Legislation and Regulations

Introduction

Because analyses by EIA are required to be policy-neutral, the projections in *AEO2007* generally are based on Federal and State laws and regulations in effect on or before October 31, 2006 (although there are exceptions to this rule, as discussed below). **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:

- The new CAFE standards finalized in March 2006, which establish higher minimum fuel economy performance requirements by vehicle footprint for light-duty trucks
- EPACT2005, which includes mandatory energy conservation standards; creates numerous tax credits for businesses and individuals; creates an RFS and eliminates the oxygen content requirement; extends royalty relief for offshore oil and natural gas producers; and extends and expands the 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 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 and a modified depreciation schedule for the Alaska natural gas pipeline
- The Maritime Security Act of 2002, which amended the Deepwater Port Act of 1974 to include offshore natural gas facilities
- State RPS programs, including the California RPS passed on September 12, 2002
- 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.

AEO2007 assumes that State taxes on gasoline, diesel, jet fuel, and E85 [*4*] will increase with inflation and that Federal taxes on those fuels will remain at the nominal rate established in 2003 (the last time the Federal taxes were changed). *AEO2007* 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 the ethanol tax credit includes a "sunset" clause that limits its duration, historically it has been extended regularly, and *AEO2007* assumes its continuation throughout the projection [*5*]. *AEO2007* also includes the biodiesel tax credits that were created under the American Jobs Creation Act and extended through 2008 under EPACT2005; however, they are not assumed to be extended further, because they have minimal history of legislative extension.

The Safe, Accountable, Flexible, Efficient Transportation Equity Act: A Legacy for Users (SAFETEA-LU) increased the Federal tax on compressed natural gas used in vehicles to 18.3 cents per equivalent gallon of gasoline and provided a credit of 50 cents per gallon through September 2009. *AEO2007* assumes that State and Federal taxes on compressed natural gas for vehicles will continue at 2006 levels in nominal terms and that the tax credit will not be extended.

The PTC for wind, geothermal, landfill gas (LFG), and some types of hydroelectric and biomass-fueled plants, established initially by the Energy Policy Act of 1992 [*6*] also is represented in *AEO2007*. Only new plants that come on line before January 1, 2008, are eligible to receive the credit. *AEO2007* does not assume extension of the PTC, which has been allowed to expire in the past, even though it has typically been renewed retroactively. In most of the extensions, the credit has been modified significantly: additional resources have been included, resources previously eligible have been excluded, and the structure and treatment of the credit itself have been changed.

Selected examples of Federal and State regulations incorporated in *AEO2007* include the following:

- New stationary diesel regulations issued by the U.S. Environmental Protection Agency (EPA) on July 11, 2006, which limit emissions of NO_x, particulate matter, SO_2, carbon monoxide, and hydrocarbons to the same levels required by the EPA's nonroad diesel engine regulations
- The Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), promulgated by the EPA in March 2005 and published in the *Federal Register* as final rules in May 2005, which will limit emissions of SO_2, NO_x, and mercury 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 floor.

AEO2007 does not include consideration of California Assembly Bill (A.B.) 32 (discussed below), which mandates a 25-percent reduction in California's greenhouse gas emissions by 2020. Implementing regulations have not been drafted and are not due to be finalized until January 2012.

In addition, California's A.B. 1493, which establishes greenhouse gas emissions standards for light-duty vehicles, is not considered in the *AEO2007* reference case. A.B. 1493 was signed into law in July 2002, and regulations were released by the California Air Resources Board in August 2004 and approved by California's Office of Administrative Law in September 2005; however, the automotive industry has filed suit to block their implementation, and the Board has not yet obtained a Clean Air Act waiver from the EPA, which is required before the regulations can be implemented.

In August 2006, seven northeastern States released a model rule for implementation of the Regional Greenhouse Gas Initiative (RGGI) [*7*], as discussed below, clarifying what had been laid out in December 2005 when the States entered into the agreement [*8*]. The RGGI, which would cap greenhouse gas emissions from power producers, requires each State to enact legislation for accomplishing the emissions reductions. Although the State RGGI caps and timelines are known, many aspects of their implementation remain uncertain, because the participating States have not yet enacted the necessary legislation. Therefore, the RGGI provisions are not modeled in the *AEO2007* reference case.

AEO2007 does include 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 reformulated gasoline (RFG) were required by 2004, but because they included allowances for small refineries, they will not be fully realized for conventional gasoline until 2008. *AEO2007* 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 (less than or equal to 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.

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

EPACT2005: Status of Provisions

EPACT2005 was signed into law by President Bush on August 8, 2005, and became Public Law 109-058 [*9*]. A number of provisions from EPACT2005 were included in the *AEO2006* projections [*10*]. Many others were not considered in *AEO2006*—particularly, those that require funding appropriations or further specification by Federal agencies or Congress before implementation.

A number of the EPACT2005 provisions not included in *AEO2006* could affect the projections. In the preparation of *AEO2007* their status was reviewed, and where possible, additional provisions were included in the projections; however, *AEO2007* still excludes those EPACT2005 provisions whose impacts are highly uncertain or that address a level of detail beyond that modeled in NEMS. Furthermore, EIA does not try to anticipate policy responses to the many studies required by EPACT2005 nor predict the impacts of research and development (R&D) funding authorizations included in the bill.

The following summary examines the status of EPACT2005 provisions that initially could not be included in *AEO2006* but potentially could be modeled in NEMS. It focuses on provisions that are newly included in *AEO2007*, as well as those that might be added in future *AEO*s. The discussion below does not provide a complete summary of all the sections of EPACT2005. More extensive summaries are available from other sources [*11*].

End-Use Demand Provisions

This section summarizes provisions of EPACT2005 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. Most of the provisions that have been funded or for which implementing regulations have been put in place since the publication of *AEO2006*, cannot be modeled in NEMS. The status of those provisions that could potentially be included in NEMS is summarized below.

Section 122 of Title I, "Weatherization Assistance," authorizes $600 million to weatherize low-income households. The weatherization program, in existence since 1976, uses Federal funds to increase the energy efficiency of low-income houses. In fiscal year (FY) 2006, funding for this program was $242 million. FY 2007 funding proposed by the U.S. House of Representatives is set at $250 million. The increase in funding could allow up to 3,200 more homes to be weatherized in FY 2007 than in FY 2006. The *AEO2007* reference case includes increases in energy efficiency in existing building envelopes to account for programs such as weatherization. At current funding levels, roughly 100,000 homes are weatherized each year. The impact of this section is considered in *AEO2007*.

Section 204 of Title II, "Use of Photovoltaic Energy in Public Buildings," authorizes funds for the establishment of a photovoltaic (PV) energy commercialization program to procure, install, and evaluate PV solar electric systems in public buildings. No funding has been appropriated to date for this measure. It is not included in *AEO2007*.

Section 206 of Title II, "Renewable Energy Security," authorizes funds for the establishment of rebates for the purchase of renewable energy systems, including PV, ground-source heat pumps, and solar water heaters. This program was to be in place starting in calendar year 2006 and last through 2010; however, no funding has been appropriated for the measure to date, and it is not included in *AEO2007*.

Section 783 of Title VII, "Federal Procurement of Stationary, Portable, and Micro Fuel Cells," authorizes funds for Federal procurement of stationary, portable, and micro fuel cells. No funding has been appropriated for the measure to date, and it is not considered in *AEO2007*.

Industrial

EPACT2005 includes few provisions that would 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 *AEO2007*.

