Levelized Costs of New Generation Resources in the Annual Energy Outlook

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Introduction

Every year, we publish updates to our *Annual Energy Outlook* (AEO), which provides long-term projections of energy production and consumption in the United States using our National Energy Modeling System (NEMS). The AEO reports our projections based on specific assumptions and methodologies.

Investment in the expansion of electric generation capacity requires an assessment of the competitive value of generation technologies in the future. To better understand investment decisions in NEMS, we use specialized measures that simplify those modeled decisions. Levelized cost of electricity (LCOE) refers to the estimated revenue required to build and operate an electric-generation plant over a specified cost recovery period. Levelized avoided cost of electricity (LACE) is the revenue available to that plant owner during the same period. Beginning with AEO2021, we include estimates for the levelized cost of storage (LCOS) for diurnal storage technology. Although LCOE, LCOS, and LACE do not fully capture all the factors considered in NEMS, when used together as a value-cost ratio (the ratio of LACE-to-LCOE or LACE-to-LCOS), they provide a reasonable comparison of first-order economic competitiveness among a wider variety of technologies than is possible using LCOE, LCOS, or LACE individually.

Levelized Cost of Electricity and Levelized Cost of Storage

The levelized cost of electricity (LCOE) represents the average revenue per unit of electricity generated that would be required to recover the costs of building and operating a generation plant during an assumed cost recovery period and for a specific duty cycle.[1] LCOE is often cited as a convenient summary measure of the overall competiveness of different generation technologies.

The levelized cost of storage (LCOS) represents the average revenue per unit of electricity discharged that would be required to recover the costs of building and operating a battery storage facility during an assumed cost recovery period and for a specific duty cycle. Although the concept is similar to LCOE, LCOS is different in that, rather than being a primary source of energy, it represents an energy storage technology that contributes to electricity generation when discharging and consumes electricity from the grid when charging. Furthermore, LCOS is calculated differently depending on whether it is supplying electricity to the grid or is on standby providing grid reliability services. In NEMS, we model battery storage in both energy arbitrage applications (where the storage technology provides energy to the grid during periods of high-cost generation and recharges during periods of lower-cost generation) and resource adequacy and spinning reserve requirements.

Key inputs[2] to calculating LCOE and LCOS include:

- Capital costs
- Fixed operations and maintenance (O&M) costs
- Variable costs that include O&M and fuel costs

[1] *Duty cycle* refers to the typical utilization or dispatch of a plant to serve base, intermediate, or peak load. Wind, solar, or other intermittently available resources are not dispatched and do not necessarily follow a duty cycle based on load conditions.
[2] The specific assumptions for each of these factors are provided in the *Assumptions to the Annual Energy Outlook*.

- Financing costs
- An assumed utilization rate for each plant type, corresponding to a typical duty cycle for dispatchable technologies or typical resource availability factor for resource-constrained technologies.

For LCOS, in lieu of fuel cost, the levelized variable cost includes the cost of purchasing electricity from the electric power grid for charging. The importance of each of these factors varies across technologies. For technologies with no fuel costs and relatively small variable costs, such as solar and wind electric-generating technologies, LCOE changes nearly in proportion to the estimated capital cost of the technology. For technologies that use fuel, both fuel cost and capital cost estimates significantly affect LCOE. Incentives, including federal tax credits, also affect the calculation of LCOE. As with any projection, these factors are uncertain because their values can vary regionally and temporally as technologies evolve and as fuel prices change. Solar photovoltaic-battery (PV-battery) hybrid technology is represented by LCOE and not LCOS because we assume it solely operates as an integrated unit supplying primary electricity to the grid, with the storage component simply allowing the dispatch of that energy during non-daylight hours.

