STATE OF INDIANA

INDIANA UTILITY REGULATORY COMMISSION

PETITION OF DUKE ENERGY INDIANA, LLC PURSUANT TO IND. CODE §§ 8-1-2-42.7 AND 8-1-2-61, FOR (1) AUTHORITY TO MODIFY ITS RATES AND CHARGES FOR ELECTRIC UTILITY SERVICE THROUGH A STEP-IN OF NEW RATES AND CHARGES USING A FORECASTED TEST PERIOD; (2) APPROVAL OF NEW SCHEDULES OF RATES AND CHARGES, GENERAL RULES AND REGULATIONS, AND RIDERS; (3) APPROVAL OF A FEDERAL MANDATE CERTIFICATE UNDER IND. CODE § 8-1-8.4-1; (4) APPROVAL OF REVISED ELECTRIC DEPRECIATION RATES APPLICABLE TO ITS ELECTRIC PLANT IN SERVICE; (5) APPROVAL OF NECESSARY AND APPROPRIATE ACCOUNTING DEFERRAL RELIEF; AND (6) APPROVAL OF A REVENUE DECOUPLING MECHANISM FOR CERTAIN CUSTOMER CLASSES	)	**CAUSE NO. 45253**

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR

REDACTED TESTIMONY OF

JOHN E. HASELDEN – PUBLIC'S EXHIBIT NO. 7

OCTOBER 30, 2019

Respectfully submitted,

Scott Franson
Attorney No. 27839-49
Deputy Consumer Counselor

TESTIMONY OF OUCC WITNESS JOHN E. HASELDEN
CAUSE NO. 45253
DUKE ENERGY INDIANA, LLC

I. INTRODUCTION

Q: Please state your name and business address.

A: My name is John E. Haselden and my business address is 115 West Washington Street, Suite 1500 South, Indianapolis, Indiana 46204.

Q: By whom are you employed and in what capacity?

A: I am a Senior Utility Analyst in the Electric Division of the Indiana Office of Utility Consumer Counselor ("OUCC"). I describe my educational background and professional work experience in Appendix A to my testimony.

Q: Have you previously testified before the Indiana Utility Regulatory Commission ("Commission")?

A: Yes. I have testified in a number of cases before the Commission, including (1) base rate cases; (2) various tracker cases (e.g., demand side management ("DSM"), renewable energy, environmental compliance, and Transmission, Distribution and Storage System Improvement Charges ("TDSIC"); and (3) applications for Certificates of Public Convenience and Necessity ("CPCN").

Q: What is the purpose of your testimony?

A: I address the following topics presented by Duke Energy Indiana, LLC ("DEI" or "Petitioner"):

- Proposed DSM/Energy Efficiency ("EE") Rider treatment; and
- The Tippecanoe Solar Power Plant ("Tippecanoe Project") and the B-Line Heights Solar Plant ("B-Line Heights Project") Projects.

Ultimately, I recommend the Commission:

- Approve DEI's proposal to defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition any issues will be litigated therein and no implied or explicit approvals of any issues will be decided in this case; and
- Deny cost recovery for the Tippecanoe and B-Line Heights Projects.

Q: Please describe the review and analysis you conducted in order to prepare your testimony.

A: I reviewed DEI's Verified Petition, Direct Testimony and Exhibits submitted in this Cause related to the topics I discuss in my testimony. I composed data requests ("DRs") and reviewed DEI's discovery responses.

Q: Are you sponsoring any attachments in this proceeding?

A: Yes. I am sponsoring:

- Attachment JEH-1 - which contains Petitioner's Responses to selected OUCC DRs ;
- Confidential Attachment JEH-1C – which contains Petitioner's Confidential Responses to OUCC DR 3.6(d);
- Attachment JEH-2 - which contains references to utility-scale solar project costs;
- Confidential Attachment JEH-3C - which is a Confidential Conceptual Site Plan for the Tippecanoe Project.

Q: To the extent you do not address a specific item or adjustment, does this mean you agree with those portions of Petitioner's proposal?

A: No. Excluding any specific adjustments or amounts DEI proposes does not indicate my approval of those adjustments or amounts. Rather, the scope of my testimony is limited to the specific items addressed herein.

II. PROPOSED TREATMENT OF THE DSM/EE RIDER

Q: What changes does DEI propose to its DSM/EE Rider?

A: DEI witness Diana L. Douglas outlines DEI's proposal[1] as follows:

- A new revenue decoupling mechanism ("RDM") that would replace the lost revenue adjustment mechanism ("LRAM") for those customers who are a part of the RDM, which are generally residential and commercial customers;
- In the event the RDM is not approved, net lost revenues will be reset to zero, subject to reconciliation of lost revenues due to new evaluation, measurement, and verification ("EM&V") related to programs offered through the implementation date of new base rates;
- A change in the revenue conversion factors;
- Collection of lost revenues incurred during 2020;
- Cosmetic changes to the tariff; and
- Continued recovery of direct and indirect program costs, including costs for EM&V, performance incentives, and DSM labor through DEI's DSM/EE Rider, as is the current practice.

---

[1] Cause No. 45253, Direct Testimony of Diana L. Douglas (Revised) (Petitioner's Exhibit No. 4), pages 81-91.

Q: Does the OUCC support DEI's DSM/EE Rider cost recovery proposal?

A: Not entirely. The OUCC has concerns regarding lost revenue recovery for DSM programs delivered in 2020.

Q: Please explain the OUCC's concerns.

A: In this proceeding, DEI proposes, as an alternative to decoupling, to collect through the DSM/EE Rider, lost revenues for measures implemented in 2020 over the measure's expected useful life ("EUL"). DEI has not yet filed its next DSM plan for the period beginning 2020. However, resulting from discussions with DEI technical personnel on October 17, 2019, the OUCC has concerns about EUL assumptions DEI is using for certain measures. The OUCC will address this matter in DEI's filing in Cause No. 43955 DSM 7 and the upcoming DSM Plan filing, expected in November 2019. While the OUCC does not have an issue with DEI's proposal to defer ratemaking treatment of future DSM costs and shareholder incentives, it is premature to lock down the terms of an LRAM in this proceeding. It should also be noted OUCC witness David Dismukes provides testimony recommending denial of revenue decoupling.

III. <u>TIPPECANOE AND B-LINE HEIGHTS SOLAR PLANT PROJECTS</u>

Q: What are the OUCC's concerns with the Tippecanoe and the B-Line Heights Projects?

A: The OUCC is concerned with these projects because they are small, expensive solar projects that primarily benefit specific localized customers and DEI. While DEI might say the purpose of these projects is to benefit all DEI customers by taking incremental steps to provide customers with clean renewable energy and to diversify DEI's generation portfolio, the same could be said for a single solar panel erected by DEI anywhere in its territory. The fact of the matter is these small projects have little to no impact on either of the aforementioned "benefits," but instead Duke is developing for image-building purposes for which all customers will pay – a lot. Furthermore, recovery of such costs is prohibited by IC 8-1-2-6 (c).

Q: What are the OUCC's specific concerns with the proposed Tippecanoe Project?

A: The first issue is DEI's inability to take advantage of the federal investment tax credit ("ITC") in a timely manner. Although eligible for the ITC, DEI does not expect to have a sufficient tax appetite to monetize the ITC until approximately 2025.[2] The ITC's monetization will be deferred a minimum of six-to-seven years and, until that time, customers will pay a return of and return on the extra 30% project cost. The second issue relates to the project's cost and design. DEI estimates the project's levelized cost of energy ("LCOE") to be $135.04/MWh.[3] This amount is approximately four times the cost of other utility-scale solar projects having LCOEs in the $35-40/MWh range.[4] Projects such as the Tippecanoe Project are relatively small and cannot achieve economies of scale necessary to compete with utility-scale solar facilities on a cost basis. To be clear, the OUCC is not opposed to small solar projects. We have a history of supporting solar and other renewables as long as they are in the best interest of the customer. This is precisely the point: If <u>utility investments</u> in solar power are in the best interests of ratepayers, those

---

[2] Attachment JEH-1, Response to OUCC DR 3.8.
[3] Attachment JEH-1, Response to OUCC DR 12.6.
[4] Attachment JEH-2.

investments should be at a scale and design that deliver the benefits of solar power at the lowest reasonable cost. DEI has designed the Tippecanoe Project to be a fixed-tilt array, instead of the currently prevalent and economic single axis design. It is likely DEI did not chose the single axis design because the project will be built on a marginal, narrow triangular site due to the highly visible location as discussed more below. This is not a competitive alternative for the procurement of utility-scale renewable energy and due to the project's unreasonably high cost, the Commission should deny recovery for this project.

Q: What are the benefits of the Tippecanoe Project?

A: In addition to the production of renewable energy, DEI witness Andrew S. Ritch states the project will support the Purdue Research Foundation's ("PRF") Discovery Park District's ("Discovery Park") economic development and sustainability goals and will set the stage for sustainable land use.[5] These claims are unsubstantiated. However, what is clear is DEI's intent to site the project in a highly visible location for image enhancing purposes. This particular location chosen for the proposed project is triangular and is sandwiched between US 52/231 and a railroad embankment at the entrance to Discovery Park[6], an area described as "non-developable" by the Director of the Discovery Park District, Jeremy Slater.[7] The location's high visibility is highlighted in the land lease agreement between DEI and the Purdue Research Foundation, as follows:

---

[5] Cause No. 45253, Direct Testimony of Andrew S. Ritch (Petitioner's Exhibit No. 24), page 11, lines 11-13.
[6] Confidential Attachment JEH-3C.
[7] https://www.wlfi.com/content/news/Duke-Energy-building-solar-panel-farm-at-Purdues-Discovery-Park-District-512657181.html.

[redacted]

In addition, the Purdue Research Foundation's enthusiasm for siting the solar project at Discovery Park to support economic development and sustainability goals was likely increased by DEI paying a continually escalating lease on a small, odd-shaped, piece of land considered "non-developable."[9] Due to the Tippecanoe Project's unreasonably high cost and the need for other Duke customers to cross-subsidize the project, the Commission should deny cost recovery for this project.

Q: **What are the OUCC's specific concerns with the proposed B-Line Solar Plant project?**

A: At a cost of approximately [redacted] for a small, 112 kW array,[10] this project is unreasonably expensive. DEI estimates the levelized cost to be $356.91/MWh[11] -- approximately ten times the cost of competitive utility-scale solar projects. The benefits of this project, as described by Mr. Ritch, will "...demonstrate DEI's commitment to identifying innovative ways to support renewable energy generation in more densely populated urban areas and supports the City of Bloomington's renewable and affordable housing goals."[12] The project is interconnected to DEI's distribution system, not to the host building – the

[8] Attachment JEH-1C, Confidential Response to OUCC DR 3.6(d), Attachment 3.6-A, page 5, paragraph 6(a).
[9] Attachment JEH-1C, Confidential Response to OUCC DR 3.6(d), Attachment 3.6-A, page 5, paragraph 5(b).
[10] See confidential exhibit to Direct Testimony of Andrew S. Ritch (Petitioner's Confidential Exhibit 24-D (ASR)), page 3.
[11] Attachment JEH-1, Response to OUCC DR 12.6.
[12] Direct Testimony of Witness Andrew S. Ritch, page 16, lines 3-6.

apartments themselves. This begs the question of how the project relates to affordable housing goals. Due to their physical proximity, a person could reasonably assume the solar panels are connected to the building. However, they are not. Regardless of whether the array connects to the building, it is not DEI ratepayers' responsibility to pay for a perceived contribution to Bloomington's affordable housing goals. In addition, despite Mr. Ritch's characterization[13], there is nothing "innovative" about solar panels installed on a parking canopy. Replicating this project at these estimated costs is not feasible without ratepayer subsidization. The Commission should not require DEI ratepayers, spread across a large part of the state, to underwrite DEI management's decisions regarding this unnecessary and unreasonably expensive project. Therefore, the OUCC recommends the Commission deny DEI's requested cost recovery for this project.

IV. RECOMMENDATIONS

Q: What does the OUCC recommend?

A: The OUCC recommends the Commission:

- Approve DEI's proposal to defer future DSM costs, lost revenues, and shareholder incentives to the forthcoming DSM plan case with the condition any issues will be litigated therein and no implied or explicit approvals of any DSM issues will be decided in this case; and
- Deny cost recovery for the Tippecanoe and B-Line Heights Projects.

---

[13] *Id.*

Q: Does this conclude your testimony?

A: Yes.

OUCC
IURC Cause No. 45253
Data Request Set No. 3
Received: July 30, 2019

OUCC 3.8

Request:

On page 31, of her testimony, Ms. Sieferman discuss the Income Tax Credits ("ITC") for renewable energy projects. Please answer the following questions:

a. What is the current value of the deferred ITC's?
b. At what time (year) in the future does DEI estimate it will be able to use the deferred ITC's
c. The ITC for solar projects is being phased out by the IRS. Will DEI be able to use the deferred ITC after the phase-out is complete?
d. for tax purposes is Duke using accelerated depreciation for renewable projects?
e. If Duke is not currently using accelerated depreciation for renewable projects, is Duke able to defer and subsequently use accelerated depreciation for tax purposes?

Response:

a. The current value of the Crane Solar ITCs is $10,999,471.
b. Duke Energy Indiana estimates that it will begin using Crane Solar ITCs around 2025.
c. Yes, Duke Energy Indiana will be able to use the deferred Crane Solar ITC after the phase-out is complete. Solar federal ITCs have a 20-year carryforward.
d. Yes, Duke Energy Indiana is using accelerated depreciation for renewable projects.
e. N/A.

Witness: Suzanne Sieferman

OUCC
IURC Cause No. 45253
Data Request Set No. 12
Received: August 29, 2019

OUCC 12.6

Request:

State DEI's estimated levelized cost of energy ("LCOE") for:

a. The TSPP project; and

b. The B-Line project.

Response:

a. $135.04
b. $356.91

Witness: Andrew S. Ritch

NIPSCO Integrated Resource Plan 2018 Update

Public Advisory Meeting Three

July 24, 2018

NiSource

NIPSCO

Overall Summary and Pricing Received

	Technology	# of Bids	Bid MW (ICAP)	# of Projects	Project MW	Average Bid Price	Pricing Units	Comments
Asset Sale or Option	Combine Cycle Gas (CCGT)	7	4,846	4	3,055	$959.61	$/kW	
	Combustion Turbine (CT)	1						
	Solar	9	1,374	5	669	$1,151.01	$/kW	
	Wind	8	1,807	7	1,607	$1,457.07	$/kW	
	Solar + Storage	4	705	3	465	$1,182.79	$/kW	
	Wind + Solar + Storage	1						
	Storage	1						
Purchase Power Agreement	Combine Cycle Gas (CCGT)	8	2,715	6	2,415	$7.86	$/kW-Mo	+ fuel and variable O&M
	Solar + Storage	7	1,055	5	755	$5.90	$/kW-Mo	+ $35/MWh (Average)
	Storage	8	1,055	5	925	$11.24	$/kW-Mo	
	Solar	26	3,591	16	1,911	$35.67	$/MWh	
	Wind	6	788	4	603	$26.97	$/MWh	
	Fossil	3	1,494	2	772	N/A		Structure not amenable to price comparison
	Demand Response	1						
	Total	90	20,585	59	13,247			

Preliminary – Subject to Due Diligence

Independent Statistics & Analysis
U.S. Energy Information Administration

February 2019

Levelized Cost and Levelized Avoided Cost of New Generation Resources in the *Annual Energy Outlook 2019*

This paper presents average values of levelized costs and levelized avoided costs for electric generating technologies entering service in 2021, 2023,[1] and 2040 as represented in the National Energy Modeling System (NEMS) for the U.S. Energy Information Administration's (EIA) *Annual Energy Outlook 2019* (AEO2019) Reference case.[2] Both values estimate the factors contributing to the capacity expansion decisions modeled, which also consider policy, technology, and geographic characteristics that are not easily captured in a single metric.

The costs for electric generating facilities entering service in 2023 are presented in the body of the report, with those for 2021[3] and 2040 included in Appendices A and B, respectively. Both a capacity-weighted average based on projected capacity additions and a simple average (unweighted) of the regional values across the 22 U.S. supply regions of the NEMS electricity market module (EMM) are provided, together with the range of regional values.

Levelized Cost of Electricity

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 generating plant during an assumed financial life and duty cycle.[4] LCOE is often cited as a convenient summary measure of the overall competiveness of different generating technologies.

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 each of these factors varies across the technologies. For technologies with no fuel costs and relatively small variable O&M costs, such as solar and wind electric generating technologies, LCOE changes nearly in proportion to the estimated capital cost of the technology. For technologies with significant fuel cost, both fuel cost and capital cost estimates significantly affect LCOE. The availability of various incentives, including state or federal tax credits (see text box on page 2), can 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.

[1] Given the long lead-time and licensing requirements for some technologies, the first feasible year that all technologies are available is 2023.
[2] AEO2019 are available online (http://www.eia.gov/outlooks/aeo/).
[3] Appendix A shows LCOE and LACE for the subset of technologies available to be built in 2021.
[4] 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.
[5] The specific assumptions for each of these factors are given in the *Assumptions to the Annual Energy Outlook*, available online (http://www.eia.gov/outlooks/aeo/assumptions/).

