A Bright Future for the Heartland: Technical Appendix

Contents

This appendix describes assumptions we used for the modified versions of the National Energy Modeling System (NEMS) and Impact Analysis for Planning (IMPLAN) models used for our analysis.

To analyze the impact of the Energy Roadmap targets in the Midwest, we relied primarily on a modified version of NEMS, developed by the Energy Information Administration (EIA), an independent division of the U.S. Department of Energy. NEMS is a comprehensive model that forecasts U.S. energy use and emissions from the electricity, transportation, industrial, and buildings (residential and commercial) sectors. The model relies on a variety of assumptions about technological progress as well as household and business behavior. Using these assumptions, it selects the technologies that can best enable the nation to meet its projected energy needs.

The first part of this appendix describes the electricity sector assumptions we used for our modified version of NEMS (which we call UCS-NEMS). We began with the electricity sector and technology assumptions included in the EIA's *Annual Energy Outlook 2009* version of the National Energy Modeling System (NEMS). (See EIA 2009b and EIA 2009f for more on NEMS, and EIA 2009d for *AEO 2009*.) We modified the EIA's assumptions for the costs, performance, and supply of several energy technologies based on more recent information, and we also updated the model to include relevant state and federal policy changes. We based the adjustments on actual project data, expert input, and cost indices for power plants, as well as Midwest modeling inputs recently developed by a multi-stakeholder group for the Midwestern Governors Association (MGA) and the Organization of MISO States (CARP modeling).

The second part of the appendix describes the assumptions and methodology for the economic impacts analysis. We evaluated these effects using state-specific data derived from IMPLAN, an input-output model that identifies interactions between all sectors of the economy. IMPLAN allowed us to obtain state-level results, and to incorporate some of the positive effects on gross state product and jobs of investments in energy efficiency, renewable energy, and other low-carbon technologies, and of savings on consumers' energy bills.

All costs are in 2007 dollars unless otherwise noted. The capital cost assumptions are without incentives, and reflect the averages for the Midwest.

Electricity Sector Assumptions

State renewable electricity standards (RESs)

We updated the EIA's state RES targets with recent UCS projections for the 29 states that had standards in place as of September 2009, plus Washington, DC. In the Midwest, Kansas established a renewable energy standard in March 2010. For states that are having implementation problems, we assumed a conservative three-year delay in reaching their targets. We applied this delay to Arizona, California, Delaware, Maryland, Michigan, Nevada, New York, North Carolina, and all six New England states. We assumed that all other states with an RES would meet their targets on schedule.

We based our analysis on the renewable energy and energy efficiency goals set forth by the Midwestern Governors Association (MGA), a nonprofit, nonpartisan collaboration of 10 Midwest states working on key public policy issues. During an energy summit in late 2007, six member states of the MGA (Illinois, Iowa, Kansas, Michigan, Minnesota, and Wisconsin) and one Canadian province (Manitoba) signed the Midwestern Greenhouse Gas Reduction Accord, which set strong goals for reducing heat-trapping emissions and promoting economic development (MGA 2007). (Three other states participated in the summit as observers.)

Nuclear loan guarantees

We included up to $18.5 billion in incentives for advanced nuclear power plants available through the Department of Energy's (DOE's) loan guarantee program. By the December 19, 2008, deadline, the DOE had received applications from 15 companies to build 16 new reactors at 10 sites. These applications requested $93 billion in loan guarantees for 22 gigawatts (GW) of capacity.

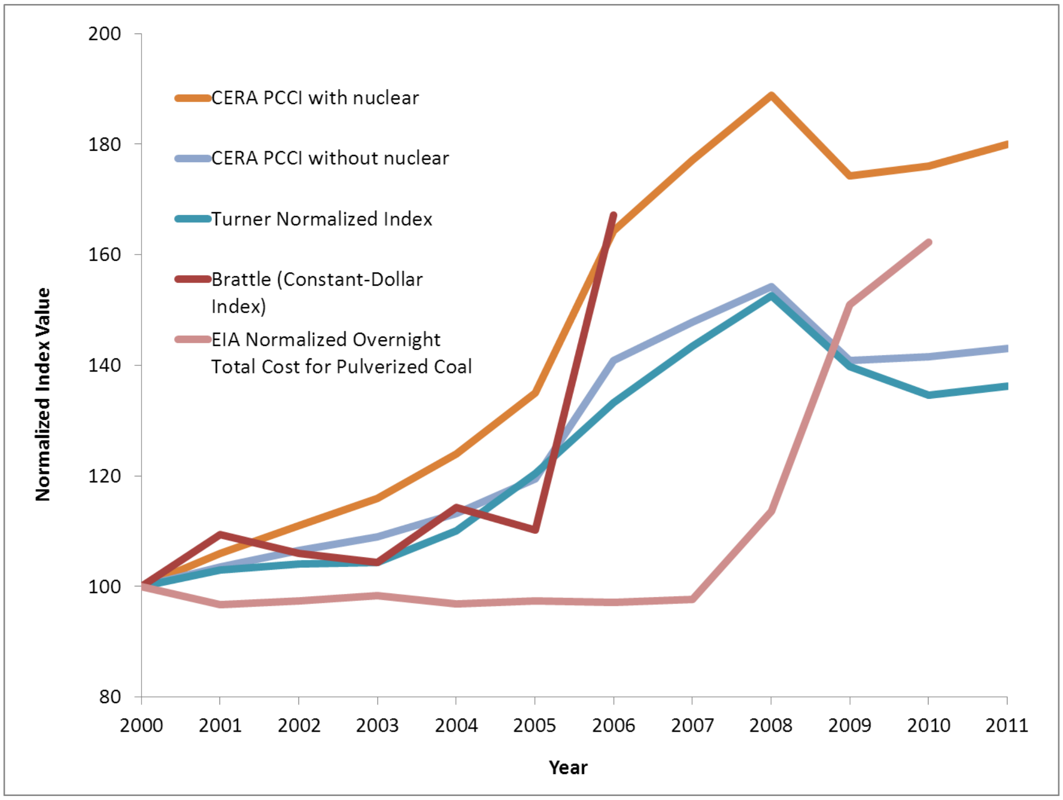
Because not enough funding is available for all these projects, and the details of each project are not available, we adopted a simplifying assumption that the loan guarantees will spur the development of 4,400 megawatts (MW) of new nuclear capacity ($18.5 billion/$93 billion * 22 GW), or four to five new plants by 2020. In fact, the DOE has narrowed the list of reactors eligible to receive loan guarantee to five applicants. This is consistent with the 4.4 GW estimated by the EIA in *AEO 2009*.

Escalation in construction costs

We adjusted the capital costs in *AEO 2009* for all technologies in our base case to reflect increases in construction and commodity costs over the past few years (Wald 2007). The increases are based on actual project data, expert input, and power plant cost indices. The EIA had assumed no real cost increases until the last few years, when it raised costs by 15 percent in *AEO 2008*, and another 24 percent in *AEO 2009*, for all conventional and renewable energy technologies (except biomass power plants, which it increased by 50 percent). The EIA raised technology costs an additional 2 percent in *AEO 2010*.

Figure 1. Escalation in the Costs of Constructing Power Plants, 2000–2011

(constant-dollar index: year 2000=100)



Source: EIA 2010, 2009c; IHS CERA 2011; Turner 2011; Chupka and Basheda 2007. **Note**: We used a GDP deflator to express all indices in constant dollars.

When we finalized these assumptions, the EIA's cost increases were more in line with levels reported in two power plant cost indices until 2009 (see Figure 1). These indices show real (inflation-adjusted) cost increases of 50–70 percent since 2000, with most of the increases occurring after 2004. However, these increases differ from the costs of actual projects, and tend to overestimate the costs of some technologies while underestimating those of others. That is because the EIA used the same factor to adjust the costs of all the technologies in *AEO 2008* and *AEO 2009*, with a few exceptions.

In *AEO 2009*, the EIA allowed the capital costs in NEMS to be adjusted through escalation factors, as in the past, or indexed to a projected producer price index based on metals and metal products. We decided to use the escalation factors, because they allowed us to adjust the escalation rate for each technology to reflect recent cost indices and real project costs. See below for more detail on the costs of each technology.

We adjusted escalation rates for construction and commodity costs for all technologies, based on data from actual projects, input from experts, and power plant cost indices.

Whenever we used data from actual projects, we applied an escalation rate that reflected the reported costs. For all other technologies, we assumed that the costs would continue to rise 2.5 percent per year (after accounting for inflation) until 2015, but would not continue to rise after that.

We based our escalation rates on information published prior to the economic recession. Commodity and construction costs for some technologies have remained relatively constant since then, or have declined. Our assumptions do not reflect these recent changes.

For example, both the IHS Cambridge Energy Research Associates Power Plant Capital Costs Index (CERA PCCI), which tracks the costs of building a portfolio of power plants in North America, and the Turner Building Cost Index showed construction costs nearly doubling between 2000 and 2008 (Figure 1). These costs dropped somewhat during the recession, but the indexes showed that the decline was modest, and in late 2009 and early 2010 costs actually rose slightly before flattening out later in 2010 (Turner 2011; IHS CERA 2010a, 2010b).

Technology learning

NEMS assumes that technology learning occurs: that is, that capital costs fall as the installed capacity of a given technology increases, and over time, reflecting improvements based on R&D. The EIA breaks down each new technology into its major components, and then identifies each component as revolutionary, evolutionary, or mature.

We used the EIA's assumptions for most technologies, except in the following four areas:

- For all mature commercial technologies, we changed the EIA's minimum learning rates, which assume that capital costs fall by a fixed amount over time, from 5 percent to 1 percent.
- For solar photovoltaics (PV), we adjusted the learning rates based on existing project data.
- For land-based wind projects, we changed the EIA's learning rates (which assumed no cost reductions) to approximate the 10 percent capital cost reductions assumed in the DOE's 2008 study of producing 20 percent of U.S. electricity from wind power by 2030 (EERE 2008).
- For new advanced nuclear plants, we assumed that learning would occur at half the rate projected by the EIA, which based its projection on international experience. Higher learning rates have been achieved in France and South Korea, largely as a result of standardization (in which one company builds one plant design over and

over). In the fractured U.S. industry, where 17 companies are proposing to build 26 units using five different designs (with more on the horizon), high learning rates are overly optimistic. Indeed, the U.S. nuclear industry saw steadily increasing construction costs through almost the entire last generation of nuclear plants.

Table 1. Learning Parameters for New Electric Generating Technologies

Technology Component	Period 1 Learning Rate	Period 2 Learning Rate	Period 3 Learning Rate	Period 1 Doublings	Period 2 Doublings	Minimum Total Learning by 2025
Pulverized coal	-	-	1%	-	-	1%
Combustion turbine–conventional	-	-	1%	-	-	1%
Combustion turbine–advanced	-	10%	1%	-	5	10%
Heat recovery steam generator	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon capture/sequestration	20%	10%	1%	3	5	20%
Balance of plant (e.g., controls, structures, and roads): IGCC	-	-	1%	-	-	5%
Balance of plant: turbine	-	-	1%	-	-	1%
Balance of plant – Combined Cycle	-	-	1%	-	-	1%
Fuel cell	20%	10%	1%	3	5	20%
Advanced nuclear	3%	2%	1%	3	5	5%
Fuel prep: biomass IGCC	20%	10%	1%	3	5	20%
Distributed generation – base	-	5%	1%	-	5	10%
Distributed generation – peak	-	5%	1%	-	5	10%
Landfill gas	-	8%	1%	-	5	10%
Geothermal	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	1%
Wind	5%	5%	1%	-	-	5%
Wind: offshore	20%	10%	1%	3	5	20%
Solar thermal	20%	10%	1%	3	5	20%
Solar PV	20%	10%	1%	3	5	20%

Technological optimism and contingency factors

We also set the EIA's technological optimism and contingency factors to 1.0, assuming that these are already reflected in our capital cost assumptions. The technological optimism factor represents the demonstrated tendency to underestimate actual costs for a first-of-a-kind, unproven technology. As experience is gained (after four units are built), the EIA gradually reduces the technological optimism factor to 1.0.

A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of cost within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."

Financing costs, fuel prices, and capacity factors

Unless otherwise noted below, we used EIA assumptions for financing costs, fuel prices, and capacity factors. Most of these variables are calculated within the model. For example, the EIA embeds a number of financing assumptions in the NEMS model for calculating interest accrued during construction, project cash flow, taxes, insurance, and tax and book depreciation over the plant's life.

The financing assumptions are the same for all technologies with the exception of construction lead times and depreciation, which vary by technology. Financing costs vary slightly over time, based on projected changes in interest rates from the NEMS macroeconomic module. Fuel prices also vary under different scenarios, based on supply and demand for different types of fuel. In all our cases, we used the EIA's fuel price assumptions from *AEO 2009*, as discussed in more detail below. Capacity factors for dispatchable technologies also vary based on their economics and operating characteristics.

Technology-specific cost and performance assumptions

This section describes the key changes we made to the cost and performance assumptions for the main renewable and conventional technologies for generating electricity included in NEMS. The end of this section summarizes the capital costs and levelized cost of electricity for each technology. These capital costs do not include investment tax credits or other capital incentives.

Wind

The model includes land-based and offshore wind turbines in the electricity sector. For land-based wind projects, current overnight capital costs are based on a 2009 analysis from the Lawrence Berkeley National Laboratory (LBNL) of 283 wind projects totaling nearly 18,641 MW, or 73 percent of the installed wind capacity in the United States at the end of 2008 (Figure 2) (Wiser and Bolinger 2009; Bolinger 2008).

These estimates include real cost escalation of 60 percent, or $700/kW, from 2003 to 2008. Among the sample of projects built in 2008, the capacity-weighted average installed cost rose to $1,915/kW, up from $1,72/kW in 2007. LBNL projected installed costs to increase by another 20 percent, or $205/kW, in 2009 to $2,120/kW (in 2008 dollars), based largely on 2008 data showing continued increases in prices for wind turbines.

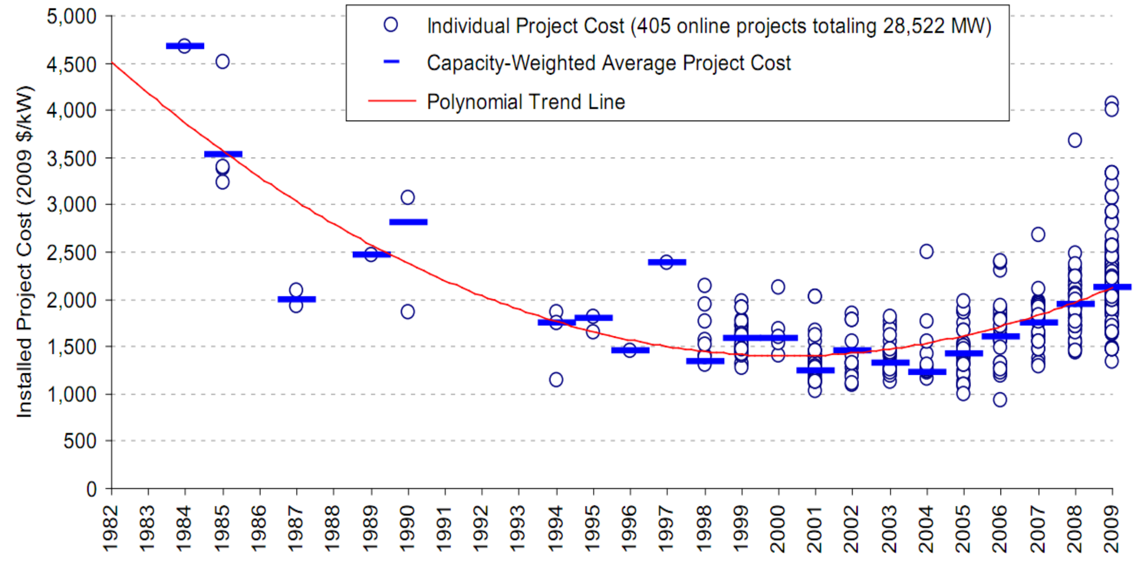
The same study suggests, however, that the trend of annual increases in turbine prices has ended, at least temporarily. The drop in commodity prices and the supply-demand balance for turbines have transformed the sector into a buyer's market. In fact, IHS CERA reported in June 2009 that construction costs for wind power plants had dropped 11 percent, owing to a drop in wind turbine and tower costs and a short-term slowdown in orders (IHS CERA 2009b).