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. The proportion of mineral component is not specified in the legislation but is to be determined by Federal procurement rules; however, as of mid-September 2006 the rules had not been promulgated. Section 108 also requires that the energy-saving impact of the rules be assessed by the EPA, in cooperation with the U.S. Department of Energy (DOE) and Department of Transportation (DOT), within 30 months of enactment. Because regulations have not been promulgated, this section is not considered in *AEO2007*. When the regulations are promulgated, their estimated impacts could be modeled in NEMS.

Section 1321 provides for the extension of tax credits for producers of coke or coke gas, effective for tax years beginning after December 31, 2005. Otherwise, the status of Section 1321 is unchanged. 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. Consequently, the provision is expected to have no impact on the *AEO2007* projections.

Coal Gasification Provisions

This section provides updates to the funding and implementation status of key tax incentive provisions in Title XIII of EPACT2005 related to coal gasification that were not addressed in *AEO2006*.

Section 1307 creates an investment tax credit program for qualifying advanced clean coal projects, funded at $1.3 billion. The section also includes an additional $350 million for qualifying gasification projects. The gasification credit for any taxable year is equal to 20 percent of the basis of any equipment to be used in the gasification process that is placed in service during the year as part of a gasification project that has been certified by DOE as eligible for the credit. The amount eligible for credit is limited to $650 million per project. Only domestic projects that employ domestic gasification applications are eligible. Applicants must, among other criteria, satisfy certain financial requirements, prove that a market exists for the project's products, and demonstrate competency in the development and operation of the project. Credits are not allowed for gasification projects receiving credits under the program for advanced coal projects. A certificate of eligibility is valid for 10 fiscal years, beginning on October 1, 2005.

In February 2006, the IRS issued guidance for the Section 1307 program. Certifications are to be issued and credits allocated to projects in annual allocation rounds. The first round of submissions began on February 21, 2005, and closed on October 2, 2006. Overall, the period for submission of applications is to run for 3 years, starting on February 21, 2006. As of August 2006, 49 applications had been received, 27 of which fell under the gasification technology program and were for CTL plants in 17 States. The 27 projects are valued at $30 billion and request tax credits of $2.7 billion. Selection of projects to receive the credits is scheduled for the end of November 2006.

Credits will be allocated first to projects that have CO_2 capture capability, use renewable fuel, or have project teams with experience that demonstrates successful operation of the gasification technology. If the requested allocations exceed $350 million, the credits will be allocated to the projects that provide the highest ratio of synthetic gas supplied to the requested allocation of credits. Any remaining credits will be applied to non-priority projects that provide the highest amount of nameplate capacity. If funds remain in the program, additional rounds will be conducted in 2007 and 2008. The $1.3 billion in tax credits for the advanced clean coal program was accounted for in *AEO2006* in the NEMS Electricity Market Module. CTL projects are eligible for the gasification credits, because gasification is the first step in the CTL process; however, because the level of interest in coal gasification projects was not known at the time, the gasification program credits were not included in *AEO2006*. Given the extent of interest in the program to date, they are included in the Petroleum Market Module for *AEO2007*.

Oil and Natural Gas Provisions

This section provides updates to the funding and implementation status of key oil and natural gas provisions of EPACT2005 that were not addressed in *AEO2006*. Most of the oil and natural gas provisions in EPACT2005 are included in Title III, "Oil and Gas." Others, covering R&D, are included in Title IX.

The Federal Energy Regulatory Commission (FERC) was authorized by Section 312 to allow natural gas storage facilities to charge market-based rates if it was believed that they would not exert market power. On June 15, 2006, FERC finalized rules implementing the provisions that would allow an applicant for interstate natural gas storage facilities to request authority to charge market-based rates even if a lack of market power had not been demonstrated. The rules are intended to mitigate natural gas price volatility by encouraging the development of new natural gas storage capacity. They apply in circumstances where market-based rates are in the public interest and necessary to encourage the construction of storage capacity and to ensure that customers are adequately protected, even in circumstances where market power may not have been demonstrated. In previous *AEO*s, storage rates were allowed to vary from regulation-based rates, depending on market conditions.

In compliance with Section 354, DOE established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through CO_2 injection, while at the same time sequestering CO_2 produced from the combustion of fossil fuels in power plants and large industrial processes. Reports issued by DOE indicate that an additional 89 billion barrels of oil could be recovered in the United States through CO_2 injection. Under the program, grants of up to $3 million will be provided to each project selected. On September 6, 2006, DOE announced the selection of the first project to receive one of the grants, a project sponsored by the University of Alabama-Birmingham to implement a demonstration project in the Citronelle oilfield in Mobile County, AL. The total project cost is estimated at $6 million, with DOE's maximum share at just under $3 million. Estimates indicate that an additional 64 million barrels of oil could be recovered from the Citronelle field by this technique.

The implementation of Section 354 was not included in previous *AEO*s, because NEMS does not represent project-level activities and because of the considerable uncertainty surrounding the eventual scope of the program. For *AEO2007*, however, additional oil resources have been added to account for increased use of CO_2-enhanced oil recovery technology.

Section 311 clarified the role of FERC as the final decisionmaking body on any issues concerning onshore facilities that export, import, or process LNG. On October 7, 2005, FERC established mandatory procedures requiring prospective applicants for LNG terminals, related jurisdictional pipelines, and other related natural gas facilities to begin the Commission's pre-filing review process at least 6 months before filing an application to site and/or construct such a facility. The procedures, which also apply to applications for modifications of existing or authorized LNG terminals, are designed to encourage applicants to cooperate with State and local officials.

In March 2005 and June 2006, FERC and DOE, in cooperation with DOT and the U.S. Department of Homeland Security, conducted three public forums on LNG designed to promote public education and encourage cooperation between State and Federal officials in areas where LNG terminals are being considered for construction. They were held in Boston, MA; Astoria, OR; and Los Angeles, CA. An additional forum is planned for Houston, TX, in the 4th quarter of 2006, fully satisfying the Section 317 requirement that a minimum of three such forums be held. Although this provision is not explicitly represented in the *AEO2007* NEMS, the model includes an assumption that there are no major regulatory impediments to the siting of new LNG facilities.

Section 301 authorized DOE to increase the capacity of the Strategic Petroleum Reserve (SPR) to 1 billion barrels from its current capacity of 727 million barrels. DOE has announced plans to add additional storage capacity to its SPR storage sites in Big Hill, TX; Bayou Choctaw, LA; West Hackberry, LA; and one new site in Richton, MS. DOE filed a draft site selection Environmental Impact Statement with the EPA on May 19, 2006, for the selection of a new site, and comments have been received. In order for the additional storage capacity to be authorized, constructed, and ultimately filled, further actions by Congress and the Executive Branch will be required; therefore, it is not considered in *AEO2007*.

Section 369 requires DOE to initiate a process for the leasing of Federal lands for research on oil shale, tar sands, and other unconventional fuels. Several industry research proposals were evaluated, and on January 17, 2006, the U.S. Department of the Interior's Bureau of Land Management announced the selection of six applicants for oil shale leases to receive further consideration. Because the lease applications are still under consideration, this provision is not accounted for in *AEO2007*.

Coal Provisions

This section provides updates to the funding and implementation status of provisions in EPACT2005 that will affect coal supply and prices but were not addressed in *AEO2006*. Many of the provisions can be found in Titles IV and XIII of EPACT2005.

