2016 Levelized Cost of New Generation Resources from the Annual Energy Outlook 2010

The table on the following page provides the average national levelized costs for the generating technologies represented in the National Energy Modeling System (NEMS) as configured for the *Annual Energy Outlook 2010* (AEO2010) reference case.[1] Levelized costs represent the present value of the total cost of building and operating a generating plant over its financial life, converted to equal annual payments and amortized over expected annual generation from an assumed duty cycle. The key factors contributing to levelized costs include the cost of constructing the plant, the time required to construct the plant, the non-fuel costs of operating the plant, the fuel costs, the cost of financing, and the utilization of the plant.[2] The availability of various incentives including state or federal tax credits can also impact these costs. The values shown in the table do not incorporate any such incentives. As with any projections, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve. When evaluating actual plant proposals, the specific technological and regional characteristics of the project must be taken into account.

In the AEO2010 reference case a 3-percentage point increase in the cost of capital is added when evaluating investments in GHG intensive technologies like coal-fired power plants without carbon control and sequestration (CCS) and coal-to-liquids (CTL) plants. While the 3-percentage point adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of a $15 per ton CO2 emissions fee when investing in a new coal plant without CCS, well within the range of the results of simulations that utilities and regulators have prepared. The adjustment should not be seen as an increase in the actual cost of financing, but rather as representing the implicit hurdle being added to GHG intensive projects to account for the possibility they may eventually have to purchase allowances or invest in other GHG emission-reducing projects that offset their emissions. As a result, the levelized capital costs of coal-fired plants without CCS are higher than would otherwise be expected.

Levelized costs can be useful when comparing different technology options to satisfy a given duty cycle requirement. For example, levelized cost could be used to determine the lowest cost new capacity available to satisfy a need for baseload[3] power that would be expected to operate at a 70 percent capacity factor or higher. In the table below, the levelized cost for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the maximum availability of each technology. However, it should be noted that a technology such as a conventional combined cycle turbine that

[1] The original full report and updated reference case are available at http://www.eia.doe.gov/oiaf/aeo/index.html.

[2] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.doe.gov/oiaf/aeo/index.html.

[3] While there are no definitive utilization breakpoints, baseload plants are facilities that operate almost continuously, generally at annual utilization rates of 70 percent or higher. Intermediate load plants are facilities that operate less frequently than baseload plants, generally at annual utilization rates between 25 and 70 percent. Peaking plants are facilities that only run when the demand for electricity is very high, generally at annual utilization rates less than 25 percent.

looks relatively expensive at its maximum capacity factor may be the most attractive option when evaluated at a lower capacity factor that would be associated with an intermediate load duty cycle. Simple combustion turbines (conventional or advanced technology) are typically used for peak load duty cycles, and are thus evaluated at a 30 percent capacity factor. The duty cycle for intermittent renewable resources of wind and solar is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset). The availability of wind or solar will not necessarily correspond to operator dispatched duty cycles and, as a result, their levelized costs are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar). In addition, intermittent technologies do not provide the same contribution to system reliability as dispatched resources, and may require additional system investment (not shown) to achieve a desired level of reliability.

As mentioned, the costs shown in the table are national averages. However, there is significant local variation in costs based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, regional wind costs range from 91 $/MWh in the region with the best available resources in 2016 to 271 $/MWh in regions where the best sites have been claimed by 2016. Costs for wind may include additional costs associated with transmission upgrades needed to access remote resources, as well as other factors that markets may or may not internalize into the market price for wind power.

Estimated Levelized Cost of New Generation Resources, 2016.

Plant Type	Capacity Factor (%)	U.S. Average Levelized Costs (2008 $/megawatthour) for Plants Entering Service in 2016				
		Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System Levelized Cost
Conventional Coal	85	69.2	3.8	23.9	3.6	100.4
Advanced Coal	85	81.2	5.3	20.4	3.6	110.5
Advanced Coal with CCS	85	92.6	6.3	26.4	3.9	129.3
Natural Gas-fired						
Conventional Combined Cycle	87	22.9	1.7	54.9	3.6	83.1
Advanced Combined Cycle	87	22.4	1.6	51.7	3.6	79.3
Advanced CC with CCS	87	43.8	2.7	63.0	3.8	113.3
Conventional Combustion Turbine	30	41.1	4.7	82.9	10.8	139.5
Advanced Combustion Turbine	30	38.5	4.1	70.0	10.8	123.5
Advanced Nuclear	90	94.9	11.7	9.4	3.0	119.0
Wind	34.4	130.5	10.4	0.0	8.4	149.3
Wind – Offshore	39.3	159.9	23.8	0.0	7.4	191.1
Solar PV	21.7	376.8	6.4	0.0	13.0	396.1
Solar Thermal	31.2	224.4	21.8	0.0	10.4	256.6
Geothermal	90	88.0	22.9	0.0	4.8	115.7
Biomass	83	73.3	9.1	24.9	3.8	111.0
Hydro	51.4	103.7	3.5	7.1	5.7	119.9

Source: Energy Information Administration, Annual Energy Outlook 2010, December 2009, DOE/EIA-0383(2009)

Electricity Market Module

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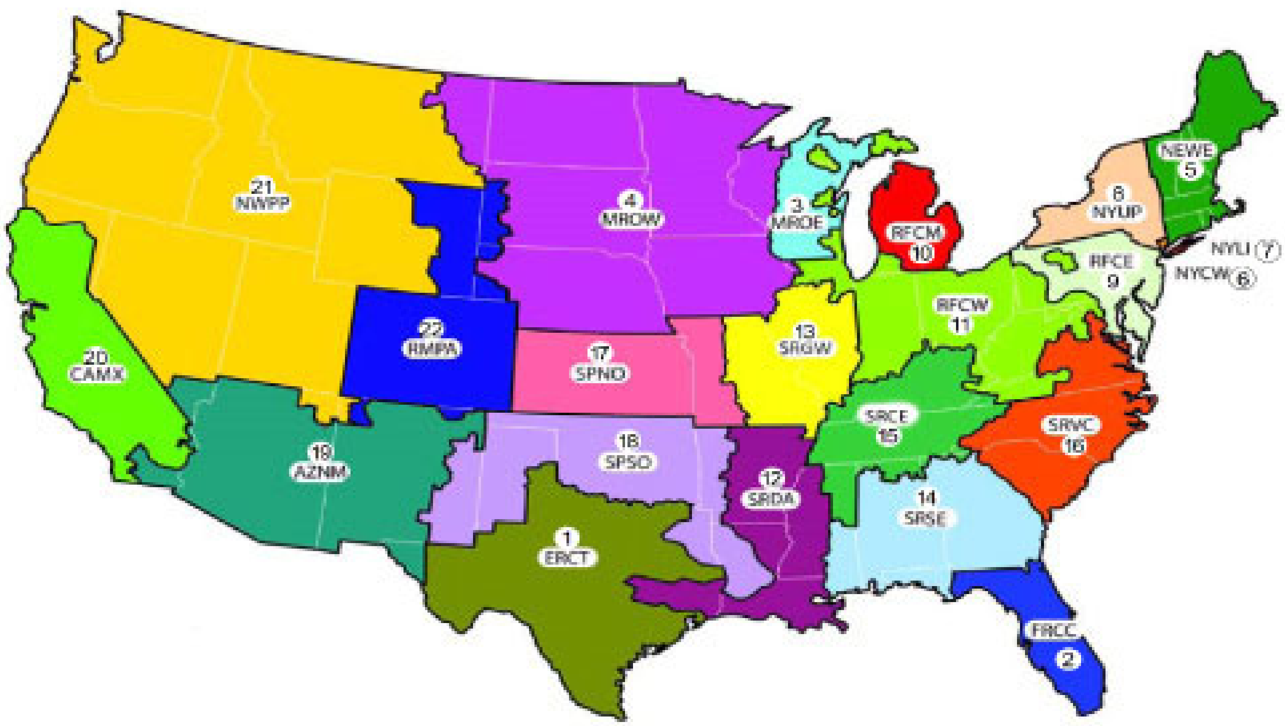
The NEMS Electricity Market Module (EMM) represents the capacity planning, dispatching, and pricing of electricity. It is composed of four submodules—electricity capacity planning, electricity fuel dispatching, electricity load and demand, and electricity finance and pricing. It includes nonutility capacity and generation, and electricity transmission and trade. A detailed description of the EMM is provided in the EIA publication, Electricity Market Module of the National Energy Modeling System 2012, DOE/EIA-M068(2012).

Based on fuel prices and electricity demands provided by the other modules of the NEMS, the EMM determines the most economical way to supply electricity, within environmental and operational constraints. There are assumptions about the operations of the electricity sector and the costs of various options in each of the EMM submodules. This section describes the model parameters and assumptions used in EMM. It includes a discussion of legislation and regulations that are incorporated in EMM as well as information about the climate change action plan. The various electricity and technology cases are also described.

EMM regions

The supply regions used in EMM are based on the North American Electric Reliability Corporation regions and subregions shown in Figure 6.

Figure 6. Electricity Market Model Supply Regions



1.	ERCT	ERCOT All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Model parameters and assumptions

Generating capacity types

The capacity types represented in the EMM are shown in Table 8.1.

Table 8.1. Generating capacity types represented in the Electricity Market Module

Capacity Type
Existing coal steam plants[1]
High Sulfur Pulverized Coal with Wet Flue Gas Desulfurization
Advanced Coal - Integrated Coal Gasification Combined Cycle
Advanced Coal with carbon sequestration
Oil/Gas Steam - Oil/Gas Steam Turbine
Combined Cycle - Conventional Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle - Advanced Gas/Oil Combined Cycle Combustion Turbine
Advanced Combined Cycle with carbon sequestration
Combustion Turbine - Conventional Combustion Turbine
Advanced Combustion Turbine - Steam Injected Gas Turbine
Molten Carbonate Fuel Cell
Conventional Nuclear
Advanced Nuclear - Advanced Light Water Reactor
Generic Distributed Generation - Baseload
Generic Distributed Generation - Peak
Conventional Hydropower - Hydraulic Turbine
Pumped Storage - Hydraulic Turbine Reversible
Geothermal
Municipal Solid Waste
Biomass - Fluidized Bed
Solar Thermal - Central Tower
Solar Photovoltaic - Fixed Tilt
Wind
Wind Offshore

[1]The EMM represents 32 different types of existing coal steam plants, based on the different possible configuration of NO_x, particulate and SO_2 emission control devices, as well as future options for controlling mercury.
Source: U.S. Energy Information Administration.

New generating plant characteristics

The cost and performance characteristics of new generating technologies are inputs to the electricity capacity planning submodule (Table 8.2). These characteristics are used in combination with fuel prices from the NEMS fuel supply modules and foresight on fuel prices, to compare options when new capacity is needed. Heat rates for fossil-fueled technologies are assumed to decline linearly through 2025.

For the *AEO2011*, EIA commissioned an external consultant to develop current cost estimates for utility-scale electric generating plants [1]. This report continues to be the basis for the cost assumptions for *AEO2012*. A cost adjustment factor, based on the producer price index for metals and metal products, allows the overnight costs to fall in the future if this index drops, or rise further if it increases.

The overnight costs shown in Table 8.2 represent the estimated cost of building a plant in a typical region of the country. Differences in plant costs due to regional distinctions are calculated by applying regional multipliers. Regional multipliers by technology were also updated for *AEO2012* based on regional cost estimates developed by the consultant. The regional variations account for multiple factors, such as differences in terrain, weather, population, and labor wages. The base overnight cost is multiplied by a project contingency factor and a technological optimism factor (described later in this chapter), resulting in the total construction cost for the first-of-a-kind unit used for the capacity choice decision.

