Issues in Focus

Issues in Focus

Introduction

This section of the *AEO* provides discussions on selected topics of interest that may affect future projections, including significant changes in assumptions and recent developments in technologies for energy production, supply, and consumption. Issues discussed this year include trends in world oil prices and production; the economics of plug-in electric hybrids; the impact of reestablishing the moratoria on oil and natural gas drilling on the Federal OCS; expectations for oil shale production; the economics of bringing natural gas from Alaska's North Slope to U.S. markets; the relationship between natural gas and oil prices; the impacts of uncertainty about construction costs for power plants; and the impact of extending the renewable PTC for 10 years. Last, in view of growing concerns about GHG emissions, the topics discussed also include the impacts of such concerns on investment decisions and their handling in *AEO2009*.

The topics explored in this section represent current, emerging issues in energy markets; however, many of the topics discussed in *AEO*s published in recent years remain relevant today. Table 4 provides a list of titles from the 2008, 2007, and 2006 *AEO*s that are likely to be of interest to today's readers. They can be found on EIA's web site at www.eia.doe.gov/oiaf/aeo/otheranalysis/aeo_analyses.html.

World Oil Prices and Production Trends in *AEO2009*

The oil prices reported in *AEO2009* represent the price of light, low-sulfur crude oil in 2007 dollars [*50*]. Projections of future supply and demand are made for "liquids," a term used to refer to those liquids that after processing and refining can be used interchangeably with petroleum products. In *AEO2009*, liquids include conventional petroleum liquids—such as conventional crude oil and natural gas plant liquids—in addition to unconventional liquids, such as biofuels, bitumen, coal-to-liquids (CTL), gas-to-liquids (GTL), extra-heavy oils, and shale oil.

Developments in the world oil market over the course of 2008 exemplify how the level and expected path of world oil prices can change even over a period of days, weeks, or months. The difficulty for projecting prices into the future continues when the period of interest extends through 2030. Long-term world oil prices are determined by four fundamental factors: investment and production decisions by the Organization of the Petroleum Exporting Countries (OPEC); the economics of non-OPEC conventional liquids supply; the economics of unconventional liquids supply; and world demand for liquids. Uncertainty about long-term world oil prices can be considered in terms of developments related to one or more of these factors.

Recent Market Trends

The first 6 months of 2008 saw the continuation of the previous years' increases in oil prices, spurred by rising demand that was satisfied by relatively high-cost exploration and production projects, such as those in ultra-deep water and oil sands, at a time when shortages in everything from skilled labor to steel were driving up costs of even the most basic production projects. An apparent lack of demand

Table 4. Key analyses from "Issues in Focus" in recent AEOs

AEO2008	*AEO2007*	*AEO2006*
Impacts of Uncertainty in Energy Project Costs	*Impacts of Rising Construction and Equipment Costs on Energy Industries*	*Economic Effects of High Oil Prices*
Limited Electricity Generation Supply and Limited Natural Gas Supply Cases	*Energy Demand: Limits on the Response to Higher Energy Prices in the End-Use Sectors*	*Changing Trends in the Refining Industry*
Trends in Heating and Cooling Degree-Days: Implications for Energy Demand	*Miscellaneous Electricity Services in the Buildings Sector*	*Energy Technologies on the Horizon*
Liquefied Natural Gas: Global Challenges	*Industrial Sector Energy Demand: Revisions for Non-Energy-Intensive Manufacturing*	*Advanced Technologies for Light-Duty Vehicles*
World Oil Prices and Production Trends in AEO2008	*Impacts of Increased Access to Oil and Natural Gas Resources in the Lower 48 Federal Outer Continental Shelf*	*Nonconventional Liquid Fuels*
	Alaska Natural Gas Pipeline Developments	*Mercury Emissions Control Technologies*
	Coal Transportation Issues	*U.S. Greenhouse Gas Intensity and the Global Climate Change Initiative*

response to high prices in developing countries, China and India in particular, led to expectations of continuing high oil prices and the bidding up of prices for the inputs needed to increase supply, such as labor, drilling rigs, and other factors. Given the apparent lack of consumer response to price increases, lags in increasing supply, and the limited availability of light crude oils, some analysts believed that a price of $200 per barrel was plausible in the near term.

By July 2008, when world oil prices neared $150 per barrel, it had become apparent that petroleum consumption in the first half of the year was lower than anticipated, and that economic growth was slowing. August saw the beginning of the current global credit crisis and a further weakening of demand; and since September 2008, the global economic downturn has reduced consumers' current and prospective near-term demand for oil while at the same time the global credit crunch has restricted the ability of some suppliers to raise capital for projects to increase future production.

In the second half of 2008, producer and consumer expectations regarding the imbalance of supply and demand in the world oil market were essentially reversed. Before August, market expectations for the future economy indicated that demand would outpace supply despite planned increases in production capacity. After September, expectations became so dismal that OPEC's October 24 announcement of a 1.5-million-barrel-per-day production cut was followed by a drop in oil prices.

Although the impacts of the current economic downturn and credit crisis on petroleum demand are likely to be large in the near term, they also are likely to be relatively short-lived. National economies and oil demand are expected to begin recovering in 2010. In contrast, their impacts on oil production capacity probably will not be realized until the 2010-2013 period, when current new investments in capacity, had they been made, would have begun to result in more oil production. As a result, just at the time when demand is expected to recover, physical limits on production capacity could lead to another wave of price increases, in a cyclical pattern that is not new to the world oil market.

Long-Term Prospects

Developments in past months demonstrate how quickly and drastically the fundamentals of oil prices and the world liquids market as a whole can change. Within a matter of months, the change in current and prospective world liquids demand has affected the perceived need for additional access to conventional resources and development of unconventional liquids supply and reversed OPEC production decisions. The price paths assumed in *AEO2009* cover a broad range of possible future scenarios for liquids production and oil prices, with a difference of $150 per barrel (in real terms) between the high and low oil price cases in 2030. Although even that large difference by no means represents the full range of possible future oil prices, it does allow EIA to analyze a variety of scenarios for future conditions in the oil and energy markets in comparison with the reference case.

Reference Case

The *AEO2009* reference case is a "business as usual" trend case built on the assumption that, for the United States, existing laws, regulations, and practices will be maintained throughout the projection period. The reference case assumes that growth in the world economy and liquids demand will recover by 2010, with growth beginning in 2010 and continuing through 2013, when world demand for liquids surpasses the 2008 level. In the longer term, world economic growth is assumed to be roughly constant, and demand for liquids returns to a gradually increasing long-term trend. As the global recession fades, oil prices (in real 2007 dollars) begin rebounding, to $110 per barrel in 2015 and $130 per barrel in 2030.

Meeting the long-term growth of world liquids demand requires higher cost supplies, particularly from non-OPEC producers, as reflected in the reference case by a 1.1-percent average annual increase in the world oil price after 2015. Increases from OPEC producers will also be needed, but the organization is assumed to limit its production growth so that its share of total world liquids supply remains at approximately 40 percent.

The growth in non-OPEC production comes primarily from increasingly high-cost conventional production projects in areas with inconsistent fiscal or political regimes and from expensive unconventional liquids production projects. The return to historically high price levels would encourage the continuation of recent trends toward "resource nationalism," with foreign investors having less access to prospective areas, less attractive fiscal regimes, and higher exploration and production costs than in the first half of this decade.

Low Price Case

The *AEO2009* low price case assumes that oil prices remain at $50 per barrel between 2015 and 2030. The low price case assumes that free market competition and international cooperation will guide the development of political and fiscal regimes in both consuming and producing nations, facilitating coordination and cooperation between them. Non-OPEC producers are expected to develop fiscal policies and investment regulations that encourage private-sector participation in the development of their resources. OPEC is assumed to increase its production levels, providing 50 percent of the world's liquids in 2030. The availability of low-cost resources in both non-OPEC and OPEC countries allows prices to stabilize at relatively low levels, $50 per barrel in real 2007 dollars, and reduces the impetus for consuming nations to invest in the production of unconventional liquids as heavily as in the reference case.

High Price Case

The *AEO2009* high price case assumes not only that there will be a rebound in oil prices with the return of world economic growth but also that they will continue escalating rapidly as a result of long-term restrictions on conventional liquids production. The restrictions could arise from political decisions as well as resource limitations. Major producing countries, both OPEC and non-OPEC, could use quotas, fiscal regimes, and various degrees of nationalization to increase their national revenues from oil production. In that event, consuming countries probably would turn to high-cost unconventional liquids to meet some of their domestic demand. As a result, in the high price case, oil prices rise throughout the projection period, to a high of $200 per barrel in 2030. Demand for liquids is reduced by the high oil prices, but the demand reduction is overshadowed by severe limitations on access to, and availability of, conventional resources.

Components of Liquid Fuels Supply

In the reference case, total liquid fuels production in 2030 is about 20 million barrels per day higher than in 2007 (Table 5). Decisions by OPEC member countries about investments in new production capacity for conventional liquids, along with limitations on access to non-OPEC conventional resources, limit the increase in production to 11.3 million barrels per day, and their share of total global liquid fuels supply drops from 96 percent in 2007 to 88 percent in 2030.

Global production of unconventional petroleum liquids rises in the reference case. Production from Venezuela's Orinoco belt and Canada's oil sands increases but remains less than is economically viable because of access restrictions in Venezuela and environmental concerns in Canada. As a result, unconventional petroleum liquids production increases by only 3.6 million barrels per day, to 6 percent of global liquid fuels supply in 2030. Relatively high prices also encourage growth in production of CTL, GTL, biofuels, and other nonpetroleum unconventional liquids (which include stock withdrawals, blending components, other hydrocarbons, and ethers) from 1.7 million barrels per day in 2007 to 7.4 million barrels per day (7 percent of total liquids supplied) in 2030.

In the low price case, from 2015 to 2030, oil prices are on average almost 60 percent lower than in the reference case. As described above, a lower price path could be caused by increased access to resources in non-OPEC countries and decisions by OPEC member countries to expand their production. In the low price case, conventional crude oil production rises to 93.6 million barrels per day in 2030, the equivalent of

Table 5. Liquid fuels production in three cases, 2007 and 2030 (million barrels per day)

		2030		
Projection	**2007**	**Reference**	**Low oil price**	**High oil price**
Conventional liquids				
Conventional crude oil and lease condensate	71.0	77.3	93.6	57.7
Natural gas plant liquids	8.0	12.4	11.2	12.1
Refinery gain	2.1	2.7	3.2	2.1
Subtotal	**81.1**	**92.4**	**108.1**	**71.9**
Unconventional liquids				
Oil sands, extra-heavy crude oil, shale oil	2.0	5.6	6.7	6.1
Coal-to-liquids, gas-to-liquids	0.2	1.6	0.8	2.8
Biofuels	1.2	5.4	3.3	7.7
Other	0.3	0.4	0.4	0.4
Subtotal	**3.7**	**13.0**	**11.2**	**17.0**
Total	**84.8**	**105.4**	**119.3**	**88.9**

89 percent of total liquids production in 2030 in the reference case. Total conventional liquids production in the low price case rises above 100 million barrels per day in 2024 and continues upward to 108.1 million barrels per day in 2030.

Production of unconventional petroleum liquids is also higher in the low price case than in the reference case, despite their generally higher costs. The increase is based on assumed changes in access to resources. In the low price case, Venezuela's production of extra-heavy oil in 2030 increases to 3.0 million barrels per day, compared with 1.2 million barrels per day in the reference case—a 150-percent increase that more than compensates for a decrease of 0.5 million barrels per day in production from Canada's oil sands. As a result, total production of unconventional petroleum liquids in 2030 is 1.1 million barrels per day higher in the low price case than in the reference case. Production of CTL, GTL, biofuels, and other unconventional liquids in 2030 (primarily in the United States, China, and Brazil) is 2.9 million barrels per day lower than in the reference case, because the profitability of such projects is reduced.

In the high price case, from 2015 to 2030, oil prices average 56 percent more than in the reference case because of severe restrictions on access to non-OPEC conventional resources and reductions in OPEC production. Conventional liquids production in 2030 is 71.9 million barrels per day, down by 9.2 million barrels per day from 2007 production. Access limitations also constrain production of Venezuelan extra-heavy oil, which in 2030 totals 0.8 million barrels per day, or 0.4 million barrels per day less than in the reference case. Production of unconventional liquids from Canada's oil sands in 2030 is 0.9 million barrels per day higher than in the reference case, however, at 5.1 million barrels per day in 2030, which more than makes up for the decrease in production of extra-heavy oil.

Production of CTL, GTL, biofuels, and other unconventional liquids totals 3.5 million barrels per day more in 2030 in the high price case than in the reference case, primarily because China's CTL production in 2030 is approximately 0.8 million barrels per day more than in the reference case, and Brazil's biofuels production is 1.0 million barrels per day more than in the reference case. In the United States, GTL production starts in 2017 and increases to 0.4 million barrels per day in 2030 in the high oil price case.

Economics of Plug-In Hybrid Electric Vehicles

PHEVs have gained significant attention in recent years, as concerns about energy, environmental, and economic security—including rising gasoline prices—have prompted efforts to improve vehicle fuel economy and reduce petroleum consumption in the transportation sector. PHEVs are particularly well suited to meet these objectives, because they have the potential to reduce petroleum consumption both through fuel economy gains and by substituting electric power for gasoline use.

PHEVs differ from both conventional vehicles, which are powered exclusively by gasoline-powered internal combustion engines (ICEs), and battery-powered electric vehicles, which use only electric motors. PHEVs combine the characteristics of both systems.

Current PHEV designs use battery power at the start of a trip, to drive the vehicle for some distance until a minimum level of battery power is reached (the "minimum state of charge"). When the vehicle has reached its minimum state of charge, it operates on a mixture of battery and ICE power, similar to some hybrid electric vehicles (HEVs) currently in use. In charge-depleting operation, a PHEV is a fully functioning electric vehicle. Some HEVs also can operate in charge-depleting operation, but only for limited distances and at low speeds. Also, PHEVs can be engineered to run in a blended mode of operation, where an onboard computer determines the most efficient use of battery and ICE power.

PHEVs are unique in that their batteries can be recharged by plugging a power cord into an electrical outlet. The distance a PHEV can travel in all-electric (charge-depleting) mode is indicated by its designation. For example, a PHEV-10 is designed to travel about 10 miles on battery power alone before switching to charge-sustaining operation.