However, as noted, commodity prices have stabilized, and some are showing signs of recovery. Orders are also increasing as project financing becomes easier with the recovering availability of credit. We assumed overnight capital costs of $1,710/kW for wind projects that came online in 2008, and $2,430/kW for those projected to come online in 2015.

We also assumed that capital costs will decline by about 10 percent from 2010 to 2030, based on wind industry estimates developed for the DOE (EERE 2008). A recent survey of wind turbine and component manufacturers showed that cost reductions of 15–22 percent may be possible under a more stable policy environment, such as a long-term extension of the production tax credit or a national RES—that would facilitate an increase in domestic wind turbine manufacturing (Wiser 2007). A growing percentage of the cost of wind equipment is being built domestically: about 60 percent in 2009, up from less than 20 percent in 2006 (Figure 2) (Wiser and Bolinger 2010).

We also modified the EIA's assumptions that the capital costs of wind increase at the regional level as wind development increases, to account for additional transmission costs, resource degradation, and siting costs. We modified the EIA's long-term capital cost multipliers for wind based on a detailed GIS analysis performed by the National Renewable Energy Laboratory (NREL) for the EIA. This analysis accounts for increases in terrain slope and population density (PERI 2007).

Figure 2. Capital Costs for Installed Wind Power, 1982–2009



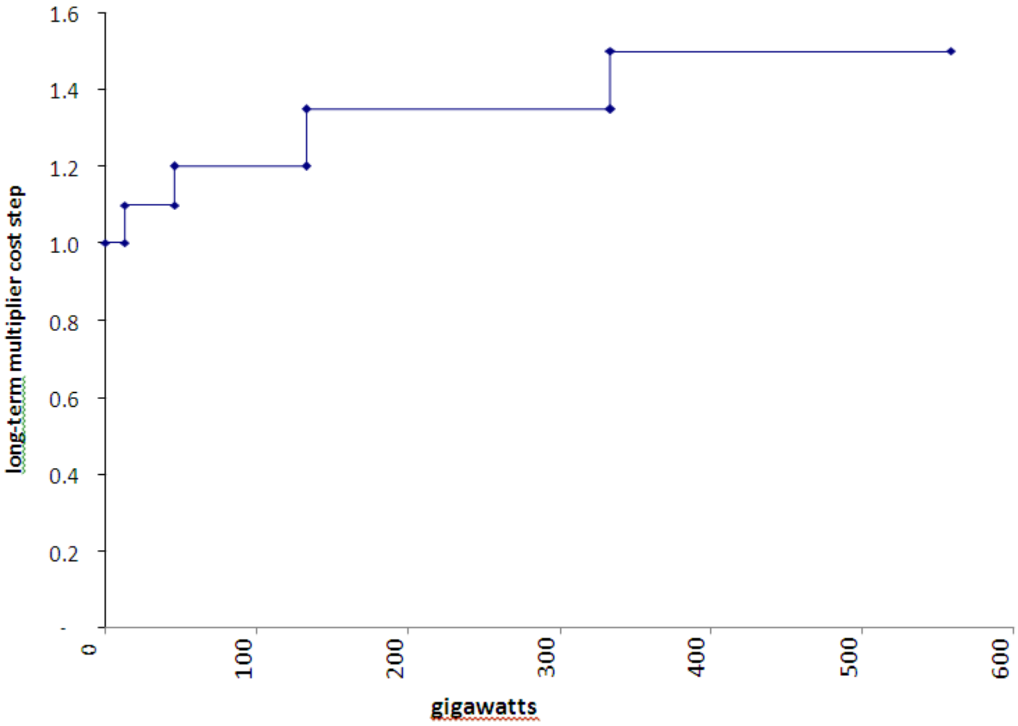
(some data points suppressed to protect confidentiality)

Source: Wiser and Bolinger 2010.

The NREL developed supply curves for the windy land area available in each wind resource class for 13 electricity reliability regions. The NREL then divided these supply curves into steps to correspond to the multiplier levels assumed by the EIA. One main difference is that the EIA includes only class 4–6 wind resources, while our analysis also included class 3 wind resources, which are being developed in several states.

Previous analyses by UCS and the EIA have shown that the NEMS model rarely uses the fairly large portion of the wind supply curve that the EIA assumes will fall into the last two multiplier levels. These levels increase capital costs by 200 and 300 percent, respectively. We effectively excluded these resources from the model, and developed additional multiplier steps at the lower end of the supply curve (1.0, 1.10, 1.20, 1.35, and 1.50, versus the EIA’s 1.0, 1.2, 1.5, 2.0, and 3.0). Figure 3 illustrates these changes for the three Midwest regions.

Figure 3. Wind Resource Supply Curves for the Midwest (wind classes 3–7 combined)



For capacity factors and operations and maintenance (O&M) costs, we used Black & Veatch's projections from the DOE 20 percent wind study (EERE 2008). That study assumes that capacity factors will continue to increase over time, based on a curve fit to historical projections and new turbine designs. It also assumes fixed O&M costs of $11.5 per kilowatt-year (kW-yr) through 2030, and variable O&M costs that decline from $7 per megawatt-hour (MWh) in 2005 to $4.4/MWh in 2030, based on historical trends.

For offshore wind, we assumed that capital costs are 70 percent higher than for land-based wind projects. This is the midpoint between the 40 percent increase assumed in EERE 2008 and a 100 percent increase based on estimates from wind manufacturers and developers. We expect costs to vary based on site-specific conditions. We also used the EIA's learning assumptions for offshore wind, which assume that this is a revolutionary technology that will likely experience greater cost reductions than land-based wind.

We also based capacity factors and O&M costs for offshore wind on EERE 2008. Capacity factors are roughly 2 percentage points higher than for land-based projects for each wind class. Fixed O&M costs are assumed to be 30 percent higher than land-based projects, while variable O&M costs are approximately three times higher.

While NEMS also includes small wind turbines in the residential sector, we did not make any changes to the EIA's assumptions for this technology.

Solar

The main technologies included in the model are concentrating solar power (CSP)[1] and utility-scale PV in the electricity sector, and distributed, building-integrated PV installed in the residential and commercial sectors.

For CSP, limited data were available on actual projects, so we reviewed several recent studies to develop our assumptions. We assumed overnight capital costs of $4,600/kW for plants starting operation in 2008, based on a Black & Veatch study (2008).While we included real escalation in capital costs, as with other technologies, the model projects capital costs to fall over time, as this escalation is more than offset by technological learning. Based on Cleetus, Clemmer, and Friedman (2009), we expect overnight capital costs to be $4,970/kW for projects that come online in 2015.

We also assumed that capacity factors would increase from 43 percent in 2010 to 49 percent in 2020 and 55 percent in 2030, with increasing levels of storage based on the mid-range of several studies. That differs from the EIA's assumptions of no increases in capacity factors over time and no storage (EIA 2009), and the assumptions in a 2006 NREL study (Blair et al. 2006). However, our assumptions are lower than in the DOE's FY09 Solar Initiative (DOE 2007a). O&M costs are based on DOE 2007a, adjusted for a lower level of storage assumed in our analysis.

Installed costs for all types of solar PV systems in the United States declined from $10.80 per watt in 1998 to $7.50 per watt in 2008, according to an LBNL study (Wiser et al. 2009). That drop is equivalent to an average annual reduction of $0.30 per watt, or 3.6 percent per year in real 2008 dollars. While a follow-up report suggested that installed costs in 2009 remained relatively flat at $7.5/watt, preliminary data suggest a significant drop in installed costs in 2010 (Barbose, Darghouth, and Wiser 2010). More recent estimates suggest that weighted-average prices declined 20.5 percent in 2010—a substantially higher rate than our estimate (SEIA 2010).

For utility-scale PV systems, we assumed overnight capital costs of $5,240/kW for projects installed in 2008, which is in the range of estimates from Black & Veatch 2008, the DOE (2007b) and the EIA (2008b). We projected that capacity factors would increase from the EIA's assumed current level of 20 percent to 26 percent by 2015, based on DOE projections (DOE 2007b). We based O&M costs on estimates for California by Navigant Consulting (Chaudhari, Frantzis, and Hoff 2004), and assusmed that they would decline

---

[1] Although the model results did not show any CSP or geothermal facilities built in the Midwest, they are among the potential options evaluated by the model. Cost assumptions for CSP and geothermal are important because their use outside the Midwest affects the prices of displaced fuel, which has an indirect effect on the Midwest.

gradually over time based on DOE projections (2007b). We assumed capital costs of $5,530/kW for projects with an in-service date of 2015.

For distributed PV systems, we assumed initial total system costs in 2008 of $7,620/kW for residential systems, and $6,170/kW for commercial systems. With learning, installed costs for residential systems are projected to fall to about $4,860/kW by 2015, $4,460/ kW by 2020, and $3,680/kW by 2030. Installed costs for commercial are projected to fall to about $3,780/kW by 2015, $3,410/ kW by 2020, and $2,660/kW by 2030. These cost projections are in the range of estimates from the EIA (2008b), the DOE (2007a), and Wiser, Barbose, and Peterman (2009).

Biopower

The main biopower technologies in the electricity sector include biomass co-fired in existing coal plants and dedicated biomass integrated gasification combined cycle (IGCC) plants. While biomass is also used for combined heat and power (CHP) in the industrial sector, we did not make any changes to the EIA's assumptions for that technology. Available biomass resources include forest residues, crop residues, urban and mill residues, and dedicated energy crops.

For biomass co-fired in existing coal plants, we increased the EIA's assumed capital costs by 65 percent, based on estimates from Black & Veatch (2008), to account for the real escalation in construction costs applied to other technologies.

There is considerable uncertainty around the cost and performance of biomass IGCC plants, as very little data exist from actual projects For capital costs, we added the difference between the EIA's costs for coal and biomass IGCC ($830/kW) to our revised estimates of the capital costs of IGCC (see below). We assumed that real cost escalation and learning would be the same as for coal IGCC. We assumed overnight capital costs of $4,600/kW for projects with an in-service date of 2015. We also assumed slightly higher heat rates than the EIA, consistent with those from Black & Veatch (O'Connell et al. 2007) and MIT (2007) for coal IGCC, plus the difference between the heat rates from the EIA (2008b) for coal and biomass IGCC. The rest of the assumptions for biomass IGCC are the same as the EIA's assumptions.

For the biomass supply curves and land-use assumptions, we used the same methodology as in Cleetus, Clemmer, and Friedman (2009).[2] The supply curves include the amount of biomass that is potentially available for energy use in the United States at different prices (Walsh 2008).

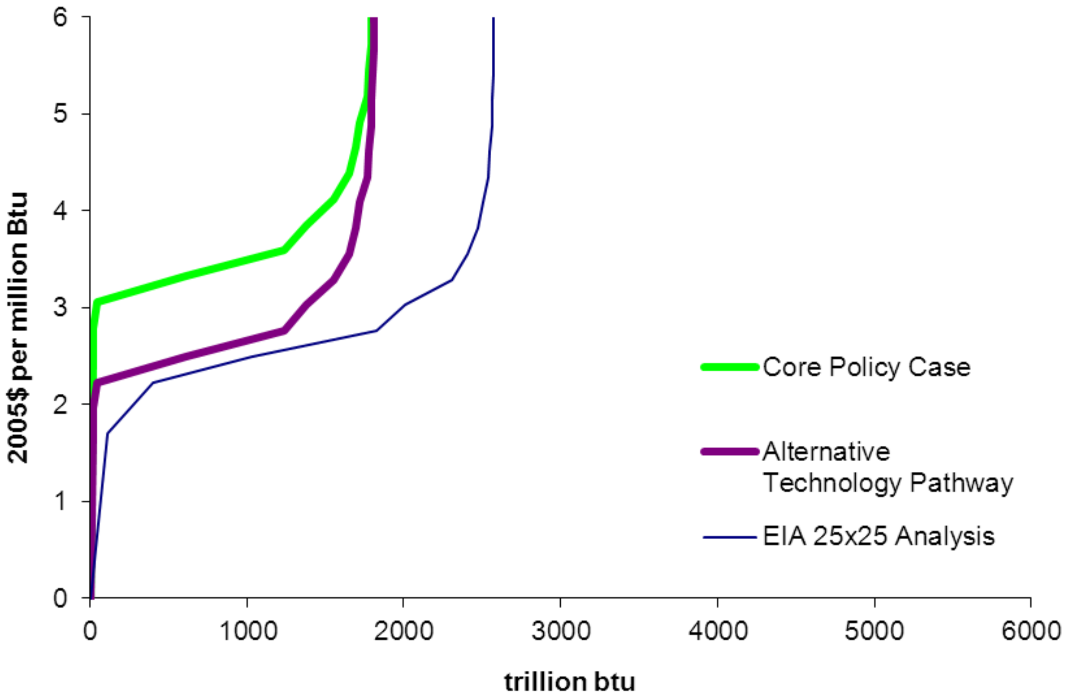
---

[2] More details on our biomass and land-use assumptions can be found at *http://www.ucsusa.org/assets/documents/global_warming/climate2030-app-g-biomass.pdf.*

We developed separate supply curves for each of the main biomass feedstocks in the model: energy crops (switchgrass), agricultural residues (corn stover and wheat straw), forestry residues, and urban wood waste and mill residues. We then added the data from those curves together to get a total biomass supply curve.[3]

The National Energy Modeling System (NEMS) includes a supply curve for each biomass feedstock for every year through 2030, and for 13 different regions of the United States. Figures 4 through 6 show the biomass supply curves used in our analysis for our core policy case and alternative technology pathway (and in the EIA's analysis of 25 percent of electricity from renewables by 2025 (EIA 2007b) for 2010, 2020, and 2030.

