would continuously monitor the appropriate parameters to determine whether the unit is operating in the lean premixed combustion mode.

(3) For any turbine that uses SCR to reduce NO_x emissions, you would continuously monitor appropriate parameters to verify the proper operation of the emission controls.

(4) For affected units that are also regulated under part 75 of this chapter, if you elect to monitor the NO_x emission rate using the methodology in appendix E to part 75 of this chapter, or the low mass emissions methodology in 40 CFR 75.19, the monitoring requirements of the turbine NSPS may be met by performing the parametric monitoring described in section 2.3 of appendix E of part 75 of this chapter or in 40 CFR 75.19(c)(1)(iv)(H).

Alternatively, you could petition the Administrator for other acceptable methods of monitoring your emissions. If you choose to use a CEMS or perform parameter monitoring to demonstrate continuous compliance, annual stack testing is not required.

If you operate any stationary combustion turbine subject to the provisions of the rule, and you choose not to comply with the SO_2 stack limit, you would monitor the total sulfur content of the fuel being fired in the turbine. There are several options for determining the frequency of fuel sampling, consistent with appendix D to part 75 of this chapter for fuel oil; and the sulfur content would be determined and recorded once per unit operating day for gaseous fuel, unless a custom fuel sampling schedule is used. Alternatively, you could elect not to monitor the total sulfur content of the fuel combusted in the turbine, if you demonstrate that the fuel does not to exceed a total sulfur content of 300 ppmw. This demonstration may be performed by using the fuel quality characteristics in a current, valid purchase contract, tariff sheet, or transportation contract, or through representative fuel sampling data which show that the sulfur content of the fuel does not exceed 300 ppmw.

If you choose to monitor combustion parameters or parameters indicative of proper operation of NO_x emission controls, the appropriate parameters would be continuously monitored and recorded during each run of the initial performance test, to establish acceptable operating ranges, for purposes of the parameter monitoring plan for the affected unit.

If you are required to periodically determine the sulfur content of the fuel combusted in the turbine, a minimum of three fuel samples would be collected during the performance test. For liquid fuels, the samples for the total sulfur content of the fuel must be analyzed using American Society of Testing and Materials (ASTM) methods D129-00, D2622-98, D4294-02, D1266-98, D5453-00 or D1552-01. For gaseous fuels, ASTM D1072-90 (Reapproved 1999); D3246-96; D4468-85 (Reapproved 2000); or D6667-01 must be used to analyze the total sulfur content of the fuel.

The applicable ranges of some ASTM methods mentioned above are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator.

What reports must I submit?

For each affected unit for which you continuously monitor parameters or emissions, or periodically determine the fuel sulfur content under the rule, you would submit reports of excess emissions and monitor downtime, in accordance with 40 CFR 60.7(c). For simple cycle turbines, excess emissions must be reported for all 4-hour rolling average periods of unit operation, including startup, shutdown, and malfunctions where emissions exceed the allowable emission limit or where one or more of the monitored process or control parameters exceeds the acceptable range as determined in the monitoring plan. Combined cycle and combined heat and power units use a 30 day rolling average to determine excess emissions.

For each affected unit for which you perform an annual performance test, you must submit an annual written report of the results of each performance test.

3.2 Health Effects Associated with NO_x and SO_2 Emissions from Stationary Combustion Turbines

3.2.1 Benefits of Reduced Nitrous Oxide Emissions

Emissions of NO_x produce a wide variety of health and welfare effects. Nitrogen dioxide can irritate the lungs at high occupational levels and may lower resistance to respiratory infection (such as influenza), although the research has been equivocal. NO_x emissions are an important precursor to acid rain and may affect both terrestrial and aquatic ecosystems. Atmospheric deposition of nitrogen leads to excess nutrient enrichment problems ("eutrophication") in the Chesapeake Bay and several nationally important estuaries along the East and Gulf Coasts. Eutrophication can produce multiple adverse effects on water quality and the aquatic environment, including increased algal blooms, excessive phytoplankton growth, and low or no dissolved oxygen in bottom waters. Eutrophication also reduces sunlight, causing losses in submerged aquatic vegetation critical for healthy estuarine ecosystems. Deposition of nitrogen-containing compounds also affects terrestrial ecosystems. Nitrogen fertilization can alter growth patterns and change the balance of species in an ecosystem.

Nitrogen dioxide and airborne nitrate also contribute to pollutant haze (often brown in color), which impairs visibility and can reduce residential property values and the value placed on scenic views.

NO_x in combination with volatile organic compounds (VOC) also serves as a precursor to ozone. Based on a large number of recent studies, EPA has identified several key health effects that may be associated with exposure to elevated levels of ozone. Exposures to high ambient ozone concentrations have been linked to increased hospital admissions and emergency room visits for respiratory problems. Repeated exposure to ozone may increase susceptibility to respiratory infection and lung inflammation and can aggravate preexisting respiratory disease, such as asthma. Repeated prolonged exposures (i.e., 6 to 8 hours) to ozone at levels between 0.08 and 0.12 ppb, over months to years may lead to repeated inflammation of the lung, impairment of lung defense mechanisms, and irreversible changes in lung structure, which could in turn lead to premature aging of the lungs and/or chronic respiratory illnesses such as emphysema, chronic bronchitis, and asthma.

Children have the highest exposures to ozone because they typically are active outside playing and exercising, during the summer when ozone levels are highest. Further, children are more at risk than adults from the effects of ozone exposure because their respiratory systems are still developing. Adults who are outdoors and moderately active during the summer months, such as construction workers and other outdoor workers, also are among those with the highest exposures. These individuals, as well as people with respiratory illnesses such as asthma, especially children with asthma, experience reduced lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during periods of moderate exertion. In addition to human health effects, ozone adversely affects crop yield, vegetation and forest growth, and the durability of materials. Ozone causes noticeable foliar damage in many crops, trees, and ornamental plants (i.e., grass, flowers, shrubs, and trees) and causes reduced growth in plants.

Particulate matter (PM) can also be formed from NO_x emissions. Secondary PM is formed in the atmosphere through a number of physical and chemical processes that transform gases such as sulfur dioxide, NO_x, and VOC into particles. Scientific studies have linked PM (alone or in combination with other air pollutants) with a series of health effects (see Chapter 8 for a detailed discussion of studies used to evaluate health impacts of PM emissions). Coarse particles can accumulate in the respiratory system and aggravate health problems such as asthma. Fine particles can penetrate deep into the lungs and are more likely than coarse particles to contribute to a number of the health effects. These health effects include decreased lung function and alterations in lung tissue and structure and in respiratory tract defense mechanisms which may be manifest in increased respiratory symptoms and disease or in more severe cases, increased hospital admissions and emergency room visits or premature death. Children, the elderly, and people with cardiopulmonary disease, such as asthma, are most at risk from these health effects.

PM also causes a number of adverse effects on the environment. Fine PM is the major cause of reduced visibility in parts of the United States, including many of our national parks and wilderness areas. Other environmental impacts occur when particles deposit onto soil, plants, water, or materials. For example, particles containing nitrogen and sulfur that deposit onto land or water bodies may change the nutrient balance and acidity of those environments, leading to changes in species composition and buffering capacity.

Particles that are deposited directly onto leaves of plants can, depending on their chemical composition, corrode leaf surfaces or interfere with plant metabolism. Finally, PM causes soiling and erosion damage to materials.

Thus, reducing the emissions of NO_x from stationary combustion turbines can help to improve some of the effects mentioned above, either those directly related to NO_x emissions, or the effects of ozone and PM resulting from the combination of NO_x with other pollutants.

3.2.2 Benefits of Sulfur Dioxide Reductions

Very high concentrations of sulfur dioxide (SO_2) affect breathing and ambient levels have been hypothesized to aggravate existing respiratory and cardiovascular disease. Potentially sensitive populations include asthmatics, individuals with bronchitis or emphysema, children and the elderly. SO_2 is also a primary contributor to acid deposition, or acid rain, which causes acidification of lakes and streams and can damage trees, crops, historic buildings and statues. In addition, sulfur compounds in the air contribute to visibility impairment in large parts of the country. This is especially noticeable in national parks.

PM can also be formed from SO_2 emissions. Secondary PM is formed in the atmosphere through a number of physical and chemical processes that transform gases, such as SO_2, into particles. Overall, emissions of SO_2 can lead to some of the effects discussed in this section—either those directly related to SO_2 emissions, or the effects of ozone and PM resulting from the combination of SO_2 with other pollutants.

3.3 Emission Reductions from the NSPS

The reductions of NOx from this NSPS for new stationary combustion turbines will essentially be zero because the new turbines that may need to install add-on controls to meet the NOx emissions limits will already be required to install these add-on controls to meet NOx reduction requirements under the Prevention of Significant Deterioration/New Source Review (PSD/NSR) programs. Therefore, we conclude that the NOx reductions resulting from the rule will essentially be zero. The expected SO_2 reductions resulting from the rule will be approximately 830 tons/year in the fifth year after promulgation of the standards.

SECTION 4

PROJECTION OF UNITS AND FACILITIES IN AFFECTED SECTORS

The regulation will affect new turbine units with capacity over 1 MW. As a result, the economic impact estimates presented in Section 7 and the small entity screening analysis presented in Section 8 are based on the population of existing units and the projection of new combustion turbine units for the next 5 years. This section begins with a review of the technical characteristics and industry distribution of existing combustion turbines contained in the Agency's Inventory Database. It presents projected growth estimates for combustion turbines greater than 1 MW and describes trends in the electric utility industry. It also presents (in Section 4.3) the estimated number of new combustion turbines that will be affected by this rule.

4.1 Profile of Existing Combustion Turbine Units

4.1.1 Distribution of Units and Facilities by Industry

Table 4-1 presents the number of combustion turbines and facilities owning turbines by NAICS code. Forty-seven percent of existing combustion turbines are in Utilities (NAICS 221), 22 percent are in Pipeline Transportation, and 18 percent are in Oil and Gas Extraction (NAICS 211). Section 4 presents industry profiles for the electric power, natural gas pipelines, and oil and gas industries. The remaining units are primarily distributed across the manufacturing sector and are concentrated in the chemical and petroleum industries.

4.1.2 Technical Characteristics

This section characterizes the population of 2,072 units by MW capacity, fuel type, hours of operation, annual MWh produced (or equivalent), and simple or combined cycle.

- MW Capacity: Unit capacities in the population range between 1 and 368 MW. Although some units have large capacities in excess of 100 MW, about half (1,000 units) have capacities between 1 and 10 MW (see Figure 4-1). Only approximately 13 percent (278 units) have capacities greater than 100 MW. The total estimated capacity of all the units in the population is 79,909 MW.

Table 4-1. Facilities With Units Having Capacities Above 1 MW by Industry Grouping and Government Sector

NAICS	Description	# Units	# Facilities
112	Animal Production	1	1
211	Oil and Gas Extraction	365	105
212	Mining (Except Oil and Gas)	3	3
221	Utilities	983	393
233	Building, Developing, and General Contracting	1	1
235	Special Trade Contractors	2	1
311	Food Manufacturing	18	11
321	Wood Products Manufacturing	3	2
322	Paper Manufacturing	17	11
324	Petroleum and Coal Products Manufacturing	34	11
325	Chemical Manufacturing	63	39
326	Plastics and Rubber Products Manufacturing	4	3
327	Nonmetallic Mineral Product Manufacturing	1	1
331	Primary Metal Manufacturing	13	4
332	Fabricated Metal Product Manufacturing	2	2
333	Machinery Manufacturing	2	2
334	Computer and Electronic Product Manufacturing	6	5
335	Electrical Equipment, Appliance, and Component Manufacturing	1	1
336	Transportation Equipment Manufacturing	3	3
337	Furniture and Related Product Manufacturing	1	1
339	Miscellaneous Manufacturing	3	3
422	Wholesale Trade, Nondurable Goods	6	4
486	Pipeline Transportation	448	244
488	Support Activities for Transportation	1	1
513	Broadcasting and Telecommunications	1	1
522	Credit Intermediation and Related Activities	3	1
541	Professional, Scientific, and Technical Services	2	2
561	Administrative and Support Services	1	1
611	Educational Services	10	8
622	Hospitals	23	14
721	Accommodation	1	1
923	Administration of Human Resource Programs	1	1
926	Administration of Economic Programs	1	1
928	National Security and International Affairs	42	12
Unknown	Industry Classification Unknown	6	5
Total		2,072	899

Source: Industrial Combustion Coordinated Rulemaking (ICCR). 1998. Data/Information Submitted to the Coordinating Committee at the Final Meeting of the Industrial Combustion Coordinated Rulemaking Federal Advisory Committee. EPA Docket Numbers A-94-63, II-K-4b2 through -4b5. Research Triangle Park, North Carolina. September 16-17.

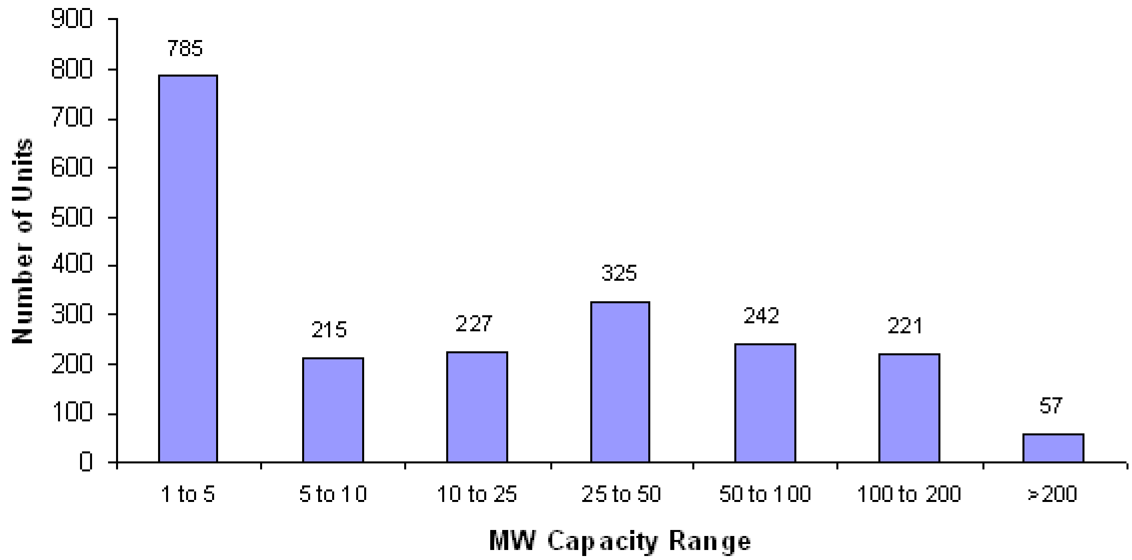

Figure 4-1. Number of Units by MW Capacity

- Fuel type: To determine the breakdown of turbines by fuel type, the EPA Region 4 spreadsheet of national combustion turbines permitted in the past few years was used. According to the spreadsheet, 41 percent of turbines were dual fuel, 3 percent fired distillate oil only, and the remaining 56 percent fired natural gas only. Many dual fuel turbines are permitted to operate up to 10 percent of the time on distillate oil, so for purposes of this estimate it was assumed that dual fuel turbines would operate 10 percent of the time on distillate oil.

- Hours of Operation: This EIA uses assumptions that new simple cycle stationary combustion turbines typically operate at a 20 percent capacity factor (or 1,752 hours per year) and combined cycle turbines typically operate at a 60 percent capacity factor (or 5,256 hours per year). These figures are based on information submitted during the public comment period for the proposed Stationary Combustion NESHAP. The same hours of operation are used in this analysis.

Table 4-2. Stationary Combustion Turbine Projections

	Total Number of New Units
Simple cycle	286
Combined cycle	69
Total in 5th year	355
Average per year	71

- Annual MWh Equivalent: Figure 4-2 presents the distribution of units by the estimated annual MWh equivalent produced by each unit. For units that are used for compression or other functions, their likely MWh output was estimated using their MW capacity and annual hours of operation. Annual MWh for 245 units lacking annual hours of operation information was not calculated. Figure 4-3 includes data for the other 1,827 units, more than one-third of which have output of between 10,000 and 50,000 MWh a year. 360 units have output of less than 5,000 MWh, and 217 units have output greater than 500,000 MWh.

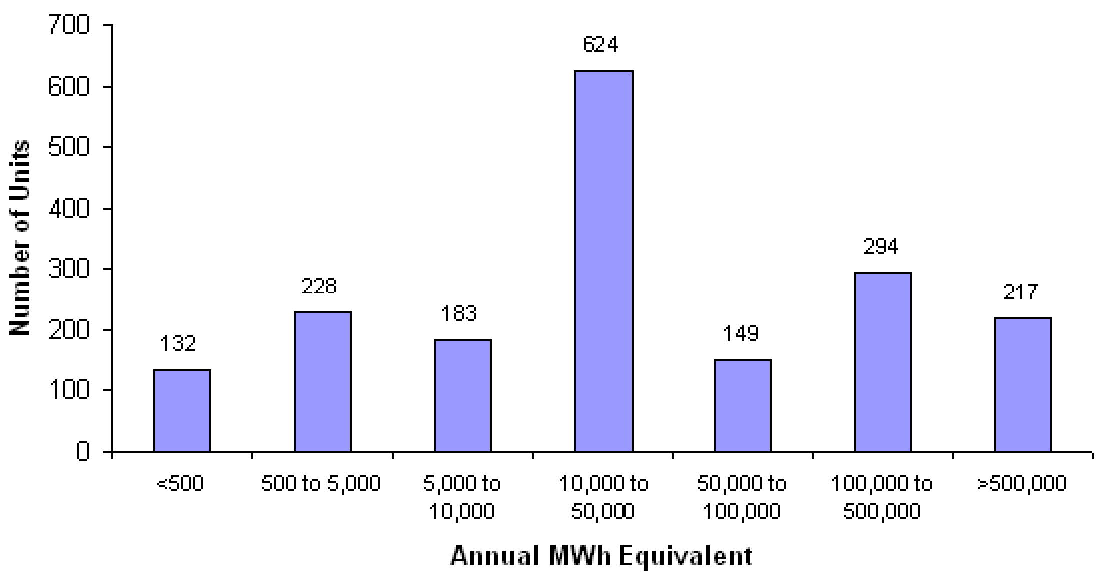

Figure 4-2. Number of Units by Annual MWh Output Equivalent

Note: Excludes 245 units for which information on annual hours of operation was unavailable.

