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Levelized Cost and Levelized Avoided Cost of New Generation Resources in the Annual Energy Outlook 2017

This paper presents average values of levelized costs and levelized avoided costs for generating technologies entering service in 2019, 2022,[1] and 2040 as represented in the National Energy Modeling System (NEMS) for the *Annual Energy Outlook 2017* (AEO2017) Reference case.[2] The costs for generating technologies entering service in 2022 are presented in the body of the report, with those for 2019[3] and 2040 included in Appendices A and B, respectively. Both a capacity-weighted average based on projected capacity additions across the 22 U.S. regions of the NEMS electricity market module (EMM) and a simple average of the regional values are provided, together with the range of regional values.

Levelized Cost of Electricity (LCOE) and its limitations

Levelized cost of electricity (LCOE) is often cited as a convenient summary measure of the overall competiveness of different generating technologies. It represents the per-kilowatthour cost (in discounted real dollars) of building and operating a generating plant over an assumed financial life and duty cycle[4]. Key inputs to calculating LCOE include capital costs, fuel costs, fixed and variable operations and maintenance (O&M) costs, financing costs, and an assumed utilization rate for each plant type.[5] 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 variable O&M costs, LCOE changes in rough proportion to the estimated capital cost of generation capacity. For technologies with significant fuel cost, both fuel cost and overnight cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits (see text box), can also impact the calculation of LCOE. 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 actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve numerous other factors not reflected in LCOE values. The ***projected utilization rate***, which depends on the load shape and the existing resource mix in

[1] The first year that all technologies are available is 2022, given the long lead time and licensing requirements for some technologies.
[2] AEO2017 reports are available at http://www.eia.gov/outlooks/aeo/index.cfm.
[3] Appendix A shows levelized cost of electricity values for plants coming online in 2019 for the subset of technologies available to be built in that year.
[4] Duty cycle refers to the typical utilization or dispatch of a plant to serve base, intermediate, or peak load. Plants using wind, solar, or other intermittently available resources are not dispatched and do not necessarily follow a duty cycle based on load conditions.
[5] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available at http://www.eia.gov/outlooks/aeo/assumptions/.

AEO2017 representation of tax incentives for renewable generation

Federal tax credits for certain renewable generation facilities have the potential to substantially reduce the realized cost of these facilities. Where applicable, the LCOE tables show both the cost without these tax credits, as well as the cost as adjusted for the tax credits assumed to be available in the year in which the plant enters service, as follows.

Production Tax Credit (PTC): New wind, geothermal, and biomass plants receive a $23/MWh ($12/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 if the plants are under construction before the end of 2016. After 2016, wind continues to be eligible for the production tax credit, but at a dollar per kilowatthour rate that declines by 20% in 2017, 40% in 2018, 60% in 2019, and expires completely in 2020. Based on documentation released by the Internal Revenue Service (IRS) (see https://www.irs.gov/irb/2016-23_IRB/ar07.html), EIA assumes that wind plants will be able to claim the credit up to four years after beginning construction. As a result, wind plants entering service in 2019 will receive the full credit, and those entering service in 2022 will receive $14/MWh (inflation-adjusted).

Investment Tax Credit (ITC): New solar PV and thermal plants are eligible to receive a 30% investment tax credit on capital expenditures if the plants are under construction before the end of 2019, after which the ITC tapers off for new starts to 26% in 2020, and 22% in 2021. In 2022, the ITC expires for residential systems and declines to 10% for business and utility-scale systems in that year and each year thereafter. All utility-scale plants not placed in service prior to January 1, 2024 receive a 10% ITC regardless of the date construction was commenced. Results in this levelized cost report only include utility-scale solar facilities and do not include distributed solar facilities. In NEMS, EIA assumes that new utility-scale solar PV plants will have a 2-year construction lead time and solar thermal plants a 3-year construction lead time. EIA assumes that all utility-scale solar plants entering service in 2019 receive the full 30% tax credit. PV plants entering service in 2022 receive 26%, whereas solar thermal plants entering service in 2022, having begun construction a year earlier receive 30%.

an area where additional capacity is needed, is one such factor. The ***existing resource mix*** in a region can directly impact 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 generation will usually have a different economic 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 LCOE values for dispatchable and non-dispatchable technologies are listed separately in the tables, because caution should be used when comparing them to one another.

Levelized Avoided Cost of Electricity (LACE) as an additional indicator

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 LCOE 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 level annualized value that is divided by average annual output of the project to develop its "levelized" avoided cost of electricity (LACE).[6] The LACE value may then be compared with the LCOE value for 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 LACE to its LCOE may be used to determine which project provides the best net economic value. Estimating avoided costs is more complex than estimating levelized costs because it requires information about how the system would have operated without the option under evaluation. In this discussion, the calculation of avoided costs is based on the marginal value of energy and capacity that would result from adding a unit of a given technology to the system as it exists or is projected to exist at a specified future date and represents the potential value available to the project owner from the project's contribution to satisfying both energy and capacity requirements. While the economic decisions for capacity additions in EIA's long-term projections use neither LACE nor LCOE concepts, the LACE and net economic values presented in this report are generally more representative of the factors contributing to the projections than looking at LCOE alone. However, both the LACE and LCOE estimates are simplifications of modeled decisions, and may not fully capture all decision factors or match modeled results.