Actual plant investment decisions are affected by the specific technological and regional characteristics of a project, which involve many other factors not reflected in LCOE values. One such factor is the projected utilization rate, which depends on the varying amount of electricity required over time and the existing resource mix in an area where additional capacity is needed. For example, a wind resource that would primarily displace existing natural gas-fired generation will usually have a different economic value than one that would displace existing coal-fired generation. A related factor is the capacity value, which depends on both the existing capacity mix and load characteristics in a region. Because load must be continuously balanced, generating units with the capability to vary output to follow demand (dispatchable technologies) generally have more value to a system than less flexible units (non-dispatchable technologies) such as those using intermittent resources to operate. The LCOE values for dispatchable and non-dispatchable technologies are listed separately in the tables because comparing them must be done carefully.

AEO2019 representation of tax incentives for renewable generation

Federal tax credits for certain renewable generation facilities can substantially reduce the realized cost of these facilities. Where applicable, the LCOE tables show the cost both with and without tax credits that EIA assumed would be available in the year in which the plant enters service, as follows.

Production Tax Credit (PTC): New wind, geothermal, and closed-loop biomass plants receive 24 dollars per megawatthour ($/MWh) of generation; other PTC-eligible technologies receive $12/MWh. The PTC values are adjusted for inflation and applied during the plant's first 10 years of service. Plants that were under construction before the end of 2016 received the full PTC. After 2016, wind continues to be eligible for the PTC but at a dollar-per-megawatthour 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, https://www.irs.gov/irb/2016-23_IRB/ar07.html), EIA assumes that wind plants have four years after beginning construction to come online and claim the PTC. As a result, wind plants entering service in 2021 will receive $19.20/MWh while those entering service in 2023 will receive $9.60/MWh (inflation-adjusted).

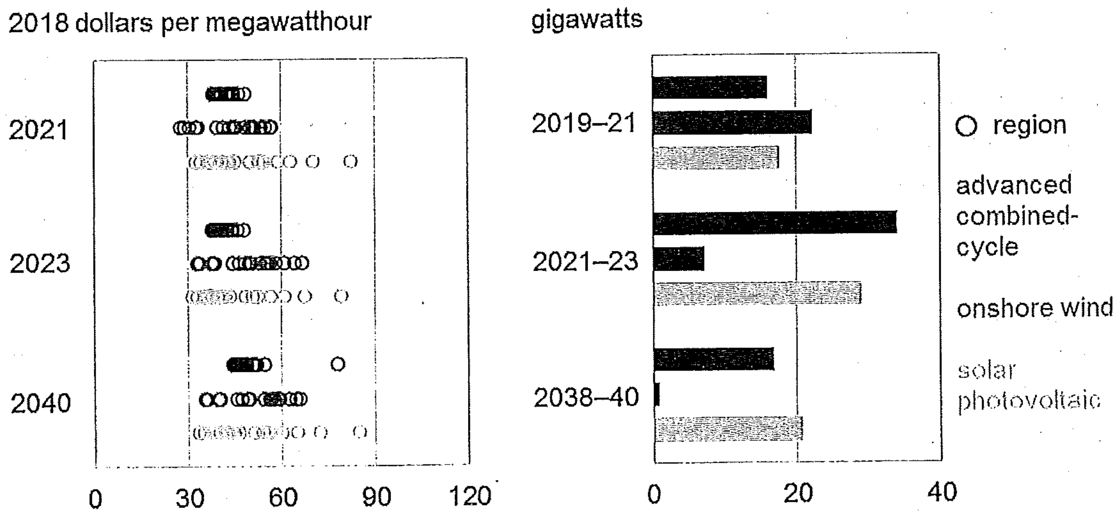
Investment Tax Credit (ITC): In June 2018, the IRS issued Notice 2018-59 (https://www.irs.gov/pub/irs-drop/n-18-59.pdf), a beginning of construction guidance for the ITC. EIA assumes all solar projects starting construction before January 1, 2020, have four years to bring the power plant online (before January 1, 2024) to receive the full 30% ITC. Solar projects include both utility-scale solar plants—those with capacity rating of 1 megawatt (MW) or greater—and small-scale systems—those with capacity rating of less than 1 MW. Projects starting construction in 2020 have three years to enter service and receive 26% ITC, and those with a 2021 construction start year have two years to enter service and claim a 22% ITC. All commercial and utility-scale plants with a construction start date on or after January 1, 2022, or those placed in service after December 31, 2023, receive a 10% ITC. ITC, however, expires completely for residential-owned systems starting in 2022. Results in this levelized cost report only include utility-scale solar facilities and do not include small-scale solar facilities.

Both onshore and offshore wind projects are eligible to claim the ITC in lieu of the PTC. Although EIA expects that onshore wind projects will choose the PTC, EIA assumes offshore wind projects will claim the ITC in lieu of the PTC because of the relatively higher capital costs for those projects.

Levelized Avoided Cost of Electricity

LCOE does not capture all of the factors that contribute to actual investment decisions, making the direct comparison of LCOE across technologies problematic and misleading as a method to assess the economic competitiveness of various generation alternatives. As illustrated by Figure 1 below, on average, wind LCOE is shown to be the same or lower than solar photovoltaic (PV) LCOE in 2021, with more wind generating capacity expected to be installed than solar PV. Wind LCOE continues to be about the same or lower than solar PV LCOE on average in 2040, but EIA projects much more solar PV capacity to be installed than wind during that time.

Figure 1. Levelized cost of electricity (with applicable tax subsidies) by region and total incremental capacity additions for selected generating technologies entering into service in 2021, 2023, and 2040



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Comparing two different technologies using LCOE alone evaluates only the cost to build and operate a plant and not the value of the plant's output to the grid. EIA believes an assessment of economic competitiveness between generation technologies can be gained by considering the avoided cost: a measure of what it would cost to generate the electricity that would be displaced by a new generation project. Avoided cost provides a proxy measure for potential revenues from sales of electricity generated from a candidate project. It may be summed over a project's 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] Using LACE and LCOE together gives a more intuitive indication of economic competitiveness for each technology than either metric separately when several technologies are available to meet load. If several technologies are available to meet load, a LACE-to-LCOE ratio (or value-cost ratio) may be calculated for each technology to determine which project provides the most value relative to its cost. Projects with a value-cost ratio greater than one (i.e., LACE is greater than

---

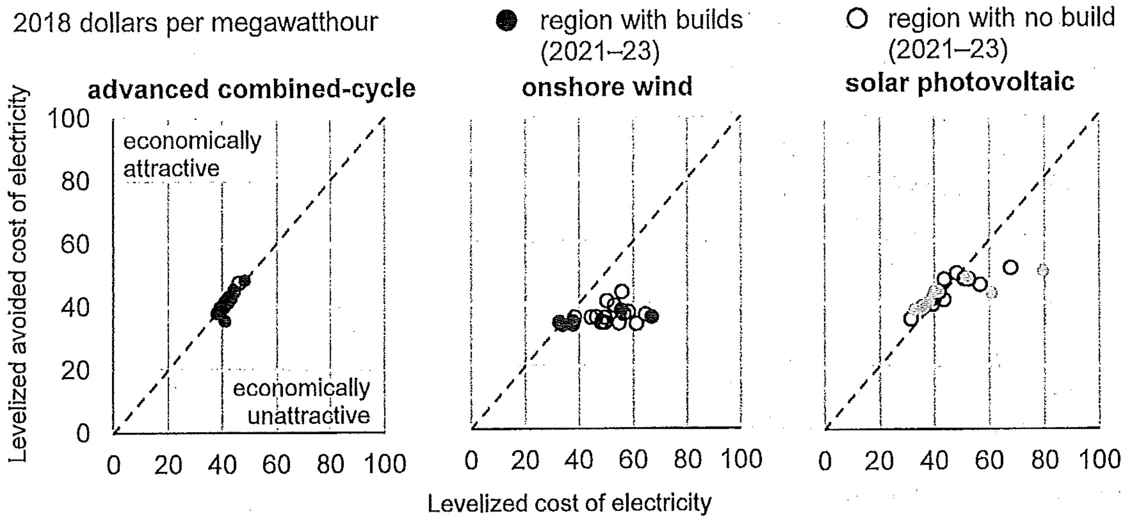
[6] Further discussion of the levelized avoided cost concept and its use in assessing economic competitiveness can be found online: http://www.eia.gov/renewable/workshop/gencosts/.

LCOE) are more economically attractive as new builds than those with a value-cost ratio less than one (i.e., LACE is less than LCOE).

Estimating LACE is more complex than estimating LCOE because it requires information about how the system would operate without the new option being considered. LACE is calculated 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 specific future date. LACE represents the potential value available to the project owner from the project's contribution to satisfy both energy and capacity requirements. LACE accounts for both the variation in daily and seasonal electricity demand in the region where a new project is under consideration and the characteristics of the existing generation fleet to which new capacity will be added, therefore comparing 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 existing natural gas-fired generation will usually have a different value than one that would displace existing coal-fired generation.

Although the economic decisions for capacity additions in EIA's long-term projections do not use either LACE or LCOE concepts, the LACE and value-cost ratio presented in this report are generally more representative of the factors contributing to the build decisions found in EIA's long-term projections than looking at LCOE alone. Figure 2 below shows selected generating technologies that are feasible to come online in 2023. The x-axis is LCOE, and the y-axis is LACE. The diagonal lines are breakeven lines, so that anything above them is considered to be economically attractive to build because the value (or LACE) is higher than the cost (or LCOE). Each dot represents an electricity market region of the United States as modeled in NEMS. Colored dots show regions where the technology is built in the AEO projection; circles show where the technology is not built from 2021 to 2023. Advanced combined-cycle (CC) and solar PV have colored dots mostly above or at the diagonal lines. Onshore wind has mostly circles at or below the diagonal line and a few colored dots below the line. This pattern is partly because the builds are calculated from capacity added in the preceding three years, and onshore wind was subject to greater tax incentives in those three years than in 2023 alone. In addition, some regions are adding uneconomic capacity builds to fulfill state-level renewable portfolio standards (RPS) that require that a certain percentage of generation come from renewables. Even so, looking at both LCOE and LACE together as shown in Figure 2 is more predictive of the full analysis from the AEO model shown in Figure 1 than LCOE alone.

Figure 2. Levelized cost of electricity and levelized avoided cost of electricity by region for selected generating technologies, 2023 online year



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Nonetheless, both the LACE and LCOE estimates are simplifications of modeled decisions, and they may not fully capture all factors considered in NEMS or match modeled results. EIA calculates levelized costs using an assumed set of capital and operating costs, but investment decisions may be affected by factors other than the project's value relative to its costs. For example, the inherent uncertainty about future fuel prices, future policies, or local considerations for system reliability may lead plant owners or investors who finance plants to place a value on portfolio diversification or other risk-related concerns. EIA considers many of the factors discussed above in its analysis of technology choice in the electricity sector in NEMS, but not all of these concepts are included in LCOE or LACE calculations. Future policy-related factors, such as new environmental regulations or tax credits for specific generation sources, can affect investment decisions. The LCOE and LACE values presented here are derived from the AEO2019 Reference case, which includes state-level renewable electricity requirements as of October 2018 and a phase-out of federal tax credits for renewable generation.

LCOE and LACE calculations

EIA calculates LCOE values based on a 30-year cost recovery period, using a real after-tax weighted average cost of capital (WACC) of 4.2%.[7] In reality, a plant's cost recovery period and cost of capital can vary by technology and project type. In the AEO2019 Reference case, EIA includes a three-percentage-point increase to the cost of capital when evaluating investments for new coal-fired power plants and new coal-to-liquids (CTL) plants without carbon capture and sequestration (CCS) and pollution control retrofits. This increase reflects observed financial risks[8] associated with major investments in long

[7]The real WACC of 4.2% corresponds to a nominal after-tax rate of 7.0% for plants entering service in 2023. For plants entering service in 2021 and 2040, the nominal WACC used to calculate LCOE was 6.8% and 7.0%, respectively. An overview of the WACC assumptions and methodology can be found in the *Electricity Market Module of the National Energy Modeling System: Model Documentation 2018* (https://www.eia.gov/analysis/pdfpages/m068index.php).

[8] See, for example, "Companies End Effort to Buy Navajo Generating Station", *Power*, September 21, 2018 for an example of both financing and off-take risks facing coal-fired capacity or "One of U.K.'s largest banks won't fund new plants or mines,"

operating-life power plants with a relatively higher rate of carbon dioxide (CO_2) emissions. AEO2019 takes into account two coal-fired technologies that are compliant with the New Source Performance Standard (NSPS) for CO_2 emissions under Section 111(b) of the Clean Air Act. One technology is designed to capture 30% of CO_2 emissions and would still be considered a high emitter relative to other new sources; therefore, it may continue to face potential financial risk if CO_2 emission controls are further strengthened. Another technology is designed to capture 90% of CO_2 emissions and would not face the same financial risk; therefore, EIA does not assume the three-percentage-point increase in the cost of capital. As a result, the LCOE values for a coal-fired plant with 30% CCS are higher than they would be if the same cost of capital were used for all technologies.

The levelized capital component reflects costs calculated using tax depreciation schedules consistent with tax laws without a sunset date, which vary by technology. For AEO2019, EIA assumes a corporate tax rate of 21% as specified in the Tax Cuts and Jobs Act of 2017. For technologies eligible for the ITC or PTC, EIA reports LCOE both with and without tax credits, which are assumed to phase out and expire based on current laws and regulations. Some technologies, notably solar PV, are used in both utility-scale generation and in distributed residential and commercial applications. The LCOE and LACE calculations presented here 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.

The LCOE values shown in Tables 1a and 1b are region-specific LCOE values using weights reflecting the projected regional capacity builds in AEO2019 (Table 1a) and unweighted (simple average, Table 1b) for new plants coming online in 2023. The weights were developed based on the cumulative capacity additions during three years, reflecting the two years preceding the online year and the online year (e.g., the capacity weight for a 2023 online year represents the cumulative capacity additions from 2021 through 2023.)

ClimateWire (subscription required), August 3, 2018 for an example of increasingly limited options in international finance markets for such plants.

Table 1a. Estimated levelized cost of electricity (capacity-weighted average[1]) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmissi on cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[3]	NB	NB	NB	NB	NB	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB	NB	NB	NB	NB	NB
Conventional CC	87	8.1	1.5	32.3	0.9	42.8	NA	42.8
Advanced CC	87	7.1	1.4	30.7	1.0	40.2	NA	40.2
Advanced CC with CCS	NB	NB	NB	NB	NB	NB	NB	NB
Conventional CT	NB	NB	NB	NB	NB	NB	NB	NB
Advanced CT	30	17.2	2.7	54.6	3.0	77.5	NA	77.5
Advanced nuclear	NB	NB	NB	NB	NB	NB	NB	NB
Geothermal	90	24.6	13.3	0.0	1.4	39.4	-2.5	36.9
Biomass	83	37.3	15.7	37.5	1.5	92.1	NA	92.1
Non-dispatchable technologies								
Wind, onshore	44	27.8	12.6	0.0	2.4	42.8	-6.1	36.6
Wind, offshore	45	95.5	20.4	0.0	2.1	117.9	-11.5	106.5
Solar PV[4]	29	37.1	8.8	0.0	2.9	48.8	-11.1	37.6
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

[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 from 2021–2023. 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 PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2023 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC 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]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table 1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	61.3	9.7	32.2	1.1	104.3	NA	104.3
Coal with 90% CCS[2]	85	50.2	11.2	36.0	1.1	98.6	NA	98.6
Conventional CC	87	9.3	1.5	34.4	1.1	46.3	NA	46.3
Advanced CC	87	7.3	1.4	31.5	1.1	41.2	NA	41.2
Advanced CC with CCS	87	19.4	4.5	42.5	1.1	67.5	NA	67.5
Conventional CT	30	28.7	6.9	50.5	3.2	89.3	NA	89.3
Advanced CT	30	17.6	2.7	54.2	3.2	77.7	NA	77.7
Advanced nuclear	90	53.8	13.1	9.5	1.0	77.5	NA	77.5
Geothermal	90	26.7	12.9	0.0	1.4	41.0	-2.7	38.3
Biomass	83	36.3	15.7	39.0	1.2	92.2	NA	92.2
Non-dispatchable technologies								
Wind, onshore	41	39.8	13.7	0.0	2.5	55.9	-6.1	49.8
Wind, offshore	45	107.7	20.3	0.0	2.3	130.4	-12.9	117.5
Solar PV[3]	29	47.8	8.9	0.0	3.4	60.0	-14.3	45.7
Solar thermal	25	119.6	33.3	0.0	4.2	157.1	-35.9	121.2
Hydroelectric[4]	75	29.9	6.2	1.4	1.6	39.1	NA	39.1

[1]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2023 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC 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]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

EIA evaluated LCOE and LACE for each technology based on assumed capacity factors, which generally correspond to the high end of their likely utilization range. This convention is consistent with the use of LCOE to evaluate competing technologies in baseload operation such as coal and nuclear plants. Some technologies, such as combined-cycle (CC) plants, while sometimes used in baseload operation, are also built to serve load-following or other intermediate dispatch duty cycles. Simple conventional or advanced combustion turbines (CT) that are typically used for peak load duty cycles are evaluated at a 30% capacity factor, which reflects the upper end of their typical economic utilization range. The duty cycle for intermittent resources is not operator controlled, but rather, it depends on weather that will 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; therefore, they are shown separately as non-dispatchable technologies. Similarly, hydroelectric resources, including facilities where storage reservoirs allow for more flexible day-to-day operation, generally have high seasonal variation in output. EIA shows them as non-dispatchable to discourage comparison with technologies that have more consistent seasonal 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, which can vary significantly by region, and will not necessarily correspond to the cumulative projected capacity factors for these both new and existing units for resources in AEO2019 or in other EIA analyses.

