Legislation and Regulations

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Introduction

Because baseline projections developed by EIA are required to be policy-neutral, the projections in *AEO2009* are based on Federal and State laws and regulations as of November 2008 [*1*]. 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. Throughout 2008, however, at the request of the Administration and Congress, EIA has regularly examined the potential implications of proposed legislation in Service Reports (see box below).

Examples of Federal and State legislation that has been enacted over the past few years and is incorporated in *AEO2009* include:

- The tax provisions of EIEA2008, signed into law on October 3, 2008, as part of Public Law 110-343, the Emergency Economic Stabilization Act of 2008 (see details below)
- The biofuel provisions of the Food, Conservation, and Energy Act of 2008 (Public Law 110-234) [*2*], which reduce the existing ethanol excise tax credit in the first year after U.S. ethanol production and imports exceed 7.5 billion gallons and add an income tax credit for the production of cellulosic biofuels

EIA Service Reports Released Since January 2008

The table below summarizes the Service Reports completed since 2008. Those reports, and others that were completed before 2008, can be found on the EIA web site at www.eia.doe.gov/oiaf/service_rpts.htm.

Title	*Date of release*	*Requestor*	*Availability on EIA web site*	*Focus of analysis*
Light-Duty Diesel Vehicles: Efficiency and Emissions Attributes and Market Issues	*February 2009*	*Senator Jeff Sessions*	*www.eia.doe.gov/oiaf/servicerpt/lightduty/index.html*	*Analysis of the environmental and energy efficiency attributes of LDVs, including comparison of the characteristics of diesel-fueled vehicles with those of similar gasoline-fueled, E85-fueled, and hybrid vehicles, as well as a discussion of any technical, economic, regulatory, or other obstacles to increasing the use of diesel-fueled vehicles in the United States.*
State Energy Data Needs Assessment	*January 2009*	*Required by EISA2007*	*www.eia.doe.gov/oiaf/servicerpt/energydata/index.html*	*Response to EISA2007 Section 805(d), requiring EIA to assess State-level energy data needs and submit to Congress a plan to address those needs.*
The Impact of Increased Use of Hydrogen on Petroleum Consumption and Carbon Dioxide Emissions	*September 2008*	*Senator Byron Dorgan*	*www.eia.doe.gov/oiaf/servicerpt/hydro/index.html*	*Analysis of the impacts on U.S. energy import dependence and emission reductions resulting from the commercialization of advanced hydrogen and fuel cell technologies in the transportation and distributed generation markets.*
Analysis of Crude Oil Production in the Arctic National Wildlife Refuge	*May 2008*	*Senator Ted Stevens*	*www.eia.doe.gov/oiaf/servicerpt/anwr/index.html*	*Assessment of Federal oil and natural gas leasing in the coastal plain of the Arctic National Wildlife Refuge in Alaska.*
Energy Market and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007	*April 2008*	*Senators Joseph Lieberman, John Warner, James Inhofe, George Voinovich, and John Barrasso*	*www.eia.doe.gov/oiaf/servicerpt/s2191/index.html*	*Analysis of impacts of the greenhouse gas cap-and-trade program established under Title I of S. 2191.*
Federal Financial Interventions and Subsidies in Energy Markets 2007	*April 2008*	*Senator Lamar Alexander*	*www.eia.doe.gov/oiaf/servicerpt/subsidy2/index.html*	*Update of 1999-2000 EIA work on Federal energy subsidies, including any additions or deletions of Federal subsidies based on Administration or Congressional action since 2000, and an estimate of the size of each current subsidy.*
Energy Market and Economic Impacts of S. 1766, the Low Carbon Economy Act of 2007	*January 2008*	*Senators Jeff Bingaman and Arlen Specter*	*www.eia.doe.gov/oiaf/servicerpt/lcea/index.html*	*Analysis of mandatory greenhouse gas allowance program under S. 1766 designed to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and at least 60 percent below 1990 levels by 2050.*

- The provisions of EISA2007 (Public Law 110-140) including: a renewable fuel standard (RFS) requiring the use of 36 billion gallons of ethanol by 2022; an attribute-based minimum CAFE standard for cars and trucks of 35 miles per gallon (mpg) by 2020; a program of CAFE credit trading and transfer; various appliance efficiency standards; a lighting efficiency standard starting in 2012; and a number of other provisions related to industrial waste heat or natural gas efficiency, energy use in Federal buildings, weatherization assistance, and manufactured housing
- Those provisions of the Energy Policy Act of 2005 (EPACT2005), Public Law 109-58, that remain in effect and have not been superseded by EISA-2007, including: mandatory energy conservation standards; numerous tax credits for businesses and individuals; elimination of the oxygen content requirement for Federal reformulated gasoline (RFG); extended royalty relief for offshore oil and natural gas producers; authorization for DOE to issue loan guarantees for new or improved technology projects that avoid, reduce, or sequester GHGs; and a PTC for new nuclear facilities
- Public Law 108-324, the Military Construction Appropriations Act of 2005, which contains provisions to encourage construction of an Alaska natural gas pipeline, including Federal loan guarantees during construction
- State RPS programs, representing laws and regulations of 27 States and the District of Columbia that require renewable electricity generation.

Examples of recent Federal and State regulations as well as earlier provisions that have been affected by court decisions that are considered in *AEO2009* include the following:

- Decisions by the D.C. Circuit Court of the U.S. Court of Appeals on February 8, 2008, to vacate and remand the Clean Air Mercury Rule (CAMR) and on July 11, 2008, to vacate and remand the Clean Air Interstate Rule (CAIR) [*3*]
- Release by the California Air Resources Board (CARB) in October 2008 of updated regulations for RFG that went into effect on August 29, 2008, allowing a 10-percent ethanol blend, by volume, in gasoline.

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

Energy Improvement and Extension Act of 2008: Summary of Provisions

The Emergency Economic Stabilization Act of 2008 (Public Law 110-343) [*4*], which was signed into law on October 3, 2008, incorporates EIEA2008 in Division B. Provisions in EIEA2008 that require funding appropriations to be implemented, whose impact is highly uncertain or that require further specification by Federal agencies or Congress, are not included in *AEO2009*. Moreover, *AEO2009* does not include any provision that addresses a level of detail beyond that modeled in NEMS. *AEO2009* addresses those provisions in EIEA2008 that establish specific tax credits and incentives, including the following:

- Extension of the residential and business tax credits for renewable energy as well as for the purchase and production of certain energy-efficient appliances, many of which were originally enacted in EPACT2005
- Removal of the cap on the tax credit for purchases of residential solar photovoltaic (PV) installations and an increase in the tax credit for residential ground-source heat pumps
- Addition of a business investment tax credit (ITC) for combined heat and power (CHP), small wind systems, and commercial ground-source heat pumps
- Provision of a tax credit for the purchase of new, qualified, plug-in electric drive motor vehicles
- Extension of the income and excise tax credits for biodiesel and renewable diesel to the end of 2009 and an increase in the amount of the tax credit for biodiesel and renewable diesel produced from recycled feedstock
- Provision of tax credits for the production of liquid petroleum gas (LPG), LNG, compressed natural gas (CNG), and aviation fuels from biomass
- Provision of an additional tax credit for the elimination of CO_2 that would otherwise be emitted into the atmosphere in enhanced oil recovery and non-enhanced oil recovery operations
- Extension and modification of key renewable energy tax provisions that were scheduled to expire at the end of 2008, including production tax credits (PTCs) for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities
- Expansion of the PTC-eligible technologies to include plants that use energy from offshore, tidal, or river currents (in-stream turbines), ocean waves, or ocean thermal gradients.

The following discussion provides a summary of the EIEA2008 provisions included in *AEO2009* 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 EIEA2008.

End-Use Demand

Residential and Commercial Buildings

EIEA2008 reinstates and extends tax credits for renewable energy and for the purchase and production of certain energy-efficient appliances, many of which were originally enacted in EPACT2005. Some of the tax credits are extended to 2016. In addition, the $2,000 cap for residential PV purchases is removed, and the cap for ground-source heat pumps is raised from $300 to $2,000. The legislation also adds business ITCs for CHP, small wind systems, and commercial ground-source heat pumps.

Residential Tax Credits

EIEA2008 Titles I and III include various extensions, modifications, and additions to the tax code that have the potential to affect future energy demand in the residential sector. Sections 103 through 106 of Title I reinstate the tax credits that were implemented under EPACT2005 for efficient water heaters, boilers, furnaces, heat pumps, air conditioners, and building shell equipment, such as windows, doors, weather stripping, and insulation. The amount of the credit varies by appliance type and ranges from $150 to $300. The maximum credit for ground-source heat pumps, which was $300 under EPACT2005, is $2,000 under EIEA2008. For solar installations, which can receive a 30-percent tax credit under both EPACT-2005 and EIEA2008, the $2,000 cap has been removed. With the cost and unit size of residential PV assumed in *AEO2009*, the credit can now reach nearly $10,000 per unit. The tax credit for small wind generators is also extended through 2016 in EIEA2008; however, penetration of residential wind installations over the next decade is projected to be negligible.

Sections 302, 304, and 305 of EIEA2008 Title III also contain provisions that can directly or indirectly affect future residential energy demand. Section 302 adds a provision to allow a tax credit for the use of biomass fuel, which can include wood, wood pellets, and crops. In NEMS, the credit is represented as a reduction in the cost of wood stoves used as the primary space heating system. Section 304 extends the $2,000 tax credit for new homes that are 50 percent more efficient than specified in the International Energy Conservation Code through 2009. Section 305 extends the PTC for refrigerators, dishwashers, and clothes washing machines that are a certain percentage more efficient than the current Federal standard. The duration and value of the credit vary by appliance and the level of efficiency achieved. For *AE02009*, it is assumed that the full amount of the credit is realized by consumers in the form of reduced purchase costs.