A number of coal-related provisions that were authorized by EPACT2005 but not included in *AEO2006* continue to be excluded from *AEO2007*. They include four loan guarantee or cost-sharing programs. Section 411 authorized a loan guarantee for a coal project in the Upper Great Plains, which must employ both renewable and advanced IGCC technologies. A loan guarantee for the Clean Coal Project in Healy, AK, authorized by Section 412, also is excluded from *AEO2007*. In Section 413, EPACT2005 authorized a cost-sharing program in support of a high-altitude (at least 4,000 feet) Western IGCC Demonstration Project. Finally, a loan guarantee for an IGCC plant located in a deregulated region was authorized by Section 414.

These provisions have spurred some activity and interest. For instance, Xcel Energy, which has proposed building a facility in Colorado with 300 to 350 megawatts of generating capacity, is a potential applicant for the Western IGCC Demonstration Project. On August 7, 2006, DOE released its plans to form a program office with functions that include the drafting of application guidelines for the various loan programs. It will also be charged with the task of awarding the loan guarantees. Although NEMS has the capability to represent these coal provisions, Congress had not appropriated funds for the provisions as of September 1, 2006, and they are not considered in *AEO2007*.

Nuclear Energy Provisions

EPACT2005 includes numerous provisions that address nuclear power generation. This section provides updates to the funding and implementation status of nuclear power generation provisions in EPACT2005 that were not addressed in *AEO2006*.

Section 1306 of Title 13 extends the PTC of 1.8 cents per kilowatthour (not adjusted for inflation) to any nuclear power plant with a "new" design that has a construction start date before January 1, 2014, and enters commercial operation by January 1, 2021. Under this program, the owner of the eligible plant can reduce its tax liability by up to 1.8 cents for each kilowatthour of plant output. For the purposes of this law, construction begins when a utility "that has applied for or been granted a combined operating license . . . initiates the pouring of safety-related concrete for the reactor building." The IRS published an initial set of guidelines for the program in May 2006 and eventually will publish a set of formal rules that will become part of the Tax Code. In EPACT-2005, the per-kilowatthour tax credit was indexed to the rate of inflation; however, the indexing provision was eliminated in the Gulf Opportunity Zone Act of 2005 (P.L. 109-135). Consequently, the credit would be constant in nominal dollars over time. Because the earliest date at which the first new nuclear unit eligible for the tax credit could become operational is about 2015, the "de-indexing" of the credit has the effect of reducing its real value by about 25 to 30 percent.

There are at least three limitations on the amount of tax credits a utility can receive. First, tax credits in any given year are limited to a maximum of $125 per kilowatt ($125 million for a 1,000-megawatt unit). Second, the tax credit can be applied only in the first 8 years of a plant's operation. Third, the credit is limited to a maximum of 6 gigawatts of new nuclear capacity nationally. If the total capacity qualifying for the tax credit exceeds 6 gigawatts, the amount of the credit per kilowatthour will be reduced proportionally. *AEO2007* assumes that up to 9 gigawatts of new capacity will receive the Title 13 PTC at 1.2 cents per kilowatthour. (*AEO2006* assumed that 6 gigawatts would receive the full 1.8 cents per kilowatthour.) *AEO2007* also assumes that participating utilities will be able to take all the tax credits in each of the first 8 years of their qualifying units' operation.

Title 17 of EPACT2005 allows the Government to guarantee loans used to construct new energy technologies "that reduce or avoid greenhouse gases," including new nuclear power plants. The Secretary of Energy can guarantee a loan of up to 80 percent of the project's cost; however, DOE will not guarantee more than 80 percent of the total debt. Thus, if a utility decided to fund a project with 80 percent debt and 20 percent equity, DOE would only guarantee up to 64 percent of the project's total cost. Such loan guarantees would affect the economics of nuclear power, because they would reduce the effective interest rates on the debt and allow utilities to use much more debt financing.

The Secretary of Energy will choose the projects that will receive the loan guarantees. The factors to be considered in the selection of projects include:

- A relatively low probability of failure
- The extent to which the project avoids, reduces, or sequesters air pollutants or emissions of greenhouse gases
- The extent to which the project will advance the goals of the President's Advanced Energy Initiative
- The extent to which the technology is ready to be employed commercially in the United States and can yield a commercially viable product.

Because of the lack of appropriating legislation, this program is not included in *AEO2007*.

Fuel Economy Standards for New Light Trucks

In March 2006, NHTSA finalized CAFE standards requiring higher fuel economy performance for light-duty trucks in MY 2008 through 2011 [*12*]. Unlike the proposed CAFE standards discussed in *AEO2006* [*13*], which would have established minimum fuel economy requirements by six footprint size classes, the final reformed CAFE standards specify a continuous mathematical function that determines minimum fuel economy requirements by vehicle footprint, defined as the wheelbase (the distance from the front axle to the center of the rear axle) times the average track width (the distance between the center lines of the tires) of the vehicle in square feet.

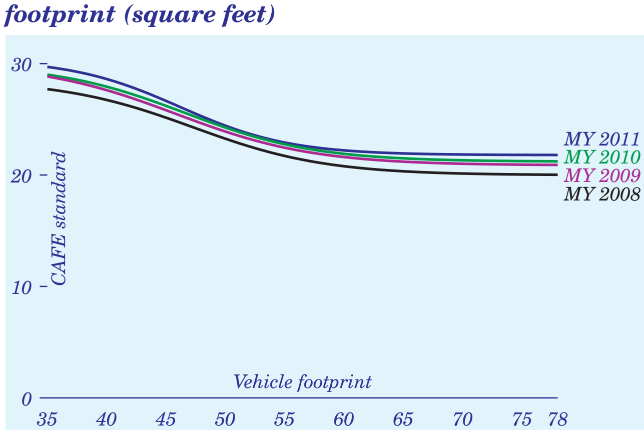
As shown in Figure 9, the new fuel economy standards vary by model year (MY) and by vehicle footprint. By eliminating the categories laid out in the proposed rule, the final rule removes the opportunity for manufacturers to reduce fuel economy requirements by altering vehicle sizes just enough to reach lower target levels. Instead, under a continuous function approach, each footprint value has an assigned fuel economy target, and small changes in vehicle footprint are not rewarded with large decreases in target values.

In addition to reforming the structure of the light truck CAFE program, NHTSA has also increased the gross vehicle weight rating (GVWR) of light trucks covered under CAFE. NHTSA defines light-duty trucks as trucks with a GVWR of 10,000 pounds or less, including pickups, vans, truck-based station wagons, and sport utility vehicles (SUVs). Current CAFE standards apply to light-duty trucks that have a GVWR of 8,500 pounds or less.

Starting in MY 2011, light truck CAFE standards will also apply to medium-duty passenger vehicles (MDPVs), which are defined as complete heavy-duty vehicles less than 10,000 pounds GVWR that are designed primarily for transportation of passengers. The definition of an MDPV does not include vehicles sold as incomplete trucks (i.e., a truck cab on chassis); vehicles that have a seating capacity of more than 12 persons; vehicles designed for more than 9 persons in seating rearward of the driver's seat; or vehicles equipped with an open cargo area (e.g., a pickup truck box or bed) of 6 feet or more in interior length. Hence, the definition of an MDPV essentially includes SUVs, short-bed pickup trucks, and passenger vans that are within the specified weight and weight-rated ranges. This implies that, starting in MY 2011, all SUVs greater than 8,500 GVWR that are currently excluded from CAFE consideration and all passenger vans less than 10,000 pounds GVWR will be included in determining a manufacturer's light truck CAFE compliance.

