# Legislation and Regulations

# Legislation and Regulations

## Introduction

Because analyses by EIA are required to be policy-neutral, the projections in *AEO2006* generally are based on Federal and State laws and regulations in effect on or before October 31, 2005. **The potential impacts of pending or proposed legislation, regulations, and standards—or of sections of legislation that have been enacted but that require implementing regulations or appropriation of funds that are not provided or specified in the legislation itself—are not reflected in the projections.**

Selected examples of Federal and State legislation incorporated in the projections include the following:

- EPACT2005, which, among other actions, includes mandatory energy conservation standards; creates numerous tax credits for businesses and individuals, covering energy-efficient appliances, hybrid vehicles, small biodiesel producers, and new nuclear power capacity; creates a renewable fuels standard (RFS); eliminates the oxygen content requirement for Federal reformulated gasoline (RFG); extends royalty relief for offshore oil and natural gas producers; and extends and expands the production tax credit (PTC) for electricity generated from renewable fuels
- The Military Construction Appropriations Act of 2005, which contains provisions to support construction of the Alaska natural gas pipeline, including Federal loan guarantees during construction
- The Working Families Tax Relief Act of 2004, which includes an extension of the 1.8-cent PTC for electricity generated from wind and closed-loop biomass to December 31, 2005; tax deductions for qualified clean-fuel and electric vehicles; and changes in the rules governing oil and natural gas well depletion
- The American Jobs Creation Act of 2004, which includes incentives and tax credits for biodiesel fuels, a modified depreciation schedule for the Alaska natural gas pipeline, and an expansion of the 1.8-cent renewable energy PTC to include geothermal and solar generation technologies
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- State renewable portfolio standard (RPS) programs, including the California RPS passed on September 12, 2002
- The State of Alaska's Right-of-Way Leasing Act Amendments of 2001, which prohibit leases across State land for a "northern" or "over-the-top" natural gas pipeline route running east from the North Slope to Canada's MacKenzie River Valley
- The Outer Continental Shelf Deep Water Royalty Relief Act of 1995 and subsequent provisions on royalty relief for new leases issued after November 2000 on a lease-by-lease basis
- The Omnibus Budget Reconciliation Act of 1993, which added 4.3 cents per gallon to the Federal tax on highway fuels
- The Energy Policy Act of 1992 (EPACT1992)
- The Clean Air Act Amendments of 1990 (CAAA90), which included new standards for motor gasoline and diesel fuel and for heavy-duty vehicle emissions
- The National Appliance Energy Conservation Act of 1987
- State programs for restructuring of the electricity industry.

*AEO2006* assumes that State taxes on gasoline, diesel, jet fuel, and E85 (fuel containing a blend of 70 to 85 percent ethanol and 30 to 15 percent gasoline by volume) will increase with inflation, and that Federal taxes on those fuels will continue at 2003 levels (the last time the Federal taxes were changed) in nominal terms. *AEO2006* also assumes that the ethanol tax credit as modified under the American Jobs Creation Act of 2004 will be extended when it expires in 2010 and will remain in force indefinitely. Although these tax and tax incentive provisions include "sunset" clauses that limit their duration, they have been extended historically, and *AEO2006* assumes their continuation throughout the forecast. *AEO2006* also includes the biodiesel tax credits created under EPACT2005, but they are not assumed to be extended, because they have no history of legislative extension.

Selected examples of Federal and State regulations incorporated in *AEO2006* include the following:

- CAIR and CAMR—promulgated by the EPA in March 2005 and published in the *Federal Register* as final rules in May 2005—which will limit emissions from power plants in the United States
- New boiler limits established by the EPA on February 26, 2004, which limit emissions of hazardous air pollutants from industrial, commercial,

and institutional boilers and process heaters by requiring that they comply with a Maximum Achievable Control Technology (MACT) floor

- Corporate average fuel economy (CAFE) standards for light trucks promulgated by the National Highway Traffic Safety Administration (NHTSA) in 2003 (but not the new proposed increase in fuel economy standards for light trucks based on vehicle footprint in model years 2008 through 2011, which have not been promulgated)
- The December 2002 Hackberry Decision, which terminated open access requirements for new onshore receiving terminals for LNG

*AEO2006* includes the CAAA90 requirement of a phased-in reduction in vehicle emissions of regulated pollutants. It also reflects "Tier 2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements finalized by the EPA in February 2000 under CAAA90. The Tier 2 standards for RFG were required by 2004, but because they included allowances for small refineries, they will not be fully realized for conventional gasoline until 2008. *AEO2006* also incorporates the ultra-low-sulfur diesel fuel (ULSD) regulation finalized by the EPA in December 2000, which requires the production of at least 80 percent ULSD (15 parts sulfur per million) highway diesel between June 2006 and June 2010 and 100 percent ULSD thereafter. It also includes the rules for nonroad diesel issued by the EPA on May 11, 2004, regulating nonroad diesel engine emissions and sulfur content in fuel.

The *AEO2006* projections reflect legislation that bans or limits the use of the gasoline blending component methyl tertiary butyl ether (MTBE) in the next several years in 25 States. It is assumed that MTBE will be phased out completely by the end of 2008 as a result of EPACT2005, which repealed the oxygenate requirement for RFG.

More detailed information on recent and proposed legislative and regulatory developments is provided below.

## EPACT2005 Summary

The U.S. House of Representatives passed H.R. 6 EH, the Energy Policy Act of 2005, on April 21, 2005, and the Senate passed H.R. 6 EAS on June 28, 2005. A conference committee was convened to resolve differences between the two bills, and a report was approved and issued on July 27, 2005. The House approved the conference report on July 28, 2005, and the Senate followed on July 29, 2005. EPACT2005 was signed into law by President Bush on August 8, 2005, and became Public Law 109-058 [*1*].

Consistent with the general approach adopted in the *AEO*, provisions in EPACT2005 that require funding appropriations to implement, whose impact is highly uncertain, or that require further specification by Federal agencies or Congress are not included in *AEO2006*. For example, EIA does not try to anticipate policy responses to the many studies required by EPACT2005, nor to predict the impact of R&D funding authorizations included in the bill. Moreover, *AEO2006* does not include any provision that addresses a level of detail beyond that modeled in EIA's National Energy Modeling System (NEMS), which was used to develop the *AEO2006* projections. *AEO2006* includes only about 30 sections of EPACT2005, which establish specific tax credits, incentives, or standards in the following areas:

- Mandatory energy conservation standards for torchiere lamps, dehumidifiers, and ceiling fan light kits in the residential sector and for lighting equipment, packaged air conditioning and heating equipment, refrigerator and freezer equipment, automatic icemakers, pre-rinse spray valves, exit signs, distribution transformers, and traffic signals in the commercial sector
- Tax credits for businesses and builders investing in energy efficiency and renewable energy properties; for purchasers of energy-efficient equipment, including water heaters, air conditioners, heat pumps, furnaces, boilers, windows, and other energy-efficient building shell products; for producers of energy-efficient clothes washers, dishwashers, and refrigerators; for purchasers of solar water heaters, solar photovoltaic (PV) equipment, and fuel cells; for businesses investing in fuel cells and microturbines; and for businesses investing in solar energy properties
- Tax credits for the purchase of vehicles with lean burn engines or with hybrid or fuel cell propulsion systems
- An RFS that requires the production and use of defined amounts of renewable fuel by specific dates
- Elimination of the oxygen content requirement for RFG
- Extension of tax credits for biodiesel producers and small ethanol producers
- A tax credit for small agri-biodiesel producers

- Royalty relief for oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico
- Restrictions on new oil and natural gas drilling in or under the Great Lakes
- Reduction of the existing capital recovery period for new electric transmission and distribution assets from 20 years to 15 years
- Expansion of the amortization period for pollution control equipment on coal-fired power plants from 5 years to 7 years
- A PTC of 1.8 cents per kilowatthour for up to 6,000 megawatts of new nuclear capacity brought online before 2021
- An investment tax credit for the construction and development of new or repowered coal-fired generating projects
- Extension, modification, and expansion of the PTC for renewable electricity generation.

The following discussion provides a summary of the provisions in EPACT2005 that are included in *AEO2006* and some of the provisions that could be included if more complete information were available about their funding and implementation. This discussion is not a complete summary of all the sections of EPACT2005. More extensive summaries are available from other sources [*2*].