Although PHEV purchase decisions may be based in part on concerns about the environment or national energy security, or by a preference for the newest vehicle technology, a comprehensive evaluation of the potential for wide-scale penetration of PHEVs into the LDV transportation fleet requires, among other things, an analysis of economic costs and benefits for typical consumers. In general, consumers will be more willing to purchase PHEVs rather than conventional gasoline-powered vehicles if the economic

benefits of doing so exceed the costs incurred. Therefore, an understanding of the economic benefits and costs of purchasing a PHEV is, in general, a fundamental factor in determining the potential for consumer acceptance that would allow PHEVs to compete seriously in LDV markets.

The major economic benefit of purchasing a PHEV is its significant fuel efficiency advantage over a conventional vehicle (Table 6). The PHEV can use rechargeable battery power over its all-electric range before entering charge-sustaining mode, and its all-electric operation is more energy-efficient than either a conventional ICE vehicle or the hybrid mode of an HEV (or the hybrid operation of the PHEV itself).

On a gasoline-equivalent basis (with electricity efficiency estimated "from the plug") a PHEV's charge-depleting battery system gets on average about 105 mpg, well above even the most efficient petroleum-based ICE. When the PHEV enters charge-sustaining mode, it also takes advantage of its hybrid ICE-battery operation to achieve a relatively efficient 42 mpg. As a result, the total annual fuel expenditures for a PHEV, combining both electricity costs and gasoline, are lower than those of a conventional ICE vehicle using gasoline. The fuel savings are amplified when the PHEV's all-electric range is increased, when gasoline prices are high, or when the difference between gasoline prices and electricity prices increases (Figure 7).

Although the lower fuel costs of PHEVs provide an obvious economic benefit, currently they are significantly more expensive to buy than a comparable conventional vehicle. The price difference results from the costs of the PHEV's battery pack and the hybrid system components that manage the use and storage of electricity. The incremental cost of the battery pack depends on its storage capacity, power output, and chemistry. For example, the electricity storage requirements for a PHEV-40, designed to travel about 40 miles on battery power alone before switching to charge-sustaining operation, are considerably larger than those for a PHEV-10. In terms of power output, PHEV batteries will be engineered to meet the typical performance needs of LDVs, such as acceleration.

Currently two competing chemistries are seen as viable options for PHEV batteries—nickel metal hydride (NiMH) and lithium-ion (Li-Ion)—with different strengths and weaknesses. NiMH batteries are cheaper to produce per kilowatthour of capacity and have a proven safety record; however, their relative weight may limit their use in PHEVs. Li-Ion batteries have the potential to store significantly more electricity in lighter batteries; however, their use in PHEVs currently is limited by concerns about their calendar life, cycle life, and safety. Different vehicle manufacturers have reached different conclusions about which battery chemistry they will use in their initial PHEV offerings, but the majority consensus is that Li-Ion batteries have the most promise for the long term [*51*], and in this analysis they are assumed to be the battery of choice.

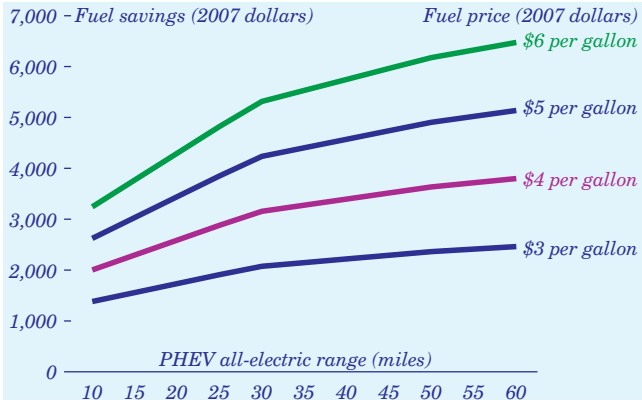
The second cost element associated with PHEVs is the cost of the additional electronic components and hardware required to manage vehicle electrical systems and provide electrical motive power. The

Table 6. Assumptions used in comparing conventional and plug-in hybrid electric vehicles

Characteristics	*Conventional ICE[a]*	*PHEV[b]*
Fuel efficiency (miles per gallon of gasoline equivalent)	*35*	*105 (charge-depleting mode) 42 (charge-sustaining mode)*
Discount rate	*10 percent*	*10 percent*
Discount period	*6 years*	*6 years*
Annual vehicle-miles traveled	*14,000*	*14,000*
Electricity price per kilowatthour	*—*	*$0.10*

[a]Light-duty vehicle with gasoline-powered internal combustion engine.
[b]Light-duty vehicle with lithium-ion battery for charge-depleting mode and hybrid gasoline-powered internal combustion and battery engine for charge-sustaining mode.

Figure 7. Value of fuel saved by a PHEV compared with a conventional ICE vehicle over the life of the vehicles, by gasoline price and PHEV all-electric driving range



conventional vehicle systems on a PHEV may be less costly than those on conventional gasoline vehicles, because the PHEV's engine and (if required) transmission are smaller, but the saving is negated by the additional costs associated with the electric motor, power inverter, wiring, charging components, thermal packaging to prevent battery overheating, and other parts.

An example of the differences in various vehicle system costs (excluding the battery pack) between a PHEV-20, designed to travel about 20 miles on battery power alone before switching to charge-sustaining operation, and a similar conventional vehicle is shown in Table 7 [*52*]. The estimated incremental cost of the PHEV-20 shown in the table represents the combined incremental costs of all vehicle systems other than the battery, at production volumes expected in 2020 or 2030.

The combined costs of the PHEV battery and battery supporting systems together represent the total incremental costs of a PHEV compared to a conventional gasoline vehicle. In the long run, however, the costs of PHEV battery and vehicle systems are not expected to remain static. Successes in research and development are expected to improve battery characteristics and reduce costs over time. In addition, as more Li-Ion batteries and system components are produced, manufacturers are expected to improve production techniques and decrease costs through economies of scale (Figure 8).

Table 7. Conventional vehicle and plug-in electric hybrid system component costs for mid-size vehicles at volume production (2007 dollars)

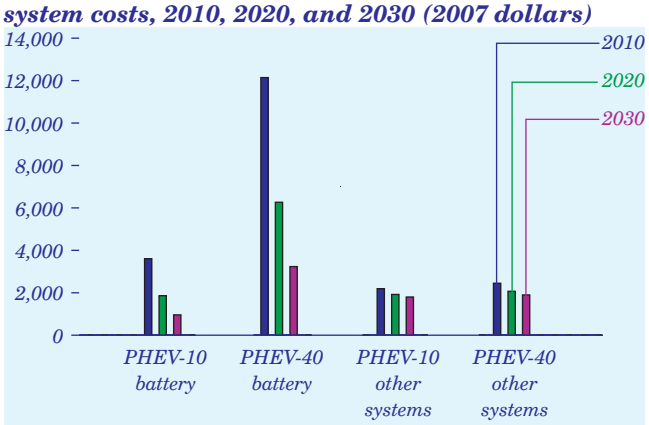
Vehicle component	Conventional ICE	PHEV-20
Engine/exhaust	2,357	1,370
Transmission	1,045	625
Accessory power	210	300
Electric traction	40	1,542
Starter motor	40	—
Electric motor	—	893
Power inverter	—	528
Electronics thermal	—	121
On-vehicle charging system	—	460
Other battery/storage costs	30	809
Fuel storage (tank)	10	10
Accessory battery	20	15
Pack tray	—	170
Pack hardware	—	500
Battery thermal	—	114
Total	**3,682**	**5,106**
PHEV incremental cost	**—**	**1,424**

To incentivize purchases of initial PHEV offerings, the recently passed EIEA2008 grants a tax credit of $2,500 for PHEVs with at least 4 kilowatthours of battery capacity (about the size of a PHEV-10 battery), with larger batteries earning an additional $417 per kilowatthour up to a maximum of $7,500 for light-duty PHEVs, which would be reached at a battery size typical for a PHEV-40 [*53*]. The credit will apply until 250,000 eligible PHEVs are sold or until 2015, whichever comes first.

ARRA2009, which was enacted in February 2009, modifies the PHEV tax credit so that the minimum battery size earning additional credits is 5 kilowatthours and the maximum allowable credit based on battery size remains unchanged at $5,000. ARRA-2009 also extends the number of eligible vehicles from a cumulative total of 250,000 for all manufacturers to more than 200,000 vehicles per manufacturer, with no expiration date on eligibility. After a manufacturer's cumulative production of eligible PHEVs reaches 200,000 vehicles, the tax credits are reduced by 50 percent for the preceding 2 quarters and to 25 percent of the initial value for the preceding third and fourth quarters. ARRA2009 is not considered in *AEO2009*.

As a result of the EIEA2008 tax credit, the combined cost of a PHEV battery and PHEV system in 2010 will be lower than it would be without the credit. Moreover, even after the credit has expired, incentivizing the purchase of PHEVs in the near term will allow both battery and battery-system manufacturers to achieve earlier economies of scale through greater initial sales, thus allowing battery and systems costs to decline more quickly than would have been the case without the tax credit. As a result, the combined incremental costs for PHEVs are expected to be

Figure 8. PHEV-10 and PHEV-40 battery and other system costs, 2010, 2020, and 2030 (2007 dollars)



significantly lower in 2030, when economies of scale and learning have been fully realized (Figure 9).

A typical consumer may be willing to purchase a PHEV instead of a conventional ICE vehicle when the economic benefit of reduced fuel expenditures is greater than the total incremental cost of the PHEV. On that basis, PHEVs face a significant challenge. Even in 2030, the additional cost of a PHEV is projected to be higher than total fuel savings unless gasoline prices are around $6 per gallon (Figure 10). In the meantime, the cost challenge for PHEVs is even greater (Figure 11), which leads to an important problem: if consumers do not choose to buy PHEVs because they are not cost-competitive with conventional vehicles in the near term, then PHEV sales volumes will not be sufficient to induce the economies of scale assumed for this analysis.

In addition to the economic challenge, PHEVs also face uncertainty with respect to Li-Ion battery life and safety [*54*]. Further, they will continue to face competition from other vehicle technologies, including diesels, grid-independent gasoline-electric hybrids, FFVs, and more efficient conventional gasoline vehicles, all of which are likely to become more fuel-efficient in the next 20 years.

Future advances in Li-Ion battery technology could address economic, lifetime, and safety concerns, paving the way for large-scale sales and significant penetration of PHEVs into the U.S. LDV fleet. For example, a technological breakthrough could conceivably allow for smaller batteries with the same capacity and power output, thus lowering incremental costs and making PHEVs attractive on a cost-benefit basis. Also, there are at least two non-economic arguments in favor of PHEVs. First, PHEVs could significantly reduce GHG emissions in the transportation

Figure 9. Incremental cost of PHEV purchase with EIEA2008 tax credit included compared with conventional ICE vehicle purchase, by PHEV all-electric driving range, 2010, 2020, and 2030 (2007 dollars)

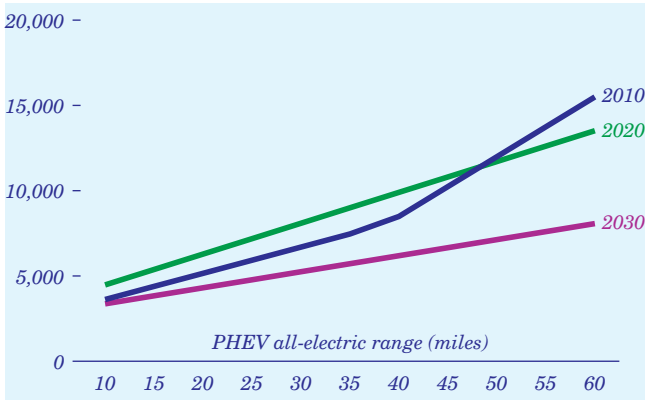


Figure 10. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2030 (2007 dollars)

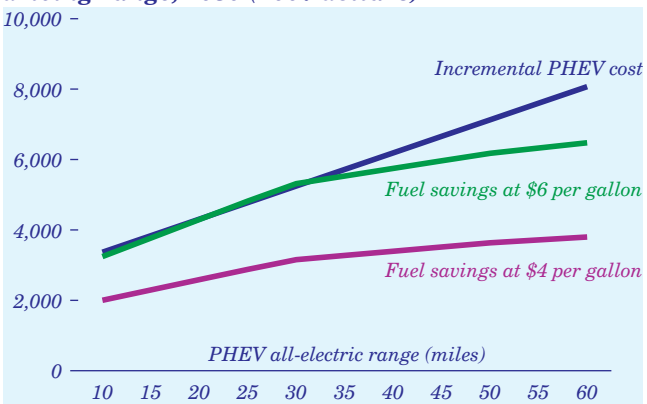


Figure 11. PHEV fuel savings and incremental vehicle cost by gasoline price and PHEV all-electric driving range, 2010 and 2020 (2007 dollars)

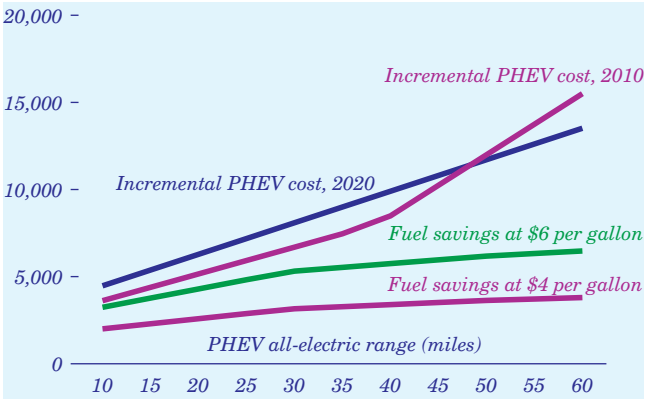
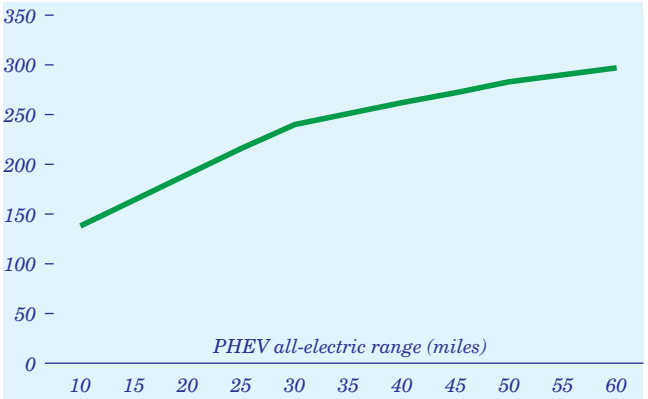


Figure 12. PHEV annual fuel savings per vehicle (gallons) by all-electric driving range



sector, depending on the fuels used to produce electricity. Second, PHEVs use less gasoline than conventional ICE vehicles (Figure 12). If PHEVs displaced conventional ICE vehicles, U.S. petroleum imports could be reduced [*55*].