To provide manufacturers adequate time to adjust their product plans to the new provision, NHTSA is making the new definition effective beginning in MY 2011. As a result, the change will not have an immediate impact on MY 2008-2010 vehicles. In addition, NHTSA is permitting manufacturers to rely on either the old or the revised definition of light trucks until MY 2011.

Figure 9. Reformed CAFE standards (miles per gallon) for light trucks, by model year and vehicle footprint (square feet)



NHTSA has also amended the "flat floor provision" to include only vehicles that have at least three rows of seats, of which the second and third rows can be detached or folded to create a flat cargo surface. Manufacturers currently offering minivans with folding seats will be able to take advantage of the new definition immediately. The new CAFE standards continue to exclude most medium- and heavy-duty pickups and most medium- and heavy-duty cargo vans that are used primarily for agricultural and commercial purposes. The change in the definition of a light truck can also have an impact on the product mix that a manufacturer will offer, because some light trucks under the current definition could be categorized as cars under the new definition, with a higher CAFE requirement.

The reformed CAFE standards impose a unique fuel economy standard on each manufacturer, based on the product mix sold in a given MY. For MY 2008 through 2010, manufacturers have the option of complying with either the new reformed CAFE standard or an unreformed CAFE standard. The unreformed CAFE standard requires manufacturers to meet an average light truck fleet standard of 22.5 miles per gallon in MY 2008, 23.1 miles per gallon in MY 2009, and 23.5 miles per gallon in MY 2010. All light truck manufacturers must adhere to the new reformed standards for MY 2011 and subsequent years.

Each manufacturer is subject to an identical fuel economy target for light truck models with the same footprint. Moreover, the same formula is applied to determine each manufacturer's required CAFE level, using the fuel economy targets for different footprints, the targets specific for each model, and the production levels of each model. Individual manufacturers face different required CAFE levels only to the extent that they produce different volumes of vehicles by footprint.

To determine compliance with the reformed CAFE standard, each manufacturer's production-weighted average fuel economy will be calculated and compared to the calculated reformed CAFE. If the weighted average fuel economy of all the manufacturer's models is at least equal to the manufacturer's calculated reformed CAFE, then the manufacturer will be in compliance with the reformed CAFE standard. If its actual fleet-wide average fuel economy is greater than its required CAFE level, the manufacturer will earn credits equal to the difference, which can be applied to any of the three preceding or subsequent model years. With this allowance, manufacturers will not be penalized for occasionally failing to meet the targets (due to market conditions, for example) but only for persistent failure to meet them. If the average fuel economy of a manufacturer's annual car or truck production falls below the defined standard, the manufacturer will be required to pay a penalty proportional to its total production for the U.S. domestic market.

The new CAFE standards are captured in the *AEO2007* projections. For MY 2008 through 2011, manufacturers are assumed to adhere to the increases in unreformed light truck standards. For MY 2011, the *AEO2007* 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 increase in light truck fuel economy after 2011 reflects projected technology adoption resulting from other market forces.

Regulation of Emissions from Stationary Diesel Engines

On July 11, 2006, the EPA issued regulations covering emissions from stationary diesel engines [*14*]—New Source Performance Standards that limit emissions of NO_x, particulate matter, SO_2, carbon monoxide, and hydrocarbons to the same levels required for nonroad diesel engines [*15*]. The regulation affects new, modified, and reconstructed diesel engines. Beginning with MY 2007 [*16*], engine manufacturers must specify that new engines less than 3,000 horsepower meet the same emissions standard as nonroad diesel engines. For engines greater than 3,000 horsepower, the standard will be fully effective in 2011 [*17*]. Stationary diesel engine fuel will also be subject to the same standard as nonroad diesel engine fuel, which reduces the sulfur content of the fuel to 500 parts per million by mid-2007 and 15 parts per million by mid-2010.

Stationary diesel engines are used to generate electricity, to power pumps and compressors, and in irrigation systems. It has been estimated that there were 663,780 such engines larger than 50 horsepower in use in 1998 [*18*]. The EPA estimates that 81,500 engines will be subject to the controls by 2015 and that total pollutant reductions will be more than 68,000 tons per year.

The new standards for stationary diesel engines are included in *AEO2007*, but they are unlikely to affect the projections materially. The nonroad diesel standards were incorporated in the *AEO* projections previously, beginning with *AEO2005*.

Federal and State Ethanol and Biodiesel Requirements

EPACT2005 requires that the use of renewable motor fuels be increased from the 2004 level of just over 4 billion gallons to a minimum of 7.5 billion gallons in 2012, after which the requirement grows at a rate equal to the growth of the gasoline pool [*19*]. The law does not require that every gallon of gasoline or diesel fuel be blended with renewable fuels. Refiners are free to use renewable fuels, such as ethanol and biodiesel, in geographic regions and fuel formulations that make the most sense, as long as they meet the overall standard. Conventional gasoline and diesel can be blended with renewables without any change to the petroleum components, although fuels used in areas with air quality problems are likely to require adjustment to the base gasoline or diesel fuel if they are to be blended with renewables.

Before EPACT2005, a major portion of the RFG pool was blended with methyl tertiary butyl ether (MTBE) to meet required oxygen levels, increase volume, improve octane, and maintain compatibility with existing petroleum product pipelines without a large increase in gasoline volatility. The oxygen content was required under CAAA90 [*20*]. Ethanol is the only other economically feasible oxygenate, but it is incompatible with existing pipelines because of its affinity for water and causes substantial increases in gasoline volatility. Because MTBE was easier to blend and ship, refiners preferred to meet oxygen requirements with MTBE. Over the past several years, however, various State and local governments have banned the use of MTBE, and some have even brought lawsuits against MTBE producers over concerns that spilled MTBE and gasoline containing MTBE were polluting groundwater.

In EPACT2005, Congress repealed the oxygen requirement for Federal RFG but declined to prohibit defective product claims against producers and blenders of MTBE. Refiners believed that the lack of an oxygenate requirement would increase their liability in future groundwater contamination cases and voluntarily eliminated MTBE from the gasoline pool in the summer of 2006.

Several of the largest MTBE-consuming States had already banned the use of MTBE and switched to ethanol-blended gasoline by the time EPACT2005 was passed. California, New York, and Connecticut implemented MTBE bans in 2004 [*21*]. Ethanol distillers, petroleum refiners, and petroleum product terminal operators invested in process changes and additional tanks to accommodate the ethanol. Despite the flexibility allowed by the EPACT2005 RFS and its repeal of the oxygen content requirement, refiners began using ethanol in all RFG in summer 2006.

Overall levels of ethanol and biodiesel use are projected to exceed the EPACT2005 requirement in all *AEO2007* cases, given the projected prices for corn and crude oil, the lack of viable substitutes for MTBE, and extension of the tax credit for ethanol blending [*22*]. EPACT2005 requires the use of 250 million gallons per year of ethanol produced from cellulose after 2013. Production of cellulosic ethanol rises only to the minimum requirement in the *AEO2007* reference case, because the projected capital costs of cellulosic ethanol plants are significantly higher than those of corn ethanol plants.

An older Federal energy law has been used specifically to promote biodiesel. The Energy Policy Act of 1992 required certain vehicle fleets to purchase alternative-fueled light vehicles, but the vehicles were not actually required to run on alternative fuels. The Energy Conservation Reauthorization Act of 1998 allowed the purchase of 450 gallons of pure biodiesel to offset the requirement to purchase one alternative-fueled light vehicle [*23*]. In *AEO2007*, biodiesel demand for Federal fleet purchase offsets is projected to be 7.4 million gallons per year in 2012 and 8.8 million gallons per year in 2030.

