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LCOE+

LEVELIZED COST OF ENERGY+

June 2024

WITH SUPPORT FROM Roland Berger

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Executive Summary

Executive Summary—Levelized Cost of Energy Version 17.0[(1)]

The results of our Levelized Cost of Energy ("LCOE") analysis reinforce what we observe across the Power, Energy & Infrastructure Industry—sizable and well-capitalized companies that can take advantage of supply chain and other economies of scale, and that have strong balance sheet support to weather fluctuations in the macro environment, will continue leading the build-out of new renewable energy assets. This is particularly true in a rising LCOE environment like what we have observed in this year's analysis. Amplifying this observation, and not overtly covered in our report, are the complexities related to currently observed demand growth and grid-related constraints, among other factors. Key takeaways from Version 17.0 of Lazard's LCOE include:

1. Low End LCOE Values Increase; Overall Ranges Tighten

   Despite high end LCOE declines for selected renewable energy technologies, the low ends of our LCOE have increased for the first time ever, driven by the persistence of certain cost pressures (e.g., high interest rates, etc.). These two phenomena result in tighter LCOE ranges (offsetting the significant range expansion observed last year) and relatively stable LCOE averages year-over-year. The persistence of elevated costs continues to reinforce the central theme noted above—sizable and well-capitalized companies that can take advantage of supply chain and other economies of scale, and that have strong balance sheet support to weather fluctuations in the macro environment, will continue leading the build-out of new renewable energy assets.

2. Baseload Power Needs Will Require Diverse Generation Fleets

   Despite the sustained cost-competitiveness of renewable energy technologies, diverse generation fleets will be required to meet baseload power needs over the long term. This is particularly evident in today's increasing power demand environment driven by, among other things, the rapid growth of artificial intelligence, data center deployment, reindustrialization, onshoring and electrification. As electricity generation from intermittent renewables increases, the timing imbalance between peak customer demand and renewable energy production is exacerbated. As such, the optimal solution for many regions is to complement new renewable energy technologies with a "firming" resource such as energy storage or new/existing and fully dispatchable generation technologies (of which CCGTs remain the most prevalent). This observation is reinforced by the results of this year's marginal cost analysis, which shows an increasing price competitiveness of existing gas-fired generation as compared to new-build renewable energy technologies. As such, and as has been noted in our historic reports, the LCOE is just the starting point for resource planning and has always reinforced the need for a diversity of energy resources, including but not limited to renewable energy.

3. Innovation Is Critical to the Energy Transition

   Continuous innovation across technology, capital formation and policy is required to fully enable the Energy Transition, which we define to include a generation mix that is diverse and advanced enough to meet the ongoing reshaping of our energy economy. The Energy Transition will also require continued maturation of selected technologies not included in our analysis (e.g., carbon capture, utilization and sequestration ("CCUS"), long duration energy storage, new nuclear technologies, etc.). While the results of this year's LCOE reinforce our previous conclusions—the cost-competitiveness of renewables will lead to the continued displacement of conventional generation and an evolving energy mix—the timing of such displacement and composition of such mix will be impacted by many factors, including those outside of the scope of our LCOE (e.g., grid investment, permitting reform, transmission queue reform, economic policy, continued advancement of flexible load and locally sited generation, etc.).

(1) This analysis has been compiled using U.S.-focused data.

Executive Summary—Levelized Cost of Storage Version 9.0[1]

The results of our Levelized Cost of Storage ("LCOS") analysis reinforce what we observe across the Power, Energy & Infrastructure Industry—energy storage system ("ESS") applications are becoming more valuable, well understood and, by extension, widespread as grid operators begin adopting methodologies to value these resources leading to increased transaction activity and infrastructure classification for the ESS asset class. Key takeaways from Version 9.0 of Lazard's LCOS include:

1. Increased LCOS Variability

   While we saw incremental declines in the low end LCOS as compared to last year's analysis, the high end increased more noticeably, resulting in a wider range of LCOS outcomes across the operational parameters analyzed. The decline on the low end was, in part, driven by a noticeable decline in cell prices resulting from increased manufacturing capacity in China and decreased mineral pricing. However, this was offset by significant increases in engineering, procurement and construction ("EPC") pricing driven, in part, by high demand, increased timeline scrutiny, skilled labor shortages and prevailing wage requirements. Also notable is the increased impact of economies of scale benefits in procurement, mirroring the observations we have seen in the LCOE in recent years.