Impact of Limitations on Access to Oil and Natural Gas Resources in the Federal Outer Continental Shelf

The U.S. offshore is estimated to contain substantial resources of both crude oil and natural gas, but until recently some of the areas of the lower 48 OCS have been under leasing moratoria [*56*]. The Presidential ban on offshore drilling in portions of the lower 48 OCS was lifted in July 2008, and the Congressional ban was allowed to expire in September 2008, removing regulatory obstacles to development of the Atlantic and Pacific OCS [*57*, *58*].

Although the Atlantic and Pacific lower 48 OCS regions are open for exploration and development in the *AEO2009* reference case, timing issues constrain the near-term impacts of increased access. The U.S. Department of Interior, MMS, is in the process of developing a leasing program that includes selected tracts in those areas, with the first leases to be offered in 2010 [*59*]; however, there is uncertainty about the future of OCS development. Environmentalists are calling for a reinstatement of the moratoria. Others cite the benefits of drilling in the offshore. Recently, the U.S. Department of the Interior extended the period for comment on oil and natural gas development on the OCS by 180 days and established other processes to allow more careful evaluation of potential OCS development.

Assuming that leasing actually goes forward on the schedule contemplated by the previous Administration, the leases must then be bid on and awarded, and the wining bidders must develop exploration and development plans and have them approved before any wells can be drilled. Thus, conversion of the newly available OCS resources to production will require considerable time, in addition to financial investment. Further, because the expected average field size in the Pacific and Atlantic OCS is smaller than the average field size in the Gulf of Mexico, a portion of the additional OCS resources may not be as economically attractive as available resources in the Gulf.

Estimates from the MMS of undiscovered resources in the OCS are the starting point for EIA's estimate of the OCS technically recoverable resource. Adding the mean MMS estimate of undiscovered technically recoverable resources to proved reserves and inferred resources in known deposits, the remaining technically recoverable resource (as of January 1, 2007) in the OCS is estimated to be 93 billion barrels of crude oil and 456 trillion cubic feet of natural gas (Table 8). The OCS areas that were until recently under moratoria in the Atlantic, Pacific, and Eastern/Central Gulf of Mexico are estimated to hold roughly 20 percent (18 billion barrels) of the total OCS technically recoverable oil—10 billion barrels in the Pacific and nearly 4 billion barrels each in the Eastern/Central Gulf of Mexico and Atlantic OCS. Roughly 76 trillion cubic feet of natural gas (or 17 percent) is estimated to be in areas formerly under moratoria, with nearly 37 trillion cubic feet in the Atlantic, 18 trillion cubic feet in the Pacific, and 21 trillion cubic feet in the Eastern/Central Gulf of Mexico. It should be noted that there is a greater degree of uncertainty about resource estimates for most of the OCS acreage previously under moratoria, owing to the absence of previous exploration and development activity and modern seismic survey data.

To examine the potential impacts of reinstating the moratoria, an OCS limited case was developed for

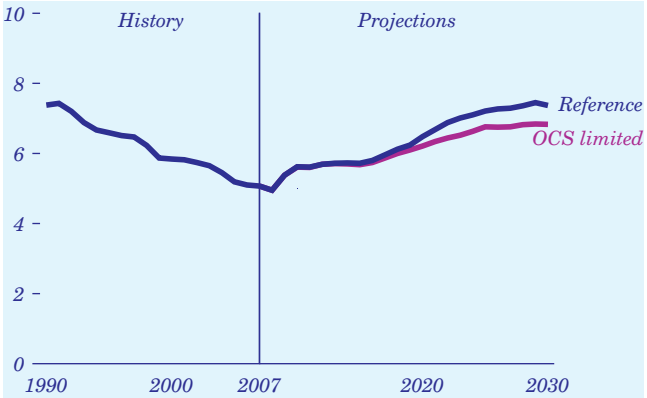
Table 8. Technically recoverable resources of crude oil and natural gas in the Outer Continental Shelf, as of January 1, 2007

Resource area and category	Crude oil (billion barrels)	Natural gas (trillion cubic feet)
Undiscovered resources		
Gulf of Mexico	*34.29*	*183.21*
Eastern and Central Gulf of Mexico (earliest leasing in 2022)	*3.65*	*21.46*
Pacific (earliest leasing in 2010)	*10.50*	*18.43*
Atlantic (earliest leasing in 2010)	*3.92*	*36.50*
Alaska	*26.61*	*132.06*
Total undiscovered	***78.97***	***391.66***
Proved reserves		
Gulf of Mexico	*3.66*	*14.55*
Pacific	*0.44*	*0.81*
Atlantic	*0.00*	*0.00*
Alaska	*0.03*	*0.00*
Total proved reserves	***4.13***	***15.36***
Inferred reserves		
Gulf of Mexico	*9.33*	*48.83*
Pacific	*0.89*	*0.26*
Atlantic	*0.00*	*0.00*
Alaska	*0.00*	*0.00*
Total inferred reserves	***10.21***	***49.09***
Total OCS resources	***93.31***	***456.11***

AEO2009. It is based on the *AEO2009* reference case but assumes that access to the Atlantic, Pacific, and Eastern/Central Gulf of Mexico OCS will be limited again by reinstatement of the moratoria as they existed before July 2008. In the OCS limited case, technically recoverable resources in the OCS total 75 billion barrels of oil and 380 trillion cubic feet of natural gas.

The projections in the OCS limited case indicate that reinstatement of the moratoria would decrease domestic production of both oil and natural gas and increase their prices (Table 9). The impact on domestic crude oil production starts just before 2020 and increases through 2030. Cumulatively, domestic crude oil production from 2010 to 2030 is 4.2 percent lower in the OCS limited case than in the reference case. In 2030, lower 48 offshore crude oil production in the OCS limited case (2.2 million barrels per day) is 20.6 percent lower than in the reference case (2.7 million barrels per day), and total domestic crude oil production, at 6.8 million barrels per day, is 7.4 percent lower than in the reference case (Figure 13).

Figure 13. U.S. total domestic oil production in two cases, 1990-2030 (million barrels per day)



In 2007, domestic crude oil production totaled 5.1 million barrels per day.

With limited access to the lower 48 OCS, U.S. dependence on imports increases, and there is a small increase in world oil prices. Oil import dependence in 2030 is 43.4 percent in the OCS limited case, as compared with 40.9 percent in the reference case, and the total annual cost of imported liquid fuels in 2030 is $403.4 billion, 7.1 percent higher than the projection of $376.6 billion in the reference case. The average price of imported low-sulfur crude oil in 2030 (in 2007 dollars) is $1.34 per barrel higher, and the average U.S. price of motor gasoline price is 3 cents per gallon higher, than in the reference case.

As with liquid fuels, the impact of limited access to the OCS on the domestic market for natural gas is seen mainly in the later years of the projection. Cumulative domestic production of dry natural gas from 2010 through 2030 is 1.3 percent lower in the OCS limited case than in the reference case. Because the volume of technically recoverable natural gas in the OCS areas previously under moratoria accounts for less than 5 percent of the total U.S. technically recoverable natural gas resource base, the impacts for natural gas volumes are smaller, relative to the baseline supply level, than those for oil volumes.

In 2030, dry natural gas production from the lower 48 offshore totals 4.1 trillion cubic feet in the OCS limited case, as compared with 4.9 trillion cubic feet in the reference case. The reduction in offshore supply of natural gas in the OCS limited case is partially offset, however, by an increase in onshore production. Reduced access in the OCS limited case results in higher natural gas prices, which increase the projection for U.S. onshore production in 2030 by 0.2 trillion cubic feet over the reference case projection. The

Table 9. Crude oil and natural gas production and prices in two cases, 2020 and 2030

Projection	Crude oil production (million barrels per day)	Crude oil price (2007 dollars per barrel)	Motor gasoline price (2007 dollars per gallon)	Natural gas production (trillion cubic feet)	Natural gas price (2007 dollars per thousand cubic feet)
2020					
Reference case	6.48	115.45	3.60	21.48	6.75
OCS limited case	6.21	115.56	3.60	21.27	6.83
Difference from reference case	-0.27	0.10	0.00	-0.21	0.08
Percent difference from reference case	-4.2	0.1	0.0	-0.7	1.2
2030					
Reference case	7.37	130.43	3.88	23.60	8.40
OCS limited case	6.83	131.76	3.91	23.00	8.61
Difference from reference case	-0.54	1.34	0.03	-0.60	0.21
Percent difference from reference case	-7.4	1.0	0.8	-2.6	2.5

average U.S. wellhead price of natural gas in 2030 (per thousand cubic feet, in 2007 dollars) is 21 cents higher in the OCS limited case, and net imports increase by 240 billion cubic feet. The higher average wellhead price for natural gas from the lower 48 States in the OCS limited case is associated with a decrease in consumption of 360 billion cubic feet in 2030 relative to the reference case. Total U.S. production of dry natural gas is 210 billion cubic feet less in 2020 and 600 billion cubic feet less in 2030 in the OCS limited case than projected in the reference case (Figure 14).

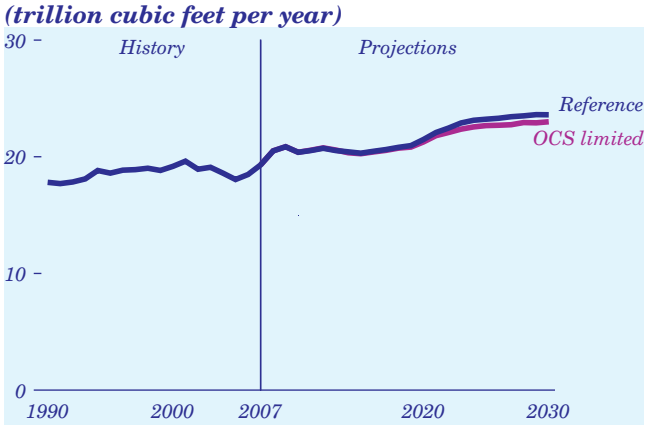
Offshore production, particularly in the OCS, has been an important source of domestic crude oil and natural gas supply, and it continues to be a key source of domestic supply throughout the projections either with or without the restoration of leasing moratoria as they existed before 2008.

Expectations for Oil Shale Production

Background

Oil shales are fine-grained sedimentary rocks that contain relatively large amounts of kerogen, which can be converted into liquid and gaseous hydrocarbons (petroleum liquids, natural gas liquids, and methane) by heating the rock, usually in the absence of oxygen, to 650 to 700 degrees Fahrenheit (*in situ* retorting) or 900 to 950 degrees Fahrenheit (surface retorting) [*60*]. ("Oil shale" is, strictly speaking, a misnomer in that the rock is not necessarily a shale and contains no crude oil.) The richest U.S. oil shale deposits are located in Northwest Colorado, Northeast Utah, and Southwest Wyoming (Table 10). Currently, those deposits are the focus of petroleum industry research and potential future production.

Figure 14. U.S. total domestic dry natural gas production in two cases, 1990-2030 (trillion cubic feet per year)



Among the three States, the richest oil shale deposits are on Federal lands in Northwest Colorado.

The Colorado deposits start about 1,000 feet under the surface and extend down for as much as another 2,000 feet. Within the oil shale column are rock formations that vary considerably in kerogen content and oil concentration. The entire column ultimately could produce more than 1 million barrels oil equivalent per acre over its productive life. To put that number in context, Canada's Alberta oil sands deposits are expected to produce about 100,000 barrels per acre.

The recoverable oil shale resource base is characterized by oil yield per ton of rock, based on the Fischer assay method [*61*]. Table 10 summarizes the approximate recoverable oil shale resource within the three States, based on the relative oil concentration in the oil shale rock. In addition to oil, the estimates include natural gas and natural gas liquids, which make up 15 to 40 percent of the total recoverable energy, depending upon the specific shale rock characteristics and the process used to extract the oil and natural gas. The three States contain about 800 billion barrels of recoverable oil in deposits with expected yields of more than 20 to 25 gallons oil equivalent per ton, which are more attractive economically than deposits with lower concentrations of oil. In comparison, on December 31, 2007, U.S. crude oil reserves were 21 billion barrels, or roughly 2.5 percent of the amount potentially recoverable from oil shale deposits in the three States [*62*].

Oil Shale Production Techniques

Liquids and gases can be produced from oil shale rock by either *in situ* or surface retorting. During the mid-1970s and early 1980s, the petroleum industry focused its efforts primarily on underground mining and surface retorting, which consumes large volumes of water, creates large waste piles of spent shale, and extracts only the richest portion of the oil shale

Table 10. Estimated recoverable resources from oil shale in Colorado, Utah, and Wyoming

Oil concentration (gallons oil equivalent per ton of rock)	Recoverable oil resource (billion barrels oil equivalent)
>10	1,500
>15	1,200
>20	850
>25	750
>30	420
>40	250

formation. There were also some experiments using a "modified *in situ* process," in which rock was mined from the base of the oil shale formation, explosive charges were set in the mined-out area (causing the roof to collapse and fragmenting the rock into smaller masses), and underground fires were set on the rubble to extract natural gas and petroleum liquids. The combustion proved difficult to control, however, and the process produced only low yields of petroleum liquids. Surface subsidence and aquifer contamination were additional issues.

The *in situ* processes now under development raise the temperature of shale formations by using electrical resistance or radio wave heating in wells that are separate from the production wells. Also being considered are "ice walls"—commonly used in construction—both to keep water out of the areas being heated and to keep the petroleum liquids that are produced from contaminating aquifers. The benefits of those methods include uniform heating of the formation; high yields of gas and liquid per ton of rock; production of high-quality liquids that commingle naphtha, distillates, and fuel oil and can be upgraded readily to marketable products; production yields of more than 1 million barrels per acre in some locations; no requirement for disposal and remediation of waste rock; reduced water requirements; scalability, so that additional production can be added readily to an existing project at production costs equal to or less than the cost of the original project; and lower overall production costs. Given these advantages, an *in situ* process is likely to be used if large-scale production of oil shale is initiated.

Although the technical feasibility of *in situ* retorting has been proved, considerable technological development and testing are needed before any commitment can be made to a large-scale commercial project. EIA estimates that the earliest date for initiating construction of a commercial project is 2017. Thus, with the leasing, planning, permitting, and construction of an *in situ* oil shale facility likely to require some 5 years, 2023 probably is the earliest initial date for first commercial production.

