

## Appendix D. Electricity Sector Assumptions

This appendix describes the changes we made to the Energy Information Administration's (EIA's) electricity sector and technology assumptions included in the Annual Energy Outlook 2008 (AEO 2008) version of NEMS for our Reference and Blueprint policy cases (see EIA 2008a). We modified the EIA's assumptions for two main reasons: to incorporate additional policies that have been enacted since this version of the model was released, and to more accurately reflect the recent increases in capital and commodity costs for new electricity technologies that are not included in the EIA's assumptions.

### D.1. UCS-NEMS Reference Case

This section describes the changes we made to the EIA's policy and technology assumptions for use in our Reference case.

#### D.1.1. Additional Policies

**Tax credits.** We included the extension and expansion of tax credits for renewable and conventional energy technologies that were part of the Emergency Economic Stabilization Act passed by Congress in October 2008. The following is a summary of the tax credit changes we implemented in NEMS for electric technologies:

- Extended the production tax credit (PTC) through 2009 for wind and through 2010 for biomass, geothermal, landfill gas, and certain hydro facilities.
- Extended the 30 percent investment tax credit (ITC) for solar concentrating thermal power (CSP) and solar photovoltaics (PV) through 2016, with no limit on the credit amounts for residential and commercial solar PV.
- Added a 30 percent tax credit for residential small wind through 2016, limited to \$1,000 per kilowatt (kW) or \$4,000.
- Increased the ITC for integrated gasification combined cycle (IGCC) with and without carbon capture and storage (CCS) from 20 percent to 30 percent, and assumed the \$2.55 billion limit specified in the law would support 3.1 gigawatts (GW) of IGCC and 2.3 GW of IGCC w/CCS based on our assumed capital cost assumptions for these technologies.
- Included incentives for CCS of \$10 per ton of carbon dioxide (CO<sub>2</sub>), implemented as a reduction in operations and maintenance (O&M) costs for both coal and natural gas plants with CCS.
- Extended the 30 percent tax credit for residential and commercial fuel cells through 2016, limited to \$3,000 per kW.
- Extended the 10 percent tax credit for commercial microturbines through 2016, limited to \$200 per kW.

We did not include the tax credits and other incentives from the February 2009 economic stimulus package in this analysis, as the modeling was completed before this bill was passed. These incentives will lower energy costs to households and businesses, and largely shift them to taxpayers. By accelerating deployment and industry learning, they

will also somewhat reduce overall costs for implementing the Blueprint policies relative to our analysis.

**State renewable electricity standards (RES).** We updated the EIA's state RES targets with recent UCS projections for the 27 states and Washington, DC, that had standards in place as of October 2008. We do not include the new RES adopted in Missouri in November 2008 or the recent increase in the Illinois RES. For states that are currently having implementation problems, we assumed a conservative three-year delay in reaching their targets. This delay was applied to Arizona, California, Delaware, Maryland, Michigan, Nevada, New York, North Carolina, and all of the New England states. All other states with an RES were assumed to meet their targets on schedule.

Based on these assumptions, we project that state renewable electricity standards will result in 71,270 megawatts (MW) of new capacity by 2025. For comparison, an April 2008 study by Lawrence Berkeley National Laboratory (LBNL) projects 69,115 MW of new capacity by 2025 (Wiser and Barbose 2008). However, the LBNL's projection did not include the new RES adopted in Michigan or the increase in the Massachusetts RES, which are included in our estimate. If you take out these states, our comparable projection is 66,570 MW of new capacity by 2025. Our projection is slightly lower than the LBNL's because it did not assume a delay in reaching the targets in any state and we assume lower electricity sales in states that have energy efficiency resource standards.

**Nuclear loan guarantees.** We included up to \$18.5 billion in incentives for advanced nuclear power plants that are available through the Department of Energy's (DOE's) loan guarantee program. In October 2008, the DOE received applications from 17 companies to build 21 new reactors at 14 nuclear plants, totaling \$122 billion in loan guarantees and 28,800 MW of capacity. Since 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 result in the development of 4,400 MW of new nuclear capacity ( $\$18.5 \text{ billion} / \$122 \text{ billion} * 28,800 \text{ MW}$ ), or approximately four new plants, by 2020.

#### **D.1.2. Construction Cost Escalation**

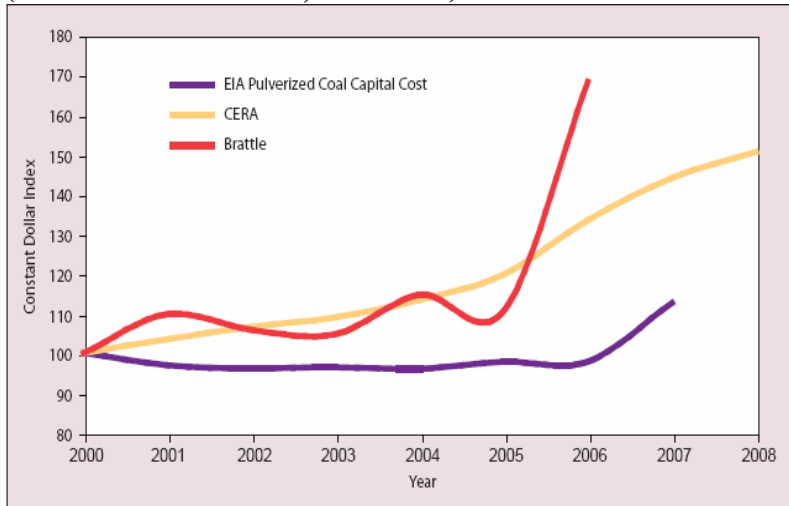
We adjusted the AEO 2008 Reference case capital costs for all technologies to reflect the increases in construction and commodity costs that have occurred over the past few years (Wald 2007). The increases are based on actual project data, expert input, and power plant cost indices. The EIA has assumed no real cost increases until last year, when it raised costs by a modest 15 percent over AEO 2007 levels for all conventional and renewable energy technologies (except for biomass power plants, which it increased by 50 percent). However, the EIA's cost increases are far below the costs of actual projects and levels reported in two power plant cost indices, as shown in Figure D.1 and described in more detail below for each technology. These indices show real (i.e., inflation-adjusted) cost increases of 50 to 70 percent since 2000, with most of the increase occurring after 2004.

We assumed cost increases that are more in line with these indices to derive updated values for current power plant costs. We also adopted the EIA's assumption for its AEO

2008 High Energy Project Cost case that assumed the real cost escalation would continue at 2.5 percent per year for all electric generating technologies, based on data from the Handy-Whitman index for electric utility construction (Figure D.2). However, we assumed the escalation would only occur until 2015 compared with the EIA’s assumption of 2030.

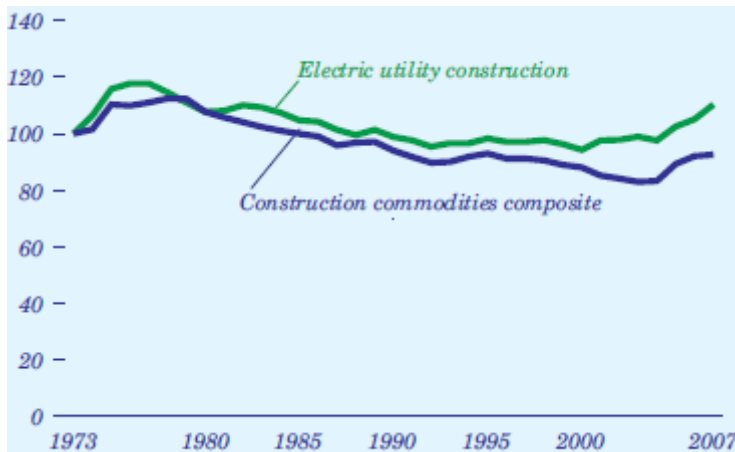
While the recent increases in construction and commodity costs are well-documented, there is considerable uncertainty about what will happen in the future. This uncertainty is reflected in the fairly wide range of long-term cost projections from various government agencies, technology experts, power plant engineering and construction firms, and the financial community. There is some evidence indicating that commodity costs are starting to decline because of the economic crisis; however, it’s not clear how long this will last. Given this uncertainty, we assumed the escalation would continue at a considerably lower level than the past four years and for a limited period of time. In addition, some of this increase is offset by technology learning effects, as discussed in more detail below.

**Figure D.1. Power Plant Construction Cost Escalation, 2000–2008 (constant dollar index, 2000=100)**



Sources: EIA, Annual Energy Outlook 2000 through 2008 (EIA 2008a), CERA 2009, Chupka and Basheda 2007. All indices are modified by UCS to be in constant dollars using a GDP deflator.

**Figure D.2. Changes in Construction Commodity Costs and Electric Utility Construction Costs, 1973–2007 (constant dollar index, 1973=100)**



Source: EIA 2008a.

### D.1.3. Technology Learning

In NEMS, technology learning—capital cost reductions that are assumed to occur as the installed capacity of a given technology increases and by a fixed amount over time (to represent things like R&D improvements)—is determined at a component level. The EIA breaks down each new technology into its major components, and then identifies each component as revolutionary, evolutionary, or mature (see Figure D.3).

**Figure D.3. 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%	-	-	5%
Combustion Turbine - conventional	-	-	1%	-	-	5%
Combustion Turbine - advanced	-	10%	1%	-	5	10%
HRSG <sup>1</sup>	-	-	1%	-	-	5%
Gasifier	-	10%	1%	-	5	10%
Carbon Capture/Sequestration	20%	10%	1%	3	5	20%
Balance of Plant - IGCC	-	-	1%	-	-	5%
Balance of Plant - Turbine	-	-	1%	-	-	5%
Balance of Plant - Combined Cycle	-	-	1%	-	-	5%
Fuel Cell	10%	5%	1%	3	5	10%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass IGCC	20%	10%	1%	3	5	20%
Distributed Generation - Base	-	5%	1%	-	5	10%
Distributed Generation - Peak	-	5%	1%	-	5	10%
Geothermal	-	8%	1%	-	5	10%
Municipal Solid Waste	-	-	1%	-	-	5%
Hydropower	-	-	1%	-	-	5%
Wind	-	-	1%	-	-	1%
Wind Offshore	20%	10%	1%	3	5	20%
Solar Thermal	20%	10%	1%	3	5	20%
Solar PV	15%	8%	1%	3	5	20%

<sup>1</sup>HRSG = Heat Recovery Steam Generator

Source: EIA 2008b

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 capital costs are reduced by a fixed level over time, from 5 percent to 1 percent.
- For solar PV, we increased the learning rates to match the EIA's assumptions for other revolutionary technologies.
- For land-based wind projects, we changed the EIA's learning rates (which assumed no cost reductions for wind) to approximate the projected 10 percent capital cost reductions assumed in the 2008 DOE study of producing 20 percent of U.S. electricity from wind power by 2030 (EERE 2008).
- For new advanced nuclear plants, industry learning is assumed to occur at half the rate projected by the EIA, which bases 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 industry environment in the United States, with 17 companies 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 experienced steadily increasing construction costs through almost the entire last generation of nuclear plants.