Several States have their own requirements for ethanol and biodiesel in their motor fuel supplies, which are reflected in *AEO2007*. Minnesota, a major producer of ethanol, has required all gasoline to contain at least 7.7 percent ethanol since 1997 [*24*]. Hawaii requires 85 percent of its gasoline to contain 10 percent ethanol, effective on April 2, 2006 [*25*]. The intention of the law is to spur local production of ethanol from sugar, but the ethanol could also come from the U.S. mainland or from Brazil.

Minnesota was also the first State to require biodiesel blending into diesel fuel, at 2 percent by volume [*26*]. The requirement became effective in mid-2005, when two new biodiesel plants, each with 30 million gallons per year capacity, began operation in the State. The law was waived several times because of quality problems with the biodiesel, but it is again in effect. Washington requires 2 percent ethanol in gasoline and 2 percent biodiesel in diesel fuel no later than November 30, 2008. The requirement will increase to 5 percent once the State can produce biodiesel equal to 3 percent of its diesel demand [*27*]. Louisiana enacted a requirement for 2 percent ethanol in gasoline and 2 percent biodiesel in diesel fuel, once sufficient capacity is built in-State [*28*, *29*]. Assuming that Louisiana’s 2-percent and Washington’s 5-percent requirements are triggered, Louisiana, Minnesota, and Washington will require 102 million gallons of biodiesel in 2012 and 146 million gallons in 2030.

The Federal and State policies on renewable fuels have various effects on gasoline supply and price. The substitution of ethanol for MTBE in RFG reduces the yield of gasoline and gasoline components from a given refinery configuration. In the long run, refiners are expected to make additional investments to get back some of the gasoline capacity they lost.

Because ethanol currently is economically competitive as a gasoline blending component in Minnesota, its use in that State is not dependent on the ethanol content requirement, which is estimated to have no adverse impact on gasoline prices. Hawaii, on the other hand, must either produce ethanol from costly sugar or ship ethanol from the U.S. mainland or Brazil. Because both options are expected to be expensive, it is likely that Hawaii’s program will raise gasoline prices. The biodiesel requirements in Minnesota, Louisiana, and Washington may increase the availability of diesel fuel in the short run and are likely to increase diesel prices after the Federal motor fuels excise tax credits for blending biodiesel expire. In the longer run, renewable fuels requirements do not affect the availability of gasoline and diesel fuel, because refiners are expected to adjust refinery expansion plans in light of these mandates.

Federal Fuels Taxes and Tax Credits

The *AEO2007* reference case and alternative cases generally assume compliance with current laws and regulations affecting the energy sector. Some provisions of the U.S. Tax Code are scheduled to expire, or may be subject to adjustment, before the end of the projection period. In general, scheduled expirations and adjustments provided in legislation or regulations are assumed to occur, unless there is significant historical evidence to support an alternative assumption. This section examines the *AEO2007* treatment of three provisions that could have significant impacts on U.S. energy markets: the gasoline excise tax, biofuel (ethanol and biodiesel) tax credits, and the PTC for electricity generation from certain renewable resources.

Excise Taxes on Highway Fuels

Excise taxes on highway fuels have been a dedicated source of funding for the Federal Highway Trust Fund since its creation in 1956. The Federal Government levies a tax of 18.4 cents per gallon on domestic gasoline sales and 24.4 cents per gallon on diesel fuel. The tax levels were last adjusted in 2003. Since 1932, when the first Federal excise tax on gasoline was imposed, it has been adjusted by Congress almost 20 times.

Because the statutes do not specify that the Federal excise taxes on highway fuels will be adjusted for inflation, and because they have not been adjusted at regular intervals in the past, they are assumed to remain at current levels in nominal terms through 2030. This assumption can, however, result in seemingly inconsistent results. For example, both the Federal Highway Administration and the Congressional Budget Office (CBO) project that the Highway Account in the Highway Trust Fund will have a negative balance by 2009, based on their respective receipts and outlays [*30*, *31*]. Because EIA does not track expenditures on specific transportation infrastructure requirements, the *AEO2007* projections for vehicle miles traveled are not affected by the loss of funding for upkeep of the Nation's transit system, including maintenance of highways and bridges, which would be necessary to support the projected levels of vehicle use.

In addition to the Federal excise tax on highway fuels, the States and some local governments also levy excise or sales taxes on highway fuels. State and local fuel taxes are kept constant in real terms in *AEO2007*, based on analysis of aggregate historical adjustments to State and local fuel taxes, and reflecting the calculation of State sales taxes as a percentage of the sales price of the fuel [*32*].

Biofuels Tax Credits

The ethanol tax credit provides a credit against Federal gasoline taxes that is worth 51 cents for every gallon of ethanol blended into the gasoline pool. For a typical gasoline blend with 10 percent ethanol, the credit reduces the Federal excise tax (18.4 cents per gallon) by 5.1 cents, resulting in an effective tax rate of 13.3 cents per gallon for the blender. Currently, the ethanol tax credit is scheduled to expire in 2010; however, it has been in effect since 1978, and while it has been adjusted both up and down, it has consistently been extended [*33*]. *AEO2007* assumes that reauthorizations will continue throughout the projections.

Biodiesel also receives a tax credit, at $1.00 per gallon for biodiesel produced from virgin oils and 50 cents per gallon for biodiesel produced from recycled oils. The credit is scheduled to expire in 2008, and *AEO2007* assumes that it will not be reauthorized. The biodiesel tax credit was established by the American Jobs Creation Act of 2004, with a 2006 expiration date. It was extended to 2008 in EPACT2005, after the industry had sought an extension to 2010 [*34*]. If the credit is reauthorized after 2008, it will have a significant impact on biodiesel production.

Production Tax Credit for Renewable Electricity Generation

A PTC of 0.95 to 1.9 cents per kilowatthour [*35*] is provided for sales of electricity generated from certain renewable resources at qualifying facilities for the first 10 years of their operation. The PTC is adjusted by the IRS each year, based on the annual inflation rate. First established in 1992, the PTC has been allowed to expire three times, followed by after-the-fact reauthorizations [*36*]. It has been modified significantly with each extension, including changes in the qualifying resources (adding some, removing others), the value and duration of the credit for certain resources, and the interaction with other aspects of the Tax Code (such as the alternative minimum tax). While the *AEO2007* reference case assumes that the PTC will expire at the end of 2007, both *AEO2007* and previous *AEO*s include alternative cases that consider the impacts of a PTC extension.

Electricity Prices in Transition

The push by some States to restructure electricity markets progressed rapidly throughout the late 1990s. Although the energy crisis in California during

2000 and 2001 slowed the momentum, 19 States and the District of Columbia currently have some form of restructuring in place. In addition, Washington State, which has not restructured its electricity market, allows its largest industrial customers to choose their suppliers.

Many States put in place special regulations to protect customers during the transition. For most, this meant a specified period of guaranteed price stability in the form of rate cuts or rate freezes, after which the market was expected to be sufficiently competitive to reduce the need for price regulation. Low transitional rates in most cases were mandated by State utility commissions and offered by regulated utilities to customers who could not or did not choose a competitive supplier—a service often referred to as Standard Offer Service (SOS). Some States required utilities to offer a separate service, often called Provider of Last Resort (POLR) service, for customers who left, or were dropped by, their competitive suppliers. POLR service sometimes offered less price protection than SOS.