- Simple vs. combined cycle: The Inventory Database did not distinguish between simple and combined cycle turbines. In order to determine the breakdown between simple and combined cycle units, the EPA's RACT/BACT/LAER Clearinghouse and the national list of combustion turbines maintained by EPA Region 4 were consulted. Both of those sources showed that the vast majority of turbines rated less than 30 MW are simple cycle. For turbines that are larger than 30 MW, approximately 40 percent were simple cycle and 60 percent were combined cycle.

4.2 Projected Growth of Combustion Turbines

The Agency estimates there will be a total of 355 new stationary turbines over the next 5 years (see Table 4-2). This projection is based on a survey of gas turbine orders for the period of June 2002 to May 2003 in the October 2003 Diesel & Gas Turbine Worldwide (D&GTW) Power Generation Order Survey. The breakdown of turbines classified as simple and combined cycle was estimated by using EPA's RACT/BACT/LAER Clearinghouse and the national list of combustion turbines maintained by EPA Region 4.

4.3 Projected Number of Affected Stationary Combustion Turbines

We estimate that 10 of the new simple-cycle turbines in the 30 to 120 MW range will install selective catalytic reduction (SCR) to meet the NO_x emission standard for the Gas Turbine NSPS. It is possible that some units could install a heat recovery steam generator (HRSG). Although a HRSG is more expensive than SCR, it has the benefit of increased power output and therefore may be a more attractive option. However, for purposes of this estimate, it was assumed that SCR would be used to comply with the rule. Combined-cycle units and simple-cycle units less than 30 MW or greater than 120 MW will not need to install a HRSG or SCR since turbines that do not exceed the NO_x emissions limits and meet the efficiency requirements are available. Existing sources are not required to comply with emission requirements in the rule.

Based on the projected estimates of simple-cycle units in the 30 to 60 MW and 60 to 120 MW ranges, a total of 10 units are expected to install an SCR. Two 30 to 60 MW units and eight 60 to 120 MW units are expected to install SCR.

It should be noted that these 10 new turbines will already be required to install these add-on controls to meet NOx reduction requirements under the PSD/NSR programs. Thus, we conclude that the control costs resulting from the proposed NSPS will be essentially zero. These sources and other affected sources are expected to follow monitoring, record keeping, and reporting requirements, conduct fuel sampling, and conduct initial performance testing.

SECTION 5

PROFILE OF THE ELECTRIC UTILITY INDUSTRY

The Agency anticipates that all of the direct costs of the NSPS will be borne by the electric services (NAICS 22111) sector. The Agency projects that growth in new combustion turbines that will be affected by the regulation will also be concentrated in the electric services. This section contains background information on this industry to help inform the regulatory process.

5.1 Electric Utility Industry (NAICS 22111)

This profile of the U.S. electric power industry provides background information on the evolution of the electricity industry, the composition of a traditional regulated electric utility, the current market structure of the electric industry, and deregulation trends and the potential future market structure of the electricity market. This profile also discusses current industry characteristics and trends that will influence the future generation and consumption of electricity.

5.1.1 Market Structure of the Electric Power Industry

The ongoing process of deregulation of wholesale and retail electric markets is changing the structure of the electric power industry. Deregulation is leading to the functional unbundling of generation, transmission, and distribution and to competition in the generation segment of the industry. This section provides background on the current structure of the industry and future deregulation trends. It begins with a brief overview of the evolution of the electric power industry because the future market structure will, in large part, be determined by the existing infrastructure and capital assets that have evolved over the past decades.

5.1.1.1 The Evolution of the Electric Power Industry

The electric utility industry began as isolated local service systems with the first electric companies evolving in densely populated metropolitan areas like New York and Chicago. Prior to World War I, rural electrification was a piecemeal process. Only small, isolated systems existed, typically serving a single town. The first high-voltage transmission network was built in the Chicago area in 1911 (the Lake County experiment). This new network connected the smaller systems surrounding Chicago and resulted in substantial production economies, lower customer prices, and increased company profits.

In light of the success of the Lake County experiment, the 1910s and 1920s saw increased consolidation and rapid growth in electricity usage. During this period, efficiency gains and demand growth provided the financing for system expansions. Even though the capacity costs (fixed costs per peak kW demanded) were typically twice as large with the consolidated/interconnected supply systems, the fixed costs per unit of energy production (kWh) were comparable to those of the old single-city system. This was the case because of load factor improvements, which resulted from aggregating customer demand.

Whereas the average fixed cost per customer was relatively unchanged as a result of the move from single-city to consolidated supply systems, large savings were realized from decreases in operating costs. In particular, fuel costs per kWh decreased 70 percent because of the improved combustion efficiency of larger plants and lower fuel prices for purchases of large quantities. In addition, operation and maintenance costs decreased 85 percent, primarily as a result of decreased labor intensity.

During the 1920s, only a small part of the efficiency gains were passed on to customers in the form of lower prices. Producers retained the bulk of the productivity increases as profits. These profits provided the internal capital to finance system expansions and to buy out smaller suppliers. Industry expansion and consolidation led to the development of large utility holding companies whose assets were shares of common stock in many different operating utilities.

The speculative fever of the 1920s led to holding companies purchasing one another, creating financial pyramids based on inflated estimates of company assets. With the stock market crash in 1929, shareholders who had realized both real economic profits and speculative gains lost large amounts of money. The financial collapse of the utility holding companies led to new levels of utility regulation.

From the 1930s through the 1960s, the regulated mandate of electric utilities was basically unchanged: to provide safe, adequate, and reliable service to all electricity users. The majority of the state and federal laws regulating utilities in place during this era had been written shortly after the Depression. The laws were primarily designed to prevent "ruinous competition" through costly duplication of utility functions and to protect customers against exploitation from a monopoly supplier.

During this period, most utilities were vertically integrated, controlling everything from generation to distribution. Economies of scale in generation and the inefficiency of duplicating transmission and distribution systems made the electric utility industry a textbook example of a natural monopoly. Electricity was viewed as a homogeneous good from which there were no product unbundling opportunities or unique product offerings on which competition could get a foothold. In addition, the industry was extremely capital-intensive, providing a sizable barrier to entry even if the monopoly status of the utilities had not been protected.

From the 1930s to the 1960s, the electric industry experienced almost continuous growth in demand. In addition, there was a steady stream of technological innovations in generation, transmission, and distribution operations. The increased economies of scale, technological advances, and fast demand growth led to steadily declining unit costs. However, in an environment of decreasing unit costs, there were few rate cases and almost no pressure from customers to change the system. This period is often referred to as the golden era for the electric utility industry.

5.1.1.2 Structure of the Traditional Regulated Utility

The utilities vary substantially in size, type, and function. Figure 5-1 illustrates the typical structure of the electric utility market. Even with the technological and regulatory changes in the 1970s and 1980s, at the beginning of the 1990s the structure of the electric utility industry could still be characterized in terms of generation, transmission, and distribution. Commercial and retail customers were in essence "captive," and rates and service quality were primarily determined by public utility commissions.

The majority of utilities are interconnected and belong to a regional power pool. Pooling arrangements enable facilities to coordinate the economic dispatch of generation facilities and manage transmission congestion. In addition, pooling diverse loads can increase load factors and decrease costs by sharing reserve capacity.

Generation. Coal-fired plants have historically accounted for the bulk of electricity generation in the United States. With abundant national coal reserves and advances in pollution abatement technology, such as advanced scrubbers for pulverized coal and flue gas-desulfurization systems, coal will likely remain the fuel of choice for most existing generating facilities over the near term.

Natural gas accounts for approximately 10 percent of current generation capacity but is expected to grow; advances in natural gas exploration and extraction technologies and new coal gasification have contributed to the use of natural gas for power generation.

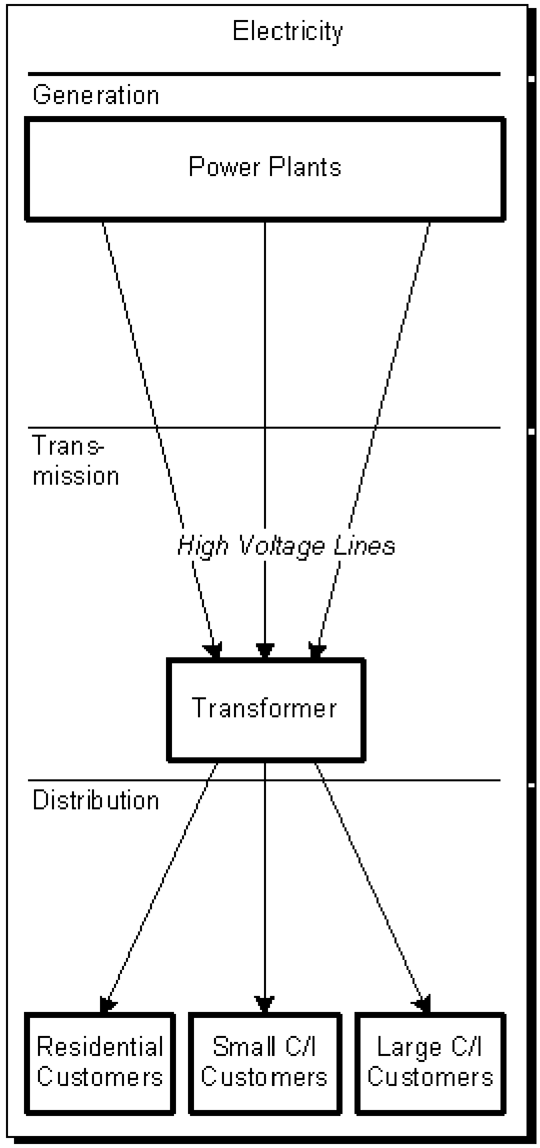

Figure 5-1. Traditional Electric Power Industry Structure

Nuclear plants and renewable energy sources (e.g., hydroelectric, solar, wind) provide approximately 20 percent and 10 percent of current generating capacity, respectively. However, there are no plans for new nuclear facilities to be constructed, and there is little additional growth forecasted in renewable energy.

Transmission. Transmission refers to high voltage lines used to link generators to substations where power is stepped down for local distribution. Transmission systems have been traditionally characterized as a collection of independently operated networks or grids interconnected by bulk transmission interfaces.

Within a well-defined service territory, the regulated utility has historically had responsibility for all aspects of developing, maintaining, and operating transmissions. These responsibilities included

- system planning and expanding,
- maintaining power quality and stability, and
- responding to failures.

Isolated systems were connected primarily to increase (and lower the cost of) power reliability. Most utilities maintained sufficient generating capacity to meet customer needs, and bulk transactions were initially used only to support extreme demands or equipment outages.

Distribution. Low-voltage distribution systems that deliver electricity to customers comprise integrated networks of smaller wires and substations that take the higher voltage and step it down to lower levels to match customers' needs.

The distribution system is the classic example of a natural monopoly because it is not practical to have more than one set of lines running through neighborhoods or from the curb to the house.

5.1.1.3 Current Electric Power Supply Chain

This section provides background on existing activities and emerging participants in the electric power supply chain.[4] Because the restructuring plans and time tables are made at the state level, the issues of asset ownership and control throughout the current supply chain in the electric power industry vary from state to state. However, the activities conducted throughout the supply chain are generally the same.

Table 5-1 shows costs by utility ownership and by segment of the supply chain. Generation accounts for approximately 75 percent of the cost of delivered electric power.

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[4]The electric power supply chain includes all generation, transmission, distribution, administrative, and market activities needed to deliver electric power to consumers.

Table 5-1. Total Expenditures in 1996 ($$10^3$)

Utility Ownership	Generation	Transmission	Distribution	Customer Accounts and Sales	Administration and General Expenses
Investor-owned	80,891,644	2,216,113	6,124,443	6,204,229	13,820,059
Publicly owned	12,495,324	840,931	1,017,646	486,195	1,360,111
Federal	3,685,719	327,443	1,435	55,536	443,809
Cooperatives	15,105,404	338,625	1,133,984	564,887	1,257,015
	112,178,091	3,723,112	8,277,508	7,310,847	16,880,994
	75.6%	2.5%	5.6%	4.9%	11.4%
	148,370,552				

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1998a. *Financial Statistics of Major Publicly Owned Electric Utilities, 1997*. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1997. *Financial Statistics of Major U.S. Investor-Owned Electric Utilities, 1996*. Washington, DC: U.S. Department of Energy.

Figure 5-2 provides an overview of the electric power supply chain, highlighting a combination of activities and service providers. The activities/members of the electric power supply chain are typically grouped into generation, transmission, and distribution. These three segments are described in the following sections.

Generation. As part of deregulation, the transmission and distribution of electricity are being separated from the business of generating electricity, and a new competitive market in electricity generation is evolving. As power generators prepare for the competitive market, the share of electricity generation attributed to nonutilities and utilities is shifting.

More than 7,000 electricity suppliers currently operate in the U.S. market. As shown in Table 5-2, approximately 42 percent of suppliers are utilities and 58 percent are nonutilities. Utilities include investor-owned, cooperatives, and municipal systems. Of the approximately 3,100 utilities operating in the United States, only about 700 generate electric power. The majority of utilities distribute electricity that they have purchased from power generators via their own distribution systems.

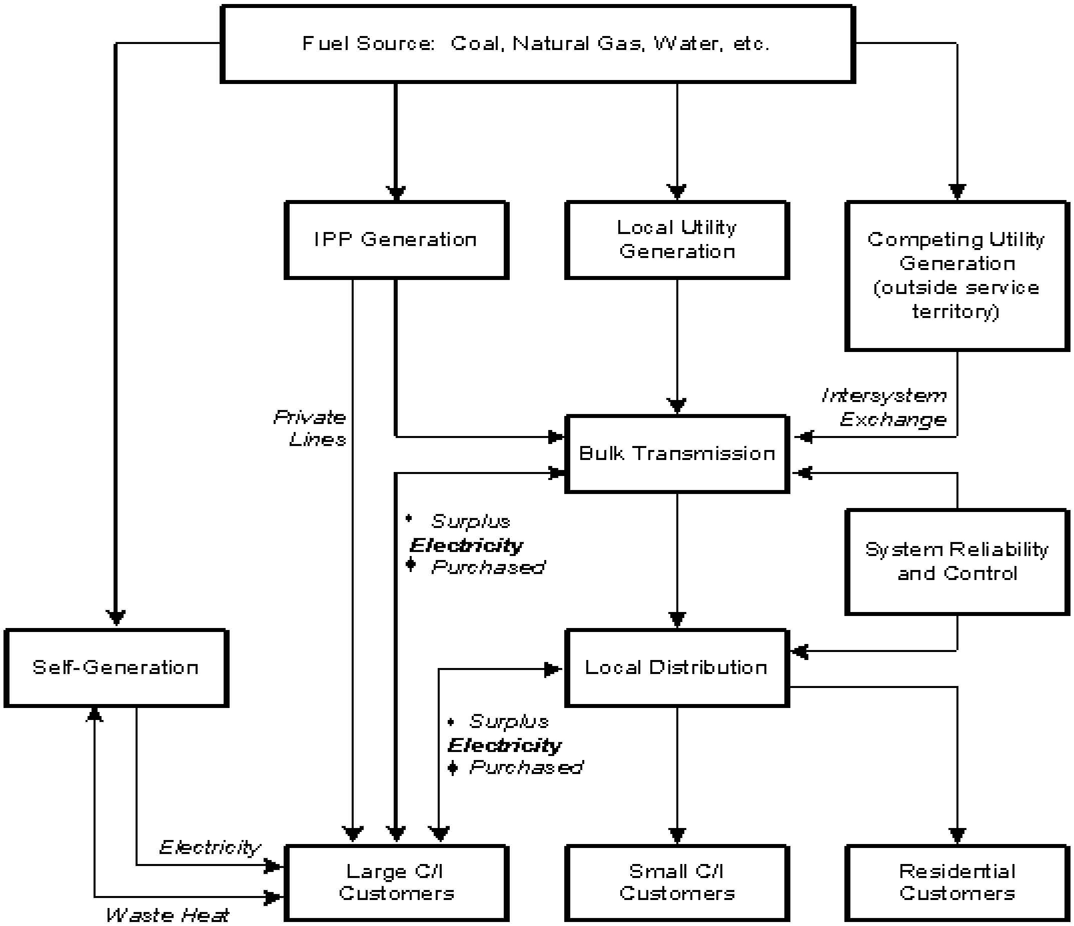


Figure 5-2. Electric Utility Industry

Utility and nonutility generators produced a total of 3,369 billion kWh in 1995. Although utilities generate the vast majority of electricity produced in the United States, nonutility generators are quickly eroding utilities' shares of the market. Nonutility generators include private entities that generate power for their own use or to sell to utilities or other end users. Between 1985 and 1995, nonutility generation increased from 98 billion kWh (3.8 percent of total generation) to 374 billion kWh (11.1 percent). Figure 5-3 illustrates this shift in the share of utility and nonutility generation.