Table 8.2. Cost and performance characteristics of new central station electricity generating technologies

Technology	Online Year[1]	Size (mW)	Lead time (years)	Base Overnight Cost in 2010 (2010 $/kW)	Contingency Factors: Project Contingency Factor[2]	Contingency Factors: Technological Optimism Factor[3]	Total Overnight Cost in 2010[4] (2010 $/kW)	Variable O&M[5] (2010 $/mWh)	Fixed O&M (2010$/kW)	Heatrate[6] in 2011 (Btu/KWh)	nth-of-a-kind Heatrate (Btu/KWh)
Scrubbed Coal New[7]	2015	1300	4	2,658	1.07	1.00	2,844	4.25	29.67	8,800	8,740
Integrated Coal-Gasification Comb Cycle (IGCC)[7]	2015	1200	4	3,010	1.07	1.00	3,220	6.87	48.90	8,700	7,450
IGCC with carbon sequestration	2017	520	4	4,852	1.07	1.03	5,348	8.04	69.30	10,700	8,307
Conv Gas/Oil Comb Cycle	2014	540	3	931	1.05	1.00	977	3.43	14.39	7,050	6,800
Adv Gas/Oil Comb Cycle (CC)	2014	400	3	929	1.08	1.00	1,003	3.11	14.62	6,430	6,333
Adv CC with carbon sequestration	2017	340	3	1,834	1.08	1.04	2,060	6.45	30.25	7,525	7,493
Conv Comb Turbine[8]	2013	85	2	927	1.05	1.00	974	14.70	6.98	10,745	10,450
Adv Comb Turbine	2013	210	2	634	1.05	1.00	666	9.87	6.70	9,750	8,550
Fuel Cells	2014	10	3	5,918	1.05	1.10	6,836	0.00	350.00	9,500	6,960
Adv Nuclear	2017	2236	6	4,619	1.10	1.05	5,335	2.04	88.75	10,460	10,460
Distributed Generation - Base	2014	2	3	1,366	1.05	1.00	1,434	7.46	16.78	9,050	8,900
Distributed Generation - Peak	2013	1	2	1,640	1.05	1.00	1,722	7.46	16.78	10,056	9,880
Biomass	2015	50	4	3,519	1.07	1.02	3,859	5.00	100.55	13,500	13,500
Geothermal[7,9]	2011	50	4	2,393	1.05	1.00	2,513	9.64	108.62	9,760	9,760
MSW - Landfill Gas	2011	50	3	7,694	1.07	1.00	8,233	8.33	378.76	13,648	13,648
Conventional Hydropower[9]	2015	500	4	2,134	1.10	1.00	2,347	2.55	14.27	9,760	9,760
Wind	2011	100	3	2,278	1.07	1.00	2,437	0.00	28.07	9,760	9,760
Wind Offshore	2015	400	4	4,345	1.10	1.25	5,974	0.00	53.33	9,760	9,760
Solar Thermal[7]	2014	100	3	4,384	1.07	1.00	4,691	0.00	64.00	9,760	9,760
Photovoltaic[7,10]	2013	150	2	4,528	1.05	1.00	4,755	0.00	16.70	9,760	9,760

[1]Online year represents the first year that a new unit could be completed, given an order date of 2011. For wind, geothermal and landfill gas, the online year was moved earlier to acknowledge the significant market activity already occuring in anticipation of the expiration of the Production Tax Credit.
[2]A contingency allowance is defined by the American Association of Cost Engineers as the "specific provision for unforeseeable elements of costs within a defined project scope; particularly important where previous experience has shown that unforeseeable events which will increase costs are likely to occur."
[3]The technological optimism factor is applied to the first four units of a new, unproven design; it reflects the demonstrated tendency to underestimate actual costs for a first-of-a-kind unit.
[4]Overnight capital cost including contingency factors, excluding regional multipliers and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2011.
[5]O&M = Operations and maintenance.
[6]For hydro, geothermal, wind, and solar technologies, the heatrate shown represents the average heatrate for conventional thermal generation as of 2010. This is used for purposes of calculating primary energy consumption displaced for these resources, and does not imply an estimate of their actual energy conversion efficiency.
[7]Capital costs are shown before investment tax credits are applied.
[8]Combustion turbine units can be built by the model prior to 2013 if necessary to meet a given region's reserve margin.
[9]Because geothermal and hydro cost and performance characteristics are specific for each site, the table entries represent the cost of the least expensive plant that could be built in the Northwest Power Pool region, where most of the proposed sites are located.
[10]Costs and capacities are expressed in terms of net AC power available to the grid for the installed capacity.
Sources: For the *AEO2012* cycle, EIA continues to use the previously developed cost estimates for utility-scale electric generating plants, prepared by external consultants for *AEO2011*. This report can be found at www.eia.gov/oiaf/beck_plantcosts/index.html. Site-specific costs for geothermal were provided by the National Energy Renewable Laboratory, "Updated U.S. Geothermal Supply Curve," February 2010.

Technological optimism and learning

Overnight costs for each technology are calculated as a function of regional construction parameters, project contingency, and technological optimism and learning factors.

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 4 units) the technological optimism factor is gradually reduced to 1.0.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary or mature. Different learning rates are assumed for each component, based on the level of experience with the design component (Table 8.3). Where technologies use similar components, these components learn at the same rate as these units are built. For example, it is assumed that the underlying turbine generator for a combustion turbine, combined cycle and integrated coal-gasification combined cycle unit is basically the same. Therefore construction of any of these technologies would contribute to learning reductions for the turbine component.

The learning function has the nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity for the technology component.

Table 8.3. Learning parameters for new generating technology components

Technology Component	Period 1 Learning Rate (LR1)	Period 2 Learning Rate(LR2)	Period 3 Learning Rate (LR3)	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[1]	-	-	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	20%	10%	1%	3	5	20%
Advanced Nuclear	5%	3%	1%	3	5	10%
Fuel prep - Biomass	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	10%
Solar PV - Module	20%	10%	1%	1	5	10%
Balance of Plant - Solar PV	20%	10%	1%	1	5	10%

[1]HRSG = Heat Recovery Steam Generator
Note: Please see the text for a description of the methodology for learning in the Electricity Market Module.
Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis.

The progress ratio (pr) is defined by speed of learning (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (LR) is an exogenous parameter input for each component (Table 8.3). The progress ratio and LR are related by:

$pr = 2^{-b} = (1 - LR)$

The parameter "b" is calculated from the second equality above (b =-(ln(1-LR)/ln(2)). The parameter "a" is computed from initial conditions, i.e.

$a = OC(C_0)/C_0^{-b}$

where C_0 is the initial cumulative capacity. Once the rates of learning (LR) and the cumulative capacity (C_0) are known for each interval, the parameters (a and b) can be computed. Three learning steps were developed to reflect different stages of learning as a new design is introduced into the market. New designs with a significant amount of untested technology will see high rates of learning initially, while more conventional designs will not have as much learning potential. Costs of all design components are adjusted to reflect a minimal amount of learning, even if new capacity additions are not projected. This represents cost reductions due to future international development or increased research and development.

Once the learning rates by component are calculated, a weighted average learning factor is calculated for each technology. The weights are based on the share of the initial cost estimate that is attributable to each component (Table 8.4). For technologies that do not share components, this weighted average learning rate is calculated exogenously, and input as a single component.

These technologies may still have a mix of revolutionary components and more mature components, but it is not necessary to include this detail in the model unless capacity from multiple technologies would contribute to the component learning. In the case of the solar PV technology, it is assumed that the module component accounts for 50 percent of the cost, and that the balance of system components accounts for the remaining 50 percent. Because the amount of end-use PV capacity (existing and projected) is significant relative to total solar PV capacity, and because the technology of the module component is common across the end-use and electric power sectors, the calculation of the learning factor for the PV module component also takes into account capacity built in the residential and commercial sectors.

Table 8.5 shows the capacity credit toward component learning for the various technologies. It was assumed that for all combined-cycle technologies, the turbine unit contributed two-thirds of the capacity, and the steam unit one-third. Therefore, building one gigawatt of gas combined cycle would contribute 0.67 gigawatts toward turbine learning, and 0.33 gigawatts toward steam learning. Components that do not contribute to the capacity of the plant, such as the balance of plant category, receive 100 percent capacity credit for any capacity built with that component. For example, when calculating capacity for the "Balance of plant - CC" component, all combined cycle capacity would be counted 100 percent, both conventional and advanced.

Table 8.4. Component cost weights for new technologies

Technology	Pulverized Coal	Combus-tion Turbine-conven-tional	Combus-tion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Seques-tration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	15%	20%	41%	0%	24%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	10%	15%	30%	30%	15%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	30%	0%	40%	0%	0%	0%	0%	30%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	30%	40%	0%	0%	0%	0%	30%	0%
Adv CC with carbon sequestration	0%	0%	20%	25%	0%	40%	0%	0%	15%	0%
Conv Comb Turbine	0%	50%	0%	0%	0%	0%	0%	50%	0%	0%
Adv Comb Turbine	0%	0%	50%	0%	0%	0%	0%	50%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	50%

Note: All unlisted technologies have a 100 percent weight with the corresponding component. Components are not broken out for all technologies unless there is overlap with other technologies.
HRSG = Heat Recovery Steam Generator.
Source: Market-Based Advanced Coal Power Systems, May 1999, DOE/FE-0400.

Table 8.5. Component capacity weights for new technologies

Technology	Pulverized Coal	Combustion Turbine-conventional	Combustion Turbine-advanced	HRSG	Gasifier	Carbon Capture/ Sequestration	Balance of Plant-IGCC	Balance of Plant-Turbine	Balance of Plant-Combined Cycle	Fuel Prep Biomass
Integrated Coal-Gasification Comb Cycle (IGCC)	0%	0%	67%	33%	100%	0%	100%	0%	0%	0%
IGCC with carbon sequestration	0%	0%	67%	33%	100%	100%	100%	0%	0%	0%
Conv Gas/Oil Comb Cycle	0%	67%	0%	33%	0%	0%	0%	0%	100%	0%
Adv Gas/Oil Comb Cycle (CC)	0%	0%	67%	33%	0%	0%	0%	0%	100%	0%
Adv CC with carbon sequestration	0%	0%	67%	33%	0%	100%	0%	0%	100%	0%
Conv Comb Turbine	0%	100%	0%	0%	0%	0%	0%	100%	0%	0%
Adv Comb Turbine	0%	0%	100%	0%	0%	0%	0%	100%	0%	0%
Biomass	50%	0%	0%	0%	0%	0%	0%	0%	0%	100%

HRSG = Heat Recovery Steam Generator.
Source: U.S. Energy Information Administration, Office of Electricity, coal, Nuclear and Renewables Analysis.

Distributed generation

Distributed generation is modeled in the end-use sectors (as described in the appropriate chapters) as well as in the EMM. This section describes the representation of distributed generation in the EMM only. Two generic distributed technologies are modeled. The first technology represents peaking capacity (capacity that has relatively high operating costs and is operated when demand levels are at their highest). The second generic technology for distributed generation represents base load capacity (capacity that is operated on a continuous basis under a variety of demand levels). See Table 8.2 for costs and performance assumptions. It is assumed that these plants reduce the costs of transmission upgrades that would otherwise be needed.

Demand storage

The electricity model includes the option to build a new demand storage technology to simulate load shifting, through programs such as smart meters. This is modeled as a new technology build, but with operating characteristics similar to pumped storage. The technology is able to decrease the load in peak slices, but must generate to replace that demand in other time slices. There is an input factor that identifies the amount of replacement generation needed, where a factor of less than 1.0 can be used to represent peak shaving rather than purely shifting the load to other time periods. This plant type is limited to operating only in the peak load slices, and for *AEO2012*, it is assumed that this capacity is limited to 3 percent of peak demand on average, with limits varying from 2 percent to 6 percent of peak across the regions.

Representation of electricity demand

The annual electricity demand projections from the NEMS demand modules are converted into load duration curves for each of the EMM regions (based on North American Electric Reliability Corporation regions and subregions) using historical hourly load data. The load duration curve in the EMM is made up of 9 time slices. First, the load data is split into three seasons (winter - December through March, summer - June through September, and fall/spring). Within each season the load data is sorted from high to low, and three load segments are created - a peak segment representing the top 1 percent of the load, and then two off-peak segments representing the next 49 percent and 50 percent, respectively. The seasons were defined to account for seasonal variation in supply availability.

Reserve margins—the percentage of capacity required in excess of peak demand needed for unforeseeable outages—are determined within the model through an iterative approach comparing the marginal cost of capacity and the cost of unserved energy. The target reserve margin is adjusted each model cycle until the two costs converge. The resulting reserve margins from the *AEO2012* Reference case range from 8 to 21 percent.

Fossil fuel-fired and nuclear steam plant retirement

Fossil-fired steam plant retirements and nuclear retirements are calculated endogenously within the model. Plants are assumed to retire when it is no longer economical to continue running them. Each year, the model determines whether the market price of electricity is sufficient to support the continued operation of existing plants. A plant is assumed to retire if the expected revenues from it are not sufficient to cover the annual going-forward costs and if the overall cost of producing electricity can be lowered by building new replacement capacity. The going-forward costs include fuel, operations and maintenance costs and annual capital additions, which are plant-specific and based on historical data. The average capital additions for existing plants are $8 per kilowatt (kW) for oil and gas steam plants, $16 per kW for coal plants and $22 per kW for nuclear plants (in 2010 dollars). These costs are added to the estimated costs at existing plants regardless of their age. Beyond 30 years of age an additional $6 per kW capital charge for fossil plants, and $32 per kW charge for nuclear plants is included in the retirement decision to reflect further investment to address impacts of aging. Age-related cost increases are due to capital expenditures for major repairs or retrofits, decreases in plant performance, and/or increased maintenance costs to mitigate the effects of aging.

EIA assumes all retirements reported as planned during the next ten years on the Form EIA-860 will occur. Additionally, the *AEO2012* nuclear projection assumes an additional 5.5 gigawatts of nuclear plant retirements by 2035 based on the uncertainty related to resolving issues associated with long-term operations and aging management.

Biomass co-firing

Coal-fired power plants are assumed to co-fire with biomass fuel if it is economical. Co-firing requires a capital investment for boiler modifications and fuel handling. This expenditure is assumed to be $274 per kW of biomass capacity. A coal-fired unit modified to allow co-firing can generate up to 15 percent of the total output using biomass fuel, assuming sufficient residue supplies are available.

Nuclear uprates

The *AEO2012* nuclear power projection assumes capacity increases at existing units. Nuclear plant operators can increase the rated capacity at plants through power uprates, which are license amendments that must be approved by the U.S. Nuclear Regulatory Commission (NRC). Uprates can vary from small (less than 2 percent) increases in capacity, which require very little capital investment or plant modification, to extended uprates of 15-20 percent, requiring significant modifications. Historically, most uprates were small, and the *AEO* projections accounted for them only after they were implemented and reported, but recent surveys by the NRC and EIA have indicated that more extended power uprates are expected in the near future. *AEO2012* assumes that all of those uprates reported to EIA as planned modifications on the Form EIA-860 will take place, representing 0.8 gigawatts of additional capacity. EIA also assumes an additional 6.5 gigawatts of nuclear power uprates will be completed over the projection period, based on interactions with industry stakeholders and the NRC. Table 8.6 provides a summary of projected uprate capacity additions by region.