### *End-Use Demand*

This section summarizes the provisions of EPACT-2005 that affect the end-use demand sectors.

#### *Buildings*

EPACT2005 includes provisions with the potential to affect energy demand in the residential and commercial buildings sector. Many are included in Title I, "Energy Efficiency." Others can be found in the renewable energy, R&D, and tax titles.

Sections 101 through 105 and Section 109 address Federal energy use, allowing for energy conservation measures in congressional buildings (Section 101); updating Executive Order mandates regarding Federal purchasing requirements and energy intensity reductions (Sections 102 through 104); extending the use of Energy Savings Performance Contracts to finance projects through 2016 (Section 105); and updating performance standards for Federal buildings (Section 109). The Federal purchasing requirements and performance standards are represented in NEMS as a result of earlier Executive Orders. Other aspects of these provisions address a level of detail that is not modeled in NEMS.

Sections 135 and 136 establish or tighten mandatory energy conservation standards for a number of residential products and appliances and commercial equipment, affecting projected residential and commercial energy use. Standards for torchiere lamps are explicitly modeled in NEMS, allowing for a direct accounting of energy savings from a maximum watt allowance. Savings resulting from standards for residential dehumidifiers and ceiling fan light kits, based on shipment estimates, are phased in over the *AEO2006* forecast period to account for capital stock turnover. Standards for explicitly modeled commercial equipment, including lighting equipment, packaged air conditioning and heating equipment, refrigerator and freezer equipment, and automatic icemakers, are directly represented in the *AEO2006* projections. Savings resulting from standards for exit signs, traffic signals, distribution transformers, and pre-rinse spray valves are estimated and phased in over the *AEO2006* forecast period to account for capital stock turnover.

Provisions under Title XIII provide tax credits to businesses and individuals for investment in energy efficiency and renewable energy properties. Section 1332 provides a tax credit of $1,000 or $2,000 to builders of homes that are 30 or 50 percent more efficient than current code in 2006 and 2007. Section 1333 allows tax credits for purchasers of energy-efficient equipment, including water heaters, air conditioners, heat pumps, furnaces, boilers, windows, and other energy-efficient building shell products. The credit is available in 2006 and 2007, and the amount varies with the technology purchased. Section 1334 provides a tax credit for producers of energy-efficient clothes washers, dishwashers, and refrigerators. Section 1335 provides tax credits for purchasers of solar water heaters, solar PV equipment, and fuel cells for the years 2006 and 2007. All these tax credits are represented in *AEO2006*. For modeling purposes, it is assumed that the credits will be passed on to consumers in the form of lower first costs for purchases of the products specified.

Section 1336 provides a business investment tax credit of 30 percent for fuel cells and 10 percent for microturbines, and Section 1337 increases the business investment tax credit for solar property from the current level of 10 percent to 30 percent. These provisions, which apply to property installed in 2006 or 2007, are included in *AEO2006*.

### *Industrial*

EPACT2005 includes few provisions that specifically affect industrial sector energy demand. Provisions in the R&D titles that may affect industrial energy consumption over the long term are not included in *AEO2006*.

Section 108 requires that federally funded projects involving cement or concrete increase the amount of recovered mineral component (e.g., fly ash or blast furnace slag) used in the cement. Such use of mineral components is a standard industry practice, and increasing the amount could reduce both the quantity of energy used for cement clinker production and the level of process-related $CO_2$ emissions. Because the proportion of mineral component is not specified in the legislation, this provision is not included in *AEO2006*. When regulations are promulgated, their estimated impact could be modeled in NEMS.

Section 1321 extends the Section 29 PTC for nonconventional fuel to facilities producing coke or coke gas. The credit is available for plants placed in service before 1993 and between 1998 and 2010. Each plant can claim the credit for 4 years; however, the total credit is limited to an annual average of 4,000 barrels of oil equivalent (BOE) per day. The value of the credit is currently $3.00 per BOE, and it will be adjusted for inflation in the future indexed to 2004. Previously, the $3.00 credit had been indexed to 1979, and its value in 2004 was estimated at $6.56 per BOE [*3*]. Because the bulk of the credits will go to plants already operating or under construction, there is likely to be little impact on coke plant capacity.

### *Transportation*

EPACT2005 includes many provisions with potential effects on energy demand, alternative fuel use, and vehicle emissions in the transportation sector. These provisions provide for research, development, and demonstration (RD&D) of technologies and alternative fuels. These provisions are not reflected in *AEO2006* because of the uncertainty associated with the impacts of RD&D programs. The act also calls for policy studies and tax incentives to promote improved energy efficiency and increase alternative fuel use. Provisions specific to the supply of alternative transportation fuels are discussed below, in the sections on petroleum and renewable energy.

EPACT2005 provides a tax credit for the purchase of vehicles that have lean burn engines or employ hybrid or fuel cell propulsion systems. The amount of the credit is based the vehicle's inertia weight, improvement in city-tested fuel economy relative to an equivalent 2002 base year value, emissions classification, and type of propulsion system. The tax credit is also sales-limited, by manufacturer, for vehicles with lean burn engines or hybrid propulsion systems. A phaseout period begins with the first calendar quarter after December 31, 2005, in which a manufacturer's sales of lean burn or hybrid vehicles reach 60,000 units. Reduction of the credits begins in the following quarter. For that quarter and the next, the applicable tax credit will be reduced by 50 percent. For the next two quarters, the tax credit will be reduced to 25 percent of the original value. These tax credits are included in *AEO2006*.

## *Petroleum, Ethanol, and Biofuel Provisions*

This section summarizes the numerous provisions of EPACT2005 affecting the supply, composition, and refining of petroleum and related products that are included in *AEO2006*.

### *Renewable Fuels Standard*

Section 1501 includes an RFS that requires the production and use of 4.0 billion gallons of renewable fuels in 2006, increasing to 7.5 billion gallons in 2012. For calendar year 2013 and each year thereafter, the minimum required volume of renewable fuels would be an amount equal to the percentage of total gasoline sold in the Nation in that year that was represented by 7.5 billion gallons in 2012. In addition, starting in 2013, the required amount of renewable fuels must include a minimum of 250 million gallons derived from cellulosic biomass. Small refineries with a capacity not exceeding 75,000 barrels per calendar day are exempted from the RFS until 2011. Noncontiguous States or territories (Alaska, Hawaii, Puerto Rico, Guam, etc.) are not covered but could petition to join the renewable fuels program. Both ethanol and biodiesel are considered to be renewable fuels, and a 2.5-gallon credit toward the RFS is provided for every gallon of cellulosic biomass ethanol produced. A program of renewable fuels credits would allow refiners, blenders, and importers flexibility to comply with the RFS across geographical regions and over successive years.

The RFS is modeled in *AEO2006*, both for the minimum required volumes and for ethanol derived from cellulosic biomass. Actual renewable fuel supplies may or may not exceed those minimum requirements, depending on the relative costs of renewable fuels and competing petroleum products. In the *AEO2006* reference case, ethanol consumption is projected to exceed the RFS, because it is projected to be available at relatively low cost. *AEO2006* implicitly reflects the ethanol production and consumption behavior that resembles the effect of a national RFS credit trading system, resulting in ethanol blending in gasoline that varies by region.

### *Elimination of Oxygen Requirement for Reformulated Gasoline*

Section 1504 eliminates the oxygen content requirement for RFG. This provision takes effect immediately in California and 270 days after enactment of EPACT2005 in the rest of the RFG regions. Without the oxygen content requirement, refiners are likely to phase out MTBE in gasoline as soon as practical to minimize exposure to environmental liabilities in the future. Several refiners have announced plans to stop making MTBE when the oxygen content requirement expires. Also in Section 1504, volatile organic compound (VOC) Control Regions 1 (southern) and 2 (northern) for RFG would be consolidated by eliminating the less stringent requirements applicable to gasoline designated for VOC Control Region 2.

Elimination of the oxygen requirement for RFG is included in *AEO2006*. MTBE is assumed to be phased out in all regions by the end of 2008. Ethanol is likely to be favored in RFG blending in most regions, based on economics and its other attractive blending characteristics, such as high octane value.