Table 2 shows the significant regional variation in LCOE values from local labor markets and the cost and availability of fuel or energy resources (such as windy sites). For example, without consideration of the PTC, the LCOE for incremental onshore wind capacity ranges from \$38.9/MWh in the region with the best available wind resources to \$72.9/MWh in the region with the lowest-quality wind resources and/or higher capital costs for the best sites. Because onshore wind plants will most likely be built in regions that offer low costs and high value, the weighted average cost across regions is closer to the low end of the range at \$42.8/MWh. Costs for wind generators may include additional expenses associated with transmission upgrades needed to access remote resources, as well as other factors that markets may not internalize into the market price for wind power.

Table 2. Regional variation in levelized cost of electricity for new generation resources entering service in 2023 (2018 $/MWh)

	Without tax credits				With tax credits[1]			
Plant type	Minimum	Simple average	Capacity-weighted average[2]	Maximum	Minimum	Simple average	Capacity-weighted average[2]	Maximum
Dispatchable technologies								
Coal with 30% CCS[3]	93.7	104.3	NB	124.7	93.7	104.3	NB	124.7
Coal with 90% CCS[3]	89.0	98.6	NB	109.8	89.0	98.6	NB	109.8
Conventional CC	42.4	46.3	42.8	55.0	42.4	46.3	42.8	55.0
Advanced CC	37.8	41.2	40.2	48.1	37.8	41.2	40.2	48.1
Advanced CC with CCS	55.6	67.5	NB	75.7	55.6	67.5	NB	75.7
Conventional CT	84.1	89.3	NB	100.1	84.1	89.3	NB	100.1
Advanced CT	71.1	77.7	77.5	86.7	71.1	77.7	77.5	86.7
Advanced nuclear	75.1	77.5	NB	81.2	75.1	77.5	NB	81.2
Geothermal	38.2	41.0	39.4	46.5	35.9	38.3	36.9	43.1
Biomass	83.1	92.2	92.1	114.1	83.1	92.2	92.1	114.1
Non-dispatchable technologies								
Wind, onshore	38.9	55.9	42.8	72.9	32.8	49.8	36.6	66.8
Wind, offshore	115.5	130.4	117.9	158.8	104.0	117.5	106.5	142.6
Solar PV[4]	40.3	60.0	48.8	106.9	31.5	45.7	37.6	79.5
Solar thermal	138.2	157.1	NB	178.7	107.3	121.2	NB	138.2
Hydroelectric[5]	39.1	39.1	39.1	39.1	39.1	39.1	39.1	39.1

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2023. See note 1 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 are based on additions from 2021–2023. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.
[3]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO_2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Note: EIA calculated the levelized costs for non-dispatchable technologies 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 37%–46% for onshore wind, 41%–50% for offshore wind, 22%–34% for solar PV, 21%–26% for solar thermal, 76% for hydroelectric. 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 2019*

LACE accounts for the differences in the grid services each technology is providing, recognizing that intermittent resources, such as wind or solar, 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. EIA calculated the LACE in this table assuming the same maximum capacity factor as used for 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 for generation requirements and to collect avoided energy costs.

Table 3. Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Coal with 30% CCS[2]	35.6	40.8	NB	48.6
Coal with 90% CCS[2]	35.6	40.8	NB	48.6
Conventional CC	35.5	41.1	38.3	48.4
Advanced CC	35.5	41.1	40.4	48.4
Advanced CC with CCS	35.5	41.1	NB	48.4
Advanced nuclear	35.7	40.3	NB	47.7
Geothermal	41.4	44.6	45.8	48.1
Biomass	35.5	41.3	41.7	48.7
Non-dispatchable technologies				
Wind, onshore	33.3	36.1	33.7	43.7
Wind, offshore	36.4	40.5	39.9	52.2
Solar PV[3]	35.1	43.4	40.3	51.1
Solar thermal	39.8	44.0	NB	51.2
Hydroelectric[4]	41.6	41.6	41.6	41.6

[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 from 2021–2023. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.
[2]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

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. The build decisions in the real world and as modeled in AEO2019, however, are more complex than a simple LACE-to-LCOE comparison because they include such factors as policy and non-economic drivers. Nevertheless, the value-cost ratio (the ratio of LACE-to-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 Tables 4a and 4b, a value index of less than one indicates that the cost of the marginal new unit of capacity exceeds its value to the system, and 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. The *average value-cost ratio* represents the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions. This range of ratios is not based on the ratio between the minimum and maximum values shown in Tables 2 and 3, but rather it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.

Table 4a. Value-cost ratio (capacity-weighted) for new generation resources entering service in 2023 (2018 $/MWh)

Plant type	Average capacity-weighted[1] LCOE with tax credits	Average capacity-weighted[1] LACE	Average value-cost ratio[2]
Dispatchable technologies			
Coal with 30% CCS[3]	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB
Conventional CC	42.8	38.3	0.90
Advanced CC	40.2	40.4	1.00
Advanced CC with CCS	NB	NB	NB
Advanced nuclear	NB	NB	NB
Geothermal	36.9	45.8	0.74
Biomass	92.1	41.7	0.45
Non-dispatchable technologies			
Wind, onshore	36.6	33.7	0.94
Wind, offshore	106.5	39.9	0.37
Solar PV[4]	37.6	40.3	1.07
Solar thermal	NB	NB	NB
Hydroelectric[5]	39.1	41.6	1.06

[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 from 2021–2023. 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 value-cost ratio* represents the economic value or the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.

[3]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). PV=photovoltaic.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

As shown in Table 4a, the capacity-weighted average value-cost ratio is greater than one for solar PV, advanced CC, and hydroelectric in 2023, suggesting that these technologies are being built in regions where they are economically viable. Furthermore, the capacity-weighted average value-cost ratio for advanced CC is close to one, suggesting that the technology has been an attractive marginal capacity addition, and the market has developed the technology to an equilibrium point where the net economic value is close to breakeven after having met load growth and/or displaced higher cost generation.[9]

Table 4b. Value-cost ratio (unweighted) for new generation resources entering service in 2023

Plant type	Average unweighted LCOE with tax credits (2018 $/MWh)	Average unweighted LACE (2018 $/MWh)	Average value-cost ratio[1]	Minimum[2]	Maximum[2]
Dispatchable technologies					
Coal with 30% CCS[3]	104.3	40.8	0.39	0.35	0.44
Coal with 90% CCS[3]	98.6	40.8	0.41	0.37	0.51
Conventional CC	46.3	41.1	0.89	0.79	0.93
Advanced CC	41.2	41.1	1.00	0.87	1.03
Advanced CC with CCS	67.5	41.1	0.61	0.53	0.78
Advanced nuclear	77.5	40.3	0.52	0.46	0.60
Geothermal	38.3	44.6	1.17	1.03	1.34
Biomass	92.2	41.3	0.45	0.41	0.49
Non-dispatchable technologies					
Wind, onshore	49.8	36.1	0.75	0.54	1.04
Wind, offshore	117.5	40.5	0.35	0.30	0.48
Solar PV[4]	45.7	43.4	0.98	0.63	1.16
Solar thermal	121.2	44.0	0.37	0.30	0.43
Hydroelectric[5]	39.1	41.6	1.06	1.06	1.06

[1]The *average value-cost ratio* represents the economic value or the average ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[2]The range of unweighted value-cost ratio is not based on the ratio between the minimum values shown in Tables 2 and 3, but it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.
[3]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

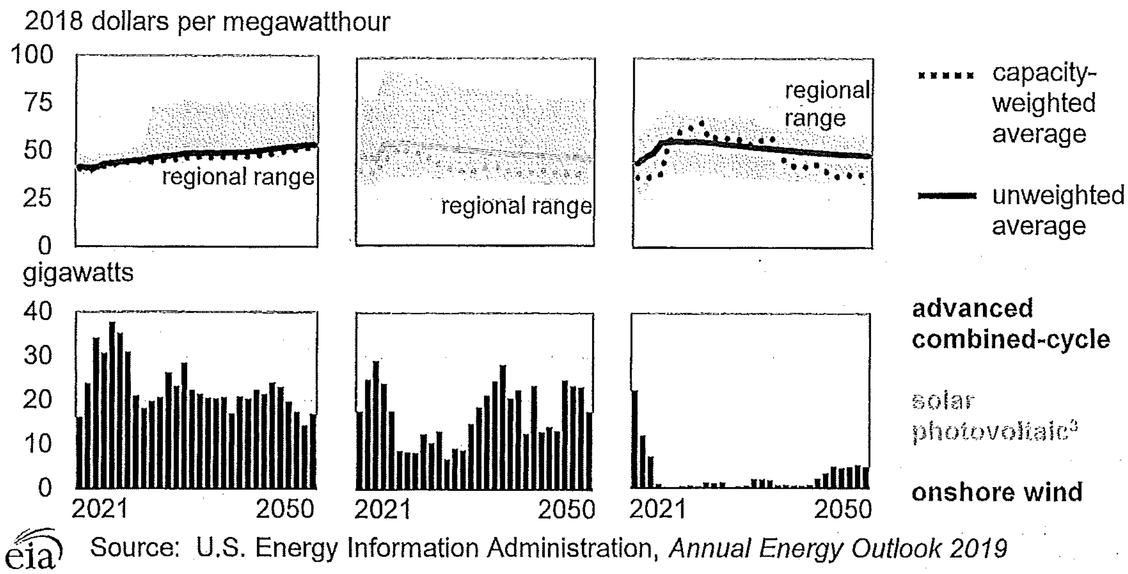
LCOE and LACE projections

Figure 3 shows capacity-weighted and unweighted LCOE for advanced CC, solar PV, and onshore wind plants entering service during the AEO2019 Reference case projection period (2021–50). Changes in costs over time reflect a number of different model factors, sometimes working in different directions. For both solar PV and onshore wind, LCOE increases in the near term with the phase-out and expiration of ITC and PTC, respectively. However, LCOE eventually declines over time because of technology improvement that tends to reduce LCOE through lower capital costs or improved performance (as

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

measured by heat rate for advanced CC plants or capacity factor for onshore wind or solar PV plants), partly offsetting the loss of the tax credits. The availability of high-quality resources may also be a factor. As the best, least-cost resources are used, future development will occur in less favorable areas, potentially resulting in lower-performing resources, higher project development costs, and higher costs to access transmission lines. For advanced CC, changing fuel prices also factor into the change in LCOE, as well as any environmental regulations affecting capital or operating costs.

Figure 3. Capacity-weighted[1] and unweighted levelized cost of electricity[2] projections and three-year moving capacity additions for selected generating technologies, 2021–50



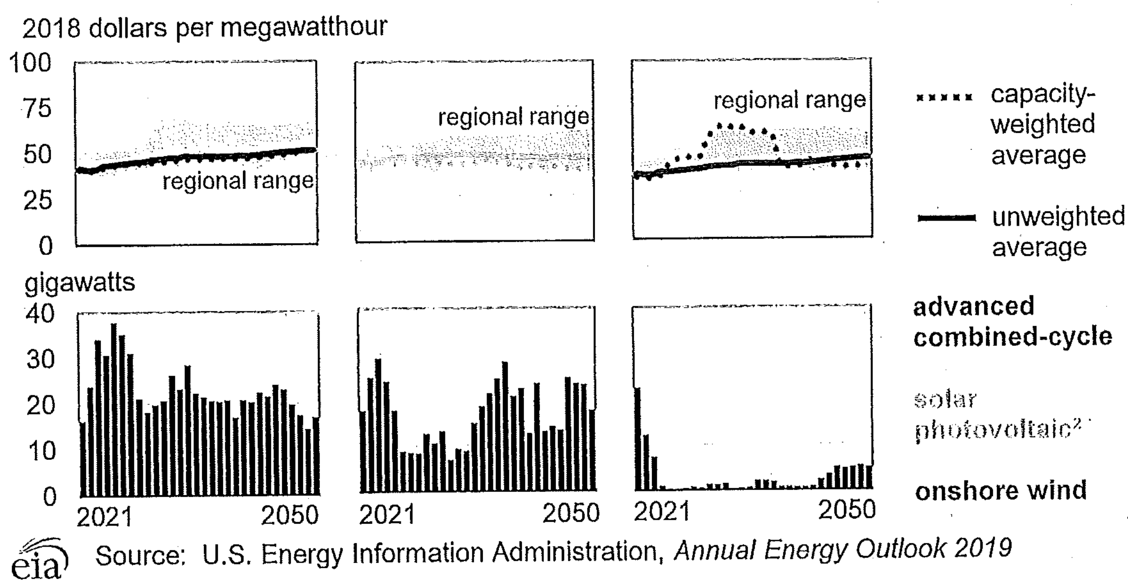
[1]Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2023 are based on additions from 2021–2023.
[2]Levelized-cost includes tax credits available for plants entering service during the projection period. See note 1 in Tables 1a and 1b.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

For advanced CC, the capacity-weighted average LCOE and unweighted average LCOE are not far apart from each other because new builds are expected across several regions throughout the projection period. The capacity-weighted average LCOE and unweighted average LCOE for solar PV are more differentiated because new capacity builds are concentrated primarily in regions with favorable resources and/or higher electricity costs. Solar PV plants continue to be installed throughout the projection period so the capacity-weighted average LCOE stays lower than the unweighted average LCOE, reflecting the build-out in low-cost regions. In the near and mid term, wind builds are significantly influenced by both state and federal policy, leading to higher-cost sites being built. Later in the projection period, well after the influence of federal tax credits has subsided, market economics are more influential in spurring wind capacity additions, and the capacity-weighted average LCOE returns to its expected position below the unweighted line.

The projected regional range for advanced CC is generally narrow in the early years, but this range widens in later years because of the increase in variable O&M costs for plants in California as a result of California's phase-out of fossil generation starting in 2030.

Figure 4 shows capacity-weighted and unweighted averages LACE over time. Changes in the value of generation, represented by LACE, are primarily a function of load growth. Wind and solar may show strong daily or seasonal generation patterns within any given region; as a result, the value of such renewable generation may see significant reductions as these time periods become more saturated with generation from resources with similar hourly operation patterns. As this saturation occurs, generation from new facilities must compete with lower-cost options in the dispatch merit order. LACE for onshore wind is generally lower than other technologies because in many regions, wind plants generate mostly at night or during fall and spring seasons when the demand for and the value of electricity are typically low. Solar PV plants produce most of their energy during the middle of the day, when higher demand increases the value of electricity, resulting in higher LACE.

Figure 4. Capacity-weighted[1] and unweighted levelized avoided cost of electricity projections and three-year moving capacity additions for selected generating technologies, 2021–50

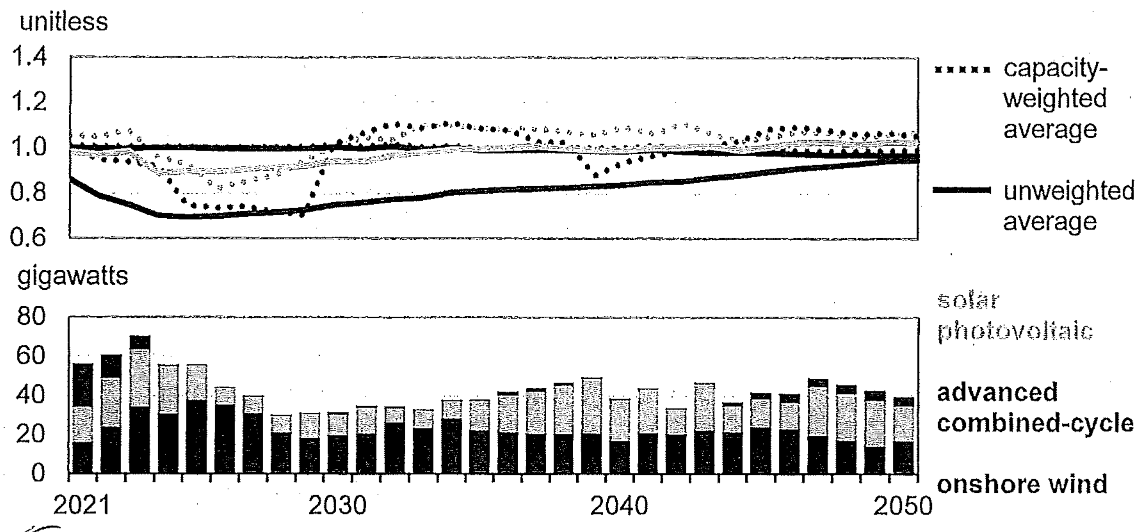


[1]Capacity-weighted average is the average levelized cost per technology, weighted by the new capacity coming online in the previous three years in each region. For example, plants coming online in 2023 are based on additions from 2021–2023.
[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.

Similar behaviors and patterns are observed with LACE as with LCOE. For onshore wind, the capacity-weighted average LACE traces the maximum bound of the regional range because California, which also has the highest LACE starting in 2030, is among the few regions with new capacity expected. The capacity-weighted LACE returns to near the level of unweighted average LACE in later years as new capacity is expected across a wider number of regions.