Actual plant investment decisions consider the specific technological and regional characteristics of a project, which involve many other factors not reflected in LCOE (or LCOS) values. One factor is the difference between the assumed technology duty cycle used in the LCOE calculation and the projected utilization rate, which depends on the amount of electricity required over time and the existing resource mix in an area where additional capacity is needed. A related factor is the capacity value (the ability to contribute to regional resource adequacy reserve margins), which depends on both the existing capacity mix and the load characteristics in a region. Because load must be continuously balanced, generating units that can vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units that use intermittent resources to operate (resource-constrained technologies). We list the LCOE values for dispatchable and resource-constrained technologies separately because they are built to provide different services to the grid, and direct comparisons of cost between dispatchable and resource-constrained technologies may not be meaningful in most contexts. We include the PV-battery hybrid LCOE under resource-constrained technologies because it is more limited in dispatch capability than generators with essentially continuous fuel supply. Combustion turbine and battery storage technologies are often used to meet regional capacity reserve requirements or when intermittent resources are not available for generation, such as during evening peak demand periods, and we show them as capacity resource technologies.

Representation of tax incentives

Federal tax credits for electric generation facilities can substantially reduce their realized cost. Cost estimates in this report are for generators in the electric power sector, which are generally eligible for federal tax credits for certain technologies. These estimates are not for systems in the residential or commercial sectors. Where applicable, we show LCOE both with and without tax credits that we assume would be available in the year in which the plant enters service. For further detail on NEMS representation of tax credits, see the Renewable Fuels Module (RFM) and Electricity Market Module (EMM) assumptions.

Levelized Avoided Cost of Electricity

LCOE and LCOS by themselves do not capture all of the factors that contribute to actual investment decisions, making direct comparisons of LCOE and LCOS across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives. In 2013, we developed levelized avoided cost of electricity (LACE) as a companion metric for LCOE to improve comparisons of economic competitiveness between generation technologies.

LACE provides a proxy measure for potential revenues (or value) from the sale of electricity generated or other ancillary services produced from a candidate project displacing (or the cost of avoiding) another marginal asset. We sum this value over a project's financial life and convert that sum into an annualized value (that is, dividing by the average annual electrical output of the project). Using LACE along with LCOE and LCOS provides a more intuitive indication of economic competitiveness for each technology than either metric separately when several technologies are available to meet load and provide other service requirements.

Estimating LACE is more complex than estimating LCOE or LCOS because it requires information about how the electrical generators on the grid would operate without the new power plant or storage facility entering service. We calculate LACE based on the marginal value of energy, capacity, and spinning reserves that would result from adding a unit of a given technology to the grid as it exists or as we project it to exist at a specific future date. It also takes into account a limit on annual intermittent generation.[3] LACE accounts for both the variation in daily and seasonal electricity demand and the characteristics of the existing generation fleet to which new capacity will be added. Therefore, LACE compares the prospective new generation resource against the mix of new and existing generation and capacity that it would displace. For example, a wind resource that would primarily displace generation from a relatively expensive natural gas-fired peaking unit will usually have a different value than one that would displace generation from a more efficient natural gas-fired, combined-cycle unit or coal-fired unit with low fuel costs.

Value-Cost Ratio

We calculate LACE-to-LCOE and LACE-to-LCOS ratios (or value-cost ratios) for each technology to determine which project provides the most value relative to its cost. When the LACE of a particular technology exceeds its LCOE or LCOS, that technology would generally be economically attractive to build. A value-cost ratio greater than one indicates that the marginal new unit brings in value higher than its cost by displacing more expensive generation and capacity options, and a value index of less than one indicates that the cost of the marginal new unit of capacity exceeds its value to the system.

The value-cost ratio of one represents a stable solution point (breakeven point) where LACE equals LCOE. Both LCOE or LCOS and LACE values are determined within an optimization model, which generally represents efficient markets. If the LCOE or LCOS exceeds LACE for a given technology, the

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[3] EIA currently models a limit of 70% of annual generation within an electricity region coming from wind and solar energy because our model currently lacks the resolution or model structure to accurately represent the cost of providing reliable generation services under very high penetration levels of intermittent resources.

model generally finds it uneconomical to build that technology unless forced by factors outside the LCOE and optimization framework. In most cases when the LACE for a given technology exceeds its LCOE or LCOS, the model will build-out that technology to the point where the two values are equal. However, sometimes constraints on build rates or other model factors may limit the ability of the model to fully build-out an otherwise economically attractive technology, leading to occasional instances with a value-cost of of greater than one.