Figure 4. Biomass Resource Supply Curves for the Midwest, 2010 (NEMS coal regions 5, 6, and 9 combined)

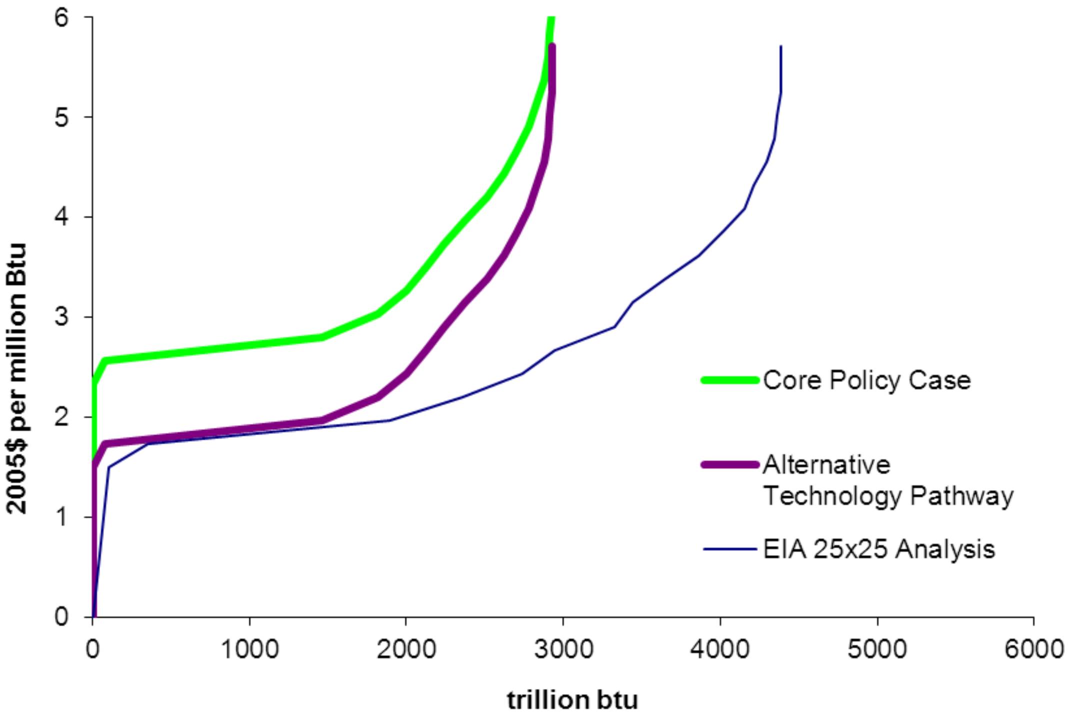


Note: Supply region 5 includes Ohio; region 6 includes Illinois, Indiana, Michigan, and Wisconsin; and region 9 includes Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota.

---

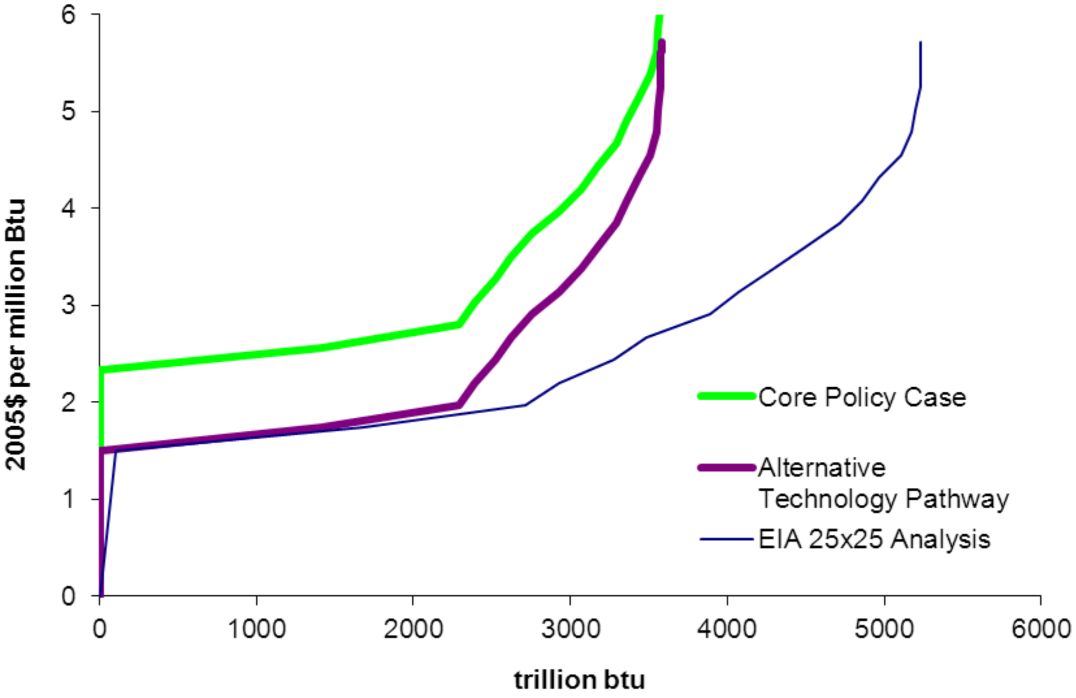
[3] Although corn and cellulosic biomass have separate supply curves, these resources compete for producing biofuels in the transportation sector.

Figure 5. Biomass Resource Supply Curves for the Midwest, 2020 (NEMS coal regions 5, 6, and 9 combined)



Note: Supply region 5 includes Ohio; region 6 includes Illinois, Indiana, Michigan, and Wisconsin; and region 9 includes Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota.

Figure 6. Biomass Resource Supply Curves for the Midwest, 2030 (NEMS coal regions 5, 6, and 9 combined)



Note: Supply region 5 includes Ohio; region 6 includes Illinois, Indiana, Michigan, and Wisconsin; and region 9 includes Iowa, Kansas, Minnesota, Missouri, Nebraska, North Dakota, and South Dakota.

In developing our supply curves, we worked extensively with Marie Walsh, an agricultural economist at the University of Tennessee, formerly at Oak Ridge National Laboratory (ORNL). Walsh and her colleagues at ORNL developed most of the original biomass supply curves used in NEMS.

To minimize the potential indirect land-use effects that could occur from growing switchgrass on cropland, we applied a fairly rough and conservative exclusion of 50 percent to the energy crop (switchgrass) supply used in the EIA 25-by-25 analysis. We also allow for most switchgrass production to occur on pasturelands and marginal agricultural lands, providing much greater life-cycle reductions in carbon emissions.

We used a rigorous approach to estimate the agricultural residues that must remain on the field to prevent erosion and maintain soil quality, based on research by Nelson and colleagues (Nelson et al. 2003; Nelson 2002). This research considers a number of environmental and best-management practices (such as a transition to reduced-till and no-till practices) by soil type, soil topography, and geographic location (Nelson 2002).

We also added some additional costs ($15 per dry ton) to account for uncertainties in projected costs for transportation, storage, and grower expenses. Our alternative technology pathway, which assumes more optimistic biomass supply costs and the ability to co-fire biomass at existing coal plants, does not include these additional costs. If we count energy crops, agricultural residues, and urban wastes, we estimate that 352 million dry tons of biomass is available in the United States for energy use in our core policy case, and 368 million dry tons of biomass in our alternative technology pathway—compared with 598 million tons in the EIA's 25-by-25 analysis.

Geothermal

The EIA's assumptions for the cost, performance, and resource potential of geothermal power plants are based on data from a 2004 study by GeothermEx for the California Energy Commission (Lovekin, Klein, and Sanyal 2004), and a 2006 study by the Geothermal Task Force for the Clean and Diversified Energy Initiative of the Western Governors' Association (CDEI 2006).

These studies did not include other potential geothermal resources, such as geothermal fluids co-produced with oil and gas, and enhanced geothermal systems (EGS), such as hot dry rock. The EIA did not include these potential resources in the geothermal supply curve because it did not believe they would see significant commercial use within the forecast horizon of 2030.

At least three new assessments address these non-conventional geothermal resources. These include a comprehensive study from MIT (Tester et al. 2006), a paper by Black Mountain Technology and NREL (Petty and Porro 2007), and a U.S. Geological Survey assessment of U.S. hydrothermal and EGS resources (Williams et al. 2008). We used the supply data from Petty and Porro in our analysis, with a few adjustments. We also incorporated recent increases in capital costs for geothermal, to make the costs consistent with the assumptions for other technologies. Finally, we projected these indices to incorporate real cost escalation through 2010.[1]

We made two additional assumptions that significantly contribute to the amount of geothermal supply absorbed by the electricity market in each year of the forecast. First, we used the EIA's learning rates, in the form of exogenous multipliers to capital and O&M costs. That reduces the costs of this technology by about 8 percent by 2020, and by 14 percent by 2030. These learning rates are conservative, and assume little to no impact from R&D.

Second, we allowed a maximum of 100 MW to be developed each year at each site. This limit—twice that assumed by the EIA—accounts for the larger capacities associated with each site in the Petty and Porro supply analysis (resulting from regional aggregation). We assumed capital costs of $6,550/kW for an in-service date 2015.

Coal

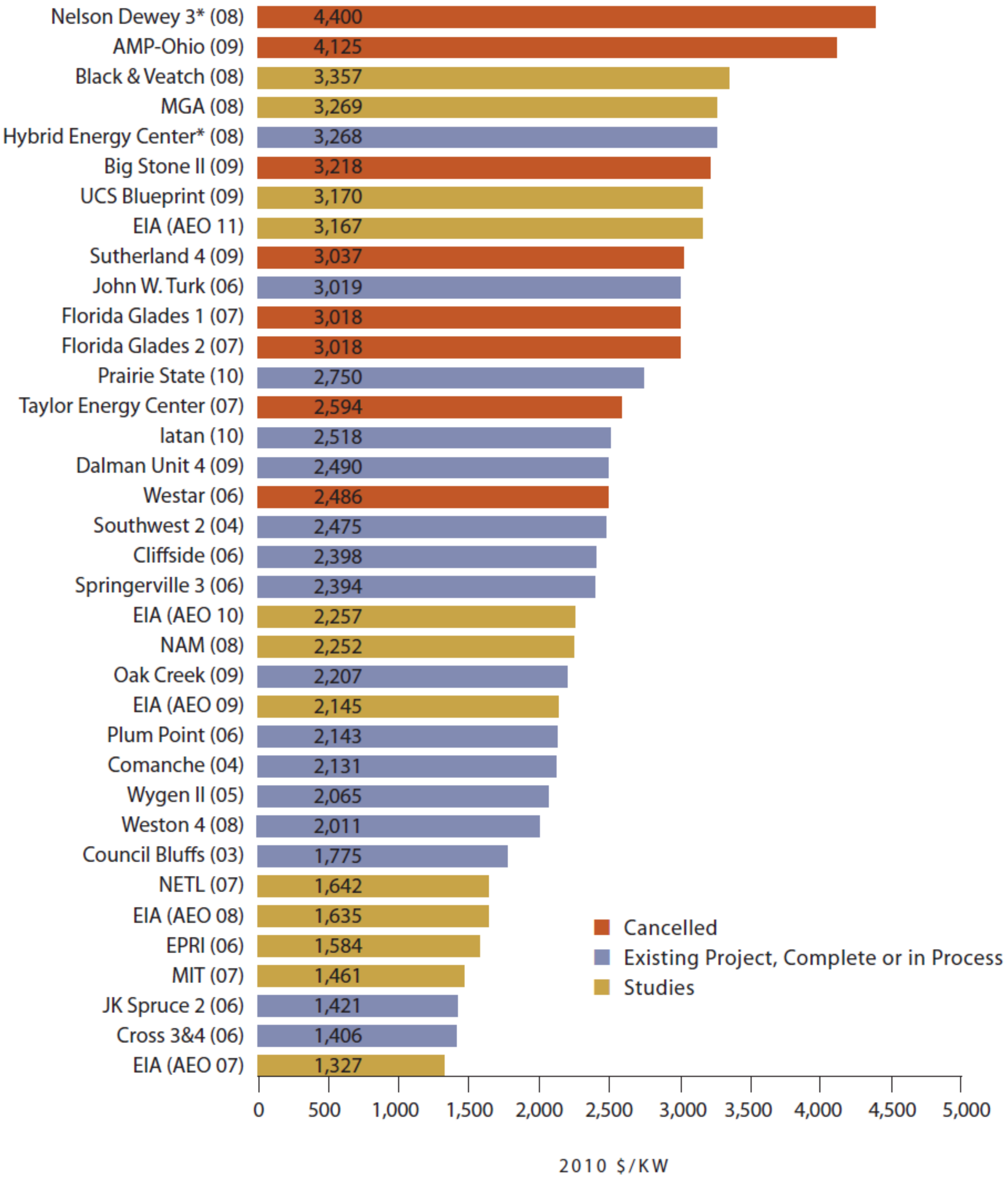
The three main coal technologies included in NEMS are new conventional pulverized coal plants (with scrubbers) and advanced IGCC plants with and without carbon capture and storage (CCS).

Pulverized coal plants. Our assumptions for overnight capital costs in the model are based largely on data from actual projects. Figure 7 shows actual "overnight" construction cost estimates for a number of coal plant proposals, and compares them with costs as projected by several studies. (Overnight costs do not include financing or escalating costs during construction.) The figure contains data from 16 existing, compete or in process projects (blue bars), 12 recent studies (yellow bars), and 8 cancelled projects (red bars). The figure includes cost estimates from several frequently used sources (EIA 2009d; EIA 2008a; EPA 2008; EIA 2007; MIT 2007; NETL 2007a; EPRI 2006).

The EIA raised its assumed capital costs estimates in each of its last four Annual Energy Outlooks as it attempted catch up with rising project prices. Over the four years, the EIA increased its estimated overnight capital costs from $1,327/kW in 2007 to $3,167/kW (for a typical 600-MW plant) in the early release of *AEO 2011* (EIA 2011; EIA 2007).

Based on recent project data, we assumed current overnight capital costs of $3,060/kW for projects with an in-service date of 2015. We also assumed higher O&M costs and heat rates than the EIA, based on data from Black & Veatch (O'Connell et al. 2007).

Figure 7. Capital Costs of Pulverized Coal Plants: Actual Projects vs. Studies



Source: EIA 2009d; EIA 2008a; EPA 2008; EIA 2007; MIT 2007; NETL 2007a; EPRI 2006.

Note: The figure includes some circulating fluidized bed plants (noted with an asterisk). The year of the cost estimate is shown next to the name of each plant and study.

IGCC plants without CCS. Reliable cost estimates for producing electricity from coal IGCC plants are very limited, as no projects have been built in the United States recently. While coal gasification technology has been demonstrated fairly extensively in the industrial sector, the use of the technology to produce electricity on a large scale is limited to a small number of demonstration plants built in the United States in the 1980s and 1990s.

Therefore, we relied heavily on existing studies and project proposals to develop our capital cost assumptions. We assumed that capital costs for IGCC plants will be 16 percent higher than those for pulverized coal plants, based on estimates from the EIA (2008b), the NETL (2007a), MIT (2007), and the MGA (2008). This translates into an overnight capital cost range of $3,200/kW to $3,800/kW (including real cost escalation) for plants with a 2015 in-service date. We assumed overnight capital costs of $3,510 per kW (including real cost escalation) for plants a 2015 in-service date.

These assumptions are consistent with cost data from three proposed IGCC projects that have been subject to extensive review and contested case proceedings before state public utility commissions. The Mesaba project in Minnesota has an estimated capital cost of more than $3,000 per kW (in 2006 dollars), including engineering, procurement, construction, and owners' costs. Total costs, including financing, transmission, and other site costs, come to nearly $3,600 per kW (DOE 2007c).