Commercial Tax Credits

Sections 103, 104, and 105 of EIEA2008 Title I extend or expand tax credits to businesses for investment in energy efficiency and renewable energy properties. Section 103 extends the EPACT2005 business ITCs (30 percent for solar energy systems and fuel cells, 10 percent for microturbines) through 2016; expands the ITC to include a 10-percent credit for CHP systems through 2016; and increases the credit limit for fuel cells from $500 to $1,500 per half kilowatt of capacity. Section 104 provides a 30-percent business ITC through 2016 for wind turbines with an electrical capacity of 100 kilowatts or less, capped at $4,000. Section 105 adds a 10-percent business ITC for ground-source heat pumps through 2016. In the *AEO2009* reference case, relative to a case without the tax credits, these provisions result in a 3.2-percent increase in electrical capacity in the commercial sector by 2016.

Section 303 of EIEA2008 Title III extends the EPACT2005 tax deduction allowed for expenditures on energy-efficient commercial building property through 2013. This provision is not reflected in *AEO2009*, because NEMS does not include economic analysis at the building level.

Industrial Sector

Under EIEA2008 Title I, "Energy Production Incentives," Section 103 provides an ITC for qualifying CHP systems placed in service before January 1, 2017. Systems with up to 15 megawatts of electrical capacity qualify for an ITC up to 10 percent of the installed cost. For systems between 15 and 50 megawatts, the percentage tax credit declines linearly with the capacity, from 10 percent to 3 percent. To qualify, systems must exceed 60-percent fuel efficiency, with a minimum of 20 percent each for useful thermal and electrical energy produced. The provision was modeled in *AEO2009* by adjusting the assumed capital cost of industrial CHP systems to reflect the applicable credit.

Section 108 extends an existing PTC, originally created under the American Jobs Creation Act of 2004 for new "refined coal" facilities producing steam coal, to those that produce metallurgical coal for the steel industry. The credit applies to coal processed with liquefied coal waste sludge and "steel industry coal" (defined as coal used for feedstock in coke manufacture). The production credit for steel industry coal is $2 per barrel of oil equivalent actually produced (equivalent to 34 cents per million Btu or $8.55 per short ton) over the first 10 years of operation for plants placed in service in 2008 and 2009. Because the *AEO2009* NEMS does not include the level of detail addressed by this tax credit, its incremental effect is not reflected in *AEO2009*. To the extent that the credit is passed on from coal suppliers as a reduction in the price of metallurgical coal, the provision would tend to reduce steel production costs and provide an incentive for domestic manufacture of coke.

Transportation Sector

EIEA2008 Title II, Section 205, provides a tax credit for the purchase of new, qualified plug-in electric drive motor vehicles. According to the legislation, a qualified plug-in electric drive motor vehicle must draw propulsion from a traction battery with at least 4 kilowatthours of capacity, use an off-board source of energy to recharge the battery, and, depending on the gross vehicle weight rating (GVWR), meet the U.S. Environmental Protection Agency (EPA) Tier II vehicle emission standards or equivalent California low-emission vehicle emission standards.

The tax credit for the purchase of a PHEV is $2,500 plus $417 per kilowatthour of traction battery capacity in excess of the minimum required 4 kilowatthours, up to a total of $7,500 for a PHEV with a GVWR of 10,000 pounds or less. The limit is raised to $10,000 for any new eligible PHEV with a GVWR between 10,000 and 14,000 pounds, $12,500 for a PHEV between 14,000 and 26,000 pounds GVWR, and $15,000 for any eligible PHEV with a GVWR greater than 26,000 pounds.

The legislation also includes a phaseout period for the tax credit, beginning two calendar quarters after the first quarter in which the cumulative number of qualified plug-in electric vehicles sold in total by all manufacturers reaches 250,000. The credit will be reduced by 50 percent in the first two calendar quarters of the phaseout period and by another 25 percent in the third and fourth calendar quarters. Thereafter, the credit will be eliminated. Regardless of calendar quarter or whether 250,000 vehicles are sold, the credit will be phased out after December 31, 2014. The tax credits for PHEVs are included in *AEO2009*.

Liquids and Natural Gas

EIEA2008 includes tax provisions that address petroleum liquids and natural gas. In Title II, "Transportation and Domestic Fuel Security Provisions, Credits for Biodiesel and Renewable Diesel," Section 202 extends income and excise tax credits for biodiesel and renewable diesel to the end of 2009. The legislation also raises the credit from 50 cents per gallon to $1 per gallon for biodiesel and renewable diesel from recycled feedstock. It also removes the term "thermal depolymerization" from the definition of renewable diesel and replaces it with "or other equivalent standard," allowing biomass-to-liquids (BTL) producers to obtain the $1 per gallon income tax credit. The legislation further specifies that the term "renewable diesel" shall include fuel derived from biomass that meets Defense Department specifications for military jet fuel or American Society for Testing and Materials specifications for aviation turbine fuel. These provisions are included in *AEO2009*.

Section 204 extends the excise tax credit for alternative fuels under Section 6426 of the Internal Revenue Code through 2009. Beginning on October 1, 2009, qualified fuel derived from coal through gasification and liquefaction processes must be produced at a facility that separates and sequesters at least 50 percent of its CO_2 emissions, increasing to 75 percent beginning in 2010. Section 204 also provides credits applicable to biomass gas versions of LPG, LNG, CNG, and aviation fuels. This provision is also included in *AEO2009*.

Coal

EIEA2008 Title I, Subtitle B, "Carbon Mitigation and Coal Provisions," modifies the tax credits available to coal consumers who sequester CO_2. In Section 111, an additional $1.25 billion is allocated to advanced coal-fired plants that separate and sequester a minimum of 65 percent of the plant's CO_2 emissions, bringing the aggregate ITC available for advanced coal projects to $2.55 billion. For this additional ITC, the allowable credit is equivalent to 30 percent of the project's qualified investment cost. Qualified investments include any expenses for property that is part of the project. For example, expenses for equipment for coal handling and gas separation would be qualifying investments if they were required for the project.

Section 112 provides an additional $250 million in ITCs for carbon sequestration equipment at qualified gasification projects, including plants producing transportation-grade liquid fuels. Eligible feedstocks for the projects include coal, petroleum residues, and biomass. To qualify for the ITC, a gasification facility must capture and sequester a minimum of 75 percent of its potential CO_2 emissions.

Section 115 of Subtitle B provides an additional tax credit for sequestration of CO_2 that would otherwise be emitted into the atmosphere from industrial sources. Tax credits of $10 per ton for CO_2 used in enhanced oil recovery and $20 per ton for other CO_2 sequestered are available. The Section 115 tax credit is limited to a total of 75 million metric tons of CO_2. In the *AEO2009* reference case, Sections 111, 112, and 115 are modeled together, resulting in 1 gigawatt of advanced coal-fired capacity with CCS by 2017.

Section 113 of Subtitle B extends the phaseout of payments by coal producers to the Black Lung Disability Trust Fund from 2013 to 2018. This provision also is modeled in the *AEO2009* reference case.

Other coal-related provisions of Subtitle B are not included in *AEO2009*, either because their effects on energy markets are minimal or nonexistent, or because they cannot be modeled directly in NEMS. They include: a provision that refunds payments to the Black Lung Disability Trust Fund for U.S. coal exports (Section 114); classification of income derived from industrial-source CO_2 by publicly traded partnerships as qualifying income (Section 116); a request for a National Academy of Sciences review of GHG provisions in the IRS Tax Code (Section 117); and a tax credit for alternative liquid fuels that is valid only through the end of 2009 (Section 204).

Renewable Energy

EIEA2008 also contains several provisions that extend and modify key tax provisions for renewable energy that were scheduled to expire at the end of 2008. Section 101 extends the PTC for wind, geothermal, landfill gas, and certain biomass and hydroelectric facilities. Wind facilities that enter service before January 1, 2010, are eligible for a tax credit of 2 cents per kilowatthour, adjusted for inflation, on all generation sold for the first 10 years of plant operation. Other eligible plants will receive the tax credit if they are on line by December 31, 2010 (but biomass plants that do not use “closed-loop” fuels [*5*] will receive a credit of 1 cent per kilowatthour).

Section 102 expands the suite of PTC-eligible technologies to include plants that use energy from offshore, tidal, or river currents (in-stream turbines), ocean waves, or ocean thermal gradients. Projects must have at least 150 kilowatts of capacity and must be on line by December 31, 2011. The PTC extension is included in *AEO2009* for all eligible technologies, with the exception of marine technologies, which are not represented in NEMS.

Section 103 extends the 30-percent ITC for business-owned solar facilities to plants entering service through December 31, 2016. The tax credit is valued at 30 percent of the initial investment cost for solar thermal and PV generating facilities that are owned by tax-paying businesses (residential owners can take advantage of tax credits discussed below; other forms of government assistance may be available to tax-exempt owners). Starting in 2017, eligible facilities will receive only a 10-percent ITC, which is not scheduled to expire. The extension through 2016 and the permanent 10-percent ITC are represented in *AEO2009*.

Section 107 authorizes continuation of the Clean and Renewable Energy Bonds (CREB) program at a level of $800 million. CREBs are issued by tax-exempt project owners (municipals and cooperatives) to raise capital for the construction of renewable energy plants. Interest on the bonds is paid by the Federal Government in the form of tax credits to the bond holders, thus providing the bond issuer with interest-free financing for qualified projects. Because NEMS assumes that all new renewable generation capacity will come from independent power producers, this provision, which targets public utilities, is not included in *AEO2009*.

Federal Fuels Taxes and Tax Credits

This section provides a review and update of the handling of Federal fuels taxes and tax credits, focusing primarily on areas for which regulations have changed or the handling of taxes or credits has been updated in *AEO2009*.

Excise Taxes on Highway Fuel

The handling of Federal highway fuel taxes remains unchanged from *AEO2008*. Consistent with current law, gasoline is assumed to be taxed at 18.4 cents per gallon, diesel fuel at 24.4 cents per gallon, and jet fuel at 4.3 cents per gallon. State fuel taxes, calculated as a volume-weighted average for diesel, gasoline, and jet fuels sold, were updated as of July 2008 [*6*]. Unlike Federal highway taxes, which remain at today’s nominal levels throughout the *AEO2009* projection, State fuel taxes are assumed to remain fixed in real terms.