External factors such as technology change, policy developments, or fuel price volatility can cause divergence of LACE and LCOE or LCOS from the breakeven point and decrease the value-cost ratio of any given technology. LCOE can increase when federal tax credits expire or when operating fuel prices rise, although LCOE generally declines over time because of technological advancements through lower capital costs or improved performance. LACE can decrease over time, particularly for solar, as generation from solar resources become more saturated with similar hourly operation patterns within a given region, forcing generation from new facilities to compete with lower-cost options in the dispatch merit order. However, we expect the market to correct the divergence between LACE and LCOE. If the value-cost ratio becomes greater than one, the model (and the market) will quickly build-out the technology until it meets the demand growth or displaces the higher-cost marginal generation. In contrast, if the value-cost ratio becomes less than one, continued load growth, technology cost declines, or perhaps higher fuel costs for a competing resource will tend to boost its value over time.

However, LACE, LCOE, and LCOS are still simplified estimates of modeled decisions. The build decisions in actuality (and as we model in the AEO), however, are more complex than a simple LACE-to-LCOE or LACE-to-LCOS comparison because they include factors not included in the LCOE, LCOS, or LACE calculations, including some policy or economic factors that operate beyond the resolution of the model. Nonetheless, the value-cost ratio (the ratio of LACE-to-LCOE or LACE-to-LCOS) provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using LCOE, LCOS, or LACE individually.

LCOE, LCOS, and LACE Calculations

We calculate all levelized costs and values based on a 30-year cost recovery period, using an after-tax weighted average cost of capital (WACC).[4] In reality, a plant's cost recovery period and cost of capital can vary by technology type. The represented technologies are selected from available electric power sector technologies modeled in NEMS's Electricity Market Module (EMM).[5] We focus on technologies with the most impact on future capacity and not on technologies from distributed residential and commercial applications.

The levelized capital component reflects costs calculated using technology-specific tax depreciation schedules and a corporate tax rate consistent with current tax laws.[6] We evaluate LCOE, LCOS, and LACE

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[4] An overview of the WACC assumptions and methodology is available in the *Electricity Market Module of the National Energy Modeling System: Model Documentation*.

[5] The list of all technologies modeled in EMM is available in "Cost and performance characteristics of new central station electricity generation technologies" table of the *Assumptions to the Annual Energy Outlook: Electricity Market Module*.

[6] New power plant constructions are assumed to be financed using parameters as assumed in the *Assumptions to the Annual Energy Outlook: Electricity Market Module*.

for each technology based on an assumed capacity factor, which generally corresponds to the high end of the technology's likely utilization range. This convention is consistent with using LCOE and LCOS to evaluate competing technologies in baseload operation, such as coal and nuclear plants. Although sometimes used in baseload operation, some technologies, such as combined-cycle plants, are also built to serve load-following or other intermediate dispatch duty cycles. We evaluate combustion turbines that are typically used for peak-load duty cycles at a 10% capacity factor, which reflects the historical average utilization rate. We also evaluate battery storage at a 10% capacity factor, reflecting an expected use for energy arbitrage, especially with intermittent renewable generation such as solar. The duty cycle for intermittent resources is not operator controlled, but rather, depends on the weather, which does not necessarily correspond to operator-dispatched duty cycles. As a result, LCOE values for wind and solar technologies are not directly comparable with the LCOE values for other technologies that may have a similar average annual capacity factor, and we show them separately as resource-constrained technologies. Hydroelectric resources, including facilities where storage reservoirs allow more flexible day-to-day operation, and PV-battery hybrid technologies generally have significant seasonal and daily variation, respectively, in availability. We label them as resource-constrained to discourage comparison with technologies that have more consistent seasonal and diurnal availability. The capacity factors for solar, wind, and hydroelectric resources are the average of the capacity factors (weighted or unweighted) for the marginal site in each region, taking into account estimated curtailments[7] that can vary significantly by region and will not necessarily correspond to the cumulative projected capacity factors for both new and existing units for resources in the AEO or our other analyses.