### *Biofuel Tax Credits*

Currently, gasoline and highway diesel fuel excise taxes are 18.4 and 24.4 cents per gallon, respectively. For each gallon of highway fuel, 0.1 cent is deposited in the Leaking Underground Storage Tank Trust Fund, which is extended through 2011 under Section 1362 of EPACT2005. The volumetric excise tax credit program, established in the American Jobs Creation Act of 2004, covers both ethanol and biodiesel. It allows producers to claim the tax credit directly on biofuels: 51 cents per gallon of ethanol, $1 per gallon of biodiesel made from agricultural commodities such as soybean oil, and 50 cents per gallon of biodiesel made from recycled oil such as yellow grease. The biodiesel tax credit is extended through 2008 under Section 1344 of EPACT2005, and the ethanol tax credit was previously extended through 2010 under the American Jobs Creation Act of 2004. Historically, the ethanol tax credit has been extended when it expired; *AEO2006* assumes that it will remain in force indefinitely. The biodiesel tax credits are included in *AEO2006*, but it is not assumed that they will be extended indefinitely, because they are relatively new and have only a short history of legislative extension.

Section 1345 provides for an additional credit up to 10 cents per gallon for small agri-biodiesel producers with annual production of 15 million gallons or less. Small ethanol producers currently cannot have production capacity above 30 million gallons per year to qualify for the special credit. Section 1347 raises the capacity limit to 60 million gallons per year. *AEO2006* includes both the credit for small agri-biodiesel producers and the change in the application of the credit for small ethanol producers.

### *Tax Incentives Related to Petroleum Refining*

Section 1323 provides temporary expensing for refinery investments, which would allow taxpayers to depreciate immediately 50 percent of the cost of all investment that increases the capacity of an existing refinery by at least 5 percent or increases the throughput of qualified fuels by at least 25 percent. Qualified fuels include oil from shale and tar sands. As a condition of eligibility, refiners of liquid fuels must report the details of refinery operations to the Internal Revenue Service. Section 392 also authorizes the EPA, in a cooperative agreement with a State, to streamline the review of a refinery permit application. Because NEMS does not model individual refinery investment decisions, this provision is not included in *AEO2006*.

## *Natural Gas Provisions*

EPACT2005 contains several provisions intended to encourage or facilitate the development of domestic oil and natural gas resources and the domestic infrastructure for importing LNG. Most are in Title III, “Oil and Gas.” Others, covering R&D and tax measures, are included in Titles IX and XIII.

Section 311 clarifies the role of the Federal Energy Regulatory Commission (FERC) as the final decisionmaking body on the construction, expansion, or operation of any facility that exports, imports, or processes LNG. Although it grants final authority to FERC, it directs the commission to consult with the States on safety issues. Section 317 requires the U.S. Department of Energy (DOE), in cooperation with the U.S. Departments of Transportation and Homeland Security, to conduct at least three forums on LNG, which are to be held in areas where LNG terminals are being considered for construction and to be designed to promote public education and encourage cooperation between State and Federal officials. Because the *AEO2006* reference case already assumes that siting issues for LNG terminals are not insurmountable, no changes were made in NEMS to address the LNG-related provisions in EPACT2005.

In addition, it is unclear to what degree this provision will affect the siting of regasification terminals.

Under Section 312, FERC is given the authority to permit a natural gas company to provide facilities for natural gas storage at market-based rates if it believes the company will not exert market power. NEMS already assumes some market impact as a result of incentive-based rates.

Sections 321, 322, and 323 clarify provisions of the Outer Continental Shelf Lands Act, the Safe Drinking Water Act, and the Federal Water Pollution Control Act. Sections 341 and 342 provide clarifications of existing programs. Sections 343 through 347 address royalty relief. Specifically, Sections 343 and 344 address incentives for natural gas production from marginal wells and from deep wells in the shallow waters of the Gulf of Mexico; Section 346 suspends royalties on offshore production in Alaska; and Section 347 provides royalty relief for production from the National Petroleum Reserve, at the discretion of the Secretary of Energy. Sections 353 and 354 deal with royalty relief for natural gas extracted from methane hydrates and for enhanced oil and natural gas production through $CO_2$ injection. None of these provisions is modeled in NEMS, and they are not included in *AEO2006*.

Section 345, which provides royalty relief for oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or natural gas lease sale occurring within 5 years after enactment, is modeled in NEMS. The minimum production volumes for which royalty payments would be suspended are as follows:

- 5,000,000 BOE for each lease in water depths of 400 to 800 meters
- 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters
- 12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters
- 16,000,000 BOE for each lease in water depths greater than 2,000 meters.

For *AEO2006*, the water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule of NEMS. The suspension volumes are 5,000,000 BOE for leases in water depths 200 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depth of 1,600 to 2,400 meters; and 16,000,000 BOE for leases in water depths greater than 2,400 meters. Examination of the resources available at 200 to 400 and 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the act would not materially affect the model results.

Section 386, which prohibits new oil and natural gas drilling in or under the Great Lakes, is included in *AEO2006*. Specifically, it states that no Federal or State permit or lease shall be issued for new oil or natural gas slant, directional, or offshore drilling in or under one or more of the Great Lakes. To reflect this provision, oil and natural gas resources underlying the Great Lakes were removed from the resource base of the Oil and Gas Supply Module in NEMS.

In Title XIII, Sections 1325 through 1327 provide tax incentives for the oil and natural gas industries that include treatment of natural gas distribution lines as 15-year property, treatment of natural gas gathering lines as 7-year property, and exclusion of prepayments on natural gas supply contracts with government utilities from arbitrage rules. NEMS does not include sufficient detail for modeling these provisions.

### *Electricity Provisions*

EPACT2005 includes provisions to improve the reliability and operation of the electricity transmission grid, reduce regulatory uncertainty, and increase consumer protection. These electricity provisions are included under Title XII, "Electricity Modernization Act of 2005." Most of them cannot be addressed at the level of detail included in NEMS or can be included only with additional specification not provided in EPACT2005. Title XIII, "Energy Tax Incentive Act of 2005," also includes tax incentives targeted toward electricity generation or transmission properties.

Section 1211 calls for the creation of mandatory reliability standards for the electricity grid to replace the voluntary standards in place today. The new standards would be administered by "electric reliability organizations" (EROs), which would be certified by FERC and would be responsible for developing and enforcing reliability standards for their regions. It is implicitly assumed in *AEO2006* that electricity will be provided reliably.

Several sections under Title XIII would affect the electric power industry. Section 1308 shortens the existing capital recovery period for new transmission and distribution assets from 20 years to 15 years. The property must have been placed in use after April 11, 2005, to qualify for the new recovery period. Section 1309 expands amortization of pollution control equipment on coal-fired plants from 5 years to 7 years. Only plants that came online after January 1, 1976, would qualify for the new amortization period. These tax changes are represented in *AEO2006*. Tax credits for nuclear and renewable energy production and for coal production and investment are discussed below.

### *Nuclear Energy Provisions*

Title VI of EPACT2005 includes several provisions designed to ensure that nuclear energy will remain a major component of the Nation's energy supply. Sections 601 through 610 update the Price-Anderson Act Amendment to the Atomic Energy Act of 1954, which ensures that adequate funds are available to the public to satisfy liability claims in the event of a nuclear accident, while limiting the liability of any individual reactor owner. EPACT2005 extends the coverage to all nuclear units brought on line through 2025, adjusts the maximum assessment and liability limit, and addresses incidents that might occur outside the United States. Section 608 allows small, modular reactors to be combined and treated as a single unit for liability purposes. These provisions are not explicitly modeled in NEMS, but *AEO2006* implicitly assumes that Price-Anderson coverage will be extended to any new nuclear units built in the United States.

Under Title XIII, Section 1306 provides a PTC for new nuclear reactors brought online through 2020. The PTC is worth 1.8 cents per kilowatthour for the first 8 years of operation, subject to an annual limit of $125 million per gigawatt of capacity. It is restricted to a total of 6 gigawatts of new nuclear capacity. This provision is included in *AEO2006*. Section 1310 modifies the rules for qualified decommissioning funds and requires that a new ruling on the amounts funded be made whenever a plant receives a license renewal.

### *Coal Provisions*

EPACT2005 includes numerous provisions that authorize funding for coal-related activities. Because they depend on future appropriations, they are not included in *AEO2006*.

Sections 431 through 438, referred to as the Coal Leasing Act, ease or remove certain requirements for coal leases on Federal lands. These provisions are not included in *AEO2006*, because specific lease requirements cannot be modeled directly in NEMS.