Table 5-2. Number of Electricity Suppliers in 1999

Electricity Suppliers	Number	Percent
Utilities	3,124	42%
Investor-owned utilities	222	
Cooperatives	875	
Municipal systems	1,885	
Public power districts	73	
State projects	55	
Federal agencies	14	
Nonutilities	4,247	58%
Nonutilities (excluding EWGs)	4,103	
Exempt wholesale generators	144	
Total	7,371	100%

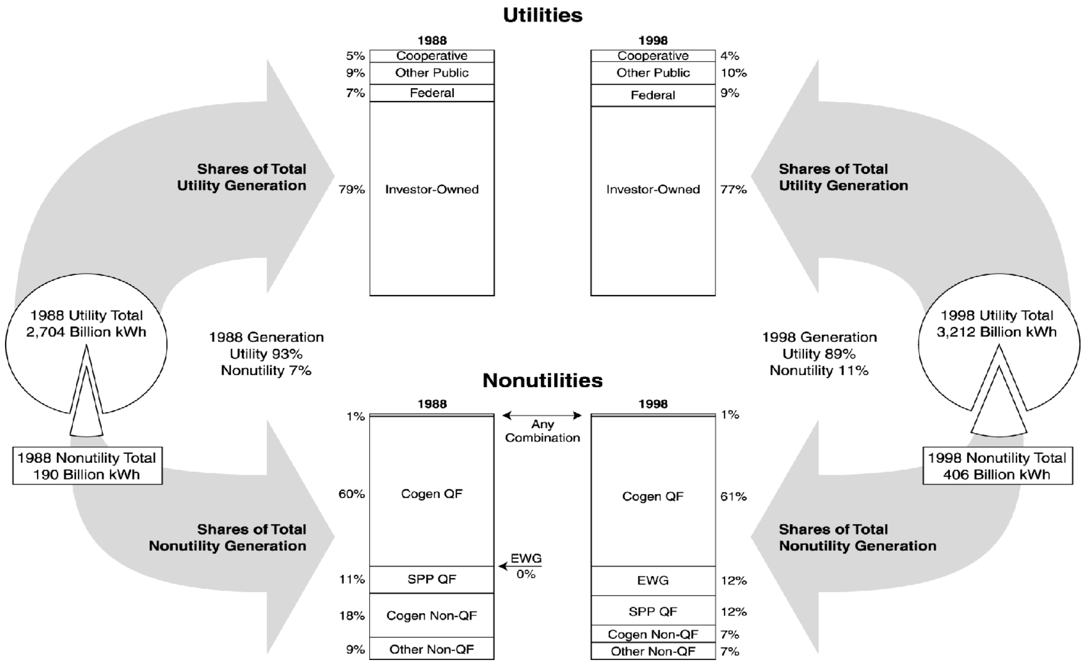
Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999g. *The Changing Structure of the Electric Power Industry 1999: Mergers and Other Corporate Combinations.* Washington, DC: U.S. Department of Energy.

Utilities. There are four categories of utilities: investor-owned utilities (IOUs), publicly owned utilities, cooperative utilities, and federal utilities. Of the four, only IOUs always generate electricity.

IOUs are increasingly selling off generation assets to nonutilities or converting those assets into nonutilities (Haltmaier, 1998). To prepare for the competitive market, IOUs have been lowering their operating costs, merging, and diversifying into nonutility businesses.

In 1995, utilities generated 89 percent of electricity, a decrease from 96 percent in 1985. IOUs generate the majority of the electricity produced in the United States. IOUs are either individual corporations or a holding company, in which a parent company operates one or more utilities integrated with one another. IOUs account for approximately three-quarters of utility generation, a percentage that held constant between 1985 and 1995.

Utilities owned by the federal government accounted for about one-tenth of generation in both 1985 and 1995. The federal government operated a small number of large utilities in 1995 that supplied power to large industrial consumers or federal installations. The Tennessee Valley Authority is an example of a federal utility.



[a] Includes facilities classified in more than one of the following FERC designated categories: cogenerator QF, small power producer QF, or exempt wholesale generator.
Cogen = Cogenerator.
EWG = Exempt wholesale generator.
Other Non-QF = Nocogenerator Non-QF.
QF = Qualifying facility.
SPP = Small power producer.
Note: Sum of components may not equal total due to independent rounding. Classes for nonutility generation are determined by the class of each generating unit.
Sources: **Utility data:** U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. DOE/EIA-0348(95)/1. Washington, DC: U.S. Department of Energy; Table 8 (and previous issues); **Nonutility data:** Shares of generation estimated by EIA; total generation from Edison Electric Institute (EEI). 1998. *Statistical Yearbook of the Electric Utility Industry 1998*. November. Washington, DC;

Figure 5-3. Utility and Nonutility Generation and Shares by Class, 1988 and 1998

Many states, municipalities, and other government organizations also own and operate utilities, although the majority do not generate electricity. Those that do generate electricity operate capacity to supply some or all of their customers' needs. They tend to be small, localized outfits and can be found in 47 states. These publicly owned utilities accounted for about one-tenth of utility generation in 1985 and 1995. In a deregulated market, these generators may be in direct competition with other utilities to service their market.

Rural electric cooperatives are the fourth category of utilities. They are formed and owned by groups of residents in rural areas to supply power to those areas. Cooperatives generally purchase from other utilities the energy that they sell to customers, but some generate their own power. Cooperatives only produced 5 percent of utility generation in 1985 and only 6 percent in 1995.

Nonutilities. Nonutilities are private entities that generate power for their own use or to sell to utilities or other establishments. Nonutilities are usually operated at mines and manufacturing facilities, such as chemical plants and paper mills, or are operated by electric and gas service companies (DOE, EIA, 1998b). More than 4,200 nonutilities operate in the United States.

Between 1988 and 1998, nonutility generators increased their share of electricity generation from 7 percent to 11 percent (see Figure 5-3). In 1978, the Public Utilities Regulatory Policies Act (PURPA) stipulated that electric utilities must interconnect with and purchase capacity and energy offered by any qualifying nonutility. In 1996, FERC issued Orders 888 and 889 that opened transmission access to nonutilities and required utilities to share information about available transmission capacity. These moves established wholesale competition, spurring nonutilities to increase generation and firms to invest in nonutility generation.

Nonutilities are frequently categorized by their FERC classification and the type of technology they employ. There are three categories of nonutilities: cogenerators, small power producers (SPPs), and exempt wholesale generators (EWGs).

Cogenerators are nonutilities that sequentially or simultaneously produce electricity and another form of energy (such as heat or steam) using the same fuel source. At cogeneration facilities, steam is used to drive a turbine to generate electricity. The waste heat and steam from driving the turbine is then used as an input in an industrial or commercial process. For a cogenerator to qualify or interconnect with utilities, it must meet certain ownership, operating, and efficiency criteria specified by FERC. In 1985, about 55 percent of nonutility generation was produced by cogenerators that qualified or met FERC's specifications and sold power to utilities. By 1995 the percentage increased to 67 percent as the push for deregulation gathered momentum. At the same time, the percentage that was produced by nonqualifying cogenerators decreased from 25 percent to 9 percent.

SPPs typically generate power using renewable resources, such as biomass, solar energy, wind, or water. However, increasingly SPPs include companies that self-generate power using combustion turbines and sell excess power back to the grid. As with cogenerators, SPPs must fulfill a series of FERC requirements to interconnect with utilities. PURPA revisions enabled nonutility renewable electricity to grow significantly, and SPPs have responded by improving technologies, decreasing costs, and increasing efficiency and reliability (DOE, EIA, 1998b). Between 1985 and 1995, the percentage of SPP nonutility generation nearly doubled to 13 percent.

EWGs produce electricity for the wholesale market. Also known as IPPs, EWGs typically contract directly with large bulk customers, such as large industrial and commercial facilities and utilities. They do not operate any transmission or distribution facilities but pay tariffs to use facilities owned and operated by utilities. Unlike with qualifying cogenerators and SPPs, utilities are not required to purchase energy produced by EWGs, but they may do so at market-based prices. EWGs did not exist until the Energy Policy Act created them in 1992, and by 1995 they generated about 2 percent of nonutility electricity.

In 1995, about 4 percent of nonutility generation was produced by facilities that were classified as any combination of cogenerator, SPP, and EWG. An additional 6 percent was produced by facilities that generate electricity for their own consumption.

Transmission. Whereas the market for electricity generation is moving toward a competitive structure, the transmission of electricity is currently (and will likely remain) a regulated, monopoly operation. In areas where power markets are developing, generators pay tariffs to distribute their electricity over established lines owned and maintained by independent organizations. Independent service operators (ISOs) will most likely coordinate transmission operations and generation dispatch over the bulk power system.

The bulk power transmission system consists of three large regional networks, which also encompass smaller groups. The three networks are geographically defined: the Eastern Interconnect in the eastern two-thirds of the nation; the Western Interconnect in the western portion; and the Texas Interconnect, which encompasses the majority of Texas. The western and eastern networks are each fully integrated with Canada. The western is also integrated with Mexico. Within each network, the electricity producers are connected by extra high-voltage connections that allow them to transfer electrical energy from one part of the network to the other.

The bulk power system makes it possible for electric power producers to engage in wholesale trade. In 1995, utilities sold 1,283 billion kWh to other utilities. The amount of energy sold by nonutilities has increased dramatically from 40 billion kWh in 1986 to 222 billion kWh in 1995, an average annual increase of 21 percent (DOE, EIA, 1996a). Distribution utilities and large industrial and commercial customers also have the option of purchasing electricity in bulk at market prices from their local utility, a nonutility, or another utility. The process of transmitting electricity between suppliers via a third party is known as wholesale wheeling.

The wholesale trade for electricity is increasingly handled by power marketers (brokers). Power marketers act as independent middlemen that buy and sell wholesale electricity at market prices (EEI, 1999). Customers include large commercial and industrial facilities in addition to utilities. Power marketers emerged in response to increased competition. Brokers do not own generation facilities, transmissions systems, or distribution assets, but they may be affiliated with a holding company that operates generation facilities. Currently, 570 power marketers operate in the United States. The amount of power sold by marketers increased from 3 million MWh to 2.3 billion MWh between 1995 and 1998. This is the equivalent of going from powering 1 million homes to powering 240 million homes (EEI, 1999). Table 5-3 lists the top ten power marketers by sales for the first quarter of 1999.

Table 5-3. Top Power Marketing Companies, First Quarter 1999

Company	Total MWh Sold
Enron Power Marketing, Inc.	78,002,931
Southern Company Energy Marketing, L.P.	38,367,107
Aquila Power Corp.	29,083,612
PG&E Energy Trading-Power, L.P.	28,463,487
Duke Energy Trading & Marketing, L.L.C.	22,276,608
LG&E Energy Marketing, Inc.	15,468,749
Entergy Power Marketing Corp.	12,670,520
PacifiCorp Power Marketing, Inc.	11,800,263
Tractebel Energy Marketing, Inc.	10,041,039
NorAm Energy Services, Inc.	9,817,306

Source: Resource Data International. 1999. "PMA Online Top 25 Power Marketer Rankings." *Power Marketers Online Magazine*. <http://www.powermarketers.com/top25a.htm.> As obtained on August 11, 1999.

Distribution. The local distribution system for electricity is expected to remain a regulated monopoly operation. But power producers will soon be able to compete for retail customers by paying tariffs to entities that distribute the power. Utilities may designate an

ISO to operate the distribution system or continue to operate it themselves. If the utility operates its own system, it is required by law to charge the same tariff to other power producers that it charges producers within its own corporate umbrella. The sale of electricity by a utility or other supplier to a customer in another utility's retail service territory is known as retail wheeling.

Supporters of retail wheeling claim that it will help lower the average price paid for electricity. The states with the highest average prices for electricity are expected to be the first to permit retail wheeling; wholesale wheeling is already permitted nationwide. In 1996, California, New England, and the Mid-Atlantic States had the highest average prices for electricity, paying 3 cents or more per kilowatt-hour than the national average of 6.9 cents (DOE, EIA, 1998b). Open access to the electricity supply, coupled with a proliferation of electricity suppliers, should combine to create falling electricity prices and increasing usage. By 2002, the nationwide average price for electricity is projected to be 11 percent lower than in 1995, an average annual decline of roughly 2 percent (Haltmaier, 1998).

The explosion in computer and other information technology usage in the commercial sector is expected to offset energy efficiency gains in the residential and industrial sectors and lead to a net increase in the demand for electricity. Retail wheeling has the potential to allow customers to lower their costs per kilowatt-hour by purchasing electricity from suppliers that best fit their usage profiles. Large commercial and industrial customers engaged in self-generation or cogeneration will also be able to sell surplus electricity in the wholesale market.

5.1.1.4 Overview of Deregulation and the Potential Future Structure of the Electricity Market

Beginning in the latter part of the 19th century and continuing for about 100 years, the prevailing view of policymakers and the public was that the government should use its power to require or prescribe the economic behavior of "natural monopolies" such as electric utilities. The traditional argument is that it does not make economic sense for there to be more than one supplier—running two sets of wires from generating facilities to end users is more costly than one set. However, since monopoly supply is not generally regarded as likely to provide a socially optimal allocation of resources, regulation of rates and other economic variables was seen as a necessary feature of the system.

Beginning in the 1970s, the public policy view shifted against traditional regulatory approaches and in favor of deregulation for many important industries including transportation, communications, finance, and energy. The major drivers for deregulation of electric power included the following:

- existence of rate differentials across regions offering the promise of benefits from more efficient use of existing generation resources if the power can be transmitted across larger geographic areas than was typical in the era of industry regulation;
- the erosion of economies of scale in generation with advances in combustion turbine technology;
- complexity of providing a regulated industry with the incentives to make socially efficient investment choices;
- difficulty of providing a responsive regulatory process that can quickly adjust rates and conditions of service in response to changing technological and market conditions; and
- complexity of monitoring utilities' cost of service and establishing cost-based rates for various customer classes that promote economic efficiency while at the same time addressing equity concerns of regulatory commissions.

Viewed from one perspective, not much changes in the electric industry with restructuring. The same functions are being performed, essentially the same resources are being used, and in a broad sense the same reliability criteria are being met. In other ways, the very nature of restructuring, the harnessing of competitive forces to perform a previously regulated function, changes almost everything. Each provider and each function become separate competitive entities that must be judged on their own.

This move to market-based provision of generation services is not matched on the transmission and distribution side. Network interactions on AC transmission systems have made it impossible to have separate transmission paths compete. Hence, transmission and distribution remain regulated. Transmission and generation heavily interact, however, and transmission congestion can prevent specific generation from getting to market. Transmission expansion planning becomes an open process with many interested parties. This open process, coupled with frequent public opposition to transmission expansion, slows transmission enhancement. The net result is greatly increased pressure on the transmission system.

Restructuring of the electric power industry could result in any one of several possible market structures. In fact, different parts of the country will probably use different structures, as the current trend indicates. The eventual structure may be dominated by a power exchange, bilateral contracts, or a combination. A strong Regional Transmission

Organization (RTO) may operate in the area, or a vertically integrated utility may continue to operate a control area. In any case, several important characteristics will change:

- Commercial provision of generation-based services (e.g., energy, regulation, load following, voltage control, contingency reserves, backup supply) will replace regulated service provision. This drastically changes how the service provider is assessed.

- Individual transactions will replace aggregated supply meeting aggregated demand. It will be necessary to continuously assess each individual's performance.

- Transaction sizes will shrink. Instead of dealing only in hundreds and thousands of MW, it will be necessary to accommodate transactions of a few MW and less.

- Supply flexibility will greatly increase. Instead of services coming from a fixed fleet of generators, service provision will change dynamically among many potential suppliers as market conditions change.

5.1.2 Electricity Generation

Because of the uncertainties associated with the future course of deregulation, forecasting deregulation's impact on generation trends, and hence growth in combustion turbines, is difficult. However, most industry experts believe that deregulation will lead to increased competition in the wholesale (and eventually retail) power markets, driving out high cost producers of electricity, and that there will be an increased reliance on distributed generation to compensate for growing demands on the transmission system.

In 2000, the United States relied on fossil fuels to produce almost 74 percent of its electricity. Table 5-4 shows a breakdown of generation by energy source.[5] Whereas natural gas seems to play a relatively minor role among utility producers, it represents 30 percent of capacity among nonutility producers. This is because nonutilities use coal and petroleum to the same extent as the larger, traditionally regulated utility power producers.

Among nonutility producers, manufacturing facilities contain the largest electricity-generating capacity. Table 5-5 illustrates that, from 1995 through 1997, manufacturing

[5]Nonutility power producers have approximately 10 percent of the capacity of utility power producers.

Table 5-4. Industry Capacity by Energy Source, 2000

Energy Source	Utility Generators (MW)	Nonutility Generators (MW)	Total (MW)
Fossil fuels	424,218	173,320	597,538
Coal	259,059	56,190	315,249
Natural gas	38,964	58,668	97,632
Petroleum	26,250	13,003	39,253
Duel-fired	99,945	45,549	145,494
Nuclear	85,519	12,038	97,557
Hydroelectric	91,590	7,478	99,068
Renewable/other	1,050	16,322	17,372
Total	602,377	209,248	811,625

Sources: U.S. Department of Energy, Energy Information Administration. 2000a. *Electric Power Annual, 1999*, Volume II. DOE/EIA-0348(99)/2. Washington, DC: U.S. Department of Energy.

Table 5-5. Installed Capacity at U.S. Nonutility Attributed to Major Industry Groups and Census Division, 1995 through 1999 (MW)

Year	Manufacturing	Transportation and Public Utilities	Services	Mining	Public Administration	Other Industry Groups	Total
1995	47,606	15,124[a]	2,165	3,428	544	1,388[a]	70,254
1996	49,529	16,050	2,181	3,313	542	1,575	73,189
1997	49,791	16,559	2,223	3,306	616	1,510	74,004
1998	51,255	24,527	2,506	3,275	534	15,989	98,085
1999	52,430	78,419	2,342	5,123	536	28,506	167,357

[a] Revised data.

Notes: All data are for 1 MW and greater. Data for 1997 are preliminary; data for prior years are final. Totals may not equal sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 2000a. *Electric Power Annual 1999,* Volume II. DOE/EIA-0348(99)/2. Washington, DC: U.S. Department of Energy.

facilities consistently had the capacity to produce over two-thirds of nonutility electricity generation. However, manufacturing share fell to less than one half of nonutility capacity in 1998/1999.

In 1997 cogenerators produced energy totaling 146 billion kWh for their own use. Cogenerators are expected to continue to increase their generation capabilities at a slightly slower rate than utilities.