#### **D.1.4. Technological Optimism and Contingency Factors**

We also set the EIA's technological optimism and contingency factors to 1.0, assuming that these factors 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 building four units), 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."

#### **D.1.5. 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 includes a number of embedded 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 the supply and demand for different types of fuel. In our Reference case, we used the EIA's fuel price assumptions for its High Energy Price case in AEO 2008, as discussed in more detail in Appendix A. In addition, capacity factors for dispatchable technologies vary based on the relative economics and operating characteristics of different technologies.

#### **D.1.6. Technology-Specific Cost and Performance Assumptions**

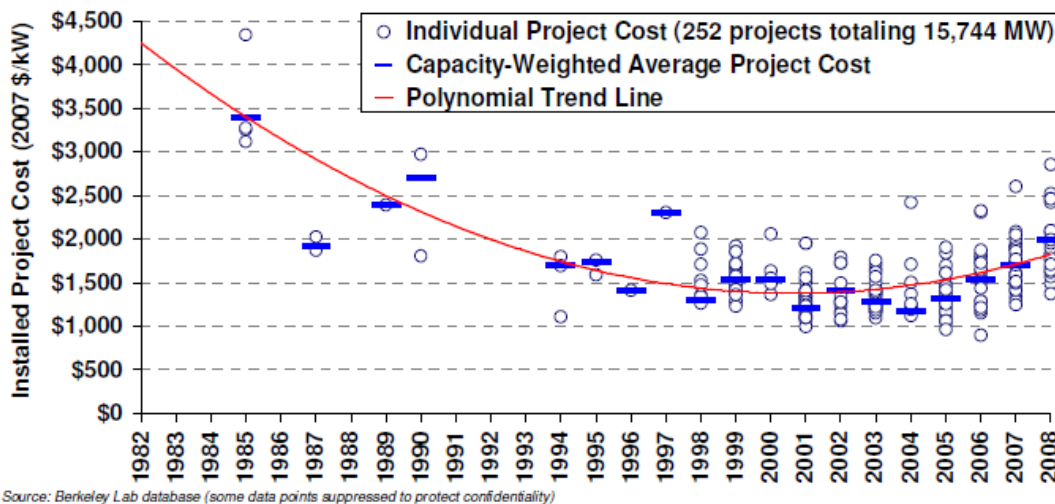
This section describes the key changes we made to the cost and performance assumptions for the main renewable and conventional electric generation technologies included in NEMS. A summary of the capital costs and levelized cost of electricity for each technology is included at the end of the section.

**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 2008 LBNL analysis of 252 wind projects totaling nearly 15,744 MW or 63 percent of the total installed wind capacity in the United States at the end of 2008 (Figure D.4) (Bolinger 2008; Wiser and Bolinger 2008). These estimates include real cost escalation of 60 percent, or \$750 per kW, between 2003 and 2008. They project installed costs to increase

by another 20 percent, or \$200 per kW, in 2009 to \$2,250 per kW (in 2007 dollars) based largely on 2008 data showing continued increases in wind turbine prices. The study claims that the weak U.S. dollar appears to be one of the largest drivers of the cost increases, followed by increases in materials and energy costs, and manufacturer profitability.

We also assume capital costs will decline by approximately 10 percent between 2010 and 2030 based on wind industry estimates developed for the DOE 20 percent wind report (EERE 2008). A recent survey of wind turbine and component manufacturers showed that cost reductions of 15 percent to 22 percent may be possible under a more stable, long-term policy environment—such as a long-term PTC extension or a national RES—that would facilitate an increase in domestic wind turbine manufacturing (Wiser 2007). Over the past two years, wind turbine and component manufacturers announced, added, or expanded 70 new facilities in the United States. Those new manufacturing facilities created 13,000 new direct jobs in 2008 (AWEA 2009).

**Figure D.4. Installed Capital Costs for Wind Power, 1982–2008**

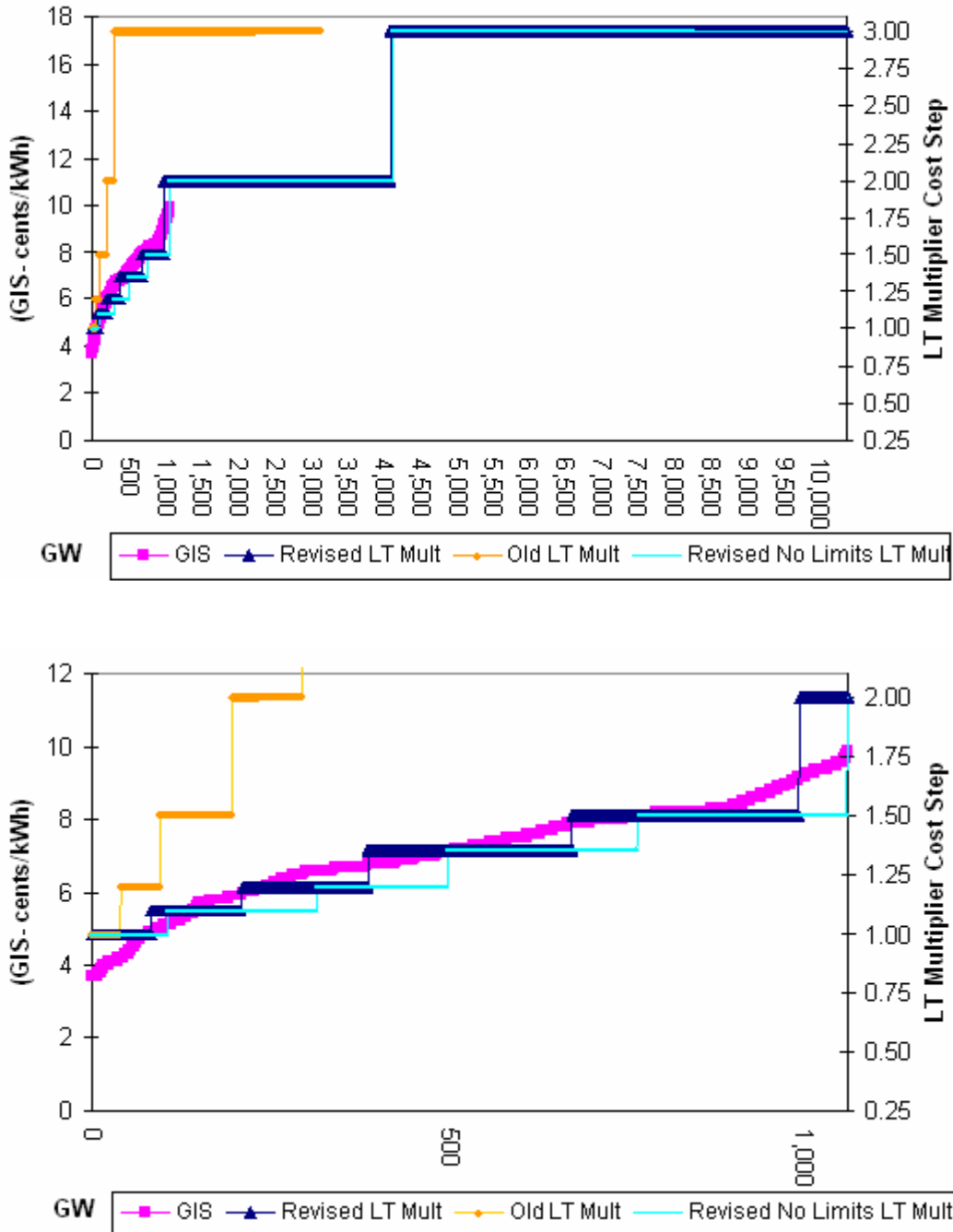


Source: Bolinger 2008.

In addition, we modify the EIA’s assumptions that increase the capital costs of wind at the regional level as wind development increases to account for additional transmission costs, resource degradation, and siting costs. We do this by modifying 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 that account for increases in slope and population density (PERI 2007). NREL developed supply curves of the windy land area available in each wind resource class for 13 electricity reliability regions. These supply curves are then divided into steps to correspond with the multiplier levels assumed by the EIA. One main difference is that the EIA only includes class 4–6 wind resources, while our analysis also includes 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, which increase capital costs by 200 and 300 percent, respectively. Thus, we effectively exclude these resources in the model and develop additional multiplier steps at the lower end of the supply curve (1.0, 1.10, 1.20, 1.35, and 1.50 vs. the EIA's 1.0, 1.2, 1.5, 2.0, and 3.0). These changes are illustrated at the national level in Figure D.5 below.

**Figure D.5. Wind Resource Supply Curves (Wind Classes 3–7 Combined)**



For capacity factors and O&M costs, we use Black & Veatch's projections from the DOE 20 percent wind study (EERE 2008). The study assumes 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 per MWh in 2030, based on historical trends.

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

Capacity factors and O&M costs for offshore wind are also based on EERE 2008. Offshore wind capacity factors are roughly 2 percentage points higher than 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 model are CSP 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. We were only able to obtain data on levelized costs for one recent project—a 64 MW project in Nevada with an in-service date of May 2007—that has a reported power purchase agreement price of 16 cents per kWh. Therefore, we reviewed several recent studies to develop our assumptions. We assume current overnight capital costs of \$4,500 per kW based on a Black & Veatch study for Arizona that includes six hours of thermal storage (Black & Veatch 2008). While we include real escalation in capital costs similar to other technologies, the model projects capital costs to fall over time as this increase is more than offset due to technology learning.