Table 8.6. Nuclear uprates by EMM region
gigawatts

Texas Reliability Entity	0.25
Florida Reliability Coordinating Council	0.67
Midwest Reliability Council - East	0.00
Midwest Reliability Council - West	0.49
Northeast Power Coordinating Council/New England	0.25
Northeast Power Coordinating Council/NYC-Westchester	0.00
Northeast Power Coordinating Council/Long Island	0.00
Northeast Power Coordinating Council/Upstate	0.50
ReliabilityFirst Corporation/East	0.82
ReliabilityFirst Corporation/Michigan	0.25
ReliabilityFirst Corporation/West	0.97
SERC Reliability Corporation/Delta	0.25
SERC Reliability Corporation/Gateway	0.00
SERC Reliability Corporation/Southeastern	0.25
SERC Reliability Corporation/Central	0.75
SERC Reliability Corporation/Virginia-Carolina	1.10
Southwest Power Pool/North	0.00
Southwest Power Pool/South	0.00
Western Electricity Coordinating Council/Southwest	0.25
Western Electricity Coordinating Council/California	0.50
Western Electricity Coordinating Council/Northwest Power Pool Area	0.00
Western Electricity Coordinating Council/Rockies	0.00
Total	7.31

Source: U.S. Energy Information Administration, Office of Electricity, Coal, Nuclear and Renewables Analysis, based on Nuclear Regulatory Commission survey www.nrc.gov/reactors/operating/licensing/power-updates.html.

Interregional electricity trade

Both firm and economy electricity transactions among utilities in different regions are represented within the EMM. In general, firm power transactions involve the trading of capacity and energy to help another region satisfy its reserve margin requirement, while economy transactions involve energy transactions motivated by the marginal generation costs of different regions. The flow of power from region to region is constrained by the existing and planned capacity limits as reported in the North American Electric Reliability Corporation and Western Electricity Coordinating Council Summer and Winter Assessment of Reliability of Bulk Electricity Supply in North America. Known firm power contracts are obtained from NERC's Electricity Supply and Demand Database 2007 and information provided in the 2011 Summer and Winter Assessments. They are locked in for the term of the contract. Contracts that are scheduled to expire by 2016 are assumed not to be renewed. Because there is no information available about expiration dates for contracts that go beyond 2016, they are assumed to be phased out by 2025. The EMM includes an option to add interregional transmission capacity. In some cases it may be more economic to build generating capacity in a neighboring region, but additional costs to expand the transmission grid will be incurred as well. Explicitly expanding the interregional transmission capacity may also make the line available for additional economy trade.

Economy transactions are determined in the dispatching submodule by comparing the marginal generating costs of adjacent regions in each time slice. If one region has less expensive generating resources available in a given time period (adjusting for transmission losses and transmission capacity limits) than another region, the regions are assumed to exchange power.

International electricity trade

Two components of international firm power trade are represented in the EMM—existing and planned transactions, and unplanned transactions. Data on existing and planned transactions are obtained from the North American Electric Reliability Corporation's Electricity Supply and Demand Database 2007. Unplanned firm power trade is represented by competing Canadian supply with U.S. domestic supply options. Canadian supply is represented via supply curves using cost data from the Department of Energy report, "Northern Lights: The Economic and Practical Potential of Imported Power from Canada," (DOE/PE-0079). International economy trade is determined endogenously based on surplus energy expected to be available from Canada by region in each time slice. Canadian surplus energy is determined using Canadian electricity supply and demand projections from the MAPLE-C model developed for Natural Resources Canada.

Electricity pricing

Electricity pricing is forecast for 22 electricity market regions in *AEO2012* for fully competitive, partially competitive and fully regulated supply regions. The price of electricity to the consumer comprises the price of generation, transmission, and distribution including applicable taxes. Transmission and distribution are considered to remain regulated in the AEO; that is, the price of transmission and distribution is based on the average cost to build, operate and maintain these systems. In competitive regions, an algorithm in place allows customers to compete for better rates among rate classes as long as the overall average cost is met. The price of electricity in the regulated regions consists of the average cost of generation, transmission, and distribution for each customer class. In the competitive regions, the generation component of price is based on marginal cost, which is defined as the cost of the last (or most expensive) unit dispatched. The competitive generation price includes the marginal cost (fuel and variable operations and maintenance), taxes, and a reliability price adjustment, which represents what customers are willing to pay for added capacity to avoid outages in periods of high demand. The price of electricity in the regions with a competitive generation market consists of the competitive cost of generation summed with the average costs of transmission and distribution. The price for mixed regions is a load-weighted average of the competitive price and the regulated price, based on the percent of electricity load in the region that has taken action to deregulate. In competitively supplied regions, a transition period is assumed to occur (usually over a ten-year period) from the effective date of restructuring, with a gradual shift to marginal cost pricing.

The Reference case assumes a transition to full competitive pricing in the three New York regions and in the ReliabilityFirst Corporation/ East region, and a 97-percent transition to competitive pricing in New England (Vermont being the only fully-regulated State in that region). Six regions fully regulate their electricity supply, including the Florida Reliability Coordinating Council, three of the SERC Reliability Corporation subregions - Southeastern (SRSE), Central (SRCE) and Virginia-Carolina (SRVC) - Southwest Power Pool Regional Entity/North (SPNO), and the Western Electricity Coordinating Council / Rockies (RMPA). The Texas Reliability Entity, which in the past was considered fully competitive by 2010, now reaches only 88-percent competitive, since many cooperatives have declined to become competitive or allow competitive energy to be sold to their customers. California returned to almost fully regulated pricing in 2002, after beginning a transition to competition in 1998, with only 7 percent competitive supply sold currently in the Western Electricity Coordinating Council (WECC)/ California region. All other regions are a mix of both competitive and regulated prices.

There have been ongoing changes to pricing structures for ratepayers in competitive States since the inception of retail competition. The AEO has incorporated these changes as they have been incorporated into utility tariffs. These have included transition period rate reductions and freezes instituted by various States, and surcharges in California relating to the 2000-2001 energy crisis there. Since price freezes for most customers have ended or will end in the next year or two, a large survey of utility tariffs found that many costs related to the transition to competition were now explicitly added to the distribution portion, and sometimes the transmission portion of the customer bill regardless of whether or not the customer bought generation service from a competitive or regulated supplier. There are some unexpected costs relating to unforeseen events. For instance, as a result of volatile fuel markets, State regulators have had a hard time enticing retail suppliers to offer competitive supply to residential and smaller commercial and industrial customers. They have often resorted to procuring the energy themselves through auction or competitive bids or have allowed distribution utilities to procure the energy on the open market for their customers for a fee. For *AEO2012*, typical charges that all customers must pay on the distribution portion of their bill (depending on where they reside) include: transition charges (including persistent stranded costs), public benefits charges (usually for efficiency and renewable energy programs), administrative costs of energy procurement, and nuclear decommissioning costs. Costs added to the transmission portion of the bill include the Federally Mandated Congestion Charges (FMCC), a bill pass-through associated with the Federal Energy Regulatory Commission passage of Standard Market Design (SMD) to enhance reliability of the transmission grid and control congestion. Additional costs not included in historical data sets have been added in adjustment factors to the transmission and distribution operations and maintenance costs, which impact the cost of both competitive and regulated electricity supply. Since most of these costs, such as transition costs, are temporary in nature, they are gradually phased out throughout the forecast. Regions found to have these added costs include the Northeast Power Coordinating Council/ New England and New York regions, the ReliabilityFirst Corporation/ East and West regions, and the WECC/ California region.

Fuel price expectations

Capacity planning decisions in the EMM are based on a life cycle cost analysis over a 30-year period. This requires foresight assumptions for fuel prices. Expected prices for coal, natural gas and oil are derived using rational expectations, or 'perfect foresight.' In this approach, expectations for future years are defined by the realized solution values for these years in a prior run. The expectations for the world oil price and natural gas wellhead price are set using the resulting prices from a prior run. The markups to the delivered fuel prices are calculated based on the markups from the previous year within a NEMS run. Coal prices are determined using the same coal supply curves developed in the Coal Market Module. The supply curves produce prices at different levels of coal production, as a function of labor productivity, and costs and utilization of mines. Expectations for each supply curve are developed in the EMM based on the actual demand changes from the prior run throughout the projection horizon, resulting in updated mining utilization and different supply curves.

The perfect foresight approach generates an internally consistent scenario for which the formation of expectations is consistent with the projections realized in the model. The NEMS model involves iterative cycling of runs until the expected values and realized values for variables converge between cycles.

Nuclear fuel prices

Nuclear fuel prices are calculated through an offline analysis which determines the delivered price to generators in mills per kilowatthour. To produce reactor grade uranium, the uranium (U_3O_8) must first be mined, and then sent through a conversion process to prepare for enrichment. The enrichment process takes the fuel to a given purity of U-235, typically 3-5 percent for commercial reactors in the United States. Finally, the fabrication process prepares the enriched uranium for use in a specific type of reactor core. The price of each of the processes is determined, and the prices are summed to get the final price of the delivered fuel. The one mill per kilowatthour charge that is assessed on nuclear generation to go to the DOE's Nuclear Waste Fund is also included in the final nuclear price. The analysis uses forecasts from Energy Resources International for the underlying uranium prices.

Legislation and regulations

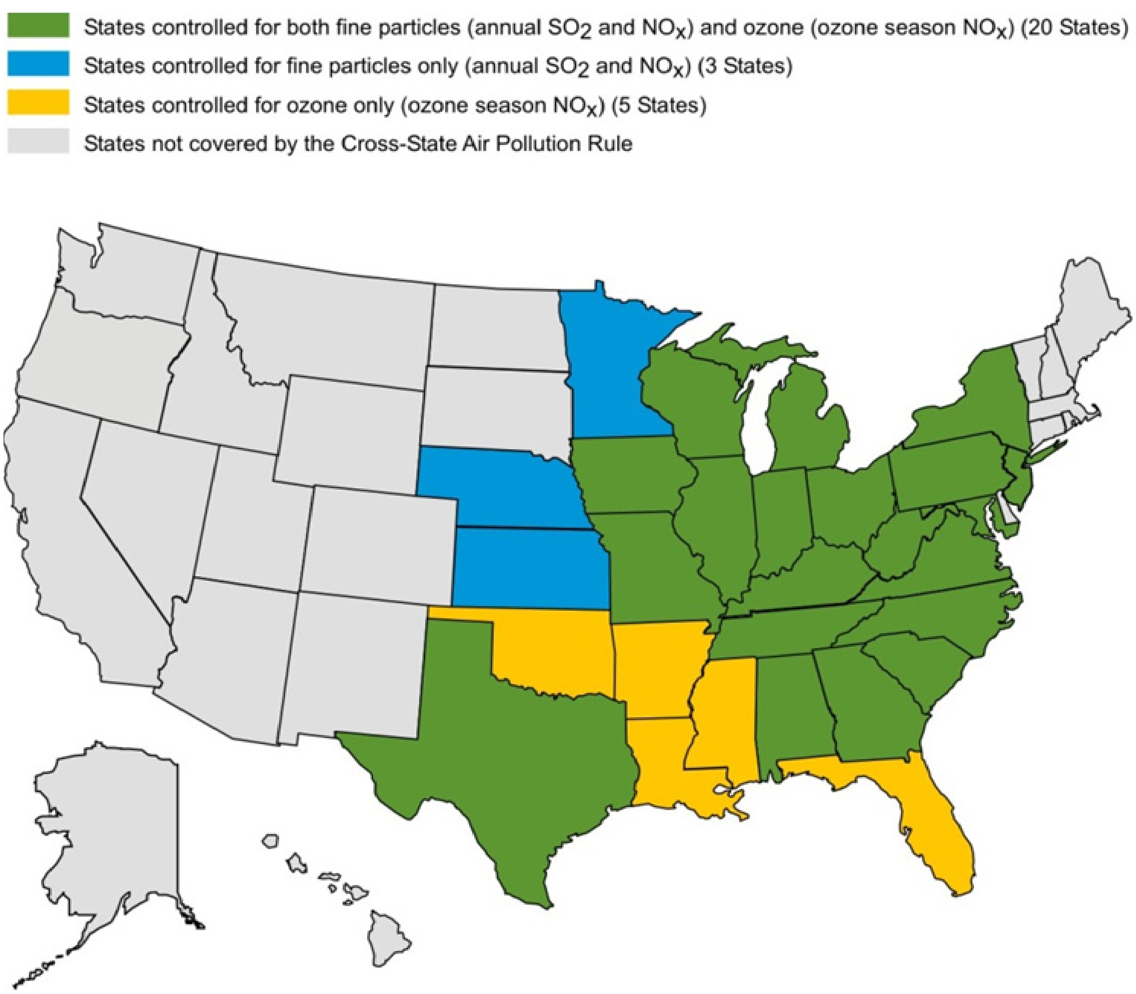
Clean Air Act Amendments of 1990 (CAAA90) and Cross-State Air Pollution Rule (CSAPR)

The Cross-State Air Pollution Rule (CSAPR) was released by EPA in July 2011 and was created to regulate SO_2 and NO_x emissions from coal, oil, and natural gas steam power plants. CSAPR is intended to help States meet their National Ambient Air Quality Standards (NAAQS) for ozone and particulate matter. CSAPR implementation has been delayed because of a stay issued by the U.S. Court of Appeals for the D.C. Circuit. However, it is included in *AEO2012* despite the stay, because the Court of Appeals had not made a final ruling at the time *AEO2012* was completed.