Table 5-6 further disaggregates capacity by prime mover and energy source at electric utilities. As the table shows, hydroelectric and steam are the two prime movers with the most units, while steam and nuclear generators have the greatest total capacity. Combustion turbines' (including the second stage of CCCTs) generation represents approximately 10 percent of total U.S. capacity.

Figure 5-4 shows the annual electricity sales by sector from 1970 with projections through 2020.

The literature suggests that electricity consumption is relatively price inelastic. Consumers are generally unable or unwilling to forego a large amount of consumption as the price increases. Numerous studies have investigated the short-run elasticity of demand for electricity. Overall, the studies suggest that, for a 1 percent increase in the price of electricity, demand will decrease by 0.15 percent. However, as Table 5-7 shows, elasticities vary greatly, depending on the demand characteristics of end users and the price structure. Demand elasticities are estimated to range from a –0.05 percent elasticity of demand for a "flat rates" case (i.e., no time-of-use assumption) up to a –0.50 percent demand elasticity for a "high consumer response" case (DOE, EIA, 1999b).

5.1.2.1 Growth in Generation Capacity

The electric industry is continuing to grow and change. Throughout the country, electric utility capacity additions are slightly outpacing capacity retirements. The trend goes beyond an increasing capacity but also shows that coal units are slowly being replaced by newer, more efficient methods of producing energy. In 1997, 71 electric utility units were closed, decreasing capacity by 2,127 MW. Of those, six were coal facilities and 43 were petroleum facilities. However, of the 62 facility additions (2,918 MW), none were coal powered, while 24 use petroleum. Gas installations slightly outpaced petroleum ones, totaling 25 new units at electric utilities in 1997. Table 5-8 outlines capacity additions and retirements at U.S. electric utilities by energy source.

Table 5-6. Existing Capacity at U.S. Electric Utilities by Prime Mover and Energy Source, as of January 1, 1998

Prime Mover Energy Source	Number of Units	Generator Nameplate Capacity (MW)
U.S. Total	10,421	754,925
Steam	2,117	469,210
Coal only	911	276,895
Other solids[a]	15	334
Petroleum only	137	22,476
Gas only	117	10,840
Other solids/coal[a]	1	2
Solids/petroleum[b]	72	10,796
Solids/gas[b]	232	36,763
Solids/petroleum/gas[b]	1	558
Petroleum/gas	624	110,324
Internal Combustion	2,892	5,075
Petroleum only	1,799	2,671
Gas only	48	66
Petroleum/gas	1,044	2,335
Other solids only[a]	1	3
Combustion Turbine	1,549	63,131
Petroleum only	625	22,802
Gas only	179	5,776
Petroleum/gas	745	34,554
Second Stage of CCCTs	202	16,224
Petroleum only	11	470
Gas only	29	2,331
Coal/petroleum	1	326
Coal/gas	1	113
Petroleum/gas	100	8,852
Waste heat	60	4,130
Nuclear	107	107,632
Hydroelectric (conventional)	3,352	73,202
Hydroelectric (pumped storage)	141	18,669
Geothermal	27	1,746
Solar	11	5
Wind	19	14

[a] Includes wood, wood waste, and nonwood waste.

[b] Includes coal, wood, wood waste, and nonwood waste.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

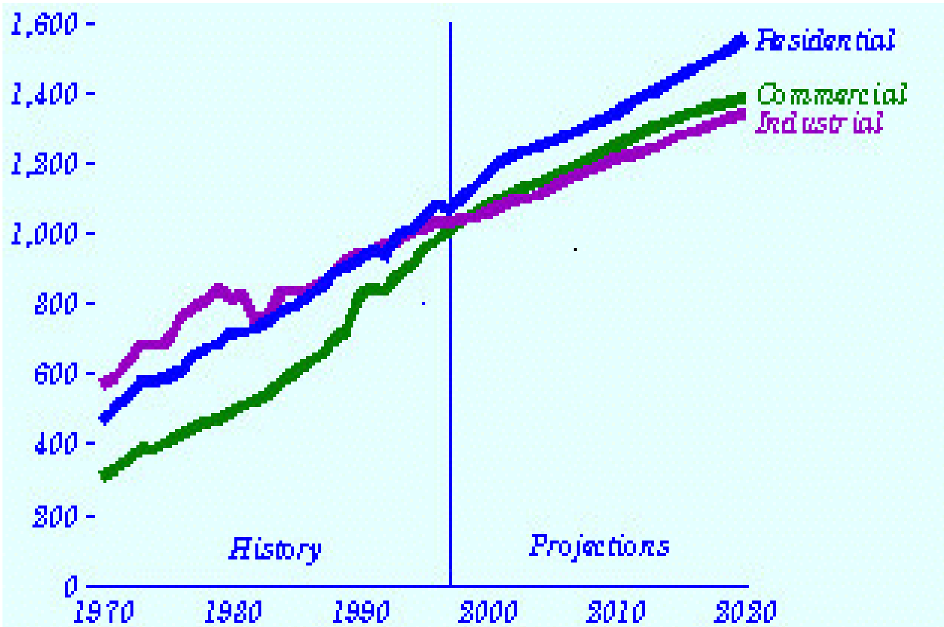


Figure 5-4. Annual Electricity Sales by Sector

Planned additions indicate a strong trend towards gas-powered turbine/stationary combustion units. Three-quarters of the gas turbine/stationary combustion units are expected to be gas-powered with the remaining quarter petroleum-powered. Based on 1998 planned additions, it is likely that all additional petroleum-fueled units in the near future will be gas turbine/stationary combustion units, not steam. Table 5-9 shows planned capacity additions by prime mover and energy source.

5.1.3 Electricity Consumption

This section analyzes the growth projections for electricity consumption as well as the price elasticity of demand for electricity. Growth in electricity consumption has traditionally paralleled GDP growth. However, improved energy efficiency of electrical equipment, such as high-efficiency motors, has slowed demand growth over the past few decades. The magnitude of the relationship has been decreasing over time, from growth of 7 percent per year in the 1960s down to 1 percent in the 1980s. As a result, determining what

Table 5-7. Key Parameters in the Cases

Case Name	Key Assumptions: Cost Reduction and Efficiency Improvements	Short-Run Elasticity of Demand (Percent)	Natural Gas Prices	Capacity Additions
AEO97 Reference Case	AEO97 Reference Case	—	AEO97 Reference Case	As needed to meet demand
No Competition	No change from 1995	—	AEO97 Reference Case	As needed to meet demand
Flat Rates (no time-of-use rates)	AEO97 Reference Case	–0.05	AEO97 Reference Case	As needed to meet demand
Moderate Consumer Response	AEO97 Reference Case	–0.15	AEO97 Reference Case	As needed to meet demand
High Consumer Response	AEO97 Reference Case	–0.50	AEO97 Reference Case	As needed to meet demand
High Efficiency	Increased cost savings and efficiencies	–0.15	AEO97 Reference Case	As needed to meet demand
No Capacity Additions	AEO97 Reference Case	–0.15	AEO97 Low Oil and Gas Supply Technology Case	Not allowed
High Gas Price	AEO97 Reference Case	–0.15	AEO97 High Oil and Gas Supply Technology Case	As needed to meet demand
Low Gas Price	AEO97 Reference Case	–0.15	AEO97 Reference Case	As needed to meet demand
High Value of Reliability	AEO97 Reference Case	–0.15	AEO97 Reference Case	As needed to meet demand
Half O&M	AEO97 Reference Case	–0.15	AEO97 Reference Case	As needed to meet demand
Intense Competition	AEO97 Reference Case	–0.15	AEO97 Reference Case	As needed to meet demand

— = not applicable.

Source: U.S. Department of Energy, Energy Information Administration, Office of Integrated Analysis and Forecasting. "Competitive Electricity Price Projections." <http://www.eia.doe.gov/oiaf/elepri97/chap3.html>. As obtained on November 15, 1999b.

Table 5-8. Capacity Additions and Retirements at U.S. Electric Utilities by Energy Source, 1997

	Additions		Retirements	
Primary Energy Source	**Number of Units**	**Generator Nameplate Capacity (MW)**	**Number of Units**	**Generator Nameplate Capacity (MW)**
U.S. total	62	2,918	71	2127
Coal	—	—	6	281
Petroleum	24	199	43	445
Gas	25	2,475	18	405
Water (pumped storage hydroelectric)	—	—	—	—
Nuclear	—	—	2	995
Waste heat	3	171	—	—
Renewable[a]	10	73	2	1

[a] Includes conventional hydroelectric; geothermal; biomass (wood, wood waste, nonwood waste); solar; and wind.

Note: Total may not equal the sum of components because of independent rounding.

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

the future growth will be is difficult, although it is expected to be positive (DOE, EIA, 1999a). Table 5-10 shows consumption by sector of the economy over the past 10 years. The table shows that since 1989 electricity sales have increased at least 10 percent in all four sectors. The commercial sector has experienced the largest increase, followed by residential consumption.

In the future, residential demand is expected to be at the forefront of increased electricity consumption. Between 1997 and 2020, residential demand is expected to increase at 1.6 percent annually. Commercial growth in demand is expected to be approximately 1.4 percent, while industry is expected to increase demand by 1.1 percent (DOE, EIA, 1999a).

Table 5-9. Fossil-Fueled Existing Capacity and Planned Capacity Additions at U.S. Electric Utilities by Prime Mover and Primary Energy Source, as of January 1, 1998

Prime Mover Energy Source	Planned Additions[a]	
	Number of Units	Generator Nameplate Capacity (MW)
U.S. Total	272	50,184
Steam	45	18,518
Coal	8	2,559
Petroleum	—	—
Gas	37	15,959
Gas Turbine/Internal Combustion	226	31,663
Petroleum	52	1,444
Gas	174	30,219

[a] Planned additions are for 1998 through 2007. Totals include one 2.9 MW fuel cell unit.

Notes: Total may not equal the sum of components because of independent rounding. The Form EIA-860 was revised during 1995 to collect data as of January 1 of the reporting year, where "reporting year" is the calendar year in which the report is required to be filed with the Energy Information Administration. These data reflect the status of electric plants/generators as of January 1; however, dynamic data are based on occurrences in the previous calendar year (e.g., capabilities and energy sources based on test and consumption in the previous year).

Source: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

Table 5-10. U.S. Electric Utility Retail Sales of Electricity by Sector, 1989 Through July 1999 (Million kWh)

Period	Residential	Commercial	Industrial	Other[a]	All Sectors
1989	905,525	725,861	925,659	89,765	2,646,809
1990	924,019	751,027	945,522	91,988	2,712,555
1991	955,417	765,664	946,583	94,339	2,762,003
1992	935,939	761,271	972,714	93,442	2,763,365
1993	994,781	794,573	977,164	94,944	2,861,462
1994	1,008,482	820,269	1,007,981	97,830	2,934,563
1995	1,042,501	862,685	1,012,693	95,407	3,013,287
1996	1,082,491	887,425	1,030,356	97,539	3,097,810
1997	1,075,767	928,440	1,032,653	102,901	3,139,761
1998	1,124,004	948,904	1,047,346	99,868	3,220,121
Percentage change 1989-1998	19%	24%	12%	10%	18%

[a] Includes public street and highway lighting, other sales to public authorities, sales to railroads and railways, and interdepartmental sales.

Sources: U.S. Department of Energy, Energy Information Administration (EIA). 1999c. *Electric Power Annual 1998*. Volumes I and II. Washington, DC: U.S. Department of Energy.

U.S. Department of Energy, Energy Information Administration (EIA). 1996b. *Electric Power Annual 1995*. Volumes I and II. Washington, DC: U.S. Department of Energy.

SECTION 6

ECONOMIC ANALYSIS METHODS

This section presents the methodology for analyzing the economic impacts of the NSPS. Implementation of this methodology will provide the economic data and supporting information needed by EPA to support its regulatory determination. This analysis is based on microeconomic theory and the methods developed for earlier EPA studies to operationalize this theory. These methods are tailored to and extended for this analysis, as appropriate, to meet EPA's requirements for an economic impact analysis (EIA) of controls placed on stationary combustion turbines.

This methodology section includes a description of the Agency requirements for conducting an EIA, background information on typical economic modeling approaches, the conceptual approach selected for this EIA, and an overview of the computerized market model used in the analysis. The focus of this section is on the approach for modeling the electricity market and its interactions with other energy markets and final product markets. Appendix A contains additional detail on estimating changes is producer and consumer surplus in the nonelectric utility markets included in the economic model.

6.1 Agency Requirements for Conducting an EIA

The CAA provides the statutory authority under which all air quality regulations and standards are implemented by OAQPS. The 1990 CAA Amendments require that EPA establish emission standards for sources releasing any of the listed HAPs.

Congress and the Executive Office have imposed requirements for conducting economic analyses to accompany regulatory actions. The Agency has published its guidelines for developing an EIA (EPA, 1999a). Section 312 of the CAA specifically requires a comprehensive analysis that considers benefits, costs, and other effects associated with compliance. On the benefits side, it requires consideration of all the economic, public health, and environmental benefits of compliance. On the cost side, it requires consideration of the effects on employment, productivity, cost of living, economic growth, and the overall economy. These effects are evaluated by measures of facility- and company-level production impacts and societal-level producer and consumer welfare impacts. The RFA and SBREFA require regulatory agencies to consider the economic impacts of regulatory actions on small entities. Executive Order 12866 requires regulatory agencies to conduct an analysis of the economic benefits and costs of all proposed regulatory actions with projected impacts (costs plus benefits) greater than $100 million. Also, Executive Order 13211 requires EPA to consider for particular rules the impacts on energy markets. The Agency's draft Economic Analysis Guidelines provide detailed instructions and expectations for economic analyses that support rulemaking (EPA, 1999a). The EIA provides the data and information needed to comply with the federal regulation, the executive order, and the guidance manual.

6.2 Overview of Economic Modeling Approaches

In general, the EIA methodology needs to allow EPA to consider the effect of the different regulatory alternatives. Several types of economic impact modeling approaches have been developed to support regulatory development. These approaches can be viewed as varying along two modeling dimensions:

- the scope of economic decisionmaking accounted for in the model and
- the scope of interaction between different segments of the economy.

Each of these dimensions was considered in recommending our approach. The advantages and disadvantages of each are discussed below.

6.2.1 Modeling Dimension 1: Scope of Economic Decisionmaking

Models incorporating different levels of economic decisionmaking can generally be categorized as *with* behavior responses and *without* behavior responses (accounting approach). Table 6-1 provides a brief comparison of the two approaches. The behavioral approach is grounded in economic theory related to producer and consumer behavior in response to changes in market conditions. In essence, this approach models the expected reallocation of society's resources in response to a regulation. The behavioral approach explicitly models the changes in market prices and production. Resulting changes in price and quantity are key inputs into the determination of a number of important phenomena in an EIA, such as changes in producer surplus, changes in consumer surplus, and net social welfare effects. For example, a large price increase may imply that consumers bear a large share of the regulatory burden, thereby mitigating the impact on producers' profits and plant closures.

In contrast, the nonbehavioral/accounting approach essentially holds fixed all interaction between facility production and market forces. In this approach, a simplifying assumption is made that the firm absorbs all control costs, and discounted cash flow analysis is used to evaluate the burden of the control costs. Typically, engineering control costs are weighted by the number of affected units to develop "engineering" estimates of the total annualized costs. These costs are then compared to company or industry sales to evaluate

Table 6-1. Comparison of Modeling Approaches

EIA With Behavioral Responses
Incorporates control costs into production function
Includes change in quantity produced
Includes change in market price
Estimates impacts for
• affected producers
• unaffected producers
• consumers
• foreign trade
EIA Without Behavioral Responses
• Assumes firm absorbs all control costs
• Typically uses discounted cash flow analysis to evaluate burden of control costs
• Includes depreciation schedules and corporate tax implications
• Does *not* adjust for changes in market price
• Does *not* adjust for changes in plant production

the regulation's impact.

6.2.2 Modeling Dimension 2: Interaction Between Economic Sectors

Because of the large number of markets potentially affected by the combustion turbines regulation, an issue arises concerning the level of sectoral interaction to model. In the broadest sense, all markets are directly or indirectly linked in the economy; thus, all commodities and markets are to some extent affected by the regulation. For example, the control costs on turbines may directly affect the market for aluminum if aluminum plants are operating turbines for self-generation of electricity or generation of process steam. However, control costs will also indirectly affect the market for aluminum because the cost of electricity will increase. As a result, the increased price of aluminum production (due to direct and indirect costs on the aluminum industry) may be passed onto consumers of aluminum products.

The appropriate level of market interactions to be included in the EIA is determined by the scope of the regulation across industries and the ability of affected firms to pass along the regulatory costs in the form of higher prices. Alternative approaches for modeling interactions between economic sectors can generally be divided in three groups:

- Partial equilibrium model: Individual markets are modeled in isolation. The only factor affecting the market is the cost of the regulation on facilities in the industry being modeled.

- General equilibrium model: All sectors of the economy are modeled together. General equilibrium models operationalize neoclassical microeconomic theory by modeling not only the direct effects of control costs, but also potential input substitution effects, changes in production levels associated with changes in market prices across all sectors, and the associated changes in welfare economywide. A disadvantage of general equilibrium modeling is that substantial time and resources are required to develop a new model or tailor an existing model for analyzing regulatory alternatives.

- Multiple-market partial equilibrium model: A subset of related markets are modeled together, with intersectoral linkages explicitly specified. To account for the relationships and links between different markets without employing a full general equilibrium model, analysts can use an integrated partial equilibrium model. In instances where separate markets are closely related and there are strong interconnections, there are significant advantages to estimating market adjustments in different markets simultaneously using an integrated market modeling approach.