Biofuels Tax Credits

The only change in the handling of Federal fuels taxes and credits has been in those that pertain to biofuels. Section 15331 of the Food, Conservation, and Energy Act of 2008 reduces the existing ethanol excise tax credit of $0.51 per gallon to $0.45 per gallon in the first year after the year in which U.S. ethanol production and imports exceed 7.5 billion gallons. In the *AEO2009* projections, U.S. ethanol production and imports exceed 7.5 billion gallons in 2008, and the tax credit is reduced in 2009. The excise tax credit for ethanol is scheduled to expire at the end of 2010. In addition, Section 15321 of the Act adds an income tax credit for the production of cellulosic biofuels. The cellulosic biofuels represented in NEMS are cellulosic ethanol, BTL diesel, and BTL naphtha. The tax credit is $1.01 per gallon, but for cellulosic ethanol it is reduced by the amount of the excise tax credit available for ethanol blends (assumed to be $0.45 per gallon). The credit will be applied to fuel produced after December 31, 2008, and before January 1, 2013.

In EIEA2008, the excise tax credit of $1.00 per gallon for biodiesel, which previously was set to expire at the end of 2008, was extended through December 31, 2009. In addition, the excise tax credit of $0.50 per gallon for biodiesel made from recycled vegetable oils or animal fat is increased to $1.00 per gallon. A representation of renewable diesel—a diesel-like hydrocarbon produced by reaction of vegetable oil or animal fat with hydrogen, also known as "non-ester renewable diesel"—has been added to NEMS for *AEO2009*.

Ethanol Import Tariff

Currently, two duties are imposed on imported ethanol. The first is an *ad valorem* tariff of 2.5 percent. The second, which is a tariff of $0.54 per gallon after the application of the *ad valorem* tariff, allows for duty-free imports from designated Central American and Caribbean countries up to a limit of 7 percent of domestic production in the preceding year. The $0.54 per gallon tariff, previously set to expire on January 1, 2009, is extended to January 1, 2011, in Section 15333 of the Food, Conservation, and Energy Act of 2008. In *AEO2009*, the second tariff is assumed to expire on January 1, 2011.

New NHTSA CAFE Standards

EISA2007 requires the National Highway Traffic Safety Administration (NHTSA) to raise the CAFE standards for passenger cars and light trucks to ensure that the average tested fuel economy of the combined fleet of all new passenger cars and light trucks sold in the United States in model year (MY) 2020 equals or exceeds 35 mpg, 34 percent above the current fleet average of 26.4 mpg [*7*]. Pursuant to this legislation, NHTSA recently proposed revised CAFE standards that substantially increase the minimum fuel economy requirements for passenger cars and light trucks for MY 2011 through MY 2015 [*8*].

The new CAFE proposal builds on NHTSA's 2006 decision to use an attribute-based methodology to determine a vehicle's minimum fuel economy standard based on vehicle footprint [*9*]. The attribute-based CAFE standard uses a mathematical function that provides a unique fuel economy target for each vehicle footprint and is the same across manufacturers. Fuel economy targets are revised upward in subsequent model years to ensure improvement over time (Figures 4 and 5). Separate continuous mathematical functions are established for passenger cars and light trucks, reflecting their different design capabilities, and their combined fuel economy levels are required to reach 35 mpg by 2020.

Individual manufacturers will be required to comply with unique fuel economy levels for their car and light truck fleets, based on the distribution of their vehicle production by footprint in each model year. Individual manufacturers face different required CAFE levels only to the extent that their production distributions differ. NHTSA has estimated the impact of the new CAFE standard on the fuel economy of new LDVs and has projected that the proposed standards represent a 4.5-percent average annual increase in fuel economy between MY 2010 and MY 2015 (Table 1) [*10*]. Because the exact sales mix of different vehicle classes for a given manufacturer cannot be known until after the model year, NHTSA projects industry-wide average fuel economies for passenger cars and light trucks based on the manufacturers' production plans.

From a fuel economy average of 31.6 mpg in MY 2015, the average annual increase from MY 2015 to MY 2020 would need to be only 2 percent to reach the EISA2007 mandate of 35 mpg by 2020. Thus, NHTSA's latest proposal is heavily front-loaded, in that it requires greater gains in the first 5-year period than in the second.

Because *AEO2009* uses NHTSA's proposed CAFE standards to represent the implementation path for the fuel economy standard required by EISA2007, the average fuel economy for LDVs in the early years of the projection is higher than projected in *AEO2008* (Figure 6). In the *AEO2009* reference case, the combined fuel economy of new LDVs from MY 2011 through MY 2015 slightly exceeds NHTSA's estimated values, because *AEO2009* allows shifting of sales between cars and light trucks and among various size classes, whereas NHTSA's estimates are based on manufacturers' production plans.

NHTSA's proposal also seeks to provide added flexibility for manufacturers to meet the new CAFE standards by: (1) allowing trading of credits between manufacturers who exceed their standards and those who do not; (2) allowing credit transfers between different vehicle classes for a single manufacturer; (3) increasing from 3 to 5 the number of years during which a manufacturer can "carry forward" credits earned from exceeding the CAFE standards in earlier model years, while leaving in place the 3-year limit for manufacturers to "carry back" credits earned in later years to meet shortfalls from previous model years; and (4) extending through 2014 the ability of manufacturers to earn a maximum 1.2 mpg of CAFE credit by producing alternative-fuel vehicles, then phasing out the "carry-back" credits between 2015 and 2019.

NHTSA's flexibility provisions do not, however, allow manufacturers to miss their annual targets grossly and then make them up by using any or all of the four provisions listed above. NHTSA retains a required minimum (92 percent of the applicable CAFE standard). Before any credit can be applied by a manufacturer, its fleet of LDVs for the model year must meet an average fuel economy standard—either 27.5 mpg or 92 percent of the CAFE for the industry-wide combined fleet of domestic and non-domestic passenger cars for that model year, whichever is higher. It is important to note that NHTSA's proposed CAFE standards are subject to change in future rulemakings.

Figure 4. Proposed CAFE standards for passenger cars by vehicle footprint, model years 2011-2015 (miles per gallon)

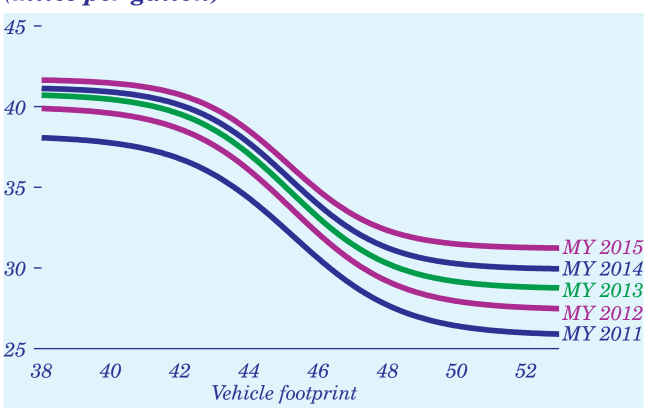
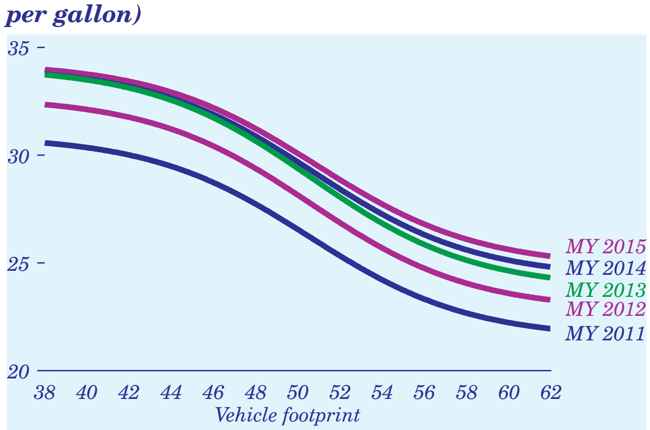


Figure 5. Proposed CAFE standards for light trucks by vehicle footprint, model years 2011-2015 (miles per gallon)



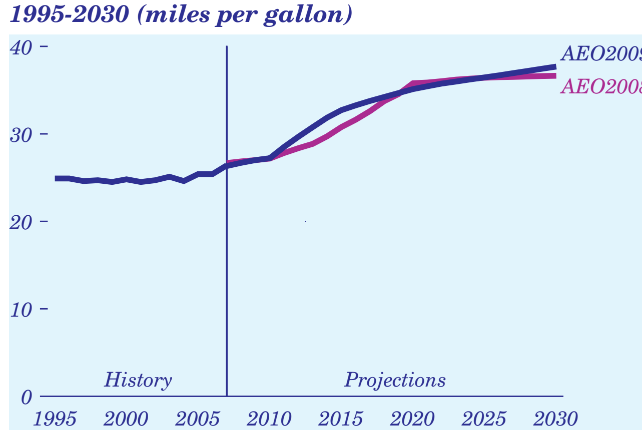
Regulations Related to the Outer Continental Shelf Moratoria and Implications of Not Renewing the Moratoria

From 1982 through 2008, Congress annually enacted appropriations riders prohibiting the Minerals Management Service (MMS) of the U.S. Department of the Interior from conducting activities related to leasing, exploration, and production of oil and natural

Table 1. Estimated fuel economy for light-duty vehicles, based on proposed CAFE standards, 2010-2015 (miles per gallon)

Model year	Passenger car	Light truck	Combined
2010	27.5	23.5	25.3
2011	31.2	25.0	27.8
2012	32.8	26.4	29.2
2013	34.0	27.8	30.5
2014	34.8	28.2	31.0
2015	35.7	28.6	31.6

Figure 6. Average fuel economy of new light-duty vehicles in the AEO2008 and AEO2009 projections, 1995-2030 (miles per gallon)



gas on much of the Federal OCS [*11*]. Further, a separate executive ban (originally put in place in 1990 by President George H.W. Bush and later extended by President William J. Clinton through 2012) also prohibited leasing on the OCS, with the exception of the Western Gulf of Mexico, portions of the Central and Eastern Gulf of Mexico, and Alaska. In combination, those actions prohibited drilling along the Atlantic and Pacific coasts, in the eastern Gulf of Mexico, and in portions of the central Gulf of Mexico. The Gulf of Mexico Energy Security Act of 2006 (Public Law 109-432) imposed yet a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

High oil and natural gas prices in recent years have affected policy toward oil and gas exploration and development of the OCS. On July 14, 2008, President Bush lifted the executive ban; and on September 30, 2008, Congress allowed the congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, lifting the executive and congressional bans removed key obstacles to development of the Atlantic and Pacific OCS.