CSAPR puts limits on annual emissions of SO2 and NOx, as well as seasonal NOx limits to address ground-level ozone. Twenty-three States are subject to the annual limits, and 25 States are subject to the seasonal limits. CSAPR consists of four individual cap and trade programs, covering two different SO2 groups, the Annual NOx group and the Seasonal NOx group (Figure 7). Each program was scheduled to begin in January 2012 with an initial annual cap, and for the Group 1 SO2 program, the cap is reduced further in 2014.

As specified in the CAAA90, EPA has developed a two-phase nitrogen oxide (NO_x) program, with the first set of standards for existing coal plants applied in 1996 while the second set was implemented in 2000. Dry bottom wall-fired, and tangential-fired boilers, the most common boiler types, referred to as Group 1 Boilers, were required to make significant reductions beginning in 1996 and further reductions in 2000. Relative to their uncontrolled emission rates, which range roughly between 0.6 and 1.0 pounds per million Btu, they are required to make reductions between 25 and 50 percent to meet the Phase I limits and further reductions to meet the Phase II limits. The EPA did not impose limits on existing oil and gas plants, but some states have additional NO_x regulations. All new fossil units are required to meet standards. In pounds per million Btu, these limits are 0.11 for conventional coal, 0.02 for advanced coal, 0.02 for combined cycle, and 0.08 for combustion turbines. These NO_x limits are incorporated in EMM.

Figure 7. States covered by CSAPR limits on sulfur dioxide and nitrogen oxide emissions



Source: U.S. Energy Information Administration.

Sample costs of adding flue gas desulfurization equipment (FGD) to remove sulfur dioxide (SO_2) and selective catalytic reduction (SCR) equipment to remove nitrogen oxides (NOx) are given below for 100, 300, 500, and 700-megawatt coal plants. In the EMM, plant-specific costs are calculated based on the size of the unit and other operating characteristics. FGD units are assumed to remove 95 percent of the SO_2, while SCR units are assumed to remove 90 percent of the NOx. For *AEO2012*, the EMM also includes an option to install a dry sorbent injection (DSI) system, which is assumed to remove 70 percent of the SO_2. However, the DSI option is only available under the mercury and air toxics rule discussed in the next section, as its primary benefit is for reducing hydrogen chloride (HCl). The costs per megawatt of capacity decline with plant size and are shown in Table 8.7.

Table 8.7. Coal plant retrofit costs
2010 dollars

Coal Plant Size (MW)	FGD Capital Costs ($/kw)	SCR Capital Costs ($/kw)	DSI Capital Costs ($/kw)
100	642	222	125
300	497	187	57
500	432	174	40
700	360	155	31

Documentation for EPA Base Case v4.10 using the Integrated Planning Model, August 2010, EPA Contract EP-W-08-018.

Mercury regulation

The Mercury and Air Toxics Standards (MATS) rule was finalized in December 2011 to fulfill EPA's requirement to regulate mercury emissions from power plants. MATS also regulates other hazardous air pollutants (HAPS) such as hydrogen chloride (HCl) and fine particulate matter (PM2.5). The rule applies to coal- and oil-fired power plants with a nameplate capacity greater than 25 megawatts. The standards are scheduled to take effect in 2015 and require that all qualifying units achieve the maximum achievable control technology (MACT) for each of the three covered pollutants. For *AEO2012*, EIA assumes that all coal-fired generating units with a capacity greater than 25 megawatts will comply with the rule beginning in 2015. All power plants are required to reduce their mercury emissions to 90 percent below their uncontrolled emissions levels.

Because the EMM does not explicitly model HCl or PM2.5, specific control technologies are assumed to be used to achieve compliance. In order to meet the HCl requirement, units must have either flue gas desulfurization (FGD) scrubbers or dry sorbent injection (DSI) systems in order to continue operating. A full fabric filter is also required to meet the PM2.5 limits and to improve the effectiveness of the DSI technology. For mercury reductions, the EMM allows plants to alter their configuration by adding equipment, such as an SCR to remove NO_x or an SO_2 scrubber. They can also add activated carbon injection systems specifically designed to remove mercury. Activated carbon can be injected in front of existing particulate control devices or a supplemental fabric filter can be added with activated carbon injection capability.

The equipment to inject activated carbon in front of an existing particulate control device is assumed to cost approximately $6 (2010 dollars) per kilowatt of capacity, while the cost of a supplemental fabric filter with activated carbon injection (often referred as a COPAC unit) is approximately $150 (2010 dollars) per kilowatt of capacity [2]. The amount of activated carbon required to meet a given percentage removal target is given by the following equations [3].

For a unit with a CSE, using subbituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 65 - (65.286 / (ACI + 1.026))

For a unit with a CSE, using bituminous coal, and simple activated carbon injection:

- Hg Removal (%) = 100 - (469.379 / (ACI + 7.169))

For a unit with a CSE, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (28.049 / (ACI + 0.428))

For a unit with a HSE/Other, and a supplemental fabric filter with activated carbon injection:

- Hg Removal (%) = 100 - (43.068 / (ACI + 0.421))

ACI = activated carbon injected in pounds per million actual cubic feet.

Power plant mercury emissions assumptions

The EMM represents 35 coal plant configurations and assigns a mercury emissions modification factor (EMF) to each configuration. Each configuration represents different combinations of boiler types, particulate control devices, sulfur dioxide (SO_2) control devices, nitrogen oxide (NO_x) control devices, and mercury control devices. An EMF represents the amount of mercury that was in the fuel that remains after passing through all the plant's systems. For example, an EMF of 0.60 means that 40 percent of the mercury that was in the fuel is removed by various parts of the plant. Table 8.8 provides the assumed EMFs for existing coal plant configurations without mercury-specific controls.

Table 8.8. Mercury emission modification factors

Configuration			EIA EMFs			EPA EMFs		
SO_2 Control	Particulate Control	NOx Control	Bit Coal	Sub Coal	Lignite Coal	Bit Coal	Sub Coal	Lignite Coal
None	BH	--	0.11	0.27	0.27	0.11	0.26	1.00
Wet	BH	None	0.05	0.27	0.27	0.03	0.27	1.00
Wet	BH	SCR	0.10	0.27	0.27	0.10	0.15	0.56
Dry	BH	--	0.05	0.75	0.75	0.50	0.75	1.00
None	CSE	--	0.64	0.97	0.97	0.64	0.97	1.00
Wet	CSE	None	0.34	0.73	0.73	0.34	0.84	0.56
Wet	CSE	SCR	0.10	0.73	0.73	0.10	0.34	0.56
Dry	CSE	--	0.64	0.65	0.65	0.64	0.65	1.00
None	HSE/Oth	--	0.90	0.94	0.94	0.90	0.94	1.00
Wet	HSE/Oth	None	0.58	0.80	0.80	0.58	0.80	1.00
Wet	HSE/Oth	SCR	0.42	0.76	0.76	0.10	0.75	1.00
Dry	HSE/Oth	--	0.60	0.85	0.85	0.60	0.85	1.00

Notes: SO_2 Controls - Wet = Wet Scrubber and Dry = Dry Scrubber, Particulate Controls, BH - fabric filter/baghouse. CSE = cold side electrostatic precipitator, HSE = hot side electrostatic precipitator, NO_x Controls, SCR = selective catalytic reduction,
— = not applicable, Bit = bituminous coal, Sub = subbituminous coal. The NO_x control system is not assumed to enhance mercury removal unless a wet scrubber is present, so it is left blank in such configurations. Sources: EPA, EMFs. www.epa.gov/clearskies/technical.html. EIA EMFs not from EPA: Lignite EMFs, Mercury Control Technologies for Coal-Fired Power Plants, presented by the Office of Fossil Energy on July 8, 2003. Bituminous coal mercury removal for a Wet/HSE/Oth/SCR configured plant, Table EMF1, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, U.S. Department of Energy, January 2003, Washington, DC.

Planned SO_2 Scrubber and NO_x control equipment additions

EIA assumes that all planned retrofits, as reported on the Form EIA-860, will occur as currently scheduled. For *AEO2012*, this includes 10.8 gigawatts of planned SO_2 scrubbers (Table 8.9) and 4.5 gigawatts of planned selective catalytic reduction (SCR).

Carbon capture and sequestration retrofits

Although a Federal greenhouse gas program is not assumed in the *AEO2012* Reference case, the EMM includes the option of retrofitting existing coal plants for carbon capture and sequestration (CCS). This option is important when considering alternate scenarios that do constrain carbon emissions. The modeling structure for CCS retrofits within the EMM was developed by the National Energy Technology Laboratory[4] and uses a generic model of retrofit costs as a function of basic plant characteristics (such as heatrate). The costs have been adjusted to be consistent with costs of new CCS technologies. The CCS retrofits are assumed to remove 90 percent of the carbon input. The addition of the CCS equipment results in a capacity derate of around 30 percent and reduced efficiency of 43 percent at the existing coal plant. The costs depend on the size and efficiency of the plant, with the capital costs ranging from $1,110 to $1,620 per kilowatt. It was assumed that only plants greater than 500 megawatts and with heat rates below 12,000 BTU per kilowatthour would be considered for CCS retrofits.

State Air Emissions Regulation

AEO2012 continues to model the Northeast Regional Greenhouse Gas Initiative (RGGI), which applies to fossil-fuel powered plants over 25 megawatts in the Northeastern United States. The State of New Jersey withdrew from the program at the end of 2011, leaving nine States in the accord. The rule caps CO_2 emissions from covered electricity generating facilities and requires that they account for each ton of CO_2 emitted with an allowance purchased at auction. Because the baseline and projected emissions were calculated before the economic recession that began in 2008, the actual emissions in the first years of the program have been less than the cap, leading to excess allowances and allowance prices at the floor price.

The California Assembly Bill 32 (AB 32), the Global Warming Solutions Act of 2006, authorized the California Air Resources Board (CARB) to set California's GHG reduction goals for 2020 and establish a comprehensive, multi-year program to reduce GHG emissions in California. As one of the major initiatives for AB 32, CARB designed a cap-and-trade program that started on January 1, 2012, with the enforceable compliance obligations beginning in 2013. Although the cap-and-trade program applies to multiple economic sectors, for *AEO2012* it is only assumed to be implemented in the electric power sector. The electric power sector represented 25 percent of the State's GHG emissions in 2008, and therefore the EMM modeled the power sector cap at 25 percent of the limits specified in the bill for all sectors.

Table 8.9. Planned SO_2 scrubber additions by EMM region
gigawatts

Texas Reliability Entity	0.0
Florida Reliability Coordinating Council	0.0
Midwest Reliability Council - East	0.0
Midwest Reliability Council - West	0.0
Northeast Power Coordinating Council/New England	0.0
Northeast Power Coordinating Council/NYC-Westchester	0.0
Northeast Power Coordinating Council/Long Island	0.0
Northeast Power Coordinating Council/Upstate	1.0
ReliabilityFirst Corporation/East	1.2
ReliabilityFirst Corporation/Michigan	0.0
ReliabilityFirst Corporation/West	4.4
SERC Reliability Corporation/Delta	0.0
SERC Reliability Corporation/Gateway	0.0
SERC Reliability Corporation/Southeastern	4.1
SERC Reliability Corporation/Central	0.2
SERC Reliability Corporation/Virginia-Carolina	0.0
Southwest Power Pool/North	0.0
Southwest Power Pool/South	0.0
Western Electricity Coordinating Council/Southwest	0.0
Western Electricity Coordinating Council/California	0.0
Western Electricity Coordinating Council/Northwest Power Pool Area	0.0
Western Electricity Coordinating Council/Rockies	0.0
Total	10.8

Source: U.S. Energy Information Administration, Form EIA-860, "Annual Electric Generator Report."

Energy Policy Acts of 1992 (EPACT92) and 2005 (EPACT05)

The provisions of the EPACT92 include revised licensing procedures for nuclear plants and the creation of exempt wholesale generators (EWGs). The EPACT05 provides a 20-percent investment tax credit for Integrated Coal-Gasification Combined Cycle capacity and a 15-percent investment tax credit for other advanced coal technologies. These credits are limited to 3 gigawatts in both cases. It also contains a production tax credit (PTC) of 1.8 cents (nominal) per kilowatthour for new nuclear capacity beginning operation by 2020. This PTC is specified for the first 8 years of operation, is limited to $125 million (per gigawatt) annually, and is limited to 6 gigawatts of new capacity. However, this credit may be shared to additional units if more than 6 gigawatts are under construction by January 1, 2014. EPACT05 extended the PTC for qualifying renewable facilities by 2 years, or December 31, 2007. It also repealed the Public Utility Holding Company Act (PUHCA).

Energy Improvement and Extension Act 2008 (EIEA2008)

EIEA2008 extended the investment tax credit of 30 percent through 2016 for solar and fuel cell facilities.