2. The Power of the IRA Is Clear

   Despite the significant increases in wholesale pricing for lithium carbonate and lithium hydroxide observed from 2022 to 2023, the IRA's grant of ITC eligibility for standalone ESS assets kept LCOS v8.0 values relatively neutral as compared to LCOS v7.0. One year later, for this year's LCOS v9.0, ITC implementation, including the application of energy community adders, is fully underway and the impacts are clear. The ITC, along with lower cell pricing and technology improvements, is leading to an increasing trend of oversizing battery capacity to offset future degradation and useful life considerations, which is not only extending useful life expectations but is also increasing residual value and overall project returns. While the ITC and energy community adder are prevalent, the domestic content adder remains uncertain, notwithstanding the various domestic manufacturing announcements. The lack of clarity related to qualifying for local content is leading to longer lead times and higher contingencies. Adding to this overall complexity is the recently proposed increase of Section 301 import tariffs on lithium-ion batteries, which many believe will lead to increased domestic battery supply but with uncertain costs results.

3. Lithium-Ion Batteries Remain Dominant

   Lithium-ion batteries remain the most cost competitive short-term (i.e., 2 – 4-hour) storage technology, given, among other things, a mature supply chain and global market demand. Lithium-ion, however, is not without its challenges. For example, safety remains a concern for utilities and commercial & industrial owners, particularly in urban areas, and longer-duration lithium-ion use cases can have challenging economic profiles. As such, industry participants have started progressing non-lithium-based technology solutions, including for longer-duration use cases and applications. Such technologies are targeting new market segments, including industrial applications, data center deployments and ultra-long duration applications in regions with high penetration of intermittent renewable energy. However, the development of long duration energy storage still requires clear demonstration of the commercial operation of these technologies, market maturation (including the development of stronger incentives for long duration projects that could capture capacity revenues in merchant and bilateral markets) and manufacturing scale to realize (long-promised) cost reductions, all resulting in greater willingness of insurance and financing participants to underwrite these projects.

(1) This analysis has been compiled using U.S.-focused data.

Executive Summary—Levelized Cost of Hydrogen Version 4.0(1)

Hydrogen continues to be regarded as a potential solution for industrial processes that will be difficult to decarbonize through other existing technologies or alternatives. Hydrogen production in the U.S. primarily comes from fossil fuels through steam-methane reforming ("SMR") and methane splitting processes resulting in "gray" hydrogen. The cost of the equipment (i.e., the "electrolyzer") and the source of the electricity (i.e., wind- and solar-derived electricity for "green" hydrogen, nuclear-derived electricity for "pink" hydrogen, etc.) continue to have the greatest impact on the levelized cost of hydrogen production. Key takeaways from Version 4.0 of Lazard's Levelized Cost of Hydrogen ("LCOH") analysis include:

1. A Maturing Industry Drives Declining Costs

   Observable declines in the results of our LCOH analysis indicate that the hydrogen electrolyzer industry is continuing to mature and will likely scale over time. Proton Exchange Membrane ("PEM") and Alkaline electrolyzers are the dominant technologies, but their higher costs relative to currently available alternatives (e.g., renewables + BESS, dispatchable gas-fired generation, etc.) hinder significant market expansion. Notably, there is a considerable price disparity across the market for electrolyzer equipment, which would be more overtly pronounced had this report included electrolyzers manufactured in China given the significantly lower price expectations. Despite this price disparity, Western-supplied electrolyzers and related equipment remain competitive given the greater level of performance validation and freedom from the potential risks of tariff and trade implications.