Economic Issues

Because no commercial *in situ* oil shale project has ever been built and operated, the cost of producing oil and natural gas with the technique is highly uncertain. Current estimates of future production costs range from at least $70 to more than $100 per barrel oil equivalent in 2007 dollars. Therefore, future oil shale production will depend on the rate of technological progress and on the levels and volatility of future oil prices.

Technology progress rates will determine how quickly the costs of *in situ* oil shale extraction can be brought down and how quickly natural gas and petroleum liquids can be produced from the process. The *in situ* retorting techniques currently available require the production zone to be heated for 18 to 24 months before full-scale production can begin.

In addition to price levels, the volatility of oil prices is particularly important for a high-cost, capital-intensive project like oil shale production, because price volatility increases the risk that costs will not be recovered over a reasonable period of time. For example, if oil prices are unusually low when production from an oil shale project begins, the project might never see a positive rate of return.

Public Policy Issues

Development of U.S. oil shale resources also faces a number of public policy issues, including access to Federal lands, regulation of CO_2 emissions, water usage and wastewater disposal, and the disturbance and remediation of surface lands. If the petroleum industry were not permitted access to Federal lands in the West, especially in Northwest Colorado, the industry would be excluded from the largest and most economical portion of the U.S. oil shale resource base.

In addition, current regulations of the U.S. Bureau of Land Management require that any mineral production activity on leased Federal lands also produce any secondary minerals found in the same deposit. On Federal oil shale lands, deposits of nahcolite (a naturally occurring form of sodium bicarbonate, or baking soda) are intermixed with the oil shales. Relative to oil and other petroleum products, nahcolite is a low-value commodity, and its price would fall even further if its production increased significantly. Thus, co-production of nahcolite could increase the cost of producing oil shale significantly, while providing little revenue in return.

Bringing Alaska North Slope Natural Gas to Market

At least three alternatives have been proposed over the years for bringing sizable volumes of natural gas from Alaska's remote North Slope to market in the lower 48 States: a pipeline interconnecting with the existing pipeline system in central Alberta, Canada;

a GTL plant on the North Slope; and a large LNG export facility at Valdez, Alaska. NEMS explicitly models the pipeline and GTL options [*63*]. The "what if" LNG option is not modeled in NEMS.

This comparison analyzes the economics of the three project options, based on the oil and natural gas price projections in the *AEO2009* reference, high oil price, and low oil price cases. The most important factors in the comparison include expected construction lead times, capital costs, and operating costs. Others include lower 48 natural gas prices, world crude oil and petroleum product prices, interest rates, and Federal and State regulation of leasing, royalty, and production tax rates. Each option also presents unique technological challenges.

Natural Gas Resources and Production Costs

Natural gas exists either in oil reservoirs as associated-dissolved (AD) natural gas or in gas-only reservoirs as nonassociated (NA) natural gas. Of the 35.4 trillion cubic feet of AD gas reserves discovered on the Central North Slope in conjunction with existing oil fields, 93 percent is located in four fields: Prudhoe Bay (23 trillion cubic feet), Point Thomson (8 trillion cubic feet), Lisburne (1 trillion cubic feet), and Kuparak (1 trillion cubic feet) [*64*]. Together, those resources are sufficient to provide 4 billion cubic feet of natural gas per day for a period of 24 years, at an expected average cost of $1.12 per thousand cubic feet (2007 dollars) [*65*]. The cost estimate is relatively low, because an extensive North Slope infrastructure has been built and paid for with revenues from oil production, and because there is considerably less exploration, development, and production risk associated with known deposits of AD natural gas.

Although additional AD natural gas might be discovered offshore or in the Arctic National Wildlife Refuge, most of the "second tier" discoveries in areas to the west and south of the Central North Slope are expected to consist of NA natural gas in gas-only reservoirs. Production costs for gas-only reservoirs are expected to be considerably higher than those for AD natural gas, because they are in remote locations. In addition, the full costs of their development will have to be paid for with revenues from the natural gas generated at the wellhead.

For the first tier of North Slope NA natural gas (29.2 trillion cubic feet) production costs are expected to average $7.91 per thousand cubic feet (2007 dollars). For the second tier, production costs are expected to average $11.03 per thousand cubic feet. Because the cost of producing NA natural gas is substantially greater than the cost of producing AD natural gas, this analysis uses the lower production costs for AD natural gas to evaluate the economic merits of the three facility options examined.

Facility Cost Assumptions

Of the three facility options, the costs associated with an Alaska gas pipeline are reasonably well defined, because they are based on the November 2007 pipeline proposals submitted to the State of Alaska by ConocoPhillips and TransCanada Pipelines, in compliance with the requirements of the Alaska Gasline Inducement Act. Costs associated with GTL and LNG facilities are more speculative, because they are based on the costs of similar facilities elsewhere in the world, adjusted for the remote Alaska location and for recent worldwide increases in construction costs (Table 11).

Key assumptions for all the options analyzed include natural gas feedstock requirements of 4 billion cubic feet per day, natural gas heating values, characteristics of the operations, and State and Federal income tax rates. The time required for planning, obtaining required permits, and facility construction is unique to each facility. Other key assumptions that are unique to each option include the following: for the Alaska pipeline option, the tariff rate for the existing pipeline from Alberta to Chicago and the spot price for natural gas in Chicago; for the LNG facility option, capital and operating costs, including the cost of building a pipeline from the North Slope to liquefaction and storage facilities in Valdez, and the value of LNG delivered in Asia and Valdez (which is contractually tied to oil prices); and for the GTL facility option, the time required to conduct tests to determine whether the Trans Alaska Pipeline System (TAPS) should be operated in batch or commingled mode with GTL, the production level and mix of product, the oil pipeline tariff and tanker rates to U.S.

Table 11. Assumptions for comparison of three Alaska North Slope natural gas facility options

Assumption	*Pipeline option*	*LNG option*	*GTL option*
Natural gas conversion efficiency (percent)	*94*	*80*	*60*
Capital costs (billion 2007 dollars)	*27.6*	*33.9*	*57.5*
Operating costs (million 2007dollars per year)	*263.0*	*392.9*	*894.3*

West Coast refiners, and the price of GTL products relative crude oil prices. The costs of testing and possibly converting TAPS into a batching crude/product pipeline are not included for the GTL option.

Discussion

To compare the economics of the three options, an internal rate of return (IRR) was calculated for each alternative, based on the projected average price of light, low-sulfur crude oil and the projected average price of natural gas on the Henry Hub spot market in the *AEO2009* reference, high oil price, and low oil price cases for the 2011-2020 and 2021-2030 periods (Table 12). The IRR calculations (Figures 15 and 16) assume that the average prices for the period in which a facility begins operation will persist throughout the 20-year economic life of the facility. Projected crude oil prices show considerably more variation across the cases and time periods than do Henry Hub natural gas prices, affecting the relative economics of the three options. In 2030, in the low and high oil price cases, crude oil prices are $50 and $200 per barrel, respectively, and lower 48 natural gas prices are $8.70 and $9.62 per million Btu, respectively (all prices in 2007 dollars).

The *AEO2009* projections show wide variations in oil prices, which are set outside the NEMS framework to reflect a range of potential future price paths. For natural gas prices, variations across the cases are smaller, reflecting the feedbacks in NEMS that equilibrate supply, demand, and prices in the natural gas market model. Natural gas price increases are held in check by declines in demand (especially in the electric power sector) and increases in natural gas drilling, reserves, and production capacity. Conversely, natural gas price declines are held in check by increases in demand and decreases in drilling, reserves, and production capacity. Natural gas prices are also restrained because only a small portion of the natural gas resource base is consumed through 2030, and the marginal cost of natural gas supply increases slowly.

IRRs for the pipeline option respond to natural gas price levels, whereas IRRs for the GTL and LNG options respond to crude oil prices (Figures 15 and 16). From 2021 through 2030, IRRs for the pipeline option vary by 15 to 17 percent across the three price cases, whereas those for the GTL and LNG options vary by 4 to 24 percent and 7 to 27 percent, respectively. On that basis, the pipeline option would be considerably less risky than either the GTL or LNG option. Also, the pipeline would involve significantly less engineering, construction, and operation risk than either of the other options.

The potential viability of an Alaska natural gas pipeline is bolstered by the fact that BP, ConocoPhillips, and TransCanada Pipelines already have committed to building a pipeline. All three have extensive

Table 12. Average crude oil and natural gas prices in three cases, 2011-2020 and 2021-2030

	2011-2020	2021-2030
Oil price (2007 dollars per barrel)		
Reference	*107.32*	*123.26*
High oil price	*154.24*	*193.25*
Low oil price	*51.61*	*50.31*
Natural gas price (2007 dollars per million Btu)		
Reference	*7.04*	*8.21*
High oil price	*7.52*	*8.50*
Low oil price	*6.24*	*7.88*

Figure 15. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2011-2020 (percent)

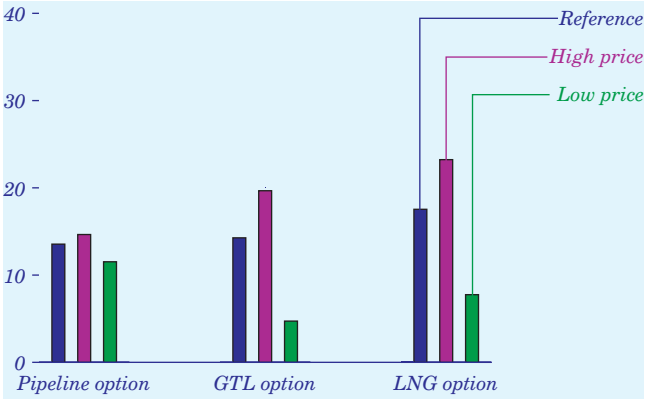
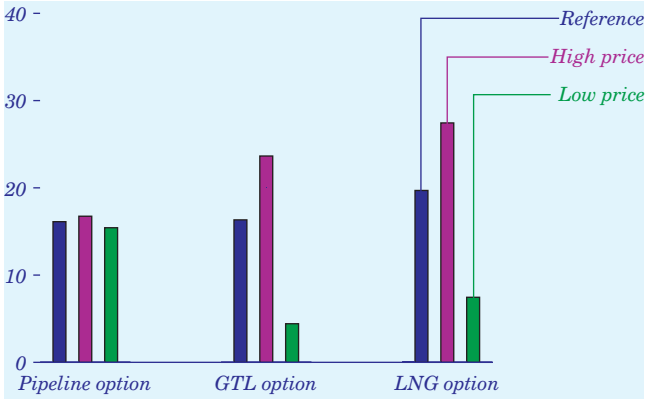


Figure 16. Average internal rates of return for three Alaska North Slope natural gas facility options in three cases, 2021-2030 (percent)



experience in building and financing large-scale energy projects, and both BP and ConocoPhillips have access to substantial portions of the less expensive North Slope AD natural gas reserves. Given that institutional support, along with the prospect for adequate rates of return, the natural gas pipeline option appears to have the greatest likelihood of being built.

Because the GTL option does not include the cost of testing and adapting the existing TAPS oil pipeline to GTL products—which would require third-party cooperation and likely cost reimbursement—the GTL rates of return are overstated. In addition, the GTL results include considerable uncertainty with regard to capital and operating costs and future environmental constraints on GTL plants. Prospects for Alaska GTL facilities are further clouded by the current absence of project sponsors.

Of the three options, an LNG export facility shows the highest rates of return in the reference and high price cases; however, it shows low rates of return in the low price case. The project risk associated with the LNG option is considerably less than that for the GTL option but greater than for the pipeline option. The LNG option is further undermined by the fact that there are large reserves of stranded natural gas elsewhere in the world that have a significant competitive advantage both because of their proximity to large consumer markets and because they would not require construction of an 800-mile supply pipeline through difficult terrain. Although there is definite interest in the LNG export option in Alaska, current advocates of the project have not yet secured letters of intent from potential buyers to purchase the LNG, nor do they have ownership of low-cost AD reserves, extensive experience in the management of large-scale projects, or strong financial backing. Finally, if shale deposits in the rest of the world turn out to be as rich in natural gas as those in the United States, worldwide demand for LNG could be reduced considerably from the levels that were expected just a few years ago.

Other Issues

The analysis described here focused primarily on the relative economics and risks associated with each of three options for a facility to bring natural gas from Alaska's North Slope to market. There are, in addition, a number of other issues that could be important in determining which facility option could proceed to construction and operation, four of which are described briefly below.

Resolving ownership issues for the Point Thomson natural gas condensate field lease. The State of Alaska has revoked the Point Thomson lease from the original leaseholders. Point Thomson holds approximately 8 trillion cubic feet of recoverable natural gas reserves, and without that supply, the existing North Slope AD reserves would be insufficient to supply a natural gas pipeline over a 20-year lifetime. The 35.4 trillion cubic feet of existing AD natural gas reserves on the Central North Slope includes Point Thomson's 8 trillion cubic feet, and without those reserves only 27.4 trillion cubic feet of North Slope gas reserves would be available, providing just 18.8 years of supply for a facility with a capacity of 4 billion cubic feet per day. As long as the ownership issue of the Point Thomson lease remains unresolved, the possibility of pursuing construction of any of the three options is diminished.

Obtaining permits for an Alaska natural gas pipeline in Canada. The pipeline option could encounter significant permitting issues in Canada, similar to those that have already been encountered by the Mackenzie Delta natural gas pipeline, whose construction has been significantly delayed as the result of a failure to secure necessary permits. Because there have been no filings for Canadian permits by any Alaska natural gas pipeline sponsor, the severity of this potential problem cannot be determined.

Exporting Alaska LNG to foreign consumers. Some parties in the United States have called for a halt to current exports of LNG from Alaska to overseas markets. If Alaska were prohibited from exporting LNG to overseas consumers, the financial risk associated with any new Alaska LNG facility would increase significantly, because the financial viability of an LNG facility would be tied solely to lower 48 natural gas prices, which are considerably lower than overseas natural gas prices.

Shipping GTL products through TAPS. The joint ownership structure of TAPS could prevent a minority owner from using the pipeline to ship GTL from the North Slope south to Valdez and on to market.

Conclusion

The *AEO2009* price cases project greater variance in oil prices than in natural gas prices. If those cases provide a reasonable reflection of potential future outcomes, then the pipeline option in this analysis would be exposed to less financial risk than the GTL and LNG options. Additionally, it is the only option that

already has the commitment of energy companies capable of financing and constructing such a large, capital-intensive energy facility. The balance of the factors evaluated here points to an Alaska natural gas pipeline as being the most likely choice for bringing North Slope natural gas to market.