Levelized cost of electricity (LCOE)

The computation for LCOE takes the following general form:

$$\text{LCOE} = \frac{(\text{fixed charge factor} \times \text{capital cost}) + \text{fixed O\&M}}{\text{generating hours}} + \text{variable O\&M} + \text{fuel}$$

where:

LCOE	=	the levelized cost of electricity, expressed in units of dollars per megawatthour ($/MWh)
fixed charge factor	=	annualizes the capital cost, accounting for the weighted average cost of capital (return on debt and return on equity), federal tax burden for the project, and the assumed cost recovery period for the project. This factor is estimated using a cash-flow model within NEMS and may vary over time due to changes to the cost of debt and cost of equity. The factor also may vary across technologies due to differing tax depreciation treatments and

[7] Intermittent resources such as wind or solar may sometimes generate at levels in excess of immediate electricity demand. If storage is not available to absorb the excess generation, it will be curtailed to ensure system stability. That is, unit operators will be instructed to turn-off or temporarily disconnect from the grid until the grid can safely accommodate the generation. Curtailed generation does not provide value to the grid and is deducted from technology capacity factors.

		market risks associated with certain carbon-intensive generation options.
capital cost	=	the initial investment per unit of capacity in the project, expressed in dollars per megawatt ($/MW). For any given technology, this cost may vary over time based on a number of factors, including declining technology costs due to learning and cost adjustments from broader economic factors, such as the construction commodity costs and resource availability for geographically constrained energy sources such as wind, geothermal, or hydro.
fixed O&M	=	the annual operations and maintenance expenditure per unit of capacity, expressed in dollars per megawatt per year ($/MW/year). This expenditure includes costs that remain relatively constant, regardless of plant utilization levels, such as worker salaries and maintenance or refurbishment costs that are scheduled on a calendar basis rather than an operating-hours basis.
generating hours	=	the number of hours per year that the plant is assumed to operate. For dispatchable generation such as coal, nuclear, or natural gas-fired plants, we calculate this number based on an annual capacity factor that corresponds to the maximum annual availability for that unit, accounting for planned maintenance and forced outages. Alternatively, in the case of units primarily serving peak load, including battery storage, this calculation is based on a 10% annual capacity factor. For intermittent renewable resources, the calculation is based on location-specific resource availability.
variable O&M	=	the operations and maintenance expenditure per unit of generation, expressed in dollars per megawatthour ($/MWh.) This expenditure includes costs that are closely tied to the actual operating hours of the equipment, such as consumable maintenance items and refurbishment costs that are scheduled based on operating hours (rather than on a calendar basis).
fuel	=	the expenditure for fuel, expressed in terms of dollars per megawatthour ($/MWh.) Fuel cost is the product of the plant heat rate (a measure of unit conversion efficiency) and the fuel price in native units (for example, dollars per thousand cubic feet for natural gas or dollars per ton for coal). For battery storage, the cost of grid charging is used as a proxy for fuel.

These costs represent the hourly average of the long-term fuel costs over the assumed financial life of the equipment (not the fuel costs for the single year for which the estimate is provided).

LCOE example

Consider a wind turbine with a capital cost of $2,000 per kilowatt (kW) ($2 million/MW) and a fixed O&M cost of $40/kW/year ($40,000/MW/year). The wind turbine has no fuel cost and no variable O&M. The fixed charge factor for wind, accounting for the standard five-year MACRS[8] depreciation, is 9% per year. The capacity factor is an average of 30% per year. Tax credits are not included in this example for simplicity.