American Recovery and Reinvestment Act (ARRA)

Updated tax credits for Renewables

ARRA extended the expiration date for the PTC to January 1, 2013, for wind and January 1, 2014, for all other eligible renewable resources. In addition, ARRA allows companies to choose an investment tax credit (ITC) of 30 percent in lieu of the PTC and allows for a grant in lieu of this credit to be funded by the U.S. Treasury. For some technologies, such as wind, the full PTC would appear to be more valuable than the 30 percent ITC; however, the difference can be small. Qualitative factors, such as the lack of partners with sufficient tax liability, may cause companies to favor the ITC grant option. *AEO2012* generally assumes that renewable electricity projects will claim the more favorable tax credit or grant option available to them.

Loan guarantees for renewables

ARRA provided $6 billion to pay the cost of guarantees for loans authorized by the Energy Policy Act of 2005. While most renewable projects which start construction prior to September 30, 2011 are potentially eligible for these loan guarantees, the application and approval of guarantees for specific projects is a highly discretionary process, and has thus far been limited. While *AEO2012* includes projects that have received loan guarantees under this authority, it does not assume automatic award of the loans to potentially eligible technologies.

Support for CCS

ARRA provided $3.4 billion for additional research and development on fossil energy technologies. A portion of this funding is expected to be used to fund projects under the Clean Coal Power Initiative program, focusing on projects that capture and sequester greenhouse gases. To reflect the impact of this provision, *AEO2012* Reference case assumes that an additional 1 gigawatt of coal capacity with CCS will be stimulated by 2017.

Smart grid expenditures

ARRA provides $4.5 billion for smart grid demonstration projects. While somewhat difficult to define, smart grid technologies generally include a wide array of measurement, communications, and control equipment employed throughout the transmission and distribution system that will enable real-time monitoring of the production, flow, and use of power from generator to consumer. Among other things, these smart grid technologies are expected to enable more efficient use of the transmission and distribution grid, lower line losses, facilitate greater use of renewables, and provide information to utilities and their customers that will lead to greater investment in energy efficiency and reduced peak load demands. The funds provided will not fund a widespread implementation of smart grid technologies, but could stimulate more rapid investment than would otherwise occur.

Several changes were made throughout the NEMS to represent the impacts of the smart grid funding provided in ARRA. In the electricity module, it was assumed that line losses would fall slightly, peak loads would fall as customers shifted their usage patterns, and customers would be more responsive to pricing signals. Historically, line losses, expressed as the percentage of electricity lost, have been falling for many years as utilities make investments to replace aging or failing equipment.

Smart grid technologies also have the potential to reduce peak demand through the increased deployment of demand response programs. In *AEO2012*, it is assumed that the Federal expenditures on smart grid technologies will stimulate efforts that reduce peak demand in 2035 by 3 percent from what they otherwise would be. Load is shifted to offpeak hours, so net energy consumed remains largely constant.

FERC Orders 888 and 889

FERC has issued two related rules (Orders 888 and 889) designed to bring low-cost power to consumers through competition, ensure continued reliability in the industry, and provide for open and equitable transmission services by owners of these facilities. Specifically, Order 888 requires open access to the transmission grid currently owned and operated by utilities. The transmission owners must file nondiscriminatory tariffs that offer other suppliers the same services that the owners provide for themselves. Order 888 also allows these utilities to recover stranded costs (investments in generating assets that are unrecoverable due to consumers selecting another supplier). Order 889 requires utilities to implement standards of conduct and an Open Access Same-Time Information System (OASIS) through which utilities and non-utilities can receive information regarding the transmission system. Consequently, utilities are expected to functionally or physically unbundle their marketing functions from their transmission functions.

These orders are represented in EMM by assuming that all generators in a given region are able to satisfy load requirements anywhere within the region. Similarly, it is assumed that transactions between regions will occur if the cost differentials between them make such transactions economical.

Electricity alternative cases

Integrated Technology cases

The Integrated High Technology Cost case combines assumptions from the end-use High Technology cases with assumptions on lower costs of new power plants, including renewables, nuclear and fossil. Assumptions for the other sectors appear in the respective chapters. This case assumes that the capital and operating costs for new fossil and nuclear plants will start 20 percent lower than in the Reference case, and will be 40 percent lower than Reference case levels in 2035.

The Integrated 2011 technology case combines assumptions from the end-use 2011 Technology cases and higher costs for new power plants. In the EMM it is assumed that the base costs of all nuclear and fossil generating technologies will remain at current costs during the projection period, with no reductions due to learning. The annual commodity cost adjustment factor is still applied as in the Reference case.

Table 8.10 shows the costs assumed for new fossil technologies across the Integrated Technology cases, while Table 8.11 shows the costs for new nuclear plants in the same cases.

Table 8.10. Cost and performance characteristics for fossil-fueled generating technologies: three cases

		Total Overnight Cost[1]		
	Total Overnight Cost in 2012 (Reference) (2010$/kW)	Reference (2010$/kW)	Low Integrated Technology (2010$/kW)	High Integrated Technology (2010$/kW)
Pulverized Coal	2844			
2015		2985	3005	2311
2020		2784	2830	2034
2025		2597	2666	1784
2030		2354	2449	1515
2035		2115	2229	1269
Advanced Coal	3220			
2015		3366	3403	2604
2020		3100	3204	2265
2025		2865	3019	1968
2030		2565	2773	1651
2035		2281	2524	1368
Advanced Coal with Sequestration	5348			
2015		5564	5650	4306
2020		5094	5321	3721
2025		4673	5013	3209
2030		4155	4605	2674
2035		3662	4191	2197
Conventional Combined Cycle	977			
2015		1026	1033	794
2020		956	972	698
2025		892	916	614
2030		809	841	520
2035		727	766	436
Advanced Gas	1003			
2015		1050	1060	813
2020		963	998	703
2025		890	940	611
2030		795	864	511
2035		706	786	424
Advanced Gas with Sequestration	2060			
2015		2141	2177	1657
2020		1949	2050	1423
2025		1782	1931	1224
2030		1576	1774	1014
2035		1383	1614	829
Conventional Combustion Turbine	974			
2015		1022	1029	790
2020		953	969	696
2025		889	913	610
2030		806	838	518
2035		724	763	434
Advanced Combustion Turbine	666			
2015		695	704	538
2020		631	663	461
2025		579	624	398
2030		512	573	329
2035		451	522	270

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.

Source: U.S. Energy Information Administration. *AEO2012* National Energy Modeling System runs: REF2012.D020112C, LTRKITEN.D031312A, HTRKITEN.D032812A

Table 8.11. Cost characteristics for advanced nuclear technology: three cases

	Overnight Cost in 2012 (Reference) (2010$/kW)	Total Overnight Cost[1] Reference (2010$/kW)	Low Integrated Technology (2010$/kW)	High Integrated Technology (2010$/kW)
Advanced Nuclear	5335			
2015		5466	5638	4231
2020		4733	5309	3456
2025		4302	5002	2954
2030		3850	4594	2477
2035		3414	4181	2049

[1]Total overnight cost (including project contingency, technological optimism and learning factors, but excluding regional multipliers), for projects online in the given year.
Source: U.S. Energy Information Administration. *AEO2012* National Energy Modeling System runs: REF2012.D020112C, LTRKITEN.D031312A, HTRKITEN.D032812A.

Electricity Environmental Regulation cases

Over the next few years electricity generators will have to begin steps to comply with a number of new environmental-Regulations, primarily through adding environmental controls at existing coal power plants. The additional cases examine the impacts of shorter economic recovery periods for the environmental controls, both with natural gas prices similar to the *AEO2012* reference case and with lower natural gas prices.

- The Reference 5 case assumes that the economic recovery period for investments in new environmental controls is reduced from 20 years to 5 years.
- The Low Gas Price 5 case uses more optimistic assumptions about future volumes of shale gas production, leading to lower natural gas prices, combined with the five-year recovery period for new environmental controls. The domestic shale gas resource assumption comes from the Low Tight Oil and Shale Gas Resource case.

Nuclear Alternative cases

For *AEO2012*, two alternate cases were run for nuclear power plants to address uncertainties about the operating lives of existing reactors, the potential for new nuclear capacity, and capacity uprates at existing plants. These scenarios are discussed in the Issues in Focus article, "Nuclear Power in *AEO2012*" in the full *AEO2012* report.

- The Low Nuclear case assumes that all existing nuclear plants are retired after 60 years of operation. In the Reference case, existing plants are assumed to run as long as they continue to be economic, implicitly assuming that a second 20-year license renewal will be obtained for most plants reaching 60 years before 2035. This case was run to analyze the impact of additional nuclear retirements, which could occur if the oldest plants do not receive a second license extension. In this case, 31 gigawatts of nuclear capacity are assumed to be retired by 2035. his case assumes that no new nuclear capacity will be added throughout the projection, excluding the capacity already planned and under construction. The case also assumes that only those capacity uprates reported to EIA will be completed. The Reference case assumes additional uprates based on Nuclear Regulatory Commission (NRC) surveys and industry reports.
- The High Nuclear case assumes that all existing nuclear units will receive a second license renewal and operate beyond 60 years (excluding one announced retirement). In the Reference case, beyond the announced retirement of Oyster Creek, an additional 5.5 gigawatts of nuclear capacity is assumed to be retired through 2035, reflecting uncertainty surrounding future aging impacts and/or costs. This case was run to provide a more optimistic outlook where all licenses are renewed and all plants are assumed to find it economic to continue operating beyond 60 years. The High Nuclear case also assumes additional planned nuclear capacity is completed based on combined license (COL) applications with the NRC. The Reference case assumes 6.8 gigawatts of planned capacity are added, while the High Nuclear case includes 13.5 gigawatts of planned capacity additions.

Notes and sources

[1] Updated Capital Cost Estimates for Electricity Generation Plants, EIA, November 2010.

[2] These costs were developed using the National Energy Technology Laboratory Mercury Control Performance and Cost Model, 1998.

[3] U.S. Department of Energy, Analysis of Mercury Control Cost and Performance, Office of Fossil Energy & National Energy Technology Laboratory, January 2003.

[4] Retrofitting Coal-Fired Power Plants for Carbon Dioxide Capture and Sequestration - Exploratory Testing of NEMS for Integrated Assessments, DOE/NETL-2008/1309, P.A. Geisbrecht, January 18, 2009.

Attachment 14

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Coming to Grips with Carbon

Hedging Carbon Risk: Protecting Customers and Shareholders from the Financial Risk Associated with Carbon Dioxide Emissions

Utilities and regulators are recognizing that it is unlikely that greenhouse gas emissions will continue to cost utilities nothing whatever over the long lifetime of new investments. Several utilities have begun to protect their customers and shareholders from this financial risk by integrating an estimated cost of carbon dioxide emissions into their evaluation of resource options, and selecting the overall least-cost portfolio of resources.

Karl Bokenkamp, Hal LaFlash, Virinder Singh and Devra Bachrach Wang

Karl Bokenkamp *is General Manager of Power Supply Planning for Idaho Power, where he is involved in integrated resource planning, fuel and water management, and risk management. He holds an M.E. in Mechanical Engineering from the University of Idaho and a B.S. in Mechanical Engineering from the University of Illinois.*

Hal LaFlash *is director of resource planning at Pacific Gas and Electric Company. He holds an M.B.A. from St. Mary's College and a B.S. in Mechanical Engineering from the University of Wisconsin.*

Virinder Singh *is a senior environmental policy analyst at PacifiCorp. He hold a Master's of International Affairs from Columbia University and a B.A. in Political Economy from the University of California at Berkeley.*

Devra Bachrach Wang *is a staff scientist with the Natural Resources Defense Council's energy program, where she works on energy policy, including energy efficiency, renewable energy, and utility regulation policy. She holds an M.A. in Energy and Resources and a B.S. in Bioengineering, both from the University of California at Berkeley.*

I. Introduction

As regulation of carbon dioxide emissions becomes increasingly likely, utilities are beginning to analyze and actively manage the financial risk associated with their portfolios' emissions. Fossil fuel-based investments made today will continue operating and emitting carbon dioxide for 30 to 40 years or more, and it is highly likely that carbon dioxide emissions will be regulated within that timeframe. As the single largest source of U.S. greenhouse gas (GHG) emissions, the electric sector is likely to figure prominently in any regulatory program to reduce emissions.

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Utilities such as PacifiCorp, Idaho Power, and Pacific Gas and Electric Company are helping to protect their customers and shareholders from the financial risk associated with future regulation by integrating an estimated future cost of emissions into their evaluation of resource options, and selecting the overall least-cost portfolio of resources. The experience gained to date provides a model for other utilities and regulators seeking to reduce exposure to the cost of future regulation of carbon dioxide emissions and to reduce customers' overall long-term cost for energy services.

II. Risk Management Is a Crucial Utility Responsibility

Integrated resource planning rose in prominence within the electric industry in the 1970s and 1980s amid market shocks associated with oil price volatility and unexpectedly high costs for nuclear power, among other factors. Such trends pushed up electricity prices and prompted regulators to require thorough planning exercises by utilities, allowing for public scrutiny of resource investment plans. With the arrival of deregulation in the mid-1990s, integrated resource plans (IRP) became a historical artifact in many states rather than a vital ongoing process.

Recent turmoil within the electric industry has focused attention once again on one of the crucial responsibilities of utilities: electric-resource portfolio management. Effective portfolio management requires a fully integrated approach to identify customer electric service needs and to select demand- and supply-side alternatives to meet those needs through a portfolio that minimizes total cost and environmental impacts, and has an acceptable level of risk.[1]

Evaluating uncertainties and demonstrating risk management is a key imperative in long-term planning.