Jurisdiction

The Submerged Lands Act (SLA) passed by Congress in 1953 established the Federal Government's title to submerged lands located on most of the OCS [*12*]. States were given jurisdiction over any natural resources within 3.45 miles (3 nautical miles) of the coastline, with the exception of Texas and the west coast of Florida, where the SLA extends the States' jurisdiction to 10.35 miles (9 nautical miles). The Outer Continental Shelf Lands Act (OCSLA), also passed in 1953, defined the OCS, separate from geologic definitions, as any submerged land outside State jurisdiction [*13*]. It also reaffirmed Federal jurisdiction over those waters and all resources therein. Further, it outlined Federal responsibilities for managing and maintaining offshore lands and authorized the Department of the Interior to formulate regulations pertaining to the leasing process and to lease the defined areas for exploration and development of OCS oil and natural gas resources.

The Coastal Zone Management Act of 1972 (CZMA) [*14*] gave States more input on activities in waters under Federal jurisdiction that affected their coastlines, encouraged coastal States to develop Coastal Zone Management Plans, and required State review of Federal actions, such as offshore leasing, that affect land and water use in their coastal areas. By virtue of the CZMA, States have the power to object to any Federal action that they deem inconsistent with their Coastal Zone Management Plan. At present, the vast majority of the U.S. coastline is covered by such plans.

MMS 5-Year Leasing Program

The OCSLA was amended in 1978 to establish specific leasing guidelines, which included the development of a 5-year leasing program. The purpose of the leasing program is to schedule all specified and proposed lease sales within a given 5-year period. The amendment also specifies a number of requirements on which the decision to include specific areas in the 5-year leasing program are to be based, including:

- Adequate information regarding the environmental, social, and economic effects of exploration and development in the area offered for lease must be considered, with no new leasing taking place if this information is not available.
- The timing and location of leasing must be based on geographic, geologic, and ecological characteristics of the region as well as location-specific risks, energy needs, laws, and stakeholder interests.
- The decisionmakers must seek balance between potential damage to the environment and coastal areas and potential energy supply.
- Areas with the greatest resource potential should have greater priority for development, particularly in areas where earlier development has proven a rich resource base.

For every 5-year leasing program, the MMS publishes a comprehensive document detailing the information and reasoning behind the leasing decisions. If a block is not included in the current 5-year leasing program, it may not be leased during the program. The first 5-year leasing program covered the period from 1980 to 1985; the current program covers the period from 2007 to 2012.

In anticipation of the possible lifting of the congressional moratorium after President Bush had lifted the executive moratorium, the MMS began initial steps toward the development of a new 5-year leasing program that would take into consideration the newly released areas. Development of the new program, which would go into effect in 2010 rather than 2012 as previously planned, began on August 1, 2008. Although its action would advance the start date for the next leasing plan by 2 years, the MMS cautioned that the development of a new 5-year leasing program remains a multi-step, multi-year process that includes three separate public comment periods, two separate draft proposals, and development of an environmental impact statement before completion of the final proposal. The final proposal must then be approved by the Secretary of the Interior. The MMS has indicated that a new 5-year leasing program could not go into effect until mid-2010, which would be the earliest that any block in the areas previously under moratoria could be offered for lease.

Leasing, Exploration, and Development

Once the 5-year leasing program is in place, the first lease sale can be offered. The actual leasing process will take 1 to 2 years, requiring preparation of draft and final environmental impact statements, periods of public comment, notices regarding the sale, approval from the governors of States bordering the area covered by the lease as mandated by the CZMA, a bidding period, the receipt and evaluation of bids, and the determination of winning bidders for each block offered for sale.

Successful bidders cannot simply begin operations when they have obtained a lease. An exploration plan must be developed and filed and must undergo technical and environmental review by the MMS before any drilling can commence. Only after obtaining the required approvals can the lease holder evaluate the area and conduct exploratory drilling, which can take from 1 to 3 years in the shallow offshore and up to 6 years in the deep offshore areas. When an initial discovery is made, a development plan must be filed for technical and environmental review by the MMS before any production can begin. Developmental drilling, along with necessary approvals, can take another 1 to 3 years. For major facilities, the MMS conducts on-site inspections, sometimes jointly with the U.S. Coast Guard, before production is allowed to begin. Air emissions permits and water discharge permits must also be obtained from the EPA. Thus, the total time required to obtain a lease, explore and develop the area, and begin actual production is between 4 and 12 years, or potentially more.

Revenue

Once awarded a lease, the lease holder pays a one-time fee plus annual rent for the right to develop the resources in the block. In addition, lease holders pay royalties to the MMS based on the value of any natural gas and oil actually produced. MMS, in turn, disburses the revenues to the appropriate Federal or State agencies. The amounts collected and distributed by the MMS in bonuses, rents, and royalties from Federal offshore oil and gas leases totaled $7.0 billion in fiscal year 2007 and $8.1 billion in fiscal year 2008 [*15*].

Under OCSLA, coastal States are entitled to 27 percent of the revenue from leases of any blocks in Federal waters that fall partially within 3 miles of the State's seaward jurisdictional boundary [*16*], a provision intended to compensate the States for any damage to or drainage from natural gas and oil resources in State waters that are adjacent to Federal leases. Between 1986 and 2003, coastal States received more than $3.1 billion in revenue from such leases [*17*].

In addition to the revenues defined by OCSLA, EPACT2005 allocated additional revenues to the States through the establishment of a new coastal impact assistance program that provides $250 million from OCS revenues per year for fiscal years 2007 to 2010 to six energy-producing coastal States: Alabama, Alaska, California, Louisiana, Mississippi, and Texas [*18*]. The Gulf of Mexico Energy Security Act of 2006 includes additional revenue-sharing provisions (for Alabama, Louisiana, Mississippi, and Texas and their coastal political subdivisions) for specific leases in the Central and Eastern Gulf of Mexico.

Future Directions

Considerable uncertainty still surrounds the issue of offshore drilling in previously restricted areas. Although the congressional moratorium was allowed to expire, some members of Congress have stated publicly that they will raise the issue again in 2009. They are joined by a number of groups and individuals who favor the moratorium and predict that it will be reinstated either partially or fully by the next Congress. Until further action is taken, however, the Atlantic and Pacific coasts are available to be leased, and offshore drilling in those areas could become a reality.

The key issue in developing the OCS is timing. A minimum of 4 years will be required before production from any new leases can begin, and many leases will require longer lead times. In addition, there is considerable uncertainty about the actual size of oil and natural gas resources in areas that have been or remain under moratorium. The actual level of technically recoverable resources also may differ from the current MMS mean resource estimate of approximately 14 billion barrels of oil and 85 trillion cubic feet of natural gas in the Atlantic and Pacific areas that were just opened for leasing. An estimated additional

3.7 billion barrels of oil and 21 trillion cubic feet of natural gas in the central and eastern Gulf of Mexico remain under moratorium through 2022 [*19*].

Loan Guarantee Program Established in EPACT2005

Title XVII of EPACT2005 [*20*] authorized DOE to issue loan guarantees to new or improved technology projects that avoid, reduce, or sequester GHGs. In 2006, DOE issued its first solicitation for $4 billion in loan guarantees for non-nuclear technologies. The issue of the size of the program was addressed subsequently in the Consolidated Appropriation Act of 2008 (the "FY08 Appropriations Act") passed in December 2008, which limited future solicitations to $38.5 billion and stated that authority to make the guarantees would end on September 30, 2009. The legislation also allocated the $38.5 billion cap as follows: $18.5 billion for nuclear plants; $6 billion for CCS technologies; $2 billion for advanced coal gasification units; $2 billion for "advanced nuclear facilities for the 'front end' of the nuclear fuel cycle"; and $10 billion for renewable, conservation, distributed energy, and transmission/ distribution technologies. DOE also was required to submit all future solicitations to both the House and Senate Appropriations Committees for approval [*21*].

DOE received all necessary approvals from Congress in the summer of 2008 and on June 30, 2008, issued two additional solicitations—one for nuclear plants and another for renewable, conservation, distributed energy, and transmission/distribution technologies [*22*, *23*]. Another solicitation, for advanced fossil fuel technologies, was issued on September 22, 2008 [*24*].

Even before it issued its 2008 solicitations, DOE had requested that Congress extend its authority to provide loan guarantees, originally set to expire at the end of fiscal year 2009, for an additional 2 years. As of November 2008, Congress had not acted on the request. Also, DOE's budget request for fiscal year 2009 indicated that only $2.2 billion in loan guarantees from the 2006 solicitation would be issued during that fiscal year. It is not clear what will happen to the rest of the program if DOE's loan guarantee authority expires as originally scheduled. *AEO2009* includes only the effects of the 2006 solicitation, which is assumed to result in the construction of 1.2 gigawatts of capacity at advanced coal-fired power plants and 250 megawatts at solar power plants [*25*].

Provisions of additional loan guarantees pursuant to the solicitations issued in 2008 could have a further effect on the projections, depending on whether the guarantees support projects that were already included in the *AEO2009* projections. For example, in October 2008 DOE received applications from 17 private and public power companies for 21 nuclear units (14 plants with a total of 28.8 gigawatts of capacity) in response to the nuclear solicitation [*26*]. In total, the utilities requested $122 billion in guarantees against total projected construction and financing costs of about $188 billion, suggesting that the $18.5 billion in the FY08 Appropriations Act could cover about 4.4 gigawatts of new nuclear capacity. *AEO2009* projects additions of 13 gigawatts of new nuclear capacity between 2000 and 2030.