- Annualized capital cost = $2 million/MW × 9% =$180,000/MW/year
- Total annual expenditure = $180,000/MW/year + $40,000/MW/year = $220,000/MW/year
- Expected generation = 30% × 8,760 hours/year = 2,628 hours/year
- Levelized cost = $220,000/MW/year ÷ 2,628 hours/year= $84/MWh

Levelized avoided cost of electricity (LACE)

LACE takes the following general form:

$$\text{LACE} = \frac{\text{energy revenue} + \text{spinning reserve revenue} + \text{capacity revenue} - \text{intermittent limit cost}}{\text{generating hours}}$$

where:

LACE	=	the levelized avoided cost of electricity, expressed in units of dollars per megawatthour ($/MWh.)
energy revenue	=	the revenue derived from serving load to meet the demand in a year, in units of dollars per megawatt per year ($/MW/year.) Energy revenue is calculated as the marginal generation price (in units of dollars per megawatthour or $/MWh) multiplied by the dispatch hours in the time period (in units of hours). The marginal generation price is typically determined by the variable cost (fuel cost plus variable O&M) of the most expensive generating unit that needs to be dispatched to meet energy demand. This price may also be affected by the cost of meeting any environmental or portfolio policy requirements by the marginal generators (that is, the cost of purchasing renewable energy credits for a non-qualifying generator) or by the cost to meet the intermittent limit constraint. The dispatch hours are the number of hours in the specific time period (summer, winter, and spring/fall and peak, intermediate, and off-peak)

[8] The Modified Accelerated Cost Recovery System (MACRS) is the current depreciation method for most assets for the purpose of federal taxes. Under MACRS, certain types of equipment have more rapid depreciation schedules relative to some other asset types.

		the unit is dispatched multiplied by the capacity factor in that time period.
spinning reserve revenue	=	the revenue made from providing spinning reserves based on the technology's ability to contribute excess capacity to the overall peak load, in units of dollars per megawatt per year ($/MW/year.) This revenue is calculated as the spinning reserve price multiplied by the spinning reserve hours over a time period. Spinning reserve price is the cost of procuring reserves, and it is typically determined by the variable cost (fuel cost plus variable O&M) of the most expensive unit that is providing spinning reserves to meet the requirement. Spinning reserve hours are the number of hours in a time period that the unit is providing spinning reserves. Generation from intermittent technologies, including wind and solar, adds to the spinning reserve requirement because more variable renewable generation means more uncertainty, so those intermittent technologies have a negative spinning reserve revenue.
capacity revenue	=	the revenue made by providing capacity to meet the planning reserve margin reliability requirement over all years in a unit's lifetime per megawatt of capacity, in units of dollars per megawatt per year ($/MW/year.) This revenue is calculated as the capacity payment times the capacity credit of the technology. Capacity payment is the payment required to incentivize the last unit to meet the regional planning reserve margin reliability requirement to the grid. Capacity credit is the technology's ability to provide system reliability reserves. For dispatchable units, the entire nameplate capacity is allowed to participate in the reliability capacity market (capacity credit of 1, or 100%). For intermittent renewables, the capacity credit is derated as a function of the availability of the resource during peak load periods and the estimated probability of correlated resource-derived outages within a given region.
intermittent limit cost	=	the cost of limiting the annual intermittent generation in each region over each year of its lifetime, in units of dollars per megawatt per year ($/MW/year.) The intermittency limit is included as a constraint in EMM based on modeler judgement because the model lacks the model resolution to accurately represent system reliability and stability with very high levels of wind and solar generation; it does not represent actual current or assumed policy with respect to any current grid operator. If this limit is hit, the EMM produces a figure that reflects how

much total system costs could be reduced if the model was allowed build capacity beyond the intermittency limit, or conversely, the loss in value to the system of imposing the intermittency limit. It is, therefore, included as a reduction in the value (LACE). This cost is non-zero only in regions and years in which the intermittency limit is met.

generating hours = the number of hours per year that the plant is assumed to operate; the derivation is identical to that described in the LCOE section.

