The Methodology Behind the Levelized Cost Analysis

Historically, the cost of generating electricity has been estimated by calculating a constant (over time) inflation-adjusted price of electricity at which the discounted revenue from the sale of electricity generated at a given plant, net of taxes, equals the discounted cost of building and operating the plant. That constant real price is referred to as the levelized cost, because the construction costs are spread over the operating life of the hypothetical plant. Specifically, utilities finance the up-front costs of construction and then repay lenders with revenue from the sale of electricity. Because of the large up-front costs incurred when a plant is built and the long operating life of most power plants, the rate at which costs and revenues are discounted is particularly salient when estimating the levelized cost. That rate is derived from the returns required by investors to finance construction, which depend on a project's market risk.

The Congressional Budget Office (CBO) uses a levelized-cost model in which estimated costs and revenues are discounted on the basis of the rates of returns to debt and equity considered necessary to attract investment in commercially viable projects. A project's costs and revenues are based on assumptions about future market conditions and technological developments that are often distinct to the underlying technology. CBO adopted most of its technical assumptions from data provided by the Energy Information Administration (EIA) after comparing those assumptions to other studies and adjusting the assumptions for its analysis. Incentives and carbon dioxide charges were incorporated into the model through various alterations to CBO's reference scenario.

Levelized-cost models for traditionally regulated utilities can be constructed by finding the price at which the discounted value of costs equals the discounted value of net revenues over the life of a power plant:

Find p^{real} such that $\sum_{t=0}^{T}(1+r^{proj})^{-t} \times C_t = \sum_{t=0}^{T}(1+r^{proj})^{-t} \times R_{t,net}$ where

$R_{t,net} = (1+i)^t \times p^{real} \times Q_t - T_t$.

The rate of return for the project, r^{proj}, may be the rate allowed by a state utility commission, which must be sufficient to attract investment for the plant to be built. Levelized costs for merchant generators can be based directly on the rates of return required to attract investment in up-front costs. In such a case, the model can be reorganized so that costs include both nominal expenditures and the returns necessary to attract financing from fixed and equity investment:

$$\text{Find } p^{real} \text{ such that } \sum_{t=t_0}^{T} R_{t,net} = \sum_{t=t_0}^{T} C_t + r^{debt} \times \sum_{t=t_0}^{T} B_{t,debt} + r^{equity} \times \sum_{t=t_0}^{T} B_{t,equity} \qquad (1)$$

In the above model, costs are discounted by providing sufficient returns to the balances of debt, B_{debt}, and equity, B_{equity}. Those balances are determined by the flows of revenue and cost. Costs and revenues are implicitly discounted on the basis of a weighted average of the required returns to debt and equity, which CBO assumes is constant:

$$\text{Find } r^{proj} \text{ such that } r^{proj} = \alpha_t \times r^{debt} + (1-\alpha_t) \times r_t^{equity} \text{ and } \sum_{t=t_0}^{T} r_t^{equity} \times B_{t,equity} = r^{equity} \times \sum_{t=t_0}^{T} B_{t,equity}$$

The ratio of debt and equity, α_t, is not constant over time because debt is typically paid first and has a lower rate of return. The variable required rate of return for equity, r_t^{equity}, decreases with the portion of debt in order to keep the rate of return for the project constant. The second condition states that the variable returns to equity, which are calculated on an annual basis, add up to the total return equity is assumed to require over the life of the plant.[1] The model can be solved by finding the levelized cost and rate of return for the project that either set the required return to equity equal to the actual return or that equate discounted revenue to discounted cost.[2] This model could be applied to either the decisions of traditionally regulated utilities or merchant generators, but the rates of return may differ in those two cases. The assumptions used by CBO are intended to represent the market environment faced by merchant generators. Financing may be cheaper for traditionally regulated utilities, where state utility commissions may fix the price of electricity, transferring risk from investors to customers.