6.3 Selected Modeling Approach Used for Combustion Turbine Analysis

To conduct the analysis for the combustion turbine NSPS, the Agency used a market modeling approach that incorporates behavioral responses in a multiple-market partial equilibrium model as described above. The majority of the regulation's control costs are projected to be associated with combustion turbines in the electricity market. These control costs will increase the price of energy, affecting almost all sectors of the economy. Because the elasticity of demand for energy varies across fuel types, it is important to use a market modeling approach to estimate the share of the burden borne by producers and consumers.

Multiple-market partial equilibrium analysis provides a manageable approach to incorporate interactions between energy markets and final product markets into the EIA to accurately estimate the impact of the regulation. The multiple-market partial equilibrium approach represents an intermediate step between a simple, single-market partial equilibrium approach and a full general equilibrium approach. This approach involves identifying and modeling the most significant subset of market interactions using an integrated partial equilibrium framework. In effect, the modeling technique is to link a series of standard partial equilibrium models by specifying the interactions between supply functions and then solving for all prices and quantities across all markets simultaneously.

Figure 6-1 presents an overview of the key market linkages included in the economic impact modeling approach used to analyze the combustion turbines NSPS. The focus of the analysis is on the energy supply chain, including the extraction and distribution of natural gas and oil, the generation of electricity, and the consumption of energy by producers of final products and services. As shown in Figure 6-1, wholesale electricity generators consume natural gas and petroleum products to generate electricity that is then used in the production of final products and services. In addition, the final product and service markets also use natural gas and petroleum products as an input into their production process. This analysis explicitly models the linkages between these market segments.

The control costs associated with the regulation will directly affect the cost of the generation of wholesale electricity using combustion turbines. In addition to the direct impact of control costs on entities installing new combustion turbines, indirect impacts are passed along the energy supply chain through changes in prices. For example, the price of natural gas will increase because of two effects: the higher price of electricity used in the natural gas industry and increased demand for natural gas generated by fuel switching from electricity to natural gas. Similarly, production costs for manufacturers of final products will change as a result of price of electricity and natural gas.

Also included in the impact model is feedback on changes in outputs in final product markets to the demand for Btus in the fuel markets. The change in facility output is determined by the size of the Btu cost increase (typically variable cost per output), the facility's production function (slope of facility-level supply curve), and the characteristics of the facility's downstream market (other market suppliers and market demanders). For example, if consumers' demand for a product is not sensitive to price, then producers can pass the cost of the regulation through to consumers and the facility output will not change. However, if only a small number of facilities in a market are affected, then competition will prevent a facility from raising its prices.

One possible feedback pathway *not* explicitly modeled is technical changes in manufacturing processes. For example, if the cost of Btus increases, a facility may use measures to increase manufacturing efficiency or capture waste heat. These facility-level responses are a form of pollution prevention. However, directly incorporating these responses into the model is beyond the scope of our analysis.[6]

[6]Technical changes are indirectly captured through the own-price and cross-price elasticities of demand used to model fuel switching. These are discussed in Section 6.4.1.

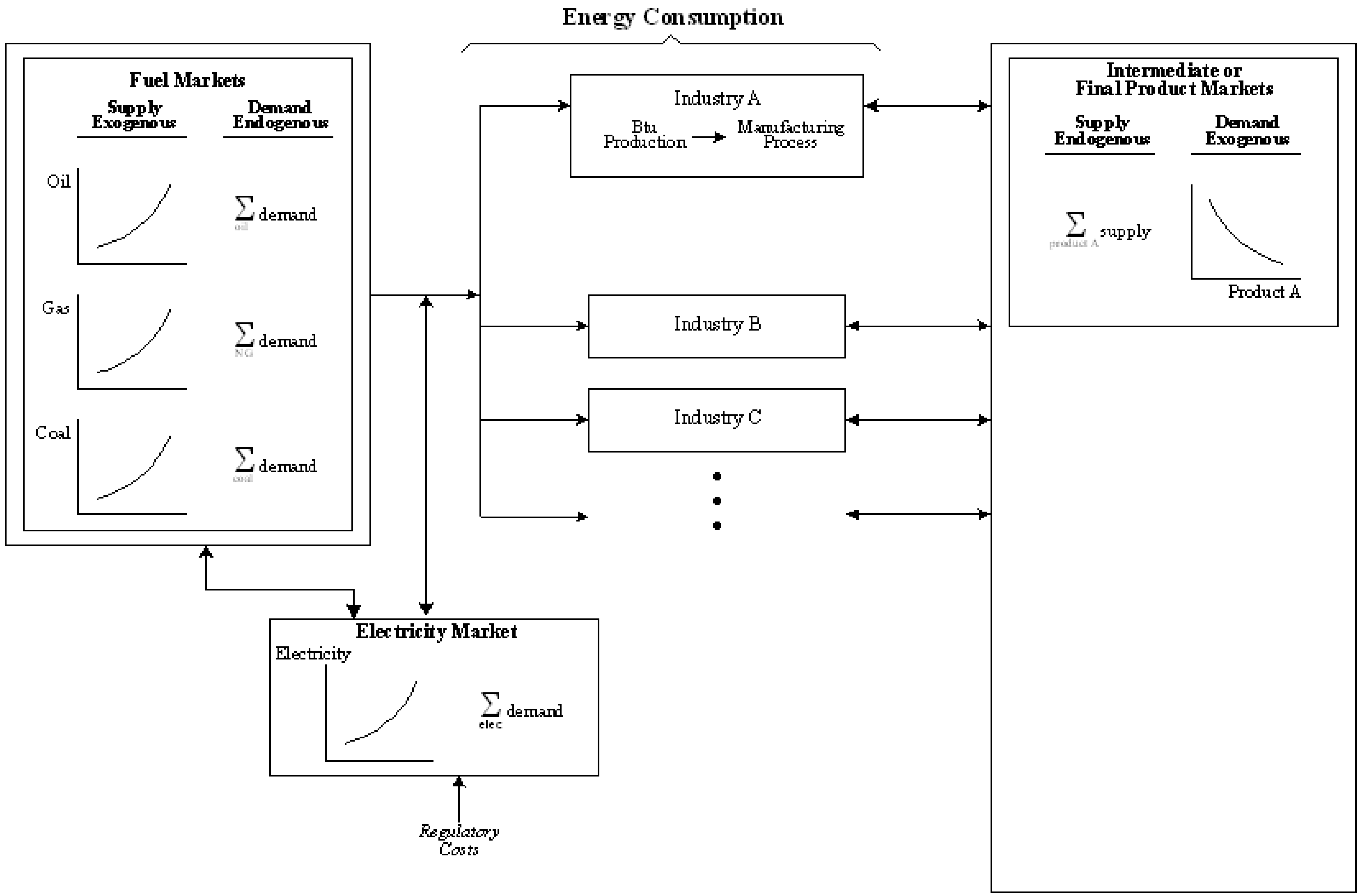


Figure 6-1. Links Between Energy and Final Product Markets

The major market segments included in the model and the intermarket linkages connecting the fuel markets and final product and service markets are described below. Because, as mentioned in Section 3, the overwhelming majority of combustion turbine units are used to generate wholesale electric power, the discussion focuses on the electricity market.

6.3.1 Electricity Markets

In this analysis, the market for base load energy and peak power are modeled separately. As the industry deregulates, it is becoming increasingly common for separate market prices to be determined for these two commodity attributes of electricity. In addition, the growth of CCCTs is being driven primarily by growth in base load energy demand, and the growth in SCCTs will be driven primarily by growth in peak demand. And because the relative impact on the control costs is greater for SCCTs compared to CCCTs, economic impacts will be different for base load energy and peak power.[7]

The base load energy and peak power market analyses compare the baseline equilibrium (without the regulation) to the regulated market equilibrium. Figure 6-2a presents a generalized market for the base load electricity that includes the installation of new turbines to meet demand growth for base load power.[8] Existing source supply is characterized by an upward-sloping marginal cost (supply) curve. The supply of new base load generation capacity is characterized by constant marginal costs and is modeled as a horizontal supply curve through the current market price. Figure 6-2b shows that the control costs associated with the rule will affect both existing and new sources of supply, shifting the market supply curve and leading to an increase in price and decrease in quantity of base load power consumed.

6.3.2 Other Energy Markets

The petroleum, natural gas, and coal markets are also included in the market model. Because the overwhelming majority of the affected combustion turbines is projected to be used in the electricity market, the other energy markets are assumed not to be directly affected by the rule. However, these markets will be indirectly affected through changes in

[7]The same controls are required for SCCTs and for CCCTs. But the relative costs are higher for SCCTs because their equipment and installation costs are approximately 40 percent less compared to CCCTs. Control costs are discussed in Section 6.1.

[8]A similar figure and analysis apply for peak load power with the exception that peak load supply is generally less responsive to price changes at the margin (i.e., base load elasticity of supply > peak load elasticity of supply).

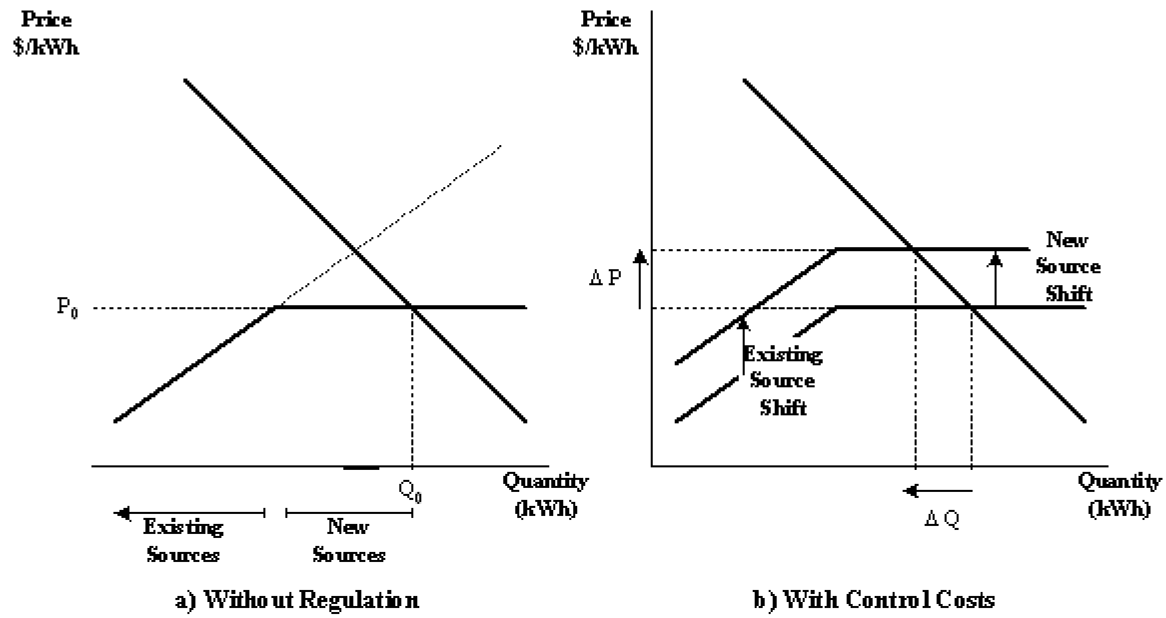


Figure 6-2. Electricity Market

input fuel prices (i.e., a supply shift) and changes in demand from final product and service markets using these energy sources (i.e., a demand shift). The ultimate impact on market price and quantities depends on the relative magnitudes of these shifts. Note the demand for other fuels may increase (Figure 6-3a) as firms switch away from electricity to petroleum, natural gas, or coal, or demand may decrease (Figure 6-3b) as the higher price for electricity suppresses economic activity decreasing demand for all fuels.

6.3.3 Supply and Demand Elasticities for Energy Markets

The market model incorporates behavioral changes based on the price elasticities of supply and demand. The price elasticities used to estimate the economic impacts presented in Section 6.3 are given in Table 6-2. Appendix B contains the sensitivity analysis for the key supply and demand elasticity assumptions.

Because most of the direct cost impacts fall on the combustion turbines in electricity markets, the price elasticities of supply in the electricity markets are important factors influencing the size and distribution of the economic impacts associated with the combustion turbine regulation. The elasticities of supply are intended to represent the behavioral

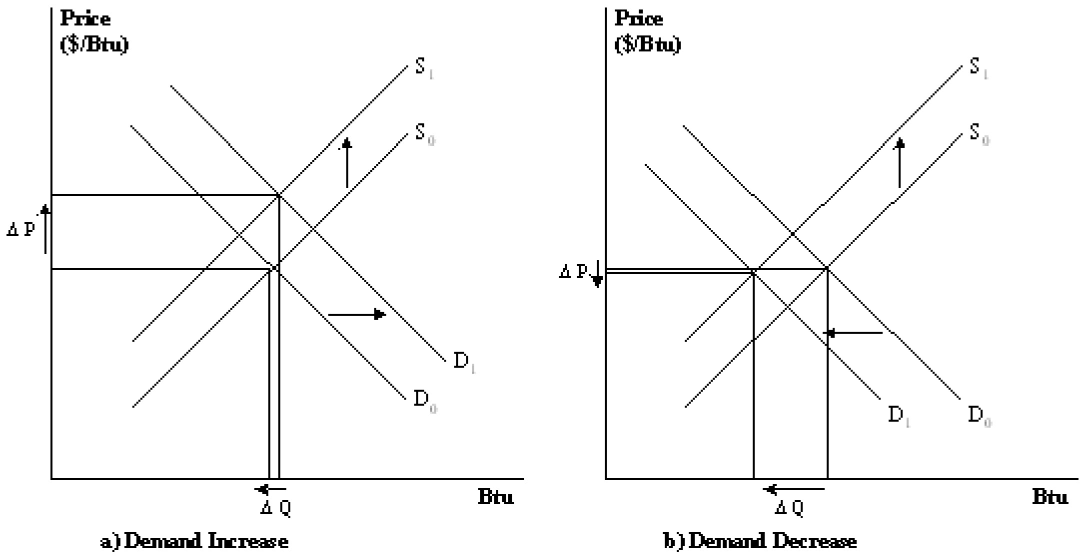


Figure 6-3. Potential Market Effects of the NSPS on Petroleum, Natural Gas, or Coal

responses from existing sources.[9] However, in general, there is no consensus on estimates of the price elasticity of supply for electricity. Estimates of the elasticity of supply for electric power were unavailable. This is in part because, under traditional regulation, the electric utility industry had a mandate to serve all its customers. In addition, utilities were compensated on a rate-based rate of return. As a result, the market concept of supply elasticity was not the driving force in utilities' capital investment decisions. To operationalize the model, a supply elasticity of 0.75 was assumed for the base load energy market. We assumed that the peak power market was one-half of base load energy elasticity. Given the uncertainty surrounding these parameters, the Agency conducted a sensitivity analysis for this value. The results of this sensitivity analysis are reported in Appendix B.

In contrast, many studies have been conducted on the elasticity of demand for electricity, and it is generally agreed that, in the short run, the demand for electricity is relatively inelastic. Most residential, commercial, and industrial electricity consumers do not significantly adjust short-run behavior in response to changes in the price of electricity. The elasticity of demand for electricity is primarily driven by long-run decisions regarding

[9]The supply curve for new sources is assumed to be horizontal, reflecting a constant marginal cost of production for new sources.

equipment efficiency and fuel substitution. Table 6-3 shows the elasticities of demand used for the commercial, residential, and transportation sectors.

Table 6-2. Supply and Demand Elasticities

Energy Sectors	Elasticity of Supply	Elasticity of Demand: Manufacturing	Commercial[a]	Transportation[a]	Residential[a]
Electricity: baseload energy	0.75	Derived demand	Derived demand	–0.24	–0.23
Electricity: peak power	0.375[b]	Derived demand	Derived demand	–0.24	–0.23
Natural gas	0.41[c]	Derived demand	Derived demand	–0.47	–0.26
Petroleum	0.58[d]	Derived demand	Derived demand	–0.28	–0.28
Coal	1.0[e]	Derived demand	Derived demand	–0.28	–0.28

[a] U.S. Department of Energy, Energy Information Administration. 2000b. "Issues in Midterm Analysis and Forecasting 1999—Table 1." <http://www.eia.doe.gov/oaif/issues/pricetbl1.html>. As obtained on May 8, 2000.

[b] Assumed to be one-half of baseload energy elasticity.

[c] Dahl, Carol A., and Thomas E. Duggan. 1996. "U.S. Energy Product Supply Elasticities: A Survey and Application to the U.S. Oil Market." *Resource and Energy Economics* 18:243-263.

[d] Hogman, William W. 1989. "World Oil Price Projections: A Sensitivity Analysis." Prepared pursuant to the Harvard-Japan World Oil Market Study. Cambridge, MA: Energy Environmental Policy Center, John F. Kennedy School of Government, Harvard University.

[e] Zimmerman, M.B. 1977. "Modeling Depletion in the Mineral Industry: The Case of Coal." *The Bell Journal of Economics* 8(2):41-65.

Table 6-3. Fuel Price Elasticities

Inputs	Own and Cross Elasticities in 2015: Electricity	Natural Gas	Coal	Residual	Distillate
Electricity	–0.074	0.092	0.605	0.080	0.017
Natural Gas	0.496	–0.229	1.087	0.346	0.014
Steam Coal	0.021	0.061	–0.499	0.151	0.023
Residual	0.236	0.036	0.650	–0.587	0.012
Distillate	0.247	0.002	0.578	0.044	–0.055

Source: U.S. Department of Energy, Energy Information Administration (EIA). January 1998c. *Model Documentation Report: Industrial Sector Demand Module of the National Energy Modeling System*. DOE/EIA-M064(98). Washington, DC: U.S. Department of Energy.

Additional elasticity of demand parameters for the commercial, residential, and transportation sectors, by fuel type (natural gas, petroleum and coal), were obtained from the Energy Information Administration. The elasticity of demand in the energy market for the manufacturing sector is not specified because the model calculates the derived demand for each of the five energy markets modeled. In effect, adjustments in the final product markets due to changes in production levels and fuel switching are used to estimate changes in demand, eliminating the need for demand elasticity parameters in the energy markets.