The late 1990s saw a promising start to competition. The fuel prices paid by generators were low enough for competitive electricity suppliers to offer rates slightly lower than SOS prices. From 2000 on, however, rapidly increasing fuel prices caused many competitive suppliers to go out of business, because the price of wholesale electricity rose above the price at which they had contracted to sell it.

Since 2004 many State-mandated transition periods with fixed prices have been coming to a close, with competitive retail markets still not developed for large groups of customers. Most residential and small commercial customers have no offers from competitive suppliers, leading many State utility commissions to consider the possibility of extending regulated, cost-of-service rates for SOS customers. Most of those States are now trying to jump-start competitive markets by having electricity suppliers bid for the right to sell energy to SOS customers. Table 2 summarizes the changes that have been made to SOS pricing in key regions and States since the start of restructuring. It also shows the percentages of retail load currently being sold directly to consumers by competitive retailers.

Most States initially required distribution utilities to offer SOS at a discount from regulated rates throughout the transition period, while a few States experimented with options that encouraged some competition. Texas and Massachusetts required utilities to offer both SOS and POLR service. The SOS provided rate stability and price reductions; the price of POLR service was determined by competitive bid. New York offered rate cuts for only 1 year and required most of its large SOS energy users to pay hourly market prices. In Maine, winners of competitive bids supplied SOS load—a method that was soon adopted by Pennsylvania for its largest utility. Both States still had mandated rate caps, however, so that in years when fuel prices were too high for load to be served at prices below capped rates, too few suppliers bid to provide SOS at competitive prices. Maine responded by raising rate caps, which has allowed the auction program for SOS to attract multiple bidders and competitive suppliers to attract more retail customers.

In 2002, New Jersey held the first auction to supply Basic Generation Service (its name for SOS) for the last year of its designated transition period. The auction attracted sufficient bidders, and New Jersey has continued to hold an annual descending clock auction to supply SOS. In a descending clock auction the bidding starts high, and prices “tick down” when supply is greater than demand. The auction ends with the price at which the amount of supply equals demand. Other States have considered the descending clock auction as a means of providing SOS competitively to customers who do not have access or have not chosen retail competitive suppliers. Illinois, which adopted the method, recently held an auction for its 2007 SOS load.

Other States have decided to jump-start competition as transition periods end, rather than extend rate caps. In the East, Maryland (starting in 2004), the District of Columbia and Massachusetts (since 2005), and Delaware and New Hampshire (since 2006) have required utilities to submit requests for proposals to serve load for SOS customers and have chosen the lowest bidding supplier. Pennsylvania has been negotiating with more utilities to offer SOS for competitive bid. Currently, the State has a proposed rulemaking out for comment that seeks to require each utility at the termination of its transition period to pass through the cost of competitively bid SOS.

In Ohio, FirstEnergy has tried to hold an auction for the supply of its SOS obligation but has not attracted many bidders. In Texas, where SOS customers were automatically transferred to retail affiliates at the start of competition, utilities whose districts have at least 40 percent of their load supplied competitively can now offer SOS if it is bid out competitively. In addition to bidding out SOS, New York, Maryland, and New Jersey require large commercial and industrial customers to pay hourly market prices if they have not chosen a competitive supplier; subsequently, most large customers in the three States have chosen competitive suppliers that offer price hedges to decrease possible price volatility or, in the case of New York, have bought hedging products separate from energy supply.

Each State has a slightly different requirement for the provision of SOS, but usually the competitive proposals are to supply load for periods of several months to 3 years, depending on the customer group or the amount of load in each customer group. The supply decrement or "tranche" is chosen on the basis of the lowest bid. Providing load in this manner is thought to allow prices to be determined competitively, but with much less volatility than would occur if energy were bought hourly on the open market. SOS loads for residential and small commercial customers

Table 2. Changes in Standard Offer Supply price determinations by supply region and State

Electricity supply region	State	Competitive (non-SOS) portion of retail load	SOS price determination, transition period	SOS price determination, post-transition period
ECAR	*MI*	*10%*	*Rate reductions (6/00-1/06).*	*Rate case.*
	OH	*17%*	*Rate reductions (1/01-12/05).*	*Rate case, new rate caps, some competitive bid.*
	Some PA, MD, and VA load		*See State rules under MAAC and SERC.*	
ERCOT	*TX*	*42%*	*SOS: rate reductions, competitive bid by utility if 40% retail load purchased competitively. POLR: competitive bid (1/01-1/07).*	*POLR for any requesting customer. Energy charges calculated at 130% of average ERCOT spot market prices: hourly for small customers, 15-minute intervals for large customers (1/07-12/08).*
MAAC	*DE* *DC* *MD*	*8%* *59%* *28%*	*Rate reductions and caps (10/99-12/08, depending on State and utility).*	*Competitive bid. Large MD SOS customers pay hourly market rates.*
	NJ	*12%*	*Rate case/price caps (8/1/99-7/31/02).*	*Competitive auction: 8/1/02. Large customers pay hourly market rates.*
	PA	*7%*	*Rate reductions and caps, shopping credits (1/99-12/10 depending on utility).*	*Some competitive bid for PECO and some other utilities (since 1/01).*
MAIN	*IL*	*19%*	*Rate reductions and caps (10/1/99-12/31/06).*	*Competitive auction (since 1/07).*
NPCC-NY	*NY*	*38%*	*Rate reductions (5/99-7/01). Large commercial and industrial customers in two major utilities put on hourly market rates.*	*Rate case for small customers. All large customers pay hourly market rates (since 9/05).*
NPCC-New England	*CT* *RI*	*2%* *11%*	*Rate reductions (7/97-12/03).*	*Generation charges passed through with an administrative charge (11/04-11/09).*
	ME	*38%*	*Competitive bid (3/00-5/05).*	*Competitive bid (since 5/05).*
	MA	*28%*	*SOS: rate reductions. POLR: competitive bid (3/98-3/05).*	*Competitive bid: SOS customers moved to POLR (since 3/05).*
	NH	*1%*	*Rate case (8/98-4/06).*	*Competitive bid (since 5/06).*
SERC	*VA*	*0.02%*	*Rate caps (1/02-12/10).*	*Not decided.*
WECC-NWP	*MT* *OR* *WA*	*21%* *3%* *2%*	*No SOS: regulated supply for small customers, supplier contract for large customers.*	—
WECC-Rocky Mountain, AZ/NM/SNV	*AZ*	*0%*	*Rate reductions (10/99-12/02).*	*Rate case with competitive bid for 50% of load (since 1/03).*
	NV	*0%*	*Rate case.*	*Not decided.*
WECC-CA	*CA*	*11%*	*Rate reductions (3/98-3/01). Suspension of competition (9/01).*	—

usually are fixed for longer periods than are loads for customers who use larger amounts of electricity.

In *AEO2007*, electricity prices are projected for 13 electricity supply regions. The weighted average of the prices constitutes the national electricity price projection. For competitive regions, price projections are based on marginal price calculations to simulate the pricing methods of hourly spot markets. It is assumed that a region will take 10 years after the implementation of competitive markets to become fully competitive, and so the amount of competitive load increases by 10 percent each year until 100 percent of electricity load is priced by marginal energy calculations. Until then, part of the load (as well as any other load from regulated States) is priced using cost-of-service calculations. Reliability costs and taxes are added to the weighted average of hourly marginal energy costs and are passed directly to the consumer. Transition price cuts and freezes have been factored into the *AEO2007* cases, although most have been phased out as initial transition periods have come to an end.