Title XIII includes several provisions that alter the tax treatment of certain coal-related activities. For example, Section 1301 sets qualifications for receipt of a PTC of $1.50 per ton between 2006 and 2009 and $2.00 per ton through 2013 for coal produced on Indian lands. This provision is not included in *AEO2006*, because only limited data are available on coal resources and production on Indian lands. (In 2000, coal was mined from Indian lands in Arizona, New Mexico, and Montana.) One possible outcome of this provision would be to accelerate production of coal from Indian lands while the credit is available; however, given the relatively short time horizon of the provision (qualifying mines must be in service before 2009) and the small share of total coal production made up by coal from Indian lands (3.6 percent in 2004), the impact on national average minemouth prices for coal is likely to be small.

Section 1307, Subsection 48A, establishes a $1.3 billion investment tax credit for the construction of new or repowered coal-fired generation projects, including $800 million for coal gasification projects and $500 million for other projects that achieve certain targets, such as 99 percent $SO_2$ removal and 90 percent mercury removal from plant emissions. For integrated gasification combined-cycle (IGCC) technologies a 20-percent investment tax credit may be applied to qualifying investments, and for other qualifying advanced technologies a 15-percent investment tax credit is applicable. Repowering projects must improve the thermal design efficiency of coal-fired plants by 4 to 7 percent. This provision is modeled in NEMS by allowing up to 3 gigawatts of IGCC and another 3 gigawatts of advanced coal-fired capacity to take advantage of the tax credit.

### *Renewable Energy Provisions*

EPACT2005 contains several provisions intended to encourage or facilitate the use of renewable energy resources for electricity production. Most are included in Title II, "Renewable Energy." Others are in the R&D, electricity, and tax titles. In addition, the act contains provisions to encourage the use of renewable energy for transportation and in end-use applications, as described above.

Section 203 requires the Federal Government, to the extent that it is "economically feasible and technically practical," to purchase a minimum amount of electricity generated from renewable resources. The Federal purchase requirement starts at 3 percent of the total amount of electricity consumed by the Federal Government in 2007 and increases stepwise to 7.5 percent of the total in 2013 and thereafter. Renewable energy used at a Federal facility that is produced on-site at the facility, on Federal lands, or on Indian land will count double toward the requirement. Although the Federal Government is a major purchaser of electricity, the required purchases are not expected to affect the projections of renewable electricity demand in *AEO2006*.

Several sections specifically address the production of hydroelectricity at proposed or existing facilities. Section 241 revises the appeals process for the licensing of hydropower projects by FERC. Appeals on license conditions and fishway rulings will now be heard in a trial-type hearing. Applicants may also propose alternatives to the conditions specified by FERC to achieve the purposes of the original license conditions. The impacts of these provisions on the cost of developing or relicensing hydroelectric projects are not clear, and they are not included in *AEO2006*.

Under Title XII, a number of electricity market provisions directly address the use of renewable resources within the Nation's electricity grid. Section 1251 requires utilities to offer net metering upon customer request. Net metering means that eligible customer-sited generation resources may be used to offset gross customer electricity purchases during the billing cycle; that is, customer generation in excess of instantaneous demand will be fed back to the utility distribution system, causing the customer's meter to effectively "run backward." Eligible resources and applicable billing cycles are not defined in the provision, but credit will be given to States that have adopted or voted on comparable standards. Current State net metering standards typically allow renewable generation (solar and sometimes wind or other renewable fuels) and sometimes allow other favored technologies, such as fuel cells, to qualify. Generation is typically netted on a monthly basis, but netting may be allowed over longer periods. *AEO2006* assumes that excess generation from customer-sited sources will offset purchased electricity at retail rates.

Section 1253 eliminates the requirement for eligible utilities to purchase electricity from qualified facilities under the Public Utility Regulatory Policies Act (PURPA), which previously required utilities to purchase generation from small cogenerators and renewable plants at a rate equal to their avoided cost of generation. Eligible utilities must have open electricity markets, including nondiscriminatory access to wholesale generation markets and to transmission and interconnection services. *AEO2006* assumes that all generation resources will compete in a nondiscriminatory market for generation, capacity, and transmission services.

Several changes to the tax code, all involving the PTC for renewable generation, are expected to have significant impacts on the growth of renewable electricity markets. Section 1301 extends the eligibility date for new renewable generation facilities to qualify for the inflation-adjusted tax credit for the first 10 years of plant operation. Eligibility was set to expire after December 31, 2005, but will now expire after December 31, 2007. Although some eligible resources will continue to get the full, inflation-adjusted credit of 1.5 cents per kilowatthour and others one-half of that amount, all new eligible facilities—including efficiency improvements or additions of capacity at existing facilities—will receive the full credit for the first 10 years of their operation. *AEO2006* specifically accounts for the extension of the eligibility period for renewable resources and the expansion of the credit to hydroelectric facilities.

In addition to the PTC modifications discussed above, Section 1302 will allow agricultural cooperatives to allocate renewable energy production tax credits to their members, based on the "amount of business" done by each member with the cooperative. Eligible cooperatives include those that are more than 50 percent owned by agricultural producers or entities owned by agricultural producers, thus allowing otherwise tax-exempt electricity cooperatives to take advantage of the PTC by transferring the benefit directly to their membership. Although this provision is not specifically modeled, *AEO2006* assumes that all eligible renewable capacity is built by tax-paying entities and thus is entitled to take the PTC.

### *Incentives for Innovative Technologies*

EPACT2005 Title XVII, "Incentives for Innovative Technologies," authorizes the Secretary of Energy, after consultation with the Secretary of the Treasury and subject to budget appropriations, to provide Federal loan guarantees for a wide variety of projects related to energy consumption and production technologies. Although EPACT2005 includes several other technology incentives, the Title XVII program has particular potential to influence the development of future energy technologies. The guarantees can cover up to 80 percent of the cost of a project over a period of up to 30 years (or 90 percent of a project's useful life, whichever is less). To be eligible, projects must avoid, reduce, or sequester air pollutants or anthropogenic greenhouse gas (GHG) emissions and must employ new or significantly improved technologies, as compared with those that are commercially available when the guarantee is issued. The eligible project categories include:

- Renewable energy systems
- Advanced fossil energy technologies, including coal gasification meeting certain requirements
- Hydrogen fuel cell technologies for residential, industrial, or transportation applications
- Advanced nuclear energy facilities
- Carbon capture and sequestration practices and technologies
- Technologies for efficient generation, transmission, and distribution of electric power
- Efficient end-use energy technologies
- Production facilities for fuel-efficient vehicles, including hybrids and advanced diesel vehicles
- Pollution control equipment
- Refineries.

Loan guarantees will also be available for gasification facilities that meet certain criteria. Eligible gasification projects include IGCC plants where 65 percent of the fuel used is a combination of coal, biomass, and petroleum coke and 65 percent of the energy output is used to produce electricity. IGCC plants with a capacity of at least 100 megawatts using western coal are also eligible. To receive loan guarantees, the IGCC projects must emit no more than 0.05 pound of $SO_2$, 0.08 pound of nitrogen oxides ($NO_x$), and 0.01 pound of particulates per million Btu of fuel input and must remove 90 percent of the mercury in any coal that is used.

Because funding levels and specific rules for this program are not yet known, its potential impacts are not represented in *AEO2006*. The program could provide a flexible tool for stimulating investment in a wide array of promising technologies [*4*]. The leverage achieved by the program will depend on the risks associated with the projects supported and the expected loss that would occur if a loan default occurred. For loans of the same size, riskier projects require more Federal funding.

## California Greenhouse Gas Emissions Standards for Light-Duty Vehicles

The State of California was given authority under CAAA90 to set emissions standards for light-duty vehicles that exceed Federal standards. In addition, other States that do not comply with the National Ambient Air Quality Standards (NAAQS) set by the EPA under CAAA90 were given the option to adopt California's light-duty vehicle emissions standards in order to achieve air quality compliance. CAAA90 specifically identifies hydrocarbon, carbon monoxide, and $NO_x$ as vehicle-related air pollutants that can be regulated. California has led the Nation in developing stricter vehicle emissions standards, and other States have adopted the California standards [*5*].