[1]Some of the studies that CBO reviewed treat both the rate of return for the project and the rates of return to equity and debt as constant. That implies a constant debt-to-equity ratio, even though debt is typically repaid more quickly. The result of that inconsistency is a return to equity that is less than the researchers assumed was necessary to attract investment. The study conducted by researchers at the Massachusetts Institute of Technology (MIT), like the CBO model, explicitly models cash flows, but the MIT model holds the rate of return to equity constant over time, which implies that the rate of return for the project increases over the operating life of the plant. (See *The Future of Nuclear Power*, MIT (2003).) Using an increasing rate implies that the financial risk of the project increases as the project matures and, therefore, reduces the value of production incentives (such as the production tax credit and preferential tax treatment for the decommissioning fund).

[2] Merchant generators are expected to finance new nuclear capacity without recourse to other projects. Accordingly, CBO uses a project-finance-based approach, in which the liabilities and assets of the power-plant project are separate from the rest of the utility's projects. Under that project-finance paradigm, taxes are a nonlinear function of price; accordingly, CBO solves this model by iteration using the Newton-Raphson method. Conversion tended to be more likely when equating discounted revenue to discounted cost.

Base-case assumptions about market and technological factor are the starting point for the levelized cost presented in the reference scenario. In accordance with equation (1), the base-case assumptions are divided among those pertaining to up-front and operating costs, net revenue (revenue net of taxes), and financing cost (the basis for discounting nominal revenue and expenditures). Later, to analyze the effect of carbon dioxide charges and EPAct incentives levelized cost, CBO modifies the base-case assumption.

Base-Case Assumptions and the Reference Scenario Model

Up-front and Operating Cost Assumptions. Expenditures in the reference scenario are based on assumptions about construction and operating costs for each technology, which attempt to capture the effect of future market forces and technical developments. Those assumptions are intended to be valid for power plants that begin operation in the later half of the next decade, when the construction of the first new nuclear power plants is expected to be completed (see Figure A-1 for a representative timeline). Accordingly, the values of some assumptions differ from currently observed values because of anticipated market changes or technological improvements.

The flow of cost for new capacity includes the up-front cost of construction and licensing, as well as the operating cost:

$$C_t = C_{t,upfront} + C_{t,oper} = (C_{t,licen} + C_{t,constr}) + C_{t,oper} \qquad (2)$$

All those costs are initially calculated on a nominal basis, because tax liability is based on nominal costs and revenues. Licensing costs, which include up-front regulatory and design costs, are considered only for nuclear technology and total $60,000 per megawatt (MW) before construction begins.[3] (Construction and operating costs are provided in Table A-1.) Unless otherwise noted, CBO used EIA's assumptions for plants that begin operating around 2015. Those assumptions are given in real 2006 dollars, but inflation is added in calculating the nominal flows of costs. Overnight construction costs represent the inflation-adjusted total of expenditures for constructing the plant. Those costs are distributed in a symmetric hump-shaped

[3] Cost assumptions are not tailored to different power plant sizes. The assumed cost per unit of capacity (measured in MW) is intended to be representative of an optimally sized plant.

(sinusoidal) pattern over the specified number of years. The utility finances licensing and construction costs because those costs are incurred before the project can generate revenue from the sale of electricity.

Operating costs, which the utility pays the year they are incurred, include costs based on the size of the plant (measured in dollars per MW) and costs based on the amount of electricity generated (dollars per megawatt hour, or MWh):

$$C_{t,oper} = (C_{t,fixedOM} + C_{t,inccap} + C_{t,insur} + C_{t,decom}) + (C_{sptfuel} + C_{t,\mathrm{var}OM} + C_{t,fuel} + C_{t,seq})$$

Operating costs given in dollars per unit of electricity generation are converted into dollars per unit of capacity based on how much electricity a unit of capacity is expected to generate per year. (The specific formulas for operating costs are presented in Table A-2.) The calculation of decommissioning costs is addressed separately because the formula is more complicated and those costs account for less than 1 percent of levelized cost in the reference scenario (see Box A-1).

Revenues and Taxes. All revenues are assumed to be generated from the sale of electricity during a plant's operating life.[4,5] Each year that a unit of capacity operates, the amount of electricity produced is proportional to the technology's capacity factor:

$$Q(\mathrm{MWh}) = 365.25(\mathrm{day/yr}) \times 24(\mathrm{hrs/day}) \times e^{cap}(\mathrm{MW} \cdot \mathrm{yr})$$

Because CBO is evaluating the cost of base-load capacity, all technologies are assumed to run at capacity factors equal to their anticipated availability (see Table A-1 for capacity factors).