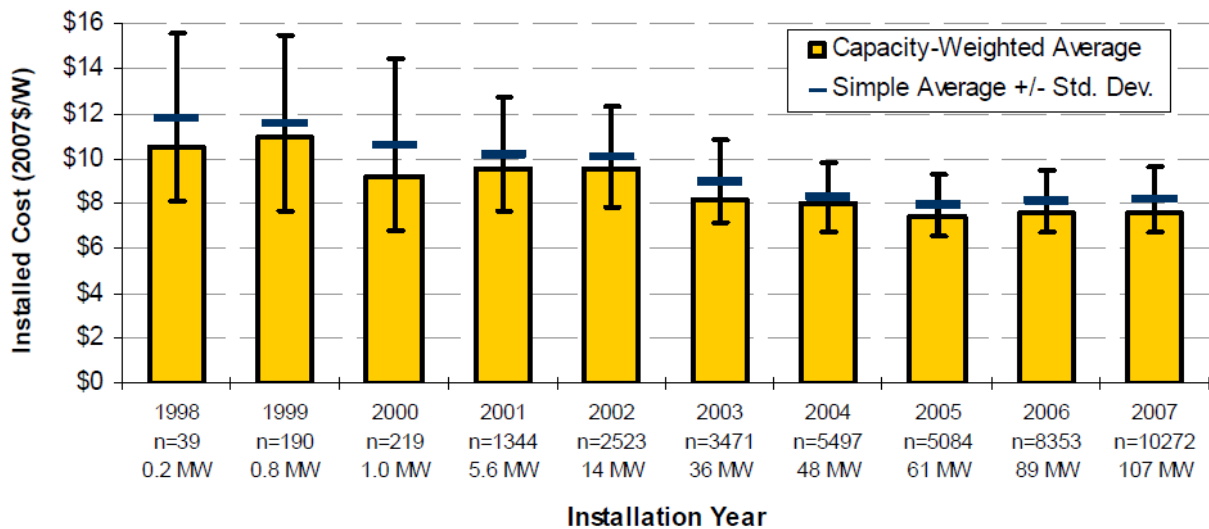
We also assume increases in capacity factors over time with increasing levels of storage based on the mid-range of several studies. We assume capacity factors will increase from 43 percent in 2010 to 49 percent in 2020 and 55 percent in 2030. This is higher than the EIA's assumption of no storage or increases in capacity factors over time (EIA 2008a) and a 2006 NREL study (Blair et al. 2006), but lower than the DOE's FY09 Solar Initiative (DOE 2007a), which assumes capacity factors will increase to 72 percent in 2015 and 82 percent in 2030 with higher levels of storage. O&M costs are based on DOE 2007a, adjusted for the lower level of storage assumed in our analysis.



Installed costs for all types of solar PV systems in the United States has declined from \$10.50 per watt in 1998 to \$7.60 per watt in 2007—equivalent to an average annual reduction of \$0.30 per watt, or 3.5% per year in real 2007 dollars—according to a February 2009 LBNL study shown in Figure D.6 (Wiser, Barbose, and Peterman 2009). The report is based on an analysis of installed cost data from nearly 37,000 residential and non-residential PV systems, totaling 363 MW of capacity and representing 76 percent of all grid-connected PV capacity installed in the United States through 2007. Most of the cost reductions occurred between 1998 and 2005, with average annual reductions of \$0.40 per watt, or 4.8 percent per year in real 2007 dollars. Costs were relatively flat from 2005 through 2007, as the rapid expansion of global PV markets created silicon supply shortages and upward pressure on PV prices. However, the study indicates that large cost reductions could occur in the next few years as most industry experts expect excess supply of PV modules in 2009, and because of the recent extension of the 30 percent federal ITC for PV through 2016.

For utility-scale PV systems, we assume overnight capital costs \$5,500 per kW for projects installed in 2010, which is in the range of estimates from Black & Veatch 2008, DOE 2007b, EIA 2008b, and SunPower Corporation. Capacity factors are projected to increase from the EIA’s assumed current level of 20 percent to 26 percent by 2015 based on DOE projections (DOE 2007b). O&M costs are based on Navigant Consulting estimates for California (Chaudhari, Frantzis, and Hoff 2004), declining gradually over time based on projections from DOE 2007b.

**Figure D.6. Total Installed Costs for Photovoltaic Systems in the United States, 1998–2007**



Source: Wiser, Barbose, and Peterman 2009.

For distributed PV systems, we assumed initial total system costs of \$8,000 per kW for residential systems and \$6,500 per kW for commercial systems. With learning, installed costs are projected to fall to approximately \$4,100 per kW by 2020 and \$3,500 per kW by 2030 for residential systems, and to about \$3,600 per kW by 2020 and \$2,800 per kW by 2030 for commercial systems. These costs projections are in the range of estimates from

EIA 2008b, DOE 2007a, Wisser, Barbose, and Peterman 2009, and SunPower Corporation (see Figure D.6.).

**Biopower.** The main technologies in the electricity sector include biomass co-firing in existing coal plants and dedicated biomass 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 this technology. Available biomass resources include forest residues, crop residues, urban and mill residues, and dedicated energy crops (see Appendix G for more detail).

For biomass co-firing 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 coal and biomass IGCC costs (\$830 per kW or a 50 percent increase) to our revised IGCC capital cost estimates discussed below. Assumptions for real cost escalation and learning are assumed to be the same as coal IGCC. We also assume slightly higher heat rates than the EIA that are consistent with heat rates from Black & Veatch (O'Connell et al. 2007) and MIT 2007 for coal IGCC plus the difference between the heat rates from EIA 2008b for coal and biomass IGCC. The rest of the assumptions for biomass IGCC are the same as the EIA's assumptions.

**Geothermal.** The EIA's assumptions for the cost, performance, and resource potential for geothermal power plants are included in the Geothermal-Electric Power Submodule of NEMS. The submodule contains a supply curve for geothermal resources that reflects estimates of the capacity, generation, and costs of producing electricity at 89 hydrothermal sites in the Western United States. The EIA also assumes that geothermal power plants will operate at a 90 percent capacity factor and includes an annual build limit of 25 MW per site until 2010 and 50 MW per site through 2030.

The data included in the EIA's geothermal supply curve are based on a 2004 study by GeothermEx, Inc. for the California Energy Commission (Lovekin, Klein, and Sanyal 2004) and a 2006 study by the Western Governors Association (WGA) Geothermal Task Force for the Clean and Diversified Energy Initiative (CDEI 2006). These studies focused on conventional hydrothermal sites with confirmed temperatures greater than 100 degrees Celsius. The CDEI study found that 5,600 MW of new hydrothermal capacity could be developed in the western United States by 2015 for less than \$80 per MWh with the PTC or less than \$103 per MWh without the PTC, and up to 13,000 MW by 2025 for less than \$200 per MWh.

Other potential geothermal resources, such as geothermal fluids co-produced with oil and gas, and enhanced geothermal systems (EGS), including hot dry rock, were not included in these studies. The EIA decided not to include these potential resources in the supply curve because it did not believe they would be in significant commercial use within the

forecast horizon of 2030. All told, the EIA supply curve includes roughly 9,000 MW of hydrothermal capacity.

At least three new updated geothermal resource assessments have been completed that address these non-conventional resources. These include a comprehensive study completed in 2006 by MIT (Tester et al. 2006) that included an assessment of the U.S. potential for EGS through 2050; a January 2007 paper by Black Mountain Technology and NREL (Petty and Porro 2007) that includes the EGS estimates from the MIT study along with updated supply estimates for hydrothermal and convective EGS resources based on eight different studies (including Lovekin, Klein, and Sanyal 2004; and CDEI 2006), and a 2008 U.S. Geological Survey (USGS) assessment of hydrothermal and EGS resources in the United States (Williams et al. 2008).

The Petty and Porro study found a total national geothermal resource potential of 126,000 MW mostly below a levelized cost of \$200 per MWh (in 2004 dollars), including 89,000 MW across all resource types in the western United States and 37,000 MW of potential almost entirely from co-produced sites in the Southeast and Southern Plains states. These data were put into a format suitable for use in NEMS and broken down into five specific resource types:

- hydrothermal flash
- hydrothermal binary
- geothermal fluids co-produced with oil and gas
- convective EGS associated with hydrothermal resources at depths less than 3 kilometers
- conductive EGS for depths between 3 and 10 kilometers

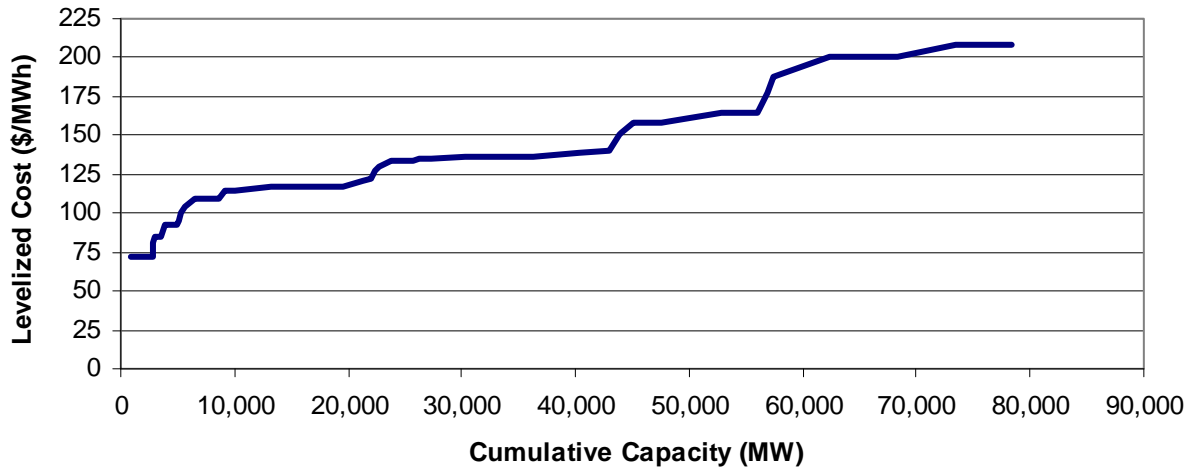
In addition to addressing the co-produced and EGS resources not included in the EIA supply, the study also more broadly assessed hydrothermal resources, generally consistent with techniques adopted in earlier USGS geothermal resource assessments. This broader assessment resulted in 27 GW of total hydrothermal potential at generally lower cost than the EIA supply analysis.