Clean Air Mercury Rule

On February 8, 2008, a three-judge panel on the D.C. Circuit of the U.S. Court of Appeals issued a decision to vacate CAMR [*27*]. In its ruling, the panel cited the history of hazardous air pollutant regulation under Section 112 of the Clean Air Act (CAA) [*28*]. Section 112, as written by Congress, listed emitted mercury as a hazardous air pollutant that must be subject to regulation unless it can be proved harmless to public welfare and the environment. In 2000, the EPA ruled that mercury was indeed hazardous and must be regulated under Section 112 and, therefore, subjected to the best available control technology for mitigation.

CAMR was promulgated under Section 111 of the CAA, which allows for the use of a cap-and-trade approach rather than implementation of best available control technology. The EPA had delisted mercury from Section 112 without making the necessary findings to show that mercury emissions could be regulated under Section 111 without harming human health or the environment. The panel stated that the EPA overstepped its authority by ignoring Congressional guidelines and the agency's own earlier findings.

With the elimination of CAMR, there is no Federal mandate to regulate mercury emissions. Even before the rule was vacated, however, many States were adopting more stringent regulations that were allowed through an EPA waiver. Most of those regulations called for the application of best available control technology on all electricity generating units of a certain capacity. After the court's decision, more States imposed their own regulations.

At the time *AEO2009* was published, roughly one-half of the States, including most of those in the Northeast, had their own mercury mitigation laws in place. Without Federal monitoring requirements, however, some of the States that had previously passed regulations may have to make modest modifications in their guidelines. At present, electricity generating units in States without mercury laws are free to emit without limitations. Because the State laws differ, a rough estimate was created that generalized the various State programs into a format that could be used in NEMS, including a rough estimate of mercury emissions within each State. Moreover, the regulatory environment is extremely fluid, with many States planning to enact new laws or make their existing laws more stringent.

Clean Air Interstate Rule

CAIR is a cap-and-trade program promulgated by the EPA in 2005, covering 28 eastern U.S. States and the District of Columbia [*29*]. It was designed to reduce sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions in order to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter ($PM_{2.5}$) and to further emissions reductions already achieved through the Acid Rain Program and the NO_x State Implementation Plan call program. The rule was set to commence in 2009 for seasonal and annual NO_x emissions and in 2010 for SO_2 emissions.

On July 11, 2008, the U.S. District Court of Appeals court unanimously overturned CAIR, ruling that it could not be implemented under the CAA [*30*]. Electric utilities were caught off guard by the court's decision to vacate CAIR. Because the rule was less than 2 years away from implementation, many power plant owners already had spent billions of dollars on pollution control equipment [*31*]. In addition, many States were relying on reductions from CAIR to meet their NAAQS for $PM_{2.5}$ and ozone, and without the rule they might not be able to meet those requirements. The price of seasonal NO_x and SO_2 emissions allowances dropped significantly after the decision. The value of SO_2 allowances has fallen by 75 percent in 2008, and because there is no market for annual NO_x emissions allowances without CAIR, their price has dropped to zero.

Several actions are pending. On September 24, 2008, the U.S. Department of Justice (DOJ) and the EPA, along with several industry representatives and environmental groups, filed petitions in the Court of Appeals asking for the case to be reheard [*32*]. In the petition, the DOJ claimed that the statement in the court's decisions that CAIR was "fundamentally flawed" was incorrect. It also claimed that vacating CAIR could potentially "result in serious harms." The court is considering their petition. On October 21, 2008, the court asked for briefs from the main plaintiffs in the case, specifically asking whether they thought CAIR should be reinstated on an interim basis until updated regulations are issued [*33*]. This development raises the possibility that such a reinstatement could occur.

On December 23, 2008, the Court of Appeals issued a new ruling that remanded but did not vacate CAIR, noting that: "Allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values" [*34*]. The change allows the EPA to modify CAIR to address the objections raised by the Court in its earlier decisions while leaving the rule in place. Because the ruling came well after the cutoff date for changes in Federal and State laws and regulation to be included in *AEO2009*, it is not reflected in the projections. Nonetheless, States still are required to meet their NAAQS, which will require emissions reductions. Therefore, it is assumed that all emissions limits in effect under CAIR remain in effect in the *AEO2009* reference case, but without the CAIR allowance trading provisions.

State Appliance Standards

State appliance standards have existed for decades, starting with California's enforcement of minimum efficiency requirements for refrigerators and several other products in 1979. In 1987, recognizing that different efficiency standards for the same products in different States could create problems for manufacturers, Congress enacted the National Appliance Energy Conservation Act (NAECA), which initially covered 12 products. The Energy Policy Act of 1992 (EPACT92), EPACT2005, and EISA2007 added additional residential and commercial products to the 12 products originally specified under NAECA.

Many different State appliance standards still exist today (Table 2); however, a key point of NAECA was to enforce Federal preemption of any State appliance standard. The preemption clause allows States to continue to mandate standards for products not covered by Federal law and to enforce standards that might have existed before Federal coverage, up to the date of Federal enforcement. Because most major appliances are covered by Federal law, the majority of State standards target less energy-intensive products. Most of the standards for products listed in Table 2 will be preempted by Federal standards within the next decade. For example, the California standard for general-service lighting will be preempted in 2012 by the Federal standard for general-service lighting required in EISA2007. States can petition DOE for a waiver to continue to enforce their own standards, as opposed to a less strict Federal standard. To date, however, no waivers have been granted.

The NEMS residential and commercial modules represent Federal appliance standards for all major appliances covered under NAECA and subsequent legislation. For products not explicitly covered in NEMS (residential dehumidifiers, for example), an off-line estimate of the impact of the standard is included in the projections by way of deducting the savings estimates from the projections without the standards included. Given that the NEMS buildings

Table 2. State appliance efficiency standards and potential future actions

State	Program (effective year of standard noted in parentheses)
AZ	Arizona's Minimum Appliance and Equipment Efficiency Standards currently apply to automatic commercial icemakers (2008) and metal halide lamp fixtures (2008). Every 3 years, the Energy Office of the Arizona Department of Commerce must conduct a comparative review and assessment of standards and submit a report of its findings and recommendations to the State legislature.
CA	California's Appliance Efficiency Regulations apply to automatic commercial ice makers (2006); commercial refrigerators and freezers (2003 phase I / 2006 phase II); consumer audio and video products (2006/2007); large packaged air conditioners above 20 tons (2006/2010); metal halide lamp fixtures (2006/2008); pool pumps (2006/2008); single-voltage external power supplies (2007/2008); general service incandescent lamps (2006); water dispensers (2003); walk-in refrigerators and freezers (2006); hot tubs (2006); commercial hot food holding cabinets (2006); under-cabinet fluorescent lamps (2006); and vending machines (2006). In addition, Assembly Bill 1109 requires a minimum efficiency standard for all general-purpose lights, with the goal of reducing energy use for indoor residential lighting to 50 percent of 2007 levels and for indoor commercial and outdoor lighting to 75 percent of 2007 levels by 2018.
CT	Connecticut efficiency standards apply to commercial refrigerators and freezers (2008) and large packaged air-conditioning equipment (2009). Standards must be reviewed biannually and increased if it is determined that higher efficiency standards would promote energy conservation and be cost-effective for consumers, and if multiple products would be available.
MD	Maryland's efficiency standards apply to bottle-type water dispensers (2009); commercial hot food holding cabinets (2009); metal halide lamp fixtures (2009); residential furnaces (2009); alternating current to direct current power supplies (2012/2013); State-regulated incandescent reflector lamps (2009); walk-in refrigerators and freezers (2009); commercial refrigeration cabinets (2010); and large packaged air-conditioning equipment (2010). Every 2 years the Maryland Energy Administration is directed to review and propose new standards to the Maryland Assembly for products not already subject to standards, or add more stringent amendments to existing standards.
MA	The Massachusetts appliance standards currently apply to medium-voltage dry-type transformers (2008); metal halide lamp fixtures (2009); residential furnaces and boilers (to be determined); residential furnace fans (to be determined); State-regulated incandescent reflector lamps (various types) (2008); and single-voltage external power supplies (2008). The State Department of Energy Resources (DOER) must file a biannual report on appliance efficiency standards, evaluating effectiveness and energy conservation. Existing Federal standards cover residential furnaces, boilers, and furnace fans; however, Massachusetts is seeking a waiver from the warm weather standard.
NV	Nevada's Assembly Bill 178 establishes efficiency standards for general-purpose lights (lamps, bulbs, tubes, or other illumination devices for indoor and outdoor use, not including lighting for people with special needs) to take effect between 2012 and 2015. Effective January 1, 2016, the Director of the Office of Energy must set a new minimum efficiency standard that exceeds the previous standard.
NY	New York efficiency standards currently not preempted by Federal legislation include consumer audio and video products (to be determined); digital television adapters (to be determined); metal halide lamp fixtures (2008); and single-voltage external power supplies (to be determined, preemption for some types starting in July 2008). New York law allows the Secretary of State, in consultation with the State Energy Research and Development Authority, to add additional products so long as they are commercially available, cost-effective, and not covered by Federal standards.
OR	Oregon efficiency standards currently not preempted by Federal legislation include automatic commercial icemakers (2008); metal halide fixtures (2008); single-voltage external power supplies (2007); and State-regulated incandescent reflector lamps (various types) (2007).
RI	Rhode Island efficiency standards not preempted by Federal standards include high-intensity discharge lamp ballasts (2007); single-voltage external power supplies (2008); metal halide lamp fixtures (2008); residential boilers and furnaces (to be determined); incandescent spot lights (2008); bottled water dispensers (2008); commercial hot food holding cabinets (2008); and walk-in refrigerators and freezers (2008). Rhode Island legislation allows for existing efficiency standards to be increased if the Chief of Energy and Community Services determines that it would promote energy conservation in the State and would be cost-effective for consumers.
VT	Vermont's Act Relating to Establishing Energy Efficiency Standards for Certain Appliances creates minimum standards for medium-voltage dry-type transformers (2008); metal halide lamp fixtures (2009); residential furnaces and boilers (to be determined); residential furnace fans (to be determined); single-voltage external power supplies (2008); and State-regulated incandescent reflector lamps (various types) (2008).
WA	Washington standards apply to automatic commercial ice makers (2008); commercial refrigerators and freezers (2007); metal halide lamp fixtures (2008); single-voltage external power supplies (2008); and State-regulated incandescent reflector lamps (various types) (2007). State efficiency legislation stipulates that standards may be increased or updated.

modules are specified at the Census Division level, State standards are not readily amenable to direct modeling in NEMS. Furthermore, the paucity of data at the State level does not allow for a direct accounting of equipment stock or energy usage, which is needed to estimate energy savings. Although NEMS does not represent State appliance standards explicitly, recent trends in energy intensity are taken into account in the projections and should represent recent State appliance efficiency standards to the extent that they affect future energy demand in the buildings sectors.