Revenues net of operating costs and tax deductions are taxed at a representative state tax rate of 4 percent and a federal tax rate of 35 percent. Taxable income at both the state and federal levels is reduced by standard deductions for interest payments and capital depreciation: licensing, design, and construction costs are depreciated according to the Modified Accelerated Cost Recovery System (MACRS) rates once the plant begins operating. State taxes are deducted from

[4] CBO assumes that power plants operate for 40 years; EIA assumed that plants recover the cost of construction and financing over 20 years.

[5] In the case of nuclear technology, a small portion of revenues are derived from returns to the decommissioning fund.

federal taxable income. If revenues exceed operating costs by less than the available deductions, the extra deductions are forfeited;[6] such an outcome does not occur in the reference scenario.

Financing Cost. Revenues net of operating costs and taxes are used to repay the holders of debt and equity. Debt and equity are issued in a constant ratio to finance construction. Once construction is completed and a plant begins operating, debt is repaid in constant payments over 20 years at a rate of return of 8 percent. All remaining revenues are considered a return to equity. The rate of return to equity varies from year to year with the ratio of outstanding debt and equity, but equity receives an effective rate of 14 percent over the life of the project.[7] The assumptions governing rates of return represent nominal rates with a 2 percent annual rate of inflation. Licensing costs are financed solely through equity. (The formulas for the financing costs are presented in Table A-3.)

Assumptions Incorporating Carbon Dioxide Charges and EPAct Incentives

As described throughout the main text of the report, various scenarios consider the possible effects of prospective carbon dioxide charges and the impact of incentives provided under the Energy Policy Act of 2005 (EPAct). The implementation of carbon dioxide charges and two provisions of EPAct—the production tax credit and the loan guarantee program—were found to be the most salient of those incentives.

Carbon Dioxide Charges. Hypothetical carbon dioxide charges—the utilities' costs of emitting a metric ton of carbon dioxide—are incorporated in the operating costs of each fossil-fuel technology considered in the analysis. The carbon dioxide charges were assumed to be proportional to the amount of carbon dioxide emitted during the generation of electricity: [8]

---

[6] The model does not incorporate the corporate alternative minimum tax (AMT), which would further constrain the amount of usable deductions in a given year. If utilities are bound by the AMT, they receive tax credits, which can be used to reduce tax liability in future years.
[7] The financing assumptions for the levelized-cost calculations represent the returns required by investors if the project is commercially viable. Utilities would not be able to finance under those terms if the levelized cost for the particular technology exceeds the expected wholesale price for electricity. For example, if new coal capacity has a significantly lower levelized cost than new nuclear capacity, then investors would tend to finance new coal capacity at the assumed rates of return and would not be willing to finance nuclear capacity under any available terms.
[8] This study considers only stack emissions of carbon dioxide—emissions resulting directly from the operation of the power plant. All technologies have additional life-cycle emissions, which are primarily from the construction and decommissioning of a facility as well as the procurement and processing of fuel. Accordingly, a price on carbon

$$C_{t,CO2} = \tau_t^{CO2} \times E_t^{CO2} = \tau_t^{CO2} \times (1 - e^{CO2}) \times E_{t,potential}^{CO2} = \tau_t^{CO2} \times (1 - e^{CO2}) \times Q \times \iota^{CO2} \times h$$

The private cost of emitting carbon dioxide for a power plant, C_{CO2}, is the product of the carbon dioxide charge and power plant emissions, E^{CO2}. Emissions are the product of potential emissions and the portion of carbon dioxide not captured and stored. Accordingly, emissions are equal to potential emissions for conventional technologies because those technologies do not capture any emissions ($e^{CO2} = 0$); but, for innovative coal and natural gas technologies, 90 percent of potential emissions are captured and stored ($e^{CO2} = .9$). Potential emissions are a product of the quantity of electricity generated, a technology's heat rate, h, and a fuel's carbon intensity, ι^{CO2}.