2. Uncertainty Around IRA Implementation

   Implementation challenges for hydrogen projects vary dramatically by markets and use cases. In the U.S., project developers are waiting for final guidance from the Treasury Department on the IRA 45(V) tax credit to provide clarity on which projects qualify for the production subsidy (up to $3 per kilogram of hydrogen). A key concern for project developers is how the production costs for green hydrogen will be impacted by hourly matching requirements which would stipulate that renewable power production must occur in the same hour as hydrogen production. Hourly matching requirements would likely lead to an increase in the results of our LCOH due to higher renewable power development costs and lower electrolyzer utilization rates. Final guidance from the Treasury Department may impact the competitiveness and adoption rate for green hydrogen relative to alternatives such as "blue" hydrogen (i.e., hydrogen produced from fossil fuels with CCUS).

3. Use Case Analysis Is Critical

   While the scope of our LCOH remains focused on the cost of production, we plan to broaden the LCOH in the coming years to evaluate various use cases (similar to the expansion of our LCOS analysis and the related "Value Snapshots"). We continue to see growing interest from key hydrogen off-takers in the chemicals industry (e.g., ammonia for use in fertilizer) and demand is expected to continue increasing for fuels produced from clean hydrogen to help decarbonize transportation sectors (e.g., maritime). In addition, several companies in hard-to-abate industrial sectors (e.g., steel, construction materials, etc.) are considering hydrogen as an alternative to fossil fuels for some heat-generating applications. Although the technology is broadly available, using hydrogen for power generation (or blending it with natural gas) will likely require capital-intensive upgrades to current generation assets, storage facilities and pipelines to protect the legacy infrastructure and avoid leakages.

(1) This analysis has been compiled using U.S.-focused data.

Lazard's Levelized Cost of Energy Analysis—Version 17.0

LAZARD

Introduction

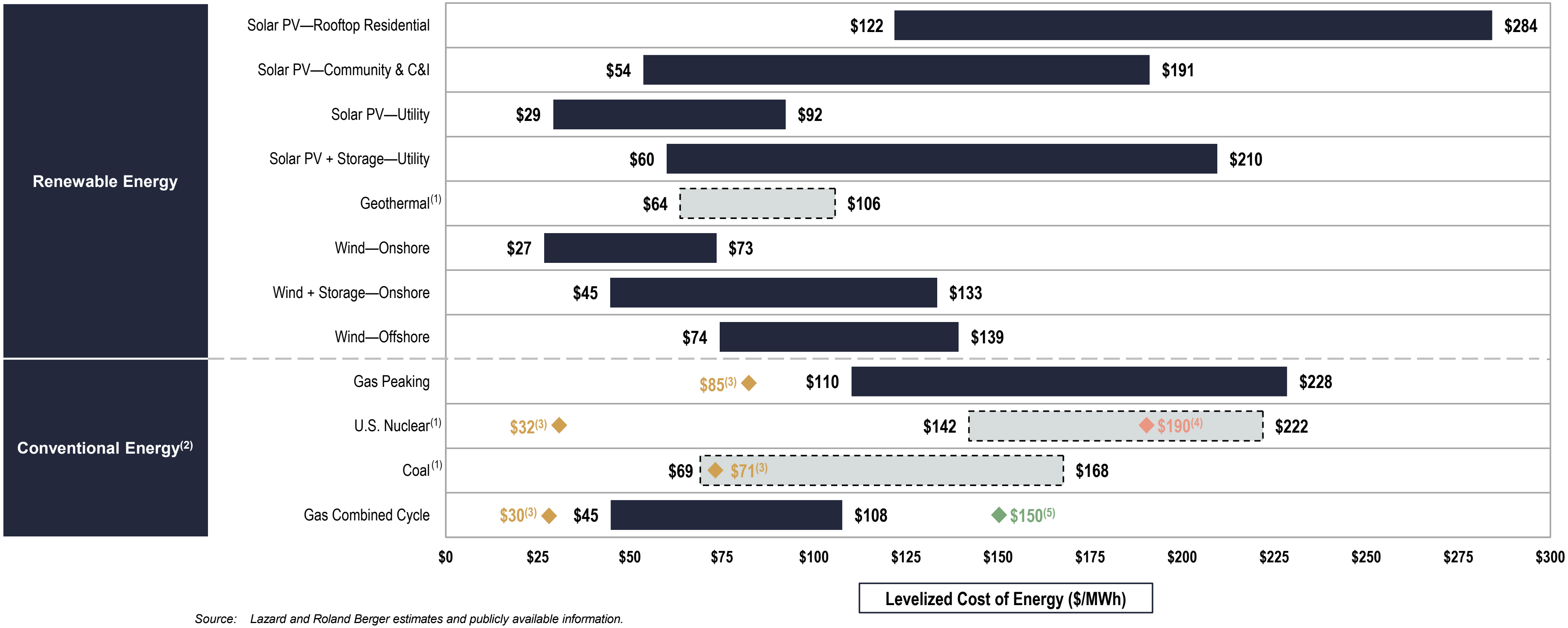
Lazard's Levelized Cost of Energy analysis addresses the following topics:

- Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities for U.S. federal tax subsidies, fuel prices, carbon pricing and cost of capital
- Illustration of how the LCOE of onshore wind, utility-scale solar and hybrid projects compare to the marginal cost of selected conventional generation technologies
- Illustration of how the LCOE of onshore wind, utility-scale solar and hybrid projects, plus the cost of firming intermittency in various regions, compares to the LCOE of selected conventional generation technologies
- Historical LCOE comparison of various technologies
- Illustration of the historical LCOE declines for onshore wind and utility-scale solar
- Appendix materials, including:
  - Deconstruction of the LCOE for various generation technologies by capital cost, fixed operations and maintenance ("O&M") expense, variable O&M expense and fuel cost
  - An overview of the methodology utilized to prepare Lazard's LCOE analysis
  - A summary of the assumptions utilized in Lazard's LCOE analysis

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, may include: implementation and interpretation of the full scope of the IRA; economic policy, transmission queue reform, network upgrades and other transmission matters, congestion, curtailment or other integration-related costs; 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 is intended to represent a snapshot in time and utilizes a wide, but not exhaustive, sample set of Industry data. As such, we recognize and acknowledge the likelihood of results outside of our ranges. Therefore, this analysis is not a forecasting tool and should not be used as such, given the complexities of our evolving Industry, grid and resource needs. Except as illustratively sensitized herein, this analysis does not consider the intermittent nature of selected renewables energy technologies or the related grid impacts of incremental renewable energy deployment. 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., airborne pollutants, greenhouse gases, etc.)

Levelized Cost of Energy Comparison—Version 17.0

Selected renewable energy generation technologies remain cost-competitive with conventional generation technologies under certain circumstances



Source: *Lazard and Roland Berger estimates and publicly available information.*

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

(1) Given the limited public and/or observable data available for new-build geothermal, coal and nuclear projects the LCOE presented herein reflects Lazard's LCOE v14.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant. Coal LCOE does not include cost of transportation and storage.

(2) The fuel cost assumptions for Lazard's LCOE analysis of gas-fired generation, coal-fired generation and nuclear generation resources are $3.45/MMBTU, $1.47/MMBTU and $0.85/MMBTU respectively, for year-over-year comparison purposes. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices" for fuel price sensitivities.