In regulated areas, unless a utility has an automatic fuel adjustment clause, customers do not immediately experience increases or decreases in generating costs, since utilities must wait until the next rate case in order to change rates. As a result, time lags between changes in electricity costs and changes in final prices to consumers are factored into the projections of regulated prices.

In past *AEO*s it was assumed that prices in fully competitive regions would reflect spot market prices and would be passed on to consumers immediately. The end of price reductions and caps in many States, along with the increase in competitively bid SOS load, is expected to push competitive regions closer to that representation of competition; however, most customers in fully competitive regions will not experience price changes immediately in response to changes in market generation costs.

In the interest of balancing the growth of competitive markets with price stability for customers, regulators in some States have mandated that SOS contracts be based on spot market prices but fixed for some period of time. Also, competitive supply often is offered at fixed prices for the contract period. Consequently, for *AEO2007*, lags have been built into the calculation of competitive energy prices to simulate the delay from the time suppliers experience cost changes to the time consumers experience price changes as a result of the length of fixed-price contracts for SOS and competitive retail service. Markets in deregulated regions are expected to become increasingly competitive over the long term, and it is assumed that the lag between the time when energy suppliers pay for energy on the spot market and the time when customer charges reflect those costs will be 6 months. For the short term, the lag is assumed to average 1 year in some regions.

State Renewable Energy Requirements and Goals: Update Through 2006

AEO2006 provided a review of renewable energy programs that were in effect in 23 States at the end of 2005 [*37*]. Since then (as of September 1, 2006), no new State programs have been adopted; however, several States with renewable energy programs in place have made changes as they have gained experience and identified areas for improvement. Revisions made over the past year range from clarification or modification of program definitions, such as which resources qualify, to substantial increases in targets for renewable electricity generation or capacity. The following paragraphs provide an overview of substantive changes in the design or implementation of State renewable energy programs.

The Arizona Corporation Commission currently is engaged in a rulemaking process for the State's energy portfolio standard (EPS), scheduled to run through the end of 2006 [*38*], which could lead to substantial changes in the Arizona program [*39*]. The most significant change proposed is an increase in the State's renewable electricity generation target. Pending final approval by the Commission and the Arizona Attorney General, the EPS target would increase from 1.25 percent of affected electricity sales to 15 percent. The new requirement would also allow trading of renewable energy credits among utilities to facilitate compliance. In addition, several new resources would be qualified to meet program requirements, including new small hydroelectric facilities (less than 10 megawatts) and geothermal power.

The original legislative authority for California's RPS, Senate Bill (S.B.) 1078, established a target of 20 percent renewable electricity generation by 2017. Subsequently, the California Energy Commission and California Public Utility Commission set an administrative goal of 20 percent by 2010 and 33 percent by 2020 [*40*]; however, key funding mechanisms were still tied to the legislative 2017 target [*41*]. On

September 26, 2006, Governor Schwarzenegger approved S.B. 107, which codifies the target of 20 percent by 2010 and calls for a formal study of the 2020 target [*42*]. S.B. 107 also modifies requirements for electricity generation from other States to qualify for the California RPS. Out-of-State generators are now limited to 10 percent of associated supplemental energy payments (SEPs) but have fewer restrictions on physical deliveries of power into the California market.

Connecticut has received new statutory authority to expand the area in which qualifying credits can be generated for the State's RPS program and to use renewable energy credits in lieu of physical energy delivery for program compliance [*43*]. In addition to the New England Independent System Operator territory, credits generated in New York, Pennsylvania, New Jersey, Delaware, and Maryland may also be used to satisfy program requirements, upon a finding that each State has a comparable RPS program.

With one of the oldest RPS programs, Maine has passed an additional requirement that 10 percent of all electricity generation *growth* must come from renewable resources [*44*]. Maine's existing target, 30 percent of total generation, had already been exceeded when the original RPS-enabling statute was enacted. The new law presumably will require the addition of new generating resources to meet the incremental requirement.

Changes in the Massachusetts RPS program, although more incremental than structural, have received significant notice among the affected parties. The changes refine the rules governing the types of biomass electricity generation facility that can qualify for the RPS program [*45*]. Previous regulations did not allow generation from "retooled" biomass plants —those in service before 1998 but subsequently upgraded to meet current environmental specifications—to qualify for the RPS, except by waiver. The changes allow that portion of the output from retooled biomass plants that is in excess of historical generation levels to qualify. This clarification is particularly significant given the importance of biomass electricity generation in meeting the Massachusetts target. In 2004, the latest year for which data are available, 35 percent of the compliance target came from biomass generation [*46*].

Nevada has issued a number of new rules within the context of the current statutory authority for the State's EPS [*47*]. Perhaps most significant is the establishment of a credit trading system to facilitate compliance by individual utilities. Credit trading is a common feature of State RPS policy, which allows utilities to purchase compliance credits from other utilities that have excess renewable electricity generation, in lieu of actually generating renewable electric power. Energy efficiency programs can now also be used to offset a portion of Nevada's renewable energy target.

The New Jersey Board of Public Utilities adopted regulations in 2006 that increase the State's renewable electricity generation target from 6.5 percent of sales by 2008 to 22.5 percent by 2021 [*48*]. The new requirement includes 17.88 percent of sales from "Class I" renewable resources, 2.5 percent of sales from "Class II" resources, and the remainder (2.12 percent of sales) from solar resources. Solar generation in excess of the target may be used to meet Class I or II requirements, and excess Class I generation may be used to meet Class II requirements. Class I facilities can use a broad range of renewable resources, including wind, ocean, geothermal, LFG, and approved biomass resources. Class II facilities include hydropower facilities less than 30 megawatts and approved "resource recovery" facilities (trash incinerators).

Wisconsin has passed new legislation increasing the State's RPS target from 2.2 percent of electricity sales by 2012 to 10 percent by 2015 [*49*]. Under the new legislation, the Wisconsin Public Service Commission is required to provide a report by 2016 indicating whether the goal of 10 percent has been achieved and, if not, what steps are required to achieve it.

The *AEO2007* reference case includes new renewable electric power projects that have been identified. It does not include additional renewable projects that might be required for full compliance with some State programs, because it is not clear whether those requirements will be enforced, in light of provisions for granting of compliance waivers, alternative compliance mechanisms, and other discretionary enforcement options. A case where compliance with nondiscretionary enforcement is assumed projects that most State renewable energy targets should be achievable, with varying impacts on regional electricity markets.

Some regions with State targets could see substantially more renewable electricity generation with nondiscretionary compliance than is projected in the *AEO2007* reference case. State standards in the Mid-Atlantic and New England regions could result in approximately 350 percent and 20 percent more renewable generation by 2030, respectively, than projected in the reference case. Biomass is expected to predominate as the fuel of choice in those regions, which lack exploitable geothermal resources and have only limited low-cost wind resources. While the total increase in renewable generation in New York is just over 10 percent by 2030, generation from nonhydropower renewable resources is nearly double the reference case projection.

In other regions, the impact of the standards is projected to be less pronounced. For example, Texas, the Southwest, and the Northwest have either largely met their renewable electricity requirements with existing and planned capacity or are projected to build sufficient renewable capacity based on economic merits within the reference case. Aggregated nationally, State renewable energy standards would result in approximately 30 percent more electricity generation from nonhydropower renewables in 2030 than is projected in the *AEO2007* reference case.