In states such as Oregon and Idaho that did not fully restructure their electric industries, utilities never stopped working with their regulators on IRPs. Other states, such as California, that did restructure have reconsidered and are now developing new tools to enable utilities to effectively manage costs and risks through portfolio management and long-term plans. Throughout the industry, there is growing recognition that portfolio management and long-term planning processes are essential to enable utilities to provide low-cost, reliable, and environmentally sensitive energy services. IRPs and long-term plans serve as common guidebooks for both the utility and the regulator, so that subsequent resource decisions are founded upon common understandings and assumptions that utilities believe will assist them in making a strong case for cost recovery.

Evaluating uncertainties and demonstrating risk management is a key imperative in long-term planning. Recent volatility in the electric market has heightened awareness among regulators regarding the importance of utility risk management, and many regulators require risk evaluation in long-term planning. For example, the Oregon PUC issued an order that requires consideration of uncertainty in resource planning.[2] The Utah PSC also requires an evaluation of different load forecasts, the risk associated with various resource options, and consideration of how an action plan addresses such risks.[3] More generally, it requires evaluation of any significant risk associated with resource options, and a demonstration of flexibility in the resulting action plan rather than a pre-determined suite of actions that cannot adjust to changing conditions.

A. Evaluating the financial risk of global warming regulation

More and more utilities, including PacifiCorp and Idaho Power, incorporate extensive risk analysis in their IRPs, with differentiation between stochastic

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and scenario risks. Stochastic risks consist of estimated deviations from an average value, and embody factors with which utilities have substantial experience and can subject to standard statistical models. (Of course, while historical experience is extremely useful in assessing risks, this information must always be combined with informed judgment about the future risk.) Natural gas prices, electricity market prices, hydropower generation, and loads all represent stochastic risks. In contrast, scenario risks represent a significant and sustained movement away from an "average" trend; these are risks that can be quantified but which are the subject of substantial uncertainty often dependent on decision points rather than broader "market" trends. By their nature, scenario risks can be more difficult to quantify than stochastic risks, and are therefore subject to more debate, either about their importance or about their potential material value. GHG regulations represent an important scenario risk associated with political decision making that utilities need to consider in their IRPs.

The Oregon PUC was one of the first to look at the financial risk associated with carbon dioxide emissions. The OPUC issued a 1993 order requiring regulated utilities to conduct sensitivity analyses on carbon dioxide emissions. The OPUC order followed a memo from the Oregon Department of Justice, which stated that the OPUC "may require utilities to consider in their least-cost plans the likelihood that external costs may be internalized in the future." Furthermore, the Commission is authorized to allow a utility to recover the costs of a cleaner but more expensive resource.[4] The order went on to say that the OPUC "would also need to find that the resource acquisition was prudent, presumably because it mitigated the risk that external costs would be internalized" in the future due to new regulation.

The pace of policy development suggests that carbon dioxide emissions may be regulated in the relatively near future, and likely within the lifetime of new utility investments.

III. Carbon Dioxide Emissions Are Likely to Be Regulated within the Lifetime of New Investments

The pace of policy development internationally and throughout the U.S. suggests that carbon dioxide emissions may be regulated in the relatively near future, and likely within the lifetime of new utility investments. These new investments will generate electricity for the next 30 to 40 years or even longer, and investments in carbon-emitting resources therefore create a financial risk for utilities and their customers.

A. National and international actions

In February 2005, the Kyoto Protocol entered into force, binding the ratifying countries to specific targets and timetables for GHG emission reductions, with strong reliance on market-based mechanisms. Just the month before, the European Union's Emissions Trading Scheme became the world's first large-scale GHG emissions trading program. And while the United States did not ratify the international treaty, several bills that would regulate carbon dioxide emissions are pending before the U.S. Congress.[5] One of these, the Climate Stewardship Act, introduced by Sens. McCain and Lieberman, received 43 votes in the Senate in 2003. The bill is expected to be brought back for another vote in the Senate, and the House has introduced a companion bill.[6]

B. State and regional actions

More than half the states around the country have developed or are developing strategies to reduce GHG emissions.[7] For example, the Northeast and Mid-Atlantic states are engaged in a cooperative Regional Greenhouse Gas Initiative (RGGI) to develop a regional cap-and-trade program to reduce carbon dioxide emissions. The goal of RGGI is to reach agreement on the design of the cap-and-trade program this year. Similarly, the governors of California, Washington, and Oregon have joined together to call for a regional GHG reduction initiative, concluding that their states "must act individually and regionally to reduce greenhouse gas emissions."[8] And just last month, in June 2005, Governor Schwarzenegger announced aggressive new GHG emission reduction targets for California.[9]

California has adopted regulations requiring reductions of GHG emissions from vehicles.[10] Other states including New York, New Jersey, and Massachusetts, have also adopted these regulations; in total, the states adopting these regulations represent nearly one-third of the U.S. car market. The California Public Utilities Commission (CPUC) is now exploring a cap-and-trade program for carbon dioxide emissions associated with the utilities' portfolios.[11] The Montana Public Service Commission has required Northwestern Energy to account for the financial risk associated with carbon dioxide emissions in its next long-term plan.[12] In addition, Washington recently passed a law regulating carbon dioxide from new power plants, requiring that 20 percent of the carbon dioxide from new plants either be taxed or mitigated through offset projects[13]; this law is similar to the carbon dioxide emission standards for new power plants that Oregon has had since 1997.[14]

C. Businesses recognize the risk

As the momentum to regulate GHG emissions continues to grow around the country and internationally, businesses are increasingly recognizing the risk associated with carbon dioxide emissions. Organizations such as the Carbon Disclosure Project and the Investor Network on Climate Risk have substantially raised the profile of climate-related risks when analyzing the financial health of companies worldwide. Last year, 13 major public pension funds, which manage $800 billion in assets, asked the Securities and Exchange Commission to require companies to disclose the financial risks they face from climate change.[15] Meanwhile, institutional shareholder groups and public pension funds filed 31 resolutions this year asking individual companies to disclose financial risks and their plans to reduce GHG emissions.[16]

As the momentum to regulate GHG emissions grows, businesses are increasingly recognizing the risk associated with carbon dioxide emissions.

In response to this pressure, some of the nation's largest utilities, including Cinergy, American Electric Power, and TXU, have issued reports on the financial risks they face from complying with regulations to address global warming. And Cinergy, one of the largest emitters of carbon dioxide in the electric industry, made global warming the central focus of its 2004 annual report.[17]

IV. Different Resources Create Widely Varying Risk Exposures

The magnitude of the carbon dioxide regulation risk faced by utilities and their customers depends on the total carbon dioxide emissions of the utilities' portfolio. Portfolios that are more dependent on carbon-emitting resources face a greater risk of increased costs. Different electricity resources have widely varying emissions of carbon dioxide, creating varying levels of financial risk. For example, the Northwest Power and Conservation Council (the Northwest's regional planning organization, established by Congress in 1980) reports that a new conventional coal plant will emit almost 1,000 metric tons of carbon dioxide per GWh, while a new combined cycle natural gas plant will emit about 400 metric tons per GWh, or 60 percent less than the coal plant.[18] Integrated gasification combined cycle (IGCC) coal-fired power plants emit nearly 800

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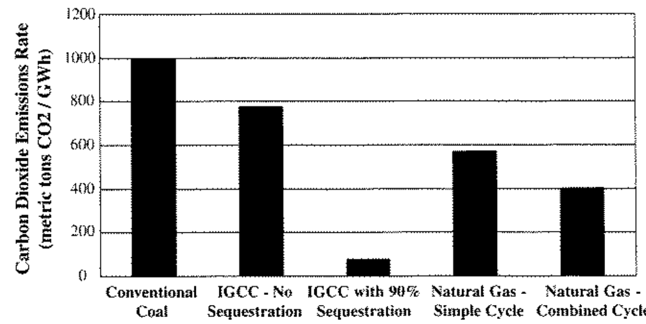
metric tons of carbon dioxide per GWh, 20 percent less than a conventional coal plant but still double a combined-cycle gas plant; with carbon capture and sequestration, these IGCC plants have the potential to decrease carbon dioxide emissions relative to standard coal plants by about 90 percent, emitting only about 80 metric tons of carbon dioxide per GWh.[19] Energy efficiency and renewable resources, such as hydro, wind, solar, geothermal, and biomass have low if any lifecycle carbon dioxide emissions. A number of these resources, particularly IGCC, solar, and many forms of biomass, are typically higher in cost than conventional generation using coal and gas. An important question is whether their lower emissions offer protection against future regulatory costs in a manner that justifies their selection by utilities seeking lowest cost and lowest risk for their customers.

Just as important as the emissions profile of the various technologies is the difficulty in reducing carbon dioxide emissions from existing thermal generation. There is no cost-effective "end-of-stack" technology option currently available to reduce carbon dioxide emissions from existing thermal plants, compared to other pollutants that are more amenable to retrofit approaches to sunk investments. This makes planning in advance of potential regulations even more crucial for carbon dioxide (**Figure 1**).



Source: Northwest Power and Conservation Council. 2005.

Figure 1: Comparison of Carbon Dioxide Emission Rates of Electricity Generation Resources

Conventional coal-fired power plants present the most serious financial risk in the face of potential carbon dioxide regulation, because of their higher GHG emissions. For example, assuming that carbon dioxide emissions will cost about $12 per ton, a 500 MW coal plant's emissions would result in approximately $50 million *per year* in cost exposure for a utility.[20] A 500 MW baseload combined cycle natural gas plant (at a 90 percent capacity factor), by contrast, would result in a cost exposure of about $20 million per year. And a less efficient 500 MW peaker gas plant with a heat rate of 9,300 Btu per kWh (and a 10 percent capacity factor) would have an exposure of about $3 million per year. A 500 MW baseload IGCC coal-fired power plant, with 90 percent carbon sequestration, would have a risk exposure of about $4 million per year. However, this is not the only fuel-related risk that utilities face. The risks associated with carbon dioxide emissions are in addition to the specific risks and costs associated with each fuel. It is the summation of these risks that utilities must consider in future resource decisions.

The magnitude of the carbon dioxide risk is large enough to merit active consideration. To protect customers and shareholders, utilities can and should factor these estimated carbon dioxide costs into their evaluation of different resource options in developing their long-term investment plans and when choosing resources in procurement.

V. A Proxy Value of the Risk Associated with Greenhouse Gas Emissions Is Useful for Planning Purposes

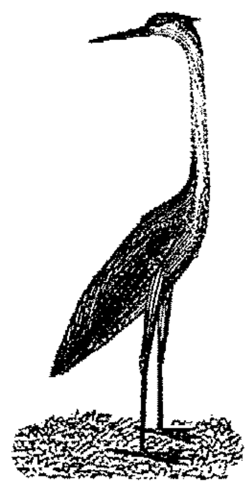
Utilities can help protect their customers and shareholders from the financial risk associated with the likely future regulation of GHG emissions by integrating an estimated cost of emissions into their evaluation of resource options, and selecting the overall least-cost portfolio. Establishing a value of the risk of GHG emission limits requires informed judgments about the likelihood of future regulation, the form such regulation might take (e.g., various options to allocate emission allowances under a cap-and-trade approach), and the likely cost under such regulation.

Utility decisions about resource investments are ideally based upon what is "known and knowable" at the time of the decision. This standard inherently includes the possibility that certain market factors can change after the time of a decision. However, utilities should make an informed judgment about the future. Since it is unlikely that GHG emissions will continue to cost utilities nothing whatever over the long lifetime of new investments, utilities should make an informed judgment about the range of reasonable policy scenarios and associated GHG costs and settle on a best estimate to use as an imputed cost in modeling resources in long-term plans and in evaluating procurement options.

There are several estimates of the potential cost of carbon dioxide emissions that utilities and regulators can look to in order to quantify the risk associated with GHG emissions. Estimates of realistic imputed costs for GHG emissions range up to about $50 per ton of carbon dioxide. These estimates are based on an analysis of current market prices and estimated costs under proposed federal policies. Utilities and regulators can also look to imputed costs now in use in other jurisdictions.