LACE Example

EMM projects marginal generation price for nine time periods each year, representing the peak hours, intermediate hours, and off-peak hours during the winter, summer, and spring/fall seasons.

The following example examines the same wind turbine mentioned in the previous example. We calculate the number of dispatched hours for each period by multiplying the number of hours in that period by the corresponding assumed capacity factor. The energy revenue available for each period, in units of dollars per megawatt per year, is calculated by multiplying dispatched hours by the marginal generation price (Table 1).

Table 1. Energy value

Time period						
Season	**Hour type**	**Marginal generation price (dollars per megawatthour)**	**Capacity factor (percent)**	**Hours in period**	**Dispatched hours**	**Energy revenue per megawatt per year**
Summer	Peak	$110	20%	29	5.8	$638
	Intermediate	$90	30%	1,435	430.5	$38,745
	Off-peak	$80	20%	1,464	292.8	$23,424
Winter	Peak	$90	30%	29	8.7	$783
	Intermediate	$80	20%	1,423	284.6	$22,768
	Off-peak	$70	35%	1,452	508.2	$35,574
Spring/fall	Peak	$80	30%	29	8.7	$696
	Intermediate	$70	40%	1,435	574	$40,180
	Off-peak	$60	35%	1,464	512.4	$30,744
Annual total					**2,626**	**$193,552**

Data source: U.S. Energy Information Administration

Because of the uncertainty of its output, we assume that additional spinning reserves equal to 25% of wind generation will need to be maintained. This value is based on an analysis of historical wind generation versus operational forecasts. We calculate the number of spinning reserve hours for each period by multiplying the number of hours in that period by the corresponding spinning reserve assessment factor (Table 2). The cost available for each period is calculated by multiplying the spinning reserve hours by the spinning reserve price. We then subtract the total spinning reserve cost from the wind revenue because wind is increasing the need for spinning reserve (that is, adding to cost, rather than increasing its value to the system in this respect).

Table 2. Spinning reserve value

Season	Hour type	Spinning reserve price (dollars per megawatthour)	Spinning reserve assessment factor (percent)	Hours in period	Spinning reserve hours	Spinning reserve cost per megawatt per year
Summer	Peak	$300	5%	29	1.5	$435
	Intermediate	$10	7.5%	1,435	107.6	$1,076
	Off-peak	$0	5%	1,464	73.2	$0
Winter	Peak	$90	7.5%	29	2.2	$196
	Intermediate	$10	5%	1,423	71.2	$712
	Off-peak	$0	8.75%	1,452	127.1	$0
Spring/fall	Peak	$5	7.5%	29	2.2	$11
	Intermediate	$0	10%	1,435	143.5	$0
	Off-peak	$0	8.75%	1,464	128.1	$0
Annual total					**657.0**	**$2,429**

Data source: U.S. Energy Information Administration

In the region used in this example, wind has a capacity credit of 15% and a capacity payment of $60,000/MW/year. The wind plant does not have a binding intermittent limit constraint, so the intermittent cost of this constraint is $0.

The wind plant earns an energy revenue of $193,552/MW/year, accrues a spinning reserve cost of $2,429/MW/year, and receives a capacity payment of 15% × $60,000/MW/year = $9,000/MW/year. The total annual revenue stream is $200,123/MW/year. With annual generation of 2,628 MWh/MW (2,628 equivalent operating hours), the average revenue per megawatthour for this plant is $76/MWh.

Value-cost ratio

The value-cost ratio is simply the ratio between the LACE (value) and the LCOE (cost) and can be thought of as the value-per-cost (unitless) for the plant. Generally, the value-cost ratio includes tax incentives in the LCOE to show a given technology's competitiveness within NEMS.

$$\text{value-cost ratio} = \frac{\text{LACE}}{\text{LCOE}}$$

Value-cost ratio example

From the examples above, the wind plant has LCOE of $84/MWh and LACE of $76/MWh, resulting in a value-cost ratio of 0.905.