California's Move Toward E10

In *AEO2009*, E10—a gasoline blend containing 10 percent ethanol—is assumed to be the maximum ethanol blend allowed in California RFG, as opposed to the 5.7-percent blend assumed in earlier *AEO*s. The 5.7-percent blend had reflected decisions made when California decided to phase out use of the additive methyl tertiary butyl ether in its RFG program in 2003, opting instead to use ethanol in the minimum amount that would meet the requirement for 2.0 percent oxygen content under the CAA provisions in effect at that time [*35*].

Recently, there has been a push in California to increase the use of ethanol, for two reasons. First, the RFS mandate in EISA2007 Title II, Subtitle A [*36*], requires greater use of renewable fuels, such as ethanol. Second, California's Low Carbon Fuel Standard (LCFS) mandates a reduction in the State's overall GHG emissions to 1990 levels by 2020 and require a 10-percent reduction in GHG emissions from passenger vehicles by 2020. Although fuel providers can use a variety of strategies to produce lower carbon fuel, increasing the ethanol blends from 5.7 percent to 10 percent is thought to be a first step toward achieving the LCFS goals. In fact, in October 2008, CARB released its first draft of the LCFS regulatory framework [*37*]. The calculation in the framework assumes that the baseline emissions for gasoline in 2010 (from which CO_2 emissions must be reduced in later years) will be from E10 (California RFG with 10 percent ethanol content), implying that most, if not all, gasoline sold in California by 2010 will be E10.

Modifications were made to California's RFG regulations and the predictive model that estimates emissions for different fuel mixes in order to increase ethanol blends above 5.7 percent. The predictive model was revised to accommodate the higher ethanol blends in determining evaporative and exhaust emissions, providing the information needed by fuel providers to increase ethanol content. For example, the increased ethanol content will result in higher NO_x emissions, and the increase must be mitigated by lowering the fuel's sulfur content.

Refineries in California may have to make substantial modifications to produce compliant fuel under the new standards (most significantly, producing fuel with only 5 parts per million sulfur), and all fuel sold in California must be compliant with the new CARB Phase 3 standards after December 31, 2009. The final approved modifications in CARB Phase 3 gasoline and the revisions in the predictive model provide refiners and importers of fuel a formal framework with which to provide compliant fuel. Already, at least one major refiner has stated that it will apply the amended CARB Phase 3 gasoline standards, presumably to increase ethanol content.

State Renewable Energy Requirements and Goals: Update Through 2008

State RPS programs continue to play an important role in *AEO2009*, growing in number while existing programs are modified with more stringent targets. In total, 28 States and the District of Columbia now have mandatory RPS programs (Table 3), and at least 4 other States have voluntary renewable energy programs. In the absence of a Federal renewable electricity standard, each State determines its own levels of generation, eligible technologies, and noncompliance penalties. The growth in State renewable energy requirements has led to an expansion of renewable energy credit (REC) markets, which vary from State to State. Credit prices depend on the State renewable requirements and how easily they can be met.

In the *AEO2009* reference case, most States are projected to meet their RPS targets. California is an exception, as a result of limits on State funding for renewable projects. Therefore, for California, the cost of achieving each target increment is estimated, and the amount of renewable capacity that exhausts the renewable funding is assumed to be built. Renewable generation in most regions is approximated, because NEMS is not a State-level model, and each State represents only a portion of one of the NEMS regions. Compliance costs in each region are tracked, and the projection for total renewable generation is adjusted as needed to be consistent with the individual State provisions.

Table 3. State renewable portfolio standards

State	Program mandate
AZ	Arizona Corporate Commission Decision No. 69127 requires 15 percent of electricity sales to be renewable by 2025, with interim goals increasing annually. A specific percentage of the target must be from distributed generation. Multiple credits may be given for solar generation and in-State manufactured systems.
CA	Public Utilities Code Sections 399.11-399.20 mandate that 20 percent of electricity sales must be renewable by 2010. There are also goals for the longer term. Renewable projects with above-market costs will be funded by supplemental energy payments from a fund, possibly limiting renewable generation to less than the 20-percent requirement.
CO	House Bill 1281 sets the renewable target for investor-owned utilities at 20 percent by 2020. There is a 10-percent requirement in the same year for cooperatives and municipals. Moreover, 2 percent of total sales must be from solar power. In-State generation receives a 25-percent credit premium.
CT	Public Act 07-242 mandates a 27-percent renewable sales requirement by 2020, including a 4-percent mandate from higher efficiency or CHP systems. Of the overall total, 3 percent may be met by waste-to-energy facilities and conventional biomass.
DE	Senate Bill 19 determined the RPS to be 20 percent of sales by 2019. There is a separate requirement for solar generation (2 percent of the total), and compliance failure results in higher penalty payments. Solar technologies receive triple credits, and offshore wind receives 3.5 times the credit amount.
HI	Senate Bill 3185 sets the renewable mandate at 20 percent by 2020. All existing renewable facilities are eligible to meet the target, which has two interim milestones.
IL	Public Act 095-0481 created an agency responsible for overseeing the mandate of 25-percent renewable sales by 2025. There are escalating annual targets. and 75 percent of the requirements must be generated from wind. The plan also includes a cap on the incremental costs added from renewable penetration.
IA	An RPS mandating105 megawatts of renewable energy capacity has already been exceeded.
ME	In 2007, Public Law 403 added to the State's RPS requirements. Originally, a mandate of 30 percent renewable generation by 2000 was set to be lower than current generation. The new law requires a 10-percent increase in renewable capacity by 2017, and that level must be maintained in subsequent years. The years leading up to 2017 also have new capacity milestones.
MD	House Bill 375 revised the RPS to contain a 20-percent target by 2022, including a 2-percent solar target. Penalty payments for "Tier 1" compliance shortfalls were also raised to 4 cents per kilowatthour under the same legislation.
MA	The RPS has a goal of a 4-percent renewable share of total sales by 2009, with subsequent 1-percent annual increases to 2014. The State also has necessary payments for compliance shortfalls.
MI	Public Act 295 established an RPS that will require 10 percent renewable generation by 2015. Bonus credits are given to solar energy.
MN	Senate Bill 4 created a 30-percent renewable requirement by 2020 for Xcel, the State's largest supplier, and a 25-percent requirement by 2025 for others. Also specified was the creation of a State cap-and-trade program that will assist the program's implementation.
MO	Proposition C, approved by voters, mandates a 2-percent renewable energy requirement in 2011, which will increase incrementally to 15 percent of generation by 2021. Bonus credits are given to renewable generation within the State.
MT	House Bill 681 expanded the RPS provisions to all suppliers. Initially the law covered only public utilities. A 15-percent share of sales must be renewable by 2015. The State operates a REC market.
NV	The State has an escalating renewable target, established in 1997 and revised in 2005, that reaches 20 percent of total electricity sales by 2015. Up to one-quarter may be met through efficiency measures. There is also a minimum requirement for PV systems, which receive bonus credits.
NH	House Bill 873 legislated that 23.8 percent of electricity sales must be renewable by 2025, and 16.3 percent of total sales must be from renewable facilities that begin operation after 2006. Compliance penalties vary by generation type.
NJ	In 2006, the RPS was revised to increase renewable energy targets. The current level for renewable generation is 22.5 percent of sales by 2021, with interim targets. There are different requirements for different technologies, including a 2-percent solar mandate.
NM	Senate Bill 418 directs investor-owned utilities to have 20 percent of their sales from renewable generation by 2020. The renewable portfolio must consist of diversified technologies, with wind and solar each accounting for 20 percent of the target. There is a separate standard of 10 percent by 2020 for cooperatives.
NY	The Public Service Commission issued RPS rules in 2005 that call for an increase in renewable electricity sales to 24 percent of the total by 2013, from the current level of 19 percent. The program is administered and funded by the State.
NC	Senate Bill 3 created an RPS of 12.5 percent by 2021 for investor-owned utilities. There is also a 10-percent requirement by 2018 for cooperatives and municipals. Through 2018, 25 percent of the target may be met through efficiency standards, increasing to 40 percent in later years.
OH	Senate Bill 221 requires 25 percent of electricity to be produced from alternative energy resources by 2025, including low-carbon and renewable technologies. One-half of the target must come from renewable sources. Municipals and cooperatives are exempt.
OR	In June 2007, Senate Bill 838 required renewable targets of 25 percent by 2025 for large utilities and 5 to 10 percent by 2025 for smaller utilities. Any source of renewable electricity on line after 1995 is considered eligible. Compliance penalty caps have not yet been determined.
PA	The Alternative Energy Portfolio Standard has an18-percent requirement by 2020. Most of the qualifying generation must be renewable, but there is also a provision that allows certain coal resources to receive credits.
RI	The program requires that 16 percent of total sales be renewable by 2020. The interim program targets escalate more rapidly in later years. If the target is not met, a generator must pay an alternative compliance penalty.

(continued on page 22)

Table 3. State renewable portfolio standards (continued)

State	Program mandate
TX	Senate Bill 20 strengthened the State RPS by mandating 5,880 megawatts of renewable capacity by 2015. There is also a target of 500 megawatts of renewable capacity other than wind.
WA	Voters approved Initiative 937, which specifies that 15 percent of sales from the State's largest generators must come from renewable sources by 2020. There is an administrative penalty of 5 cents per kilowatthour for noncompliance. Generation from any facility that came on line after 1999 is eligible.
WI	Senate Bill 459 strengthened the State RPS with a requirement that, by 2015, each utility's renewable share of total generation must be at least 6 percentage points above the renewable share from 2001 to 2003. There is also a non-binding goal.