6.3.4 Final Product and Service Markets

Producers of final products and services are segmented into industrial, commercial, transportation, and residential sectors. The industrial sector is further partitioned into the 23 manufacturing, agricultural, and mining sectors. A partial equilibrium analysis was conducted for each of these sectors. Changes in production levels and fuel switching due to the regulation's impact on the price of electricity are then linked back into the energy markets.

6.3.4.1 Modeling the Impact on the Industrial and Commercial Sectors

The impact of the regulation on these sectors was modeled using changes in the cost of Btus used in production processes. In this context, Btus refer to the generic energy requirements that are used to generate process heat, process steam, or shaft power. As shown in Figure 6-4, the regulation will increase the cost of Btu production indirectly through increases in the price of Btus due to control costs on wholesale electricity generators. The effect is similar to placing a tax on certain types of energy sources (i.e., on Btus generated by combustion turbines). The firms' reactions to the change in the cost of Btu production feeds back into the energy markets in two ways (see Figure 6-4). The first feedback pathway is through changing the fuel used in the production process. This can include fuel switching, such as switching from gas turbines to power processes to diesel engines, and/or process changes that increase energy efficiency and reduce the amount of Btus required per unit of output. Fuel switching impacts are modeled using cross-price elasticities of demand between energy sources and own-price elasticities.

EPA modeled fuel switching using secondary data developed by the U.S. Department of Energy for the National Energy Modeling System (NEMS). Table 6-3 contains fuel price elasticities of demand for electricity, natural gas, petroleum products, and coal. The diagonal elements in the table represent own-price elasticities. For example, the table indicates that for steam coal, a 1 percent change in the price of coal will lead to a 0.499 percent decrease in the use of coal. The off diagonal elements are cross-price elasticities and indicate fuel

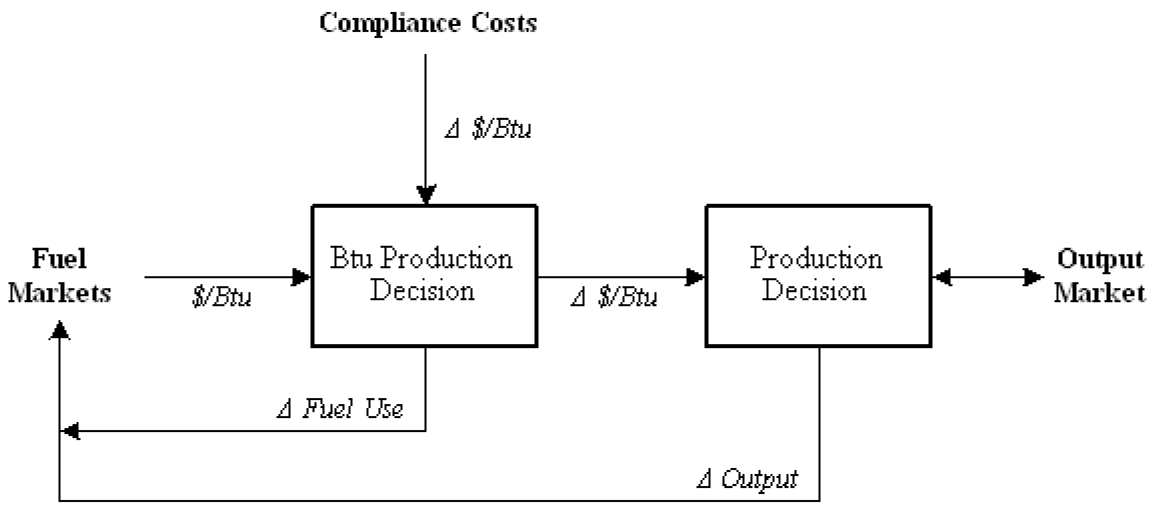


Figure 6-4. Fuel Market Interactions with Facility-Level Production Decisions

switching propensities. For example, for steam coal, the second column indicates that a 1 percent increase in the price of coal will lead to a 0.061 percent increase in the use of natural gas.

The second feedback pathway to the energy markets is through the facility's change in output. Because Btus are an input into the production process, price increases (↑$/Btu) lead to an upward shift in the industry supply curve. In a perfectly competitive market, the point where supply equals demand determines the market price and quantity. A shift in the industry supply curve leads to a change in the equilibrium market price and quantity. EPA assumed constant returns to scale in production so that the percentage change in the equilibrium market quantity in each final product and service market equals the percentage change in Btus consumed by industries.

The change in equilibrium supply and demand in each final industrial and commercial sector was modeled using a partial equilibrium approach. The size of the regulation-induced shifts in the final product supply curves is a function of the indirect fuel costs (determined by the change in fuel prices and the fuel intensity) relative to variable production costs in each manufacturing industry.

It was assumed that the demand for final industrial and commercial products and services is unchanged by the regulation. However, because the demand function quantifies the change in quantity demanded in response to a change in price, the baseline demand conditions are important in determining the regulation's impact. Because prices changes are anticipated to be small, the key demand parameters are the elasticity of demand with respect to changes in the price of final products. Demand elasticities for each of the sectors included in the analysis are reported in Table 6-4.

6.3.4.2 Impact on the Residential Sector and Transportation Sectors

The residential and transportation sector does not bear any direct costs associated with the regulation because they do not own combustion turbines. However, they bear indirect costs due to price increases. These sectors' change in energy demand in response to changes in energy prices is modeled as a series of demand curves parameterized by elasticity of demand parameters (see Table 6-2).

6.3.4.3 Impact on the Government Sector

All combustion turbines projected to be installed by government entities will be for local generation of electricity. These municipal generators are grouped into the electricity energy market; thus the government sector is not explicitly included in the model.

6.4 Summary of the Economic Impact Model

We summarize the linkages used to operationalize the estimation of economic impacts associated with the compliance costs in Figure 6-5.

Control costs on new turbines used for generators will shift the supply curve for wholesale electricity. The new equilibrium price and quantity in the electricity market will determine the distribution of impacts between producers (electricity generators) and consumers. Changes in wholesale electricity generators' demand for input fuels (due to changes in the market quantity of electricity) feed back into the natural gas, coal, and petroleum markets.

Finally, manufacturers experience supply curve shifts due to changes in prices for natural gas, petroleum, electricity, and coal. The share of these costs borne by producers (manufactures) and consumers is determined by the new equilibrium price and quantity in the final product and service markets. Changes in manufacturers' Btu demands due to fuel switching and changes in production levels feed back into the energy markets.

Adjustments in price and quantity in all energy and final product markets occur simultaneously. A computer model was used to numerically simulate market adjustments by iterating over commodity prices until equilibrium is reached (i.e., until supply equals demand in all markets being modeled) and to estimate the economic impact of the regulation (change in producer and consumer surplus) in the sectors of the economy being modeled.

Table 6-4. Supply and Demand Elasticities for Industrial and Commercial Sectors

NAICS	Description	Supply	Demand
Industrial Sectors			
311	Food	0.75	–1.00
312	Beverage and Tobacco Products	0.75	–1.30
313	Textile Mills	0.75	–1.50
314	Textile Product Mills	0.75	–1.50
315	Apparel	0.75	–1.10
316	Leather and Allied Products	0.75	–1.20
321	Wood Products	0.75	–1.00
322	Paper	0.75	–1.50
323	Printing and Related Support	0.75	–1.80
325	Chemicals	0.75	–1.80
326	Plastics and Rubber Products	0.75	–1.80
327	Nonmetallic Mineral Products	0.75	–1.00
331	Primary Metals	0.75	–1.00
332	Fabricated Metal Products	0.75	–0.20
333	Machinery	0.75	–0.50
334	Computer and Electronic Products	0.75	–0.30
335	Electrical Equip., Appliances, and Components	0.75	–0.50
336	Transportation Equipment	0.75	–0.50
337	Furniture and Related Products	0.75	–1.80
339	Miscellaneous	0.75	–0.60
11	Agricultural Sector	0.75	–1.80
23	Construction Sector	0.75	–1.00
21	Other Mining Sector	0.75	–0.30
Commercial Sector (NAICS 42-45;51-56;61-72)		0.75	–1.00

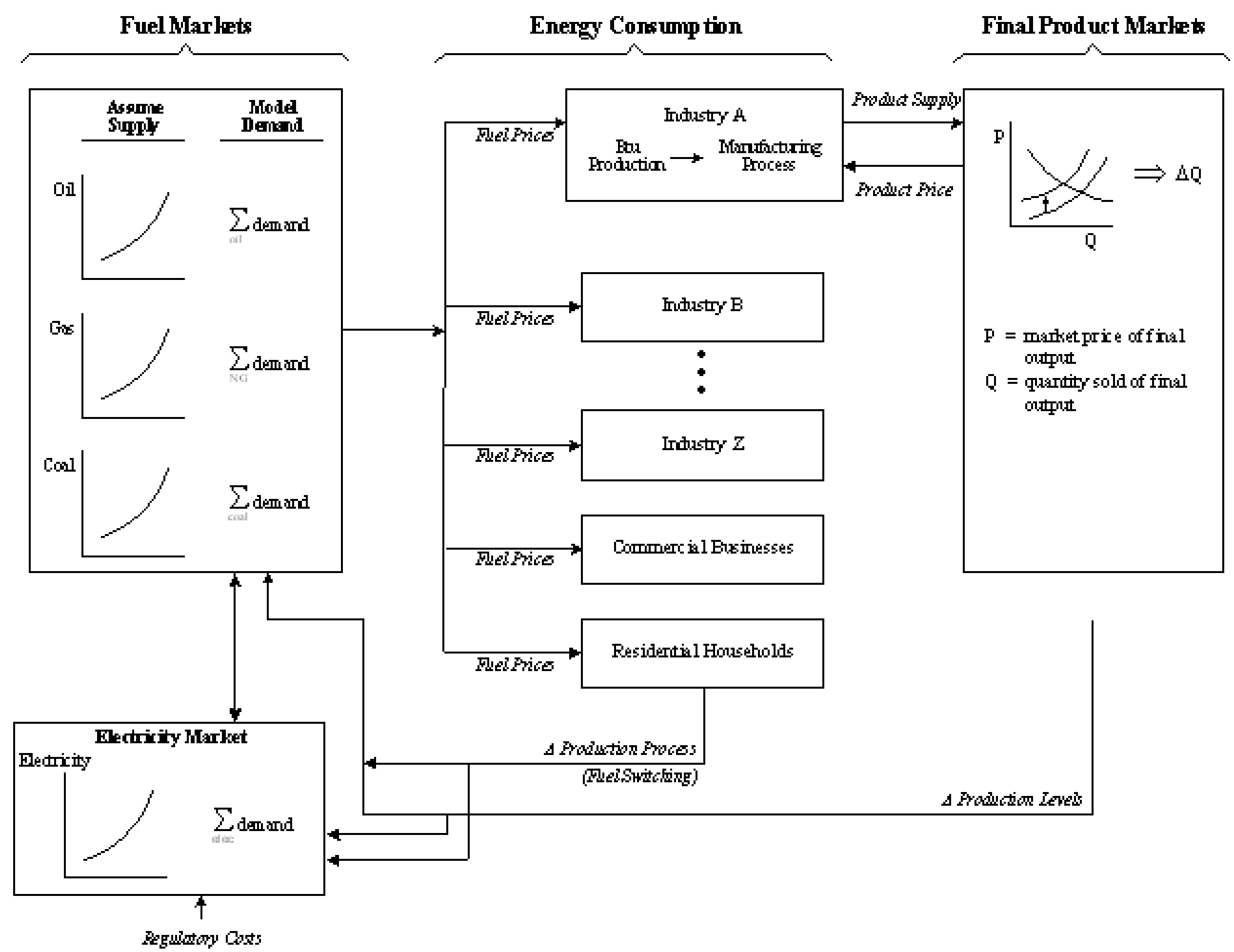


Figure 6-5. Operationalizing the Estimation of Economic Impact

This model comprises a series of computer spreadsheet modules. The modules integrate the engineering inputs and the market-level adjustment parameters to estimate the regulation's impact on the price and quantity in each market being analyzed. At the heart of the model is a market-clearing algorithm that compares the total quantity supplied to the total quantity demanded for each market commodity. Appendix A describes the computer model in more detail.

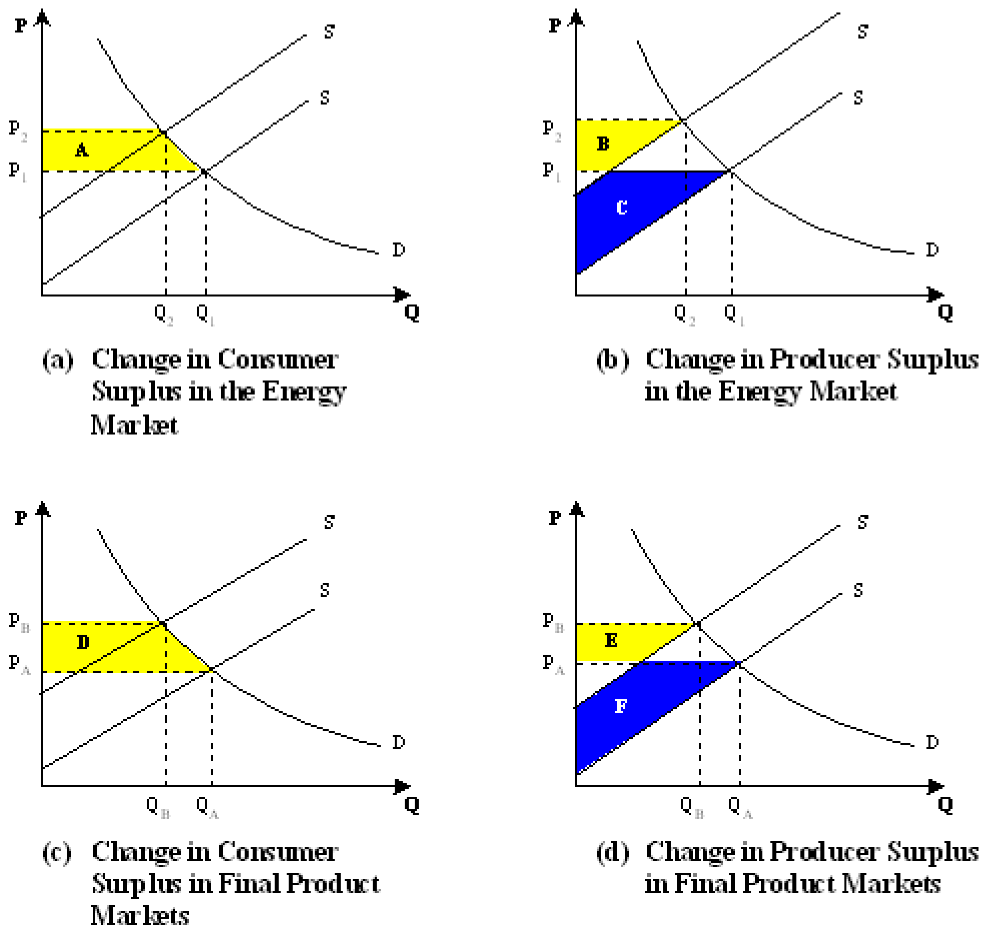
6.4.1 Estimating Changes in Social Welfare

The combustion turbine regulation will impact almost every sector of the economy either directly through control costs or indirectly through changes in the price of energy and final products. For example, a share of control costs that originate in the energy markets are passed through the final product markets and are borne by both the producers and consumers of final products. To estimate the total change in social welfare without double-counting impacts across the linked partial equilibrium markets being modeled, EPA quantified social welfare changes for the following categories:

- change in producer surplus in the energy markets,
- change in producer surplus in the final product and service markets,
- change in consumer surplus in the final product and service markets, residential and transportation energy markets.

Figure 6-6 illustrates the change in producer and consumer surplus in the intermediate energy market and the final product markets. For example, assume a simple world with only one energy market, wholesale electricity, and one final product market, pulp and paper. If the regulation increased the cost of generating wholesale electricity, then part of the cost of the regulation will be borne by the electricity producers as decreased producer surplus and part of the costs will be passed on to the pulp and paper manufacturers. In Figure 6-6a, the pulp and paper manufacturers are the consumers of electricity, so the change in consumer surplus is displayed. This change in consumer surplus in the energy market is captured by the final product market (because the consumer is the pulp and paper industry in this case), where it is split between consumer surplus and producer surplus in those markets. Figure 6-6b shows the change in producer surplus in the energy market.

As shown in Figures 6-6c and 6-6d, the cost affects the pulp and paper industry by shifting up the supply curve in the pulp and paper market. These higher electricity prices therefore lead to costs in the pulp and paper industry that are distributed between producers and consumers of paper products in the form of lower producer surplus and lower consumer surplus. Note that the change in consumer surplus in the intermediate energy market must



(a) Change in Consumer Surplus in the Energy Market

(b) Change in Producer Surplus in the Energy Market

(c) Change in Consumer Surplus in Final Product Markets

(d) Change in Producer Surplus in Final Product Markets

Figure 6-6. Changes in Economic Welfare with Regulation

equal the total change in consumer and producer surplus in the final product market. Thus, to avoid double-counting, the change in consumer surplus in the intermediate energy market was not quantified; instead the total change in social welfare was calculated as

$$\text{Change in Social Welfare} = \sum \Delta PSE + \sum \Delta PSF + \sum \Delta CSF + \sum \Delta CSRT \quad (6.1)$$

where

ΔPSE = change in producer surplus in the energy markets,

ΔPSF = change in producer surplus in the final product markets,

ΔCSF = change in consumer surplus in the final product markets, and

$\Delta CSRT$ = change in consumer surplus residential and transportation energy markets.

Appendix A contains the detailed equations used to calculate the change in producer and consumer surplus in the appropriate intermediate and final product markets.

SECTION 7

ECONOMIC IMPACT ANALYSIS

Control measures implemented to comply with the NSPS will impose regulatory costs on affected facilities in the energy, manufacturing, commercial, and government sectors. These costs will be distributed between producers and consumers through changes in energy prices and changes in prices of final products and services. This section describes the compliance costs of the regulatory alternatives and presents the economic impact estimates, including energy impacts, of the NSPS.