Policy-related factors, such as environmental regulations and investment or production tax credits for specified generation sources, can also impact investment decisions. The LCOE and LACE values presented here are derived from the AEO2017 Reference case, which includes the impacts of the Clean Power Plan (CPP), state-level renewable electricity requirements as of November 2016, and an extension and phase-out of federal tax credits for renewable generation.

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 the factors discussed in the previous paragraphs in its analysis of technology choice in the electricity sector in NEMS, not all of these concepts are included in LCOE or LACE calculations.

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[6] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found in this article: http://www.eia.gov/renewable/workshop/gencosts/.

LCOE and LACE calculations

The LCOE values shown for each utility-scale generation technology in Table1a (regional values weighted based on projected capacity additions), Table 1b (unweighted average of regional values), and Table 2 (minimum and maximum range across regions) are calculated based on a 30-year cost recovery period, using a real after-tax weighted average cost of capital (WACC) of 5.5%.[7] In reality, the cost recovery period and cost of capital can vary by technology and project type. Because regulators and the investment community have continued to push energy companies to invest in technologies that are less greenhouse gas-intensive, there is considerable financial risk associated with major investments in long-lived power plants with a relatively higher rate of carbon dioxide emissions. The trend is captured in the AEO2017 Reference case through a 3-percentage-point adder to the cost of capital when evaluating investments in new coal-fired power plants, new coal-to-liquids (CTL) plants without carbon capture and storage (CCS), and pollution control retrofits. For AEO2017, two new coal-fired technologies are available that are compliant with the new source performance standard for carbon emissions under Section 111(b) of the Clean Air Act. One design only captures 30% of CO2 emissions and would still be considered a high emitter relative to other new sources and thus may continue to face potential financial risk if carbon emission controls are further strengthened. Another design captures 90% of CO2 emissions and would not face the same financial risk, and therefore does not receive the 3-percentage-point increase in cost of capital. As a result, the LCOE values for the coal-fired plant with 30% CCS are higher than they would be if the same cost of capital was used for all technologies.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with permanent tax law, which vary by technology. Since the literature and common usage of LCOE supports the reporting of LCOE both with and without tax credits, Tables 1a and 1b report both calculations for technologies where an investment or production tax credit is available for plants entering service in 2022. Tax credits are assumed to phase-out and expire based on current laws and regulations.

Some technologies, notably solar photovoltaic (PV), are used in both utility-scale generating plants and distributed end-use residential and commercial applications. The LCOE and LACE calculations presented in this paper apply only to the utility-scale use of those technologies. Costs are expressed in terms of net alternating current (AC) power available to the grid for the installed capacity.

Tables 1a and 1b show the LCOE for each technology as evaluated based on the capacity factor indicated, which generally corresponds to the high end of its likely utilization range. This convention is consistent with the use of LCOE to evaluate competing technologies in baseload operation. Some technologies, such as combined cycle plants, while sometimes used in baseload operation, are also built to serve load-following or other intermediate dispatch duty cycles.

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[7]The real WACC of 5.5% corresponds to a nominal after-tax rate of 7.8% for plants entering service in 2022. The WACC used to calculate LCOE for plants coming online in 2040, which is presented in Appendix B, is 7.8% nominal or 5.8% real. An overview of the WACC assumptions and methodology can be found in the *Electricity Market Module of the National Energy Modeling System: Model Documentation*. This report can be found at http://www.eia.gov/outlooks/aeo/nems/documentation/electricity/pdf/m068(2014).pdf.

Simple combustion turbines (conventional or advanced technology) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor, reflecting the upper-end of their potential utilization range. 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 LCOE values are not directly comparable to those for other technologies (even where the average annual capacity factor may be similar) and therefore are shown in a separate section (Non-Dispatchable Technologies) on each of the tables. The capacity factors shown for solar, wind, and hydroelectric resources in Tables 1a and 1b are averages of the capacity factor for the marginal site in each region, weighted by the projected capacity builds in each region for Table 1a and unweighted for Table 1b. These capacity factors can vary significantly by region. Projected capacity factors for these resources in the AEO2017 or other EIA analyses represent cumulative capacity additions (including existing units) and will not necessarily correspond to these levels.

The LCOE values shown in Table 1a are a weighted average of region-specific LCOE values using weights reflecting the regional shares of projected capacity builds; Table 1b reports an unweighted average across all 22 EMM regions. Table 2 shows the significant regional variation in LCOE values based on local labor markets and the cost and availability of fuel or energy resources such as windy sites. For example, without consideration of production tax credits, the LCOE for incremental onshore wind capacity coming online in 2022 ranges from $43.4/MWh in the region with the best available resources to $75.6/MWh in the region with lowest quality wind resources and/or higher capital costs for the best sites. In general, onshore wind plants will get built in regions that offer low costs and/or high value, so the weighted average cost across regions is closer to the low-end of the range, at $55.8/MWh. Costs shown for wind generators 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.