The analysis of the cost uncertainty from the undetermined future prices of emitting carbon dioxide uses carbon dioxide charges based on the permit prices associated with two hypothetical cap-and-trade programs. Those permit prices are taken from the MIT Emissions Prediction and Policy Analysis model and inserted into CBO's levelized-cost model.[9] (Table A-4 has the list of the permit prices inputted into the levelized-cost model.) Because the permit prices increase considerably over time, closing power plants before 2058—the end of the operating life under the base-case assumptions—minimizes the levelized costs of new capacity using conventional fossil-fuel technologies. In CBO's levelized-cost model, power plants would close when operating costs (including carbon dioxide charges) exceed revenues from the sale of electricity. Under the less stringent cap, conventional fossil-fuel power plants, if built, would close around 2048 in the model. Under the more stringent cap, conventional fossil-fuel plants, if built, would close in 2033.

---

dioxide may raise the levelized cost of all technologies. Such additional life-cycle emissions are not included in this analysis because they are difficult to measure and are probably an order of magnitude smaller than the stack emissions from coal or natural gas capacity.

[9] Those permit prices were published by Sergey Paltsev and others in *Assessment of U.S. Cap-and-Trade Proposals*, Working Paper No. 13176 (Cambridge, Mass.: National Bureau of Economic Research, June 2007). See Joseph V. Spadaro, Lucille Langlois, and Bruce Hamilton, *Greenhouse Gas Emissions of Electricity Generation Chains: Assessing the Difference*, (International Atomic Energy Agency, February 2000), p. 21.

Production Tax Credits.[10] During each of the first eight years of operation, the utility owning a qualified new nuclear capacity receives federal tax credits for each MW of qualified capacity:

$$CreditsIssued_t = Min\left(18 \times Q, 125000, 125000 \times \frac{6000}{QualifiedCapacity(MW)}\right).$$

If constraints are not binding, the operator receives a credit of $18 per MWh. The credit is constrained to $125,000 per MW, implying that if the reactor operates at a capacity factor above 80 percent, credits are not issued for the additional electricity. In addition, if more than 6,000MW of capacity qualifies for the production tax credit, the $125,000 per MW limit is divided proportionately among the qualifying capacity.

The Internal Revenue Service classifies the production tax credit as a general business tax credit, which is not refundable; therefore, the credit cannot reduce a utility's tax payments below zero in any year.[11] If a utility's credits exceed its tax liability in any given year, those credits may be applied (carried back) to tax payments from previous years or held (carried forward) to apply to future tax payments. General business tax credits can be carried back for 2 years and carried forward for 20 years.

In the model, a utility applies the credits as early as possible because the credit is valued in nominal dollars. Accordingly, the amount of credits applied in any year is the lesser of the utility's balance of such credits and federal tax payment in the absence of credits:

$$CreditsApplied_t = Min(CreditsBalance_t, T_{t,fed}). \qquad (2)$$

In the model all taxable revenue is typically assumed to come from the sale of electricity generated by the capacity; however, the utility may be able to accelerate the application of credits by using the credits against the taxable income of their other assets. For that reason, CBO assumes 50 percent of credits are applied in the year they are issued, 25 percent are applied the following year, and the remaining 25 percent are applied the year after that.

[10] Investment tax credits are also included in the model for coal with carbon capture-and-storage technology. The utility is issued credits equal to 20 percent of construction expenditures in the year the plant begins operating. Deductions from MACRS are reduced by 10 percent.

[11] The redemption of the credit in a given year may be further limited by the AMT, because the production tax credits do not count toward the AMT.

Loan Guarantees. The loan guarantee program reduces the private cost of financing construction by transferring financial risk from investors to taxpayers; but the program increases the amount of up-front private costs because the utility pays the subsidy cost.[12] The addition of the loan guarantee to the reference scenario leads to specific changes in the terms for debt and equity (see Table A-5).

The loan guarantee program is assumed to have three direct effects on the assumptions from the reference scenario:

1) The utility finances construction by issuing 80 percent debt—the maximum amount of guaranteed debt allowed under the program—and 20 percent equity,[13]
2) The interest rate for guaranteed debt is equal to the projected Treasury-bill rate plus a margin intended to cover administrative costs, and
3) The utility uses equity to finance the subsidy cost of the guarantee.