Natural Gas and Crude Oil Prices in *AEO2009*

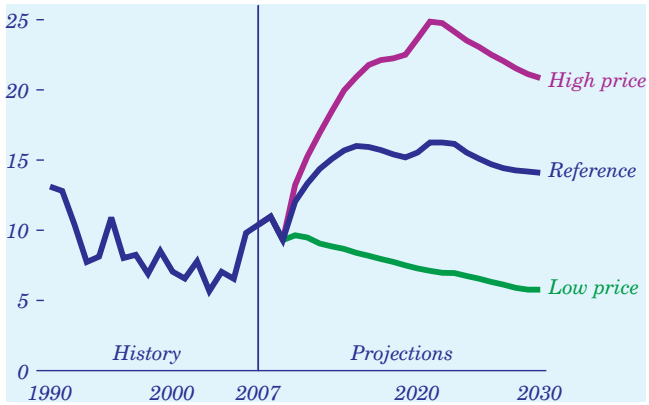
If oil and natural gas were perfect substitutes in all markets where they are used, market forces would be expected to drive their delivered prices to near equality on an energy-equivalent basis. The price of West Texas Intermediate (WTI) crude oil generally is denominated in terms of barrels, where 1 barrel has an energy content of approximately 5.8 million Btu. The price of natural gas (at the Henry Hub), in contrast, generally is denominated in million Btu. Thus, if the market prices of the two fuels were equal on the basis of their energy contents, the ratio of the crude oil price (the spot price for WTI, or low-sulfur light, crude oil) to the natural gas price (the Henry Hub spot price) would be approximately 6.0. From 1990 through 2007, however, the ratio of natural gas prices to crude oil prices averaged 8.6; and in the *AEO2009* projections from 2008 through 2030, it averages 7.7 in the low oil price case, 14.6 in the reference case, and 20.2 in the high oil price case (Figure 17).

The key question, particularly in the reference and high oil price cases, is why market forces are not expected to bring the ratios more in line with recent history. A number of factors can influence the ratio of oil prices to natural gas prices, as discussed below.

Crude Oil and Natural Gas Supply Markets

The methods and costs of transporting petroleum and natural gas are significantly different. The crude oil supply market is an international market, whereas the U.S. natural gas market is confined primarily to North America. In 2007, 43 percent of the oil and petroleum products consumed in the United States came by tanker from overseas sources [*66*]. In contrast, only 3 percent of total U.S. natural gas consumption came from overseas sources, by LNG tanker. Moreover, the domestic resource bases for the two fuels are significantly different. It is expected that lower 48 onshore natural gas resources will play a dominant role in meeting future domestic demand for natural gas, whereas imports of crude oil and petroleum products will continue to account for a significant portion of U.S. petroleum consumption.

Figure 17. Ratio of crude oil price to natural gas price in three cases, 1990-2030



Approximately 180 billion barrels of crude oil reserves and undiscovered resources are estimated to remain in the United States, equal to about 24 years of domestic consumption at 2007 levels; however, with more than 70 percent of those resources located offshore or in the Arctic, they will be relatively expensive to develop and produce [*67*]. The remaining U.S. natural gas resource base is much more abundant, estimated at 1,588 trillion cubic feet or nearly 70 years of domestic consumption at 2007 levels [*68*]. In addition, more than 70 percent of remaining U.S. natural gas resources are located onshore in the lower 48 States, which significantly reduces the cost of new domestic natural gas production.

The large domestic natural gas resource base has been estimated in one study to be sufficient to keep the long-run marginal cost of new domestic natural gas production between $5 and $8 (2007 dollars) per thousand cubic feet through 2030; however, the costs used in that study represent a period when drilling was unusually expensive, because oil and natural gas prices were high. In the future, cost for natural gas development and production could decline significantly as the demand for well drilling equipment and personnel comes into equilibrium with the available supply for those services [*69*].

In the *AEO2009* reference case, which projects a relatively low long-run marginal cost of natural gas, domestic production increasingly satisfies U.S. natural gas consumption. In 2030 more than 97 percent of the natural gas consumed in the United States is produced domestically, yet only 31 percent of the currently estimated U.S. natural gas resource base is produced by 2030. LNG imports remain a relatively small portion of U.S. natural gas supply, with their share peaking in 2018 at 6.5 percent and then falling to 3.5 percent in 2030.

The current opportunities for competition between oil and natural gas are relatively small in the United States (that is, the two U.S. supply markets are weakly linked). Although the relatively low costs projected for production of natural gas make it economically attractive in U.S. consumption markets where it competes with oil, particularly in the reference and high oil price cases, they are not low enough to make the United States a competitive source of natural gas for the world LNG market.

Also, large-scale conversion of lower 48 natural gas into liquid fuels is expected to be precluded by the inability of project sponsors to secure long-term natural gas supply contracts at guaranteed prices and volumes. Natural gas producers are unlikely to be able or willing to guarantee long-term volumes and prices.

Substitution of Natural Gas for Petroleum Consumption

In a relatively high oil price environment, as in the *AEO2009* reference and high oil price cases, consumers can reduce oil consumption through energy conservation and by switching to other forms of energy, such as natural gas, coal, renewables, and electricity. Natural gas is not necessarily the least expensive or quickest option to implement (in comparison with reducing transportation vehicle-miles traveled, for example).

In the residential, commercial, and electric power sectors, petroleum consumption is relatively small, accounting for only 6.5 percent of total U.S. petroleum consumption in 2007. Gradually converting all the petroleum consumption in those sectors to other fuels would have only a modest impact on natural gas consumption and prices.

In the industrial sector, the most feasible opportunity for substituting natural gas for petroleum is in heat and power uses, which amount to about 0.61 quadrillion Btu per year [*70*]; however, most petroleum consumption in the industrial sector (such as diesel and gasoline consumption by off-road vehicles in agricultural and construction activities; petroleum coke; refinery still gas, which is both produced and consumed in refineries; and road asphalt) is not well suited for conversion to natural gas. Also, there is considerable uncertainty about the extent to which petroleum feedstocks for chemical manufacturing could be replaced with natural gas before 2030. At a minimum, considerable downstream investment in chemical manufacturing processes would be required in order to convert to natural gas feedstock.

The greatest potential for large-scale substitution of natural gas for petroleum is in the transportation sector—especially, in local fleet vehicles refueled at a central facility, such as local buses, which consumed 0.18 quadrillion Btu in 2006 [*71*]. Wider use of natural gas as a fuel for transportation fleets also has been advocated; however, the idea faces significant hurdles given the relatively low energy density of natural gas; the cost, size, and weight of onboard storage systems; and the challenge of establishing a refueling infrastructure. In addition, any significant increase in natural gas use could raise natural gas prices sufficiently to reduce the ratio of natural gas prices to oil prices.

The Honda Civic GX and Civic LX-S vehicles provide a uniform basis for comparing the attributes of a natural-gas-fueled LDV (the GX) and a gasoline-fueled LDV (the LX-S) that use the same design platform (Table 13). The Honda GX is about 34 percent more expensive, carries 39 percent less fuel (resulting in a much shorter refueling range of about 200 to 220 miles), and provides 50 percent less cargo space, 19 percent less horsepower, and 15 percent less torque. Although natural gas has a high octane rating of 130, the GX horsepower and torque are reduced by the rate at which natural gas can be injected into the piston cylinders because of its lower energy density.

Although the higher cost and other disadvantages of natural gas vehicles could be offset at least partially

Table 13. Comparison of gasoline and natural gas passenger vehicle attributes

Attribute	*Gasoline-fueled 2009 Honda Civic LX-S*	*Natural-gas-fueled 2009 Honda Civic GX*	*Percent difference*
Sticker price (2007 dollars)	*18,855*	*25,190*	*34*
Curb weight (pounds)	*2,754*	*2,910*	*6*
Fuel tank capacity (gallons)	*13.2*	*8.0*	*-39*
Passenger space (cubic feet)	*90.9*	*90.9*	*—*
Cargo space (cubic feet)	*12.0*	*6.0*	*-50*
Horsepower at 6,300 rpm	*140*	*113*	*-19*
Torque at 4,300 rpm	*128*	*109*	*-15*

by their lower fuel costs, the lack of an extensive natural gas refueling infrastructure will remain a difficult hurdle to overcome. Consumers are unlikely to purchase natural gas vehicles if there is considerable uncertainty as to whether they can be refueled when and where they need to be. Similarly, service station owners are unlikely to install natural gas refueling equipment if the number of natural gas vehicles on the road is insufficient to pay for the infrastructure costs.

In 2008, there were only 778 service stations in the United States with natural gas refueling capability out of a total of more than 120,000 service stations [*72*]. Public refueling capability for natural gas, ethanol, methanol, and electric vehicles has fluctuated considerably over time, as the different vehicle options have gained and lost favor with the public. Even after the more than 15 years that these alternative fuel options have existed, fewer than 1 percent of the Nation's public service stations currently offer refueling capability for any alternative fuel.

Without an extensive public refueling network, the potential for market penetration by natural gas vehicles will be limited, and until a substantial number have been purchased, an extensive public refueling network is unlikely to develop. Market penetration by natural gas vehicles is also limited by the many alternatives that consumers have for reducing vehicle petroleum consumption, including buying smaller vehicles, reducing vehicle-miles traveled, and buying hybrid electric or, potentially, all-electric vehicles. In addition, price volatility in crude oil and natural gas markets obscures the long-term financial viability of natural gas vehicles. Consequently, *AEO2009* assumes that widespread adoption of natural gas vehicles in the United States is unlikely under current laws and policies.

Conclusion

Through 2030, an abundance of low-cost, onshore lower 48 natural gas resources, in conjunction with a limited set of opportunities to substitute natural gas for petroleum, is projected to raise the ratio of oil prices to natural gas prices above the historical range, as reflected in *AEO2009* reference and high oil price cases. Unless there is large-scale growth in the use of natural gas in the transportation sector, it is unlikely that fuel substitution in the other end-use sectors will be sufficient to reduce the price ratio significantly before 2030.

Electricity Plant Cost Uncertainties

Construction costs for new power plants have increased at an extraordinary rate over the past several years. One study, published in mid-2008, reported that construction costs had more than doubled since 2000, with most of the increase occurring since 2005 [*73*]. Construction costs have increased for plants of all types, including coal, nuclear, natural gas, and wind.

The cost increases can be attributed to several factors, including high worldwide demand for generating equipment, rising labor costs, and, most importantly, sharp increases in the costs of materials (commodities) used for construction, such as cement, iron, steel, and copper. Commodity prices continued to rise through most of 2008, but as oil prices dropped precipitously in the last quarter of the year, commodity prices began to decline. The most recent power plant capital cost index published by Cambridge Energy Research Associates (CERA) shows a slight decline in the index over the past 6 months, and CERA analysts expect further declines [*74*].

The current financial situation in the United States will also affect the costs of future power plant construction. Financing large projects will be more difficult, and as the slowing economy leads to lower demand for electricity, the need for new capacity may be limited. The resultant easing of demand for construction materials and equipment could lead to lower costs for materials and equipment when new investment does take place in the future. Fluctuating commodity prices, combined with the uncertain financial environment, increase the challenge of projecting future capital costs.

Because some plant types—coal, nuclear, and most renewables—are much more capital-intensive than others (such as natural gas), the mix of future capacity builds and fuels used can differ, depending on the future path of construction costs. If construction costs increase proportionately for all plant types, natural-gas-fired capacity will become more economical than more capital-intensive technologies. Over the longer term, higher construction costs are likely to lead to higher energy prices and lower energy consumption.

The *AEO2009* version of NEMS includes updated assumptions about the costs of new power plant construction. It also assumes that power plant costs will be influenced by the real producer price index for

metals and metal products, leading to a decline in base construction costs in the later years of the projections. As sensitivities to the *AEO2009* reference case, several alternative cases assuming different trends in capital costs for power plant construction were used to examine the implications of different cost paths for new power plant construction.

Power Plant Capital Cost Cases

For the *AEO2009* reference case, initial capital costs for new generating plants were updated on the basis of costs reported in late 2007 and early 2008. The reference case cost assumptions reflect an increase of roughly 30 percent relative to the cost assumptions used in *AEO2008*, and they are roughly 50 percent higher than those used in earlier *AEO*s. Because there is a strong correlation between rising power plant construction costs and rising commodity prices, construction costs in *AEO2009* are tied to a producer price index for metals and metal products. The nominal index is converted to a real annual cost factor, using 2009 as the base year. The resulting reference case cost factor remains nearly flat for the next few years, then declines by a total of roughly 15 percent to the end of the projection in 2030. As a result, future capital costs are lower even before technology learning adjustments are applied. The same cost factor is applied to all technology types.

Although the correlation between construction costs and the producer price index for metals has been high in recent years, it is possible that costs could be affected by other factors in the future. There is also uncertainty in the metals index forecast, as with any projection. Therefore, the sensitivity cases do not use the metals index to adjust plant costs but instead use exogenous assumptions about future cost adjustment factors to provide a range of cost assumptions.

In the frozen plant capital costs case, base overnight construction costs for all new electricity generating technologies are assumed to remain constant at 2013 levels (which is when the cost factor peaks in the reference case). Because cost decreases still can occur as a result of technology learning, costs do decline slightly from 2013 to 2030 in the frozen costs case. In 2030, costs for all technologies are roughly 20 percent higher than in the reference case.

In the high plant capital costs case, base overnight construction costs for all new generating plants are assumed to continue increasing throughout the projection, by assuming that the cost factor increases by 25 percentage points from 2013 to 2030. Again, cost decreases still can occur as a result of technology, partially offsetting the increases. For most technologies, however, costs in 2030 are above current costs. Plant construction costs in 2030 in the high plant capital costs case are about 50 percent higher than in the reference case.

In the falling plant capital costs case, base overnight construction costs for all generating technologies fall more rapidly than in the reference case, starting in 2013. In 2030, the cost factor is assumed to be 25 percentage points below the reference case value.

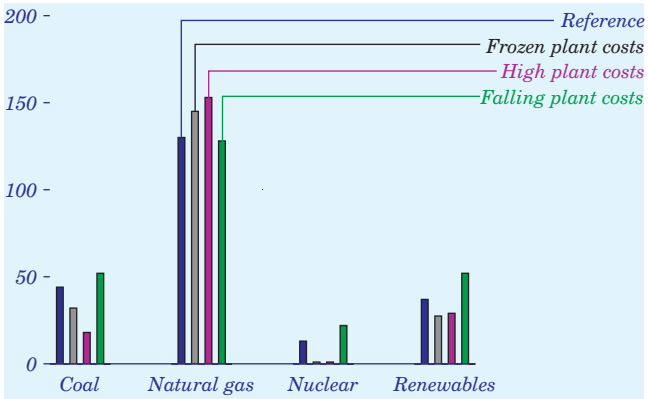
Results

Capacity Additions

Overall capacity requirements, as well as the mix of generating types, change across the alternative plant cost cases. In the reference case, 259 gigawatts of new generating capacity is added from 2007 to 2030. In the frozen and high plant costs cases, capacity additions fall to 247 gigawatts and 237 gigawatts, respectively. In the falling plant costs case, additions increase to 288 gigawatts.