As previously indicated, LACE provides an estimate of the cost of generation and capacity resources displaced by a marginal unit of new capacity of a particular type, thus providing an estimate of the value of building such new capacity. This is especially important to consider for intermittent resources, such as wind or solar, that have substantially different duty cycles than the baseload, intermediate, and peaking duty cycles of conventional generators. Table 3 provides the range of LACE estimates for different capacity types. The LACE estimates in this table have been calculated assuming the same maximum capacity factor as in the LCOE. Values are not shown for combustion turbines, because combustion turbines are generally built for their capacity value to meet a reserve margin rather than to meet generation requirements and avoided energy costs.

When the LACE of a particular technology exceeds its LCOE at a given time and place, that technology would generally be economically attractive to build. While the build decisions in the real world, and as modeled in the AEO, are somewhat more complex than a simple LACE to LCOE comparison, including such factors as policy and non-economic drivers, the net economic value, or net difference between LACE and LCOE, provides a reasonable point of comparison of first-order economic competitiveness among a wider variety of technologies than is possible using either LCOE or LACE tables individually. In Table 4a and Table 4b, a negative difference indicates that the cost of the marginal new unit of capacity exceeds its value to the system, as measured by LACE; a positive difference indicates that the marginal new unit brings in value in excess of its cost by displacing more expensive generation and capacity options. The “Average Net Difference” represents the average of the “LACE minus LCOE” calculation, where the difference is calculated for each of the 22 regions. This range of differences is not based on the difference between the minimum and maximum values shown in Table 2 and Table 3, but represents the lower and upper bound resulting from the LACE minus the LCOE calculations for each of the 22 regions. The net difference from 2022 to 2040 tends to approach zero as the most economically attractive resources are built.[8]

The average net differences shown in Table 4a and Table 4b are for plants coming online in 2022, consistent with Tables 1-3. The weighted average net difference is above zero in 2022 for advanced combined cycle units, geothermal, solar PV, and onshore wind, suggesting that these technologies are being built in regions where they are economically viable. Additional tables showing the LCOE cost components, regional variation in LCOE and LACE and net differences for 2040 are provided in Appendix B.

Changes in cost from 2022 to 2040 reflect a number of different factors, sometimes working in different directions. Technology improvement tends to reduce LCOE through lower capital costs or improved performance (as measured by heat rate for fossil-fired plants or capacity factor for renewable plants). For fossil-fired plants, changing fuel prices also factor into the change in LCOE. For renewable resources such as wind, hydroelectric, or geothermal, the availability of high quality resources may also be a factor. As the best, least-cost resources are exploited, development will be forced into less favorable areas, potentially resulting in higher development costs, higher costs to access transmission lines, or access to lower-performing resources. Changes in the value of generation are a function of load growth. However, renewables such as wind and solar may show strong daily or seasonal generation patterns. As a result, the value of such renewable generation may see significant reductions as these periods become more saturated with generation and generation from new sources must compete with lower-cost options in the dispatch merit order.

[8] For a more detailed discussion of the LACE versus LCOE measures, see *Assessing the Economic Value of New Utility-Scale Electricity Generation Projects*, which can be found at http://www.eia.gov/renewable/workshop/gencosts/pdf/lace-lcoe_070213.pdf

Table 1a. Estimated LCOE (weighted average of regional values based on projected capacity additions) for new generation resources, plants entering service in 2022

	U.S. Capacity-Weighted[1] Average LCOE (2016 $/MWh) for Plants Entering Service in 2022							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Levelized Tax Credit[2]**	**Total LCOE including Tax Credit**
Dispatchable Technologies								
Coal 30% with carbon sequestration[3]				NB				
Coal 90% with carbon sequestration[3]				NB				
Natural Gas-fired								
Conventional Combined Cycle	87	14.0	1.4	42.0	1.1	58.6	NA	58.6
Advanced Combined Cycle	87	14.0	1.3	37.5	1.0	53.8	NA	53.8
Advanced CC with CCS				NB				
Conventional Combustion Turbine	30	36.8	6.6	54.3	3.0	100.7	NA	100.7
Advanced Combustion Turbine	30	22.8	2.6	58.8	3.0	87.1	NA	87.1
Advanced Nuclear	90	70.8	12.6	11.7	1.0	96.2	NA	96.2
Geothermal	90	29.2	13.3	0.0	1.5	44.0	-2.9	41.1
Biomass	83	47.2	15.2	34.2	1.2	97.7	NA	97.7
Non-Dispatchable Technologies								
Wind – Onshore	41	39.8	13.1	0.0	2.9	55.8	-11.6	44.3
Wind – Offshore				NB				
Solar PV[4]	25	59.8	10.1	0.0	3.8	73.7	-15.6	58.1
Solar Thermal				NB				
Hydroelectric[5]	60	54.1	3.1	5.2	1.5	63.9	NA	63.9

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2018-2022. Technologies for which capacity additions are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[2]The tax credit component is based on targeted federal tax credits such as the production or investment tax credit available for some technologies. It only reflects tax credits available for plants entering service in 2022. Not all technologies have tax credits, and are indicated as "NA" or not available. The results are based on a regional model and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[3]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. Two levels of CCS removal are modeled, 30% and 90%. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table 1b. Estimated LCOE (simple average of regional values) for new generation resources, for plants entering service in 2022