As illustrated in Figure 5, when considering both the value and cost of building and operating a power plant, advanced CC, solar PV, and onshore wind all reach market equilibrium or a break-even point. The break-even point represents a stable solution point where LACE equals LCOE. Once a technology achieves a value-cost ratio greater than one (*grid parity*), its value-cost ratio tends to remain close to unity as seen with advanced CC. If the value-cost ratio becomes significantly greater than one, the market will quickly build-out the technology until it meets the demand growth and/or displaces the higher cost incumbent generation. Similarly, if the value-cost ratio becomes negative, continued load growth, technology cost declines, or perhaps escalation in the fuel cost of a competing resource will tend to reduce the technology costs and/or increase the technology value to the grid over time.

Figure 5. Value-cost ratio and three-year moving capacity additions for selected generating technologies, 2021–50



Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Market shocks may cause a divergence between LACE and LCOE, therefore disturbing the market equilibrium. These market shocks include technology change, policy developments, or fuel price volatility that can increase or decrease the value-cost ratio of any given technology. However, EIA expects the market to correct the divergence by either building the high-value resource (if the value-cost ratio increased) or waiting for slow-acting factors such as load growth to increase the value in the case of a value-cost ratio decrease, as seen for the capacity-weighted average value-cost ratios of both wind and solar PV.

Appendix A: LCOE tables for new generation resources entering service in 2021

Table A1a. Estimated levelized cost of electricity (capacity-weighted average[1]) for new generation resources entering service in 2021 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Conventional CC	87	8.9	1.5	35.2	1.0	46.7	NA	46.7
Advanced CC	87	7.1	1.4	30.9	1.0	40.5	NA	40.5
Conventional CT	30	25.6	6.9	49.3	2.7	84.6	NA	84.6
Advanced CT	30	19.7	2.7	54.8	3.3	80.6	NA	80.6
Non-dispatchable technologies								
Wind, onshore	43	33.4	13.1	0.0	2.3	48.8	-12.1	36.7
Solar PV[3]	31	41.0	8.3	0.0	2.9	52.2	-12.3	39.9

[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 are based on additions from 2019–2021.
[2]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2021 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC 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]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table A1b. Estimated levelized avoided cost of electricity (unweighted average) for new generation resources entering service in 2021 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Conventional CC	87	9.1	1.5	35.0	1.1	46.8	NA	46.8
Advanced CC	87	7.4	1.4	31.8	1.1	41.6	NA	41.6
Conventional CT	30	28.3	6.9	51.5	3.2	89.9	NA	89.9
Advanced CT	30	18.1	2.7	57.1	3.2	81.1	NA	81.1
Non-dispatchable technologies								
Wind, onshore	41	40.2	13.7	0.0	2.5	56.5	-12.1	44.4
Solar PV[2]	29	50.2	8.9	0.0	3.3	62.5	-15.1	47.4

[1]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2020 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC 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]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table A2. Regional variation in levelized cost of electricity for new generation resources entering service in 2021 (2018 $/MWh)

	Range for total system levelized costs				Range for total system levelized costs with tax credits[1]			
Plant type	Minimum	Simple average	Capacity-weighted average[2]	Maximum	Minimum	Simple average	Capacity-weighted average[2]	Maximum
Dispatchable technologies								
Conventional CC	42.6	46.8	46.7	55.7	42.6	46.8	46.7	55.7
Advanced CC	38.1	41.6	40.5	48.5	38.1	41.6	40.5	48.5
Conventional CT	84.4	89.9	84.6	100.5	84.4	89.9	84.6	100.5
Advanced CT	74.6	81.1	80.6	90.2	74.6	81.1	80.6	90.2
Non-dispatchable technologies								
Wind, onshore	39.6	56.5	48.8	69.3	27.5	44.4	36.7	57.2
Solar PV[3]	41.7	62.5	52.2	111.6	32.6	47.4	39.9	82.8

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2021. See note 1 in Tables A1a and A1b.
[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 are based on additions from 2019–2021.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Note: EIA calculated the levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region that can vary significantly by region. The capacity factor ranges for these technologies are 36%–45% for onshore wind and 22%–34% for solar PV. 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 2019*

Table A3. Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2021 (2018 $/MWh)

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Conventional CC	36.2	41.6	41.7	49.0
Advanced CC	36.2	41.6	40.8	49.0
Non-dispatchable technologies				
Wind, onshore	33.9	36.6	34.7	44.0
Solar PV[4]	33.7	44.8	41.7	52.9

[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 are based on additions from 2019–2021.
[2]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table A4a. Value-cost ratio (capacity-weighted) for new generation resources entering service in 2021 (2018 $/MWh)

Plant type	Average capacity-weighted[1] LCOE with tax credits	Average capacity-weighted[1] LACE	Average value-cost ratio[2]
Dispatchable technologies			
Conventional CC	46.7	41.7	0.89
Advanced CC	40.5	40.8	1.01
Non-dispatchable technologies			
Wind, onshore	36.7	34.7	1.00
Solar PV[3]	39.9	41.7	1.05

[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 from 2019–2021.
[2]The *average value-cost ratio* represents the net economic value or the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table A4b. Value-cost ratio (unweighted) for new generation resources entering service in 2021

Plant type	Average unweighted LCOE with tax credits (2018 $/MWh)	Average unweighted LACE (2018 $/MWh)	Average value-cost ratio[1]	Minimum[2]	Maximum[2]
Dispatchable technologies					
Conventional CC	46.8	41.6	0.89	0.79	0.93
Advanced CC	41.6	41.6	1.00	0.88	1.04
Non-dispatchable technologies					
Wind, onshore	44.4	36.6	0.86	0.60	1.23
Solar PV[3]	47.4	44.8	0.98	0.61	1.20

[1]The *average value-cost ratio* represents the net economic value or the average ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[2]The range of unweighted value-cost ratio is not based on the ratio between the minimum values shown in Tables A2 and A3, but it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.
[3]Costs are expressed in terms of net AC power available to the grid for the installed capacity.
CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Appendix B: LCOE and LACE tables for new generation resources entering service in 2040

Table B1a. Estimated levelized cost of electricity (capacity-weighted average[1]) for new generation resources entering service in 2040 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[2]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[3]	NB	NB	NB	NB	NB	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB	NB	NB	NB	NB	NB
Conventional CC	87	7.8	1.5	40.3	1.1	50.7	NA	50.7
Advanced CC	87	6.5	1.4	37.9	1.2	46.9	NA	46.9
Advanced CC with CCS	NB	NB	NB	NB	NB	NB	NB	NB
Conventional CT	NB	NB	NB	NB	NB	NB	NB	NB
Advanced CT	30	15.0	2.7	63.2	3.8	84.6	NA	84.6
Advanced nuclear	NB	NB	NB	NB	NB	NB	NB	NB
Geothermal	93	18.8	15.9	0.0	1.5	36.2	-1.9	34.3
Biomass	NB	NB	NB	NB	NB	NB	NB	NB
Non-dispatchable technologies								
Wind, onshore	42	27.6	13.2	0.0	2.7	43.5	NA	43.5
Wind, offshore	NB	NB	NB	NB	NB	NB	NB	NB
Solar PV[4]	30	30.9	8.6	0.0	3.1	42.6	-3.1	39.5
Solar thermal	NB	NB	NB	NB	NB	NB	NB	NB
Hydroelectric[5]	73	39.4	13.7	1.4	1.9	56.3	NA	56.3

[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 from 2038–2040. 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 tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2040 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC 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]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table B1b. Estimated levelized cost of electricity (unweighted average) for new generation resources entering service in 2040 (2018 $/MWh)

Plant type	Capacity factor (%)	Levelized capital cost	Levelized fixed O&M	Levelized variable O&M	Levelized transmission cost	Total system LCOE	Levelized tax credit[1]	Total LCOE including tax credit
Dispatchable technologies								
Coal with 30% CCS[2]	85	58.9	9.7	36.7	1.2	106.5	NA	106.5
Coal with 90% CCS[2]	85	47.9	11.2	36.5	1.2	96.8	NA	96.8
Conventional CC	87	9.2	1.5	43.0	1.2	55.0	NA	55.0
Advanced CC	87	6.9	1.4	39.7	1.2	49.2	NA	49.2
Advanced CC with CCS	87	17.5	4.5	50.6	1.2	73.8	NA	73.8
Conventional CT	30	27.8	6.9	62.2	3.6	100.5	NA	100.5
Advanced CT	30	15.6	2.7	63.7	3.6	85.5	NA	85.5
Advanced nuclear	90	49.3	13.1	10.0	1.1	73.5	NA	73.5
Geothermal	93	22.6	16.4	0.0	1.5	40.5	-2.3	38.3
Biomass	83	31.0	15.7	37.1	1.3	85.1	NA	85.1
Non-dispatchable technologies								
Wind, onshore	40	34.6	13.8	0.0	2.9	51.3	NA	51.3
Wind, offshore	45	87.5	20.3	0.0	2.6	110.4	NA	110.4
Solar PV[3]	29	40.0	8.9	0.0	3.7	52.7	-4.0	48.7
Solar thermal	25	99.5	33.3	0.0	4.7	137.5	-10.0	127.5
Hydroelectric[4]	63	35.9	9.7	1.9	2.2	49.6	NA	49.6

[1]The tax credit component is based on targeted federal tax credits such as the PTC or ITC available for some technologies. It reflects tax credits available only for plants entering service in 2040 and the substantial phase out of both the PTC and ITC as scheduled under current law. Technologies not eligible for PTC or ITC 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]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table B2. Regional variation in levelized cost of electricity for new generation resources entering service in 2040 (2018 $/MWh)

	Range for total system levelized costs				Range for total system levelized costs with tax credits[1]			
Plant type	Minimum	Simple average	Capacity-weighted average[2]	Maximum	Minimum	Simple average	Capacity-weighted average[2]	Maximum
Dispatchable technologies								
Coal with 30% CCS[3]	90.8	106.5	NB	160.0	90.8	106.5	NB	160.0
Coal with 90% CCS[3]	84.2	96.8	NB	111.8	84.2	96.8	NB	111.8
Conventional CC	50.6	55.0	50.7	81.1	50.6	55.0	50.7	81.1
Advanced CC	44.4	49.2	46.9	78.1	44.4	49.2	46.9	78.1
Advanced CC with CCS	60.8	73.8	NB	82.3	60.8	73.8	NB	82.3
Conventional CT	92.2	100.5	NB	137.1	92.2	100.5	NB	137.1
Advanced CT	77.1	85.5	84.6	119.8	77.1	85.5	84.6	119.8
Advanced nuclear	71.4	73.5	NB	77.0	71.4	73.5	NB	77.0
Geothermal	35.8	40.5	36.2	43.3	33.9	38.3	34.3	40.9
Biomass	77.4	85.1	NB	109.4	77.4	85.1	NB	109.4
Non-dispatchable technologies								
Wind, onshore	35.3	51.3	43.5	66.0	35.3	51.3	43.5	66.0
Wind, offshore	97.8	110.4	NB	133.7	97.8	110.4	NB	133.7
Solar PV[4]	36.0	52.7	42.6	92.6	33.5	48.7	39.5	84.9
Solar thermal	121.3	137.5	NB	156.5	112.7	127.5	NB	145.3
Hydroelectric[5]	38.9	49.6	56.3	64.6	38.9	49.6	56.3	64.6

[1]Levelized cost with tax credits reflects tax credits available for plants entering service in 2040. See note 1 in Tables B1a and B1b.

[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 are based on additions from 2038–2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.

[3]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). CT=combustion turbine. PV=photovoltaic.

Note: EIA calculated the levelized costs for non-dispatchable technologies are calculated based on the capacity factor for the marginal site modeled in each region that can vary significantly by region. The capacity factor ranges for these technologies are 37%–46% for onshore wind, 41%–50% for offshore wind, 22%–34% for solar PV, 21%–26% for solar thermal, 30%–79% for hydroelectric. 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 2019*

Table B3. Regional variation in levelized avoided cost of electricity for new generation resources entering service in 2040 (2018 $/MWh)

Plant type	Minimum	Simple average	Capacity-weighted average[1]	Maximum
Dispatchable technologies				
Coal with 30% CCS[2]	42.5	48.0	NB	67.3
Coal with 90% CCS[2]	42.5	48.0	NB	67.3
Conventional CC	42.4	48.3	44.5	67.1
Advanced CC	42.4	48.3	46.8	67.1
Advanced CC with CCS	42.4	48.3	NB	67.1
Advanced nuclear	41.5	46.8	NB	56.7
Geothermal	48.8	55.6	65.8	66.7
Biomass	42.6	48.5	NB	67.4
Non-dispatchable technologies				
Wind, onshore	37.8	41.9	40.2	61.3
Wind, offshore	41.9	47.4	NB	73.2
Solar PV[3]	38.4	46.8	42.9	58.5
Solar thermal	41.1	48.4	NB	55.3
Hydroelectric[4]	41.7	51.1	57.6	65.8

[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 from 2038–2040. Technologies for which capacity additions are not expected do not have a capacity-weighted average and are marked as *NB* or not built.

[2]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). PV=photovoltaic.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table B4a. Value-cost ratio (capacity-weighted) for new generation resources entering service in 2040

Plant type	Average capacity-weighted[1] LCOE with tax credits (2018 $/MWh)	Average capacity-weighted[1] LACE (2018 $/MWh)	Average value-cost ratio[2]
Dispatchable technologies			
Coal with 30% CCS[3]	NB	NB	NB
Coal with 90% CCS[3]	NB	NB	NB
Conventional CC	50.7	44.5	0.88
Advanced CC	46.9	46.8	1.00
Advanced CC with CCS	NB	NB	NB
Advanced nuclear	NB	NB	NB
Geothermal	34.3	65.8	1.93
Biomass	NB	NB	NB
Non-dispatchable technologies			
Wind, onshore	43.5	40.2	0.94
Wind, offshore	NB	NB	NB
Solar PV[4]	39.5	42.9	1.09
Solar thermal	NB	NB	NB
Hydroelectric[5]	56.3	57.6	1.02

[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 from 2038–2040. 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 value-cost ratio* represents the economic value or the average of the ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.

[3]Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). PV=photovoltaic.

Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

Table B4b. Value-cost ratio (unweighted) for new generation resources entering service in 2040

Plant type	Average unweighted LCOE with tax credits (2018 $/MWh)	Average unweighted LACE (2018 $/MWh)	Average value-cost ratio[1]	Minimum[2]	Maximum[3]
Dispatchable technologies					
Coal with 30% CCS[3]	106.5	48.0	0.45	0.42	0.52
Coal with 90% CCS[3]	96.8	48.0	0.50	0.44	0.60
Conventional CC	55.0	48.3	0.88	0.81	0.94
Advanced CC	49.2	48.3	0.99	0.86	1.03
Advanced CC with CCS	73.8	48.3	0.66	0.55	0.83
Advanced nuclear	73.5	46.8	0.64	0.58	0.74
Geothermal	38.3	55.6	1.48	1.19	1.96
Biomass	85.1	48.5	0.57	0.52	0.70
Non-dispatchable technologies					
Wind, onshore	51.3	41.9	0.84	0.63	1.08
Wind, offshore	110.4	47.4	0.43	0.36	0.72
Solar PV[4]	48.7	46.8	0.99	0.69	1.19
Solar thermal	127.5	48.4	0.38	0.29	0.45
Hydroelectric[5]	49.6	51.1	1.04	0.89	1.21

[1]The *average value-cost ratio* represents the economic value or the average ratio of LACE-to-LCOE calculation, where the ratio is calculated for each of the 22 regions based on the cost with tax credits for each technology, as available.
[2]The range of unweighted value-cost ratio is not based on the ratio between the minimum values shown in Tables B2 and B3, but it represents the lower and upper bound resulting from the ratio of LACE-to-LCOE calculations for each of the 22 regions.
[3] Because the New Source Performance Standard (NSPS) under Section 111(b) of the Clean Air Act requires conventional coal plants to be built with CCS to meet specific CO2 emission standards, EIA modeled two levels of CCS removal: 30%, which meets the NSPS, and 90%, which exceeds the NSPS but may be seen as a build option in some scenarios. The coal plant with 30% CCS is assumed to incur a three-percentage-point increase to its cost of capital to represent the 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, EIA assumes that hydroelectric generation has seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.
CCS=carbon capture and sequestration. CC=combined-cycle (natural gas). PV=photovoltaic.
Source: U.S. Energy Information Administration, *Annual Energy Outlook 2019*