We used the supply data from this assessment in our analysis with a few adjustments. First, we worked with Petty, co-author of the study, to incorporate recent increases in capital costs for geothermal to make the costs consistent with the assumptions for other technologies. This was done by applying specific price indices for drilling, turbines, heat exchangers, construction materials, labor, and steel to modify costs from 3rd-quarter 2004 values to end-of-year 2006 values. We also removed the effects of inflation. We then projected these indices to incorporate additional real cost escalation through 2010. Second, we assumed co-produced sites would not be available for commercial development until after 2030 due primarily to consideration of market factors other than cost. This exclusion of the co-produced resources effectively limits supply to the western United States.

While geothermal supply information is the key input to the Geothermal-Electric Power Submodule, two additional assumptions were made that also significantly contribute to the amount of geothermal supply absorbed by the electricity market in each year of the forecast.

First, we use the EIA's learning rates, in the form of exogenous multipliers to capital and O&M costs, which result in cost reductions of approximately 8 percent by 2020 and 14 percent by 2030. These learning rates are conservative and assume little to no impact from R&D. Second, annual build limits allow 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 characterization (resulting from regional aggregation). A revised version of the supply curve for the year 2010 is shown in Figure D.7.

**Figure D.7. Geothermal Resource Supply Curve, 2010**

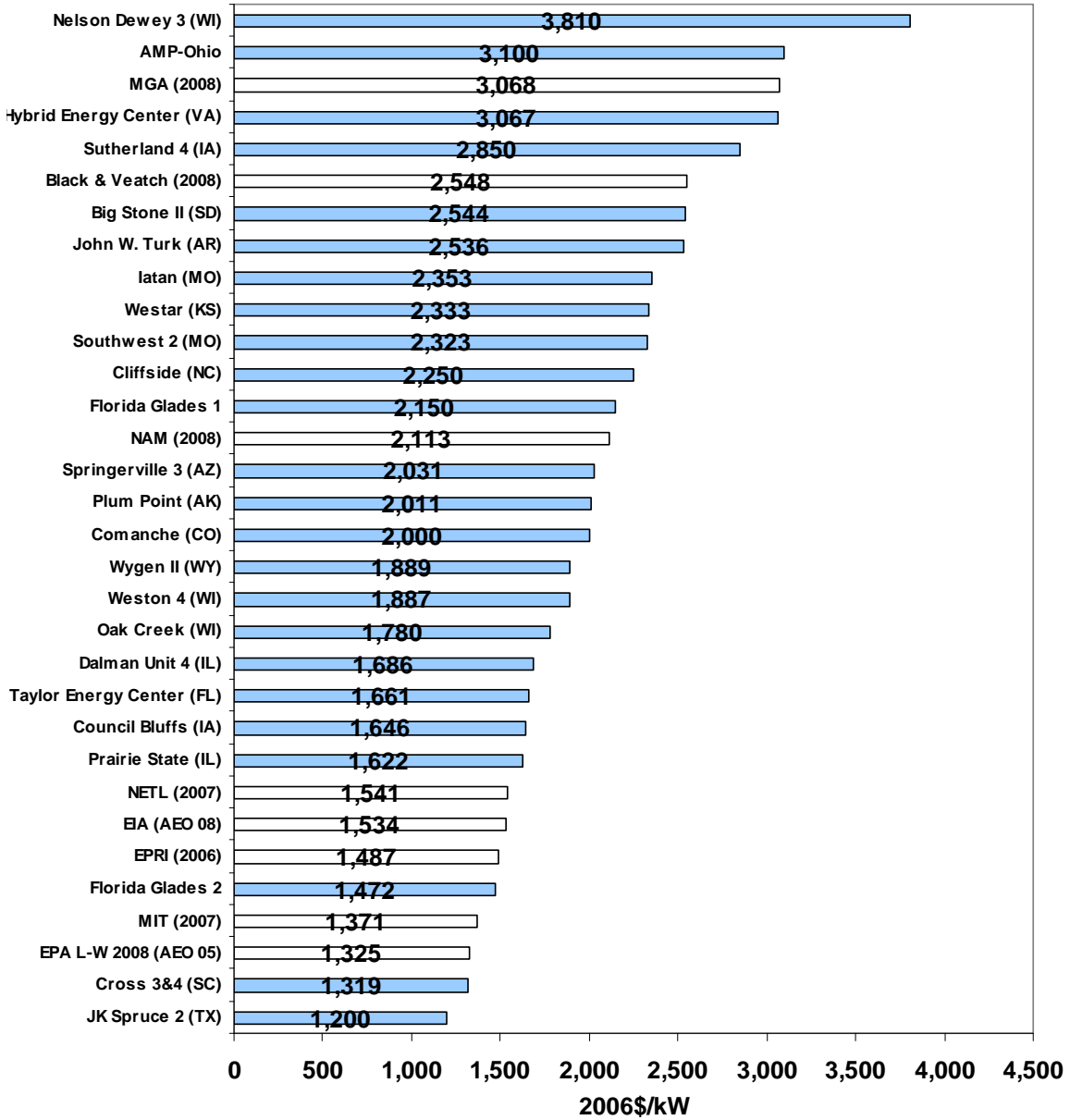


**Coal.** The three main coal technologies included in NEMS include new conventional pulverized coal plants (with scrubbers) and advanced IGCC plants with and without CCS.

*Pulverized coal plants.* Overnight capital costs are based largely on data from actual projects. The costs of actual projects have been much higher than most projections, as shown in Figure D.8, which compares data from 24 projects (dark bars) to 8 recent studies (white bars). Near the bottom of the figure, you can see cost estimates from several frequently used sources (EIA 2008a, EPA 2008, MIT 2007, NETL 2007, and EPRI 2006). The costs listed near these estimates are from projects that were either built, under construction, approved, or proposed several years ago, before most of the recent cost escalation occurred. The actual proposed plants near the top of the list are all based on more recently proposed projects.

The range of capital costs for projects with in-service dates of 2010 to 2013 is about \$2,500 to \$3,800 per kW (in 2006 dollars), which is two to three times higher than the studies at the bottom of the list. The estimates by Black & Veatch (O’Connell 2008) and for modeling that is being completed for the Midwestern Governors Association (MGA 2008) are within this range, as both of these sources are basing their estimates on recent project data. Based on these data, we assume current overnight capital costs of \$2,700 per kW in 2009 and nearly \$3,000 per kW for projects with a 2015 in-service date. We also assume higher O&M costs and heat rates than the EIA based on data from Black & Veatch (O’Connell et al. 2007).

**Figure D.8. Pulverized Coal Plant Capital Costs, Actual Projects vs. Studies**



*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 application of the technology for producing 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 assume that capital costs for IGCC plants will be 16 percent higher than pulverized coal plants based on estimates from EIA 2008b, NETL 2007, MIT 2007, and MGA 2008. This translates in overnight capital costs of \$3,140 per kW in

2009, rising to \$3,475 per kW (including real cost escalation) for plants with a 2015 in-service date.

These assumptions are consistent with cost data from three proposed IGCC projects that have been subjected 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, and construction (EPC) and owners' costs, with a total cost of nearly \$3,600 per kW including financing, transmission, and other site costs (DOE 2007c). The Edwardsport project in Indiana has an estimated cost of \$3,150 per kW (in 2011 dollars), not including financing costs, and including a 4 percent escalation rate per year through 2011 (Duke Energy 2007). Both of these cost estimates are likely to be on the low side, as it has been several months since they have received updated estimates from vendors. The proposed 630 MW Mountaineer project in West Virginia has a reported cost of \$2.23 billion (LCG Consulting 2007), or \$3,540 per kW (in 2012 dollars).

A 2007 analysis by Emerging Energy Research estimates capital costs of \$3,300 per kW for 2007 projects, which it claims is about twice as high as projects proposed in 2004 (EER 2007). Other commonly referred to sources such as EIA 2008a, MIT 2007, NETL 2007, and IPCC 2005 assume capital costs for IGCC ranging from \$1,326 to \$1,977 per kW. As indicated above, 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 the *n*th of a kind plant.

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

- 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 EPC 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 a slightly lower availability and average lifetime capacity factors.
- Increased the construction lead time from four years to five years assuming projects will experience delays due to uncertainty around future costs, federal CO<sub>2</sub> regulations, limited technology guarantees, and other factors that have been cited by recent projects.
- Used slightly higher heat rates based on an MIT study 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 of producing electricity that provide useful data for comparative purposes. For example, an NRG proposal to shut down two units at its Indian River plant in Delaware and convert the site to a 600 MW IGCC plant ranked third behind a natural gas combined cycle plant and an offshore wind project, according to an evaluation completed by outside consultants for the Delaware Public Service Commission (New Energy Opportunities et

al. 2007). The project was reported to have a levelized cost of \$107 per MWh in real 2005 dollars, not including CCS.

Minnesota Department of Commerce testimony before the Minnesota Public Utilities Commission estimated that the Mesaba IGCC proposal would have a levelized cost of \$96 to \$131 per 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 between \$110 and \$120 per MWh (Standard and Poor's 2007).

*IGCC plants with CCS.* For capital costs, we assume coal IGCC w/CCS plants are 41 percent higher than IGCC plants without CCS based on a range of estimates (EIA 2008b, MIT 2007, NETL 2007, and MGA 2008). This results in overnight capital costs of approximately \$4,800 per kW for a project with a 2015 in-service date.

The cost of transportation (via pipeline) and storage will vary depending on the distance and quantity 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 bodies 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, MIT 2007 indicates that most geologic sequestration will likely occur in saline formations because of their large storage potential and broad distribution.

For coal plants near good sequestration sites, MIT 2007 estimates that the cost of transporting and injecting CO<sub>2</sub> should be less than 20 percent of the total cost for capture, compression, transport, and injection. Because the NEMS model does not currently have the capability of distinguishing between different types of storage sites and the transportation distance to those sites, a simple average cost must be used.

The only information we were able to find from an actual IGCC project integrated with CCS was an estimate for the canceled DOE FutureGen project. In June 2007, the DOE issued a draft environmental impact statement for the project that included a cost estimate of \$1.76 billion for the 275 MW project (\$6,400 per kW). This cost is nearly twice as high as the DOE's 2004 estimate for the project of \$950 million (in 2004 dollars). While this is a demonstration project that 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 that result from adding CCS to an IGCC plant are well documented in MIT 2007. MIT estimates that adding CCS will reduce the efficiency of an IGCC plant by 23 percent. As we assume for IGCC plants without CCS, we use slightly higher heat rates than the EIA 2008b based on MIT assumptions and less efficiency improvement



over time. Our assumptions for capacity factors and lead times are the same as for IGCC without CCS plants.