		U.S. Average LCOE (2016 $/MWh) for Plants Entering Service in 2022						
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Levelized Tax Credit[1]**	**Total LCOE including Tax Credit**
Dispatchable Technologies								
Coal 30% with carbon sequestration[2]	85	94.9	9.3	34.6	1.2	140.0	NA	140.0
Coal 90% with carbon sequestration[2]	85	78.0	10.8	33.1	1.2	123.2	NA	123.2
Natural Gas-fired								
Conventional Combined Cycle	87	13.9	1.4	40.8	1.2	57.3	NA	57.3
Advanced Combined Cycle	87	15.8	1.3	38.1	1.2	56.5	NA	56.5
Advanced CC with CCS	87	29.5	4.4	47.4	1.2	82.4	NA	82.4
Conventional Combustion Turbine	30	40.7	6.6	58.6	3.5	109.4	NA	109.4
Advanced Combustion Turbine	30	25.9	2.6	62.7	3.5	94.7	NA	94.7
Advanced Nuclear	90	73.6	12.6	11.7	1.1	99.1	NA	99.1
Geothermal	91	32.2	12.8	0.0	1.5	46.5	-3.2	43.3
Biomass	83	44.7	15.2	41.2	1.3	102.4	NA	102.4
Non-Dispatchable Technologies								
Wind – Onshore	39	47.2	13.7	0.0	2.8	63.7	-11.6	52.2
Wind – Offshore	45	133.0	19.6	0.0	4.8	157.4	-11.6	145.9
Solar PV[3]	24	70.2	10.5	0.0	4.4	85.0	-18.2	66.8
Solar Thermal	20	191.9	44.0	0.0	6.1	242.0	-57.6	184.4
Hydroelectric[4]	59	56.2	3.4	4.8	1.8	66.2	NA	66.2

[1]The tax credit component is based on targeted federal tax credits such as the production or investment tax credit available for some technologies. It only reflects tax credits available for plants entering service in 2022. Not all technologies have tax credits, and are indicated as "NA" or not available. The results are based on a regional model and state or local incentives are not included in LCOE calculations. See text box on page 2 for details on how the tax credits are represented in the model.

[2]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. Two levels of CCS removal are modeled, 30% and 90%. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table 2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, 2022

Plant Type	Range for Total System Levelized Costs (2016 $/MWh) Minimum	Non-weighted average	Capacity-weighted[2] average	Maximum	Range for Total System Levelized Costs with Tax Credits[1] (2016 $/MWh) Minimum	Non-weighted average	Capacity-weighted average	Maximum
Dispatchable Technologies								
Coal with 30% carbon sequestration[3]	128.9	140.0	NB	196.3	128.9	140.0	NB	196.3
Coal with 90% carbon sequestration[3]	102.7	123.2	NB	142.5	102.7	123.2	NB	142.5
Natural Gas-fired								
Conventional Combined Cycle	52.4	57.3	58.6	83.2	52.4	57.3	58.6	83.2
Advanced Combined Cycle	51.6	56.5	53.8	81.7	51.6	56.5	53.8	81.7
Advanced CC with CCS	63.1	82.4	NB	90.4	63.1	82.4	NB	90.4
Conventional Combustion Turbine	98.8	109.4	100.7	148.3	98.8	109.4	100.7	148.3
Advanced Combustion Turbine	85.9	94.7	87.1	129.8	85.9	94.7	87.1	129.8
Advanced Nuclear	95.9	99.1	96.2	104.3	95.9	99.1	96.2	104.3
Geothermal	42.8	46.5	44.0	53.4	40.0	43.3	41.1	49.3
Biomass	84.8	102.4	97.7	125.3	84.8	102.4	97.7	125.3
Non-Dispatchable Technologies								
Wind – Onshore	43.4	63.7	55.8	75.6	31.9	52.2	44.3	64.0
Wind – Offshore	136.6	157.4	NB	212.9	125.1	145.9	NB	201.4
Solar PV[4]	58.3	85.0	73.7	143.0	46.5	66.8	58.1	110.5
Solar Thermal	176.7	242.0	NB	372.8	134.6	184.4	NB	284.3
Hydroelectric[5]	57.4	66.2	63.9	69.8	57.4	66.2	63.9	69.8

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2022, See note in Tables 1a and 1b.
[2]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2018-2022. Technologies for which capacity additions are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.
[3]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.
[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[5]As modeled, hydroelectric 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 Onshore – 36% to 45%, Wind Offshore – 41% to 50%, Solar PV – 21% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 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 2017, January 2017, DOE/EIA-0383(2017).

Table 3. Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, 2022

Plant Type	Range for Levelized Avoided Costs (2016 $/MWh)			
	Minimum	Non-weighted Average	Capacity weighted[1] average	Maximum
Dispatchable Technologies				
Coal 30% with carbon sequestration[2]	47.4	58.7	NB	80.2
Coal 90% with carbon sequestration[2]	47.4	58.7	NB	80.2
Natural Gas-fired Combined Cycle				
Conventional Combined Cycle	47.3	58.1	58.4	80.0
Advanced Combined Cycle	47.3	58.1	59.3	80.0
Advanced CC with CCS	47.3	58.1	NB	80.0
Advanced Nuclear	47.6	57.3	59.3	64.5
Geothermal	51.5	65.3	70.4	79.8
Biomass	47.5	58.3	54.6	80.3
Non-Dispatchable Technologies				
Wind – Onshore	44.1	53.2	54.0	76.3
Wind – Offshore	47.1	57.8	NB	79.0
Solar PV[3]	42.5	64.7	66.8	82.9
Solar Thermal	39.7	69.9	NB	92.3
Hydroelectric[4]	46.1	57.4	58.2	79.5