Although this analysis projects that most States would meet their RPS targets without triggering compliance "safety valves" (such as alternative compliance payments), it also suggests that limitations on the funding of California's RPS program could cause that State not to reach its legislated targets [*50*]. Under current law, California utilities may apply for SEPs from the State to cover above-market costs of acquiring renewable energy resources. The SEPs are funded through a dedicated surcharge on consumer utility bills. As of September 2006, the California Energy Commission, which is responsible for administering the SEP program, had not awarded any SEPs and had developed a current account of around $300 million. Funding authorizations through 2011 should provide an additional $77 million per year in new funds. The surcharge authority must be renewed by 2012.

With the expiration of the Federal PTC at the end of 2007, as assumed in this case, and limits on supplemental funding (without which compliance is waived), California is projected to achieve a nonhydropower renewable electricity generation share of 12 percent by 2012. Thereafter, the State's qualifying renewable generation is projected to grow only to the extent that such power is economically competitive without the SEP. This projection may underestimate overall compliance with the California RPS program, however, to the extent that recently passed program modifications facilitate increased use of resources from other States.

State Regulations on Airborne Emissions: Update Through 2006

Implementation of the Clean Air Interstate Rule and Clean Air Mercury Rule

In May 2005, the EPA published two final rules aimed at reducing emissions from coal-fired power plants. CAIR [*51*] requires 28 States and the District of Columbia to reduce emissions of SO_2 and/or NO_x. CAMR [*52*] requires the States to reduce emissions of mercury from new and existing coal-fired plants [*53*].

The two rules cap emissions at the regional and national levels; however, each State can decide how to meet its own cap, as long as the minimum program milestones are met. For CAIR, the States have until March 2007 to submit implementation plans to the EPA, which then will have until September 2007 to review the plans and identify modifications, if necessary. For CAMR, the States must present their plans by November 2007, and the EPA then will have 6 months to accept the plans or require modifications.

Both CAIR and CAMR provide States the flexibility to participate in a regional cap and trade program. Several States, including most of those in the Northeast, have said as of September 2006 that they will not participate in the cap and trade program for mercury emissions under CAMR [*54*], because they plan to adopt more stringent standards. In addition, some States plan to place mandatory restrictions on individual coal-fired plants in order to reduce the possibility that localized areas will continue to have high levels of mercury emissions. Those restrictions differ from the Federal plan of enforcing only statewide caps.

Final decisions regarding the structure of State programs and participation in the regional trading program will not be made until after November 2007. Currently, both CAIR and CAMR are represented as regional cap and trade programs in *AEO2007*. This approach will be reevaluated when the final State programs have been submitted and reviewed by the EPA.

Regional Greenhouse Gas Initiative

The governors of the seven States participating in the RGGI—Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont—have committed to enact legislation individually for achieving the desired emission reductions under the agreement. The group originally consisted of nine States, but Massachusetts and Rhode Island have withdrawn. In Maryland, recently adopted legislation requires the State to join the RGGI by June 2007 [*55*]. Pennsylvania, the District of Columbia, and several Canadian provinces are observers to the program.

When the original RGGI agreement was signed in December 2005, each participating State agreed to cap its greenhouse gas emissions from power production beginning in January 2009. The States were provided CO_2 allocations based on their average emissions for the 3-year period from 2000 to 2002, with exceptions. States that had built or were anticipating new plants between 2002 and 2009 were allowed additional allowances to reflect the level of emissions expected in January 2009. The governors of the seven States currently participating have already agreed to their respective allowance allotments.

For the seven northeastern States, the annual cap is approximately 121 million short tons, representing a 6.1-percent increase over their combined CO_2 emissions in 2000. After January 2009, the RGGI requires each participating State to hold its emissions at or below its CO_2 allotment. The caps remain unchanged until the end of 2014, after which they are reduced by 2.5 percent annually. Thus, by the end of 2018, CO_2 emissions in the participating States will be 10 percent below the levels at which the allocations were issued.

The August 2006 model rule clarifies several provisions on how States can achieve their emission reductions. It also provides compliance flexibility if prices rise beyond what is anticipated, although threshold levels have not been determined. One-quarter of potential revenue from the auction or sale of emission credits must go to consumer benefits or strategic energy purposes. This broad category includes energy price discounts, renewable and low-carbon energy investments, and energy efficiency programs. Also, CO_2 emission reductions by power producers before the January 2009 start date will be credited for use during the cap period.

Other States and provinces may participate in the RGGI through carbon offset programs. If the price of credits remains below $7 (2005 dollars) per short ton of CO_2, power producers may account for 3.3 percent of their emissions through offset programs in any State or province, including capture of landfill methane and sulfur hexafluoride, afforestation, end-use efficiency programs, and agricultural emission reductions. For each ton of CO_2 avoided or sequestered in the projects, the power producer will be provided one emission credit for use or sale. In order for an offset program to be eligible, it cannot be part of any other State mandate and must be attributable only to the RGGI. If the price of CO_2 credits is sustained above $7 for more than 12 months, power producers will be able to offset up to 5 percent of their CO_2 emissions. If credit prices surpass $10 for a sustained 12-month period, then producers will be able to offset 10 percent of their emissions and may participate in international credit markets.

The individual States still must enact their own legislation to achieve the RGGI milestones. State legislation will determine compliance issues, such as credit allocations, enforcement methods, and options for exiting the agreement. Each State will be responsible for issuing its own allowances. Some States may choose to sell them at a certain price; others may hold auctions. They may also be given away, or the States may use a combination of methods.

Although the State RGGI caps and timelines are known, many aspects of their implementation remain uncertain, because the participating States have not yet enacted the necessary legislation. Therefore, the RGGI provisions are not modeled in *AEO2007*.

California Greenhouse Gas Legislation

A.B. 32, "California Global Warming Solutions Act of 2006," which was signed into law by Governor Arnold Schwarzenegger on September 27, 2006 [*56*], calls for a 25-percent reduction in CO_2 emissions by 2020. The first major controls, for the industrial sector, are scheduled to take effect in 2012. The plan grants the California Air Resources Board lead authority for establishing how much industry groups contribute to global warming pollution, assigning emission targets, and setting noncompliance penalties. It sets a 2009 date for establishing how the system will work and then allows 3 years for the State's industries to prepare for the 2012 startup of mandatory emissions reductions [*57*].

It is not yet known what sources of greenhouse gas emissions will be subject to the restrictions, although the bill states that all major sources of CO_2 will be included. The bill does not mention the transportation sector, which is covered in separate legislation. A.B. 32 also specifies that all emissions from the generation of power consumed within the State are expected to be subject to the new laws. Because California imports power from neighboring States, emissions in those States may also be affected. In addition, California collaborates on its greenhouse gas policy with the States of Washington and Oregon through the West Coast Governors' Global Warming Initiative [*58*].

A.B. 32 delegates most of the responsibility for implementation and enforcement to the California Air Resources Board. Although the bill indicates that the reduction program will rely on market-based compliance mechanisms, it does not indicate the course of action that will be taken to reduce emissions. Reliance on a market-based compliance mechanism suggests the possible use of a credit trading program. If this is the case, issues such as credit distribution, offset allowances, price caps, and other restrictions will be decided by January 2009.

The Air Resources Board will also coordinate enforcement issues with the State's Public Utilities Commission and Energy Resources Conservation and Development Commission. Regulations on the monitoring of greenhouse gas emissions must be in place by 2008, when accurate reports on emissions from all major sources will be mandatory. Final regulations for the emissions reduction program will be presented in January 2011 and will become operative in January 2012. Because the program specifics have not been developed, A.B. 32 is not modeled in *AEO2007*.