California Assembly Bill 1493 (A.B. 1493), signed into law in July 2002, required the California Air Resources Board (CARB) to develop and adopt GHG emissions standards for light-duty vehicles that would provide the maximum feasible reduction in emissions. In determining the maximum feasible standard, CARB was required to consider cost-effectiveness, technological capability, economic impacts, and flexibility for manufacturers in meeting the standard. CARB was not allowed to consider the following compliance options: mandatory trip reductions; land use restrictions; additional fees and/or taxes on any motor vehicle, fuel, or vehicle miles traveled; a ban on any vehicle category; reduction in vehicle weight; or a limitation or reduction of speed limits on any street or highway in the State. Tailpipe emissions of $CO_2$, which are directly proportional to vehicle fuel consumption, account for the vast majority of total GHG emissions from vehicles. In August 2004, CARB released a report detailing its proposed GHG emissions standards for light-duty vehicles, which were approved by California's Office of Administrative Law on September 15, 2005.

The standards approved in September 2005 cover GHG emissions associated with vehicle operation, air conditioning operation and maintenance, and production of vehicle fuel. The standards apply to noncommercial light-duty passenger vehicles manufactured for model years 2009 and beyond. The standards, specified in terms of $CO_2$ equivalent emissions, apply to vehicles in two size classes: passenger cars and small light-duty trucks with a loaded vehicle weight rating of 3,750 pounds or less; and heavy light-duty trucks with a loaded vehicle weight rating greater than 3,750 pounds and a gross vehicle weight rating less than 8,500 pounds. The $CO_2$ equivalent emission standard for heavy light trucks includes noncommercial passenger trucks between 8,500 pounds and 10,000 pounds. The regulations approved in September 2005 set near-term standards, to be phased in between 2009 and 2012, and mid-term standards, to be phased in between 2013 and 2016. After 2016, the emissions standards are assumed to remain constant. Table 2 summarizes the $CO_2$ equivalent standards.

In October 2003, California, 11 other States, 3 cities, and several environmental groups filed a petition in

*Table 2. CARB emissions standards for light-duty vehicles, model years 2009-2016*

| Tier | Model Year | $CO_2$ equivalent emissions standard (grams per mile): Passenger cars and small light trucks (under 3,751 pounds) | Heavy light trucks (3,751 to 8,500 pounds) |
|---|---|---|---|
| Near term | 2009 | 323 | 439 |
| | 2010 | 301 | 420 |
| | 2011 | 267 | 390 |
| | 2012 | 233 | 361 |
| Mid-term | 2013 | 227 | 355 |
| | 2014 | 222 | 350 |
| | 2015 | 213 | 341 |
| | 2016 | 205 | 332 |

the U.S. Court of Appeals, arguing that the EPA should regulate GHG emissions from vehicles. In July 2005, the court ruled that the EPA was not required to regulate GHG emissions under the Clean Air Act.

Given the constraints on using other measures, improvements in fuel economy are the only practical way to meet the standards. The automotive industry, which opposes A.B. 1493, has filed suit against CARB, arguing that California GHG emissions standards are in essence fuel economy standards and therefore are preempted by a Federal statute that gives the U.S. Department of Transportation the only authority to regulate fuel economy [*6*]. CARB has not yet obtained a Clean Air Act waiver from the EPA, which would be required before it can implement its GHG emissions standards. For this reason and due to the uncertainty surrounding the pending lawsuit, A.B. 1493 is not represented in the *AEO2006* reference case. Potential impacts of the regulations were examined, however, in *AEO2005*, using the *AEO2005* reference case as a starting point to estimate their likely effects on vehicle prices, GHG emissions, regional energy demand, and regional fuel prices [*7*].

## Proposed Revisions to Light Truck Fuel Economy Standards

In August 2005, NHTSA published proposed reforms to the structure of CAFE standards for light trucks and increases in light truck CAFE standards for model years 2008 through 2011 [*8*]. Under the proposed new structure, NHTSA would establish minimum fuel economy levels for six size categories defined by the vehicle footprint (wheelbase multiplied by track width), as summarized in Table 3. For model years 2008 through 2010, the new CAFE standards would provide manufacturers the option of complying with either the standards defined for each individual footprint category or a proposed average light truck fleet standard of 22.5 miles per gallon in 2008, 23.1 miles per gallon in 2009, and 23.5 miles per gallon in 2010. All light truck manufacturers would be required to meet an overall standard based on sales within each individual footprint category after model year 2010.

*Table 3. Proposed light truck CAFE standards by model year and footprint category (miles per gallon)*

| Model year | Vehicle category and footprint range (square feet): 1 (≤43.0) | 2 (>43.0-47.0) | 3 (>47.0-52.0) | 4 (>52.0-56.5) | 5 (>56.5-65.0) | 6 (>65.0) |
|---|---|---|---|---|---|---|
| 2008 | 26.8 | 25.6 | 22.3 | 22.2 | 20.7 | 20.4 |
| 2009 | 27.4 | 26.4 | 23.5 | 22.7 | 21.0 | 21.0 |
| 2010 | 27.8 | 26.4 | 24.0 | 22.9 | 21.6 | 20.8* |
| 2011 | 28.4 | 27.1 | 24.5 | 23.3 | 21.9 | 21.3 |

**Decrease due to changes in production plans provided to NHTSA and used to establish an average that increases over time.*

In determining the proposed light truck fuel economy standards, NHTSA addressed concerns related to energy conservation, technology feasibility and economic practicability, other regulations on fuel economy, and safety. In the evaluation of technology and economic practicability, NHTSA used gasoline price projections from the *AEO2005* reference case, which projected that gasoline prices would range from $1.54 to $1.61 per gallon (2004 dollars) over the 2004-2025 forecast period. For the same period, the *AEO2006* reference case projects a range of $1.95 to $2.26 per gallon (2004 dollars). NHTSA, which will likely receive and address comments related to many issues, specifically asked for comments on the appropriate gasoline price projection to use in defining the final rule. Use of the *AEO2006* reference case gasoline prices in the final rule could impact the final CAFE standards. For example, using higher gasoline prices in technology evaluations could lead to a finding that additional technologies are economically practical, with corresponding changes in fuel economy standards for some footprint categories.

Because the new light truck fuel economy standards have not been finalized, they are not included in the *AEO2006* reference case. An alternative case was developed to examine the potential energy impacts of the proposed standards. Because NEMS does not currently represent the footprint-based standards included in NHTSA's recent proposal, the alternative case assumes that manufacturers will adhere to the proposed increases in light truck fleet standards. For model year 2011, the alternative case applies a fleet-wide standard of 24 miles per gallon, based loosely on the change between 2010 and 2011 in the proposed footprint-based standards. Because no further changes in fuel economy standards beyond 2011 are assumed, the projected trends in light truck fuel economy after 2011 reflect projected technology adoption and market forces.

New light truck fuel economy in the alternative case (Table 4) is projected to be 6 percent higher than the reference case projection in 2011 (24.9 miles per gallon, compared with 23.4 miles per gallon in the reference case). Consistent with the reference case projections, light truck fuel economy continues to improve after 2011 in the alternative case, to 27.4 miles per gallon in 2030, 4 percent higher than the reference case projection of 26.4 miles per gallon. The higher CAFE standards lead to higher prices for light trucks, resulting from increased use of lightweight materials, more complex valve trains, and advanced transmissions. In the alternative case, the average price of a new light truck is projected to be 1.2 percent ($350) higher than in the reference case in 2011 and 0.5 percent ($170) higher in 2030. That increase is at least partially offset, however, by the expected reduction in fuel costs that would result from the increase in average fuel efficiency.

***Table 4. Key projections for light truck fuel economy in the alternative CAFE standards case, 2011-2030***

| Projection | 2011 | 2015 | 2020 | 2030 |
|---|---|---|---|---|
| Fuel economy of new light trucks (miles per gallon) | 24.9 | 25.2 | 26.0 | 27.4 |
| Increase from reference case projection for purchase price of new light trucks (2004 dollars) | 350 | 250 | 210 | 170 |
| Annual reduction from reference case projection for energy use by all light-duty vehicles (quadrillion Btu) | 0.13 | 0.26 | 0.35 | 0.44 |
| Cumulative reduction from reference case projection for energy use by all light-duty vehicles, 2004-2030 (quadrillion Btu) | 0.31 | 1.19 | 2.76 | 6.85 |

Total projected energy use by light-duty vehicles, including both cars and light trucks, in the alternative case is projected to be 0.7 percent (0.13 quadrillion Btu) lower than the reference case projection in 2011 and 1.8 percent (0.44 quadrillion Btu) lower in 2030. Cumulative energy use by light-duty vehicles from 2004 to 2030 is almost 7 quadrillion Btu lower in the alternative case than projected in the reference case.