The loan guarantee indirectly affects the required return to equity, which increases to account for the decrease in the share of equity financing.

The increase in the portion of debt financing under the loan guarantee program may increase the risk of the project by reducing the amount of internal (equity) financing. The model allows for a change in the returns required to attract investment from equity due to the loan guarantee program decreasing the amount of equity financing. Specifically, the model assumes the minimum increase in the required rate of return to equity consistent with the utility's choice of 45 percent debt financing in the reference scenario. In the reference scenario, the utility presumably decided to forgo the higher tax deductions associated with a larger portion of debt financing, because more debt financing would have increased the required rates of return.

In all scenarios, the utility finances the new capacity by issuing a portion of debt, α, that minimizes levelized cost. To choose the optimal portion of debt financing, the utility must

[12] The subsidy cost is the Treasury's expected loss from guaranteeing the debt of the utility.
[13] Throughout the analysis, using the maximum portion of guaranteed debt minimized levelized cost.

consider what the required returns for debt and equity will be under each combination of debt and equity financing.

$$\underset{\alpha}{Min}\, p_{\alpha}^{real} = f(\alpha, r_{\alpha}^{debt}, r_{\alpha}^{equity}) \text{ where } r_{\alpha}^{debt} = (.45 \times r_{.45}^{debt} + (\alpha - .45) \times r_{\alpha}^{equity}) \text{ and } r_{\alpha}^{equity} = g(\alpha, r_{\alpha}^{debt})$$

The formula for the levelized cost, p^{real}, is given in equation (1). The relationship between the rate of return to debt and the portion of debt financing is based on the simplifying assumption that the incremental debt (above 45 percent) has no prospect for recovery in the case of default.[14] The relationship between the rate of return to equity and the portion of debt financing is not specified; instead, that rate of return is based on the assumption that issuing 45 percent debt financing was optimal in the reference scenario:

$$p_{\alpha}^{real} \geq p_{\alpha^*}^{real} \text{ where } \alpha^* = .45,\ r_{\alpha^*}^{equity} = .14, \text{ and } r_{\alpha^*}^{debt} = .08$$

For simplicity, levelized costs are assumed to be the same in the optimal case and under the increase in debt financing. That assumption implies that the minimum increase in the rates of return for equity is consistent with the utility minimizing levelized cost.

Based on this methodology, the rates of return to equity increase by about 2 percentage points under the loan guarantee program. Those increases result from changes in the share of equity finance, but do not include increased risk from changes in decisions about which projects are carried out. Because the loan guarantee program reduces the amount of equity financing, investors might tend toward riskier projects under its protection. Accordingly, the analysis may understate the increase in the required rate of return to equity under the loan guarantee program.

The utility pays a subsidy cost equal to a portion of guaranteed debt at the time of issuance. This subsidy cost is treated like the licensing and design cost in equation (2); in other words, the subsidy cost is financed with equity, and the utility receives tax deductions for the subsidy cost based on MACRS rates. Under the base-case assumptions, CBO assumed a hypothetical subsidy cost for commercially viable projects equal to 12.5 percent of the issue of debt. In the uncertainty analysis regarding financing costs displayed in Figure 3-6, CBO used hypothetical subsidy costs for commercially viable projects of 5 to 27.5 percent of debt. Those subsidy costs were selected to be consistent with the underlying returns to debt. Actual subsidy costs will be

[14] The rate of return to debt may also differ from the rate of return to equity because debt is paid first each period. For simplicity, incremental debt was assumed to be as risky as equity.

determined on a project-by-project basis, and some of the projects evaluated for the loan guarantee program may not be commercially viable.

Box A-1.

Decommissioning Costs and Preferential Tax Treatment

During day-to-day operations, low levels of radiation inevitably contaminate the equipment used at a nuclear power plant, as well as the facility's structural underpinnings. The utility is responsible for safely disposing of all contaminated material once the plant is retired. For large commercial nuclear plants retired in the 1990s, the decommissioning process cost roughly $350,000 per megawatt (MW).[15] However, the present value of that cost for a new power plant would be small; even without preferential treatment, decommissioning costs would make up less than 1 percent of levelized costs in the reference scenario. Accordingly, the value of incentives that reduce decommissioning costs would be limited for new nuclear capacity.

