



## Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013

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This paper presents average levelized costs for generating technologies that are brought on line in 2018<sup>1</sup> as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2013* (AEO2013) Early Release Reference case.<sup>2</sup> Both national values and the minimum and maximum values across the 22 U.S. regions of the NEMS electricity market module are presented.

Levelized cost is often cited as a convenient summary measure of the overall competitiveness of different generating technologies. It represents the per-kilowatthour cost (in real dollars) of building and operating a generating plant over an assumed financial life and duty cycle. Key inputs to calculating levelized costs include overnight capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.<sup>3</sup> The importance of the factors varies among the technologies. For technologies such as solar and wind generation that have no fuel costs and relatively small O&M costs, the levelized cost changes in rough proportion to the estimated overnight capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect the levelized cost. The availability of various incentives, including state or federal tax credits, can also impact the calculation of levelized cost. The values shown in the tables in this discussion do not incorporate any such incentives.<sup>4</sup> As with any projection, there is uncertainty about all of these factors and their values can vary regionally and across time as technologies evolve and fuel prices change.

It is important to note that, while levelized costs are a convenient summary measure of the overall competitiveness of different generating technologies, actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other considerations. The **projected utilization rate**, which depends on the load shape and the existing resource mix in an area where additional capacity is needed, is one such factor. The **existing resource mix** in a region can directly affect the economic viability of a new investment through its effect on the economics surrounding the displacement of existing resources. For example, a wind resource that would primarily displace existing natural gas

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<sup>1</sup> 2018 is shown because the long lead time needed for some technologies means that the plant could not be brought on line prior to 2018 unless it was already under construction.

<sup>2</sup> The full report is available at <http://www.eia.gov/forecasts/aeo/er/index.cfm>.

<sup>3</sup> 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>.

<sup>4</sup> These results do not include targeted tax credits such as the production or investment tax credit available for some technologies. Costs are estimated using tax depreciation schedules consistent with current law, which vary by technology.

generation will usually have a different value than one that would displace existing coal generation.

A related factor is the **capacity value**, which depends on both the existing capacity mix and load characteristics in a region. Since load must be balanced on a continuous basis, units whose output can be varied to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies) or those whose operation is tied to the availability of an intermittent resource. The levelized costs for dispatchable and nondispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Since projected utilization rates, the existing resource mix, and capacity values can all vary dramatically across regions where new generation capacity may be needed, the direct comparison of the levelized cost of electricity across technologies is often problematic and can be misleading as a method to assess the economic competitiveness of various generation alternatives. Conceptually, a better assessment of economic competitiveness can be gained through consideration of avoided cost, a measure of what it would cost the grid to generate the electricity that is otherwise displaced by a new generation project, as well as its levelized cost. Avoided cost, which provides a proxy measure for the annual economic value of a candidate project, may be summed over its financial life and converted to a stream of equal annual payments, which may then be divided by average annual output of the project to develop a figure that expresses the “levelized” avoided cost of the project. This levelized avoided cost may then be compared to the levelized cost of the candidate project to provide an indication of whether or not the project’s value exceeds its cost. If multiple technologies are available to meet load, comparisons of each project’s levelized avoided cost to its levelized project cost may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than for simple levelized costs, because they require tools to simulate the operation of the power system with and without any project under consideration. The economic decisions regarding capacity additions in EIA’s long-term projections reflect these concepts rather than simple comparisons of levelized project costs across technologies.

Policy-related factors, such as investment or production tax credits for specified generation sources, can also impact investment decisions. Finally, although levelized cost calculations are generally made using an assumed set of capital and operating costs, the inherent uncertainty about future fuel prices and future policies, may cause plant owners or investors who finance plants to place a value on **portfolio diversification**. While EIA considers many of these factors in its analysis of technology choice in the electricity sector, these concepts are not well represented in the context of levelized cost figures.

The levelized cost shown for each utility-scale generation technology in the tables in this discussion are calculated based on a 30-year cost recovery period, using a real after tax weighted average cost of capital (WACC) of 6.6 percent. In reality, the cost recovery period and cost of capital can vary by technology and project type. In the AEO2013 reference case a 3-percentage point increase in the cost of capital is added when evaluating investments in

greenhouse gas (GHG) intensive technologies like coal-fired power and coal-to-liquids (CTL) plants without carbon control and sequestration (CCS). While the 3-percentage point adjustment is somewhat arbitrary, in levelized cost terms its impact is similar to that of an emissions fee of \$15 per metric ton of carbon dioxide (CO<sub>2</sub>) when investing in a new coal plant without CCS, similar to the costs used by utilities and regulators in their resource planning. 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.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale plants and distributed end-use residential and commercial applications. As noted above, the levelized cost calculations presented in the tables apply only to utility-scale use of those technologies.