NOVEMBER 2018

LAZARD'S LEVELIZED COST OF ENERGY ANALYSIS—VERSION 12.0

LAZARD

Introduction

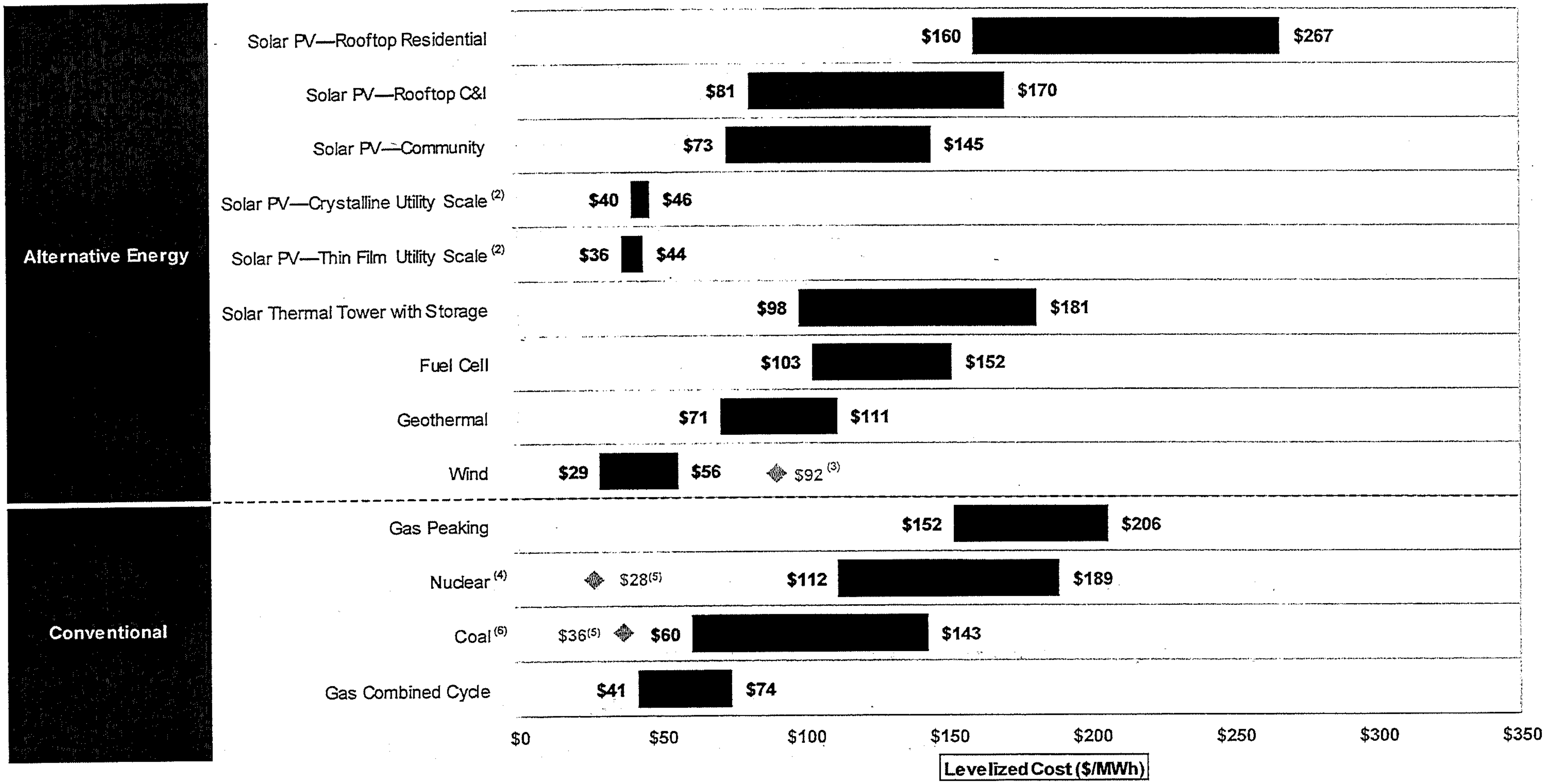
Lazard's Levelized Cost of Energy ("LCOE") analysis addresses the following topics:

- Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities, as relevant, for U.S. federal tax subsidies, fuel prices and costs of capital
- Illustration of how the LCOE of wind and utility-scale solar compare to the marginal cost of selected conventional generation technologies
- Historical LCOE comparison of various utility-scale generation technologies
- Illustration of the historical LCOE declines for wind and utility-scale solar technologies
- Illustration of how the LCOE of utility-scale solar compares to the LCOE of gas peaking and how the LCOE of wind compares to the LCOE of gas combined cycle generation
- Comparison of assumed capital costs on a $/kW basis for various generation technologies
- Decomposition of the LCOE for various generation technologies by capital cost, fixed operations and maintenance expense, variable operations and maintenance expense and fuel cost, as relevant
- A methodological overview of Lazard's approach to our LCOE analysis
- Considerations regarding the usage characteristics and applicability of various generation technologies
- An illustrative comparison of the cost of carbon abatement of various Alternative Energy technologies relative to conventional generation
- Summary assumptions for Lazard's LCOE analysis
- Summary of Lazard's approach to comparing the LCOE for various conventional and Alternative Energy generation technologies

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.)

Levelized Cost of Energy Comparison—Unsubsidized Analysis

Certain Alternative Energy generation technologies are cost-competitive with conventional generation technologies under certain circumstances(1)



Source: *Lazard estimates.*

Note: Here and throughout this presentation, unless otherwise indicated, the analysis assumes 60% debt at 8% interest rate and 40% equity at 12% cost. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital" for cost of capital sensitivities.

(1) Such observation does not take into account other factors that would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.).

(2) Unless otherwise indicated herein, the low end represents a single-axis tracking system and the high end represents a fixed-tilt design.

(3) Represents the estimated implied midpoint of the LCOE of offshore wind, assuming a capital cost range of approximately $2.25 – $3.80 per watt.

(4) Unless otherwise indicated, the analysis herein does not reflect decommissioning costs or the potential economic impacts of federal loan guarantees or other subsidies.

(5) Represents the midpoint of the marginal cost of operating fully depreciated coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to the decommissioning and site restoration costs. Inputs are derived from a benchmark of operating, fully depreciated coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research. Please see page titled "Levelized Cost of Energy Comparison—Alternative Energy versus Marginal Cost of Selected Existing Conventional Generation" for additional details.

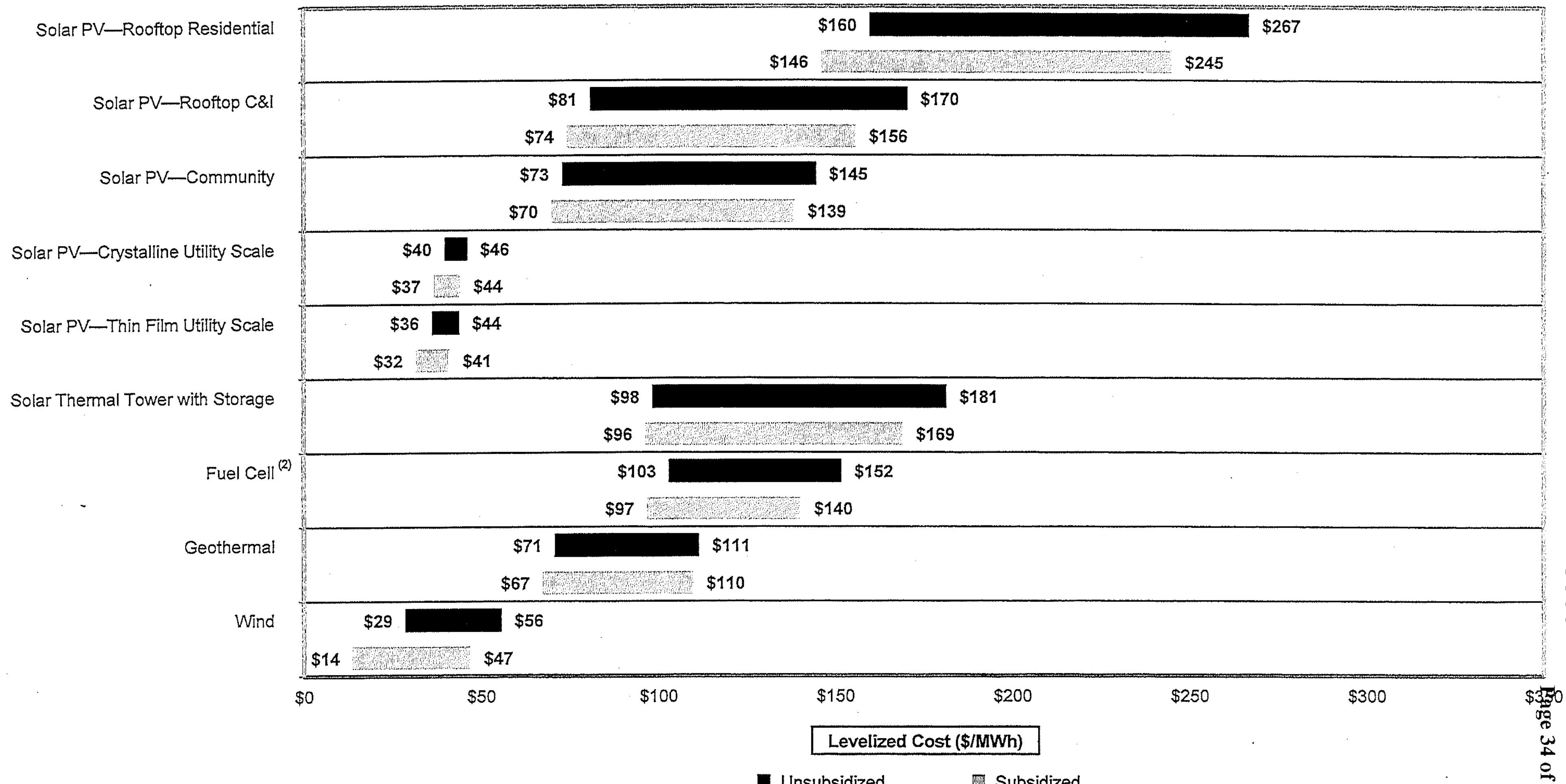
(6) Unless otherwise indicated, the analysis herein reflects average of Northern Appalachian Upper Ohio River Barge and Pittsburgh Seam Rail coal. High end incorporates 90% carbon capture and compression. Does not include cost of transportation and storage.

Cause No. 45253
OUCC Attachment JEH-2
Page 33 of 50

This study has been prepared by Lazard for general informational purposes only, and it is not intended to be, and should not be construed as, financial or

Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies(1)

Given the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC") in December 2015 and resulting subsidy visibility, U.S. federal tax subsidies remain an important component of the economics of Alternative Energy generation technologies



Source: *Lazard estimates.*

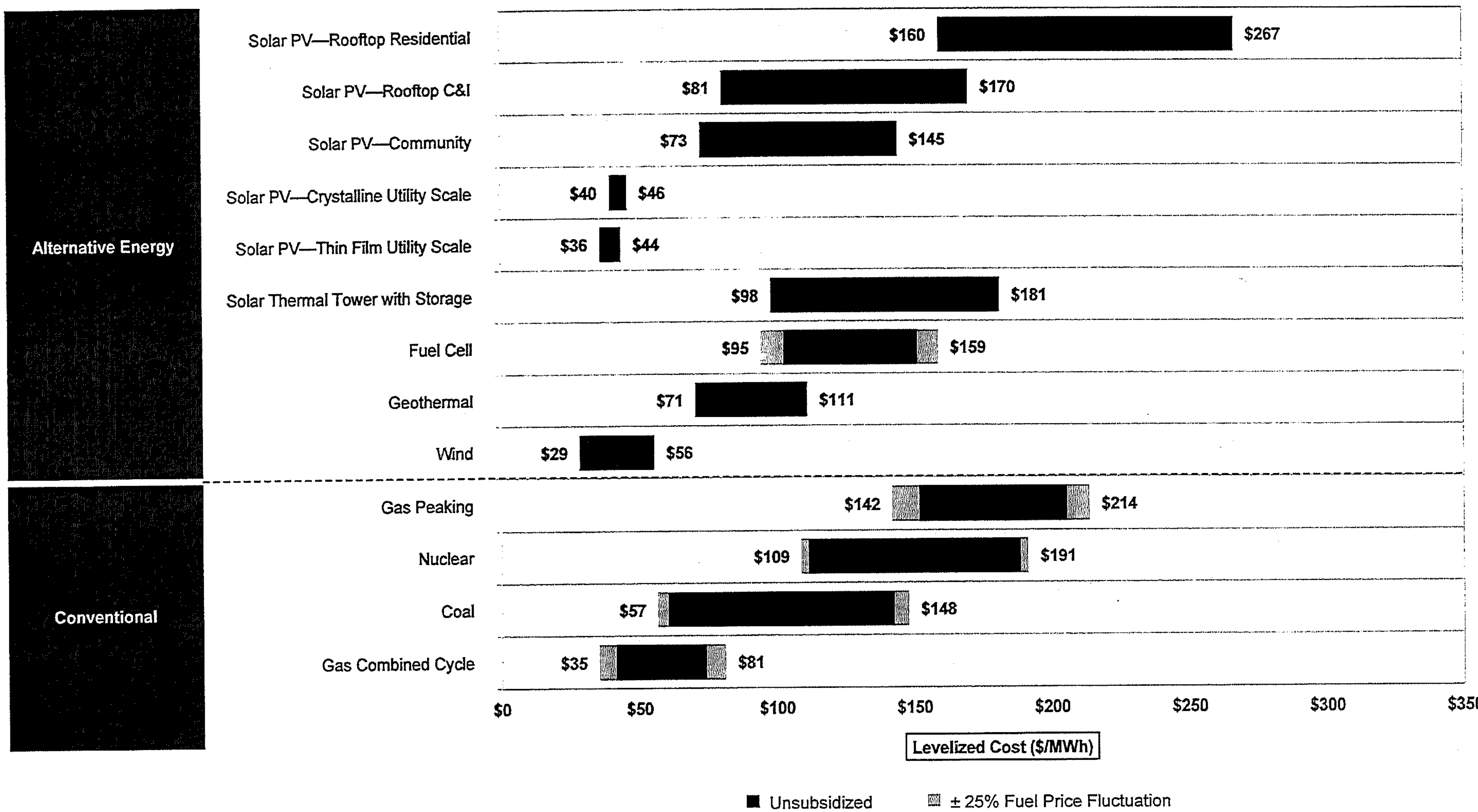
Note: The sensitivity analysis presented on this page also includes sensitivities related to the U.S. Tax Cuts and Jobs Act ("TCJA") of 2017. The TCJA contains several provisions that impact the LCOE of various generation technologies (e.g., a reduced federal corporate income tax rate, an ability to elect immediate bonus depreciation, limitations on the deductibility of interest expense and restrictions on the utilization of past net operating losses). On balance, the TCJA reduced the LCOE of conventional generation technologies and marginally increased the LCOE for Alternative Energy technologies.

(1) The sensitivity analysis presented on this page assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, tax equity and debt.

(2) The ITC for fuel cell technologies is capped at $1,500/0.5 kW of capacity.

Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices

Variations in fuel prices can materially affect the LCOE of conventional generation technologies, but direct comparisons against "competing" Alternative Energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)



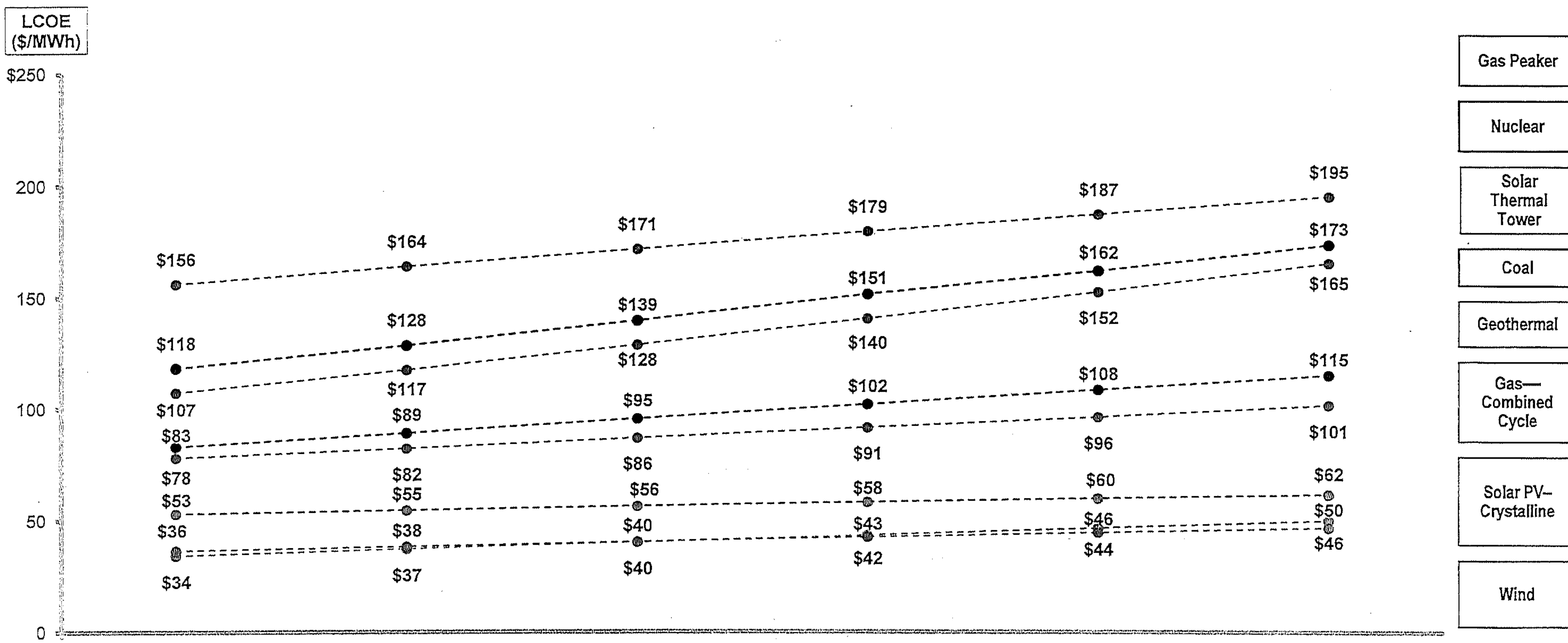
Cause No. 45253
OUCC Attachment JEH-2
Page 35 of 50