## State Renewable Energy Requirements and Goals: Update Through 2005

*AEO2005* provided a summary of 17 State renewable energy programs in existence as of December 31, 2003, in 15 States [*9*]. They included RPS programs in 9 States, renewable energy mandates in 4 States, and renewable energy goals in 4 States. Since 2003, 7 more States and the District of Columbia have established renewable energy programs (Table 5), including 6 RPS programs and two renewable energy goals. No new mandates have been enacted since 2003, although a renewable goal instituted in Vermont will become mandatory if it has not been met by 2012. In addition, major changes and refinements have been made in a number of the State programs that were in existence before 2004 (Table 6). No Federal renewables requirement currently exists, although a nationwide RPS was again considered in 2005.

Although generally resembling earlier versions, some of the new programs and changes to existing programs include unique or unusual features:

- Colorado's new RPS is the first enacted through a voter initiative. The new RPS allows a covered Colorado utility (40,000 or more customers) to opt out of the RPS, or an exempt utility to opt in, with a majority vote involving a minimum of 25 percent of the utility's customers.
- Connecticut's RPS now includes energy conservation.
- Delaware's RPS includes municipal utilities and some rural electric cooperatives, although they may opt out.
- Qualifying renewables under Hawaii's RPS now include electricity conservation measures, such as district cooling systems using seawater air conditioning, solar and heat pump water heating, and ice storage, as well as reject heat in some instances.

- Under 2005 legislation, compliance with Minnesota's objective (goal) now becomes linked to the application for a certificate of need for new transmission or generation facilities.
- New York's goals set in 2004 and the 2005 changes in the Illinois program both resulted from public utility commission orders rather than from legislation.
- In New York, the development of new generating capacity using renewable fuels is supported through centralized procurement by the New York State Energy Research and Development Authority, with funds collected through a charge on investor-owned utilities.
- The Illinois program allows imports of electricity only from directly adjacent jurisdictions designated as serious or severe NAAQS nonattainment areas.
- Vermont's goal is to meet 100 percent of additional electricity demand through 2012 with allowed renewable resources (up to 10 percent of total demand), and it broadly defines renewable

***Table 5. Basic features of State renewable energy requirements and goals enacted since 2003***

| State | Year enacted | Requirements | Accepts existing capacity | Out-of-State supply | Credit trading |
|---|---|---|---|---|---|
| ***Renewable Portfolio Standards*** | | | | | |
| *Colorado* | *2004* | *3-10% of generation, 2007-2015; 4% of requirement must be solar* | *Yes* | *Yes* | *Yes* |
| *Delaware* | *2005* | *1-10% of retail sales, 2007-2019* | *Yes* | *Yes* | *Yes* |
| *District of Columbia* | *2005* | *11% of sales by 2022; 3.5% of requirement must be solar* | *Yes* | *Yes* | *Yes* |
| *Maryland* | *2004* | *3.5-7.5% of sales, 2006-2019* | *Yes* | *Yes* | *Yes* |
| *Montana* | *2005* | *5-15% of sales, 2008-2015* | *Yes* | *Yes* | *Yes* |
| *Rhode Island* | *2004* | *3-16% of sales, 2007-2019* | *Yes* | *Yes* | *Yes* |
| ***Goals*** | | | | | |
| *New York* | *2004* | *25% of generation by 2013* | *Yes* | *Yes* | *No* |
| *Vermont* | *2005* | *All growth, up to 10% of total sales, 2005-2012; goal becomes mandatory if not met by 2012* | *Yes* | *—* | *—* |

***Table 6. Major changes in existing State renewable energy requirements and goals since 2003***

| State | Date of change | New requirements |
|---|---|---|
| *Connecticut* | *July 2005* | *Effective January 1, 2006, Public Law 05-01 adds Class III renewables to the State RPS, to include new customer-side combined heat and power systems and electricity savings from energy conservation and load management at commercial and industrial facilities, equal to 1% of generation in 2007, 2% in 2008, 3% in 2009, and 4% in 2010.* |
| *Hawaii* | *June 2004* | *Senate Bill 2474 changes the goal of the State RPS, from 9% of sales by 2010 to 20% of sales by 2020, and includes ocean technologies, electricity conservation, and some cogeneration.* |
| *Illinois* | *July 2005* | *An Illinois Commerce Commission resolution adopts a sustainable energy plan that replaces the State renewable energy goal of 15% of sales by 2020 with an RPS requiring the State's largest electric utilities to begin supplying 2% renewable energy to Illinois customers by January 1, 2007, increasing by 1% annually to 8% by 2013; at least 75% of the requirement must be from wind power.* |
| *Minnesota* | *May 2005* | *Statute 216B.243 links compliance with the State's renewable energy goal of 10.0% of electricity sales (by power producers other than Xcel Energy, see Statute 216B.1691) to obtaining a certificate of need for new transmission or generation capacity.* |
| *Nevada* | *June 2005* | *Assembly Bill 03 increases overall renewables requirement from 5-15% of sales 2003-2013, to 6-20%, but (a) delays compliance by 2 years to 2005-2015, and (b) permits up to one-quarter of the requirement to be met by efficiency measures reducing electricity use.* |
| *Pennsylvania* | *November 2004* | *Senate Bill 1030 changes individual utility goals to RPS requiring 5.7% of sales in 2007, increasing to 18% in 2020 (with solar increasing to at least 0.5% of sales); RPS includes waste coal, coal gasification, and demand-side management and includes both credit trading and some capacity from out-of-State suppliers in interconnected areas.* |
| *Texas* | *August 2005* | *Senate Bill 20 increases overall renewable energy requirement from 2,000 megawatts of new renewable capacity by 2009 to 5,880 megawatts by 2015, including a non-mandatory target of at least 500 megawatts from sources other than wind.* |

energy as that which “relies on a resource that is being consumed at a harvest rate at or below its natural regeneration rate” [*10*]. The Vermont legislation is designed to encourage contracts for new renewables capacity by allowing the new capacity to meet multiple States’ RPS requirements. New renewable capacity in Vermont can be counted toward Vermont’s program, while its renewable energy credits may be marketed separately to renewables credit markets in neighboring States.

- Pennsylvania’s new Alternative Energy Portfolio Standard includes waste coal and coal gasification, which can contribute as much as 10 percent of the renewable generation requirement (set at 18 percent of total generation in 2020).

The 23 State renewable energy programs in effect in 2005 generally are concentrated in three broad geographic areas, with 11 jurisdictions along the Northeastern and Mid-Atlantic seaboard (Connecticut, Delaware, the District of Columbia, Maine, Maryland, Massachusetts, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont), 6 in the Southwest (Arizona, California, Colorado, Nevada, New Mexico, and Texas), 4 in the upper Midwest (Illinois, Iowa, Minnesota, and Wisconsin), and Hawaii and Montana each standing alone. No Southern, Southeastern, or Northwestern State (except Montana) currently has a renewable energy program.

Although efforts to coordinate renewable energy programs among adjacent States have begun, no formal or informal coordination systems have been finalized. An example of efforts to establish such a system include the newly formed Mid-Atlantic Organization of PJM States, Inc. In order to prevent double counting, however, States in most interconnected regions now coordinate identification and tracking of the origins and contracted destinations of renewable energy transactions via power pools or other organizations. The New England States use the Generation Information System of the New England Power Pool (NEPOOL), and the Mid-Atlantic States employ PJM’s Generation Attribute Tracking System (GATS). Although the Midwestern Power Pool does not currently track the region’s renewable generation, a multi-State Midwestern effort is underway to establish the Midwest Renewable Energy Tracking System (MRETS). Similarly, the California Energy Commission and the Western Governors’ Association are collaborating to establish a Western Renewable Energy Generation Information Tracking System (WREGIS).

### *New Renewable Energy Capacity, 2004-2005*

Table 7 summarizes EIA’s understanding of new renewable energy capacity entering service in 2004 and 2005. However, it is difficult to quantify the specific impacts of State renewable programs. First, neither the individual States nor other sources identify all the new renewable energy capacity that is built, and some new capacity may not be reported. Although large wind projects typically are recognized, smaller projects, such as landfill gas (LFG) or end-user sited PV installations, may go unreported. Further, new capacity is not necessarily added in response to State renewable energy programs. Projects may be constructed for other reasons, and they may or may not qualify for the State programs. Projects located in one State may serve the requirements of another State or different States over time.