[1]The capacity-weighted average is the average levelized avoided cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2018-2022. Technologies for which capacity additions are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[2]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table 4a. Difference between capacity-weighted levelized avoided costs of electricity (LACE) and capacity-weighted levelized costs of electricity (LCOE) for plants entering service in 2022

	Comparison of capacity-weighted[1] LCOE with tax credits and capacity-weighted LACE (2016 $/MWh)		
Plant Type	Average LCOE	Average LACE	Average Net Difference[2]
Dispatchable Technologies			
Coal 30% with carbon sequestration [3]	---------------NB---------------		
Coal 90% with carbon sequestration[3]	---------------NB---------------		
Natural Gas-fired			
Conventional Combined Cycle	58.6	58.4	-0.2
Advanced Combined Cycle	53.8	59.3	5.4
Advanced CC with CCS	---------------NB---------------		
Advanced Nuclear	96.2	59.3	-36.9
Geothermal	41.1	70.4	29.4
Biomass	97.7	54.6	-43.0
Non-Dispatchable Technologies			
Wind – Onshore	44.3	54.0	9.7
Wind – Offshore	---------------NB---------------		
Solar PV[4]	58.1	66.8	8.6
Solar Thermal	---------------NB---------------		
Hydroelectric[5]	63.9	58.2	-5.7

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2018-2022. Technologies for which capacity additions are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[2]The "Average Net Difference" represents the net economic value or the average of the (LACE minus LCOE) calculation, where the difference is calculated for each of the 22 regions based on the cost with tax credits for each technology, where tax credits are applicable.

[3]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table 4b: Difference between levelized avoided costs of electricity (LACE) and levelized costs of electricity (LCOE) for plants entering service in 2022

Plant Type	Comparison of non-weighted average LCOE with tax credits and non-weighted average LACE (2016 $/MWh)				
	Average LCOE	Average LACE	Average Net Difference[1]	Range of Non-Weighted Differences[2] Minimum	Maximum
Dispatchable Technologies					
Coal 30% with carbon sequestration[3]	140.0	58.7	-81.3	-116.2	-70.7
Coal 90% with carbon sequestration[3]	123.2	58.7	-64.5	-77.4	-50.2
Natural Gas-fired					
Conventional Combined Cycle	57.3	58.1	0.9	-5.1	9.3
Advanced Combined Cycle	56.5	58.1	1.7	-4.2	9.0
Advanced CC with CCS	82.4	58.1	-24.2	-35.2	-9.5
Advanced Nuclear	99.1	57.3	-41.7	-56.3	-34.6
Geothermal	43.3	65.3	21.9	10.9	39.8
Biomass	102.4	58.3	-44.1	-70.6	-27.6
Non-Dispatchable Technologies					
Wind – Onshore	52.2	53.2	1.0	-17.4	20.9
Wind – Offshore	145.9	57.8	-88.1	-141.9	-52.1
Solar PV[4]	66.8	64.7	-2.0	-42.5	21.4
Solar Thermal	184.4	69.9	-114.5	-215.3	-57.7
Hydroelectric[5]	66.2	57.4	-8.8	-20.6	9.8

[1]The "Average Net Difference" represents the average of the (LACE minus LCOE) calculation, where the difference is calculated for each of the 22 regions based on the cost with tax credits for each technology, where tax credits are applicable.

[2]This "range of differences" is not based on the difference between the minimum values shown in Table 2 and Table 3, but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

[3]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Appendix A: LCOE tables for plants entering service in 2019

Table A1a. Estimated LCOE (weighted average of regional values based on projected capacity additions) for new generation resources, for plants entering service in 2019

		U.S. Capacity-Weighted[1] Average LCOE (2016 $/MWh) for Plants Entering Service in 2019						
Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Levelized Tax Credit	Total LCOE with Tax Credit[2]
Dispatchable Technologies								
Natural Gas-fired								
Conventional Combined Cycle	87	11.6	1.4	35.2	1.1	49.3	NA	49.3
Advanced Combined Cycle	87	11.9	1.3	30.9	1.0	45.2	NA	45.2
Conventional Combustion Turbine	30	34.2	6.6	48.6	3.3	92.7	NA	92.7
Advanced Combustion Turbine	30	19.8	2.6	53.1	2.9	78.3	NA	78.3
Non-Dispatchable Technologies								
Wind – Onshore	39	36.0	13.7	0.0	2.7	52.4	-17.8	34.5
Solar PV[3]	26	56.4	9.6	0.0	4.0	70.1	-16.9	53.1
Solar Thermal	26	122.7	31.1	0.0	5.1	158.9	-36.8	122.1

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region are based on additions in 2017-2019. Technologies for which no new capacity builds are expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[2]Levelized cost with tax credits reflects tax credits available for plants entering service in 2019, see note 2 in Tables 1a. Not all technologies have tax credits, and are marked as "NA" or not available.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table A1b. Estimated LCOE (simple average of regional values) for new generation resources, for plants entering service in 2019