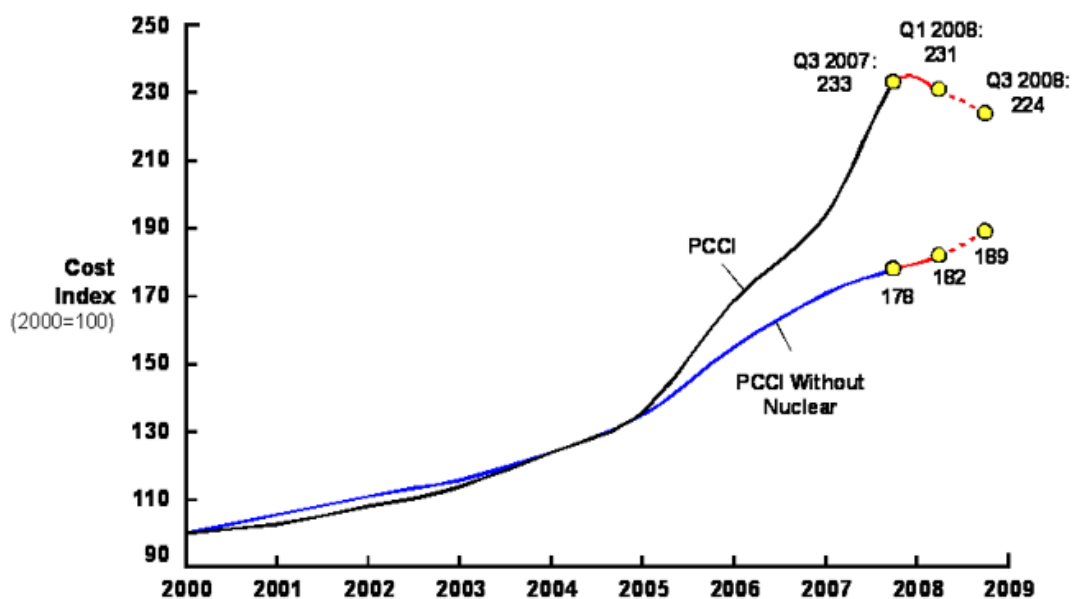
**Natural Gas.** The main technologies included in NEMS include conventional and advanced natural gas combustion turbine (NGCT) peaking plants, conventional and advanced natural gas combined cycle (NGCC) plants, and advanced NGCC plants with CCS. The cost and performance assumptions for new advanced NGCC and NGCT plants are based on Black & Veatch data (O’Connell 2008) from actual projects, and data collected by the California Energy Commission (CEC 2007) for more than 30 plants installed in California from 2001 to 2006. The capital costs for conventional NGCC and NGCT plants were estimated by multiplying the costs for advanced plants by the ratio of conventional to advanced plant costs using the EIA’s assumptions (EIA 2008b).

For NGCC plants with CCS, we assume capital costs are 95 percent higher than NGCC plants without CCS based on a range of estimates (EIA 2008b, NETL 2007, IPCC 2005, and MGA 2008). We also assume slightly higher heat rates than the EIA that are consistent with the increases we assumed for NGCC plants without CCS.

**Nuclear.** The cost of nuclear electricity is largely driven by plant construction costs. It is difficult to reliably project construction costs for a U.S. nuclear plant today because there is no recent U.S. experience to draw upon. 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. Only three years after its 2005 ground breaking, the Olkiluoto plant in Finland is three years behind its originally scheduled 2009 on-line date, with cost overruns currently exceeding 50 percent. Numerous quality problems have been reported, and project principals are in arbitration over responsibility for the delays and overruns (World Nuclear News 2009).

Over the past five years, construction costs have increased for all generating technologies, but most dramatically for nuclear plants. A power plant capital cost index developed by Cambridge Energy Research Associates (CERA) shows nuclear capital costs increasing by 131 percent between 2000 and the first quarter of 2008 (in nominal dollars), compared with 82 percent for other power plants (CERA 2009).

**Figure D.9. Nuclear Power Plant Construction Costs Rising Faster than Other Technologies (nominal dollar cost index, 2000 = 100)**

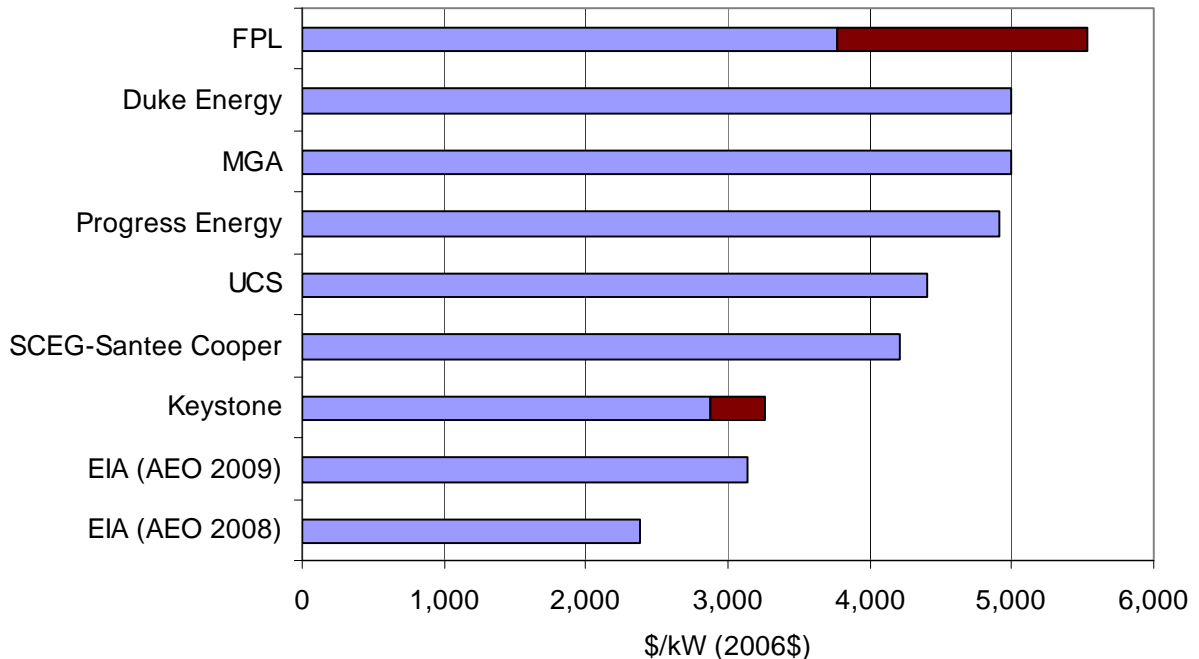


Source: CERA 2009.

These costs increases are evident in recent plant proposals. In November 2008, Duke Energy revised its overnight construction cost estimate for two units proposed for Cherokee County, SC, to \$5,000 per kW, about double its original estimate (World Nuclear News 2008). Utilities applying for loan guarantees that month estimated that total costs for their proposed 21 plants, including escalation and financing, would amount to \$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, as shown in the Figure D.10 below (FPL 2008, Loder 2008, Progress Energy 2008a, Progress Energy 2008b, Reuters 2008)

In this analysis, we conservatively assume that overnight capital costs for new nuclear plants will initially average \$4,400 per kW (in 2006 dollars) for plants with a 2016 in-service date, not including financing costs. As discussed above, we also assume industry learning could reduce those costs by nearly 7 percent by 2030 at half the rate projected by the EIA, which bases its projection on international experience.

**Figure D.10. Overnight Capital Costs for Advanced Nuclear Plants**



Notes: All cost 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, which is represented by the darker bars in the graph. FPL, Duke Energy, Progress Energy, and SCEG-Santee Cooper are proposed plants, while EIA, MGA, UCS, and Keystone are studies. Sources: FPL 2008, Loder 2008, Progress Energy 2008a, Progress Energy 2008b, Reuters 2008, World Nuclear News 2008, MGA 2008, The Keystone Center 2007, EIA 2008b.

There are a number of reasons why there is a high risk that actual nuclear construction costs will exceed the assumption used in this analysis. 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 significant pinch points throughout the supply chain. Two decades ago, the United States had about 400 suppliers and 900 nuclear, or N-stamp, certificate holders (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 simultaneous forging demand from other sectors. Only JSW has the capability to manufacture ultra-heavy forgings, above 500 tons; the company's prices have reportedly increased by about 12 percent in six months with a 30 percent down payment requirement (Nucleonics Week 2007a).

Currently, it takes about six years to procure and manufacture other long lead-time components, including reactor cooling pumps, diesel generators, and control and instrumentation equipment. Nuclear Regulatory Commission Chairman Dale Klein has indicated that heavy reliance on foreign suppliers could require more time for quality

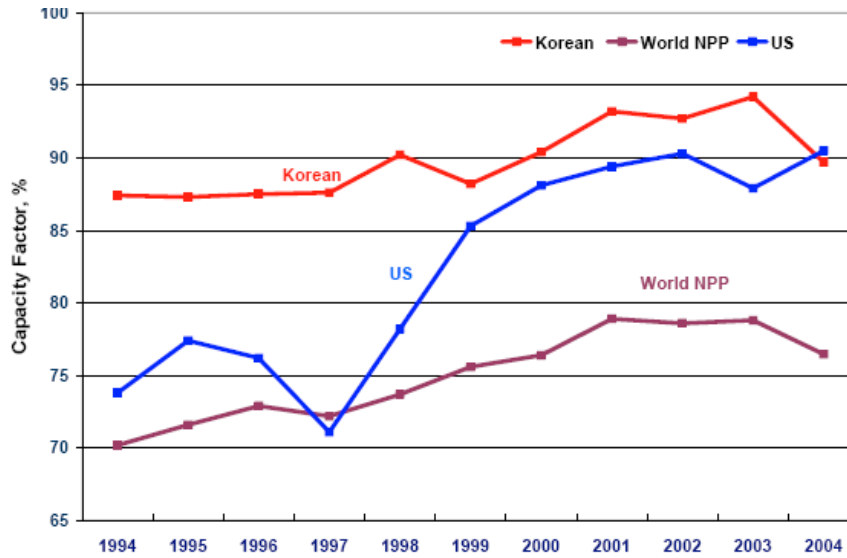
control inspections, to make sure substandard materials are not incorporated into U.S. plants (Nucleonics Week 2007a). Expansion of domestic production capacity in all these areas is possible, but will take time.