In all the plant costs cases, the vast majority of new capacity is fueled by natural gas, in part because coal, nuclear, and renewable technologies are more capital-intensive; however, the fuel shares of total builds do differ among the cases (Figure 18). Coal-fired plants make up 18 percent of all the new capacity built in the reference case through 2030. Across the alternative cases, their share ranges from 9 percent to 20 percent. In the frozen plant costs and high plant costs cases, no nuclear capacity is built beyond the 1.2 gigawatts of planned additions. In the falling plant

Figure 18. Cumulative additions to U.S. electricity generation capacity by fuel in four cases, 2008-2030 (gigawatts)



costs case, more than 20 gigawatts of nuclear capacity is built. Renewable capacity makes up a 22-percent share of all new capacity built in the reference case; the renewable share remains between 21 and 22 percent in the high plant costs and frozen plant costs cases and increases to 25 percent in the falling plant costs case.

Electricity Generation and Prices

Differences among the projections for generation fuel mix in the different cases are not as large as the differences in the projections for capacity additions, because the construction cost assumptions do not affect the operation of existing capacity. Coal maintains the largest share of total generation through 2030, ranging from 44 percent to 47 percent in 2030 across the four cases (Figure 19). The renewable share in 2030 is nearly the same in all the cases, from 14 percent to 15 percent, because all the cases assume that the same State and regional RPS goals must be met. In the frozen and high plant costs cases, biomass co-firing is used predominantly to meet RPS requirements, rather than investment in new renewable capacity. In the falling plant costs case, generation from biomass co-firing is less than projected in the reference case, and wind generation provides more of the renewable requirement.

Nuclear generation provides 18 percent of total generation in 2030 in the reference case, compared with 16 percent in the frozen and high plant costs cases and 19 percent in the falling plant costs case. Natural-gas-fired generation, typically the source of marginal electricity supply, follows an opposite path, increasing by 22 percent from the reference case projection in 2030 in the high plant costs case and by 14 percent in the frozen plant costs case, and decreasing by 11 percent in the falling plant costs case. As a result, delivered natural gas prices vary among the different cases, increasing by as much as 10 percent from the reference case projection in the high plant costs case and decreasing by 6 percent in the falling plant costs case. Electricity prices in 2030, following the trend in natural gas prices, are 5 percent higher than the reference case projection in the high plant costs case (where electricity prices also rise in response to higher construction costs) and 5 percent lower than the reference case projection in the falling plant costs case (Figure 20).

Tax Credits and Renewable Generation

Background

Tax incentives have been an important factor in the growth of renewable generation over the past decade, and they could continue to be important in the future. The Energy Tax Act of 1978 (Public Law 95-618) established ITCs for wind, and EPACT92 established the Renewable Electricity Production Credit (more commonly called the PTC) as an incentive to promote certain kinds of renewable generation beyond wind on the basis of production levels. Specifically, the PTC provided an inflation-adjusted tax credit of 1.5 cents per kilowatthour for generation sold from qualifying facilities during the first 10 years of operation. The credit was available initially to wind plants and facilities that used "closed-loop" biomass fuels [*75*] and were placed in service after passage of the Act and before June 1999.

The 1992 PTC has lapsed periodically, but it has been renewed before or shortly after each expiration date, typically for an additional 1- or 2-year period. In addition, eligibility has been extended to generation from many different renewable resources [*76*], including

Figure 19. Electricity generation by fuel in four cases, 2007 and 2030 (billion kilowatthours)

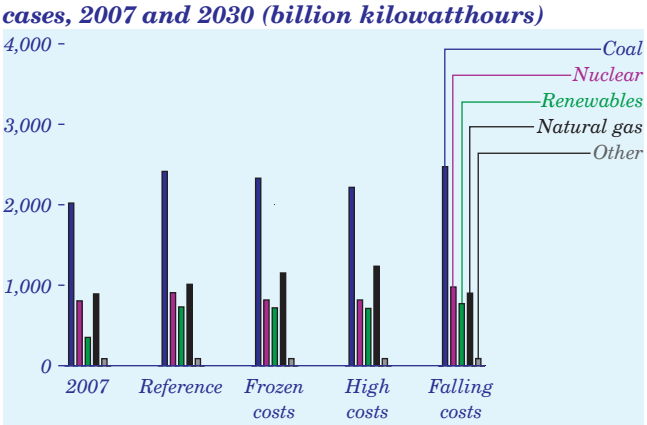
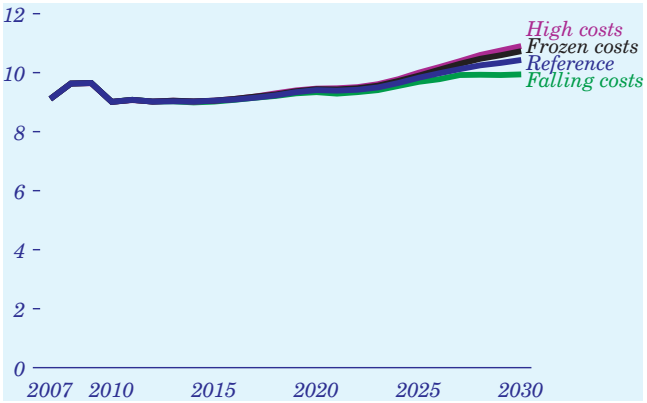


Figure 20. Electricity prices in four cases, 2007-2030 (2007 cents per kilowatthour)

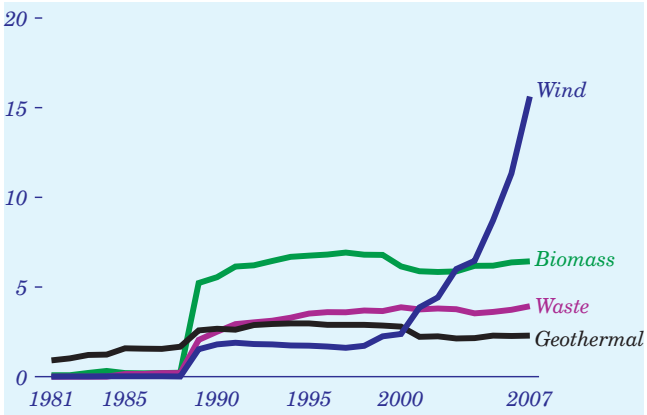


poultry litter, geothermal energy [*77*], certain hydroelectric facilities [*78*], "open-loop" biomass [*79*], landfill gas, and, most recently, marine energy resources. Open-loop biomass and landfill gas currently receive one-half the PTC value (1 cent rather than the current inflation-adjusted 2 cents available to other eligible resources). Eligibility of new projects for the PTC was set to expire at the end of 2008, but it was extended to December 31, 2009, for wind capacity and to December 31, 2010, for other eligible renewable facilities [*80*].

As this publication was being prepared, the PTC was further extended and modified by ARRA2009, which extends eligibility for the PTC to December 31, 2012, for wind projects and to December 31, 2013, for all other eligible renewable resources. In addition, project owners may elect to receive a 30-percent ITC in lieu of the PTC, and may further elect to receive an equivalent grant in lieu of the ITC. Project owners electing the grant must commence their projects during 2009 or 2010. These recently passed provisions are not included in *AEO2009*.

The PTC has contributed significantly to the expansion of the wind industry over the past 10 years. Since 1998, wind capacity has grown by an average of more than 25 percent per year (Figure 21). Although some of the more recent growth may be attributable to State programs, especially the mandatory RPS programs now in effect in 28 States and the District of Columbia, the importance of the PTC is evidenced by the growth of wind power installations in States without renewable mandates, either today or at the time the installations were constructed, and by the significant drop in new wind installations during periods when the PTC has been allowed to lapse.

Figure 21. Installed renewable generation capacity, 1981-2007 (gigawatts)



Although other renewable generation facilities, such as geothermal or poultry litter plants, have been able to claim the PTC, none has grown as dramatically as wind power. Possible explanations for their slower rate of expansion include longer construction lead times and less favorable economics for some facilities. In addition, some provisions of the PTC may limit its ability to be used fully or efficiently for some projects. For example, project owners that do not pay Federal income taxes (such as municipal utilities and rural electric cooperatives) cannot claim the PTC, even though they may be eligible for other Federal assistance. Also, the owners of for-profit projects must have sufficient tax liability to claim the full PTC, and their eligibility for PTC payments may be limited by the Federal alternative minimum tax law.

The wind industry, in particular, has developed several alternative ownership and finance structures to help minimize the impact of the limitations [*81*]. There is some evidence, however, that the restrictions reduce the value of the PTC to project owners. In addition, the financial crisis of 2008 may exacerbate the problems for some projects [*82*]. As part of ARRA2009, developers may, for a limited time, convert the PTC into a 30-percent ITC and then into a grant. This provision may lessen the impact of the financial crisis on the ability of wind developers to use the PTC. As noted above, the provisions of ARRA2009 are not included in *AEO2009*.

Future Impacts

Because *AEO2009* represents only those laws and policies in effect on or before November 4, 2008, the renewable energy PTC is assumed to expire at the end of 2009 for wind and at the end of 2010 for other eligible renewables; however, the program has a long history of renewal and extension, and there is considerable interest, both in Congress and in the renewable energy industry, in keeping the credit available over the longer term, as seen in the recent extension to 2013.

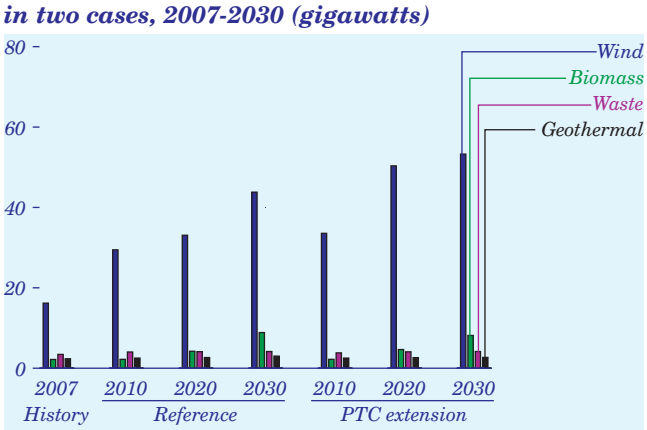
To examine the potential impacts of a PTC extension, *AEO2009* includes a production tax credit extension case that examines the potential impacts of extending the current credit through 2019. Because EIA does not develop or advocate policy, the PTC extension case is included here only to assess the potential impacts of such an extension and should not be construed as a proposal for, or endorsement of, any legislative action.

Aside from the expiration date, no changes in current PTC provisions are assumed in the PTC extension case. The credit is valued at 2 cents per kilowatthour (in 2008 dollars, adjusted for projected inflation rates) for wind, geothermal, and hydroelectric generation and at 1 cent per kilowatthour for biomass and landfill gas [*83*]. It is assumed that all eligible facilities will receive the credit for the first 10 years of plant operation, and that they will use the credit efficiently and completely, without further modification of the law. The extension is assumed to be continuous over the 10-year period and not subject to the periodic cycle of expiration and renewal that has affected the PTC in the past.

For wind power installations, a 10-year extension of the PTC results in significantly more capacity growth than in the reference case (Figure 22). In the near term, capacity increases would be comparable to those seen over the past several years, followed by a period of several years in which the capacity expansion is slower, corresponding to a projected lull in electricity demand growth. Significant additional growth in wind capacity occurs thereafter, before the assumed 2019 expiration date, with total capacity increasing to approximately 50 gigawatts in 2020, as compared with 33 gigawatts in the reference case. Additional capacity expansion occurs after 2020 in both cases, particularly in the reference case, where 11 gigawatts of installed capacity is added from 2020 to 2030 as compared with 2 gigawatts in the PTC extension case.

For eligible technologies other than wind, no significant changes in capacity installations are projected in the PTC extension case relative to the reference case. In part, this may be a result of the shorter lead times associated with wind technology: wind plants can be built before the projected slowdown in electricity demand growth after 2010, potentially "crowding out" other PTC-eligible investments. In addition, the economics for wind installations are fundamentally more favorable than for other PTC-eligible resources, and the resource base for wind power is more widespread.

Figure 22. Installed renewable generation capacity in two cases, 2007-2030 (gigawatts)



Because eligible renewable generation still accounts for a relatively small share of total U.S. electricity generation, the PTC extension case has relatively minor impacts outside the markets for renewable generation. A 10-year extension of the PTC reduces average electricity prices in 2020 by approximately 1 percent relative to the reference case. The extension costs the Federal Government approximately $7.7 billion from 2010 to 2019 (in 2007 dollars) [*84*], while cumulative savings on electricity expenditures from 2010 to 2019 total about $13 billion in comparison with the reference case.

Total electricity generation in 2020 in the PTC extension case is less than 0.5 percent greater than in the reference case. The increase in wind-powered electricity generation in the PTC extension case primarily offsets the use of natural gas in the power sector, reducing natural-gas-fired generation by about 5 percent in 2020 compared to the reference case. Impacts on other generation fuels generally are less than 1 percent. The maximum reduction in CO_2 emissions from the electric power sector (occurring before 2020) is about 0.5 percent compared to the reference case.

Greenhouse Gas Concerns and Power Sector Planning

Background

Concerns about potential climate change driven by rising atmospheric concentrations of GHGs have grown over the past two decades, both domestically and abroad. In the United States, potential policies to limit or reduce GHG emissions are in various stages of development at the State, regional, and Federal levels. In addition to ongoing uncertainty with respect to future growth in energy demand and the costs of fuel, labor, and new plant construction, U.S. electric power companies must consider the effects of potential policy changes to limit or reduce GHG emissions that would significantly alter their planning and operating decisions. The possibility of such changes may already be affecting planning decisions for new generating capacity.