A. Current GHG market prices

The primary market in GHG emission allowances is the European Union's Emissions Trading Scheme (ETS). Since the ETS began full trading in January



2005, the price of emission allowances has ranged from a low of about $9 per ton of carbon dioxide to a high of about $22.[21] In the U.S., the Chicago Climate Exchange provides a forum for entities to voluntarily trade GHG emissions. In recent months, allowances on the Chicago Climate Exchange have been trading at prices between $1.50 and $2 per ton of carbon dioxide[22]; however, since entities participating in the Chicago Climate Exchange voluntarily entered into the exchange, the current prices are very likely lower than would be expected under a regulatory program with enforceable emission limits and comprehensive coverage. The Climate Trust, which invests in carbon dioxide offset projects to mitigate the impact of fossil fuel power plants, estimates the average cost of carbon dioxide based on their investments to range from approximately $3 up to $6 per ton.[23]

B. Estimated GHG costs under proposed federal policies

The Energy Information Administration's analysis of the McCain–Lieberman Climate Stewardship Act found carbon dioxide allowances to be in the range of $15 to $34 per metric ton, over the period 2010–2020 (in 2001 dollars).[24] The Massachusetts Institute of Technology's Joint Program on the Science and Policy of Global Change modeled an earlier and more stringent version of the Climate Stewardship Act and found that the emissions allowance price of carbon dioxide would likely range from $21 per ton in 2010 to $36 per ton in 2020 (in 2001 dollars).[25] In addition, the Energy Information Administration's analysis of another bill before Congress, the Clean Power Act, estimated that carbon dioxide allowance prices in 2010 would range from $15 to $25 per ton of carbon dioxide and in 2020 would range from $14 to $33 dollars per ton (in 1999 dollars).[26] In addition to current proposals in Congress, the National Commission on Energy Policy has proposed a national cap on carbon dioxide intensity that caps market-clearing prices at $7 per ton of carbon dioxide beginning in 2010,

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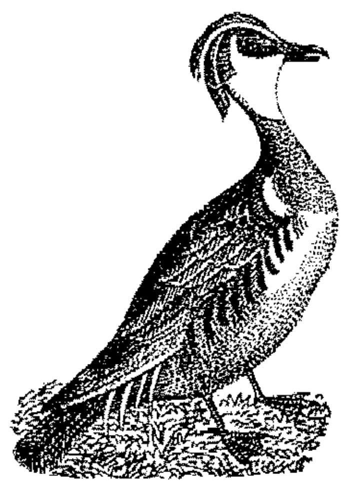
with a 5 percent increase annually thereafter.

C. Estimated carbon dioxide costs currently used by utilities and regulators

Several utilities and regulators have already established estimated costs of GHG emissions to use in planning and procurement. These values are at the conservative end of the spectrum of likely costs, largely due to the continuing uncertainty about when regulations will be enacted and what those costs will be.

The Oregon PUC has required its regulated utilities to use several sensitivities in modeling carbon dioxide costs, including $0, $10, $25, and $40 (in 1990 dollars). While the OPUC did not require utilities to incorporate a carbon dioxide value (above $0 per ton) into the *base case* of their IRP modeling efforts, PacifiCorp decided in 2002 to propose such an approach. PacifiCorp found that the risks of future carbon dioxide regulations were significant enough to warrant "prudently preparing" through appropriate planning. Rather than adopt one of the OPUC-mandated sensitivity values for its IRP base case, PacifiCorp developed its own value for carbon dioxide based upon internal review of a variety of data from domestic and international sources. PacifiCorp staff reviewed several categories of data, including the current carbon dioxide offset market in the U.S.; existing markets for GHG emissions in the United Kingdom and Denmark (which developed an emissions market before the European Union's development of implementation plans for its compliance with the Kyoto Protocol); and macroeconomic analyses of several federal proposals to cap GHG emissions, including analyses by the U.S. Department of Energy.



In its 2002 IRP, PacifiCorp assumed that carbon dioxide limits would begin in 2008. By the time it prepared its 2004 IRP, lack of regulations in the U.S. led PacifiCorp to push back the assumed initiation of limits. Instead of assuming full implementation of carbon dioxide limits in 2008, the company's base case scenario assumes a 50 percent probability of an $8 per ton carbon dioxide cost starting in 2010, increasing to 75 percent in 2011 and a 100 percent probability of occurrence by 2012.[27] The introduction of such probabilities was intended to capture uncertainty more effectively.

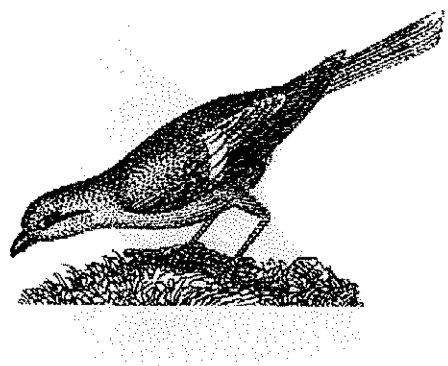
As required by the OPUC, PacifiCorp also conducted scenario analysis using costs of $0, $10, $25, and $40 per ton carbon dioxide (in 1990 dollars). The company applied these values to all portfolios that passed an initial evaluation screen based on cost under the base case. The result was an understanding of the possible spread of costs for an individual portfolio based on multiple variations of different risks, including carbon dioxide as well as fuel prices, power market prices, and others. The company could then rank portfolios according to risk and incorporate this information into the final selection of an optimal portfolio.

The base case scenario used in Idaho Power Company's (IPC) 2004 IRP assumes a $12.30 per ton cost for carbon dioxide emissions beginning in 2008; scenario analysis was also conducted at $0 and $49.21 per ton of carbon dioxide. The estimated costs of carbon dioxide emissions used in the risk analysis are based on the Oregon Public Utilities Commission's order, and "IPC also confirmed that these costs represent reasonable estimates of the risk that IPC and its customers face due to potential future regulation of carbon dioxide emissions."[28] In its risk analysis, Idaho Power estimated a 50 percent probability of a cost of $12.30 per ton of carbon dioxide, a 30 percent probability of zero cost, and a 20 percent probability of a cost of $49.21 per ton.[29]

Pacific Gas and Electric Company's 2004 Long-Term Procurement Plan assumed an imputed cost of $8 per ton of carbon dioxide. In December 2004, the California Public Utilities Commission (CPUC) issued a decision requiring the utilities under its jurisdiction to use an estimated cost for GHG emissions in evaluating new long-term resource commitments and in developing future long-term plans. The Decision adopted a range of costs between \$8 and \$25 per ton of carbon dioxide, pending a final decision on a single value, and required that the estimated cost of carbon dioxide enter the utilities' analysis of long-term commitments in 2007.[30] In April 2005, the CPUC adopted the final imputed costs for carbon dioxide emissions: a levelized cost of \$8 per ton of carbon dioxide, based on a cost stream of \$5 per ton in the near term, \$12.50 per ton by 2008, and \$17.50 per ton of carbon dioxide by 2013.[31] The report upon which the CPUC based its imputed cost assessed the range of likely future scenarios of carbon dioxide regulation, and the associated costs, and concluded that this was a conservative and reasonable estimate.[32]

VI. Utilities Can Reduce Exposure to the Financial Risk Associated with Carbon Dioxide Emissions

Utilities can select a portfolio that reduces exposure to the cost of future regulation of carbon dioxide emissions, while balancing other goals, by including an estimated cost for carbon dioxide emissions in integrated resource planning and in evaluating procurement options. Once a reasonable proxy value of the financial risk associated with carbon dioxide emissions has been assessed, it should be used to inform decision makers about tradeoffs between resource investments in order to properly manage and mitigate the risk.



In general, the ultimate goal of long-term planning processes is to ensure that adequate resources are available to reliably serve the demand for the energy services that utilities provide, while balancing costs, risks, and environmental concerns. Utilities can ensure that resource investments achieve this goal by including all costs and significant risks in modeling portfolio and resource options. Investment decisions should be made with a full understanding of the total costs of each resource alternative, based on the best information available at the time of the investment. Otherwise, customers and utilities could be locked into investments that expose them to higher costs in later years.

As Idaho Power explained in its IRP: "Idaho Power Company believes it is prudent to incorporate reasonable estimates for the cost of carbon dioxide emissions into the IRP resource modeling and analysis, and to thereby actively seek to lessen the Company's and customers' exposure to the financial risk associated with carbon dioxide emissions."[33] Moreover, utilities believe that incorporating carbon dioxide into planning and procurement demonstrates foresight and prudence due to the long lead-times to acquire certain resources, and the long depreciated lives of those resources once they are developed. By comparison, utilities that do not build carbon risk into their long-term planning will be left with few avenues to reduce costs in complying with regulations, due to sunk costs and more limited and costly options to reduce emissions from existing resources.

VII. Incorporating an Estimated Carbon Cost into Planning and Procurement: Examples from Three Leading Utilities

In order to develop a resource portfolio that minimizes overall costs and risks, utilities should incorporate their best estimate of the cost of carbon dioxide emissions as an integral part of their long-term plan and procurement modeling processes, just like

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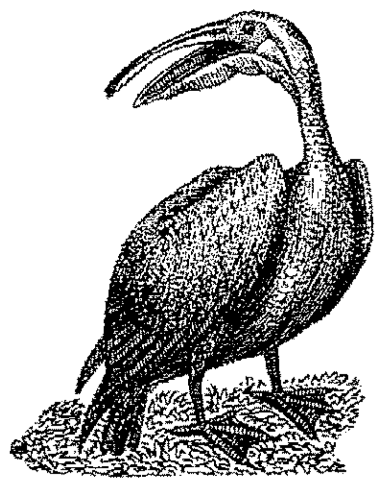
other readily foreseeable and significant costs and risks. The estimated cost should be modeled as an operational cost of each carbon-emitting resource. The outcome of such a modeling process should be a resource portfolio that reduces the utilities' and their customers' exposure to this financial risk to a level that the utility believes is appropriate.

Different utilities have used different methodologies to account for the financial risk of carbon dioxide emissions in their long-term planning and procurement processes. In this section, we discuss the methodology used by three of the leading utilities in this arena, PacifiCorp, Idaho Power, and Pacific Gas and Electric Company, as well as stakeholder reactions to the policy. The three utilities that contributed to this article all agree on the importance of including the future risk of carbon dioxide regulation in their resource planning decisions. However, the examples cited for each utility do not necessarily mean that the other two utilities endorse or would propose similar ways of addressing the issue.

Each of the utilities discussed in this section has integrated an estimated cost for carbon dioxide emissions into their evaluation of resource options. In all cases, the financial risk of carbon dioxide emissions is one of many factors influencing the utilities' decisions about resource investments. The experience gained to date provides insight for other utilities and their regulators seeking to reduce exposure to the cost of future regulation of carbon dioxide emissions and to reduce their customers' overall long-term cost for energy services.

A. Idaho Power Company

In its 2004 Integrated Resource Plan, Idaho Power Company analyzed 12 different portfolios of resources. These portfolios were developed to explore a variety of different resource alternatives, ranging from portfolios with an emphasis on wind generation to an emphasis on coal generation to diversified portfolios, and the costs and benefits of each. Idaho Power analyzed the total cost of each portfolio over 30 years, including an estimated cost of \$12.30 per ton of carbon dioxide in its base case analysis. (Idaho Power derived the selected value from the \$10 per ton value in 1990 dollars required by the Oregon PUC for risk analysis.) Idaho Power also analyzed and ranked the total cost of the portfolios under four different scenarios, which included variations in the estimated cost of carbon dioxide emissions (from \$0 to \$49.21 per ton of carbon dioxide) as well as other variables. Idaho Power then selected five of the portfolios for further risk analysis, in order to identify a portfolio that was robust under a variety of possible scenarios.



Idaho Power's final portfolio was a balanced and diversified portfolio that faced the second-lowest exposure to the financial risk associated with carbon dioxide emissions of the five "finalist" portfolios. Idaho Power's use of an estimated cost of carbon dioxide emissions materially influenced the selection of the final portfolio, increasing the procurement of energy efficiency, renewable energy, and other low-emitting resources, but it remained one factor among many used to select the best portfolio.

Idaho Power's IRP lays out a 10-year resource plan as well as a near-term action plan. Because Idaho Power intends to acquire the resources identified in the IRP using separate competitive solicitations or procurement processes for each type of resource, Idaho Power does not intend to incorporate an estimated cost for carbon dioxide emissions into its actual procurement process.

B. PacifiCorp

PacifiCorp incorporated an estimated cost for carbon dioxide emissions into its IRP in two ways. First, it built in an assumption of an \$8 per ton value in its forecasts for natural gas prices and for emissions

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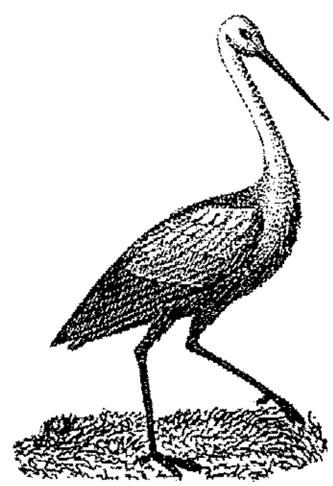
allowances for nitrogen oxide and sulfur dioxide over a 20-year period, which in turn affected the electric market price forecast. (Note that higher carbon dioxide values actually reduce costs associated with nitrogen oxide and sulfur dioxide emissions due to less coal-fired generation and an associated rise in excess allowances.) These market prices then helped the company determine cost-effectiveness for different resource options, and, with variations and multiple model runs, they also helped the company understand the risk associated with carbon dioxide regulation. Second, carbon dioxide costs were attributed to emissions associated with different portfolios, with an assumption that emissions are capped at 2000 levels.[34] Conversely, portfolios with emissions below 2000 levels received credits associated with excess allowances that could be sold to other emitters.[35] This approach adds cost to thermal generation while effectively rewarding renewable energy and demand-side energy efficiency for their emissions-free attributes. Finally, PacifiCorp subjected each portfolio that survived initial cost and risk analysis to carbon dioxide values ranging from $0 to $40 per ton to comply with the OPUC's 1993 order.