		U.S. Average LCOE (2016 $/MWh) for Plants Entering Service in 2019						
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Levelized Tax Credit[1]**	**Total LCOE with Tax Credit**
Dispatchable Technologies								
Natural Gas-fired								
Conventional Combined Cycle	87	11.9	1.4	35.6	1.2	50.1	NA	50.1
Advanced Combined Cycle	87	13.6	1.3	32.7	1.2	48.8	NA	48.8
Conventional Combustion Turbine	30	35.2	6.6	50.5	3.5	95.8	NA	95.8
Advanced Combustion Turbine	30	22.5	2.6	56.7	3.5	85.3	NA	85.3
Non-Dispatchable Technologies								
Wind – Onshore	40	40.8	13.6	0.0	2.8	57.1	-17.8	39.3
Solar PV[2]	24	62.8	10.5	0.0	4.4	77.7	-18.9	58.8
Solar Thermal	20	167.6	44.0	0.0	6.1	217.6	-50.3	167.3

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2019, see note in Tables 1a and 1b. Not all technologies have tax credits, and are marked as "NA" or not available.

[2] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table A2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, plants entering service in 2019

	Range for Total System LCOE (2016 $/MWh)				Range for Total LCOE with Tax Credits[1] (2016 $/MWh)			
Plant Type	Minimum	Non-weighted average	Capacity-weighted[2] average	Maximum	Minimum	Non-weighted average	Capacity-weighted average	Maximum
Dispatchable Technologies								
Natural Gas-fired								
Conventional Combined Cycle	45.8	50.1	49.3	58.9	45.8	50.1	49.3	58.9
Advanced Combined Cycle	45.1	48.8	45.2	56.2	45.1	48.8	45.2	56.2
Conventional Combustion Turbine	87.2	95.8	92.7	107.6	87.2	95.8	92.7	107.6
Advanced Combustion Turbine	77.6	85.3	78.3	96.7	77.6	85.3	78.3	96.7
Non-Dispatchable Technologies								
Wind – Onshore	40.4	57.1	52.4	69.4	22.6	39.3	34.5	51.6
Solar PV[3]	53.5	77.7	70.1	129.9	41.3	58.8	53.1	96.4
Solar Thermal	158.9	217.6	158.9	335.3	122.1	167.3	122.1	258.0

[1]Levelized cost with tax credits reflects tax credits available in 2019, see note 2 in Tables 1a.

[2]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2017-2019.Technologies for which new capacity builds are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

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 Onshore – 36% to 45%, Solar PV – 21% to 32%, and Solar Thermal – 11% to 26%. 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 2017, January 2017, DOE/EIA-0383(2017).

Appendix B: LCOE and LACE tables for plants entering service in 2040

Table B1a. Estimated LCOE (weighted average of regional values based on projected capacity additions) for new generation resources, for plants entering service in 2040

	U.S. Capacity-Weighted[1] Average LCOE (2016 $/MWh) for Plants Entering Service in 2040							
Plant Type	Capacity Factor (%)	Levelized Capital Cost	Fixed O&M	Variable O&M (including fuel)	Transmission Investment	Total System LCOE	Levelized Tax Credit[2]	Total LCOE with Tax Credit
Dispatchable Technologies								
Coal 30% with carbon sequestration[3]				NB				
Coal 90% with carbon sequestration[3]				NB				
Natural Gas-fired								
Conventional Combined Cycle				NB				
Advanced Combined Cycle	87	11.7	1.3	41.8	1.0	55.8	NA	55.8
Advanced CC with CCS				NB				
Conventional Combustion Turbine				NB				
Advanced Combustion Turbine	30	18.4	2.6	66.3	3.4	90.7	NA	90.7
Advanced Nuclear				NB				
Geothermal	91	24.7	16.5	0.0	1.5	42.6	-2.5	40.2
Biomass	83	34.9	15.2	24.5	1.1	75.7	NA	75.7
Non-Dispatchable Technologies								
Wind – Onshore	42	44.4	13.0	0.0	2.9	60.3	NA	60.3
Wind – Offshore				NB				
Solar PV[4]	24	45.3	10.4	0.0	3.8	59.5	-4.5	54.9
Solar Thermal				NB				
Hydroelectric[5]	37	43.4	2.9	3.3	1.3	50.9	NA	50.9

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2036-2040. Technologies for which no new capacity builds are expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[2]Levelized cost with tax credits reflects tax credits available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992. Not all technologies have tax credits, and are marked as "NA" or not available.

[3]Due to new regulations (CAA 111b), coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. Two levels of CCS removal are modeled, 30% and 90%. The coal with 30% removal is assumed to incur a 3 percentage-point adder to their cost-of-capital to represent risk associated with higher emissions.