The proposed 630-MW Mountaineer project in West Virginia has a reported cost of $2.23 billion (LCG Consulting 2007), or $3,540/kW (in 2012 dollars). However, costs at the 618-MW Edwardsport IGCC facility in Indiana have been coming in much higher than our estimate. In 2010, estimated costs for the project rose to $2.9 billion, or 23 percent higher than the 2009 estimate and 53 percent higher than the original price tag in 2006 (Duke Energy Indiana 2010; O'Malley 2010). The resulting capital cost is $4,693/kW (including financing costs).

A 2007 analysis by Emerging Energy Research estimated capital costs of $3,300/kW for 2007 projects, which it claims is about twice as high as for projects proposed in 2004 (IHS EER 2007). Other commonly referred to sources (such as EIA 2008a, MIT 2007, NETL 2007a, and IPCC 2005) assume capital costs for IGCC ranging from $1,326 to $1,977/kW. As noted, these sources do not reflect all of the recent escalation in costs, do not include owners' costs, and in some cases (e.g., MIT 2007) assume some cost reductions for from learning.

We also made the following changes to the EIA's assumptions for coal IGCC plants. We:

- Reduced the maximum capacity factor from 85 percent to 80 percent, based on data from Black & Veatch (EERE 2008). According to Standard & Poor's, while major IGCC suppliers have claimed readiness and assume capacity factors of 85 percent, no contractor has offered a fixed-price turnkey contract with liquidated damages for cost, time, and performance (Standard & Poor's 2007). IGCC projects are also expected to have teething problems similar to the demonstration projects from the late 1980s and early 1990s, resulting in slightly lower availability and average lifetime capacity factors.

- Increased the construction lead time from four years to five years, assuming that projects will experience delays because of uncertainty around future costs, federal CO_2 regulations, limited technology guarantees, and other factors cited by recent projects.
- Used slightly higher heat rates, based on an MIT study (MIT 2007), and slightly higher O&M costs, based on data from Black & Veatch (EERE 2008).

A few recently proposed IGCC projects have also reported all-in levelized costs for producing electricity that provide useful data for comparative purposes. For example, staff from the Minnesota Department of Commerce, testifying before the Minnesota Public Utilities Commission, estimated that the Mesaba IGCC proposal would have a levelized cost of $96 to $131/MWh (in 2006 dollars), without transmission or CCS, and $155 to $190 per MWh, with transmission and CCS (Amit 2006). MidAmerican Energy Holdings announced that it had received a reasonably firm contractual offer for an IGCC plant with CCS in Wyoming with a levelized cost $110 to $120/MWh (Standard and Poor's 2007).

IGCC plants with CCS. We assumed that the capital costs of coal IGCC plants with CCS are 41 percent higher than those of IGCC plants without CCS, based on a range of estimates (EIA 2008b; MGA 2008; MIT 2007; NETL 2007a). We assumed capital costs of about $4,870/kW for a project with an in-service date of 2015.

Estimates published after we finalized our assumptions have estimated costs of $5,000/kW to $6,500/kW (in 2010 dollars) (EIA 2011; Exelon 2010), and the Tenaska IGCC plant with CCS in Taylorville, IL, is reporting a cost of $5,263/kW, which falls within this range (WorleyParsons 2010).

The cost of transportation (via pipeline) and storage will vary depending on the distance and quantity of gas transported, and the type, depth, and properties of the storage site. Potential storage sites include depleted oil and gas fields, saline formations, deep coal seams, and other geological formations. Reservoirs with porous and permeable rock at depths of roughly one kilometer appear to be the most promising. Initial projects would likely occur in depleted oil and gas fields to facilitate enhanced oil recovery, which can offset some of the costs of CCS. However, an MIT study (2007) indicates that most geologic sequestration will likely occur in saline formations, because of their large storage potential and broad distribution.

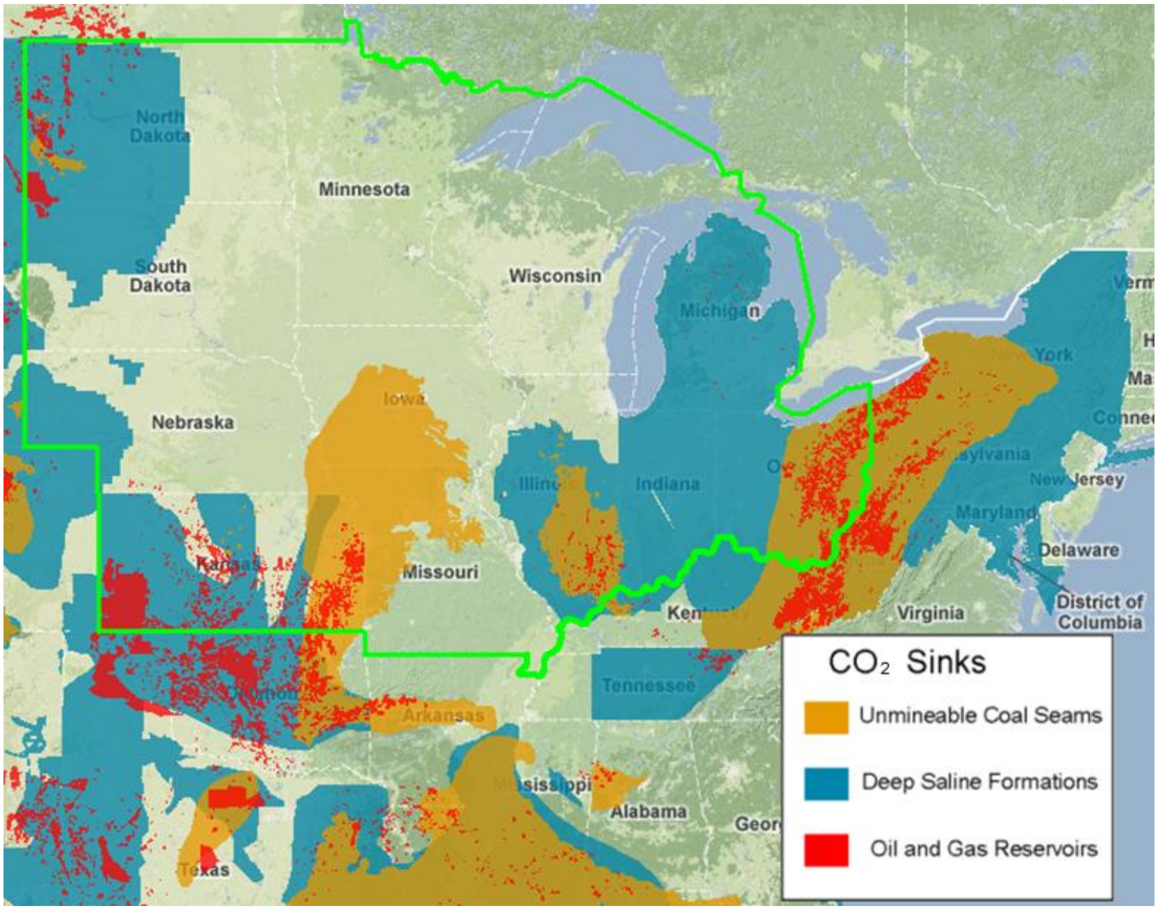
The National Energy Technology Laboratory estimates that the 12 Midwest states have the capacity to sequester 188 to 310 billion tons of CO_2—more than 90 percent in saline formations (Table 2 and Figure 8) (NETL 2007b).

Table 2. Capacity in Midwest States for Sequestering CO_2 Underground (billion metric tons)

State	Low Estimate	High Estimate
Illinois	20.7	78.2
Indiana	22.5	44.3
Iowa	0.0	0.0
Kansas	2.7	5.4
Michigan	51.1	51.1
Minnesota	0.0	0.0
Missouri	0.2	0.6
Nebraska	13.4	13.4
North Dakota	29.8	32.2
Ohio	19.6	19.6
South Dakota	28.2	65.2
Wisconsin	0.0	0.0
Total	**188.2**	**310.1**

Source: NETL 2007b.

Figure 8. Potential Sites for Sequestering CO_2 in the Midwest



Source: NETL 2007b.

For coal plants near good sequestration sites, MIT analysts (2007) estimate that the cost of transporting and injecting CO_2 should be less than 20 percent of the total cost for capturing, compressing, transporting, and injecting the CO_2. Because the NEMS model cannot distinguish between different types of storage sites and the transportation distance to those sites, a simple average cost is used.

In June 2007, the DOE issued a draft environmental impact statement that included a cost estimate of $1.76 billion for the 275-MW project ($6,400/kW). This cost is nearly twice as high as the DOE's 2004 estimate for the project ($950 million, in 2004 dollars). While this is a demonstration project, and therefore should have higher initial costs than commercial projects, achieving the range of costs assumed in this analysis would appear to require significant cost reductions.

The energy penalties from adding CCS to an IGCC plant are well documented in MIT 2007. The MIT study estimates that adding CCS will reduce the efficiency of an IGCC plant by 23 percent. Just as we assumed for IGCC plants without CCS, we used slightly higher heat rates than the EIA (2008b), based on the MIT assumptions and more modest improvements in efficiency over time. Our assumptions for capacity factors and lead times are the same as for IGCC plants without CCS.

Natural gas

The main natural gas technologies included in NEMS are conventional and advanced natural gas combustion turbine (NGCT) peaking plants, conventional and advanced natural gas combined cycle (NGCC) plants, and advanced NGCC plants with CCS.

The cost and performance assumptions for new advanced NGCC and NGCT plants are based on Black & Veatch data from actual projects (O'Connell 2008), and data collected by the California Energy Commission for more than 30 plants installed in California from 2001 to 2006 (CEC 2007).

We estimated the capital costs for conventional NGCC and NGCT plants by multiplying the costs for advanced plants by the ratio of the costs of conventional plants to those of advanced plants, using the EIA's assumptions (EIA 2008b). For NGCC, we assumed overnight capital costs of $1,100 per kW for an in service date of 2015.

For NGCC plants with CCS, we assumed that capital costs are 95 percent higher than those of NGCC plants without CCS, based on a range of estimates (MGA 2008; EIA 2008b; NETL 2007a; IPCC 2005). We also assumed slightly higher heat rates than the EIA, consistent with the increases we assumed for NGCC plants without CCS. For NGCC with CCS, we assumed overnight capital costs of $2,080/kW for an in-service date of 2016, which is the first year the model shows NGCC with CCS coming online.

Nuclear

The cost of electricity based on nuclear power is largely driven by plant construction costs. It is difficult to reliably project construction costs for U.S. nuclear plants today because there is no recent U.S. experience to draw on.

Recent experience with reactors under construction in Europe, however, along with recent broad trends in the cost of commodities and construction, show the same vulnerability to cost escalation that plagued the last generation of nuclear plants. Three years after the owners broke ground in 2005, for example, the Olkiluoto plant in Finland was three years behind its scheduled operating date of 2009, and cost overruns have exceeded 80 percent. Numerous quality problems have been reported, and project principals are in arbitration over responsibility for the delays and overruns (Wald 2007).

Construction costs have increased for all technologies for generating electricity over the past decade, but most dramatically for nuclear plants. A power plant capital cost index developed by CERA shows the costs of nuclear power plants rising 131 percent from 2000 to the first quarter of 2008 (in nominal dollars), compared with 82 percent for other power plants (IHS CERA 2009a). The most recent CERA analysis shows costs declining for nuclear power in 2008, but leveling off and increasing slightly in 2009, 2010 and the first half of 2011 (IHS CERA 2011).

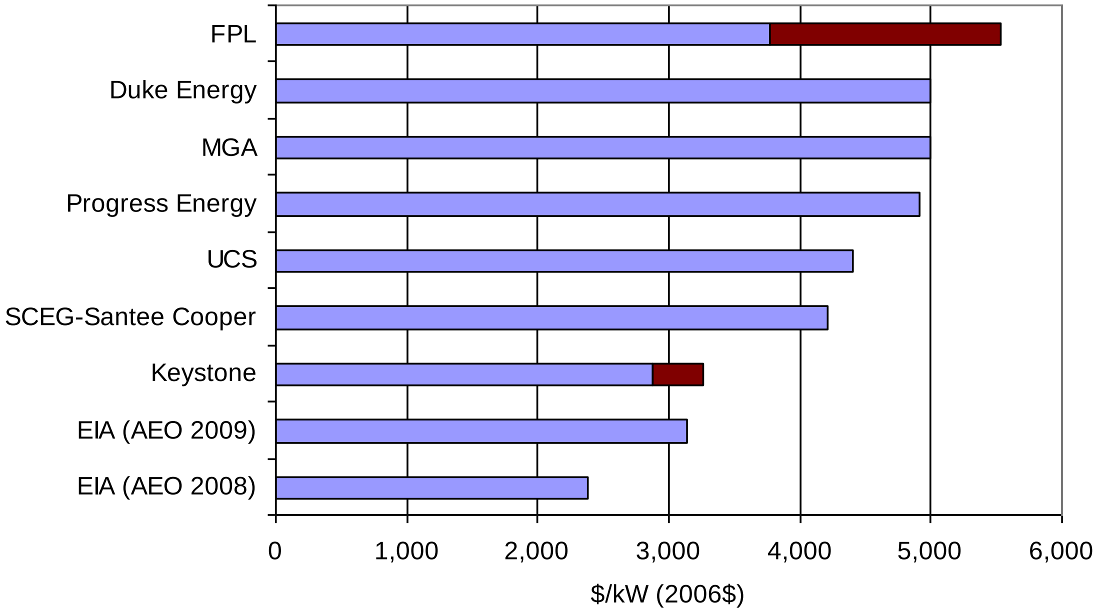
These cost increases are evident in recent proposals for nuclear plants. In November 2008, Duke Energy revised its estimate of overnight construction costs for two units proposed for Cherokee County, SC, to $5,000 per kW—about double its original estimate (*World Nuclear News* 2008). Cost estimates from utilities applying for loan guarantees that month for 21 proposed plants, including escalation and financing, totaled $188 billion—$9 billion per plant, or more than $6,500 per kW.

Several other proposed plants have shown a range of $3,800 to $5,500 per kW, not including financing costs (Figure 9) (FPL 2008; Loder 2008; Progress Energy 2008a; Progress Energy 2008b; Reuters 2008). A recent report showed a range of $2,350 to $10,308 per kW (in 2008 dollars), with an average of $4,880/kW for estimates from 2007 to 2009 (Cooper 2009).

More recent data published after we finalized our assumptions suggest even higher numbers. In the most recent Annual Energy Outlook, the EIA estimated $5,275/kW for a plant built in 2010. Excelon estimated a range of $5,000 to $6,000/kW in 2016 (Exelon 2010). Koplow estimated all-in costs of $7,452 to $9,375/kW based on information from the proposed Bell Bend and Levy nuclear power plants (Koplow2010).

In our analysis, we conservatively assumed that overnight capital costs (not including financing costs) for new nuclear plants will initially average $5,240/kW (in 2007 dollars) for plants with a 2016 in-service date, which is the first year the model shows new nuclear plants coming online. Although some recent estimates for nuclear power plants have come in higher, the drop in commodity prices has been reflected in nuclear plant construction costs. IHS CERA reported a decrease in the costs of nuclear power plants in the last year, although this trend has slowed as commodity prices have stabilized (IHS CERA 2009b). As noted, we also assumed that industry learning could reduce those costs by nearly 7 percent by 2030—or half the rate projected by the EIA, which bases its projection on international experience.