In 2008, three States (Michigan, Missouri, and Ohio) enacted new renewable legislation, and three others (Delaware, Maryland, and Massachusetts) modified existing legislation. Missouri's new RPS was approved by voters in the November 2008 election. In California, voters rejected two propositions that would have strengthened the State RPS. One would have increased the renewable requirement to 50 percent of electricity generated by 2025 and allowed for the use of a 20-year feed-in tariff [*38*]; the other would have established a $5 billion fund to support renewable electricity generation and transportation projects. The propositions were not supported by many environmentalists, who saw them as poorly written and potentially causing harm to the renewable industry. Both were defeated easily.

Michigan. Public Act 295 [*39*] established Michigan's first RPS. Signed into law in October 2008, the Act requires that all electricity suppliers generate 10 percent of their electricity from renewable sources by 2015. There are also intermediate benchmarks. Each supplier has its own standard, based on current levels of renewable generation. Coal-fired plants that sequester at least 85 percent of their emissions also qualify toward the target, as do all renewable technologies except new hydroelectric facilities; however, improvements on existing hydroelectric facilities will receive energy credits. Like most programs, Michigan's RPS will use RECs to promote compliance. Bonus credits are given to solar generators as well as facilities using in-State labor and manufactured equipment [*40*]. Up to 10 percent of the total requirement may be met through energy optimization and advanced system credits, which lower electricity demand.

Missouri. On November 4, 2008, voters approved Proposition C [*41*], changing Missouri's renewable goal into an enforceable mandate. The requirement goes into effect in 2011 with a 2-percent renewable target, which increases in four phases to reach the final 15-percent target by 2021. REC trading will be used, with in-State renewable generation eligible for 1.25 REC for each megawatthour of electricity generated. A small percentage of the overall renewable requirement must be met through solar generation. Suppliers subject to the RPS are required to offer their retail costumers a rebate of $2.00 per installed watt of small-scale solar systems.

Ohio. In May 2008, Ohio enacted legislation [*42*] that requires most retail electricity providers to produce 25 percent of their electricity from alternative energy resources by 2025. Alternatives are defined as low-carbon technologies, including nuclear energy and coal with carbon sequestration. Plants that come on line after 1998 are considered eligible toward meeting the target. Within the 25-percent requirement is a separate provision that increases the required renewable share of annual generation from 0.25 percent in 2009 to 12.5 percent in 2024. There are also energy efficiency and load-reducing requirements. Municipal and cooperative suppliers are exempt from all provisions.

REC trading is expected to help Ohio achieve its requirements. The REC prices will be capped at $45 per megawatthour, with more severe penalties incurred if the solar requirement is not met; however, there is also a provision that exempts suppliers from the mandates if they can show that they would incur incremental costs 3 percent above the total cost of a conventional alternative. Suppliers exempted from the annual requirement may have to meet stiffer compensatory targets in subsequent years.

Delaware. Senate Bill 328 [*43*] amended Delaware's existing RPS by awarding offshore wind 3.5 times as many credits as are received by conventional renewable technologies toward meeting the mandate. Analysis has shown that this provision makes offshore wind development economical under business-as-usual assumptions.

Maryland. House Bill 375 [*44*] increased the State's renewable energy requirement to 20 percent of total generation by 2022. The requirement must be met with resources classified in the legislation as "tier 1," which include all renewable forms of generation except existing large hydroelectric facilities. Senate Bill 348 [*45*], also enacted in 2008, expanded the definition of tier 1 resources to include "poultry litter-to-energy" facilities. Also included in the tier 1 resource target is a solar energy mandate that increases annually until it reaches 2 percent in 2022. Smaller amounts of electricity generated from tier 2 resources (large hydropower facilities) are included until 2019.

Along with its increased mandatory target, House Bill 375 includes higher compliance caps. A shortfall in renewable generation from tier 1 resources other than solar energy will cost a supplier 4 cents per kilowatthour. If it can be shown, however, that achieving the target would cost more than one-tenth of the supplier's total energy sales, the target may be deferred until the next year (an "off-ramp" that was added with the higher compliance caps in House Bill 375). Penalties for solar shortfalls are much larger, 45 cents per kilowatthour in the initial shortfall year, but they decrease by 5 cents annually until they reach and remain at 5 cents per kilowatthour beginning in 2023. Funds generated from the penalties will go to an energy investment fund for support of renewable energy technology advancement and deployment.

Massachusetts. The State RPS requirements are modeled through 2014 in *AEO2009*. Electricity suppliers in Massachusetts are required to increase their annual renewable generation from 4 percent of total generation in 2009 to 9 percent in 2014. The State DOER has the option of extending the 1-percent annual increase through 2020. Renewable requirements beyond 2014 are not assumed in *AEO2009*. In December 2008, the DOER enacted regulations establishing a target of 15 percent renewable generation by 2020, with the presumption of increasing the target thereafter. *AEO2009* is based on regulations in effect as of November 2008 and does not include the new target.

Updated State Air Emissions Regulations

Regional Greenhouse Gas Initiative

In September 2008, the first U.S. mandatory auction of CO_2 emission permits occurred among six States in the Northeast that are part of the Regional Greenhouse Gas Initiative (RGGI). The RGGI program includes 10 Northeastern States that have agreed to curtail and reverse growth in CO_2 emissions. It covers all electricity generating units with a capacity of at least 25 megawatts and requires them to hold an allowance for each ton of CO_2 emitted [*46*].

The first year of mandatory compliance is 2009 and each State's CO_2 "carbon budget" already has been determined. The budgets consist of historically based baselines with a cushion for emissions growth, so that meeting the cap is expected to be relatively easy initially and become more difficult over time. Overall, the RGGI region must maintain emissions of 188 million tons CO_2 for the next 5 years, followed by a mandatory 2.5-percent annual decrease through 2018, when the CO_2 emissions level should be 10 percent below the initial calculated budget. The requirements are expected to cover 95 percent of CO_2 emissions from the region's electric power sector. Each State has its own emissions budget, and the allowances will be auctioned at a uniform price across the entire region.

Before the first auction, several rules were agreed to by the States:

- Auctions will be held quarterly, following a single-round, sealed-bid format.
- Allowances will be sold at a uniform price, which is the highest price of the rejected bids.
- States may hold a small number of allowances for their own use; however, most States have decided to auction all their allowances.
- Each emitter must buy one allowance for every ton of CO_2 emitted.
- Future allowances will be made available for purchase up to 4 years before their official vintage date, as a way to control price fluctuations.
- A reserve price of $1.86 per allowance in real dollars will be in effect for each auction, as a way to preserve allowance prices in auctions where demand is low and to avoid collusion among emitters that could threaten a fair market.
- The revenue from the auctions can be spent at the State's discretion, although at least 25 percent must go to a fund that benefits consumers and promotes low-carbon energy development.

In the first auction, the six participating States (Connecticut, Maine, Maryland, Massachusetts, Rhode Island, and Vermont) sold 12,600,000 allowances at a price of $3.07 per allowance [*47*]. The next auction, held in December 2008, included the original six States along with New York, New Jersey, New Hampshire, and Delaware. Issues such as emission leakage [*48*], which is especially relevant in the Mid-Atlantic region, have been studied, but no specific solutions have been implemented.

RGGI is included in the *AEO2009* reference case. The effect is minimal in the early years, given the relatively generous emissions budget. Because it is difficult to capture the nuances of State initiatives in NEMS, which is a regional model, independent estimates were made for the Mid-Atlantic region to determine eligible generation facilities and their emissions caps (for Pennsylvania, an observing member that it is not participating in the cap-and-trade program and is not subject to any mandatory reductions, emissions are not restricted).

Western Climate Initiative

Developed independently of RGGI, the Western Climate Initiative (WCI) [*49*] is also a regional GHG reduction program. Participants in the WCI include seven U.S. States (Arizona, California, Montana, New Mexico, Oregon, Utah, and Washington) and four Canadian Provinces, with additional observer States and provinces in the United States, Canada, and Mexico.

The WCI seeks to reduce GHG emissions to levels 15 percent below 2005 emissions by 2020. Reductions will be achieved through an allowance cap-and-trade program, and each participating State or province will be able to determine its own allowance allocation method. Allowances will be based on a regionally agreed emissions estimate, likely taking into account some growth in GHG emissions through the first year of mandatory compliance in 2012. Although each jurisdiction will choose the specifics of allowance distribution, a minimum of 10 percent of allowances must be auctioned in 2012, and the requirement rises in subsequent years. In the initial compliance year, electricity generators and large industrial facilities in the WCI region, as well as outside facilities with energy products consumed in the region, will be required to provide one allowance for each ton of CO_2 equivalent released into the atmosphere.

WCI is similar to RGGI, but they also have important differences. Although the first phase of the WCI program (2012 to 2015) will not cover emissions from fossil fuels used in smaller facilities or in mobile sources, all fuels are expected to be covered by 2015, including those used in the transportation, industrial, and residential sectors (none of which is covered by RGGI in any period). All fuels will be regulated upstream at the distributor level. The 2015 cap will grow above the first phase cap, which covers only facilities emitting more than 10,000 tons CO_2 equivalent annually. Those sources will continue to be covered after the inclusion of combustion fuels, but the emissions will not be counted twice. Larger stationary facilities will be regulated at the emission source, and their fuels will not be subject to upstream regulation. Mandatory emissions monitoring of the stationary sources will begin in January 2010.

Another distinction is that the WCI will account for nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride, not just CO_2 as in RGGI. The additional GHGs will be measured in terms of their CO_2-equivalent global warming potentials, and allowances will be issued accordingly. WCI documents estimate that 90 percent of the region's GHG emissions will be subject to regulation after additional combustion fuels are included in 2015.

Although no final caps have been determined, the permissible GHG ceiling will decline over the program, which currently ends in 2020. No formal determination of how to continue the program beyond 2020 has been made. In order to control the price of allowances, a reserve price will be set as the floor. Up to 49 percent of emissions reductions may occur through offset programs such as forestation and agriculture reform. The list of qualifying offsets remains to be determined but must be agreed on by all participants. There are still some details to be worked out between the WCI and the individual jurisdictions within the region that have their own GHG mitigation laws. Two prime examples are California, which has passed its own GHG legislation, and British Columbia, which is mitigating emissions through a tax. The issues will be addressed after the specifics of the program have been determined.