7.1 Engineering Control Cost Inputs

To calculate the total cost of the NO_x emission standard by the fifth year after promulgation, one calculated them based on the requirements of the NSPS. It has been noted earlier in this EIA (Chapter 3) that the add-on controls that the ten new turbines would have to apply to comply with this proposal will already be applied in response to Prevention of Significant Deterioration/New Source Review (PSD/NSR) requirements. Thus, the total capital cost of this proposal is essentially zero. The requirements of this NSPS are those for inital performance testing, fuel sampling, monitoring and recordkeeping. Table 7-1 shows the total annual cost associated with these requirements in the fifth year after promulgation for each MW range. These annual costs total $3.4 million. As a result, the total annual cost of the NSPS is $3.4 million (1998$).

7.1.1 Computing Supply Shifts in the Electricity Market

For the purpose of the market model, the electric services industry is broken into two market sectors: base load energy and peak power. As shown in Section 4 (Table 4-3), EPA estimates approximately two-thirds of new combustion turbine units are projected to contribute to the base load energy market, and the remaining one-third are projected to contribute to the peak power market. As a result, the control costs for the electricity are distributed 67 percent to the electric base load energy market and 33 percent to the peak power market. The relative shift in the supply curve for each segment is presented as the percentage shift in the price of the marginal unit produced. The percentage shift is calculated

Table 7-1. Total Capital and Annual Cost of the Proposed NSPS in the Fifth Year

Total Capital Cost	
Control cost	$0
Total Annual Cost	
Control cost	$0
Initial performance testing	$369,200
Fuel sampling	$206,681
Monitoring and recordkeeping	$2,393,730
Reporting	$440,519
Total	$3,410,130

Source: Alpha-Gamma Technologies, Inc. January 30, 2005. "Cost Impact of Proposed NSPS for Stationary Combustion Turbines." Memorandum to Jaime Pagan, EPA OAQPS ESD Combustion Group from Melanie Taylor, Alpha-Gamma Technologies, Inc.

as the ratio of compliance costs to the revenue of the affected portion of the industry[10] (see Table 7-2). Affected sources with performance testing, fuel sampling, monitoring and recordkeeping, and reporting have shifts of 0.1 percent for base and peak load. The remaining segments are unaffected (i.e., supply shift equals zero).

Figure 7-1 illustrates the supply shifts and shows the with-regulation supply curve S_1. In this example, the regulation leads to an increased supply by unaffected units, crowding out the new units with compliance costs.

7.2 Market-Level Results

The model projects the NSPS standard will increase base load electricity price by 0.03 percent and peak power prices by 0.04 percent (see Table 7-3). Domestic production declines by 0.005 and 0.011 percent, respectively.

[10]Revenue in the electric utility industry was segmented into the base load and peak power markets assuming an 80/20 split, respectively. This ratio was estimated based on discussions with industry experts.

Table 7-2. Summary of Turbine Cost Information and Supply Shifts

	Share Units of Market (%)	Revenue[a] ($$10^9$)	Control Costs[a] ($$10^6$)	Supply Shift (%)
Base Load Energy				
Existing	97.5%	$173.29	—	0.0%
New affected: initial performance testing, fuel sampling, monitoring and recordkeeping, and reporting only	2.3%	$4.17	$2.2	0.1%
Total	100.0%	$177.64	$2.2	0.0%
Peak Power				
Existing	97.5%	$43.32	—	0.0%
New affected: initial performance testing, fuel sampling, monitoring and recordkeeping, and reporting only	2.3%	$1.04	$1.2	0.1%
Total	100.0%	$44.40	$3.4	0.0%

[a]Revenues and costs are in 1998$.

The analysis also shows the impact on distribution of electricity supply (see Table 7-4). The increase in the price of electricity will make it profitable for unaffected sources to increase supply, displacing approximately 0.1 percent of affected new supply. This increase in supply implies that fewer older units may be retired as a result of the regulation. The remaining change in quantity results from decreased consumer demand as the prices of base load energy and peak power increase. However, all these effects are very small.

In the natural gas and petroleum markets, both the price and quantity increase, indicating that an increase in demand for the fuel (due to fuel switching) dominates the upward shift in the supply curve (increased electricity costs as a fuel input). Price increases in these markets are below 0.1 percent. Price and quantity decrease in the coal market, reflecting the decreased demand for coal as electric utilities reduce output. Market-level impacts on downstream product and service markets are essentially zero.

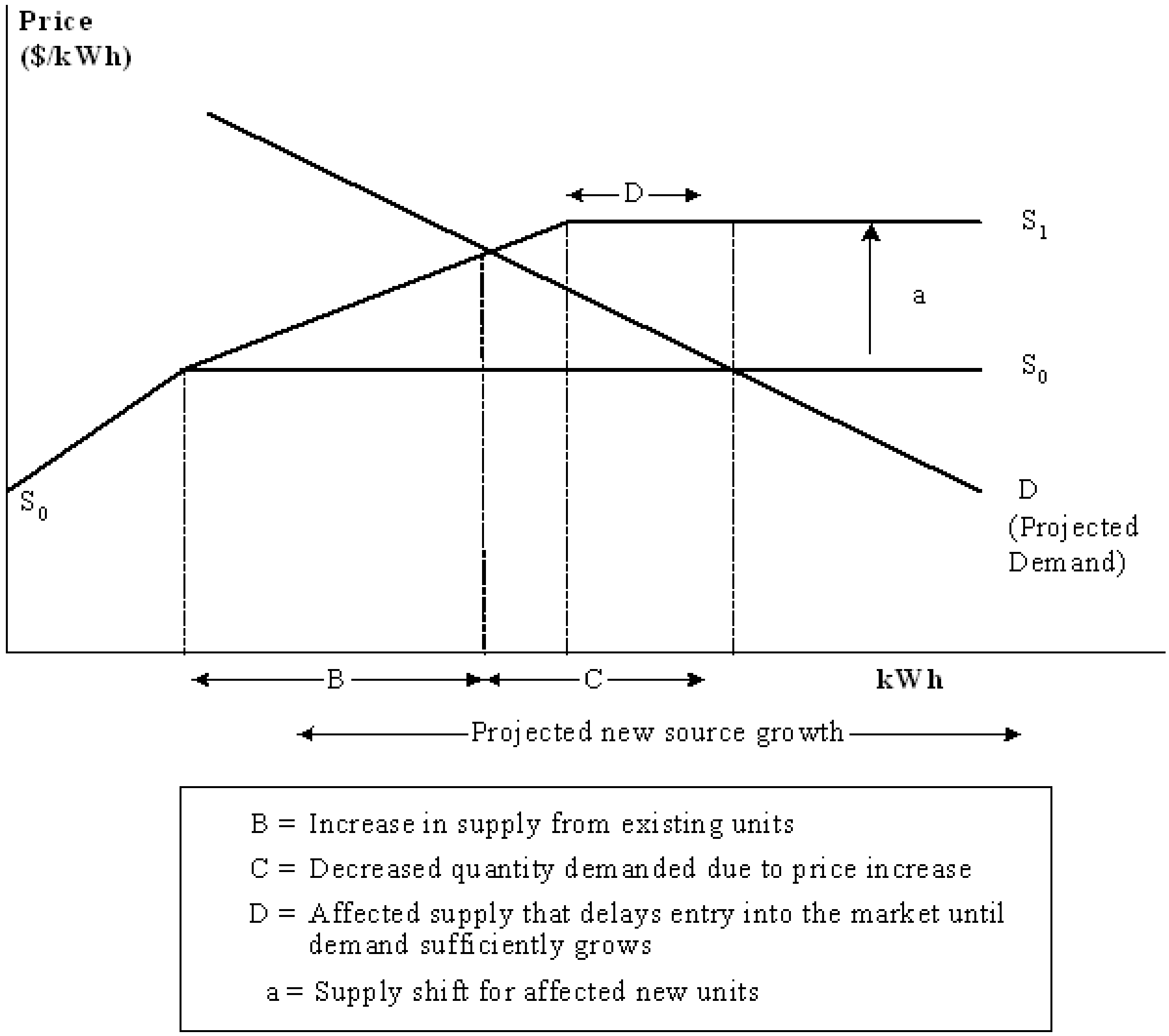


Figure 7-1. Market for Baseload Electricity

7.3 Social Cost Estimates

The social impact of a regulatory action is traditionally measured by the change in economic welfare that it generates. The social costs of the rule will be distributed across producers of energy and their customers. Producers experience welfare impacts resulting from changes in profits corresponding with the changes in production levels and market prices. Consumers experience welfare impacts due to changes in market prices and

Table 7-3. Market-Level Impacts of Stationary Combustion Turbines NSPS Standard: 2010

Energy Markets		Percent Change Price	Quantity
Petroleum		0.002	0.001
Natural Gas		0.007	0.002
Base Electricity		0.028	–0.005
Peak Electricity		0.044	–0.011
Coal		–0.001	–0.001
Industrial Sectors NAICS Description	**Description**	**Percent Change Price**	**Quantity**
311	Food	0.000	0.000
312	Beverage and Tobacco Products	0.000	0.000
313	Textile Mills	0.000	–0.000
314	Textile Product Mills	0.000	0.000
315	Apparel	0.000	0.000
316	Leather and Allied Products	0.000	0.000
321	Wood Products	0.000	0.000
322	Paper	0.000	–0.000
323	Printing and Related Support	0.000	0.000
325	Chemicals	0.000	–0.000
326	Plastics and Rubber Products	0.000	–0.000
327	Nonmetallic Mineral Products	0.000	–0.000
331	Primary Metals	0.000	–0.000
332	Fabricated Metal Products	0.000	0.000
333	Machinery	0.000	0.000
334	Computer and Electronic Products	0.000	0.000
335	Electrical Equipment, Appliances, and Components	0.000	0.000
336	Transportation Equipment	0.000	0.000
337	Furniture and Related Products	0.000	0.000
339	Miscellaneous	0.000	0.000
11	Agricultural Sector	0.000	–0.000
23	Construction Sector	0.001	–0.001
21	Other Mining Sector	0.001	0.000
Commercial Sector		0.000	0.000

[a]Actual value for all 0.000 entries for the various sectors is > –0.001 and < 0.

consumption levels. However, it is important to emphasize that this measure does not include benefits that occur outside the market, that is, the value of reduced levels of air pollution with the regulation.

The national compliance cost estimates are often used to approximate the social cost of the rule. The engineering analysis estimated annual costs of $3.4 million. In cases where the engineering costs of compliance are used to estimate social cost, the burden of the regulation is measured as falling solely on the affected producers, who experience a profit loss exactly equal to these cost estimates. Thus, the entire loss is a change in producer surplus with no change (by assumption) in consumer surplus, because no change in market price is estimated. This is typically referred to as a "full-cost absorption" scenario in which all factors of production are assumed to be fixed and firms are unable to adjust their output levels when faced with additional costs.

Table 7-4. Changes in Market Shares for Electricity Suppliers

	Baseline Shares (%)	With Regulation Shares (%)
Existing—unaffected	97.5	97.6
New—initial performance testing, fuel sampling, monitoring and recordkeeping, reporting only	2.3	2.3
New—controls, initial performance testing, fuel sampling, monitoring and recordkeeping, reporting	0.1	0.0

In contrast, the economic analysis conducted by the Agency accounts for behavioral responses by producers and consumers to the regulation, as affected producers shift costs to other economic agents. This approach results in a social cost estimate that may differ from the engineering compliance cost estimate and also provides insights on how the regulatory burden is distributed across stakeholders. As shown in Table 7-5, the economic model estimates the total social cost of the rule to be $2 million. The social cost estimate is slightly less than the estimated engineering costs as a result of behavioral changes of producers and consumers. Therefore the social costs primarily reflect higher costs by existing units to increase supply, and the deadweight loss to consumers as price increases and quantity decreases. It should be noted that this social cost estimate does not account for the benefits of emission reductions associated with this NSPS and hence is not net of these impacts to society.

Table 7-5. Distribution of Social Costs of Stationary Combustion Turbines NSPS: 2010 ($1998 10^6)

Sectors/Markets	Change in: Producer Surplus	Change in: Consumer Surplus	Change in: Social Welfare
Energy Sector			
Petroleum (NAICS 32411, 4861)	$7	NA	NA
Natural Gas (NAICS 21111, 4862, 2212)	$6	NA	NA
Electricity (NAICS 22111, 221122, 221121)	$68	NA	NA
Coal (NAICS 2121)	–$1	NA	NA
Subtotal:	$80	NA	NA

Industrial Sector NAICS	Description	Change in: Producer Surplus	Change in: Consumer Surplus	Change in: Social Welfare
311	Food	–$1	–$0	–$1
312	Beverage and Tobacco Products	$0	$0	$0
313	Textiles Mills	–$0	$0	–$0
314	Textile Product Mills	$0	$0	$0
315	Apparel	$0	$0	$0
316	Leather and Allied Products	$0	$0	$0
321	Wood Products	$0	$0	–$0
322	Paper	–$1	–$0	–$1
323	Printing and Related Support	$0	$0	–$0
325	Chemicals	–$2	–$1	–$3
326	Plastics and Rubber Products	–$1	–$0	–$1
327	Nonmetallic Mineral Products	–$1	–$0	–$1
331	Primary Metals	–$2	–$1	–$3
332	Fabricated Metal Products	$0	–$1	–$1
333	Machinery	$0	–$0	–$0
334	Computer and Electronic Products	$0	–$0	–$0
335	Electrical Equipment, Appliances, and Components	$0	$0	–$0
336	Transportation Equipment	–$1	–$0	–$1
337	Furniture and Related Products	$0	$0	$0
339	Miscellaneous	$0	$0	$0
11	Agricultural Sector	–$1	–$1	–$2
23	Construction Sector	–$8	–$6	–$14
21	Other Mining Sector	$0	$1	–$1
Industrial Sector Subtotal:		–$18	–$11	–$29
Commercial Sector		–$14	–$10	–$24
Residential Sector		NA	–$23	–$26
Transportation Sector		NA	–$6	–$6
Subtotal		–32	–$50	–$82
Grand Total		$48	–$50	–$2

The analysis also shows important distributional impacts across stakeholders. For example, the model projects consumers will bear a burden of $50 million, as a result of higher energy prices. In contrast, producer surplus increases by $48 million as energy producers, particularly the electricity industry, become more profitable with higher prices.

7.4 Energy Impact Analysis

Executive Order 13211, "Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use" (66 Fed. Reg. 28355 [May 22, 2001]), requires EPA to prepare and submit a Statement of Energy Effects to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, for certain actions identified as "significant energy actions." Section 4(b) of Executive Order 13211 defines "significant energy actions" as "any action by an agency (normally published in the *Federal Register*) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking:

- that is a significant regulatory action under Executive Order 12866 or any successor order, and is likely to have a significant adverse effect on the supply, distribution, or use of energy; or
- that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action."

Although the NSPS is considered to be a significant regulatory action under Executive Order 12866, it is not a "significant energy action" because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. No Statement of Energy Effects is required for this rule, but the following energy impact estimates are included for informational purposes.

Energy Price Effects. As described in the market-level results section, electricity prices are projected to increase by less than 0.1 percent. Petroleum and natural gas prices are all projected to increase by less than 0.1 percent. The price of coal is projected to decrease slightly.

Impacts on Electricity Supply, Distribution, and Use. We project the increased compliance costs for the electricity market will result in an annual production decline of approximately 0.2 billion kWh. Note these effects have been mitigated to some degree since sectors previously using electricity in the baseline will switch to other energy sources (see below).

Impacts on Petroleum, Natural Gas, and Coal Supply, Distribution, and Use. The rule will lead to higher electricity prices relative to other fuel types, resulting in fuel switching. The model projects increases in petroleum production/consumption of approximately 300 barrels per day. Similarly, natural gas production/consumption is projected to increase by 2 million cubic feet per day. The model also projects decreases in coal production/consumption of approximately 30 short tons per year. We expect that there will be no discernable impact on the import of foreign energy supplies, and no other adverse outcomes are expected to occur with regards to energy supplies. Also, the increase in cost of energy production should be minimal given the very small increase in fuel consumption resulting from back pressure related to operation of add-on control devices, such as SCR emission control devices. All of the estimates presented above account for some passthrough of costs to consumers as well as the direct cost impact to producers.

SECTION 8

SMALL ENTITY IMPACTS

The regulatory costs imposed on domestic producers and government entities to reduce air emissions from combustion turbines will have a direct impact on owners of the affected facilities. Firms or individuals that own the facilities with combustion turbines are legal business entities that have the capacity to conduct business transactions and make business decisions that affect the facility. The legal and financial responsibility for compliance with a regulatory action ultimately rests with these owners, who must bear the financial consequences of their decisions. Environmental regulations potentially affect all sizes of businesses, but small businesses may have special problems relative to large businesses in complying with such regulations.

The RFA of 1980 requires that special consideration be given to small entities affected by federal regulations. The RFA was amended in 1996 by SBREFA to strengthen the RFA's analytical and procedural requirements. Prior to enactment of SBREFA, EPA exceeded the requirements of the RFA by requiring the preparation of a regulatory flexibility analysis for every rule that would have any impact, no matter how minor, on any number, no matter how small, of small entities. Under SBREFA, however, the Agency decided to implement the RFA as written and to require a regulatory flexibility analysis only for rules that will have a significant impact on a substantial number of small entities. In practical terms, the amount of analysis of impacts to small entities has not changed, for SBREFA required EPA to increase involvement of small entities in the rulemaking process.

This section investigates characteristics of businesses and government entities that are likely to install new combustion turbines affected by this rule and provides a preliminary screening-level analysis to assist in determining whether this rule is likely to impose a significant impact on a substantial number of the small businesses within this industry.

The screening-level analysis employed here is a "sales test," which computes the annualized compliance costs as a share of sales/revenue for existing companies/government entities. Existing companies/government entities with combustion turbines are used to provide insights into future companies/government entities that are likely to install new turbines that are affected by the regulation.