California and 10 States in the Northeast are moving forward with mandatory emissions reduction programs. For 10 Northeastern States, 2009 is the inaugural year of the RGGI, a cap-and-trade program for power plant emissions of CO_2 [*85*]. RGGI sets a cap of 188 million metric tons CO_2 in 2009 for power generating facilities with rated capacity greater than 25 megawatts and lowers that cap annually to 169 million metric tons in 2018. Although RGGI represents the first legally binding regulation of CO_2 emissions in the United States and will influence future decisions about investments in generating capacity, its overall impact is expected to be modest. In 2006, CO_2 emissions from power plants covered by RGGI accounted for only 7 percent of the CO_2 emitted from all U.S. power plants, and their total 2006 emissions—at 164 million metric tons—already were below the 2018 goal of 169 million metric tons.

Other regional initiatives also are being developed. The WCI consists of seven Western U.S. States and four Canadian Provinces [*86*]. A draft rule released in July 2008 aims at an economy-wide cap on six GHGs, including CO_2. The cap level and details of the program design still are being developed. In November 2007, the governors of 10 Midwestern States signed the Midwestern Greenhouse Gas Reduction Accord [*87*], currently in the preliminary stages of development, with the broad goal of creating a multi-sector, interstate cap-and-trade program for the member States.

At the State level, 37 individual States have released State-specific climate change mitigation plans; however, the only legally binding requirements outside the RGGI States are in California, which has passed Assembly Bill (A.B.) 32, the Global Warming Solutions Act of 2006 [*88*]. A.B. 32 aims to reduce the State's GHG emissions to 1990 levels by 2020. Although specific regulations associated with A.B. 32 remain to be finalized, the law requires that policies be designed to meet the reduction targets.

At the national level, numerous bills to reduce GHGs have been introduced in the U.S. Congress in recent years. As of July 2008, a total of 235 bills, amendments, and resolutions addressing climate change in some form had been introduced in the 110th Congress. Nine of the bills—three in the House and six in the Senate—specifically proposed a cap-and-trade system for CO_2 and other GHGs. Of the nine, the Boxer-Lieberman-Warner Climate Security Act (S. 3036) progressed the farthest, reaching the floor of the Senate in June 2008 [*89*].

Even without the enactment of national emissions limits, many State utility regulators and the banks that finance new power plants are requiring assessments of GHG emissions for new projects. For example, many State public utility commissions now are requiring that utilities review projected CO_2 emissions in their integrated resource plans (IRPs) [*90*]. The IRP process is intended to keep public utility regulators at the State level informed of their utilities' strategies to meet future demand and supply. The treatment of projected CO_2 emissions has differed among utilities. Some have included an emissions price in their base case scenarios; others have done so in alternative scenarios. Typically, the emissions prices used have ranged from $5 to $80 per metric ton.

Several major banks in the United States also have decided to include future CO_2 emissions as a factor in their decisionmaking processes for financing of new power plants. In February 2008, Citibank, JPMorgan Chase, and Morgan Stanley announced the formation of "The Carbon Principles," which provide climate change guidelines for advisors and lenders to power companies in the United States [*91*]. Adopters of the principles would commit to:

- Encourage clients to pursue cost-effective energy efficiency, renewable energy, and other low-carbon alternatives to conventional generation, taking into consideration the potential value of avoided CO_2 emissions
- Ascertain and evaluate the financial and operational risk to fossil fuel generation financings posed by the prospect of domestic CO_2 emissions controls through the application of an "Enhanced Diligence Process," and use the results of this diligence as a contribution to the determination whether a transaction is eligible for financing and under what terms
- Educate clients, regulators, and other industry participants regarding the additional diligence required for fossil fuel generation financings, and encourage regulatory and legislative changes consistent with the principles.

Reflecting Concerns Over Greenhouse Gas Emissions in AEO2009

Key questions in the development of the *AEO2009* projections included the degree to which ongoing debate about potential climate change policies, together with the actions taken by State regulators and the financial community, already are affecting

planning and operating decisions in the electric power sector, and how best to capture those impacts in the analysis. Although existing plants continue to be operated on a least-cost basis without adjustments for GHG emissions levels, concerns about GHG emissions do appear to be having an impact on decisions about new plants.

When regulators and banks are reviewing the projected GHG emissions of new plants in their investment evaluation process, they are implicitly adding a cost to some plants, particularly those that involve GHG-intensive technologies. The implicit cost could be represented by adding an amount to the operating costs of plants that emit CO_2 to reflect the value of emissions; however, doing so would affect not only planning decisions for new capacity but also future utilization decisions for all plants—something that does not appear to be occurring on a widespread basis in markets today.

Alternatively, the costs of building and financing new GHG-intensive capacity could be adjusted to reflect the implicit costs being added by utilities, their regulators, and the financial community. This option better reflects current market behavior, which is focused on discouraging power companies from investing in high-emission technologies. As a result, in the *AEO2009* reference case, a 3-percentage-point increase is added to the cost of capital for investments in GHG-intensive technologies, such as coal-fired power plants without CCS and CTL plants.

Although the 3-percentage-point adjustment is somewhat arbitrary, its impact in levelized cost terms is similar to that of a $15 fee per metric ton of CO_2 for investments in new coal-fired power plants without CCS—well within the range of the results of simulations that utilities and regulators have prepared. The adjustment should be seen not as an increase in the actual cost of financing but rather as representing the implicit costs being added to GHG-intensive projects to account for the possibility that, eventually, they may have to purchase allowances or invest in other projects that offset their emissions.

Two alternative cases were prepared to show how the representation of investment behavior in the electric power sector affects the *AEO2009* reference case projections, given uncertainty about the evolution of potential GHG policies. In the no GHG concern case, the cost-of-capital adjustment for GHG-intensive technologies is removed to represent a future in which concern about GHG emissions wanes or efforts to implement GHG reduction regulations subside. This case reflects an approach similar to that used for the reference case in past *AEO*s. In the LW110 case, the GHG emissions reduction policy called for in S. 2191, the Lieberman-Warner Climate Security Act of 2007 introduced in the 110th Congress, is analyzed [*92*]. This case illustrates a future in which an explicit Federal policy limiting GHG emissions is enacted, affecting both planning and operating decisions.

Because the projected impact of any policy to reduce GHG emissions will depend on its detailed specifications—which may differ significantly from those in the LW110 case—results from the LW110 case do not apply to other past or future policy proposals. Rather, projections in the two alternative cases illustrate the potential importance to the electric power industry of GHG policy changes, and why uncertainty about such changes weighs heavily on planning and investment decisions.

Findings

The imposition of a GHG reduction policy would affect all aspects of the electric power industry, including decisions about the types of plants built to meet growing electricity demand, the fuels used to generate electricity, the prices consumers will pay in the future, and GHG emissions from electric power plants.

Capacity

Generating capacity investment decisions in the two sensitivity cases differ from those in the *AEO2009* reference case (Figure 23). The overall amounts of new capacity added in the reference case and the no GHG concern case are similar, but there are differences in the mix of plant types built. New coal builds without CCS are higher in the no GHG concern case than in the reference case, as the concern that new regulations might be coming dampens investment in new coal-fired plants in the reference case. On the other hand, new natural-gas-fired plants, which are not as GHG-intensive, are more attractive economically in the reference case. In an environment of uncertainty about future regulation of CO_2 emissions, natural gas becomes the primary choice for new capacity additions; without such uncertainty, coal remains the primary choice. Concern about possible new regulations plays a role in the construction of a modest amount of nuclear power and renewable energy capacity in the reference case, but other incentives also influence their selection. It is unclear whether utilities would be willing to incur the high

costs of building new nuclear plants in the absence of concerns about potential GHG regulations.

The cap-and-trade policy adopted in the LW110 case changes the mix of capacity additions significantly relative to the other cases. The adjusted cost of capital in the reference case increases the cost of building new GHG-intensive facilities but does not change the cost of operating those plants already in service or new plants once they are built. The introduction of an explicit cap on GHG emissions adds a cost to the emissions generated from existing and new facilities, making carbon-intensive coal-fired plants more expensive to build and operate. As a result, approximately 35 percent of the existing fleet of coal-fired plants is retired by 2030 in the LW110 case, and 33 percent more new capacity is added than in the reference case, replacing the retired capacity. The explicit GHG emission constraint results in the construction of a different mix of new capacity additions, with new nuclear power, renewables, and coal with CCS making up a majority of the capacity added. The new capacity additions lead to a significantly different portfolio of generation assets and generation by fuel in 2030.

The results show that implementation of the LW110 case would lead to greater use of coal with CCS, nuclear, and renewable capacity; however, there is significant uncertainty around the projections. New coal-fired plants with CCS equipment have not been fully commercialized, and it is unclear when they might be and what they would cost. Similarly, a rapid expansion of nuclear capacity also would present challenges, including uncertainty both about the cost of the plants and about public acceptance of them. There also may be limits to a rapid expansion of renewable generation, because many of the best resources are located far from electricity load centers. Previous EIA analysis has found that, if the expansion is limited, the electricity industry may rely more heavily on new natural-gas-fired plants to reduce GHG emissions, leading to higher allowance costs and higher electricity prices [*93*].

Generation by Fuel

Among the three cases examined, total electricity generation in 2030 is lowest in the LW110 case (Figure 24 and Table 14). The explicit cap raises the price of electricity, which over time slows the growth in demand for electricity, lowering generation requirements. The opposite is true in the no GHG concern case, where lower electricity prices stimulate higher demand for electricity and increase generation requirements. Generation from coal drops the most in the LW110 case. Relative to the *AEO2009* reference case, the explicit GHG emission cap reduces the total amount of electricity generated from all coal-fired plants by 33 percent and the amount from coal-fired plants without CCS by 68 percent in 2030, as older coal plants are retired and the marginal costs of units still operating, which must hold allowances, are higher. Despite their high initial capital costs, new coal-fired units with CCS are less expensive to operate than traditional coal-fired plants without CCS, given a tight constraint on CO_2 emissions. The shares of renewables and nuclear power in the generation mix also increase significantly in the LW110 case, as low-emissions technologies are added to meet the growing demand for electricity.

Electricity Prices

Projected electricity prices are lowest in the no GHG concern case, where there is no cap on emissions, and coal-fired plants with relatively low fuel costs

Figure 23. Cumulative additions to U.S. generating capacity in three cases, 2008-2030 (gigawatts)

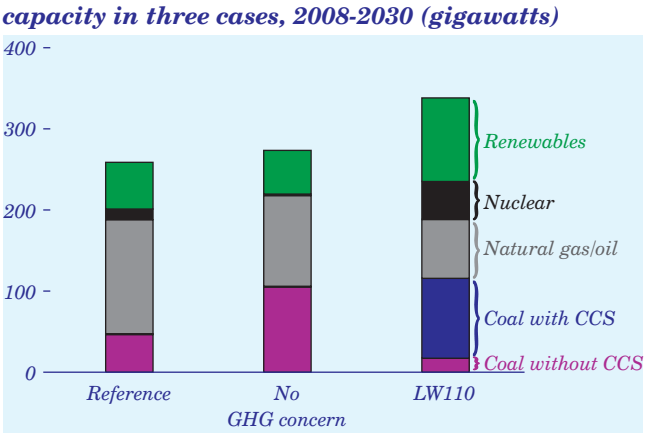
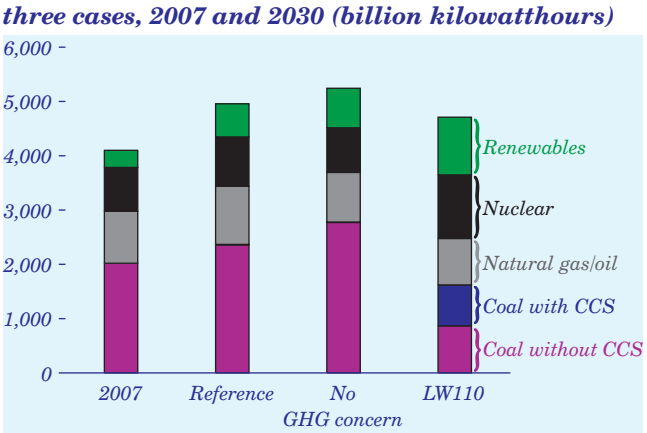


Figure 24. U.S. electricity generation by source in three cases, 2007 and 2030 (billion kilowatthours)



continue to dominate the mix of generation (Figure 25). Greater reliance on natural gas in the reference case leads to higher electricity prices when construction of carbon-intensive facilities, including coal-fired plants, is dampened because of uncertainty about possible GHG regulations.

An explicit cap on GHG emissions adds an additional cost to the generation of electricity from CO_2-emitting sources. To lower emissions in the LW110 case, the industry turns to more expensive resources and allowance purchases to cover remaining emissions. Therefore, electricity generated from fossil fuels becomes more expensive, while higher priced low-emitting sources, such as nuclear, renewables, and coal with CCS, become more cost-competitive. As a result, the cost of generating electricity increases. In 2030, the price of electricity is 22 percent higher in the LW110 case than in the reference case and 26 percent higher than in the no GHG concern case.

Emissions

The electric power sector is expected to play a major role in any effort to reduce GHG emissions in the United States (Figure 26). The sector accounted for 41 percent of energy-related CO_2 emissions in 2007, and its emissions are projected to grow. On the other hand, a wide array of fuels and technologies with

Table 14. Summary projections for alternative GHG cases, 2020 and 2030

		2020			2030		
State	2007	Reference	No GHG concern	LW110	Reference	No GHG concern	LW110
Delivered energy prices (2007 dollars per unit)							
Motor gasoline (per gallon)	2.80	3.60	3.59	3.85	3.88	3.79	4.37
Jet fuel (per gallon)	2.17	2.99	2.97	3.30	3.32	3.24	3.95
Diesel (per gallon)	2.74	3.47	3.44	3.78	3.83	3.72	4.45
Natural gas (per thousand cubic feet)							
Residential	13.05	12.85	12.64	14.84	14.71	14.29	18.97
Electric power	7.22	7.35	7.15	9.01	8.94	8.47	12.51
Coal, electric power sector (per million Btu)	1.78	1.92	1.94	5.25	2.04	2.16	8.72
Electricity (cents per kilowatthour)	9.11	9.41	9.33	10.23	10.43	10.08	12.70
Energy consumption (quadrillion Btu)							
Liquids	40.75	38.93	38.97	38.35	41.60	41.66	39.87
Natural gas	23.70	24.09	23.78	22.88	25.04	24.02	22.45
Coal	22.74	23.98	24.80	20.30	26.56	30.62	16.40
Nuclear power	8.41	8.99	8.77	9.36	9.47	8.58	12.21
Renewable/other	6.05	9.26	9.28	11.15	10.67	10.71	15.24
Electricity imports	0.11	0.06	0.06	0.10	0.10	0.04	0.31
Total	**101.77**	**105.31**	**105.65**	**102.16**	**113.43**	**115.62**	**106.46**
Electricity generation (billion kilowatthours)							
Petroleum	66	58	58	55	60	61	53
Natural gas	892	898	852	828	1,012	854	803
Coal	2,021	2,156	2,235	1,846	2,415	2,779	1,621
Nuclear power	806	862	840	897	907	822	1,170
Renewable	352	617	619	789	730	728	1,063
Other (includes pumped storage)	22	28	28	27	28	27	27
Total	**4,159**	**4,618**	**4,632**	**4,442**	**5,153**	**5,272**	**4,737**
Carbon dioxide emissions (million metric tons)							
Electric power sector, by fuel							
Petroleum	66	40	40	37	41	42	36
Natural gas	376	357	340	325	378	321	260
Coal	1,980	2,089	2,142	1,685	2,299	2,494	868
Other	12	12	12	12	12	12	13
Total	**2,433**	**2,497**	**2,534**	**2,059**	**2,729**	**2,869**	**1,176**
Total carbon dioxide emissions, all sectors	**5,991**	**5,982**	**6,044**	**5,436**	**6,414**	**6,745**	**4,615**

various emission levels are used in the electric power sector, providing some flexibility for altering emissions levels without turning to wholly unknown technologies or requiring end-use consumers to purchase any new equipment. Increases in CO_2 emissions from

the electric power sector are projected to continue through 2030 in the no GHG concern case and the *AEO2009* reference case. In the no GHG concern case, emissions are expected to rise as demand for electricity increases and coal's share of the national generation mix grows to 53 percent in 2030. Emissions also continue to increase through 2030 in the reference case but at a slower rate because of the reduced reliance on coal for generation.