Figure 9. Estimates of Overnight Capital Costs for Advanced Nuclear Plants (various sources)



Source: Cleetus, Clemmer, and Friedman 2009; EIA 2009d, 2008b; FPL 2008; Loder 2008; MGA 2008; Progress Energy 2008a; Progress Energy 2008b; Reuters 2008; *World Nuclear News* 2008; Keystone Center 2007.
Note: All estimates include real escalation in construction costs, but not interest accrued during construction, or financing costs. Florida Power and Light's (FPL's) estimate and the Keystone study assume a low- and a high-cost range, represented by the darker bars. FPL, Duke Energy, Progress Energy, and SCEG-Santee Cooper are proposed plants, while EIA, MGA, UCS, and Keystone are studies.

There is a high risk that actual nuclear construction costs will exceed the assumptions we used in our analysis, for several of reasons. The nuclear industry has been moribund in the United States, France, and Russia for nearly 20 years, and therefore faces significant scale-up challenges, with pinch points throughout the supply chain. Two decades ago the United States had about 400 suppliers and 900 holders of N-stamp certificates (sub-suppliers) licensed by the American Society of Mechanical Engineers. Today those numbers are 80 and 200, respectively (*Nucleonics Week* 2007a).

Worldwide forging capacity for pressure vessels, steam generators, and pressurizers is also quite limited. Two companies in the world can supply heavy forgings—Japan Steel Works (JSW) and France's Creusot Forge—and the nuclear industry will be competing with demand from other sectors. Only JSW has the capability to manufacture ultra-heavy forgings, above 500 tons, and the company's prices have at times increased prices drastically requiring large down payments (*Nucleonics Week* 2007a).

It now takes about six years to procure and manufacture other long-lead-time nuclear components, including reactor cooling pumps, diesel generators, and control and instrumentation equipment. Dale Klein, then chair of the Nuclear Regulatory Commission, indicated that heavy reliance on foreign suppliers could require more time for quality-control inspections, to ensure that U.S. plants do not incorporate substandard materials (*Nucleonics Week* 2007a). Expansion of domestic production capacity in all these areas is possible, but will take time.

The availability of skilled labor is also problematic. A 2005 study for the Tennessee Valley Authority cited a lack of craft labor within a 400-mile radius as forcing a longer construction schedule for nuclear power plants (Toshiba Corp. et al. 2005). Others have also cited this problem, at least in the United States (*U.S. News* 2008; NPR 2007; *Nucleonics Week* 2007b; *IBEW Journal* 2005).

There is now additional uncertainty around the costs of increased safety measures at existing and new nuclear power plants. Given the effects of the March 11, 2011, earthquake and tsunami on the Fukushima Daiichi nuclear power plant in Japan, proposals for new plants will likely be subject to additional reviews and changes, potentially causing delays and adding costs to their construction and operation.

We also made the following changes to the EIA's assumptions for advanced nuclear plants. We:

- Increased fixed O&M costs from $66 per kW-year to $110 per kW-year, including the cost of capital additions to U.S. reactors. This cost is in the middle of the range in a Keystone study (Keystone Center 2007), developed with input from a diverse stakeholder group, including the nuclear industry.
- Increased variable O&M costs from $0.48 to $7.50 per MWh, which include decommissioning costs. This is based on the middle of the range from the 2007 Keystone study, which assumes a fund to recover $500 million in decommissioning costs, and includes data from recent projects that assume $1 billion in decommissioning costs.
- Reduced the maximum capacity factor from 90 percent to 85 percent. U.S. nuclear capacity factors rose from less than 60 percent during most of the 1980s to just above 90 percent in 2007 and 2008. However, lifetime average capacity factors have been closer to 75 percent, reflecting both teething problems early in the life of nuclear power plants and aging challenges later on (Joskow 2006; MIT 2003).

We also adopted a few fairly optimistic EIA assumptions for advanced nuclear plants, including:

- Fuel costs of about 0.75 cents per kWh. While these costs are consistent with current long-term contracts, they do not reflect higher spot-market prices, which have increased as much as ninefold over the past eight years (in constant dollars). According to the 2007 Keystone study, most contracts are set to expire by 2012. And "recent analyses by MIT suggest that low production, dampened investment related to long-term contracts, and lagging expansion of enrichment capacity are likely to lead to continued higher prices into the future" (Neff 2007).

- Financing costs and terms that are similar to other technologies in NEMS. No nuclear plant has been built in the United States for decades, and there is considerable risk of schedule delays, cost overruns, and regulatory disallowances. In light of past experience, state regulators may impose cost caps before construction begins. All these factors may lead to a higher required return on investment and/or lower bond ratings, even for very large utilities. Federal loan guarantees can improve financing terms significantly, but it is unclear what impact they will have on debt-equity structure, return on equity, and return on debt.

Finally, we adopted the EIA's assumption that existing plants will be relicensed and continue operating through the end of their 20-year license extension, and will then be retired.

Transmission

The EIA includes transmission costs for all new electric generating capacity in NEMS. These costs vary by region, ranging from $200 to $500/ kW (in 2007 dollars). This range is consistent with a 2009 LBNL study that found a median cost of transmission for wind of $300 per kW, or roughly $15/MWh (Mills, Wiser, and Porter 2009). That study was based on a sample of 40 detailed transmission studies from 2001 to 2008 that included wind energy resource areas in their analysis.

As noted, we included additional transmission, resource degradation, and siting costs for wind at increasing levels of penetration, based on GIS modeling by the NREL for the EIA (PERI 2007). We assumed that these factors could increase the capital costs of wind by up to 50 percent. We also allowed the model to build more transmission lines between regions in the Midwest, and to regions to the east that are part of the PJM regional transmission organization.

Summary of cost and performance assumptions

The capital cost assumptions for new fossil fuel, nuclear, and renewable energy technologies in our base case are shown in Tables 3 through 6, as are assumptions for O&M costs and heat rates. Table 7 also shows assumed improvements in capacity factors over time for wind and solar technologies. These capacity factors are used to determine the amount of electricity generated each year by each of the technologies. This generation is broken down further into nine time periods, representing three seasons (winter, summer, and fall/spring) and three times during a 24-hour period.

Table 3. Total Overnight Capital Costs in UCS-NEMS 2015 and 2030 for the Base Case, Core Policy Case, and Alternative Technology Pathway

	Base Case		Core Policy Case		Alternative Technology Pathway	
Technology	**2015**	**2030**	**2015**	**2030**	**2015**	**2030**
Scrubbed coal (new)	3,060	3,040	3,060	3,040	3,060	3,040
Integrated coal-gasification combined cycle (IGCC)	3,510	3,270	3,500	3,270	3,500	3,270
IGCC with carbon sequestration	4,870	4,220	4,870	4,220	4,870	4,220
Conv. gas/oil combined cycle	1,130	1,120	1,130	1,120	1,130	1,120
Advanced gas/oil combined-cycle	1,100	1,030	1,100	1,030	1,100	1,030
Advanced CC with carbon sequestration *	2,080	1,770	2,080	1,770	-	1,770
Conventional combustion turbine	800	790	800	790	800	790
Advanced combustion turbine	740	670	740	670	740	670
Fuel cells	7,340	5,950	7,340	5,950	7,340	5,950
Advanced nuclear *	5,240	5,020	5,240	5,020	-	5,020
Biomass	4,600	4,150	4,600	4,150	4,600	4,150
Geothermal	6,550	6,550	6,550	6,550	6,550	6,550
Conventional hydropower	2,190	2,230	2,390	2,460	2,390	2,460
Wind	2,430	2,310	2,430	2,310	2,300	2,310
Wind (offshore)	3,580	3,150	3,580	3,140	3,580	3,150
Solar thermal	4,970	3,900	4,970	3,900	4,970	3,900
Photovoltaic	5,530	3,970	5,530	3,970	5,530	3,970

* for plants entering service in 2016—the first year for which the model shows advanced gas/oil combined-cycle plants and advanced nuclear plants coming online.

Table 4. Comparison of Variable Operations and Maintenance (O&M) Costs between UCS-NEMS and *AEO 2009*

Technology	UCS-NEMS ($2007 mills/kWh)	AEO 2009 ($2007 mills/kWh)
Scrubbed coal (new)	1.7	4.6
Integrated coal-gasification combined cycle (IGCC)	4.0	2.9
IGCC with carbon sequestration	4.4	4.4
Conv. gas/oil combined cycle	4.4	2.1
Advanced gas/oil combined-cycle	3.1	2.0
Advanced CC with carbon sequestration *	2.9	2.9
Conventional combustion turbine	3.5	3.6
Advanced combustion turbine	2.9	3.2
Fuel cells	47.7	47.9
Advanced nuclear	7.7	0.5
Distributed generation -base	7.1	7.1
Distributed generation -peak	7.1	7.1
Biomass	6.7	6.7
MSW - landfill Gas	0.0	0.0
Geothermal	-	-
Conventional hydropower	3.5	2.4
Wind	7.2	-
Wind offshore	21.5	-
Solar thermal	-	-
Photovoltaic	-	-

Table 5. Comparison of Fixed Operations and Maintenance (O&M) Costs between UCS-NEMS and *AEO 2009*

Technology	UCS-NEMS ($2007/kW)	*AEO 2009* ($2007 /kW)
Scrubbed coal (new)	36.08	27.53
Integrated coal-gasification combined cycle (IGCC)	38.95	38.67
IGCC with carbon sequestration	45.25	46.12
Conv. gas/oil combined cycle	9.71	12.48
Advanced gas/oil combined-cycle	14.72	11.7
Advanced CC with carbon sequestration *	19.79	19.9
Conventional combustion turbine	12.04	12.11
Advanced combustion turbine	6.75	10.53
Fuel cells	5.62	5.65
Advanced nuclear	112.44	90.02
Distributed generation -base	15.94	16.03
Distributed generation -peak	15.94	16.03
Biomass	64.09	64.45
MSW - landfill Gas	113.62	114.25
Geothermal	163.74	164.64
Conventional hydropower	13.89	13.63
Wind	11.76	30.3
Wind offshore	15.33	89.48
Solar thermal	75.64	56.78
Photovoltaic	24.53	11.68

* Declines over time

Table 6. Comparison of Heat-Rate Assumptions between UCS-NEMS and *AEO 2009*

	UCS-NEMS		AEO 2009	
Technology	Heat Rate in 2008 (Btu/kWh)	Heat Rate nth-of a-kind (Btu/kWh)	Heat Rate in 2008 (Btu/ kWh)	Heat Rate nth-of a-kind (Btu/kWh)
Scrubbed Coal New	9,200	9,000	9,200	8,740
Integrated Coal-Gasification Combined Cycle (IGCC)	8,868	8,314	8,765	7,450
IGCC with carbon sequestration	10,942	10,204	10,781	8,307
Conv Gas/Oil Comb Cycle	6,990	6,990	7,196	6,800
Adv Gas/Oil Comb Cycle (CC)	6,870	6,870	6,752	6,333
ADV CC with carbon sequestration	8,731	8,030	8,613	7,493
Conv Combustion Turbine	9,266	9,266	10,810	10,450
Adv Combustion Turbine	9,104	8,900	9,289	8,550
Fuel Cells	7,930	6,960	7,930	6,960
Advanced Nuclear	10,400	10,400	10,434	10,434
Distributed Generation -Base	9,200	8,900	9,050	8,900
Distributed Generation -Peak	10,257	9,880	10,069	9,880
Biomass	9,014	8,460	9,646	7,765
MSW - Landfill Gas	13,648	13,648	13,648	13,648
Geothermal	35,376	33,729	34,633	30,301
Conventional Hydropower	10,022	10,022	9,919	9,919
Wind	10,022	10,022	9,919	9,919
Wind Offshore	10,022	10,022	9,919	9,919
Solar Thermal	10,022	10,022	9,919	9,919
Photovoltaic	10,022	10,022	9,919	9,919

Note: For hydro, wind, and solar technologies, the heat rate shown represents the average heat rate for conventional thermal generation as of 2007. This is used to calculate primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.

Table 7. UCS-NEMS Projections of Capacity Factors for Wind and Solar Technologies

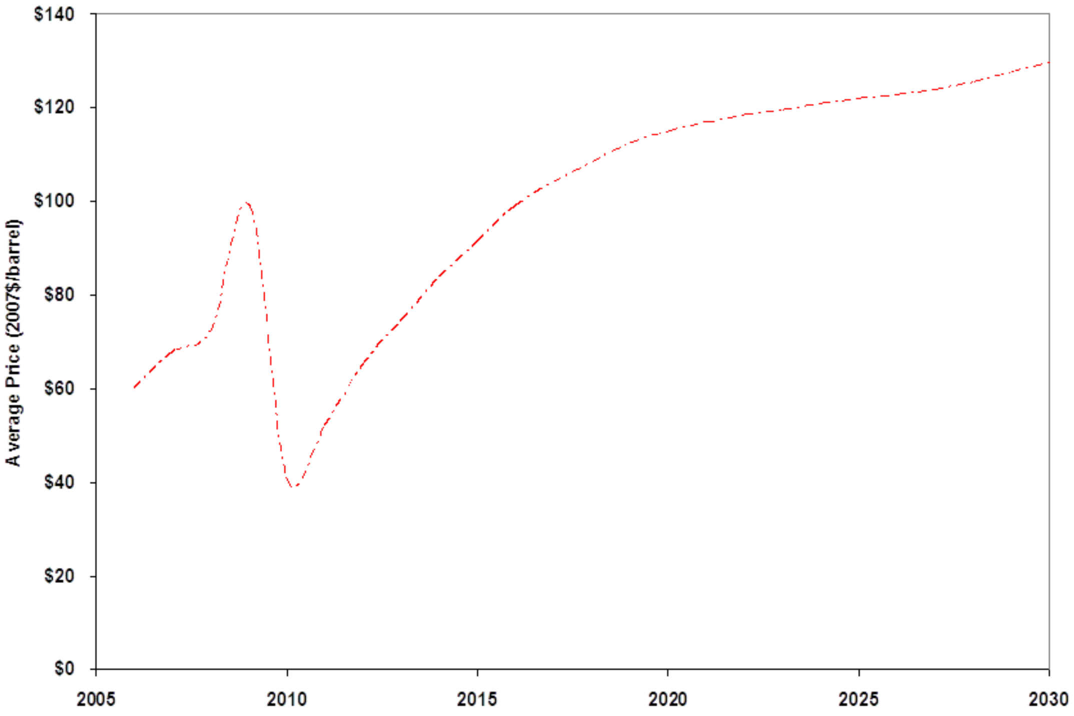
	2005	2010	2015	2020	2025	2030
Onshore Wind						
Class 3	32.2%	34.9%	36.4%	37.5%	38.0%	38.4%
Class 4	36.0%	39.0%	40.7%	41.9%	43.0%	43.0%
Class 5	39.8%	42.6%	44.2%	45.0%	46.0%	46.0%
Class 6	43.6%	45.9%	47.5%	48.2%	49.0%	49.0%
Offshore Wind						
Class 3	33.8%	36.6%	38.2%	39.4%	40.0%	40.3%
Class 4	37.8%	40.9%	42.7%	44.0%	45.0%	45.0%
Class 5	41.8%	44.7%	46.4%	47.3%	48.0%	48.0%
Class 6	45.8%	48.2%	49.9%	50.6%	51.0%	51.0%
Concentrating Solar Power	43.0%	43.0%	45.0%	48.3%	51.7%	55.0%
Utility-Scale PV	20.4%	23.2%	1.0%	1.0%	1.0%	1.0%
Distributed PV	16.0%	17.8%	1.0%	1.0%	1.0%	1.0%

Fuel price assumptions

For our base case, we adopted the EIA's assumptions from its updated *Annual Energy Outlook 2009* report (EIA 2009e) to project oil, natural gas, and coal prices. The updated *AEO 2009* reference case included updated assumptions for drilling and pipeline construction in the oil and natural gas industry, refinery costs, and capital costs in the liquefied natural gas supply chain. The EIA's updated *AEO 2009* report also reflects the provisions of the American Recovery and Reinvestment Act of 2009 and to reflect recent changes in the economic outlook.