When applied to different resource portfolios, the higher carbon dioxide cost scenarios, particularly the $25 and $40 per ton values, had the biggest impact on cost differentials among portfolios. Coal-heavy portfolios looked unattractive due to the cost of emissions above 2000 levels, while "balanced" portfolios that avoided excessive exposure to high gas prices while exhibiting a much lower emissions level than coal-heavy portfolios fared well due to the sale of excess emissions allowances.[36]

PacifiCorp's use of an estimated carbon cost is not limited to planning; it is also firmly tied into purchasing efforts. PacifiCorp built on its modeling efforts in the IRP by employing a forward price curve for electricity in evaluating procurement options that includes the impact of an $8 per ton estimated cost for carbon dioxide. The curve serves as a market price referent for bids submitted to the utility's 2004 request-for-proposals for renewable resources. Of course, since the vast majority of renewables emit little to no carbon dioxide, the bids themselves do not face carbon dioxide costs, but the market price referent curve includes a market with thermal resources, so the carbon dioxide-free renewables benefit from incorporating carbon dioxide into the price referent.



PacifiCorp also applied the estimated carbon dioxide cost to its 2003 request for proposals (RFP) for thermal resources. In the 2003 RFP, PacifiCorp compared bids to a "next best alternative," which was a combined-cycle natural gas plant proposed by the company to build and own. Because that plant would be an owned resource, the utility assumed that it would have to bear carbon dioxide costs. For bids proposing a power-purchase agreement, the company assumed that the counterparties could pass along carbon dioxide costs to the utility when regulations arrive. Bids were therefore assumed to have the same carbon dioxide costs as the utility-owned plant. However, the utility offered counterparties the ability to explicitly indemnify the utility for any carbon dioxide-related price risks in exchange for a payment of up to $8 per ton in accordance with the IRP assumptions. Effectively, the utility was offering an insurance payment to protect ratepayers from potentially costly regulations.

The resource selected in the 2003 thermal RFP won based on least cost, without indemnifying PacifiCorp for the carbon dioxide risk. However, negotiations between PacifiCorp and potential counterparties prior to final selection included dialogues on contractual language and collateralization to support a supplier's obligation to hold carbon dioxide-related risk. In particular,

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the negotiations raised concerns among PacifiCorp staff that counterparties did not fully appreciate what it meant to hold such risk. For example, a project developer disposed to perceiving little risk of future GHG regulations could claim to bear the risk without a clear plan to cover the commitment in case of regulations and associated imposition of costs. This initial experience should prove instructive for the utility and bidders alike when another thermal RFP is issued.

C. Pacific Gas and Electric Company

The California PUC recently adopted a new policy requiring its regulated utilities to explicitly account for the financial risk associated with carbon dioxide emissions in evaluating long-term resource commitments. The CPUC found that "[i]t is likely that greenhouse gas emissions will be regulated within the timeframe addressed in the utilities' [long-term procurement plans] and the lifetime of the utilities' long-term resource commitments," and concluded that "[g]reenhouse gas emissions pose a real and substantial financial risk to customers and the utilities."[37]

PG&E will be using the CPUC-adopted "greenhouse gas adder" in evaluating offers it receives in response to competitive solicitations, as well as in its next long-term procurement plan. In accordance with CPUC requirements, PG&E's solicitations will be "all-source" solicitations, welcoming both renewable and non-renewable bids, as well as utility-owned and contracted resources. These resource options will be evaluated using a least-cost/best-fit analysis, which uses market value, portfolio fit, credit, location, and other factors to rank all of the offers received and to select the best mix of resources. The "GHG adder" will be one element of the market value evaluation, and will affect the relative market valuations of resources based on their carbon dioxide emissions.

PG&E is currently in the process of conducting its first competitive solicitation and using the estimated cost for GHG emissions in its evaluation. PG&E's current competitive solicitation is for particular peaking and intermediate products and the resources compared are likely to have similar emission profiles, so the "GHG adder," as just one of many factors used in evaluating bids, is unlikely to have a substantial impact on the outcome of the solicitation. But since PG&E conducts all-source solicitations, at some point it expects to compare resources with significantly different emissions profiles, where the "GHG adder" could have a material effect on the outcome of the solicitation.

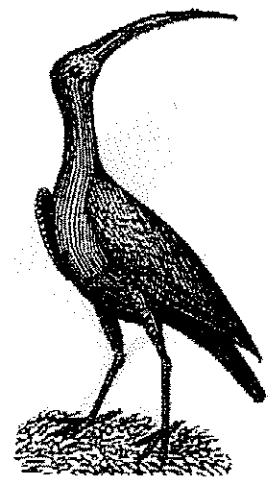
D. Stakeholder views

Stakeholder reaction to the introduction of an estimated cost for GHG emissions has been diverse, though typically accepting. Idaho Power's IRP elicited supportive comments on its use of a carbon risk value. PacifiCorp's IRP drew a range of comments reflecting its diverse service territory, which stretches from the Oregon coast to Utah and eastern Wyoming. Utah Commission staff had questions about the mechanics of the estimated carbon dioxide cost and the basis of the valuation, but not about the existence of the estimated cost itself. In California, the issue was the subject of formal regulatory hearings in which numerous issues were debated. As with any kind of scenario risk, this type of debate is to be expected.

The first threshold issue discussed in some areas was whether regulation of carbon dioxide emissions is likely within the lifetime of new investments. An overwhelming majority of stakeholders agree that such regulation is likely. However, other voices expressed concern. For example, the Utah Committee of Consumer Services, while "appreciating PacifiCorp's proactive approach," also felt that the uncertainty surrounding the existence and extent of future regulations made them uncomfortable with any value in the base case. In California, some utilities asserted that it would be premature for the Commission to adopt an estimated future cost of carbon dioxide emissions, and that instead the Commission and the utilities should wait to act until carbon dioxide is regulated. By the time carbon dioxide is regulated it may be too late for utilities to protect customers and shareholders from increased costs associated with long-term commitments made earlier. Electric resources are long-term, capital-intensive investments. Once carbon dioxide is regulated, utilities that do not plan now will probably not be able to reshape their portfolios overnight, at least not without incurring massive costs.

Selection of an appropriate estimated cost of carbon dioxide emissions was also the subject of considerable discussion among stakeholders. Some pointed to the lack of federal action to date as a reason to reduce the estimated cost — but not eliminate it entirely. Conversely, other stakeholders asserted that the estimated cost was not high enough, given increasing prices in European markets. Such conflicting comments reflect both different interests, as well as the inherent challenge of quantifying a scenario risk.

Some stakeholders expressed concern that the actual cost of carbon dioxide emissions might ultimately be higher or lower than the estimated cost. However, the most simple and compelling consideration is that the risk of GHG regulations clearly exists, and therefore to value carbon dioxide is prudent utility management; planning and purchasing decisions that are made today must use the best available information. Uncertainty about future costs is simply a fact of life in the electric industry, and utilities must continue to make long-lived investment decisions based on the best information available at the time of the investment.



Stakeholder discussion also centered around the possibility that the use of an estimated carbon cost could increase rates in the near-term before carbon dioxide emissions are regulated. Incurring a small cost in the near-term to hedge against a much larger risk is appropriate. Utilities routinely incur these "insurance premium" type costs to hedge other risks such as natural gas price risk. Moreover, it is often prudent to incur modest, near-term costs in order to protect customers from much larger potential future costs, *even if* those future costs do not end up being as large as anticipated.

Ultimately, both PacifiCorp's and Idaho Power's IRPs received high praise from regulators, environmental stakeholders, and other stakeholders such as customer groups. The praise reflected in part the fact that the utilities examined numerous cost and risk factors that led to diverse resource selections. The financial risk associated with carbon dioxide emissions was one of many factors used to select the optimal portfolio, and no single factor dominated planning decisions. PG&E, for its part, has been a national leader in calling for responsible market-based responses to the risks associated with global climate change, and the company was an early supporter of the California PUC's decision, which attracted widespread support from other key stakeholders.

VIII. Conclusion

Risk management is increasingly recognized as a crucial responsibility of utility portfolio managers. The financial risk associated with likely future regulation of carbon dioxide emissions is becoming a focus of utilities' and regulators' risk management efforts, as they recognize the imprudence of assuming that carbon dioxide emissions will not cost anything over the 30-year or longer lifetime of new investments. Utilities can

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help protect their customers and shareholders from this financial risk by integrating an estimated cost of carbon dioxide emissions into their evaluation of resource options, and selecting the overall least-cost portfolio of resources. Utilities can learn from the experience that some utilities have gained at managing this risk to ensure that today's investments do not lock customers or shareholders into much higher costs tomorrow if greenhouse gases are regulated.■

Endnotes:

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2. Oregon Public Utility Commission, Order No. 93-695, *In the Matter of the Development of Guidelines for the Treatment of External Environmental Costs*, entered May 17, 1993.

3. Utah Public Service Commission, Docket 90-2035-01, June 18, 1992.

4. Oregon Public Utility Commission, *supra*, at note 2, p. 3. The Oregon Department of Justice also prohibited the OPUC from penalizing utilities for not purchasing higher-cost resources with lower external costs.

5. This includes S.342 and H.R.759, Climate Stewardship Act of 2005; S.150, Clean Power Act of 2005; H.R.1451, Clean Smokestacks Act of 2005; H.R.1873, Clean Air Planning Act of 2005.

6. H.R.4067, Climate Stewardship Act of 2004.

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Protection Agency Press Release, West Coast States Strengthen Joint Climate Protection Strategy, Nov. 18, 2004.

9. Office of Gov. Schwarzenegger, Executive Order S-3-05, June 1, 2005.

10. California Assembly Bill 1493 (Statutes of 2002, Ch. 200, Pavley).

11. California Public Utilities Commission, Decision No. 04-12-048, Dec. 16, 2004.

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22. Chicago Climate Exchange, *Chicago Climate Exchange Market Data*, accessed May 1, 2005, available at www.chicagoclimatex.com/trading/stats/monthly/index.html.

23. Correspondence with Michael Ashford, Deputy Director, The Climate Trust, May 31, 2005.

24. Energy Information Administration, *Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003*, June 14, 2004, available at www.eia.doe.gov/oiaf/analysispaper/sacsa/index.html.

25. S. Paltsev *et al.*, *Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: The McCain-Lieberman Proposal*, MIT Joint Program on the Science and Policy of Global Change, Report No. 97, June 2003, at 21, scenario 7.

26. Energy Information Administration, *Analysis of Strategies for Reducing Multiple Emissions from Electric Power Plants with Advanced Technology Scenarios*, SR/OIAF/2001-05, Oct. 2001.

27. PacifiCorp, *2004 Integrated Resource Plan*, 2004, at 155, available at www.pacificorp.com/Navigation/Navigation23807.html.

28. Idaho Power Company, *2004 Integrated Resource Plan*, July 2004, at 71, available at www.idahopower.com/energycenter/2004irp.htm.

29. *Id.*, at 72.

30. For example, in analyzing a bid for a 10-year contract that would begin delivery in 2006, the utility would not include the adder in the cost estimate for 2006, but would include the adder beginning in 2007 and continue including it for all the subsequent years of the analysis.

31. CPUC Decision 05-04-024, Conclusion of Law 7.

32. Energy and Environmental Economics and Rocky Mountain Institute, *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*, prepared for California Public Utilities Commission, Oct. 25, 2004, at 89, available at www.ethree.com/cpuc_avoidedcosts.html. Adopted in CPUC Decision 05-04-024, April 7, 2005.

33. Idaho Power Company, *supra* at note 28, p. 71.

34. PacifiCorp assumed that emissions costs would apply to new resources identified through the IRP, rather than emissions from existing generation. The assumption was based on a forecast of a cap-and-trade approach to GHG emissions, rather than a tax on all carbon dioxide emissions. The forecast also assumed that the cap-and-trade regime would "grandfather" existing generation and their emissions by issuing emissions allowances equal to their annual total, with cuts to come from subsequent resources. Since the IRP does not make decisions on whether a utility should own generation or acquire the output of generation owned by another entity, it does not address the question of whether there is carbon dioxide risk associated with power purchases.

35. Customers would ultimately receive the credits earned by sales of excess allowances.

36. Modeling results revealed that the $25 per ton and $40 per ton values substantially impacted the price for NO_x and SO_x emissions allowances as well as natural gas prices. Consequently, these carbon dioxide values had the biggest impact on electricity market prices.

37. California Public Utilities Commission, Decision No. 04-12-048, Dec. 16, 2004, Findings of Fact 76 and 77.

❖ MEETINGS OF INTEREST ❖

Conference	Date	Place	Sponsor	Contact
Renewable Portfolio Standards–Western US	July 27–28	San Diego	Power Marketing Association	(201) 784-5389
Energy 2005: The Solutions Network	Aug. 14–17	Long Beach, CA	U.S. Department of Energy	http://www.energy2005.ee.doe.gov/
2005 Electric Market Forecasting Conference	Sept. 14–16	Coeur d'Alene Resort on Lake Coeur d'Alene, Idaho	EPIS	http://www.epis.com/epis_events/events.htm
Air Quality V: Mercury, Trace Elements, SO_3, and Particulate Matter	Sept. 19–21	Arlington, VA	Energy & Environmental Research Center	(701) 777-5246
Principles of Power and Gas Trading	Oct. 3–7	Oxford, UK	Oxford Princeton Program	http://www.oxfordprinceton.com/
2005 IEEE PES Transmission & Distribution Conference & Exposition	Oct. 9–14	New Orleans	IEEE Power Engineering Society	http://www.ieeet-d.org/
Nuclear Energy in Europe Conference	Oct. 17–18	Brussels	EU Conferences	http://www.euconferences.com/

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