In the LW110 case, in contrast, CO_2 emissions from the electric power sector are projected to fall significantly over time. In this case, CO_2 emissions from the electric power sector in 2030 are projected to be 52 percent below their 2007 level and 57 percent below the level in the reference case.

Figure 25. U.S. electricity prices in three cases, 2005-2030 (2007 cents per kilowatthour)

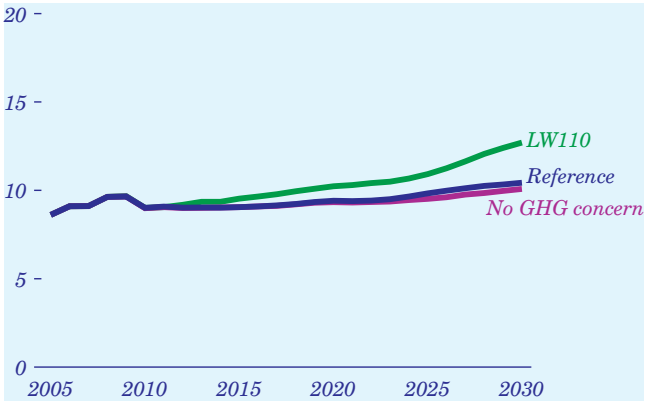
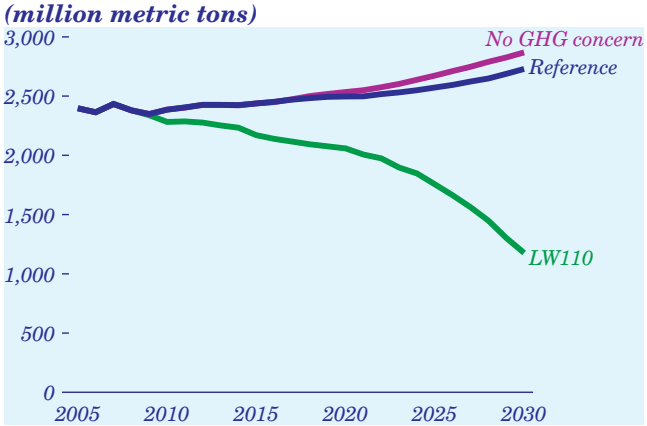


Figure 26. Carbon dioxide emissions from the U.S. electric power sector in three cases, 2005-2030 (million metric tons)



Endnotes for Issues in Focus

50. Appendix tables in this report also include projections for the average prices of all grades of imported crude oil.
51. M.A. Kromer and J.B. Heywood, *Electric Powertrains: Opportunities and Challenges in the U.S. Light-Duty Vehicle Fleet*, LFEE 2007-03 RP (Cambridge, MA: Massachusetts Institute of Technology, May 2007), web site http://web.mit.edu/sloan-auto-lab/research/beforeh2/files/kromer_electric_powertrains.pdf.
52. Electric Power Research Institute, *Advanced Batteries for Electric-Drive Vehicles*, 1009299 (Palo Alto, CA, May 2004), web site www.evworld.com/library/EPRI_adv_batteries.pdf; and A. Simpson, *Cost-Benefit Analysis of Plug-In Hybrid Electric Vehicle Technology*, NREL/CP-540-40485 (Golden, CO: National Renewable Energy Laboratory, November 2006), web site www.nrel.gov/vehiclesandfuels/vsa/pdfs/40485.pdf.
53. U.S. House of Representatives, 110th Congress, "Energy Improvement and Extension Act of 2008," H.R. 6049, web site www.govtrack.us/congress/bill.xpd?bill=h110-6049.
54. F.R. Kalhammer, B.M. Kopf, D.H. Swan, V.P. Roan, and M.O. Walsh, *Status and Prospects for Zero Emissions Vehicle Technology: Report of the ARB Independent Expert Panel 2007* (Sacramento, CA: State of California Air Resources Board, April 13, 2007), web site www.arb.ca.gov/msprog/zevprog/zevreview/zev_panel_report.pdf.
55. A. Bandivadekar, K. Bodek, L. Cheah, C. Evans, T. Groode, J. Heywood, E. Kasseris, M. Kromer, and M. Weiss, *On the Road in 2035: Reducing Transportation's Petroleum Consumption and GHG Emissions*, LFEE 2008-05 RP (Cambridge, MA: Massachusetts Institute of Technology, July 2008), web site http://web.mit.edu/sloan-auto-lab/research/beforeh2/otr2035.
56. The Alaska OCS has not been subject to leasing restrictions since 2007. In the North Aleutian Basin of Alaska, the Congressional moratorium was lifted in 2004, and the Presidential withdrawal was lifted in 2007.
57. See Legislation and Regulations, "Regulations Related to the Outer Continental Shelf Moratoria and Implications of Not Renewing the Moratoria."
58. The ban on areas in the Eastern and Central Gulf of Mexico through 2022 imposed by the Gulf of Mexico Energy Security Act of 2006 remains in place. *AEO-2009* assumes no restrictions on drilling in the Atlantic and Pacific OCS through 2030.
59. U.S. Department of the Interior, Minerals Management Service, *Draft Proposed Outer Continental Shelf (OCS) Oil and Gas Leasing Program 2010-2015* (Washington, DC, January 2009), web site www.mms.gov/5%2Dyear/2010-2015New5-YearHome.htm.

60. This discussion is based largely on data from U.S. Department of Energy, Office of Naval Petroleum and Oil Shale Reserves, *Strategic Significance of America's Oil Shale Resource, Volume II, Oil Shale Resources, Technology and Economics* (Washington, DC, March 2004), web site www.fossil.energy.gov/ programs/reserves/npr/publications/npr_strategic_ significancev2.pdf.
61. The Fischer assay is a standardized laboratory test for determining oil and natural gas yields from oil shale rock.
62. Energy Information Administration, *Advance Summary, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids Reserves, 2007 Annual Report*, DOE/EIA-0216(2007) Advance Summary (Washington, DC, October 2008), Table 1, p. 5, web site www.eia.doe.gov/ pub/oil_gas/natural_gas/data_publications/advanced_ summary/current/adsum.pdf.
63. The GTL option is represented in NEMS in the form of facilities with capacities of 34,000 barrel per day that can be added incrementally when oil and petroleum product prices are sufficiently high to make their operation profitable.
64. Alaska Department of Natural Resources, Division of Oil and Gas, *Alaska Oil and Gas Report 2007* (Anchorage, AK, July 2007), Table III.1, p. 3-2, web site www. dog.dnr.state.ak.us/oil/products/publications/annual/ report.htm.
65. K.W. Sherwood and J.D. Craig, *Prospects for Development of Alaska Natural Gas: A Review as of January 2001* (Anchorage, AK: U.S. Department of Interior, Minerals Management Service, Resource Evaluation Office), Chapters 4 and 5, web site www.mms.gov/ alaska/re/natgas/akngas2.pdf. Resource recovery costs were updated for this analysis, to reflect the escalation of drilling costs over time.
66. All 2007 oil and natural gas supply and consumption figures are taken from Energy Information Administration, *Annual Energy Review 2007*, DOE/EIA-0384 (2007) (Washington, DC, June 2008), web site www. eia.doe.gov/emeu/aer/contents.html.
67. Crude oil and natural gas resource figures are those represented in NEMS, which are based on the most current U.S. Geological Survey and U.S. Minerals Management Service undiscovered resource estimates. They include proven crude oil and natural gas reserves as of January 1, 2007.
68. When the entire natural gas resource base in Alaska is included in the U.S. natural gas resource estimate, the total represents more than 75 years of domestic supply at 2007 consumption rates.
69. INGAA Foundation, *Availability, Economics and Production Potential of North American Unconventional Natural Gas Supplies*, F-2008-3, Table 32 (Washington, DC, November 2008).
70. Energy Information Administration, 2002 Manufacturing Energy Consumption Survey data, web site www.eia.doe.gov/emeu/mecs, supplemented with other EIA industrial data.
71. S.C. Davis, S.W. Diegel, and R.G. Boundy, *Transportation Energy Data Book: Edition 27*, ORNL-6981 (Oak Ridge, TN, 2008), Table 2.5, web site http://cta.ornl. gov/data/index.shtml.
72. U.S. Department of Energy, Alternative Fuels Data Center, "Alternative Fueling Station Total Counts by State and Fuel Type," web site www.afdc.energy. gov/afdc/fuels/stations_counts.html; and U.S. Census Bureau, "Industry Statistics Sampler, NAICS 4471, Gasoline Stations," web site www.census.gov/econ/ census02/data/industry/E4471.HTM. Census Bureau numbers are based on the firm's primary business function and do not include general retail establishments, like Walmart and Costco, that sell gasoline and diesel. *NPN Magazine* (web site www.npnweb.com), reports more than 160,000 U.S. service stations on its *NPN MarketFacts 2008* Highlights page.
73. Cambridge Energy Research Associates, "Construction Costs for New Power Plants Continue to Escalate: IHS CERA Power Capital Costs Index" (press release, May 27, 2008), web site www.cera.com/aspx/cda/ public1/news/pressReleases/pressReleaseDetails.aspx ?CID=9505.
74. Cambridge Energy Research Associates, "IHS CERA Power Capital Costs Index Shows Power Plant Construction Costs Decreasing Slightly" (press release, December 17, 2008), web site http://press.ihs.com/ article_display.cfm?article_id=3953.
75. Closed-loop biomass is defined as any organic material from a plant that is cultivated exclusively for use in producing electricity at a qualifying facility.
76. Solar installations received the credit for a brief period, from 2004 to 2005. Certain types of coal facilities can claim a tax credit under Section 45 of the U.S. Internal Revenue Code, and some qualifying nuclear plants may also claim a production tax credit.
77. Geothermal energy is also eligible for a 10-percent Federal ITC, but a facility cannot claim both credits.
78. Eligibility is limited to "incremental" generation resulting from capital investments at existing hydroelectric facilities.
79. Open-loop biomass includes waste and residue materials from certain agricultural, forestry, and urban or industrial processes.
80. Marine resources must be in service by December 31, 2011, to be eligible for the PTC.
81. See, for example, J.P. Harper, M.D. Karcher, and M. Bolinger, *Wind Project Financing Structures: A Review & Comparative Analysis*, LBNL-63434 (Berkeley, CA: Lawrence Berkeley National Laboratory, September 2007), web site http://eetd.lbl.gov/EA/EMP/ reports/63434.pdf.
82. C. Carlson and G.E. Metcalf, "Energy Tax Incentives and the Alternative Minimum Tax," *National Tax Journal*, Vol. 61, No. 3 (September 2008), web site www.entrepreneur.com/tradejournals/article/ 190149936.html.

83. Because the projection does not show any use of closed-loop resources, the open-loop credit value is assumed. EIA currently does not model marine energy technologies.
84. Using a real discount rate of 7 percent. PTC costs for 2009, estimated at $3.6 billion, are not included.
85. The participating States are New York, New Jersey, Connecticut, Massachusetts, Maine, New Hampshire, Vermont, Rhode Island, Delaware, and Maryland. See Regional Greenhouse Gas Initiative, web site www.rggi.org/states.
86. Western Climate Initiative, "Draft Design of the Regional Cap-and-Trade Program" (July 23, 2008), web site www.westernclimateinitiative.org/ewebeditpro/items/O104F18808.PDF.
87. Midwestern Greenhouse Gas Reduction Accord, "Energy Security and Climate Stewardship Platform for the Midwest 2007," web site www.midwesternaccord.org/Platform.pdf.
88. State of California, Assembly Bill No. 32, "California Global Warming Solutions Act of 2006," web site www.arb.ca.gov/cc/docs/ab32text.pdf.
89. D. Samuelsohn, "Senate Emissions Bill Headed for Defeat," *Greenwire* (June 5, 2008), web site www.eenews.net/eenewspm/2008/06/05/archive/1?terms=Boxer-Lieberman-Warner+ (subscription site).
90. L. Johnston, E. Hausman, A. Sommer, B. Biewald, T. Woolf, D. Schlissel, A. Roschelle, and D. White, *Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning* (Cambridge, MA: Synapse Energy Economics, March 2, 2007), web site www.synapse-energy.com/Downloads/SynapsePaper.2007-03.0.Climate-Change-and-Power.A0009.pdf.
91. See Morgan Stanley, "Leading Wall Street Banks Establish The Carbon Principles" (Press Release, February 4, 2008), web site www.morganstanley.com/about/press/articles/6017.html.
92. The LW110 case is based on S. 2191, which is the most recent GHG bill analyzed by EIA as of November 2008. The choice is not meant to imply that EIA supports or does not support S. 2191 or any other particular past or future proposal.
93. Energy Information Administration, *Energy and Economic Impacts of S. 2191, the Lieberman-Warner Climate Security Act of 2007*, SR/OIAF/2008-01 (Washington, DC, April 2008), web site www.eia.doe.gov/oiaf/servicerpt/s2191/index.html.