The updated *AEO 2009* oil price projections are lower in the near- and mid- term owing to the global financial crisis and recession combined with the provisions of the American Recovery and Reinvestment Act of 2009. However, the updated *AEO 2009* expected the global economy to begin recovering in 2010 and return to long-term growth trends in later years (Figure 10) (EIA 2009e).

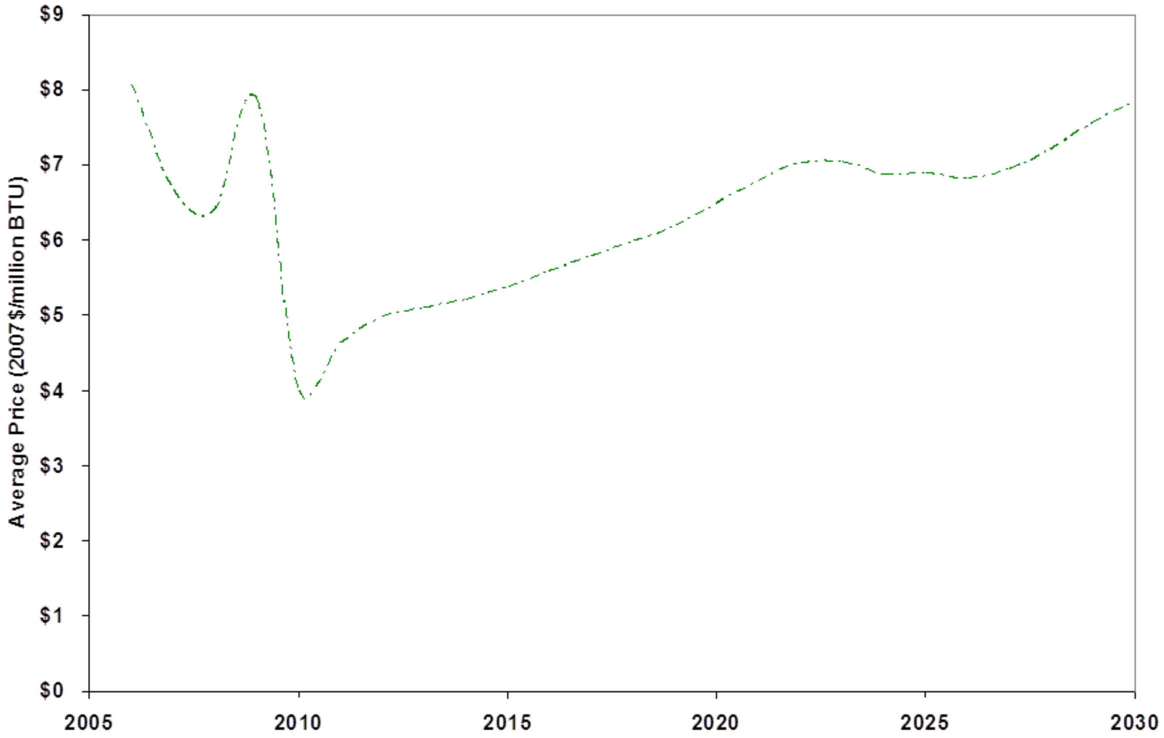
Figure 10. Oil Prices: Reference Case, Updated *AEO 2009*



Source: EIA 2009e.

The wellhead price of natural gas generally increases in the updated *AEO 2009* reference case, as more expensive domestic resources are used to meet demand. Prices decline for a brief period after the Alaska pipeline begins operating in 2020, but the market quickly absorbs the additional natural gas supplies from Alaska, and prices resume their rise (Figure 11) (EIA 2009e).

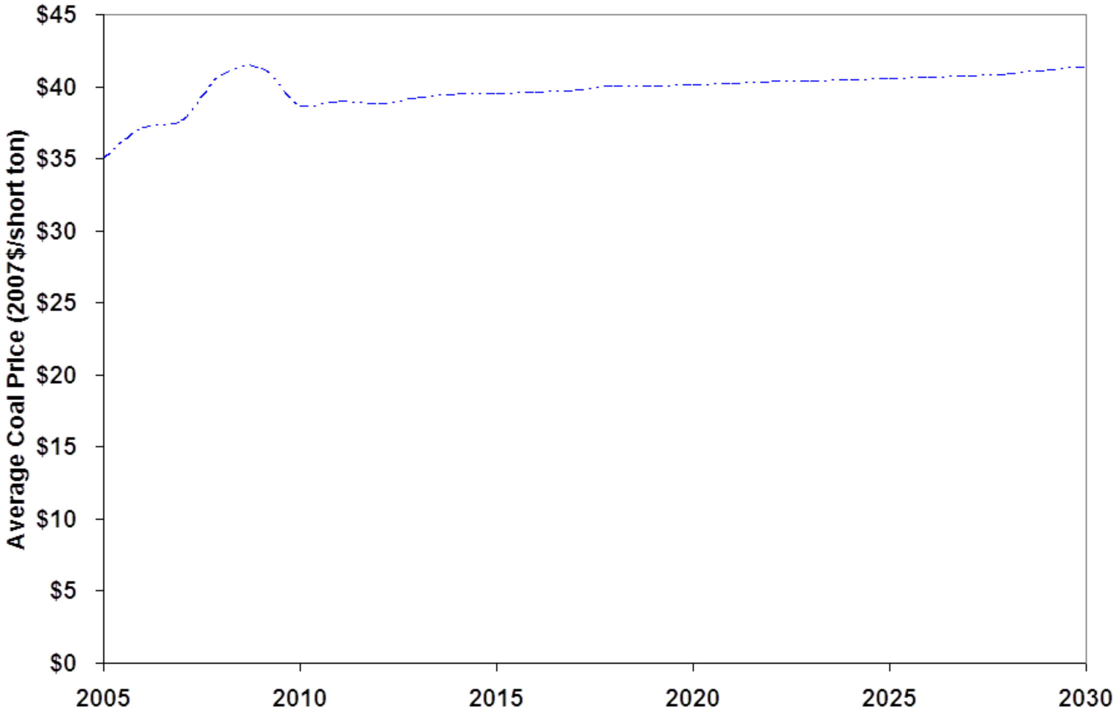
Figure 11. Average Wellhead Prices for Natural Gas: Reference Case, Updated *AEO 2009*



Source: EIA 2009e.

The updated *AEO 2009* showed that coal prices rose significantly from 2007 through 2008, reflecting rising prices for the equipment, parts, supplies, and fuel used at coal mines. After the initial run-up, however, prices are projected to level off and then fall slightly through 2020, as mine capacity declines and production shifts away from the higher-cost mines of central Appalachia (Figure 12) (EIA 2009e).

Figure 12. Average Prices of Delivered Coal: Reference Case, Updated *AEO 2009*



Source: EIA 2009e.

Methodology for Analyzing Economic Impacts

The three main macroeconomic impacts estimated in our study include changes in employment, wage and salary compensation, and gross state product (GSP) (all reported in real 2007 dollars). We estimated those impacts using state and regional economic data derived from the IMPLAN (Impact Analysis for Planning) model.[4] IMPLAN is an input-output (I-O) model that identifies interactions among all sectors of the economy. For each of the benchmark years, each change in an industry's spending pattern is matched to an appropriate industry multiplier. The approach used in this analysis is consistent with previous UCS studies (UCS 2009) and the NREL's Jobs and Economic Development Impact (JEDI) model.[5]

Input-output models were initially developed to trace supply linkages in the economy. Thus, the impacts of our policy scenarios depend on the structure of the Midwest economy. For example, I-O models can show how increasing purchases of renewable energy and energy efficiency technologies and related equipment not only directly benefit the construction and manufacturing sectors, but also indirectly benefit industries that provide goods and services to those sectors, such as banking and accounting. I-O models also quantify the induced economic activity that results from the re-spending of higher incomes, and of savings on consumer energy costs.

For each industry sector, we used state- and region-specific IMPLAN multipliers that identify the employment or economic activity generated from a given level of spending. For example, employment multipliers show the number of direct, indirect, and induced jobs supported for each $1 million of expenditures (final demand) in a specific sector. In this analysis, a job is defined as sufficient wages to employ one person full-time for one year.

To derive the net economic and employment benefits from the policy scenarios in our study, we first calculated changes in expenditures in each state and the regional economy compared with our base case. These changes stem from the construction, manufacturing, operation, and maintenance of renewable energy and energy efficiency technologies, and the resulting changes in consumer energy bills.

We also calculated annual average capital expenditures for each technology, to estimate the long-term impact on jobs and economic activity in the construction and manufacturing sectors. This provided a consistent basis for combining these effects with

---

[4] We adapted the national data in IMPLAN 2008 (the latest version available) for our analysis. See Minnesota IMPLAN Group at *http://implan.com/V4/Index.ph.p.*

[5] See *http://www.nrel.gov/analysis/jedi/.*

the long-term jobs created to sustain the annual operations and maintenance of these technologies.

Next, we analyzed the economic losses resulting from the change in expenditures on coal and natural gas power plants displaced or avoided in the policy scenarios compared with the base case.[6] We then derived the net impact on each state and the regional economy by subtracting these losses from the gains stemming from investments in renewable energy and efficiency.

We made several adjustments to the methodology of merely matching state and regional expenditures and multipliers. First, we assumed that only a portion of the expenditures for renewable and conventional generation technologies are spent in the Midwest. We assumed that the remaining expenditures would be spent on goods and services imported from other states and countries, and therefore would not generate any economic benefits in the Midwest.

Table 8 shows the local share of expenditures (also known as regional purchase coefficients, or RPCs) we used to allocate spending on energy technologies across the region, and to each state. The local share of expenditures for manufacturing biomass, landfill gas, coal, and natural gas power plants were derived directly from IMPLAN data by industry sector for each state and the Midwest as a whole, as these more established technologies are well represented in the model. We also assumed a 50 percent local share of construction labor for these technologies.[7]

For wind and solar, which have grown dramatically over the past few years and are not well represented in IMPLAN, we based the local share of manufacturing and construction labor on recent state and regional supply chain data collected by the wind and solar industries and federal agencies. According to the American Wind Energy Association (AWEA), the number of facilities manufacturing wind turbines and components in the United States has increased from a few dozen in 2004 to more than 240 in 2010, not including many facilities at the sub-supplier level (AWEA 2010).

Based on this information, AWEA estimates that the domestic share of U.S. wind turbine manufacturing rose from 20–25 percent in 2005 to some 50 percent in 2010. Another study using data from the U.S. Department of Commerce estimates an even higher

---

[6] This includes avoided capital, financing, operations and maintenance, and fuel costs.

[7] This is consistent with labor parameters in the National Renewable Energy Laboratory's JEDI natural gas and coal models. See *http://www.nrel.gov/analysis/jedi/.*

domestic content of 36 percent in 2006, increasing to 68 percent in 2009 (David 2010; Wiser and Bolinger 2010).

Given the high concentration of wind turbine and component manufacturing facilities in the Midwest, we assumed that the region will follow these national trends. For states with existing turbine (nacelle), tower, and blade manufacturing, we assumed that 50 percent of the expenditures for those components would be sourced locally, given the size, weight, and high cost of transporting of towers and blades over long distances.

For states with suppliers of components for this equipment, such gearboxes and generators, we assigned a lower local share of 5–25 percent. For states that do not have any companies supporting these activities, we conservatively assumed that all the equipment would have to be imported through 2030.

We assumed that at least 75 percent of construction labor would be sourced within a state.[8] In Minnesota and Indiana, we assumed a 90 percent local share for construction labor, because those states have two very large construction firms that are building wind projects in several states across the country.

For solar PV, we estimated local shares for each state and the region using data from the Solar Energy Industries Association on 416 companies involved in the installation, manufacturing, and distribution supply chain in the Midwest (Figure 13 (SEIA 2011). We assumed that all construction labor for installing solar PV would be sourced locally, given the relative ease of installation, and links to established residential and commercial building industries.

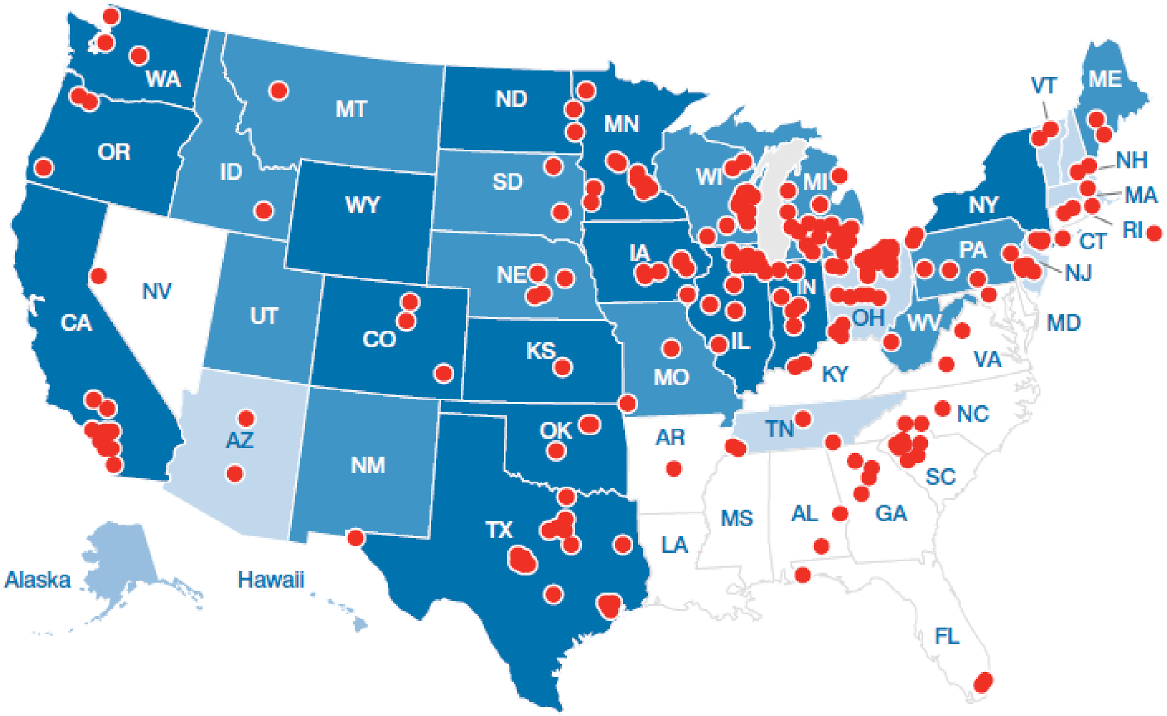
While some 115 companies in the region are now involved in manufacturing and supplying PV panels, a considerable amount of PV manufacturing is also occurring in other states and countries. Given their modularity, such panels are relatively easy and inexpensive to transport.