***Table 7. New U.S. renewable energy capacity, 2004-2005 (installed megawatts, nameplate capacity)***

| Year | Biomass | Geothermal | Conventional hydroelectric | Landfill gas | Solar photovoltaics | Wind | Total |
|---|---|---|---|---|---|---|---|
| **2004** | | | | | | | |
| Without standards | 0.0 | 0.0 | 65.8 | 32.5 | 0.0 | 199.8 | **298.1** |
| With standards | 19.9 | 0.0 | 4.5 | 30.0 | 3.0 | 281.6 | **339.1** |
| **2005** | | | | | | | |
| Without standards | 0.0 | 0.0 | 133.2 | 14.7 | 0.0 | 1,077.1 | **1,225.0** |
| With standards | 34.1 | 37.0 | 26.1 | 24.6 | 3.6 | 1,716.7 | **1,842.1** |
| **2004 and 2005** | | | | | | | |
| Without standards | 0.0 | 0.0 | 199.0 | 47.2 | 0.0 | 1,276.9 | **1,523.1** |
| With standards | 54.0 | 37.0 | 30.6 | 54.8 | 6.6 | 1,998.2 | **2,181.2** |
| Total | 54.0 | 37.0 | 229.6 | 102.0 | 6.6 | 3,275.1 | **3,704.3** |
| **Percentages** | | | | | | | |
| Without standards | 0.0 | 0.0 | 86.6 | 46.3 | 0.0 | 39.0 | **41.1** |
| With standards | 100.0 | 100.0 | 13.3 | 53.7 | 100.0 | 61.0 | **58.9** |

Projects located in States without renewable programs may be explicitly or implicitly targeted to serve programs in other States and, therefore, may be at least partially "caused" by another State's renewable program despite not being enumerated as such.

New renewable energy capacity built today that appears unsupported by a State renewable program may result from an earlier favorable experience with a State program. For example, Table 7 does not include 362 megawatts of wind capacity from new projects in Iowa in the "With Standards" category, because Iowa's mandate was fully met by 2000; nor does it include 62 megawatts of new wind capacity built in North Dakota, which has no requirement, although the new capacity serves Minnesota's RPS. Nevertheless, Table 7 provides some indication of the extent to which renewable programs are resulting in the construction of new renewable energy capacity and also suggests the extent to which other key factors (for example, the Federal PTC) may promote growth in renewable capacity.

Differences among renewable energy capacity additions in different States can result from a range of factors separate from State renewable programs, including differences in natural endowments, electricity consumption levels and rates of demand growth, the availability of alternatives, the presence or absence of renewable energy proponents and champions, and variations in consumer preferences. On the other hand, while States with renewable energy requirements accounted for only 45 percent of total U.S. electricity supply, they accounted for almost 60 percent of all new renewable energy capacity added in 2004 and 2005.

EIA's analysis indicates that State-level requirements probably have led to somewhat more biomass, geothermal, LFG, and solar capacity than would otherwise have been built, although the additional amounts are small. Hydroelectric capacity does not appear to have been advanced by State-level renewables requirements. Expansion of wind power capacity appears to be strongly affected by the combination of State requirements and the Federal PTC, as evidenced by the substantial construction of new wind capacity in 2005, particularly in States with RPS programs.

Among States with requirements and goals, the amount of renewable capacity added in 2004 and 2005 varies significantly. Of the 23 States with renewable requirements in 2004 and 2005, 4 have reported no new renewable energy capacity (although requirements in Delaware, the District of Columbia, and Maryland are new, and Connecticut is estimated to have met its program requirements already). In another 7 States (Arizona, Hawaii, Massachusetts, New Jersey, Rhode Island, Vermont, and Wisconsin) 15 megawatts or less has been added over the 2-year period. In 3 States (Maine, Nevada, and Pennsylvania), between 25 and 35 megawatts has been added; in 2 (Colorado and Illinois) between 65 and 75 megawatts has been added; and in 4 (Minnesota, Montana, New Mexico, and New York) between 100 and 200 megawatts has been added in each State over the past 2 years. California, with nearly 500 megawatts, and Texas, with more than 700 megawatts, together account for 55 percent of all new U.S. renewable capacity attributed to State-level renewable energy requirements and goals in 2004 and 2005.

In contrast, Oklahoma and Washington, which have no renewable energy requirements, each installed between 250 and 300 megawatts of new renewable capacity in 2004 and 2005, and other States without programs added smaller amounts. Most of the new capacity in those States is wind power, suggesting that good resources and the Federal PTC may be the primary factors leading to new wind power installations there.

Despite the expansion of State renewable energy programs, new renewables capacity accounted for a fairly small fraction of new U.S. electricity supply added in 2004 and 2005. Including conventional hydroelectricity, all renewables currently account for 9.3 percent of total U.S. electricity generation, with nonhydroelectric renewables accounting for 2.2 percent. The 3,700 megawatts of new renewables capacity added during 2004 and 2005 accounted for 12 percent of the 32,000 megawatts of new generating capacity that entered service during the period.

## State Air Emission Regulations That Affect Electric Power Producers

Several States have recently enacted air emission regulations that will affect the electricity generation sector. The regulations govern emissions of $NO_x$, $SO_2$, $CO_2$, and mercury from power plants. Where firm compliance plans have been announced, State regulations are represented in *AEO2006*. For example, installations of $SO_2$ scrubbers and selective catalytic reduction (SCR) and selective noncatalytic reduction (SNCR) $NO_x$ removal technologies associated with the largest State program, North Carolina's Clean Smokestacks Initiative, are included. Figure 9 shows historical trends in $SO_2$ emissions for selected States.

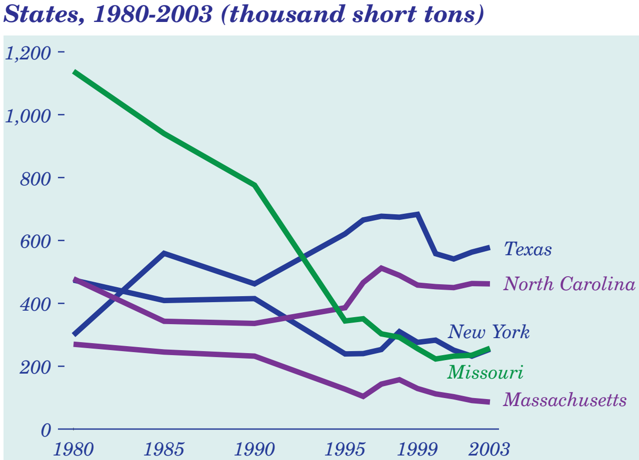
## Federal Air Emissions Regulations

In 2005, the EPA finalized two regulations, CAIR and CAMR, that would reduce emissions from coal-fired power plants in the United States. Both CAIR and CAMR are included in the *AEO2006* reference case. The EPA has received 11 petitions for reconsideration of CAIR and has provided an opportunity for public comment on reconsidering certain aspects of CAIR. Public comments were accepted until January 13, 2006. The EPA has also received 14 petitions for reconsideration of CAMR and is willing to reconsider certain aspects of the rule. Public comments were accepted for 45 days after publication of the reconsideration notice in the *Federal Register*. Several States and organizations have filed lawsuits against CAMR. The ultimate decision of the courts will have a significant impact on the implementation of CAMR.

### *Clean Air Interstate Rule*

The final CAIR was promulgated by the EPA in March 2005 and published in the *Federal Register* as a final rule in May 2005 [*11*]. The rule is intended to reduce the atmospheric interstate transport of fine particulate matter ($PM_{2.5}$) and ozone [*12*]. Both $SO_2$ and $NO_x$ are precursors of $PM_{2.5}$. $NO_x$ is also a precursor to the formation of ground-level ozone. CAIR would require 28 States and the District of Columbia to reduce $SO_2$ and/or $NO_x$ emissions in a two-phase program. The Phase I cap for $NO_x$ becomes effective in 2009, and the Phase I cap for $SO_2$ starts in 2010 [*13*]. The Phase II limits for both $NO_x$ and $SO_2$ start in 2015. The rule would apply to all fossil-fuel-fired boilers and turbines serving electrical generators with capacity greater than 25 megawatts that provide electricity for sale. It would also apply to CHP units larger than 25 megawatts that sell at least one-third of their potential electrical output and supply more than 219,000 megawatthours of electricity to the grid. Table 8 shows EPA estimates of CAIR's impacts on $SO_2$ and $NO_x$ emissions. The *AEO2006* reference case projections for $SO_2$ and $NO_x$ emissions are very close to the EPA numbers.