[4] Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table B1b. Estimated LCOE (simple average of regional values) for new generation resources, for plants entering service in 2040

	U.S. Average LCOE (2016 $/MWh) for Plants Entering Service in 2040							
Plant Type	**Capacity Factor (%)**	**Levelized Capital Cost**	**Fixed O&M**	**Variable O&M (including fuel)**	**Transmission Investment**	**Total System LCOE**	**Levelized Tax Credit[1]**	**Total LCOE with Tax Credit**
Dispatchable Technologies								
Coal 30% with carbon sequestration[2]	85	77.7	9.3	34.6	1.2	122.8	NA	122.8
Coal 90% with carbon sequestration[2]	85	63.9	10.8	34.4	1.2	110.3		110.3
Natural Gas-fired								
Conventional Combined Cycle	87	11.8	1.4	45.6	1.2	60.0	NA	60.0
Advanced Combined Cycle	87	12.6	1.3	43.2	1.2	58.3	NA	58.3
Advanced CC with CCS	87	22.4	4.4	53.9	1.2	81.9	NA	81.9
Conventional Combustion Turbine	30	34.5	6.6	66.8	3.5	111.4	NA	111.4
Advanced Combustion Turbine	30	19.6	2.6	67.7	3.5	93.4	NA	93.4
Advanced Nuclear	90	59.4	12.6	16.5	1.1	89.6	NA	89.6
Geothermal	92	35.6	20.3	0.0	1.5	57.4	-3.6	53.8
Biomass	83	37.1	15.2	37.5	1.3	91.0	NA	91.0
Non-Dispatchable Technologies								
Wind – Onshore	41	41.7	13.1	0.0	2.7	57.6	NA	57.6
Wind – Offshore	45	104.4	19.6	0.0	4.9	128.8	NA	128.8
Solar PV[3]	24	54.5	10.5	0.0	4.4	69.4	-5.4	63.9
Solar Thermal	20	154.2	44.0	0.0	6.1	204.3	-15.4	188.9
Hydroelectric[4]	57	52.5	3.5	4.6	1.8	62.4	NA	62.4

[1]Levelized cost with tax credits reflects tax credits available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992. Not all technologies have tax credits, and are marked as "NA" or not available.

[2]Due to new regulations (CAA 111b), coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. Two levels of CCS removal are modeled, 30% and 90%. The coal with 30% removal is assumed to incur a 3 percentage-point adder to their cost-of-capital to represent risk associated with higher emissions.

[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[4]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table B2. Regional variation in levelized cost of electricity (LCOE) for new generation resources, plants entering service in 2040

Plant Type	Range for Total System LCOE (2016 $/MWh)				Range for Total LCOE with Tax Credits[1] (2016 $/MWh)			
	Minimum	Non-weighted average	Capacity-weighted[2] average	Maximum	Minimum	Non-weighted average	Capacity-weighted[2] average	Maximum
Dispatchable Technologies								
Coal 30% with carbon sequestration[3]	112.2	122.8	NB	180.4	112.2	122.8	NB	180.4
Coal 90% with carbon sequestration[3]	102.6	110.3	NB	124.6	102.6	110.3	NB	124.6
Natural Gas-fired								
Conventional Combined Cycle	54.8	60.0	NB	86.8	54.8	60.0	NB	86.8
Advanced Combined Cycle	53.2	58.3	55.8	84.2	53.2	58.3	55.8	84.2
Advanced CC with CCS	65.9	81.9	NB	90.2	65.9	81.9	NB	90.2
Conventional Combustion Turbine	102.0	111.4	NB	152.1	102.0	111.4	NB	152.1
Advanced Combustion Turbine	86.0	93.4	90.7	129.1	86.0	93.4	90.7	129.1
Advanced Nuclear	87.1	89.6	NB	93.8	87.1	89.6	NB	93.8
Geothermal	35.3	57.4	42.6	78.1	33.3	53.8	40.2	72.9
Biomass	73.2	91.0	75.7	114.5	73.2	91.0	75.7	114.5
Non-Dispatchable Technologies								
Wind – Onshore	37.7	57.6	60.3	69.4	37.7	57.6	60.3	69.4
Wind – Offshore	111.8	128.8	NB	172.7	111.8	128.8	NB	172.7
Solar PV[4]	48.1	69.4	59.5	115.1	44.6	63.9	54.9	105.4
Solar Thermal	149.1	204.3	NB	314.8	137.8	188.9	NB	291.1
Hydroelectric[5]	55.3	62.4	50.9	69.7	55.3	62.4	50.9	69.7

[1]Levelized cost with tax credits reflects tax credits available in 2040, which includes a permanent 10% investment tax credit for geothermal and solar technologies, based on the Energy Policy Act of 1992.
[2]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2036-2040. Technologies for which new capacity builds are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.
[3]Due to new regulations (CAA 111b), coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. Two levels of CCS removal are modeled, 30% and 90%. The coal with 30% removal is assumed to incur a 3 percentage-point adder to their cost-of-capital to represent risk associated with higher emissions.
[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[5]As modeled, hydroelectric 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 Onshore – 38% to 52%, Wind Offshore – 41% to 50%, Solar PV – 21% to 32%, Solar Thermal – 11% to 26%, and Hydroelectric – 46% 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 2017, January 2017, DOE/EIA-0383(2017).