Source: *Lazard estimates.*

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration for utility-scale generation technologies is the impact of the availability and cost of capital[1] on LCOE values; availability and cost of capital have a particularly significant impact on Alternative Energy generation technologies, whose costs reflect essentially the return on, and of, the capital investment required to build them

Midpoint of Unsubsidized LCOE[2]



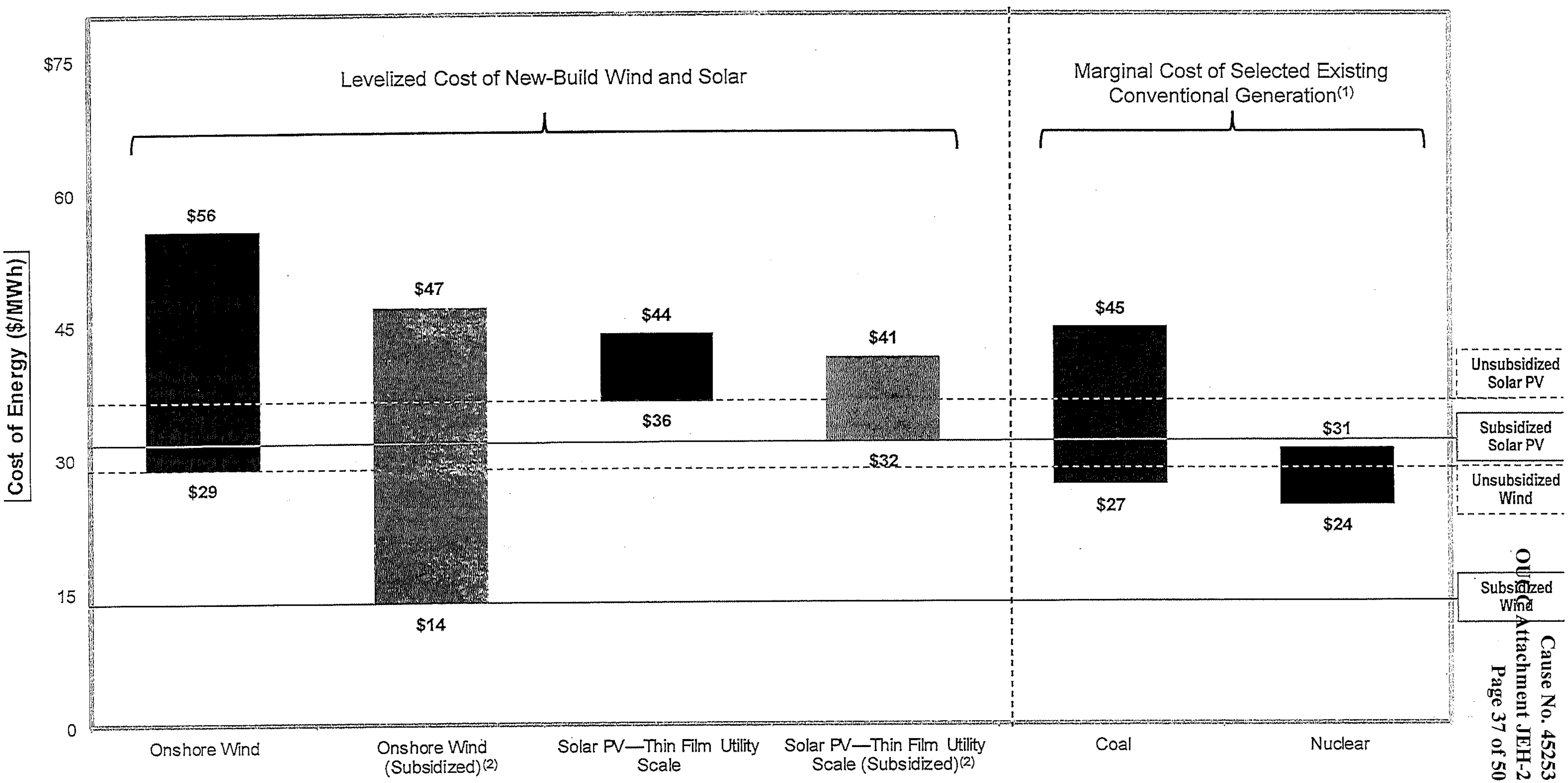
After-Tax IRR/WACC	5.4%	6.2%	6.9%	7.7%	8.4%	9.2%
Cost of Equity	9.0%	10.0%	11.0%	12.0%	13.0%	14.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Cause No. 45253
OUCC Attachment JEH-2
Page 36 of 50

Source: *Lazard estimates.*
Note: Analysis assumes 60% debt and 40% equity.
(1) Cost of capital as used herein indicates the cost of capital for the asset/plant and not the cost of capital of a particular investor/owner.
(2) Reflects the average of the high and low LCOE for each respective cost of capital assumption.

Levelized Cost of Energy Comparison—Alternative Energy versus Marginal Cost of Selected Existing Conventional Generation

Certain Alternative Energy generation technologies, which became cost-competitive with conventional generation technologies several years ago, are, in some scenarios, approaching an LCOE that is at or below the marginal cost of existing conventional generation technologies



Source: *Lazard estimates.*

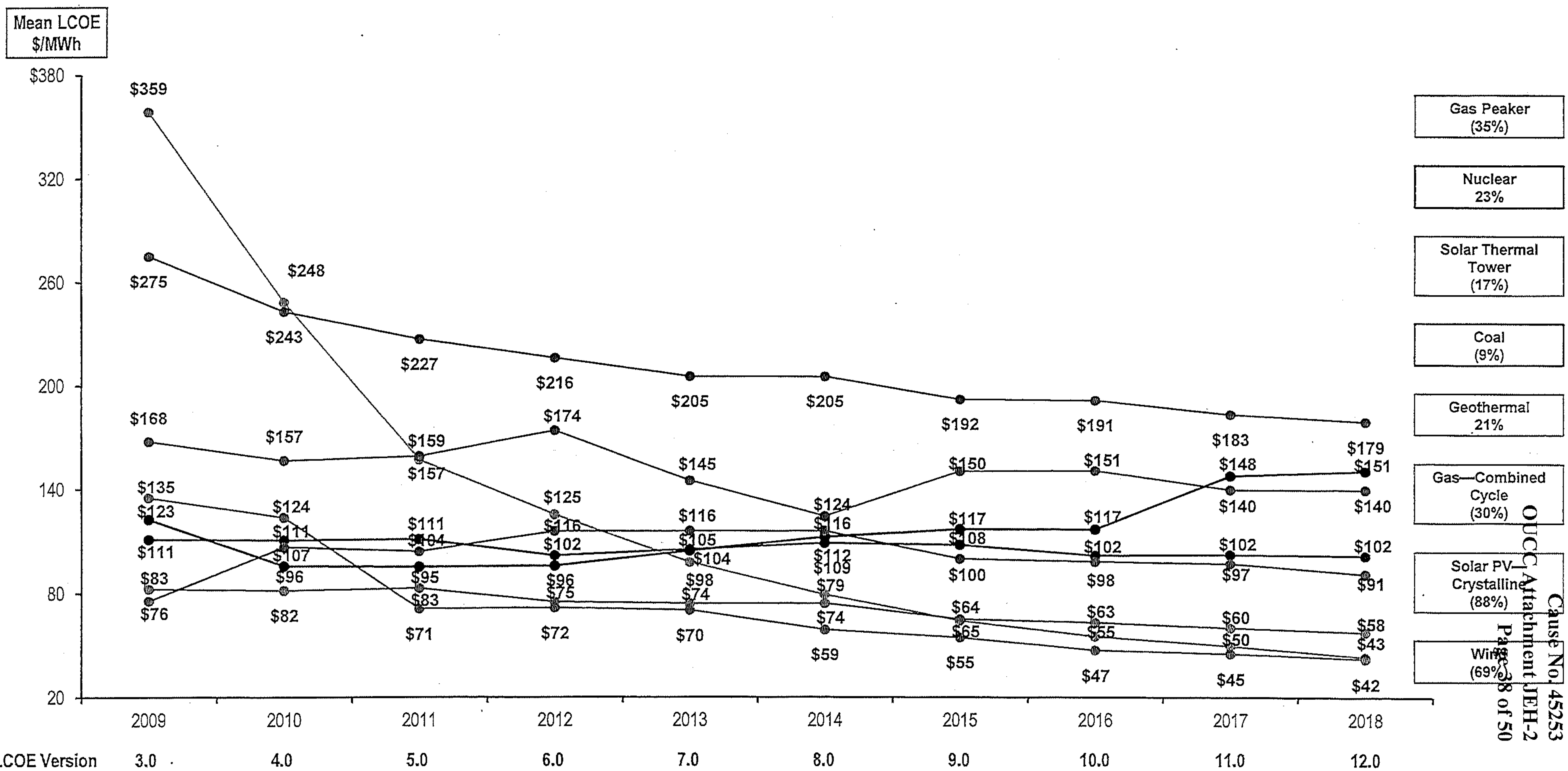
(1) Represents the marginal cost of operating, fully depreciated coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned coal plant is equivalent to the decommissioning and site restoration costs. Inputs are derived from a benchmark of operating, fully depreciated coal and nuclear assets across the U.S. Capacity factors, fuel, variable and fixed operating expenses are based on upper and lower quartile estimates derived from Lazard's research.

(2) The subsidized analysis includes sensitivities related to the TCJA and U.S. federal tax subsidies. Please see page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

Levelized Cost of Energy Comparison—Historical Utility-Scale Generation Comparison

Lazard's unsubsidized LCOE analysis indicates significant historical cost declines for utility-scale Alternative Energy generation technologies driven by, among other factors, decreasing supply chain costs, improving technologies and increased competition

Selected Historical Mean Unsubsidized LCOE Values[(1)]



Cause No. 45253
OUCC Attachment JEH-2
Page 38 of 50

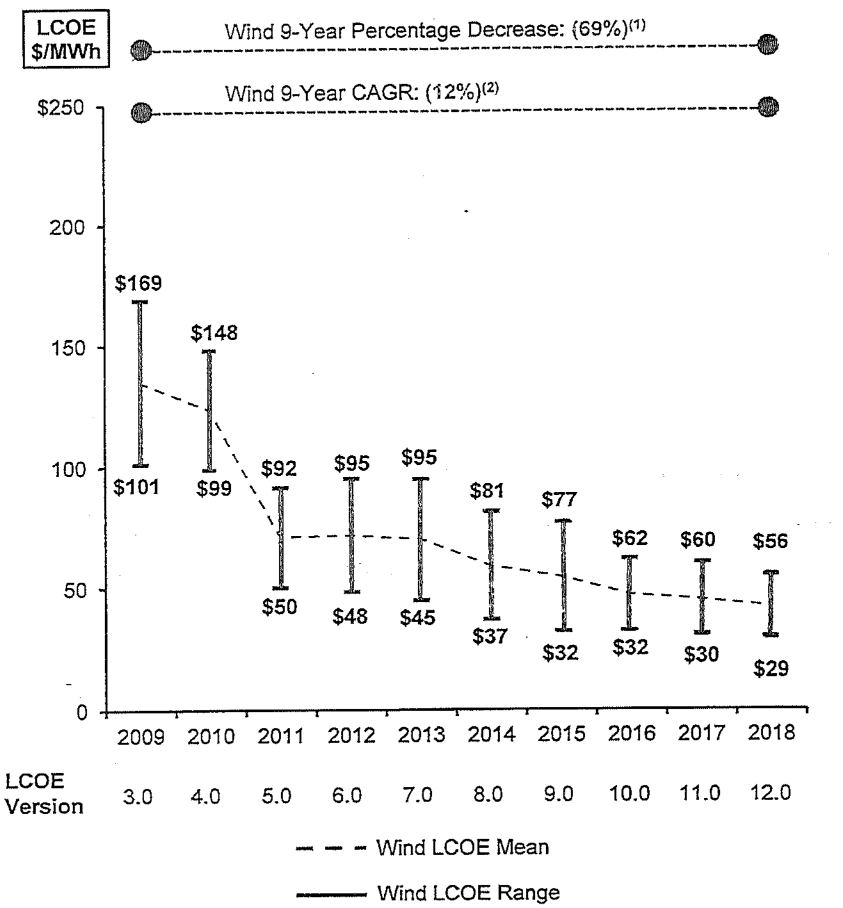
Source: Lazard estimates.

(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE—Version 3.0.

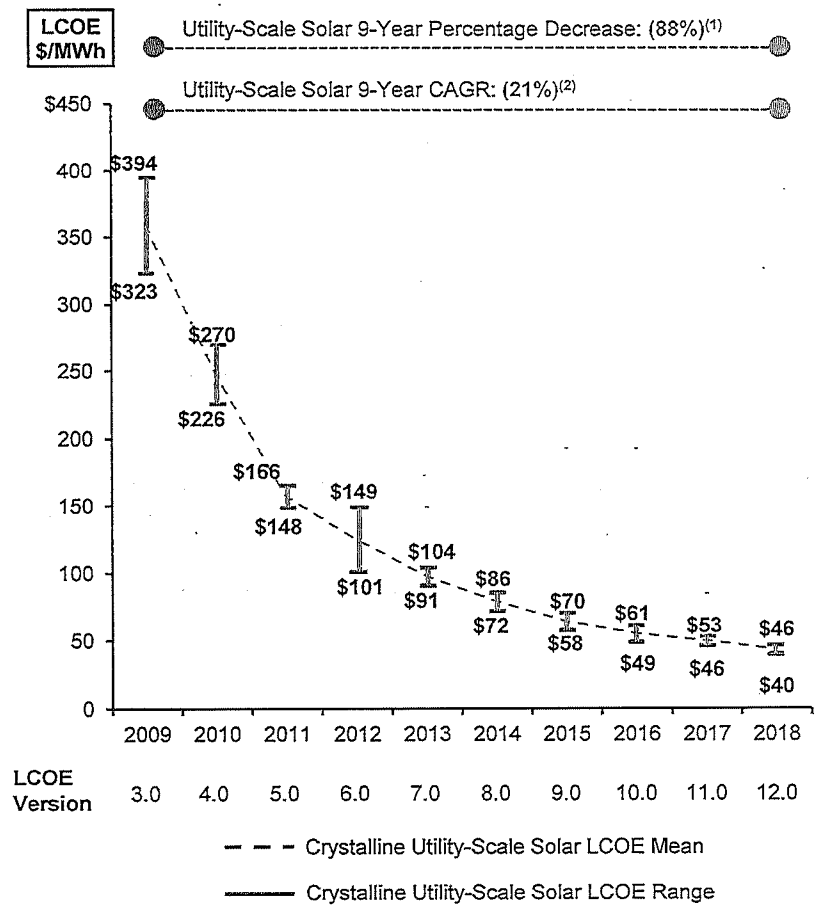
Levelized Cost of Energy Comparison—Historical Alternative Energy LCOE Declines

In light of material declines in the pricing of system components (e.g., panels, inverters, turbines, etc.) and improvements in efficiency, among other factors, wind and utility-scale solar PV have seen dramatic historical LCOE declines; however, over the past several years the rate of such LCOE declines have started to flatten