The federal government provides financial incentives for utilities that deposit payments in a special fund reserved for covering the costs of decommissioning a nuclear power plant. In CBO's model, such payments are included in operating costs:

$$P_{decom} = \frac{(1-t^{fund})\times r^{fund}}{[1+(1-t^{fund})\times r^{fund}]^{40}-1}\times C_{t,decom} \text{ where } r^{fund} = r^{proj} \text{ for } t = 2018 \text{ to } 2057$$

The above formula indicates that the constant annual payments to the decommissioning fund are proportional to decommissioning costs, with the size of payments depending on the rate of return to the decommissioning fund, the rate at which returns are taxed, and the length of the plant's operating life. In the reference scenario, the tax rate for the fund is 35 percent, but in subsequent analyses that incorporate EPAct incentives, the fund is taxed at a rate of 20 percent.[16] That

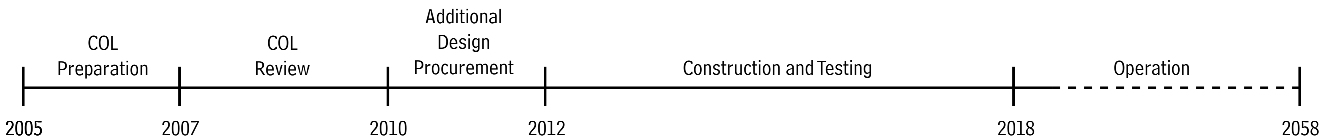
[15] Based on information provided in Nuclear Energy Association (NEA), *Decommissioning Nuclear Power Plants*, (Organisation for Economic Co-operation and Development, 2003), which gives a decommissioning cost of $479,000 per MW for the Maine Yankee plant, $291,000 per MW for the Trojan plant, and $475,000 per MW for the Zion plant. (CBO adjusted the cost reported by NEA from 2001 to 2006 dollars using the gross domestic price index.)

[16] The preferential treatment of the fund also enables utilities to deduct decommissioning costs as they make payments to the fund, instead of receiving a deduction when they decommission the plant. For simplicity, the model assumes utilities maintain a decommissioning fund regardless of the tax rate and are allowed to take deductions as they makes payments to the fund.

preferential tax rate reduces the levelized cost of nuclear capacity from $72.31 per megawatt hour to $72.18 per megawatt hour.

Figure A-1.

Representative Timeline for the Deployment of New Nuclear Capacity



Source: Congressional Budget Office.

Table A-1.

Assumptions in CBO's Reference Scenario

	Label	Value by Technology: Advanced Nuclear	Conventional Coal	Conventional Natural Gas	Innovative Coal	Innovative Natural Gas
Construction						
Time (years)	t^{constr}	6	4	3	4	3
Overnight Cost (dollars per MW)	C^{overn}	2,358,082	1,498,535	684,650	2,471,450	1,387,531
Operating Cost						
Fuel cost (dollars per million Btu)	c^{fuel}	0.75	1.74	6.26	1.74	6.26
Heat rate (million Btu per MWh)	h	10.40	9.01	6.44	9.90	8.30
Fixed O&M (dollars per MW)	$C_{fixedOM}$	66,048	26,787	11,379	44,271	19,360
Variable O&M (dollars per MWh)	c^{varOM}	0.48	4.46	1.95	4.32	2.86
Spent fuel disposal fee (dollars per MWh)[a]	$c^{sptfuel}$	1.00	n.a.	n.a.	n.a.	n.a.
Incremental capital (dollars per MW)[b]						
Operating less than 30 years	C_{inccap}	19,000	15,000	6,000	21,707	12,160
Operating 30 years or more	C_{inccap}	48,000	21,000	12,000	30,389	24,320
Fuel's CO_2 intensity (metric ton per million Btu)[c]	I^{CO2}	0	0.095	0.053	0.095	0.053
Portion of CO_2 captured (percent)	e^{CO2}	n.a	0	0	90	90
CO_2 transport and storage (dollars per metric ton)	c^{seq}	n.a.	n.a.	n.a.	4.00	4.00
Revenue						
Operating life (years)	$t^{operating}$	40	40	40	40	40
Capacity factor (percent)	e^{cap}	90	85	87	82	84