In the tables in this discussion, the levelized cost for each technology is evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30-percent capacity factor. The duty cycle for intermittent renewable resources, wind and solar, is not operator controlled, but dependent on the weather or solar cycle (that is, sunrise/sunset) and so will not necessarily correspond to operator dispatched duty cycles. 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) and therefore are shown in separate sections within each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Table 1 are simple averages of the capacity factor for the marginal site in each region. These capacity factors can vary significantly by region and can represent resources that may or may not get built in EIA capacity projections. These capacity factors should not be interpreted as representing EIA's estimate or projection of the gross generating potential of resources actually projected to be built.

As mentioned above, the costs shown in Table 1 are national averages. However, as shown in Table 2, there is significant regional variation in levelized costs based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, levelized wind costs for incremental capacity coming on line in 2018 range from \$73.5/MWh in the region with the best available resources in 2018 to \$99.8/MWh in regions where levelized costs are highest due to lower quality wind resources and/or higher capital costs at the best sites where additional wind capacity could be added. Costs shown 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.

**Table 1. Estimated levelized cost of new generation resources, 2018**

Plant type	U.S. average levelized costs (2011 \$/megawatthour) for plants entering service in 2018					
	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
<b>Dispatchable Technologies</b>						
Conventional Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced Coal	85	84.4	6.8	30.7	1.2	123.0
Advanced Coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural Gas-fired						
Conventional Combined Cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced Combined Cycle	87	17.4	2.0	45.0	1.2	65.6
Advanced CC with CCS	87	34.0	4.1	54.1	1.2	93.4
Conventional Combustion Turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced Combustion Turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced Nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111.0
<b>Non-Dispatchable Technologies</b>						
Wind	34	70.3	13.1	0.0	3.2	86.6
Wind - Offshore	37	193.4	22.4	0.0	5.7	221.5
Solar PV <sup>1</sup>	25	130.4	9.9	0.0	4.0	144.3
Solar Thermal	20	214.2	41.4	0.0	5.9	261.5
Hydro <sup>2</sup>	52	78.1	4.1	6.1	2.0	90.3

<sup>1</sup> Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>2</sup> As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: These results do not include targeted tax credits such as the production or investment tax credit available for some technologies, which could significantly affect the levelized cost estimate. For example, new solar thermal and PV plants are eligible to receive a 30-percent investment tax credit on capital expenditures if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plants are eligible to receive either: (1) a \$22 per MWh (\$11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if placed in service before the end of 2013 (or 2012, for wind only).

Source: U.S. Energy Information Administration, Annual Energy Outlook 2013, December 2012, DOE/EIA-0383(2012)

**Table 2. Regional variation in levelized cost of new generation resources, 2018**

Range for total system levelized costs (2011 \$/megawatthour) for plants entering service in 2018			
Plant type	Minimum	Average	Maximum
<b>Dispatchable Technologies</b>			
Conventional Coal	89.5	100.1	118.3
Advanced Coal	112.6	123.0	137.9
Advanced Coal with CCS	123.9	135.5	152.7
Natural Gas-fired			
Conventional Combined Cycle	62.5	67.1	78.2
Advanced Combined Cycle	60.0	65.6	76.1
Advanced CC with CCS	87.4	93.4	107.5
Conventional Combustion Turbine	104.0	130.3	149.8
Advanced Combustion Turbine	90.3	104.6	119.0
Advanced Nuclear	104.4	108.4	115.3
Geothermal	81.4	89.6	100.3
Biomass	98.0	111.0	130.8
<b>Non-Dispatchable Technologies</b>			
Wind	73.5	86.6	99.8
Wind - Offshore	183.0	221.5	294.7
Solar PV <sup>1</sup>	112.5	144.3	224.4
Solar Thermal	190.2	261.5	417.6
Hydro <sup>2</sup>	58.4	90.3	149.2

<sup>1</sup> Costs are expressed in terms of net AC power available to the grid for the installed capacity.

<sup>2</sup>As modeled, hydro is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

Note: The levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region, which can vary significantly by region. The capacity factor ranges for these technologies are as follows: Wind – 30% to 39%, Wind Offshore – 33% to 42%, Solar PV- 22% to 32%, Solar Thermal – 11% to 26%, and Hydro – 30% to 65%. The levelized costs are also affected by regional variations in construction labor rates and capital costs as well as resource availability.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2013, December 2012, DOE/EIA-0383(2012)