Unsubsidized Wind LCOE



Unsubsidized Solar PV LCOE

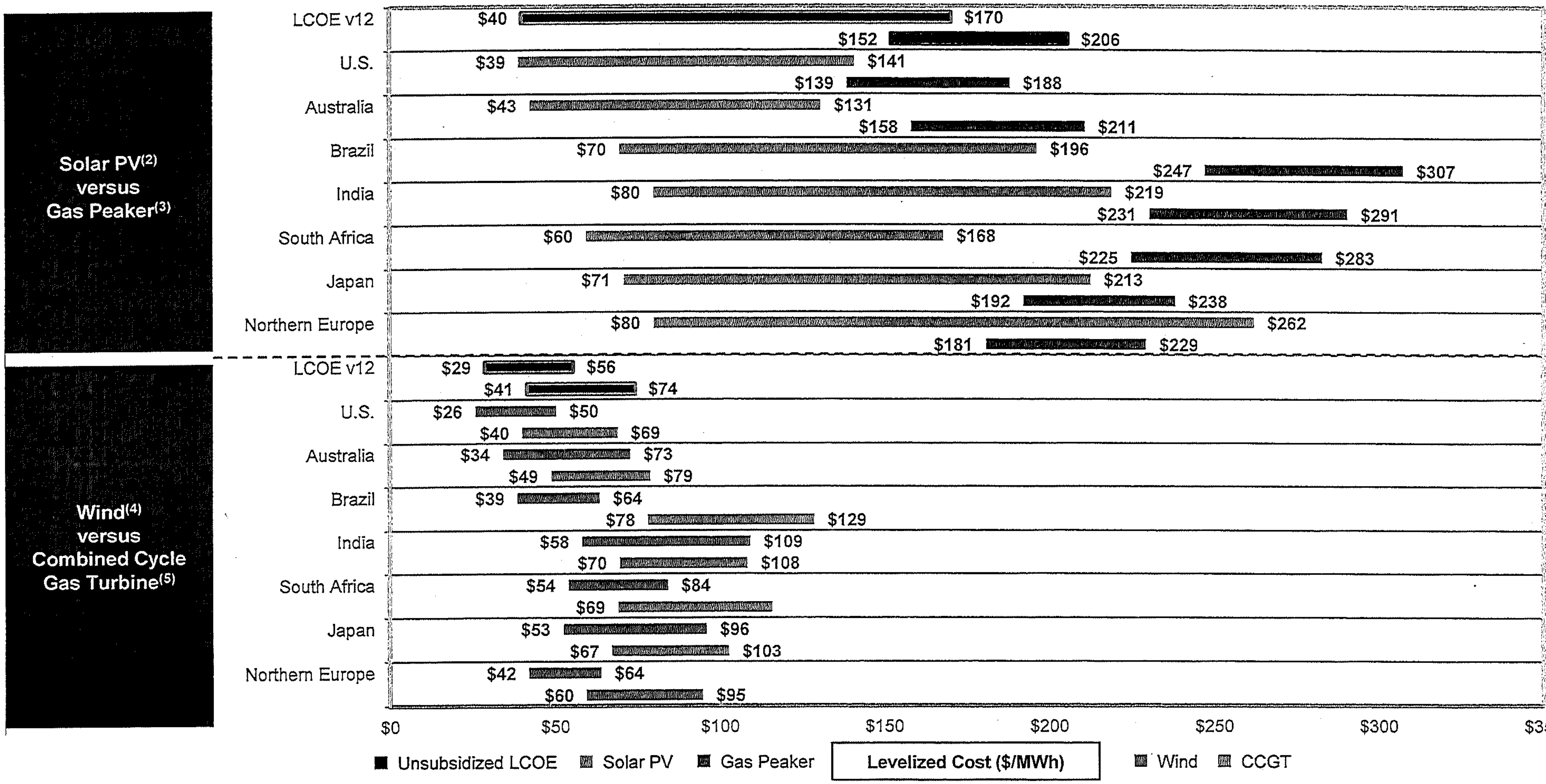


Cause No. 45253
OUCC Attachment JEH-2
Page 39 of 50

Source: *Lazard estimates.*
(1) Represents the average percentage decrease of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Solar PV versus Peaking and Wind versus CCGT—Global Markets(1)

Solar PV and wind have become an increasingly attractive resource relative to conventional generation technologies with similar generation profiles; without storage, however, these resources lack the dispatch characteristics of such conventional generation technologies



Source: Lazard estimates.

(1) Equity IRRs are assumed to be 10% for the U.S., 12% for Australia, Japan and Northern Europe and 18% for Brazil, India and South Africa. Cost of debt is assumed to be 6% for the U.S., 8% for Australia, Japan and Northern Europe, 14.5% for Brazil, 13% for India and 11.5% for South Africa.

(2) Low end assumes crystalline utility-scale solar with a single-axis tracker. High end assumes rooftop C&I solar. Solar projects assume illustrative capacity factors of 21% – 28% for the U.S., 26% – 30% for Australia, 26% – 28% for Brazil, 22% – 23% for India, 27% – 29% for South Africa, 16% – 18% for Japan and 13% – 16% for Northern Europe.

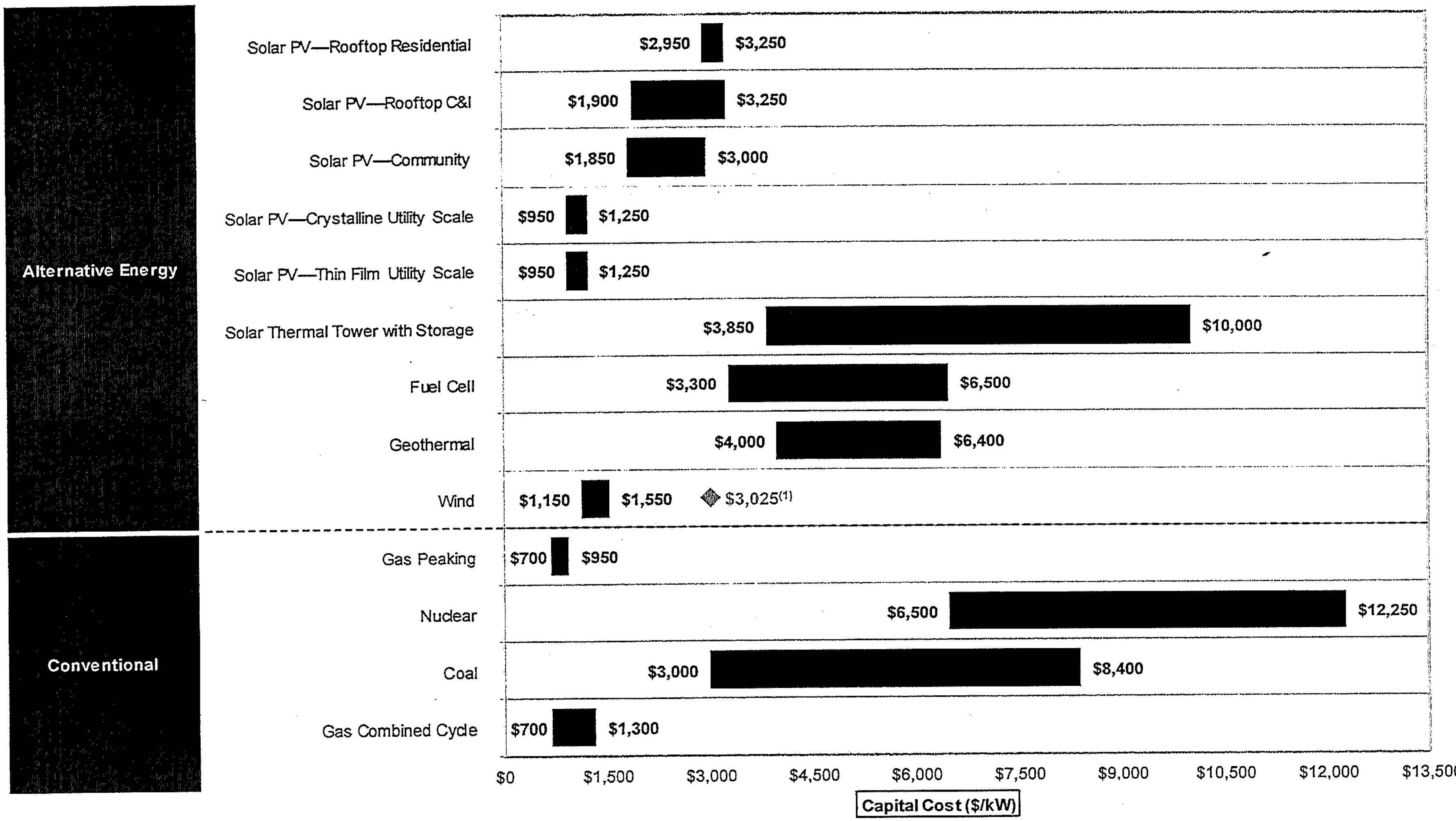
(3) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes a capacity factor of 10% for all geographies.

(4) Wind projects assume illustrative capacity factors of 38% – 55% for the U.S., 29% – 46% for Australia, 45% – 55% for Brazil, 25% – 35% for India, 31% – 36% for South Africa, 22% – 30% for Japan and 33% – 38% for Northern Europe.

(5) Assumes natural gas prices of $3.45 for the U.S., $4.00 for Australia, $8.00 for Brazil, $7.00 for India, South Africa and Japan and $6.00 for Northern Europe (all in U.S. $ per MMBtu). Assumes capacity factors of 43% – 80% on the high and low ends, respectively, for all geographies.

Capital Cost Comparison

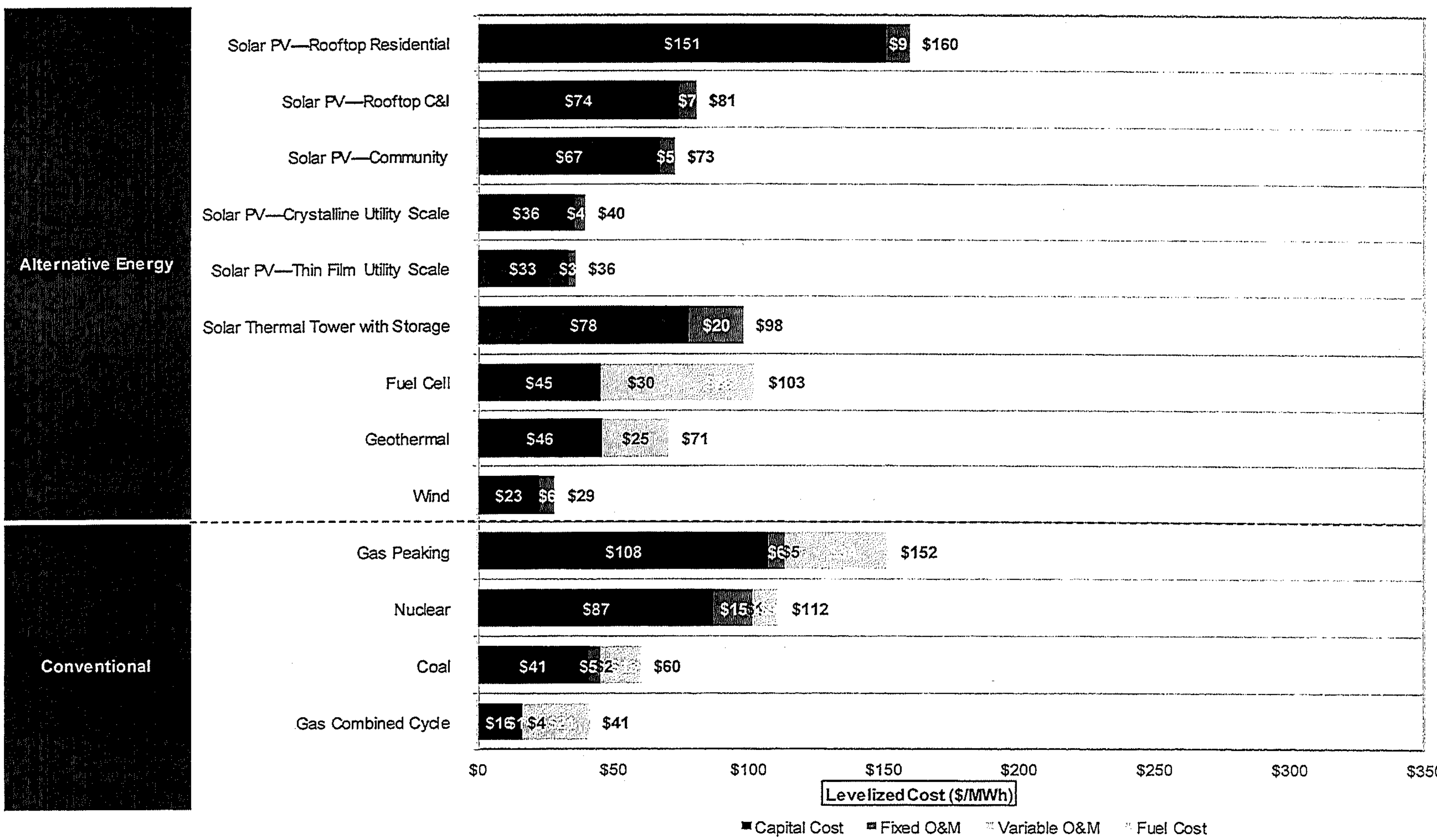
While capital costs for a number of Alternative Energy generation technologies are currently in excess of some conventional generation technologies, declining costs for many Alternative Energy generation technologies, coupled with uncertain long-term fuel costs for conventional generation technologies, are working to close formerly wide gaps in LCOE values



Source: *Lazard estimates.*
(1) Represents the estimated midpoint of the total capital cost for offshore wind.

Levelized Cost of Energy Components—Low End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of Alternative Energy generation technologies is the ability of technological development and increased production volumes to materially lower operating expenses and capital costs for Alternative Energy generation technologies

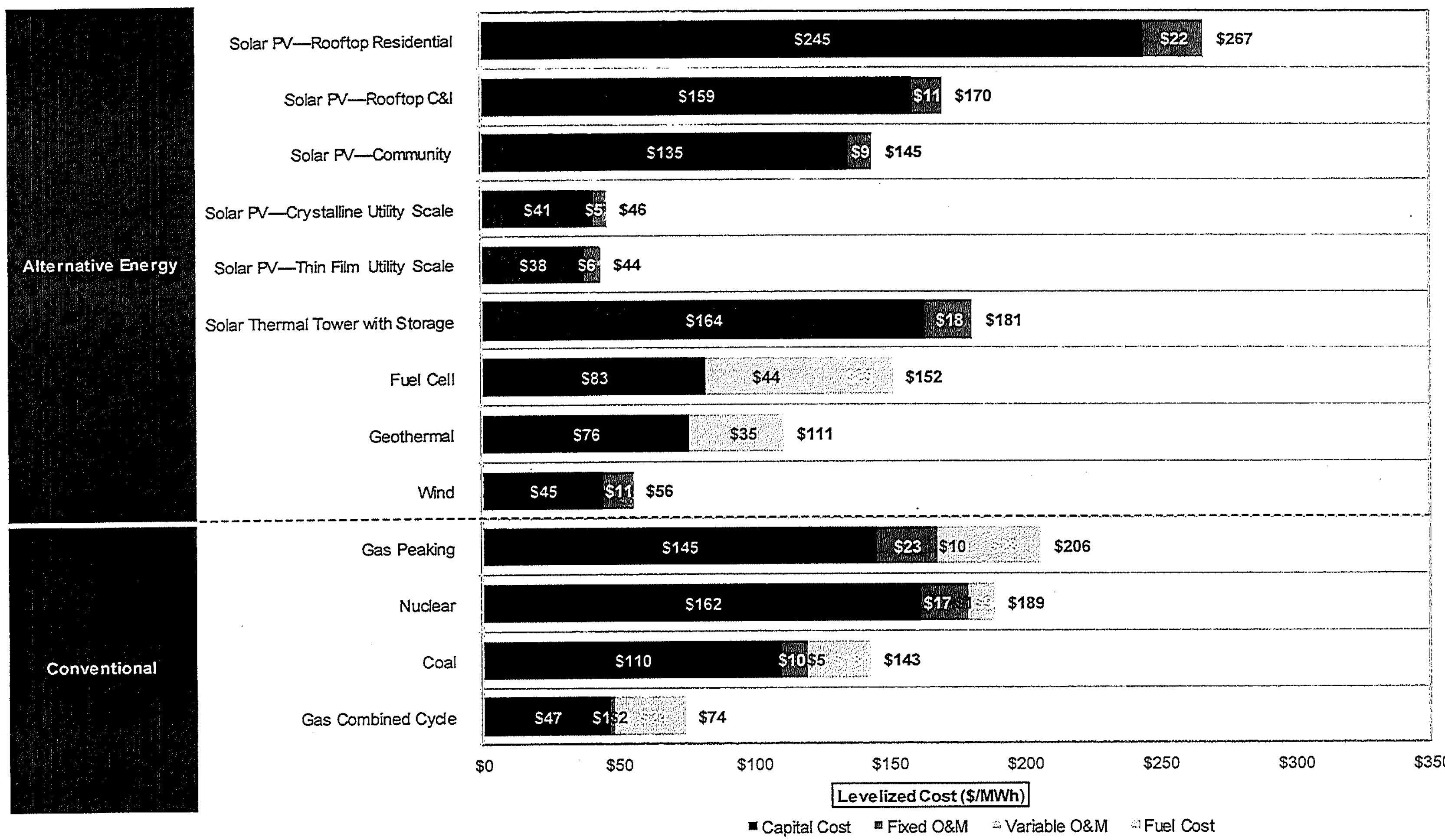


Cause No. 45253
OUCC Attachment JEH-2
Page 42 of 50

Source: Lazard estimates.

Levelized Cost of Energy Components—High End

Certain Alternative Energy generation technologies are already cost-competitive with conventional generation technologies; a key factor regarding the long-term competitiveness of Alternative Energy generation technologies is the ability of technological development and increased production volumes to materially lower operating expenses and capital costs for Alternative Energy generation technologies



Cause No. 45253
OUCC Attachment JEH-2
Page 43 of 50

Source: Lazard estimates.