The distribution of these companies varies greatly across the region. In Ohio, Michigan, and Illinois, which have the highest concentration of manufacturers and suppliers, we assumed that 25 percent of the manufacturing would be sourced within the state. For states with fewer manufacturers, we assumed a range of 0–15 percent.

---

[8] This is consistent with labor parameters in NREL's JEDI wind model. See *http://www.nrel.gov/analysis/jedi/.*

Figure 13. U.S. Facilities That Manufacture Wind Turbines and Components



Source: AWEA 2010.

Second, we assumed that 90 percent of the expenditures for energy efficiency would be made within each state, and 95 percent within the region, based on information from existing energy efficiency programs. We also added 10 percent to the cost of energy efficiency investments, to account for the cost of implementing programs in each state.

Third, we adjusted the effects on employment to account for future changes in productivity in specific industry sectors. Using data from the U.S. Bureau of Labor Statistics, we developed productivity trends for our analysis (BLS 2010). These trends suggest that productivity rates will vary widely among sectors. Annual productivity gains are forecast to range from 0.47 percent in the primary metals sectors to 4.95 percent in manufacturing sectors.

Fourth, we allocated a portion of the regional construction, manufacturing, and O&M benefits to each Midwest state, to account for intraregional transfers not captured in individual state analyses. For example, wind turbine manufacturers in Iowa, tower manufacturers in North Dakota, and construction firms in Minnesota will likely supply equipment and services to other states in the region. Regional RPCs and multipliers will capture the effects of that activity, but state RPCs and multipliers will not. We allocated these intraregional transfers to each state based on the distribution of companies that now build, manufacture, operate, and maintain power plants that produce electricity from renewable sources, coal, and natural gas in the region (Table 9).

Table 8. Regional Purchase Coefficients for Energy Technology Spending

	Region	Illinois	Indiana	Iowa	Michigan	Minnesota	North Dakota	Ohio	South Dakota	Wisconsin
State/Region Technology Purchase Coefficients										
Wind										
Mfg										
Turbine/nacelle	0.50	0.50	0.25	0.50	0.50	0.25	0.05	0.50	0.05	0.50
Tower	0.50	0.50	0.00	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Blade	0.50	0.00	0.00	0.50	0.00	0.50	0.50	0.00	0.50	0.50
Construction labor	0.90	0.75	0.90	0.75	0.75	0.90	0.75	0.75	0.75	0.75
Solar										
Mfg	0.25	0.25	0.05	0.05	0.25	0.15	0.00	0.15	0.00	0.15
Construction labor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Biomass										
Mfg (boilers, feed handling, other)	0.89	0.35	0.17	0.17	0.28	0.48	0.15	0.45	0.17	0.58
Turbines	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction labor	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Fuel	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
Coal										
Mfg	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction labor	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Fuel	0.07	0.09	0.46	0.00	0.00	0.00	0.98	0.27	0.00	0.00
Natural Gas										
Mfg	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction labor	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Fuel	0.10	0.00	0.01	0.00	0.37	0.00	1.00	0.11	0.03	0.00
Landfill										
Mfg (boilers, feed handling, other)	0.89	0.35	0.17	0.17	0.28	0.48	0.15	0.45	0.17	0.58
Turbines	0.95	0.00	0.95	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Construction labor	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50

Note: RPCs are based on analysis of current manufacturing, labor trends, and technology deployment derived from industry data and estimates. RPCs for fossil fuels are based on analysis of EIA data on production and imports and exports in each industry.

Table 9. Allocation of Regional Benefits of Spending on Energy Technology to Midwest States (based on RPCs, capital expenditures, and O&M expenditures)

	Illinois	Indiana	Iowa	Michigan	Minnesota	North Dakota	Ohio	South Dakota	Wisconsin
Wind									
Construction	14.10%	1.85%	20.44%	9.51%	18.31%	7.27%	11.73%	7.48%	9.31%
O&M	21.37%	3.61%	18.98%	11.24%	14.76%	5.33%	15.88%	5.65%	3.19%
Biomass CHP and BDed Gas									
Construction	30.34%	6.11%	17.64%	2.51%	26.99%	0.08%	10.31%	0.11%	5.91%
O&M	36%	7%	57%	0%	0%	0%	0%	0%	0%
Biomass Co-firing									
Construction	0.09%	28.43%	0.00%	17.67%	0.00%	0.02%	40.84%	0.02%	12.93%
O&M	4.70%	29.40%	0.15%	14.59%	0.18%	0.02%	35.87%	0.03%	15.07%
Landfill									
Construction	83.33%	0.00%	4.64%	0.00%	1.84%	0.00%	0.00%	0.00%	10.19%
O&M	83.33%	0.00%	4.64%	0.00%	1.84%	0.00%	0.00%	0.00%	10.19%
Coal									
Construction	42.36%	12.85%	9.84%	6.81%	3.49%	1.16%	11.50%	0.13%	11.87%
O&M	20.38%	46.85%	0.00%	0.00%	0.00%	1.78%	31.00%	0.00%	0.00%
Natural Gas & Oil									
Construction	10.53%	9.14%	11.73%	16.62%	16.44%	0.00%	12.15%	1.64%	21.75%
O&M	0.00%	11.88%	0.00%	44.60%	0.00%	0.01%	43.49%	0.02%	0.00%

Note: RPCs = regional purchase coefficients. CHP = combined heat and power. BDed gas = dedicated biomass gasification plants.

References

American Wind Energy Association, Blue-Green Alliance, United Steelworkers (AWEA). 2010. *Winds of change: A manufacturing blueprint for the wind industry*.

Amit, E. 2006. Testimony before the Minnesota Public Utilities Commission on the Excelsior Energy proposed coal IGCC project. Docket no. E6472/M-05-1993. November 9.

Barbose, G., N. Darghouth, and R. Wiser. 2010. *Tracking the sun III: The installed costs of photovoltaics in the U.S. from 1998–2009*. LBNL-4121E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Black & Veatch. 2008. *Renewable energy transmission initiative: Phase IA final report.* 149148.0010. Sacramento, CA: California Institute for Energy and the Environment, RETI Stakeholder Steering Committee. Online at *http://www.energy.ca.gov/reti/documents/index.html*.

Blair, N., W. Short, M. Mehos, and D. Heimiller. 2006. Concentrating solar deployment system (CSDS): A new model for estimating U.S. concentrating solar power market.

Bolinger, M. 2008. Trends in U.S. wind power prices and the factors that influence them. Presentation at WINDPOWER 2008, Houston, TX, June 2. Berkeley, CA: Lawrence Berkeley National Laboratory.

Bureau of Labor Statistics (BLS). 2010. *Employment and output by industry, 1998, 2008, and projected 2018*. Washington, DC: U.S. Department of Commerce. Online at *ftp://ftp.bls.gov/pub/special.requests/ep/ind.employment/ep_table_207.xls*.

California Energy Commission (CEC). 2007. *Comparative costs of California central station electricity generation technologies*. Draft staff report. CEC-200-2007-011-SD. Sacramento, CA. Online at *http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF*.

Chaudhari, M., L. Frantzis, and T.E. Hoff. 2004. PV grid connected market potential under a cost breakthrough scenario. Prepared by Navigant Consulting. San Francisco, CA: Energy Foundation. Online at *http://www.ef.org/documents/EF-Final-Final2.pdf*.

Chupka, M.W., and G. Basheda. 2007. *Rising utility construction costs: Sources and impacts.* Cambridge, MA: The Brattle Group.

Clean Air Task Force (CATF) and Western Resource Advocates (WRA). 2003. *The last straw: Water use by power plants in the arid West*. Boston, MA. Online at: *http://www.catf.us/resources/publications/files/The_Last_Straw.pdf*.

Clean and Diversified Energy Initiative (CDEI). 2006. *Geothermal task force report.* Denver: Western Governors' Association.

Cleetus, R., S. Clemmer, and D. Friedman. 2009. *Climate 2030: A national blueprint for a clean energy economy*. Cambridge, MA: Union of Concerned Scientists.

Cooper, Mark. 2009. *The economics of nuclear reactors: Renaissance or relapse?* South Royalton, VT: Institute for Energy and the Environment, Vermont Law School. Online at*: http://www.nirs.org/neconomics/cooperreport_neconomics062009.pdf.*

David, A. 2010. *Impact of wind energy installations on domestic manufacturing and trade.* ID-25. Washington, DC: U.S. International Trade Commission.

Department of Energy (DOE). 2007a. *Concentrating solar power: FY09 proposed solar initiative*. Budget summit meeting at the National Press Club, March 15. Washington, DC.

Department of Energy (DOE). 2007b. *Government performance review act FY08,* Appendix D. Washington, DC.

Department of Energy (DOE). 2007c. *Notice of financial award for the Mesaba IGCC plant*. Washington, DC.

Department of Energy (DOE). 2005. *Power plant water management R&D program summary*. Washington, DC: Office of Fossil Energy.

Department of Energy (DOE) and Department of Agriculture (USDA). 2005. *Biomass as feedstock for a bioenergy and bioproducts industry: The technical feasibility of a billion-ton annual supply.* Oak Ridge, TN: Oak Ridge National Laboratory. Online at *http://feedstockreview.ornl.gov/pdf/billion_ton_vision.pdf.*

Dixon, D., and R. Bedard. 2007. *Assessment of waterpower potential and development needs*, Table 3-1. EPRI report no. 1014762. Palo Alto, CA: Electric Power Research Institute.

Duke Energy Indiana. 2010. Duke Energy Indiana files cost update for clean coal gasification power plant. Press release, April 16. Online at *http://www.duke-energy.com/news/releases/2010041601.asp.*

Electric Power Research Institute (EPRI). 2006. Generation technologies in a carbon-constrained world. Presentation by Steve Gehl, technical executive, May 18, to the National Wind Coordinating Collaborative, Palo Alto, CA.

Electric Power Research Institute (EPRI). 2002. Water and sustainability, vol. 3. U.S. water consumption for power production: The next half century. Report 1006786. Prepared by Bevilacqua-Knight. Palo Alto, CA.

Energy and Environmental Analysis (EEA) and Blue Mountain Energy. 2006. *High density housing, mega-developments: An assessment of Arizona and Nevada comparing central power to a distributed energy approach.* Oak Ridge, TN: Prepared for Oak Ridge National Laboratory.

Energy Efficiency and Renewable Energy, Office of (EERE). 2008. *20% wind energy by 2030: Increasing wind energy's contribution to U.S. electricity supply*. DOE/GO-102008-2578. Washington, DC: U.S. Department of Energy.

Energy Information Administration (EIA). 2011a. Annual Energy Outlook 2011 *early release.* Washington, DC: Department of Energy. Online at *http://www.eia.gov/forecasts/aeo/*.

Energy Information Administration (EIA). 2011b. *Assumptions to the Annual Energy Outlook 2009: Electricity market module.* Washington, DC: U.S. Department of Energy. Online at *http://www.eia.gov/forecasts/aeo/assumptions/pdf/electricity.pdf.*

Energy Information Administration (EIA). 2010. *Assumptions to the Annual Energy Outlook 2010: Electricity market module.* DOE/EIA-0554(2010). Washington, DC: U.S. Department of Energy. Online at: *http://www.eia.gov/oiaf/aeo/assumption/electricity.html*.

Energy Information Administration (EIA). 2009a. *Electric power annual 2007*. Washington, DC: U.S. Department of Energy. Online at *http://www.eia.doe.gov/cneaf/electricity/epa/epa_sum.html.*

Energy Information Administration (EIA). 2009b. *Assumptions to the Annual Energy Outlook 2009: Electricity market module.* DOE/EIA-0554(2009). Washington, DC: U.S. Department of Energy. Online at: *http://www.eia.doe.gov/oiaf/aeo/assumption/electricity.html*.

Energy Information Administration (EIA). 2009c. *Archive listing of Annual Energy Outlook forecasts & related products.* Washington, DC: U.S. Department of Energy. Online at *http://www.eia.doe.gov/oiaf/archive.html#aeo.*

Energy Information Administration (EIA). 2009d. *Annual Energy Outlook 2009 with projections to 2030*. Washington, DC: U.S. Department of Energy. Online at *http://www.eia.doe.gov/oiaf/aeo/aeoref_tab.html.*

Energy Information Administration (EIA). 2009e. *An updated Annual Energy Outlook 2009 reference case*. SR-OIAF/2009-03 Washington, DC: U.S. Department of Energy. Online at *http://www.eia.gov/oiaf/servicerpt/stimulus/index.html.*

Energy Information Administration (EIA). 2009f. *The National Energy Modeling System: An overview*. DOE/EIA-0581(2009). Washington, DC: U.S. Department of Energy. Online at *http://www.eia.gov/oiaf/aeo/overview/.*

Energy Information Administration (EIA). 2008a. *Annual Energy Outlook 2008 with projections to 2030*. DOE/EIA-0383(2008). Washington, DC: U.S. Department of Energy. Online: *http://www.eia.gov/oiaf/archive/aeo08/index.html*.

Energy Information Administration (EIA). 2008b. *Assumptions to the Annual Energy Outlook 2008 with projections to 2030.* DOE/EIA-0554(2008). Washington, DC: U.S. Department of Energy. Online at *www.eia.doe.gov/oiaf/aeo/assumption/pdf/0554(2008).pdf.*

Energy Information Administration (EIA). 2007. *Annual electric generator report*. EIA-860. Washington, DC: U.S. Department of Energy. Online: *http://www.eia.gov/cneaf/electricity/page/eia860.html*

Energy Information Administration (EIA). 2007b. *Energy and economic impacts of implementing both a 25-percent renewable portfolio standard and a 25-percent renewable fuel standard by 2025*. Washington, DC: U.S. Department of Energy.

Energy Information Administration (EIA). 2007. *Annual Energy Outlook 2007 with projections to 2030.* Washington, DC: Department of Energy. Online at *http://www.eia.doe.gov/oiaf/archive/aeo07/index.html*.

Energy Information Administration (EIA). 2002. Cooling system information. In *Steam-electric plant operation and design report*. Form 767. Online: *http://www.eia.gov/cneaf/electricity/page/eia767.html*

Environmental Protection Agency (EPA). 2008. *EPA analysis of the Lieberman-Warner Climate Security Act of 2008.* Washington, DC. Online at *http://www.epa.gov/climatechange/downloads/s2191_EPA_Analysis.pdf.*

Environmental Protection Agency (EPA). 2006b. *1999 national emission inventory documentation and data.* Online at *http://www.epa.gov/ttn/chief/net/1999inventory.html#final3haps*, accessed March 6, 2009.

Exelon. 2010. *Exelon 2020: A low-carbon roadmap, 2010 update.* Chicago, IL: Exelon. Online at *http://www.exeloncorp.com/assets/newsroom/downloads/docs/bro_Exelon2020_Update_2010.pdf*.

Florida Power & Light (FPL). 2008. Total project cost estimate range (year spent $). Testimony before the Florida Public Service Commission. Docket no. 070650-EI, exhibit SDS-8. Tallahassee.

Freese, B., S. Clemmer, and A. Nogee. 2008. *Coal power in a warming world: A sensible transition to cleaner energy options*. Cambridge, MA: Union of Concerned Scientists.