Skilled labor availability is also problematic. A 2005 study prepared for the Tennessee Valley Authority identified a lack of craft labor availability within a 400 mile radius, which forced the adoption of the longer construction schedule (Toshiba Corporation et al. 2005). Others have also cited this problem, at least in the United States (NPR 2007; Nucleonics Week 2007b)

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

- Increased fixed O&M costs from \$66 per kW-yr to \$110 per kW-yr, including the cost of U.S. reactor capital additions, based on the middle of the range of values specified in a 2007 Keystone study (The Keystone Center 2007) developed with input from a broad and diverse stakeholder group, including the nuclear industry.
- Increased variable O&M costs from \$0.48 per MWh to \$7.50 per MWh, which includes decommissioning costs. This is based on the middle of the range of costs from the Keystone Center 2007 study, which assumes a sinking fund to recover \$500 million in decommissioning costs, and 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 have increased from below 60 percent during most of the 1980s to just above 90 percent in 2007 and 2008 (Figure D.11). However, lifetime average capacity factors have been closer to 75 percent, reflecting both teething problems early in life and aging challenges later on (MIT 2003; Joskow 2006).

**Figure D.11. Nuclear Power Plant Capacity Factors**

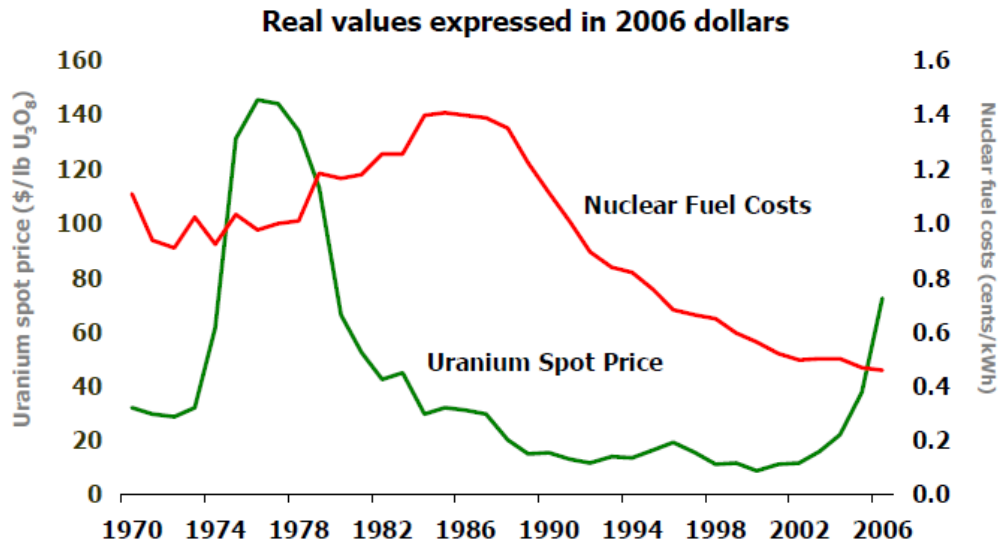


Source: Westinghouse.

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

- Fuel costs of approximately 0.75 cents per kWh. While these costs are consistent with current long-term contracts, they do not reflect higher spot-market prices that have experienced up to a ninefold increase over the past eight years (in constant dollars). According to the Keystone Center 2007 study, most contracts are set to expire by 2012 and “recent analyses by MIT (Neff 2007) suggest that low production, dampened investment related to long-term contracts, and lagging expansion of enrichment capacity are the likely to lead to continued higher prices into the future.”
- 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 delay, cost overruns, and regulatory disallowances. In light of past experience, state regulators may impose cost caps before construction begins. All of these factors can lead to a higher required return on investment and/or bond de-ratings, even for very large utilities. Federal loan guarantees can improve financing terms significantly, but it is not clear what impact they will have on debt-equity structure, return on equity, and return on debt.

**Figure D.12. Nuclear Fuel Costs and Uranium Spot Prices**



Source: The Keystone Center 2007.

Finally, we adopt the EIA’s assumption that existing plants are re-licensed and continue operating through the end of their 20-year license extension and then they are retired.

**Transmission.** The EIA includes transmission costs for all new sources of electric generating capacity in NEMS. These costs vary by region, ranging from \$200 to \$500 per kilowatt (in 2006 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 per MWh (Mills, Wisner, and Porter 2009). The study was based on a sample of 40 detailed transmission studies, completed from 2001 to 2008, that included wind energy resource areas in their analysis.

As discussed above, additional transmission, resource degradation, and siting costs are included for wind at increasing levels of penetration based on GIS modeling completed by NREL for the EIA’s (PERI 2007). We assume these factors can increase the capital costs for wind by up to 50 percent (see Figure D.5 above).

**Summary of Cost and Performance Assumptions.** Our Reference case capital costs for new fossil fuel, nuclear, and renewable energy technologies are shown in Table D.1. Operation and maintenance (O&M) costs, heat rates, and other assumptions for these technologies are shown in Table D.2. Assumed improvements in capacity factors over time for wind and solar technologies are shown in Table D.3. These capacity factors are used to determine annual electricity generation for these technologies. This generation is broken down further into nine different time periods, representing three different seasons (winter, summer, and fall/spring) and three different times during a 24 hour period.

The overall cost of electricity from various fossil fuel, nuclear, and renewable energy technologies in our Reference for 2015 and 2030 are shown in Figure D.13 and Figure D.14.

**Table D.1. Overnight Capital Costs for New Power Plants, Reference Case (2006\$/kW)**

<b>Plant Type</b>	<b>2015</b>	<b>2020</b>	<b>2025</b>	<b>2030</b>
COAL - IGCC	\$3,475	\$3,411	\$3,329	\$3,255
COAL - IGCC w/CCS	\$4,816	\$4,668	\$4,504	\$4,347
COAL - PC	\$2,975	\$2,949	\$2,892	\$2,856
NGCC	\$1,096	\$1,082	\$1,057	\$1,037
NGCC w/CCS	\$2,974	\$2,016	\$1,935	\$1,861
NUCLEAR	\$4,431	\$4,381	\$4,377	\$4,313
BIOMASS - IGCC	\$4,573	\$4,444	\$4,295	\$4,155
GEOTHERMAL	\$4,393	\$4,459	\$4,315	\$4,172
SOLAR - PV Central	\$5,590	\$5,036	\$4,427	\$4,038
SOLAR - PV Commercial	\$5,124	\$3,590	\$3,196	\$2,801
SOLAR - PV Residential	\$6,465	\$4,114	\$3,859	\$3,490
SOLAR - Thermal	\$4,463	\$4,068	\$3,771	\$2,752
WIND – Land-based	\$2,315	\$2,280	\$2,332	\$2,300
WIND - Offshore	\$4,011	\$3,861	\$3,687	\$3,527

Notes: Based on the average costs from 13 regions in the United States. Includes real escalation in construction costs until 2015 and technology learning effects through 2030, but does not include tax credits. Transmission costs are also not included, except for some additional transmission costs for wind projects that are incurred at higher levels of penetration over time. Geothermal capital costs are based on the average costs of developing hydrothermal flash projects in the western United States.