Levelized Cost of Energy Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOE analysis consists of creating a power plant model representing an illustrative project for each relevant technology and solving for the $/MWh figure that results in a levered IRR equal to the assumed cost of equity (see appendix for detailed assumptions by technology)

Unsubsidized Wind — High Case Sample Illustrative Calculations

Year (1)		0	1	2	3	4	5		20
Capacity (MW)	(A)		150	150	150	150	150		150
Capacity Factor	(B)		38%	38%	38%	38%	38%		38%
Total Generation ('000 MWh)	(A) x (B) = (C)*		499	499	499	499	499		499
Levelized Energy Cost ($/MWh)	*(D)*		*$55.6*	*$55.6*	*$55.6*	*$55.6*	*$55.6*		*$55.6*
Total Revenues	**(C) x (D) = (E)***		$27.8	$27.8	$27.8	$27.8	$27.8		$27.8
Total Fuel Cost	(F)		–	–	–	–	–		–
Total O&M	(G)*		5.5	5.6	5.7	5.9	6.0		8.4
Total Operating Costs	**(F) + (G) = (H)**		$5.5	$5.6	$5.7	$5.9	$6.0		$8.4
EBITDA	**(E) - (H) = (I)**		$22.3	$22.2	$22.0	$21.9	$21.8		$19.4
Debt Outstanding - Beginning of Period	(J)		$139.5	$136.7	$133.7	$130.5	$127.0		$24.8
Debt - Interest Expense	(K)		(11.2)	(10.9)	(10.7)	(10.4)	(10.2)		(2.0)
Debt - Principal Payment	(L)		(2.8)	(3.0)	(3.2)	(3.5)	(3.8)		(11.9)
Levelized Debt Service	(K) + (L) = (M)		($13.9)	($13.9)	($13.9)	($13.9)	($13.9)		($13.9)
EBITDA	**(I)**		$22.3	$22.2	$22.0	$21.9	$21.8		$19.4
Depreciation (MACRS)	(N)		(46.5)	(74.4)	(44.6)	(26.8)	(26.8)		–
Interest Expense	(K)		(11.2)	(10.9)	(10.7)	(10.4)	(10.2)		(2.0)
Taxable Income	**(I) + (N) + (K) = (O)**		($35.4)	($63.2)	($33.3)	($15.3)	($15.2)		$17.4
Tax Benefit (Liability) (2)	**(O) x (tax rate) = (P)**		$14.2	$25.3	$13.3	$6.1	$6.1		($7.0)
After-Tax Net Equity Cash Flow	**(I) + (M) + (P) = (Q)**	($93.0)(3)	$22.5	$33.5	$21.4	$14.1	$13.9		($1.5)
IRR For Equity Investors		12.0%							

Key Assumptions (4)	
Capacity (MW)	150
Capacity Factor	38%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$36.5
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Equity	40.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	40%
Economic Life (years) (5)	20
MACRS Depreciation (Year Schedule)	5
Capex	
EPC Costs ($/kW)	$1,550
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,550
Total Capex ($mm)	$233

Technology-dependent
Levelized

Source: *Lazard estimates.*
Note: Wind—High LCOE case presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Assumes full monetization of tax benefits or losses immediately.
(3) Reflects initial cash outflow from equity investors.
(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

Energy Resources—Matrix of Applications

While the LCOE for Alternative Energy generation technologies is, in some cases, competitive with conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate load vs. peaking or intermittent technologies)

- This analysis does not take into account potential social and environmental externalities or reliability-related considerations

		Carbon Neutral/ REC Potential	Location			Dispatch			
			Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Base-Load
Alternative Energy	Solar PV(1)	✓	✓	✓	Universal(2)	✓	✓		
	Solar Thermal	✓		✓	Varies	✓	✓	✓	
	Fuel Cell	✗	✓		Universal				✓
	Geothermal	✓		✓	Varies				✓
	Onshore Wind	✓		✓	Varies	✓			
Conventional	Gas Peaking	✗	✓	✓	Universal		✓	✓	
	Nuclear	✓		✓	Rural				✓
	Coal	✗(3)		✓	Co-located or rural				✓
	Gas Combined Cycle	✗		✓	Universal			✓	✓

Source: *Lazard estimates.*
(1) Represents the full range of solar PV technologies; low end represents thin film utility-scale solar single-axis tracking, high end represents the high end of rooftop residential solar.
(2) Qualification for RPS requirements varies by location.
(3) For the purposes of this analysis, carbon neutrality also considers the emissions produced during plant construction and fuel extraction.

Cause No. 45253
OUCC Attachment JEH-2
Page 45 of 50

Cost of Carbon Abatement Comparison

As policymakers consider ways to limit carbon emissions, Lazard's LCOE analysis provides insight into the implicit "costs of carbon avoidance", as measured by the abatement value offered by Alternative Energy generation technologies. This analysis suggests that policies designed to promote wind and utility-scale solar development could be a particularly cost-effective means of limiting carbon emissions; providing an implied value of carbon abatement of $26 – $34/Ton vs. Coal and $10 – $25/Ton vs. Gas Combined Cycle

- These observations do not take into account potential social and environmental externalities or reliability or grid-related considerations

		Conventional Generation			Alternative Energy Generation			
	Units	Coal	Gas Combined Cycle	Nuclear	Wind	Solar PV Rooftop	Solar PV Utility Scale	Solar Thermal with Storage
Capital Investment/KW of Capacity [1]	$/kW	$3,000	$700	$6,500	$1,150	$2,950	$950	$3,850
Total Capital Investment	$mm	1,800	490	4,030	1,162	8,673	1,558	5,044
Facility Output	MW	600	700	620	1,010	2,940	1,640	1,310
Capacity Factor	%	93%	80%	90%	55%	19%	34%	43%
Effective Facility Output	MW	558	558	558	558	558	558	558
MWh/Year Produced [2]	GWh/yr	4,888	4,888	4,888	4,888	4,888	4,888	4,888
Levelized Cost of Energy	$/MWh	$60	$41	$112	$29	$160	$36	$98
Total Cost of Energy Produced	$mm/yr	$296 2	$203	$546	$140	$781	$178 1	$480
CO_2 Equivalent Emissions	Tons/MWh	0.92	0.51	—	—	—	—	—
Carbon Emitted	mm Tons/yr	4.51	2.50	—	—	—	—	—
Difference in Carbon Emissions	mm Tons/yr							
vs. Coal		—	2.01	4.51	4.51	4.51	4.51 3	4.51
vs. Gas		—	—	2.50	2.50	2.50	2.50	2.50
Difference in Total Energy Cost	$mm/yr							
vs. Coal		—	($93)	$250	($155)	$485	($118) 4	$185
vs. Gas		—	—	$343	($63)	$578	($25)	$278
Implied Abatement Value/(Cost)	$/Ton							
vs. Coal		—	$46	($55)	$34	($108)	$26 5	($41)
vs. Gas		—	—	($137)	$25	($231)	$10	($111)

: Favorable vs. Coal/Gas : Unfavorable vs. Coal/Gas

Implied Carbon Abatement Value Calculation (Solar vs. Coal)—Methodology

4 Difference in Total Energy Cost (Solar vs. Coal) = 1 – 2
= $178 mm/yr (Solar) – $296 mm/yr (Coal) = ($118) mm/yr

5 Implied Carbon Abatement Value (Solar vs. Coal) = 4 ÷ 3
= $118 mm/yr ÷ 4.51 mm Tons/yr = $26/Ton

Source: *Lazard estimates.*
(1) Inputs for each of the various technologies are those associated with the low end LCOE.
(2) All facilities illustratively sized to produce 4,888 GWh/yr.

Levelized Cost of Energy—Key Assumptions

		Solar PV				
	Units	Rooftop—Residential	Rooftop—C&I	Community	Utility Scale—Crystalline [2]	Utility Scale—Thin Film [2]
Net Facility Output	MW	0.005	1	5	50	50
Total Capital Cost [1]	$/kW	$2,950 – $3,250	$1,900 – $3,250	$1,850 – $3,000	$1,250 – $950	$1,250 – $950
Fixed O&M	$/kW-yr	$14.50 – $25.00	$15.00 – $20.00	$12.00 – $16.00	$12.00 – $9.00	$12.00 – $9.00
Variable O&M	$/MWh	—	—	—	—	—
Heat Rate	Btu/kWh	—	—	—	—	—
Capacity Factor	%	19% – 13%	25% – 20%	25% – 20%	32% – 21%	34% – 23%
Fuel Price	$/MMBtu	—	—	—	—	—
Construction Time	Months	3	3	4 – 6	9	9
Facility Life	Years	25	25	30	30	30
Levelized Cost of Energy	$/MWh	$160 – $267	$81 – $170	$73 – $145	$40 – $46	$36 – $44

Source: *Lazard estimates.*
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.
(2) Left column represents the assumptions used to calculate the low end LCOE for single-axis tracking. Right column represents the assumptions used to calculate the high end LCOE for fixed-tilt design. Assumes 50 MW system in high insolation jurisdiction (e.g., Southwest U.S.).

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Solar Thermal Tower with Storage	Fuel Cell	Geothermal	Wind—Onshore	Wind—Offshore
Net Facility Output	MW	135 – 110	2.4	20 – 50	150	210 – 385
Total Capital Cost [(1)]	$/kW	$3,850 – $10,000	$3,300 – $6,500	$4,000 – $6,400	$1,150 – $1,550	$2,250 – $3,800
Fixed O&M	$/kW-yr	$75.00 – $80.00	—	—	$28.00 – $36.50	$80.00 – $110.00
Variable O&M	$/MWh	—	$30.00 – $44.00	$25.00 – $35.00	—	—
Heat Rate	Btu/kWh	—	8,027 – 7,260	—	—	—
Capacity Factor	%	43% – 52%	95%	90% – 85%	55% – 38%	55% – 45%
Fuel Price	$/MMBtu	—	3.45	—	—	—
Construction Time	Months	36	3	36	12	12
Facility Life	Years	35	20	25	20	20
Levelized Cost of Energy	$/MWh	$98 – $181	$103 – $152	$71 – $111	$29 – $56	$62 – $121

Source: *Lazard estimates.*
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Levelized Cost of Energy—Key Assumptions (cont'd)

	Units	Gas Peaking	Nuclear	Coal	Gas Combined Cycle
Net Facility Output	MW	241 – 50	2,200	600	550
Total Capital Cost [(1)]	$/kW	$700 – $950	$6,500 – $12,250	$3,000 – $8,400	$700 – $1,300
Fixed O&M	$/kW-yr	$5.00 – $20.00	$115.00 – $135.00	$40.00 – $80.00	$6.00 – $5.50
Variable O&M	$/MWh	$4.70 – $10.00	$0.75 – $0.75	$2.00 – $5.00	$3.50 – $2.00
Heat Rate	Btu/kWh	9,804 – 8,000	10,450 – 10,450	8,750 – 12,000	6,133 – 6,900
Capacity Factor	%	10%	90%	93%	80%
Fuel Price	$/MMBtu	$3.45 – $3.45	$0.85 – $0.85	$1.45 – $1.45	$3.45 – $3.45
Construction Time	Months	12 – 18	69 – 69	60 – 66	24 – 24
Facility Life	Years	20	40	40	20
Levelized Cost of Energy	$/MWh	$152 – $206	$112 – $189	$60 – $143	$41 – $74

Source: Lazard estimates.
(1) Includes capitalized financing costs during construction for generation types with over 24 months construction time.

Summary Considerations

Lazard has conducted this analysis comparing the LCOE for various conventional and Alternative Energy generation technologies in order to understand which Alternative Energy generation technologies may be cost-competitive with conventional generation technologies, either now or in the future, and under various operating assumptions, as well as to understand which technologies are best suited for various applications based on locational requirements, dispatch characteristics and other factors. We find that Alternative Energy technologies are complementary to conventional generation technologies, and believe that their use will be increasingly prevalent for a variety of reasons, including environmental and social consequences of various conventional generation technologies, RPS requirements, carbon regulations, continually improving economics as underlying technologies improve and production volumes increase and government subsidies in certain regions.

In this analysis, Lazard's approach was to determine the LCOE, on a $/MWh basis, that would provide an after-tax IRR to equity holders equal to an assumed cost of equity capital. Certain assumptions (e.g., required debt and equity returns, capital structure, etc.) were identical for all technologies in order to isolate the effects of key differentiated inputs such as investment costs, capacity factors, operating costs, fuel costs (where relevant) and other important metrics on the LCOE. These inputs were originally developed with a leading consulting and engineering firm to the Power & Energy Industry, augmented with Lazard's commercial knowledge where relevant. This analysis (as well as previous versions) has benefited from additional input from a wide variety of Industry participants.

Lazard has not manipulated capital costs or capital structure for various technologies, as the goal of the study was to compare the current state of various generation technologies, rather than the benefits of financial engineering. The results contained in this study would be altered by different assumptions regarding capital structure (e.g., increased use of leverage) or capital costs (e.g., a willingness to accept lower returns than those assumed herein).

Key sensitivities examined included fuel costs and tax subsidies. Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: import tariffs; capacity value vs. energy value; stranded costs related to distributed generation or otherwise; network upgrade, transmission, congestion or other integration-related costs; significant permitting or other development costs, unless otherwise noted; and costs of complying with various environmental regulations (e.g., carbon emissions offsets or emissions control systems). This analysis also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distribution generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.).

AFFIRMATION

I affirm, under the penalties for perjury, that the foregoing representations are true.

John E. Haselden
Senior Utility Analyst
Indiana Office of Utility Consumer Counselor
Cause No. 45253
Duke Energy Indiana, LLC

October 30, 2019
Date

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing was served by electronic mail this 30th day of October to the following:

DEI
Kelley A. Karn
Melanie D. Price
Elizabeth A. Herriman
Andrew J. Wells
Duke Energy Business Services, LLC
kelley.karn@duke-energy.com
melanie.price@duke-energy.com
beth.herriman@duke-energy.com
andrew.wells@duke-energy.com

Kay E. Pashos
Mark R. Alson
Ice Miller LLP
kay.pashos@icemiller.com
mark.alson@icemiller.com

Nucor
Anne E. Becker
Amanda Tyler
Ellen Tennant
Lewis & Kappes, P.C.
abecker@Lewis-Kappes.com
atyler@Lewis-Kappes.com
atennant@Lewis-Kappes.com

Peter J. Mattheis
Shaun C. Mohler
Stone Mattheis Xenopoulos & Brew, PC
pjm@smxblaw.com
smohler@smxblaw.com

Sierra Club
Kathryn A. Watson
Cantrell Strenski & Mehringer, LLP
kwatson@csmlawfirm.com
Tony Mendoza
tony.mendoza@sierraclub.org

Walmart
Eric E. Kinder
Barry A. Naum
Spilman Thomas & Battle, PLLC
ekinder@spilmanlaw.com
bnaum@spilmanlaw.com

INDUSTRIAL GROUP
Tabitha L. Balzer
Aaron A. Schmoll
Todd A Richardson
Lewis & Kappes, P.C.
TBalzer@Lewis-Kappes.com
ASchmoll@LewisKappes.com
trichardson@LewisKappes.com

CAC, INCAA, EWG
Jennifer A. Washburn
Margo Tucker
Citizens Action Coalition of Indiana, Inc.
jwashburn@citact.org
mtucker@citact.org

SDI
Robert K. Johnson, Esq.
rjohnson@utilitylaw.us

Damon E. Xenopoulos
Stone Mattheis Xenopoulos & Brew, PC
dex@smxblaw.com

Kroger
Kurt J. Boehm, Esq.
Jody Kyler Cohn
Boehm, Kurtz & Lowry
kboehm@bkllawfirm.com
JKylerCohn@BKLlawfirm.com

Kevin Higgins
Energy Strategies, LLC
khiggins@energystrat.com

John P. Cook
John Cook & Associates
john.cookassociates@earthlink.net

ICC
Jeffery A. Earl
Bose McKinney LLP
jearl@boselaw.com

ChargePoint
David T. McGimpsey
Bingham Greenebaum Doll LLP
dmcgimpsey@bgdlegal.com

FEA Dept. of Navy
Shannon M. Matera, Esq.
NAVFAC Southwest, Dept. of the Navy
Shannon.Matera@navy.mil

Cheryl Ann Stone, Esq.
NSWC Crane, Dept. of the Navy
Cheryl.Stone1@navy.mil

Kay Davoodi
Larry Allen
Utility Rates and Studies Office
NAVFAC HQ, Dept. of the Navy
Khojasteh.Davoodi@navy.mil
larry.r.allen@navy.mil

Hoosier Energy
Christopher M. Goffinet
Huber Goffinet & Hagedorn
cgoffinet@hepn.com

Mike Mooney
Hoosier Energy REC, Inc.
mmooney@hepn.com

ILDC
Neil E. Gath
Gath Law Office
ngath@gathlaw.com

Erin Hutson
LIUNA
ehutson@liuna.org

Wabash Valley
Randolph G. Holt
Jeremy Fetty
Liane K. Steffes
Parr Richey
r_holt@wvpa.com
jfetty@parrlaw.com
lsteffes@parrlaw.com

Greenlots
Erin C. Borissov
Parr Richey
eborissov@wvpa.com

OUCC Consultants
David J. Garrett
Resolve Utility Consulting PLLC
dgarrett@resolveuc.com

Glenn A. Watkins
Jennifer R. Dolen
Technical Associates, Inc.
watkinsg@tai-econ.com
jenny.dolen@tai-econ.com

Lane Kollen
J. Kennedy & Associates
lkollen@jkenn.com

David Dismukes
Julie McKenna
Acadian Consulting
daviddismukes@acadianconsulting.com
juliemckenna@acadianconsulting.com

Scott Franson
Deputy Consumer Counselor

INDIANA OFFICE OF UTILITY CONSUMER COUNSELOR
PNC CENTER
115 West Washington Street, Suite 1500 South
Indianapolis, IN 46204
infomgt@oucc.in.gov
317/232-2494 – Telephone
317/232-5923 – Facsimile