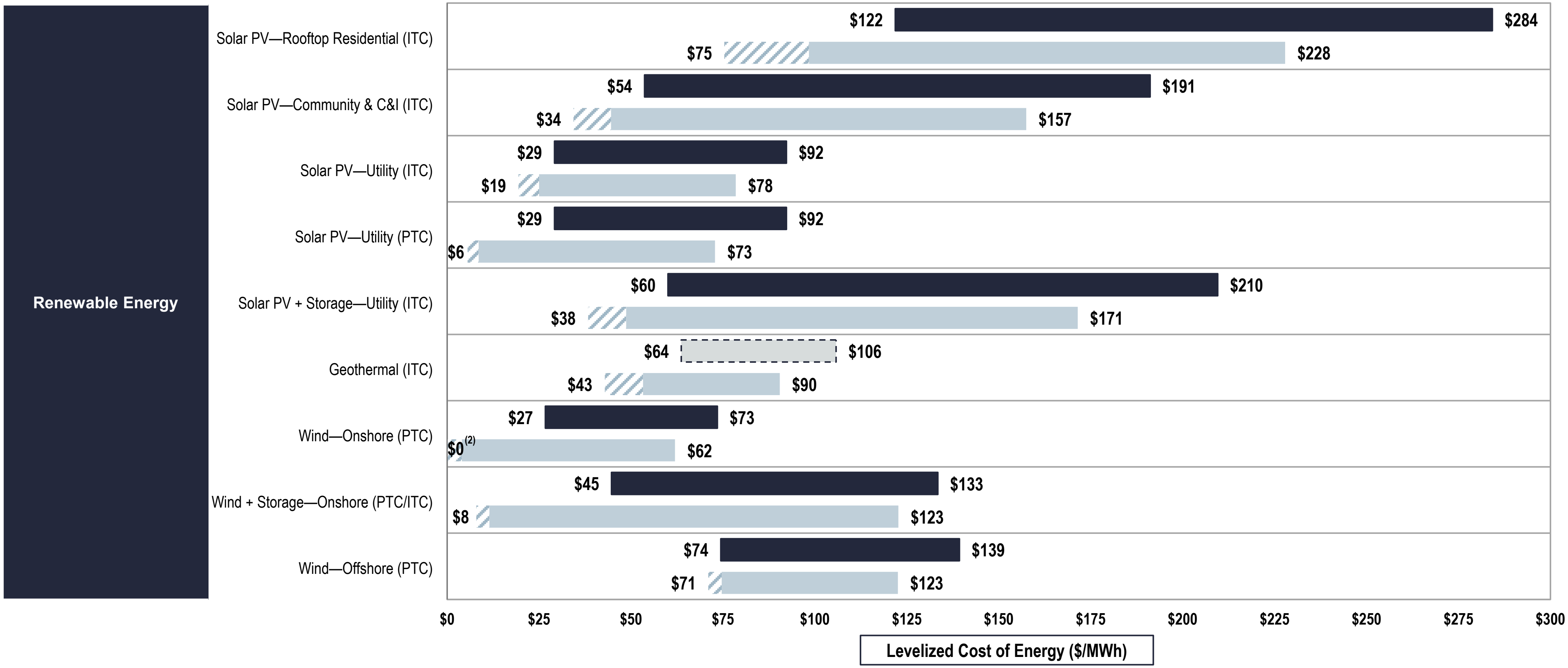
(3) Reflects the average of the high and low LCOE marginal cost of operating fully depreciated gas peaking, gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas, 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. See page titled "Levelized Cost of Energy Comparison—New Build Renewable Energy vs. Marginal Cost of Existing Conventional Generation" for additional details.

(4) Represents the illustrative midpoint LCOE for Vogtle nuclear plant units 3 and 4 based on publicly available estimates. Total operating capacity of ~2.2 GW, total capital cost of ~$31.5 billion, capacity factor of ~97%, operating life of 60 – 80 years and other operating parameters estimated by Lazard's LCOE v14.0 results adjusted for inflation. See Appendix for more details.

(5) Reflects the LCOE of the observed high case gas combined cycle inputs using a 20% blend of green hydrogen by volume (i.e., hydrogen produced from an electrolyzer powered by a mix of wind and solar generation and stored in a nearby salt cavern). No plant modifications are assumed beyond a 2% increase to the plant's heat rate. The corresponding fuel cost is $6.66/MMBTU, assuming ~$5.25/kg for green hydrogen (unsubsidized PEM). See LCOH—Version 4.0 for additional information.