**Table D.2. Cost and Performance Characteristics of New Electricity Technologies**

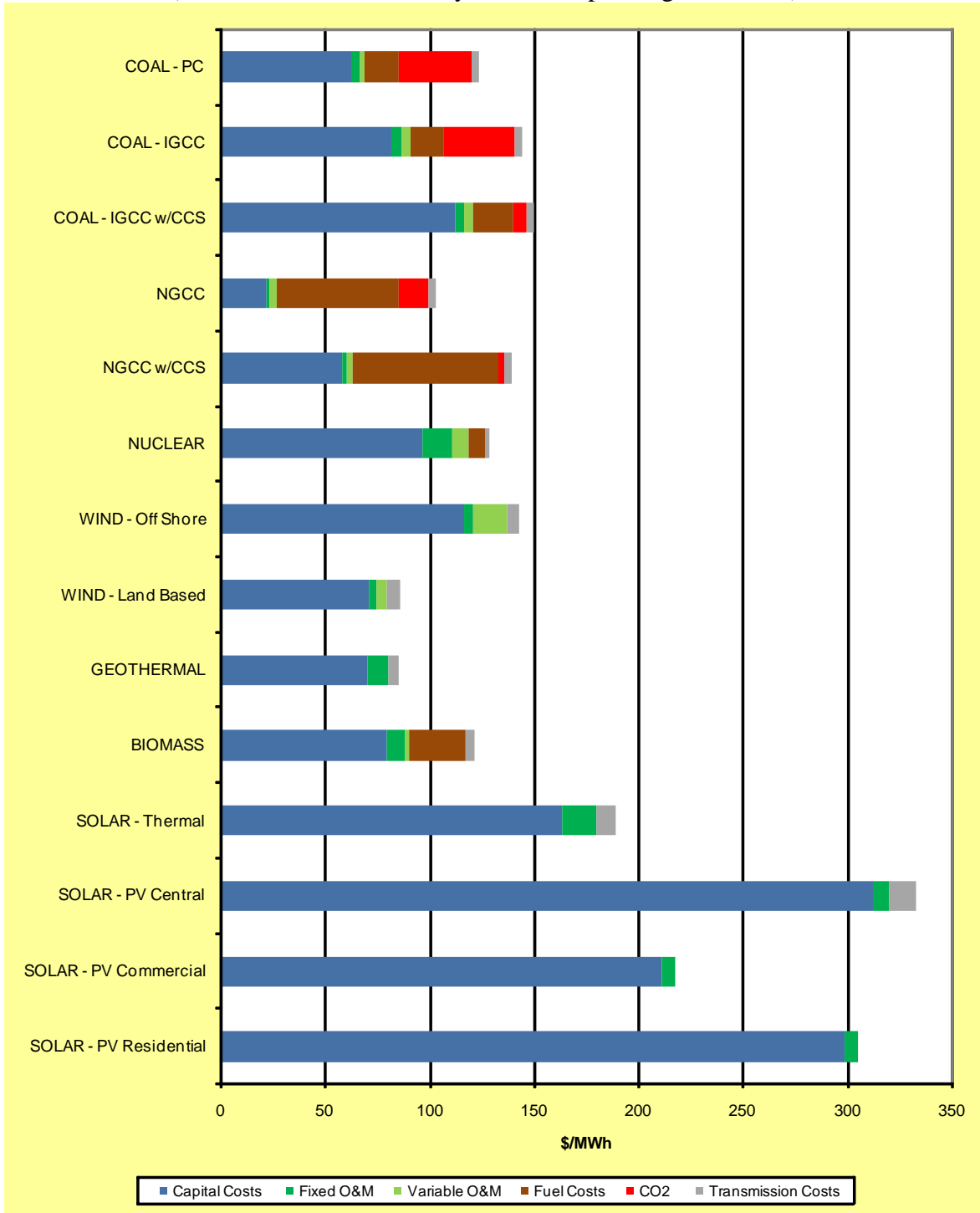
Technology	Online Year	Size (MW)	Lead Time (Years)	Variable O&M (\$2006 mills/kWh)	Fixed O&M (\$2006/kW)	Heatrate in 2007 (Btu/kWh)	Heatrate nth-of-a-kind (Btu/kWh)
Scrubbed Coal New	2011	600	4	1.7	35.3	9,200	9,000
Integrated Coal-Gasification Corr	2013	550	5	3.9	38.1	8,868	8,314
IGCC with Carbon Sequestration	2013	380	5	4.32	44.27	10,942	10,204
Conv Gas/Oil Comb Cycle	2010	250	3	4.3	9.5	6,990	6,990
Adv Gas/Oil Comb Cycle (CC)	2010	400	3	3	14.4	6,870	6,870
ADV CC with Carbon Sequestrat	2010	400	3	2.86	19.36	8,731	8,030
Conv Combustion Turbine	2009	160	2	3.47	11.78	9,266	9,266
Adv Combustion Turbine	2009	230	2	2.8	6.6	9,104	8,900
Fuel Cells	2010	10	3	46.62	5.5	7,930	6,960
Advanced Nuclear	2016	1350	6	7.5	110	10,400	10,400
Distributed Generation -Base	2009	5	2	6.9	16	9,200	8,900
Distributed Generation -Peak	2010	2	3	6.9	16	10,257	9,880
Biomass	2011	80	4	6.5	63	9,014	8,460
MSW - Landfill Gas	2010	30	3	0.0	111	13,648	13,648
Geothermal	2011	100	4	0.0	75-137	10,000	10,000
Conventional Hydropower	2011	500	4	3.4	13.6	10,022	10,022
Wind	2009	50	2	7.0	11.5	10,022	10,022
Wind Offshore	2010	100	3	21.0	15	10,022	10,022
Solar Thermal	2010	100	3	0.0	74	10,022	10,022
Photovoltaic	2009	5	2	0.0	24	10,022	10,022

**Table D.3. Capacity Factors Projections for Wind and Solar Technologies**

	2005	2010	2015	2020	2025	2030
<b>Onshore Wind</b>						
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%
<b>Offshore Wind</b>						
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%
<b>Concentrating Solar Power</b>	43.0%	43.0%	45.0%	48.3%	51.7%	55.0%
<b>Utility Scale PV</b>	20.4%	23.2%	26.0%	26.0%	26.0%	26.0%
<b>Distributed PV</b>	16.0%	17.8%	20.0%	22.5%	25.0%	25.0%

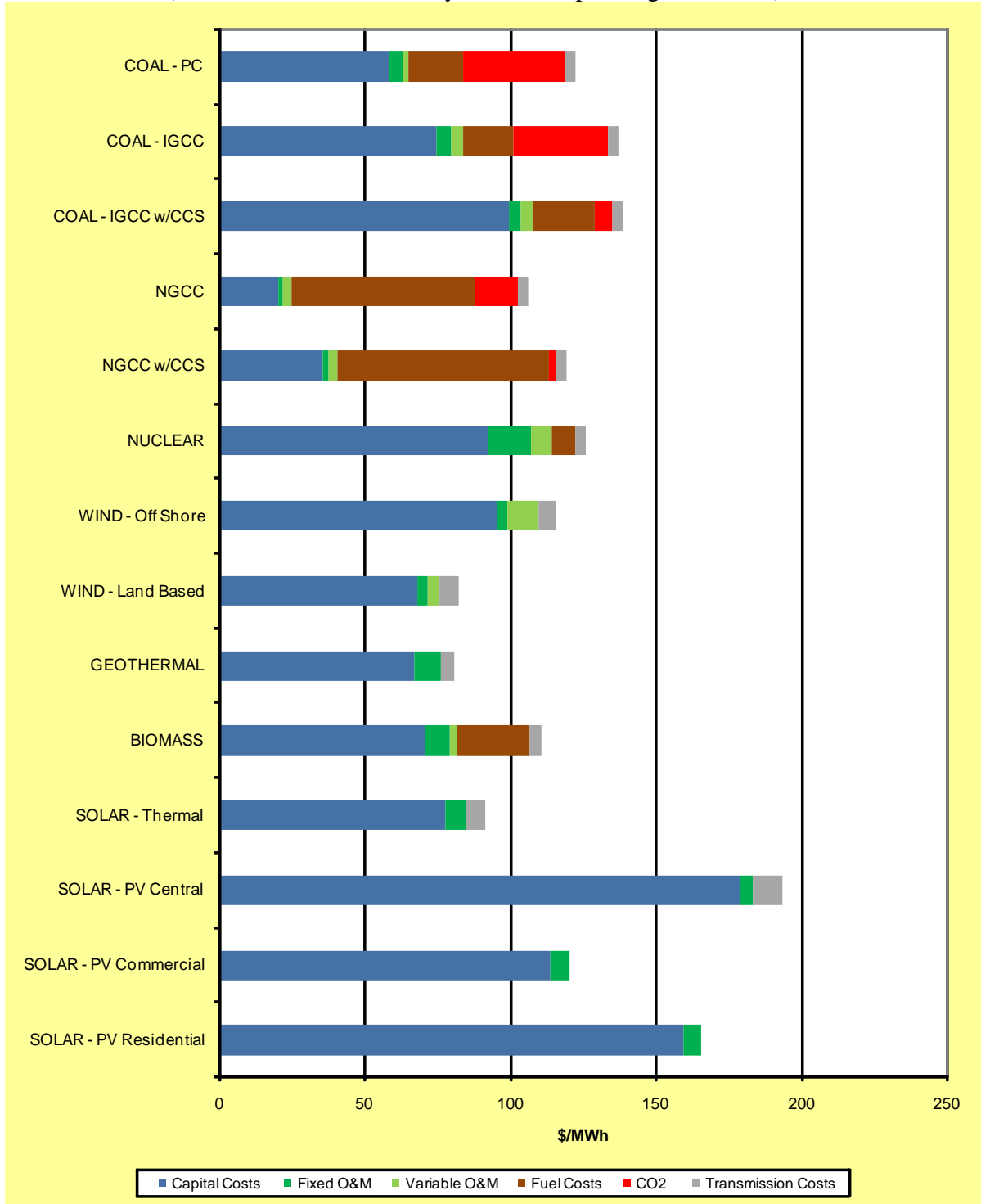


**Figure D.13. Cost of Electricity from Various Sources in 2015, Reference Case**  
(levelized cost of electricity, in dollars per megawatt-hour)



Notes: PC = pulverized coal; IGCC = integrated gasification combined cycle; CCS = carbon capture and storage; NGCC = natural gas combined cycle. The levelized cost of electricity includes the annualized cost of capital, operation and maintenance, and fuel costs from the Reference case. It also includes a CO<sub>2</sub> price of \$40/ton for illustrative purposes (where applicable). It does not include the cost of transmitting power or integrating facilities into the grid, or cost reductions from tax credits and other incentives for renewable and conventional technologies reflected in the model.

**Figure D.14. Cost of Electricity from Various Sources in 2030, Reference Case**  
(levelized cost of electricity, in dollars per megawatt-hour)



Notes: PC = pulverized coal; IGCC = integrated gasification combined cycle; CCS = carbon capture and storage; NGCC = natural gas combined cycle. The levelized cost of electricity includes the annualized cost of capital, operation and maintenance, and fuel costs from the Reference case. It also includes a CO<sub>2</sub> price of \$40/ton for illustrative purposes (where applicable). It does not include the cost of transmitting power or integrating facilities into the grid, or

cost reductions from tax credits and other incentives for renewable and conventional technologies reflected in the model.

## **D.2. Climate 2030 Blueprint Case**

We assume a package of market-oriented policies, which includes standards and incentives to increase investment in renewable energy by consumers and the electricity sector, will be needed to overcome the market barriers currently limiting growth. No single policy can adequately address the range of market barriers faced by different renewable energy technologies that are at different stages of development. However, due to model limitations, we do not explicitly model all of the policies that we believe are needed in this analysis. Rather, we assume these policies will help facilitate the development of particular technologies included in the analysis and contribute to a national renewable electricity standard (RES), which we do explicitly model.

**National RES.** The Blueprint includes a national RES that begins at 4 percent of projected electricity sales in 2010 and ramps up gradually on an annual basis to 40 percent in 2030, after including the reductions in electricity sales due to energy efficiency and CHP. This is equivalent to approximately 25 percent of our Reference case electricity sales in 2030, not including energy efficiency and CHP. The assumed annual ramp-up rate (1 to 1.5 percent of our Reference case sales) is consistent with the average rates of standards in leading states such as Illinois, Minnesota, New Jersey, and Oregon, as well as the stronger national RES proposals.

We also assumed that:

- all U.S. electric service providers are required to meet the targets;
- eligible technologies include biomass, geothermal, incremental or new (at existing dams) hydroelectric, landfill gas, solar, and wind; and
- existing renewable generation (except existing hydro) is eligible to meet the targets.

**Planned solar additions.** We increased the EIA's planned additions for CSP and utility-scale PV through 2020, based on information on actual proposals and signed power purchased agreements between utilities and solar developers. We also increased planned additions for distributed PV technologies. We assumed that the combination of the recent federal tax credit extensions for solar, requirements included for solar technologies in state renewable electricity standards, net metering, other state incentives and policies for solar, and a national RES would be enough to support the development of these planned projects.