8.1 Identifying Small Businesses

As described in Section 3 of this report, the Agency has projected that approximately 355 new combustion turbines will begin operation during the next 5-years. Approximately 10 sources would be required to comply with the NO_x emission standard for the Gas Turbine NSPS by applying add-on controls, as mentioned earlier in this report (Chapter 3). However, as also mentioned earlier in this report, these 10 new turbines will already be required to install add-on controls to meet NOx reductions under the PSD/NSR programs. The only requirements on them due to this NSPS will be initial performance testing, fuel sampling, monitoring and recordkeeping, and reporting. No existing combustion turbines will be affected by the regulation. However, because it is not possible to project specific companies or government organizations that will purchase combustion turbines in the future, the small entity screening analysis for the combustion turbine rule is based on the evaluation of existing owners of combustion turbines. It is assumed that the existing size and ownership distribution of combustion turbines contained in the Inventory Database is representative of the future growth in new combustion turbines. The remainder of this section presents cost and sales information on small companies and government organizations that own existing combustion turbines of 1 MW or greater.

8.2 Screening-Level Analysis

Based on the Inventory Database and Small Business Administration (SBA) definitions, 29 small entities own 51 units, which are located at 35 facilities.[11] The 51 units owned by small entities represent approximately 2.5 percent of the 2,072 units in the Inventory Database with valid capacity information. This implies that approximately 1 out of the 10 new affected units will be owned by a small entity. Based on our previous research, the 29 small entities have an average revenue (sales) of approximately $80 million. We compared the average unit compliance costs ($3.4/10 = $0.34 million) with the average sales value and for a typical small entities and calculated the cost to sales ratio for the potentially affected small entity is 0.3 percent.

[11]Public and private electric service providers are defined as small if their annual generation is less than 4 million kWh. Local government entities that own combustion turbines are defined as small if the city population is fewer than 50,000. In the manufacturing sector, companies are defined as small if the total employment of the parent company is fewer than 500.

8.3 Assessment

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of today's rule on small entities, small entity is defined as:

- a small business whose parent company has fewer than 100 or 1,000 employees, depending on size definition for the affected NAICS code, or fewer than 4 billion kW-hr per year of electricity usage;
- a small governmental jurisdiction that is a government of a city, county, town, school district, or special district with a population of fewer than 50,000; and
- a small organization that is any not-for-profit enterprise, which is independently owned and operated and is not dominant in its field.

It should be noted that small entities in one three-digit NAICS codes are affected by this rule, and the small business definition applied to this industry by NAICS code is that listed in the SBA size standards (13 CFR 121).

The economic impacts of the NSPS are expected to be insignificant. In addition, since there is only one small entity affected by this rule, there is no significant impact (economic) to a substantial number of small entities (or SISNOSE).

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APPENDIX A

OVERVIEW OF THE MARKET MODEL

To develop estimates of the economic impacts on society resulting from the regulation, the Agency developed a computational model using a framework that is consistent with economic analyses performed for other rules. This approach employs standard microeconomic concepts to model behavioral responses expected to occur with the regulation. This appendix describes the spreadsheet model in detail and discusses how the Agency

- characterized the supply and demand in the energy markets,
- characterized supply and demand responses in industrial and commercial markets,
- introduced a policy "shock" into the electricity market by using control cost-induced shifts in the supply functions of affected supply segments (new and existing sources),
- introduced indirect shifts in market supply functions resulting from changes in energy prices
- used a solution algorithm to determine a new with-regulation equilibrium in each market.

A.1 Energy Markets

The operational model includes five energy markets: coal, electricity (base load energy), electricity (peak power), natural gas, and petroleum. The following sections describe supply and demand equations the Agency developed to characterize these markets. The data source for the price and quantity data used to calibrate the model is the Department of Energy's Supplemental Tables to the Annual Energy Outlook 2000 (DOE, EIA, 2001).

A.1.1 Supply Side Modeling

The Agency modeled the existing market supply of energy markets (Q_{Si}) using a single representative supplier with an upward-sloping supply curve. The Cobb-Douglas (CD) function specification is

$$Q_{S_i} = A_i \bullet \left(p_i - c_i - \sum_{i=1}^{n} \alpha_i \Delta p_i\right)^{\varepsilon^{S_i}} \qquad \text{(A.1)}$$

where

Q_{S_i}	=	the supply of energy product i,
A_i	=	a parameter that calibrates the supply equation to replicate the estimated 2005 level of production (Btu),
p_i	=	the 2005 ($/Btu) market price for product i, and
c_i	=	direct compliance costs (electricity markets only). Supply shifts were computed and reported in Section 6, Table 6-2.
$\sum_{i=1}^{n} \alpha_i \Delta p_i$	=	indirect effects of changes in input prices, where α is the fuel share, i indexes the energy market. The fuel share is allowed to vary using a fuel switching rule using cross-price elasticities of demand between energy sources, as described in Section 5 of the report.
ε^{S_i}	=	the domestic supply elasticity for product i.

For the electricity markets, new supply sources are characterized with a constant marginal cost (supply) curve. In baseline, these units are willing to supply their generation capacity at the baseline market price (P_{0i}). With regulation, affected sources are willing to supply their generation capacity if the new price (P_{1i}) exceeds costs (baseline + direct + indirect) :

$$P_{1i} \geq \left[P_{0i} + c_i + \sum_{i=1}^{n} \alpha_i \Delta p_i\right] \qquad \text{(A.2)}$$

A.1.2 Demand Side Modeling

Market demand in the energy markets (Q_{Di}) is expressed as the sum of the energy, residential, transportation, industrial, and commercial sectors:

$$Q_{Di} = \sum_{j=1}^{n} q_{Dij} , \tag{A.3}$$

where i indexes the energy market and j indexes the consuming sector. The Agency modeled the residential, and transportation sectors as single representative demanders using a simple Cobb Douglas specification:

$$q_{Dij} = A_{ij} p_i^{\eta_{ij}} , \tag{A.4}$$

where p is the market price, η is an assumed demand elasticity (actual values are presented in Section 5, Table 5-2), and A is a demand parameter. In contrast, the energy, industrial and commercial sectors demand is modeled as a derived demand resulting from the production/consumption choices in agricultural, energy, mining, manufacturing, and service industries. Changes in energy demand for these industries respond to changes in output and fuel switching that occurs in response to changes in relative energy prices projected in the energy markets. For each sector, energy demand is expressed as follows:

$$q_{Dij1} = (1 + \%\Delta Q_{Dj}) \cdot (q_{Dij0}) \cdot FSW \tag{A.5}$$

where q_D is demand for energy, Q_D is output in the final product or service market, FSW is a factor generated by the fuel switching algorithm, i indexes the energy market, j indexes the market. The subscripts 0 and 1 represent baseline and with regulation conditions, respectively.

A.2 Industrial and Commercial Markets

Given data limitations associated with the scope of potentially affected industrial and commercial markets, EPA used an alternative approach to estimate the relative changes in price and quantities. These measures are used to compute change in economic welfare as described in Section A.4.

A.2.1 Compute Percentage Change in Market Price

First, we computed the change in production costs resulting from changes in the market price of fuels (determined in the energy markets):

$$\%\Delta c_j = \sum_{i=1}^{n} \alpha_i \Delta p_i \ , \qquad (A.6)$$

where α is the fuel share,[12] i indexes the energy market, and j indexes the industrial or commercial market. We use the results from equation A.6 and the market supply and demand elasticities to compute the change in market price:

$$\%\Delta p_j = \%\Delta c_j \cdot \left[\frac{\varepsilon^{s_i}}{\varepsilon^{s_i} - \eta_i} \right] \qquad (A.7)$$

A.2.2 Compute Percentage Change in Market Quantity

Using the percentage change in the price calculated in Equation A.7 and assumptions regarding the market demand elasticity, the relative change in quantity was computed. For example, in a market where the demand elasticity is assumed to be -1 (i.e., unitary), a 1 percent increase in price results in a 1 percent decrease in quantity. This change was then input into equation A.5 to determine energy demand.

A.3 With-Regulation Market Equilibrium Determination

Market adjustments can be conceptualized as an interactive feedback process. Supply segments face increased production costs as a result of the rule and are willing to supply smaller quantities at the baseline price. This reduction in market supply leads to an increase in the market price that all producers and consumers face, which leads to further responses by producers and consumers and thus new market prices, and so on. The new with-regulation equilibrium is the result of a series of iterations in which price is adjusted and producers and consumers respond, until a set of stable market prices arises where total market supply equals market demand (i.e., $Qs = Q_D$) in each market. Market price adjustment takes place based on a price revision rule that adjusts price upward (downward) by a given percentage in response to excess demand (excess supply).

The algorithm for determining with-regulation equilibria can be summarized by seven recursive steps:

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[12]The fuel share is allowed to vary using a fuel switching rule using cross-price elasticities of demand between energy sources, as described in Section 5.

1. Impose the control costs on electricity supply segments, thereby affecting their supply decisions.

2. Recalculate the market supply in the energy markets. Excess demand exists.

3. Determine the new energy prices via a price revision rule.

4. Recalculate energy market supply.

5. Account for fuel switching given new energy prices. Solve for new equilibrium in final product and service market.

6. Compute energy demand.

7. Compare supply and demand in energy markets. If equilibrium conditions are not satisfied, go to Step 3, resulting in a new set of energy prices. Repeat until equilibrium conditions are satisfied (i.e., the ratio of supply to demand is arbitrarily close to one).

A.4 Computing Social Costs

In the energy markets, consumers(residential and transportation) and producer surplus were calculated using standard methods based on the price and quantity before and after regulation. In the industrial and commercial markets, however, there is no easily defined price or quantity due to the wide variety of products that fall under each sector (i.e. NAICs code). Therefore, methods of calculating consumer and producer surplus are defined based on relative changes in price and quantity and total industry sales rather than on the price and quantity directly. The following sections describe how we derive welfare estimates for these markets.

A.4.1 Change in Consumer Surplus

If price and quantities were available, a linear approximation of the change in consumer surplus can be calculated using the following formula:

$$\Delta CS = -[(\Delta P)\ Q_0 - 0.5(\Delta Q)\ (\Delta P)], \qquad (A.8)$$

where Q_0 denotes the baseline quantity. Given the model only estimates relative changes in price and quantity for each industrial/commercial market, changes in consumer surplus were calculated using these data and total revenue by NAICS code as shown below:

$$\Delta CS = -[(\Delta P)\, Q_1 - 0.5\, (\Delta Q)\, (\Delta P)]\, (P_1\, Q_1)/(P_1\, Q_1)$$

$$\Delta CS = -[\%\Delta P - 0.5\ (\%\Delta P)\, (\%\Delta Q)]\, (P_1\, Q_1). \qquad (A.9)$$

A.4.2 Change in Producer Surplus

If price and quantities were available, a linear approximation could also be used to compute the change in producer surplus:

$$\Delta PS = -[((CC/Q_1) - \Delta P)(Q_1 - \Delta Q)] + 0.5\, [(CC/Q_1 - \Delta P)\, (\Delta Q)], \qquad (A.10)$$

where CC/Q_1 equals the per-unit "cost-shifter" of the regulation. Again, we transform this equation into one that relies only on percentage changes in price and quantity, total revenue,[13] and compliance costs:

$$\Delta PS = -\ [((CC/Q_1) - \Delta P)(Q_1 - \Delta Q)] + 0.5\ [((CC/Q_1) - \Delta P)(\Delta Q)](P_1\, Q_1)/(P_1\, Q_1)$$

$$\Delta PS = -\ [(\%\ \text{cost shift} - \%\Delta P)(1 - \%\Delta Q) + 0.5\ (\%\ \text{cost shift} - \%\Delta P\ )(\%\Delta Q)][P_1\, Q_1]$$

$$\Delta PS = -\ [\%\ \text{cost shift} - \%\Delta P\ ][1 - 0.5(\%\Delta Q)][TR], \qquad (A.11)$$

[13]Multiplying price and quantity in an industry yields total industry revenue. The U.S. Census Bureau provides shipment data for the NAICs codes included in the economic model.

APPENDIX B

ASSUMPTIONS AND SENSITIVITY ANALYSIS

In developing the economic model to estimate the impacts of the stationary combustion turbine NSPS, several assumptions were necessary to make the model operational. This appendix lists and explains the major model assumptions and describes their potential impact on the analysis results. Sensitivity analyses are presented for numeric assumptions.

Assumption: The domestic markets for energy are perfectly competitive.

Explanation: Assuming that the markets for energy are perfectly competitive implies that individual producers are not capable of unilaterally affecting the prices they receive for their products. Under perfect competition, firms that raise their price above the competitive price are unable to sell at that higher price because they are a small share of the market and consumers can easily buy from one of a multitude of other firms that are selling at the competitive price level. Given the relatively homogeneous nature of individual energy products (petroleum, coal, natural gas, electricity), the assumption of perfect competition at the national level seems to be appropriate.

Possible Impact: If energy markets were in fact imperfectly competitive, implying that individual producers can exercise market power and thus affect the prices they receive for their products, then the economic model would understate possible increases in the price of energy due to the regulation as well as the social costs of the regulation. Under imperfect competition, energy producers would be able to pass along more of the costs of the regulation to consumers; thus, consumer surplus losses would be greater, and producer surplus losses would be smaller in the energy markets.

Assumption: Base load energy and peak power represent 80 percent and 20 percent, respectively, of the total cost of electricity production.

Explanation: With deregulation, it is increasingly common for base load energy and peak power to be traded as different commodities. This economic model segments the electricity market into these separate markets. However, no production cost or sales data are currently available to partition the electricity market into base load and peak power markets. The 80/20 percent was obtained from discussions with industry experts.

Sensitivity Analysis: Table B-1 shows how estimated economic impacts change as the share of base load versus peak power costs varies.

Table B-1. Sensitivity Analysis: Base Load and Peak Power Markets' Share of Electricity Production Costs ($\$10^6$)

	Base Load = 70% Peak = 30%	Base Load = 80% Peak = 20%	Base Load = 90% Peak = 10%
Change in producer surplus	213	208	203
Change in consumer surplus	–215	–209	–204
Change in social welfare	–2	–2	–2

Assumption: The elasticity of supply in the base load and peak power electricity markets for existing sources is approximately 0.75 and 0.38, respectively.

Explanation: The price elasticity of supply in the electricity markets represents the behavioral responses from existing sources to changes in the price of electricity. However, there is no consensus on estimates of the price elasticity of supply for electricity. This is in part because, under traditional regulation, the electric utility industry had a mandate to serve all its customers and utilities were compensated on a rate-based rate of return. As a result, the market concept of supply elasticity was not the driving force in utilities' capital investment decisions. This has changed under deregulation. The market price for electricity has become the determining factor in decisions to retire older units or to make higher cost units available to the market.

***Sensitivity Analysis*:** Table B-2 shows how the economic impact estimates vary as the elasticity of supply in the electricity markets varies.

Table B-2. Sensitivity Analysis: Elasticity of Supply in the Electricity Markets

	ES = –25%	Base Case	ES = + 25%
Change in producer surplus	235	208	185
Change in consumer surplus	–237	–209	–187
Change in social welfare	–2	–2	–2

Assumption: The domestic markets for final products and services are all perfectly competitive.

***Explanation**:* Assuming that these markets are perfectly competitive implies that the producers of these products are unable to unilaterally affect the prices they receive for their products. Because the industries used in this analysis are aggregated across a large number of individual producers, it is a reasonable assumption that the individual producers have a very small share of industry sales and cannot individually influence the price of output from that industry.

Possible Impact: If these product markets were in fact imperfectly competitive, implying that individual producers can exercise market power and thus affect the prices they receive for their products, then the economic model would understate possible increases in the price of final products due to the regulation as well as the social costs of the regulation. Under imperfect competition, producers would be able to pass along more of the costs of the regulation to consumers; thus, consumer surplus losses would be greater, and producer surplus losses would be smaller in the final product markets.

Assumption: The elasticity of supply in final product markets.

Explanation: The final product markets are modeled at the two-, and three-digit NAICS codes level to operationalize the economic model. Because of the high level of aggregation, elasticities of supply and demand estimates are not often available in the literature. The elasticities of supply and demand in the final product markets primarily determine the distribution of economic impacts between producers and consumers.

Sensitivity Analysis: Table B-3 shows how the economic impact estimates vary as the supply and demand elasticities in the final product markets vary.

Table B-3. Sensitivity Analysis: Supply and Demand Elasticities in the Final Product Markets

	ES = –25% ED = +25%	ES = Base Case ED = Base Case	ES = +25% ED = –25%
Change in producer surplus	185	208	231
Change in consumer surplus	–187	–209	–233
Change in social welfare	–2	–2	–2

Assumption: The amount of energy (in terms of Btus) required to produce a unit of output in the final product markets remains constant as output changes and prices.

Explanation: The importance of this assumption is that when output in the final product markets changes as a result of a change in energy prices, it is assumed that the amount of fuel used changes in the same proportion as output, although the distribution of fuel usage among fuel types may change due to fuel switching. This change in the demand for fuels feeds into the energy markets and affects the equilibrium price and quantity in the energy markets.

Possible Impact: For example, fuel usage per unit output may change if the price of energy increases because of increased energy efficiency. National energy-efficiency trends are included in the model through projected Btu consumption (i.e., Btu consumption is projected to grow more slowly than output). However, if the regulation leads to increased energy efficiency because of higher fuel prices, this will result in a smaller economic impact than the model results presented in Section 6 indicate.

Assumption: Sensitivity to Fuel Switching.

Sensitivity Analysis: Table B-4 shows how the economic impact estimates vary as fuel-switching is turned on or off in the model.

Table B-4. Sensitivity Analysis: Own- and Cross-Price Elasticities Used to Model Fuel Switching

	Base Case	Without Fuel Switching
Change in producer surplus	208	207
Change in consumer surplus	–209	–208
Change in social welfare	–2	–2

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