IBEW Journal. 2005. *2005 worker shortage threatens utility.* April. Online at *http://www.ibew.org/articles/05journal/0504/p12_shortage.htm.*

IHS Cambridge Energy Research Associates (IHS CERA). 2011. Power plant construction costs: Cost pressures returning. Press release, July 6. Online at *http://press.ihs.com/press-release/energy-power/power-plant-construction-costs-cost-pressures-returning.*

IHS Cambridge Energy Research Associates (IHS CERA). 2010a. Power plant construction costs rise for first time since Q1 2008, but gain is limited. Press release, July 15. Online at *http://press.ihs.com/press-release/energypower/power-plant-construction-costs-rise-first-time-q1-2008-gain-limited.*

IHS Cambridge Energy Research Associates (IHS CERA). 2010b. Power plant construction costs: Recovery paused as costs go flat once more. Press release, December 21. Online at *http://press.ihs.com/press-release/energypower/power-plant-construction-costs-recovery-paused-costs-go-flat-once-more.*

IHS Cambridge Energy Research Associates (IHS CERA). 2009a. *Power capital and costs.* Cambridge, MA. Online at *http://www.ihsindexes.com/.*

IHS Cambridge Energy Research Associates (IHS CERA). 2009b. Power plant construction costs continue to fall, but decline is limited: IHS CERA power capital costs index. Press release, December 18. Online at *http://press.ihs.com/press-release/energy-power/IHS CERA-power-plant-construction-costs-continue-fall-decline-limited.*

IHS Cambridge Energy Research Associates (IHS CERA). 2008. Construction costs for new power plants continue to escalate: IHS CERA power capital costs index. Press release, May 27. Online at *http://energy.ihs.com/News/Press-Releases/2008/IHS CERA-Power-Capital-Costs-Index.htm.*

IHS Emerging Energy Research (IHS EER). 2007. *TECO, Nuon cancellations underscore IGCC's woes*. Clean energy generation advisory no. CPG 715-071005. Cambridge, MA. Online at *http://www.cleanenergyaction.org/documents/Coal%20Science/IGCC%20Cancellations%20-%20EER%20-%20Oct%20%205%20%202007.pdf.*

Intergovernmental Panel on Climate Change (IPCC). 2005. *IPCC special report on carbon dioxide capture and storage.* Prepared by Working Group III of the Intergovernmental Panel on Climate Change, edited by B. Metz, O. Davison, H.C. de Coninck, M. Loos, and L.A. Meyer. Cambridge, UK: Cambridge University Press.

International Monetary Fund (IMF). 2009a. *World economic outlook: Crisis and recovery.* Washington, DC. Online at *http://www.imf.org/external/pubs/ft/weo/2009/01/index.htm.*

International Monetary Fund (IMF). 2009b. *World economic outlook update: Contractionary forces receding but weak recovery ahead.* Washington, DC. Online at: http://www.imf.org/external/pubs/ft/weo/2009/update/02/index.htm

Joskow, P. 2006. Future prospects for nuclear: A U.S. perspective. Presentation at the University of Paris, Dauphine, May 19. Cambridge, MA: Massachusetts Institute of Technology.

Kagel, A., D. Bates, and K. Gawell, 2007. A guide to geothermal energy and the environment. Washington, DC: Geothermal Energy Association. Online at *www.geo-energy.org/publications/reports/Environmental%20Guide.pdf.*

Keystone Center. 2007. *Nuclear power joint fact-finding*. Keystone, CO. Online at *http://www.ne.doe.gov/pdfFiles/rpt_KeystoneReportNuclearPowerJointFactFinding_2007.pdf.*

Koplow, D. 2010. Review of accelerated depreciation, investment tax credit, and production tax credit provisions of Senator Kerry's and Senator Lieberman's American Power Act. Memorandum to Friends of the Earth. Cambridge, MA: Earth Track, Inc., June 17. Online at: *http://www.foe.org/sites/default/files/MoreKerryLiebermanNukeGiveaways.pdf.*

Kozubal, E., and C. Kutscher. 2003. Analysis of a water-cooled condenser in series with an air-cooled condenser for a proposed 1-MW geothermal power plant. *Geothermal Resources Council Transactions* 27. Washington, DC: National Renewable Energy Laboratory.

LCG Consulting. 2007. Costs rise for AEP's proposed new IGCC plant in West Virginia. Los Altos, CA.

Loder, A. 2008. Price triples for Progress Energy's proposed nuclear plant in Levy: Progress Energy's planned plant costs $17-billion. *St. Petersburg Times*, March 11.

Lovekin, J., C. Klein, and S. Sanyal. 2004. *New geothermal site identification and qualification*. Consultant report no. P500-04-051. Prepared by GeothermEx. Sacramento: California Energy Commission, Public Interest Energy Research.

Massachusetts Institute of Technology (MIT). 2007. *The future of coal: Options for a carbon-constrained world.* Cambridge, MA. Online at *http://web.mit.edu/coal/.*

Massachusetts Institute of Technology (MIT). 2003. *The future of nuclear power.* Cambridge, MA.

Midwestern Governors Association (MGA). 2009. *Midwestern Energy Security and Climate Stewardship Roadmap 2009: Summary of Advisory Group recommendations*. Washington, DC: Midwestern Governors Association. Online at: *http://www.midwesterngovernors.org/Publications/Roadmap.pdf.*

Midwestern Governors Association (MGA). 2008. *Final assumptions for power sector modeling.* Presentation prepared by ICF and the modeling subgroup of the Midwest Greenhouse Gas Reduction Accord Advisory Group, November 14. Washington, DC.

Midwestern Governors Association (MGA). 2007. *Midwestern Greenhouse Gas Accord*. Signed at Midwestern Energy Security and Climate Stewardship Summit in Milwaukee, WI. Online at: *http://www.midwesterngovernors.org/Publications/Greenhouse%20gas%20accord_Layout%201.pdf.*

Mills, A., R. Wiser, and K. Porter. 2009. *The cost of transmission for wind energy: A review of transmission planning studies*. Berkeley, CA: Lawrence Berkeley National Laboratory, Environmental Energy Technologies Division. Online at *http://eetd.lbl.gov/EA/EMP*.

National Energy Technology Laboratory (NETL). 2007a. *Cost and performance baseline for fossil energy plants, vol. 1. Bituminous coal and natural gas to electricity*. Final report. DOE/NETL-2007/1281. Pittsburgh, PA: U.S. Department of Energy.

National Energy Technology Laboratory (NETL). 2007b. *Carbon sequestration atlas of the United States and Canada.* Pittsburgh, PA: U.S. Department of Energy. Online at *http://www.netl.doe.gov/technologies/carbon_seq/refshelf/atlas/ATLAS.pdf*.

National Mining Association (NMA). 2008. Most requested statistics: U.S. coal industry. Online at *http://www.nma.org/pdf/c_most_requested.pdf,* accessed March 31, 2009.

National Public Radio (NPR). 2007. A missing generation of nuclear energy workers. *Marketplace,* April 26. Online at *http://marketplace.publicradio.org/shows/2007/04/26/PM200704265.html*.

National Renewable Energy Laboratory (NREL). 2006. *Cooling for parabolic trough power plants*. Presentation at the Parabolic Trough Workshop, Incline Village, NV. Golden, CO.

National Research Council (NRC). 2002. *Coal waste impoundments: Risks, responses, and alternatives*. Washington, DC: National Academy of Sciences.

Neff, T. 2007. Dynamic relationships between uranium and SWU prices: A new equilibrium, building the nuclear future: Challenges and opportunities. Cambridge, MA: Massachusetts Institute of Technology, Center for International Studies.

Neff, T. 2006. Uranium and enrichment supply: Supply, demand and price outlook. Presentation. Cambridge, MA: Massachusetts Institute of Technology, Center for International Studies.

Nelson, R.G., M.E. Walsh, J.J. Sheehan, and R. Graham. 2003. Methodology to estimate removable quantities of agricultural residues for bioenergy and bioproduct use. *Applied Biochemistry and Biotechnology* 113(1–3):0013–0026.

Nelson, R.G. 2002. Resource assessment and removal analysis for corn stover and wheat straw in the Eastern and Midwestern United States: Rainfall and wind-induced erosion methodology. *Biomass and Bioenergy* 22:349–363.

New Energy Opportunities, La Capra Associates, Merrimack Energy Group, and E.L. Selgrade. 2007. Report on evaluation of bids submitted in response to Delmarva Power and Light Company's RFP. Prepared for the Delaware Public Service Commission. Docket no. 06-241, February 21.

Nucleonics Week. 2007a. Supply chain could slow the path to construction, officials say. Comments of Ray Ganthner, Areva. February 15.

Nucleonics Week. 2007b. Vendors' relative risk rising in new nuclear power markets, January 18.
O'Connell, R. 2008. Will wind power remain competitive? Presentation at Windpower 2008 Conference, Houston, TX.

O'Connell, R., R. Pletka, S. Block, R. Jacobson, P. Smith, S. Tilley, and A. York. 2007. *20 percent wind energy penetration in the United States: A technical analysis of the energy resource*. Overland Park, KS: Black & Veatch. Online at *http://www.20percentwind.org/Black_Veatch_20_Percent_Report.pdf*.

Office of Surface Mining (OSM). 2005. *2005 annual report.* Washington, DC: U.S. Department of the Interior.

O'Malley, C. 2010. Electric rates likely to rise with cost of Duke Energy coal gasification plant. *Indiana Economic Digest*, July 1. Online at *http://www.indianaeconomicdigest.net/main.asp?SectionID=31&ArticleID=54983*.

Patriot Coal. 2009. Appalachia operations. St. Louis, Missouri. Online at *http://www.patriotcoal.com/appalachia.asp*, accessed on March 6, 2009.

Petty, S., and G. Porro. 2007. Updated geothermal supply characterization. Proceedings of the Thirty-Second Workshop on Geothermal Reservoir Engineering, January 23–24. Stanford, CA: Stanford University.

Princeton Energy Resources International (PERI). 2007. *Revising the long term multipliers in NEMS: Quantifying the incremental transmission costs due to wind power*. Report to the EIA for use in *AEO 2008***.** Rockville, MD.

Progress Energy. 2008a. Progress Energy Florida files nuclear plant application with NRC. Press release, August 1. Online at *http://www.progress-energy.com/aboutus/news/article.asp?id=19142*, accessed April 1, 2009.

Progress Energy. 2008b. Progress Energy Florida estimates fuel, nuclear and environmental costs for 2009. Press release, August 29. Online at *http://www.progress-energy.com/aboutus/news/article.asp?id=19482*, accessed April 1, 2009.

Reuters. 2008. SCE&G & Santee Cooper announce contract to build two new nuclear units. May 28. Online at *http://www.reuters.com/article/pressRelease/idUS203833+27-May-2008+BW20080527*.

Solar Energy Industries Association (SEIA). 2011. Solar works for America. Washington, DC. Online at *http://www.solarworksforamerica.com/*.

Solar Energy Industries Association (SEIA). 2010. *U.S. solar market insight: 2010 year in review*. Washington, DC. Online at *http://www.seia.org/galleries/pdf/SMI-YIR-2010-ES.pdf.*

Standard and Poor's. 2007. *Which power generation technologies will take the lead in response to carbon controls?* May 11. New York, NY.

Stoddard, L., J. Abiecunas, and R. O'Connell, 2006. *Economic, energy, and environmental benefits of concentrating solar power in California*. Golden, CO: National Renewable Energy Laboratory.

Tellinghuisen, S., D. Berry, B. Miller, T. Hutchins-Cabibi, C. Benjamin, and N. Theerasatiankul. 2008. *A sustainable path: Meeting Nevada's energy and water demands*. Boulder, CO: Western Resource Advocates. Online at *http://www.westernresourceadvocates.org/water/NVenergy-waterreport.pdf.*

Tester, J.W., S. Petty, J. Garnish, A. Batchelor, L. Drake, and R. Veatch. 2006. *The future of geothermal energy: Energy recovery from enhanced/engineered geothermal systems (EGS)—Assessment of impact for the U.S. by 2050*. Final report to the U.S. Department of Energy Geothermal Program. Cambridge, MA: Massachusetts Institute of Technology.

Toshiba Corp., General Electric Co., USEC, Bechtel Power Corp., and Global Nuclear Fuel–America. 2005. ABWR cost/schedule/COL project at TVA's Bellefonte site. Knoxville, TN: Tennessee Valley Authority. Online at *http://www.nuclear.gov/np2010/reports/mainReportAll5.pdf.*

Turner Construction Company (Turner). 2011. *Turner Building Cost Index*. New York, NY. Online at *http://www.turnerconstruction.com/Uploads/Documents/CI2q2011.pdf.*

Union of Concerned Scientists (UCS). 2009. *Clean power, green jobs*. Cambridge, MA. Online at *http://www.ucsusa.org/assets/documents/clean_energy/Clean-Power-Green-Jobs-25-RES.pdf.*

U.S. News and World Report. 2008. A worker shortage in the nuclear industry. March 13. Online at *http://www.usnews.com/money/careers/articles/2008/03/13/a-worker-shortage-in-the-nuclear-industry.html.*

Wald, M.L. 2007. Costs surge for building power plants. *New York Times*, July 10.

Walsh, M. 2008. *U.S. Cellulosic Biomass Feedstock Supplies and Distribution.* June 24. Oak Ridge, TN: M&E Biomass

Williams, C.F., M.J. Reed, R.H. Mariner, J. DeAngelo, and S.P. Galanis Jr. 2008. *Assessment of moderate- and high-temperature geothermal resources of the United States*. USGS fact sheet 2008-3082, 4. Washington, DC: U.S. Department of the Interior, U.S. Geological Survey.

Wiser, R. 2007. Wind power and the production tax credit: An overview of recent research. Testimony before the U.S. Senate Finance Committee, March 29. Washington, DC.

Wiser, R., and G. Barbose. 2008. *Renewable portfolio standards in the United States: A status report with data through 2007*. LBNL-154E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Wiser, R., G. Barbose, C. Peterman, and N. Darghouth. 2009. *Tracking the sun II: The installed costs of photovoltaics in the U.S. from 1998–2008*. LBNL-2674E. Berkeley, CA: Lawrence Berkeley National Laboratory.

Wiser, R., and M. Bolinger. 2010. *2009 wind technologies market report*. Golden, CO: National Renewable Energy Laboratory. Online at *http://www.nrel.gov/docs/fy10osti/48666.pdf*.

Wiser, R., and M. Bolinger. 2009. *2008 wind technologies market report*. Golden, CO: National Renewable Energy Laboratory. Online at *http://eetd.lbl.gov/ea/ems/reports/2008-wind-technologies.pdf.*

Wiser, R., and M. Bolinger. 2008. *Annual report on U.S. wind power installation, cost, and performance trends, 2007*. LBNL-275E. Berkeley, CA: Lawrence Berkeley National Laboratory.

World Nuclear News. 2009. Olkiluoto 3 losses to reach €1.7 billion. February 26. Online at *http://www.world-nuclear-news.org/newsarticle.aspx?id=24732*.

World Nuclear News. 2008. Duke raises cost estimate for Lee plant. November 7. Online at *http://www.world-nuclear-news.org/NN-Duke_raises_cost_estimate_for_Lee_plant-0711084.html*.

WorleyParsons. 2010. *Taylorville Energy Center: Facility cost report.* North Sydney, NSW, Australia. Online at *http://www.icc.illinois.gov/electricity/tenaska.aspx.*