**Coal with CCS demonstration program.** We assume a new federal program will provide \$9 billion to cover the incremental costs of building eight new full-scale advanced coal IGCC with CCS demonstration projects between 2013 and 2016 in several regions of the country that are actively considering proposals. We assume this funding will come from a small portion of the auction revenues collected from the cap-and-trade program. This policy is consistent with the recommendations included in the UCS report *Coal Power in a Warming World* (Freese, Clemmer, and Noguee 2008).

**Efficiency.** As discussed in more detail in Appendix C, policies to increase energy efficiency reduce electricity sales 35 percent by 2030 compared with our Reference case

and CHP in industry and buildings more than triples over current levels based on an analysis by the American Council for an Energy Efficient Economy (ACEEE).

### **D.3. Renewable Energy Technical Potential**

This section describes the key assumptions and references we used to estimate the technical potential for producing electricity from renewable energy in Table 5.1 in the main body of the report. Estimates of technical potential reflect the availability of a renewable resource and include some environmental and economic exclusions. Other factors—such as land-use conflicts, higher short-term costs, limited transmission capacity, ramp-up constraints, public acceptance, and other barriers—will limit how quickly and to what extent we can tap this potential. While these factors are generally not reflected in the technical potential estimates, many of them are explicitly included in the renewable energy supply curves included in the model.

**Wind.** The United States has more than 8,000 GW of land-based wind power potential, 2,000 GW of shallow offshore wind potential, and 3,000 GW of deep offshore wind potential according to a 2007 Black & Veatch study for the American Wind Energy Association (O’Connell et al. 2007). The estimates are based on a GIS analysis completed by NREL, using updated wind resource assessments for most states and including several environmental and land-use exclusions. The study also found that the United States has 600,000 MW of land-based wind potential at costs below \$100 per MWh, and another 400,000 MW of offshore wind potential at costs below \$150 per MWh, not including federal incentives but including the cost of connecting to the existing transmission system.

**Concentrating Solar Power.** NREL completed a GIS analysis that identified a technical potential for 7,000 GW of CSP capacity in the southwestern United States covering 53,727 square miles of land area, after screening out urban centers, national parks, other protected areas, lands with slopes greater than 1 percent, and areas with solar resources less than 6.75 kWh per square meter per day (DOE 2007a). This potential equates to roughly 10 times the current electricity generating capacity of the entire United States. NREL also identified 200 GW of optimal locations after considering distances to existing transmission lines, and estimated that as much as 80 GW of CSP capacity could be built by 2030.

**Photovoltaics.** A Navigant Consulting analysis shows a technical potential for residential and commercial building integrated PV of 1,000 GW by 2025, assuming growth in the building stock and increases in PV density (Chaudhari, Frantzis, and Hoff 2004). While we were not able to find any estimates of the potential for utility-scale PV, its potential is virtually unlimited because it can be sited in many locations.

**Geothermal.** In its first comprehensive assessment in more than 30 years, the USGS estimated over 33,000 MW of potential capacity from conventional hydrothermal sources located on private and accessible public lands across 13 western states (Williams et al. 2008). The study also found that the United States has the potential for an additional 517,800 MW from Enhanced Geothermal Systems (EGS). An MIT study estimates that

the United States has an additional 44,000 MW of potential geothermal capacity that could be developed by 2050 by co-producing electricity, oil, natural gas at depleted oil and gas fields, primarily in the Southeast and Southern Plains states (Tester et al. 2006; Petty and Porro 2007).

**Bioenergy.** A 2005 DOE study found that the United States has the technical potential to produce 1.3 billion dry tons of biomass per year for energy use (DOE and USDA 2005). This included 370 million dry tons from forest lands and 1 billion tons from agricultural lands comprising 446 million tons from agricultural residues, 377 million tons of perennial energy crops, 87 million tons of dry grains for biofuels, and 87 million tons of other agricultural waste such as animal manure. This biomass could be used to produce electricity, transportation fuels, and heat. While this represents a reasonable technical potential, we used different biomass supply assumptions in this analysis to incorporate additional sustainability and environmental criteria (see more details in Appendix G).

**Hydropower.** A 2007 EPRI study found that non-dammed rivers, tides, and ocean and constructed waterway currents have the potential to supply more than 140 GW of new capacity, while conventional hydropower has the potential to expand by 62 GW, not counting efficiency improvements (Dixon and Bedard 2007).

## **D.4 References and Calculations for Equivalencies in Table 9.3 and Table 9.6**

### **Coal Use Equivalencies**

Estimates of the number of train cars of coal needed for each ton of coal are from the EIA's Annual Electric Generator Report (EIA 2007) and Electric Power Annual (EIA 2009a). The number of miles of train cars saved was calculated by applying a coal car to coal consumption ratio (miles of coal cars per short ton of coal) to the projected cumulative coal production savings under the Blueprint.

Assumptions for the average coal consumption per power plant are also based on data from EIA 2007 and EIA 2009a. The estimated number of coal power plants avoided were calculated from the Blueprint's projected coal consumption savings.

Coal mining waste savings are based on data from the EPA's Final Programmatic Environmental Impact Statement on Mountaintop Mining/Valley Fills in Appalachia study in 2005 (DOI 2005) and data from Patriot Coal (2009). The estimated number of tons of mountaintop mining waste savings was calculated by applying an overburden-to-coal ratio to the projected coal production savings under the Blueprint.

Estimates of the number of gallons of slurry and number of slurry ponds created per ton of wet-processed coal are from a National Academies study (NRC 2002). The number of slurry ponds displaced was calculated by applying a slurry production rate (gallons of slurry per ton of wet-processed coal) to projected wet-processed coal savings under the Blueprint.

Assumptions for asthma cases related to particulate matter from coal plants per ton of coal consumed are based on data from the American Lung Association (ALA 2007). Estimates of asthma attacks avoided were calculated from the Blueprint’s projected coal consumption savings. This estimate does not include the effects of tighter emission standards.

Assumptions for mine injuries per ton of coal produced are based on National Mining Association data (NMA 2008). Estimates of miner injuries were calculated from the Blueprint’s projected coal production savings.

Mercury emissions from coal plants are based on data from the EPA National Emission Inventory (EPA 2006b). The total mercury savings were calculated by applying a mercury emission to coal consumption ratio (tons of mercury emitted per ton of coal consumed) to the projected coal consumption savings under the Blueprint. These mercury savings estimates do not include the effects of tighter emission standards.

These assumptions are outlined in Table D.2 below.

**Table D.2. Coal Use Equivalencies Assumptions and Sources**

	<b>Assumptions</b>	<b>Assumption Source</b>
Coal train cars, volume and length	1 coal car: 100 short tons, 53	EIA 2008a
Coal heat rate	10164 Btu/kWh	EIA 2007
Coal average energy content	20.2 million Btu/short ton	EIA 2009a
Coal plant capacity factor	72.6%	EIA 2009a
Miles of Appalachian ridgeline removed	300 sq. miles in 2003	DOI 2005, OSM 2005
Coal produced from mountaintop removal mining	989 million short tons in 2003	DOI 2005, OSM 2005
Overburden-to-coal ratio	15-to-1	Patriot Coal 2009
Surface mining acreage	5.8 million acres in 2002	DOI 2005, OSM 2002
Wet-processed coal	35% of coal produced in 2000	NRC 2002
Amount of slurry produced	1000 million gallons in 2000	NRC 2002
Number of asthma attacks caused by coal-fired power plants	550,000 in 2004	ALA 2007
Number of mine injuries	5068 injuries/billion short tons	NMA 2008
Mercury emitted from coal plants	47.8 tons in 1999	EPA 2006b

**Water use equivalencies**

Assumptions for water consumption per MWh of electricity generated from different technologies are based on numerous sources (see Table D.3 and CATF and WRA 2003, and Tellinghuisen et al. 2008.)

Estimates only include water use at the power plant. They do not include any water use for growing biomass. This should be close to zero for energy crops, because the energy crop supply curves developed by Walsh and her colleagues at the University of Tennessee (see Appendix G) assume that switchgrass will only be grown in areas that do not need irrigation.

Water use for biomass power plants assumes lower EPRI 2002 values for improved biomass steam plant, based on the assumption that most of the biomass will either be co-fired in existing coal plants (which have lower water use per kWh than biomass) or in new biomass IGCC plants that are more efficient.

The rates used here and listed below in Table D.3 are for water consumption, in which water is removed from a source but is not directly returned because it has been evaporated or transpired. Another type of water use generally considered but not used here is water withdrawal, where water is removed from the ground or diverted from a surface source for use, but is returned to the source at a higher temperature (EERE 2008)

**Table D.3: Water Consumption Rates for Electric Generating Technologies<sup>1</sup>**

	<b>Water Consumption Rate (Gallons/MWh)</b>	<b>Source</b>
Coal, Steam	541	EIA 2002
Coal, IGCC	365	NETL 2007
Coal, IGCC with CCS	500	NETL 2007
Coal, PC with CCS	1,438	NETL 2007
Gas-Fired Combined Cycle <sup>2</sup>	180	EPRI 2002
Gas-Fired Combined Cycle with CCS	583	NETL 2007
Oil- or Gas-Fired Steam	662	EIA 2002
Combustion Turbine	50	EERE 2008
Bioenergy <sup>3</sup>	475	EPRI 2002
Concentrating Solar Thermal <sup>4</sup>	78-760	EEA 2006, Stoddard 2006
Geothermal, Binary, Dry Cooling	0	Kagel, Bates, and Gawell 2007
Geothermal, Binary, Hybrid Cooling	191	Kozubal and Kutscher 2003
Geothermal, Binary, Wet Cooling	1,690	Kozubal and Kutscher 2003

(1) Reductions in water consumption are calculated based on the reduction in fossil fuel generation and the increase in renewable electricity generation under the Blueprint compared with the Reference case. See Appendix D for assumptions and sources.

(2) The incremental water use of natural gas CHP generation over existing on-site boiler systems is essentially zero. (EEA 2006)

(3) Only includes water use at the power plant. No additional water is needed for biomass residues. Water usage for growing energy crops (mainly switchgrass) is assumed to be negligible as we assumed



energy crops would only be grown on land that does not need irrigation in the eastern half of the United States.

- (4) The range represents the use of dry cooling vs. wet cooling. Dry cooling is more common in the Southwest where the vast majority of concentrating solar plants will be located.

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