***Figure 9. Sulfur dioxide emissions in selected States, 1980-2003 (thousand short tons)***




Under CAIR, the States would be responsible for allocating $NO_x$ emissions allowances and taking the lead in pursuing enforcement actions, and they would have flexibility in choosing the sources to be controlled. They could meet the emissions reduction requirements either by joining the EPA-managed cap and trade program for power plants or by achieving reductions through emissions control measures on sources in other sectors (industrial, transportation, residential, or commercial) or on a combination of electricity generating units and sources in other sectors. The 28 CAIR States are required to submit State Implementation Plans (SIPs) to the EPA by September 2006, showing how they intend to meet their respective caps.

In order to participate in the cap and trade program, States would be required to regulate power plant emissions within their boundaries. The EPA would be responsible for assigning State emissions budgets, reviewing and approving State plans, and administering the emissions and allowance tracking systems. Sources currently subject to the CAAA90 Title IV rules and to the $NO_x$ SIP Call trading program can use allowances banked from those programs before 2010 for compliance with CAIR. CAIR would require additional reductions in $NO_x$ emissions for States affected by the $NO_x$ SIP Call. State $NO_x$ emissions caps are based on each State's share of region-wide heat input.

The EPA plans to meet the $SO_2$ emission reduction requirements by implementing a progressively more stringent retirement ratio on $SO_2$ allowances for electricity generating units of different vintages under the CAAA90 Title IV Acid Rain Program. New $SO_2$ allowances would not be issued under CAIR; power

***Table 8. Estimates of national trends in annual emissions of sulfur dioxide and nitrogen oxides, 2003-2020 (million short tons)***

| | | Projections | | |
|---|---|---|---|---|
| Emissions | 2003 | 2010 | 2015 | 2020 |
| **EPA** | | | | |
| Sulfur dioxide | 10.6 | 6.1 | 4.9 | 4.2 |
| Nitrogen oxides | 4.2 | 2.4 | 2.1 | 2.1 |
| **AEO2006** | | | | |
| Sulfur dioxide | 10.6 | 5.9 | 4.6 | 4.0 |
| Nitrogen oxides | 4.2 | 2.3 | 2.1 | 2.1 |

plants would instead use the current pool of $SO_2$ allowances issued under Title IV. Allowances issued for vintage years 2004 through 2009 could be retired on a 1-to-1 basis, but allowances issued for vintage years 2010 through 2014 would have to be retired on a 2-to-1 basis, requiring two Title IV allowances to be retired for each ton of $SO_2$ emissions. Allowances issued for vintage years 2015 and later would be retired on a basis of approximately 2.9 to 1. This retirement procedure is designed to integrate the CAIR rules with the existing Title IV $SO_2$ emissions reduction program.

### *Clean Air Mercury Rule*

CAMR (proposed as the Utility Mercury Reduction Rule) for controlling mercury emissions from new and existing coal-fired power plants was promulgated by the EPA in March 2005 and published as a final rule in the *Federal Register* in May 2005 [*14*]. Power plants with capacity greater than 25 megawatts and CHP units larger than 25 megawatts that sell at least one-third of their electricity would be subject to CAMR.

Under CAMR, Section 112 of the CAAA90 would be modified to allow regulation of mercury emissions under a cap and trade program. The EPA estimates that CAMR, using the cap and trade approach, would reduce mercury emissions by nearly 70 percent when fully implemented. The program would be implemented in two phases with a banking provision. The Phase I cap, to be met in 2010, would be 38 short tons; the Phase II cap, to be met in 2018, would be 15 short tons. In addition to these national caps, new power plants would be subject to output-based limits on mercury emissions.

Under the cap and trade approach, States would submit plans to the EPA to demonstrate that they would meet their assigned State-wide mercury emissions budgets. With EPA approval, the States could then participate in the cap and trade program. Allowances would be allocated by the States to power companies, which could either sell or bank any excess allowances. The final rule does not include a safety valve mechanism for allowance prices.

## Update on Transition to Ultra-Low-Sulfur Diesel Fuel

On November 8, 2005, the EPA Administrator signed a direct final rule that will shift the retail compliance date for offering ULSD for highway use from September 1, 2006, to October 15, 2006. The change will allow more time for retail outlets and terminals to comply with the new 15 parts per million (ppm) sulfur standard, providing time for entities in the diesel fuel distribution system to flush higher sulfur fuel out of the system during the transition. Terminals will have until September 1, 2006, to complete their transitions to ULSD. The previous deadline was July 15, 2006.

There is no change in the June 1, 2006, start date for refiners to be producing ULSD. Also, during the extended transition period, diesel fuel meeting a 22-ppm level can be temporarily marketed as ULSD at the retail pump. Finally, the EPA extended the beginning date for the restriction on how much ULSD can be downgraded to higher sulfur fuel by 15 days, to October 15, 2006, to be consistent with the end of the new transition dates.

The 45-day transition delay will help to ensure nationwide availability of 15-ppm ULSD before the introduction of new model year 2007 diesel trucks and buses designed to operate on the improved fuel. These minor timing adjustments do not affect the *AEO2006* projections.

## State Restrictions on Methyl Tertiary Butyl Ether

By the end of 2005, 25 States had barred, or passed laws banning, any more than trace levels of MTBE in their gasoline supplies, and legislation to ban MTBE was pending in 4 others. Some State laws address only MTBE; others also address ethers such as ethyl tertiary butyl ether (ETBE) and tertiary amyl methyl ether (TAME). *AEO2006* assumes that all State MTBE bans prohibit the use of all ethers for gasoline blending.

Even with the removal of the oxygen content requirement for RFG in EPACT2005, RFG is still expected to be blended with ethanol, because it is not clear where else refiners could obtain the clean, high-octane blending components needed to replace MTBE, which supplies 11 percent of the volume and a significant portion of the rated octane of RFG. Aromatic compounds and olefins are high-octane blending components, but they are limited by the RFG requirements and by the Federal Mobile Source Air Toxics program. Isooctane and alkylate are clean, high-octane blending components, but refinery capacity to produce them is limited, and it is often less expensive to use ethanol at up to 10 percent by volume to offset part of the volume loss resulting from the removal of MTBE.

As noted above, EPACT2005 also mandates the use of 7.5 billion gallons of renewable motor fuels, such as ethanol and biodiesel, by 2012 and requires renewable motor fuel use to grow at the rate of overall motor fuel use thereafter. In addition, some States have their own renewable fuels programs. Minnesota currently requires all its gasoline supply to be blended with 10 percent ethanol, increasing to 20 percent ethanol if at least 50 percent of the new cars sold in the State can be guaranteed by their manufacturers to be compatible with the higher blend. Most current automobiles can use a maximum of only 10 percent ethanol in gasoline, and automakers worry that widespread use of gasoline with 20 percent ethanol content will result in misfueling of vehicles not designed to use more than 10 percent ethanol.

Several other State programs are contingent upon local ethanol supplies. Montana's MTBE ban takes effect only when 40 million gallons of ethanol production capacity is available in the State; and Hawaii has a pending requirement for 85 percent of its gasoline to be blended with 10 percent ethanol if enough ethanol can be produced in the State.

### Volumetric Excise Tax Credit for Alternative Fuels

On August 10, 2005, President Bush signed into law the Safe, Accountable, Flexible, and Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) [*15*]. The act includes authorization for a multitude of transportation infrastructure projects, establishes highway safety provisions, provides for R&D, and includes a large number of miscellaneous provisions related to transportation, most of which are not included in *AEO2006* because their energy impacts are vague or undefined. Section 11113, which provides a volumetric excise tax credit of 50 cents per gallon for alternative fuels, such as liquid fuels derived from the Fischer-Tropsch process, is included in *AEO2006*. This tax credit is expected to have a small impact on transportation energy consumption, because it is scheduled to expire on September 30, 2009, and only a small quantity of alternative fuels will be produced in the pilot or demonstration projects that are expected to qualify for the credit.