Continued

Table A-1. **Continued**

Assumptions in CBO's Reference Scenario

	Label	Value by Technology				
		Advanced Nuclear	Conventional Coal	Conventional Natural Gas	Innovative Coal	Innovative Natural Gas
Tax Rate						
Federal (percent)	τ^{fed}	35	35	35	35	35
State (percent)	τ^{state}	4	4	4	4	4
Financing						
Debt						
Share (percent)	α	45	45	45	45	45
Rate of return (percent)	r^{debt}	8	8	8	8	8
Term of debt (years)	t^{debt}	20	20	20	20	20
Equity						
Share (percent)	$1 - \alpha$	55	55	55	55	55
Rate of return for equity (percent)	r^{equity}	14	14	14	14	14
Inflation (percent)	i	2	2	2	2	2

Source: Congressional Budget Office.

Notes: MW = megawatt; Btu = British thermal unit; MWh = megawatt hour; O&M = operating and maintenance; n.a. = not applicable; CO_2 = carbon dioxide.

Electricity-generating capacity is measured in MW; the electrical power generated by that capacity is measured in MWh. During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.

In CBO's analysis, advanced nuclear technology refers to third-generation reactors. Conventional coal plants are assumed to use pulverized coal technology, which produces energy by burning a crushed form of solid coal. Conventional natural gas power plants are assumed to convert gas into electricity using combined-cycle turbines.

a. The waste disposal fee is assumed to have a constant nominal value.

b. For simplicity, incremental capital costs are considered operating costs.

c. Carbon intensities are taken from Deutsch and Joskow (2003).

Table A-2.

Components of Cost

Type of Cost	Nominal Value in Year t (Dollars per MW)
Up-front Costs	
Licensing and design[a]	$C_{t,licen} = 10{,}000 \times (1+i)^{(t-2006)}$ for $t = 2006$ to 2011
Construction[b]	$C_{t,constr} = C^{overn} \times (1+i)^{(t-2006)} \times \delta \times \sin\left(\frac{t - 2017.5 - t^{constr}}{t^{constr}}\right)$ for $t = 2018 - t^{constr}$ to 2017
Operating Costs (for $t = 2018$ to 2057)	
Fuel	$C_{t,fuel} = Q \times c^{fuel} \times h \times (1+i)^{(t-2006)}$
Variable operating and maintenance	$C_{t,varOM} = Q \times c^{varOM} \times (1+i)^{(t-2006)}$
Spent-fuel disposal	$C_{sptfuel} = Q \times c^{sptfuel}$
CO_2 transport and storage[c]	$C_{t,seq} = Q \times h \times i^{CO_2} \times e^{CO_2}(1+i)^{(t-2006)}$
Other operating costs[d]	$C_{t,X} = C_X \times (1+i)^{(t-2006)}$

Source: Congressional Budget Office.

Notes: MW = megawatt; CO_2 = carbon dioxide.

Electricity-generating capacity is measured in megawatts; the electrical power generated by that capacity is measured in megawatt hours.

a. Licensing and design costs are incorporated only for nuclear technology, because such costs are expected to be relatively small for conventional fossil-fuel technologies. However, innovative fossil-fuel technologies with carbon capture-and-storage (CCS) capability may incur substantial licensing and design costs; so in that regard, the results of the analysis would tend to understate the cost advantage of nuclear technology over innovative technologies.

b. The symbol δ is a constant of integration that is selected so the sum of construction costs across years (in 2006 dollars) equals the assumed overnight cost (the cost of building a plant as if it were built and paid for overnight). The values of the constant of integration depend on construction time.

c. Costs for the transport and storage of CO_2 would be a factor only for innovative fossil-fuel plants with CCS capability throughout the analyses. CCS facilities incur the costs of capture and storage even though there is no private incentive for capturing and storing CO_2 in the scenarios in the absence of carbon dioxide charges.

d. Other operating costs include fixed operating and maintenance, liability insurance, decommissioning, and incremental capital costs. For simplicity, the cost of incremental capital is included as an operating expense although such charges may be depreciated.