Table B3: Regional variation in levelized avoided costs of electricity (LACE) for new generation resources, plants entering service in 2040

	Range for Levelized Avoided Costs (2016 $/MWh)			
Plant Type	Minimum	Non-weighted Average	Capacity-Weighted[1] average	Maximum
Dispatchable Technologies				
Coal 30% with carbon sequestration[2]	57.4	66.8	NB	81.5
Coal 90% with carbon sequestration[2]	57.4	66.8	NB	81.5
Natural Gas-fired				
Conventional Combined Cycle	57.2	66.1	NB	81.3
Advanced Combined Cycle	57.2	66.1	64.9	81.3
Advanced CC with CCS	57.2	66.1	NB	81.3
Advanced Nuclear	57.3	65.8	NB	73.8
Geothermal	56.7	68.7	75.7	80.8
Biomass	57.2	66.1	70.8	80.8
Non-Dispatchable Technologies				
Wind – Onshore	50.3	60.9	59.8	75.8
Wind – Offshore	56.9	65.5	NB	83.8
Solar PV[3]	49.7	72.2	73.4	91.2
Solar Thermal	48.7	76.9	NB	101.3
Hydroelectric[4]	56.9	62.9	46.4	68.0

[1]The capacity-weighted average is the average levelized avoided cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2036-2040. Technologies for which new capacity builds are not projected do not have a capacity-weighted average, and are marked as “NB” or not built.
[2]Due to new regulations (CAA 111b), coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. Two levels of CCS removal are modeled, 30% and 90%. The coal with 30% removal is assumed to incur a 3 percentage-point adder to their cost-of-capital to represent risk associated with higher emissions.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
[4]As modeled, hydroelectric 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.
Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table B4a: Difference between capacity-weighted levelized avoided costs of electricity (LACE) and capacity-weighted levelized costs of electricity (LCOE), plants entering service in 2040

	Comparison of capacity-weighted[1] LCOE with tax credits and capacity-weighted LACE (2016 $/MWh)		
Plant Type	**Average LCOE**	**Average LACE**	**Average Net Difference[2]**
Dispatchable Technologies			
Coal 30% with carbon sequestration[3]	---------------NB---------------		
Coal 90% with carbon sequestration[3]	---------------NB---------------		
Natural Gas-fired			
Conventional Combined Cycle	---------------NB---------------		
Advanced Combined Cycle	55.8	64.9	9.1
Advanced CC with CCS	---------------NB---------------		
Advanced Nuclear	---------------NB---------------		
Geothermal	40.2	75.7	35.5
Biomass	75.7	70.8	-4.9
Non-Dispatchable Technologies			
Wind – Onshore	60.3	59.8	-0.4
Wind – Offshore	---------------NB---------------		
Solar PV[4]	54.9	73.4	18.5
Solar Thermal	---------------NB---------------		
Hydroelectric[5]	50.9	46.4	-4.5

[1]The capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in each region. The capacity additions for each region were based on additions in 2036-2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average, and are marked as "NB" or not built.

[2]The "Average Net Difference" represents the average of the LACE minus LCOE calculation, where the difference is calculated for each of the 22 regions based on the cost with tax credits for each technology, where tax credits are applicable. This "range of difference" is not based on the difference between the minimum values shown in Table B2 and Table B3, but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

[3] Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).

Table B4b: Difference between levelized avoided costs of electricity (LACE) and levelized costs of electricity (LCOE), plants entering service in 2040

	Comparison of LCOE with tax credits and LACE (2016 $/MWh)				
				Range of Non-Weighted Differences[2]	
Plant Type	Average LCOE	Average LACE	Average Net Difference[1]	Minimum	Maximum
Dispatchable Technologies					
Coal 30% with carbon sequestration[3]	122.8	66.8	-56.1	-98.9	-42.0
Coal 90% with carbon sequestration[3]	110.3	66.8	-43.6	-61.6	-33.1
Natural Gas-fired					
Conventional Combined Cycle	60.0	66.1	6.1	-5.5	12.7
Advanced Combined Cycle	58.3	66.1	7.8	-2.8	13.7
Advanced CC with CCS	81.9	66.1	-15.7	-23.7	-7.2
Advanced Nuclear	89.6	65.8	-23.8	-36.3	-16.3
Geothermal	53.8	68.7	14.9	-4.2	47.4
Biomass	91.0	66.1	-24.9	-53.0	-1.7
Non-Dispatchable Technologies					
Wind – Onshore	57.6	60.9	3.3	-11.1	22.6
Wind – Offshore	128.8	65.5	-63.3	-103.1	-33.1
Solar PV[4]	63.9	72.2	8.2	-32.3	32.4
Solar Thermal	188.9	76.9	-112.0	-214.3	-57.2
Hydroelectric[5]	62.4	62.9	0.5	-8.5	12.4

[1]The "Average Net Difference" represents the average of the LACE minus LCOE calculation, where the difference is calculated for each of the 22 regions based on the cost with tax credits for each technology, where tax credits are applicable.

[2]This "range of differences" is not based on the difference between the minimum values shown in Table B2 and Table B3 but represents the lower and upper bound resulting from the LACE minus LCOE calculations for each of the 22 regions.

[3]Due to new regulations (CAA 111b), conventional coal plants cannot be built without CCS because they are required to meet specific CO_2 emission standards. The coal plant with 30% removal is assumed to incur a 3 percentage-point adder to its cost-of-capital to represent the risk associated with higher emissions from a plant of that design.

[4]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

[5]As modeled, hydroelectric 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.

Source: U.S. Energy Information Administration, Annual Energy Outlook 2017, January 2017, DOE/EIA-0383(2017).