Unlike RGGI, the WCI is not included in the *AEO2009* reference case, because the WCI model rules were released after November 2008. Similarly, the Midwestern Climate Initiative, which is in a preliminary stage, is not included in *AEO2009*. Regional and State GHG initiatives continue to evolve rapidly, and it is likely that *AEO2010* will include additional programs.

Endnotes for Legislation and Regulations

1. Including several ballot initiatives for energy-related legislation, where the results of the balloting are known.
2. For the complete text of the Food, Conservation, and Energy Act of 2008, see web site http://frwebgate.Access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_public_laws&docid=f:publ246.110.pdf.
3. On December 23, 2008, after the November 2008 cut-off date for inclusion of changes in Federal and State laws and regulations in *AEO2009*, the United States Court of Appeals for the District of Columbia issued a new ruling that remanded but did not vacate CAIR, noting that "Allowing CAIR to remain in effect until it is replaced by a rule consistent with our opinion would at least temporarily preserve the environmental values." Source: United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIRRemand Order.pdf. This change allows the EPA to modify CAIR to address the objections raised by the Court in its earlier decision while leaving the rule in place. The change is not reflected in *AEO2009*.
4. For complete text of the Emergency Economic Stabilization Act of 2008, including Division B, "Energy Improvement and Extension Act of 2008," see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=110_cong_bills&docid=f:h1424enr.txt.pdf.
5. "Closed-loop" refers to fuels that are grown specifically for energy production, excluding wastes and residues from other activities, such as farming, landscaping, forestry, and woodworking.
6. Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees, and Environmental Taxes and Fees" (July 9, 2008).
7. U.S. Department of Transportation, National Highway Traffic Safety Administration, "Summary of Fuel Economy Performance," NHTSA-2007-28040-0001 (Washington, DC, March 2007), web site www.regulations.gov/fdmspublic/component/main?main=DocumentDetail&o=09000064802ad392.
8. U.S. Department of Transportation, National Highway Traffic Safety Administration, 49 CFR Parts 523, 531, 533, 534, 536, and 537 [Docket No. NHTSA-2008-0089] RIN 2127-AK29, *Notice of Proposed Rulemaking: Average Fuel Economy Standards Passenger Cars and Light Trucks Model Years 2011-2015* (Washington, DC, April 2008), pp. 14-15, web site www.nhtsa.dot.gov/portal/site/nhtsa/menuitem.43ac99aefa80569eea57529cdba046a0/.
9. A vehicle's footprint is defined as the wheelbase (the distance from the center of 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.
10. U.S. Department of Transportation, National Highway Traffic Safety Administration, *Preliminary Regulatory Impact Analysis: Corporate Average Fuel Economy for MY 2011-2015 Passenger Cars and Light Trucks* (Washington, DC, April 2008), pp. 374-375, web site www.nhtsa.gov/staticfiles/DOT/NHTSA/Rulemaking/Rules/Associated%20Files/CAFE_2008_PRIA.pdf.
11. Most recently, the Consolidated Omnibus Appropriations Act of 2008 (Public Law 110-161, H.R. 2764) included the OCS moratorium as Sections 104, 105 and 412.
12. "OCS Lands Act History," web site www.mms.gov/aboutmms/OCSLA/ocslahistory.htm.
13. "OCS Lands Act History," web site www.mms.gov/aboutmms/OCSLA/ocslahistory.htm.
14. "Congressional Action to Help Manage Our Nation's Coasts," web site http://coastalmanagement.noaa.gov/czm/czm_act.html.
15. U.S. Department of the Interior, Minerals Management Service, "2001-Forward MRM Statistical Information: Reported Royalty Revenues," web site www.mrm.mms.gov/mrmwebstats/home.aspx.
16. See web site www.mms.gov/aboutmms/pdffiles/ocsla.pdf, p. 21, paragraph 1.
17. See web site www.mms.gov/ooc/newweb/publications/2003%20FACT.pdf, p. 7.
18. Energy Policy Act of 2005, Title III, Subtitle G, Section 384, "Coastal Impact Assistance Program," p. 147, web site www.epa.gov/oust/fedlaws/publ_109-058.pdf.
19. U.S. Department of the Interior, Minerals Management Service, *Report to Congress: Comprehensive Inventory of U.S. OCS Oil and Natural Gas Resources: Energy Policy Act of 2005—Section 357* (Washington, DC, February 2006), pp. v and vi, web site www.mms.gov/PDFs/2005EPAct/InventoryRTC.pdf.
20. For the complete text of the Energy Policy Act of 2005, see web site http://frwebgate.access.gpo.gov/cgi-bin/getdoc.cgi?dbname=109_cong_public_laws&docid=f:publ058.109.pdf.
21. See *AEO2008* for more detailed discussion of the program and the FY 2008 Appropriations Act.
22. At the same time, DOE also issued a solicitation for the front end of the nuclear fuel cycle. Because NEMS does not contain a direct representation of the front end of the nuclear fuel cycle, that solicitation is not considered in this analysis.
23. U.S. Department of Energy, "DOE Announces Solicitation for $30.5 Billion in Loan Guarantees" (Washington, DC, June 30, 2008), web site www.lgprogram.energy.gov/press/063008.pdf.
24. U.S. Department of Energy, "DOE Announces Solicitation for $8.0 Billion in Loan Guarantees" (Washington, DC, September 22, 2008), web site www.lgprogram.energy.gov/press/092208.pdf.

25. A detailed discussion of the rationale for this assumption can be found in *AEO2008*. In brief, in 2007, DOE released technology-specific information about the requested guarantees from the 2006 solicitation. Included in that information were the requested dollar amounts of the guarantees, by technology. It was assumed, basically, that the dollar amounts of the approved guarantees would be proportional to the requested dollar amounts.
26. U.S. Department of Energy, "DOE Announces Loan Guarantee Applications for Nuclear Power Plant Construction" (Washington, DC, October 2, 2008), web site www.lgprogram.energy.gov/press/100208.pdf.
27. United States Court of Appeals for the District of Columbia Circuit, No. 05-1097, web site http://pacer.cadc.uscourts.gov/docs/common/opinions/200802/05-1097a.pdf.
28. "The Clean Air Act [As Amended Through P.L. 108–201, February 24, 2004]," web site http://epw.senate.gov/envlaws/cleanair.pdf.
29. U.S. Environmental Protection Agency, "Clean Air Interstate Rule," web site www.epa.gov/airmarkets/progsregs/cair/.
30. United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site http://pacer.cadc.uscourts.gov/docs/common/opinions/200807/05-1244-1127017.pdf.
31. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Rehearing_Petition_as_Filed.pdf.
32. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Rehearing_Petition_as_Filed.pdf.
33. U.S. Environmental Protection Agency, web site www.epa.gov/airmarkets/progsregs/cair/docs/CAIR_Pet_Reply_Filed.pdf.
34. United States Court of Appeals for the District of Columbia Circuit, No. 05-1244, web site www.epa.gov/airmarkets/progsreg/cair/docs/CAIRRemandOrder.pdf.
35. The requirements for reformulated gasoline can be found in the 1990 Amendments to the Clean Air Act, Title II, Sec. 219 (web site www.epa.gov/oar/caa/caaa.txt). An excellent discussion of the history of oxygenate and other environmentally-based requirements for gasoline can be found in U.S. Environmental Protection Agency, *Fuel Trends Report: Gasoline 1995-2005*, EPA420-R-08-002 (Washington, DC, January 2008), web site www.epa.gov/otaq/regs/fuels/rfg/properf/420r08002.pdf.
36. Congressional Research Service, *Energy Independence and Security Act of 2007: A Summary of Major Provisions*, Order Code RL34294 (Washington, DC, December 2007), web site http://energy.senate.gov/public/_files/RL342941.pdf.
37. California Air Resources Board, "Low Carbon Fuel Standard Workshop: Review of the Draft Regulation" (October 16 2008), web site www.arb.ca.gov/fuels/lcfs/101608lcfsreg_prstn.pdf.
38. A feed-in-tariff guarantees a specified price, usually above the market level, on a long-term electricity purchasing agreement.
39. State of Michigan, 94th Legislature, Enrolled Senate Bill No. 213, web site www.legislature.mi.gov/documents/2007-2008/publicact/pdf/2008-PA-0295.pdf.
40. Although solar generation receives one bonus credit for each megawatthour produced, facilities using equipment manufactured in the same State and in-State workforces receive only 0.1 credit as a bonus.
41. Missouri Secretary of State, Amendment to Chapter 393 of the Revised Statutes of Missouri, Relating to Renewable Energy, web site www.sos.mo.gov/elections/2008petitions/2008-031.asp.
42. 127th General Assembly of the State of Ohio, Amended Substitute Senate Bill Number 221, web site www.legislature.state.oh.us/bills.cfm?ID=127_SB_0221.
43. State of Delaware, 144th General Assembly, Senate Bill 328, web site http://legis.delaware.gov/lis/lis144.nsf/vwLegislation/SB+328?Opendocument.
44. State of Maryland, House Bill 375, web site http://mlis.state.md.us/2008rs/billfile/HB0375.htm.
45. State of Maryland, Senate Bill 348, web site http://mlis.state.md.us/2008RS/billfile/SB0348.htm.
46. Regional Greenhouse Gas Initiative, "About RGGI," web site www.rggi.org/about/documents.
47. Regional Greenhouse Gas Initiative, "RGGI States' First CO_2 Auction Off to a Strong Start" (September 29, 2008), web site www.rggi.org/docs/rggi_press_9_29_2008.pdf.
48. Regional Greenhouse Gas Initiative, "Potential Emissions Leakage and the Regional Greenhouse Gas Initiative (RGGI)" (March 2008), web site http://rggi.org/docs/20080331leakage.pdf.
49. Western Climate Initiative, *Design Recommendations for the WCI Regional Cap-and-Trade Program* (September 23, 2008), web site www. westernclimate initiative.org/ewebeditpro/items/ O104F19865.PDF.