Table A-3.

Revenue, Tax, and Financing Components

Type of Cost	Nominal Value in Year *t* (Dollars per MW)
Revenue	
Net revenue	$R_{t,\,net} = (1+i)^{(t-2006)} \times p^{real} \times Q - T_{t,\,fed} - T_{t,\,state}$
State income tax	$T_{t,\,state} = Max(0, \tau^{state} \times (R_{t,\,gross} - C_{t,\,oper} - r^{debt} \times B_{t,\,debt} - D_{t,\,capital}))$
Federal income tax	$T_{t,\,fed} = Max(0, \tau^{fed} \times (R_{t,\,gross} - C_{t,\,oper} - r^{debt} \times B_{t,\,debt} - D_{t,\,capital} - T_{t,\,state}))$
Capitalized deduction	$D_{t,\,capital} = r_t^{MACRS} \sum_t C_{t,\,constr} + C_{t,\,licen}$
Financing	
Debt	
Balance	$B_{t,\,debt} = (1+r^{debt}) \times B_{t-1,\,debt} + I_{t,\,debt} - P_{tdebt}$
Issue	$I_{t,\,debt} = \alpha \times C_{t,\,constr}$
Payment	$P_{t,\,debt} = B_{2017,\,debt} \times \dfrac{(1+r^{debt})^{t^{debt}} \times r^{debt}}{(1+r^{debt})^{t^{debt}} - 1}$
Equity	
Balance	$B_{t,\,equity} = (1+r_t^{equity}) \times B_{t-1,\,equity} + I_{t,\,equity} - P_{t,\,equity}$
Issue	$I_{t,\,equity} = (1-\alpha) \times C_{t,\,constr} + C_{t,\,licen}$
Payment	$P_{t,\,equity} = R_{t,\,net} - C_{t,\,oper} - P_{t,\,debt}$

Source: Congressional Budget Office.

Notes: MW = megawatt.

Electricity-generating capacity is measured in megawatts (MW); the electrical power generated by that capacity is measured in megawatt hours (MWh). During a full hour of operation, 1 MW of capacity produces 1 MWh of electricity, which can power roughly 800 average households.

Table A-4.

Prospective Carbon Dioxide Charges by Stringency of Cap

(2006 dollars per metric ton of CO_2)

	Carbon Dioxide Constraints		
	No Cap on Emissions	Emissions Capped at 2008 Level	Emissions Capped at 80 Percent Below 1990 Level by 2050
2015	0	19	55
2020	0	23	67
2025	0	27	81
2030	0	33	99
2035	0	40	121
2040	0	48	146
2045	0	59	177
2050	0	72	217

Source: Congressional Budget Office.

Notes: CO_2 = carbon dioxide.

Carbon dioxide charges are the permit prices estimated for the specified cap in Sergey Paltsev and others, *Assessment of U.S. Cap-and-Trade Proposals,* Working Paper No. 13176 (Cambridge, Mass.: National Bureau of Economic Research, June 2007). Costs for other greenhouse gas emissions that would be regulated under those cap-and-trade programs are not included, which understates the levelized cost for fossil-fuel technologies. CBO interpolated the data to get CO_2 charges between the five-year intervals and extrapolated the data to obtain CO_2 charges through 2057.

Table A-5.

Assumptions for the Loan Guarantee Provided Under EPAct

	Reference Scenario (Percent)	Reference Scenario with EPAct Incentives (Percent)
Guaranteed Debt		
Share	0	80
Rate of return	n.a.	5 1/2
Nonguaranteed Debt		
Share	45	0
Rate of return	8	n.a.
Equity		
Share	55	20
Rate of return[a]	14	15 3/4

Source: Congressional Budget Office.

Notes: EPAct = Energy Policy Act of 2005; n.a. = not applicable.

As illustrated in the table, construction costs are financed with guaranteed debt, nonguaranteed debt, and equity. Licensing and design costs and subsidy costs are financed entirely with equity.

a. The required rate of return under the reference scenario with EPAct incentives is determined within the model and is 15.6 percent for nuclear technology and 15.8 percent for innovative fossil-fuel technologies.