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

The Investment Tax Credit ("ITC"), Production Tax Credit ("PTC") and Energy Community adder, among other provisions in the IRA, are important components of the LCOE for renewable energy technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise indicated, this analysis does not include other state or federal subsidies (e.g., domestic content adder, etc.). The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

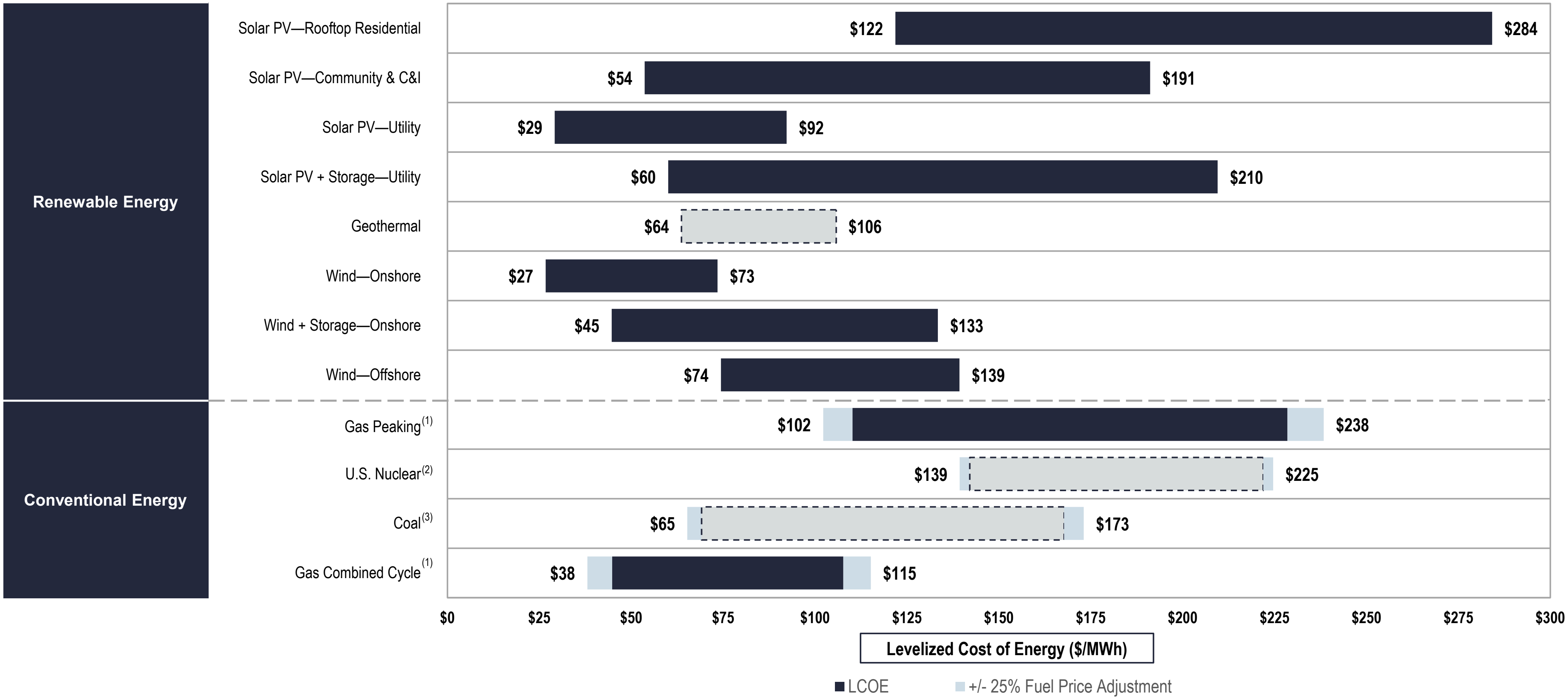
(1) This sensitivity analysis assumes that projects qualify for the full ITC/PTC, have a capital structure that includes sponsor equity, debt and tax equity and assumes the equity owner has taxable income to monetize a portion of the tax credits.

(2) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix A for further details). Lazard's LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying an after-tax IRR/WACC of 7.7%). Implied IRRs at this level for Wind—Onshore (PTC) is 13% (i.e., the value of the PTC and Energy Community adder result in an implied IRR greater than the assumed 12%).

(3) This sensitivity analysis assumes that projects qualify for the full ITC/PTC and also includes an Energy Community adder of 10% for ITC projects and $3/MWh for PTC projects.

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 to "competing" renewable energy generation technologies must take into account issues such as dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. peaking or intermittent technologies)



Source: Lazard and Roland Berger estimates and publicly available information.

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled "Levelized Cost of Energy Comparison—Version 17.0".

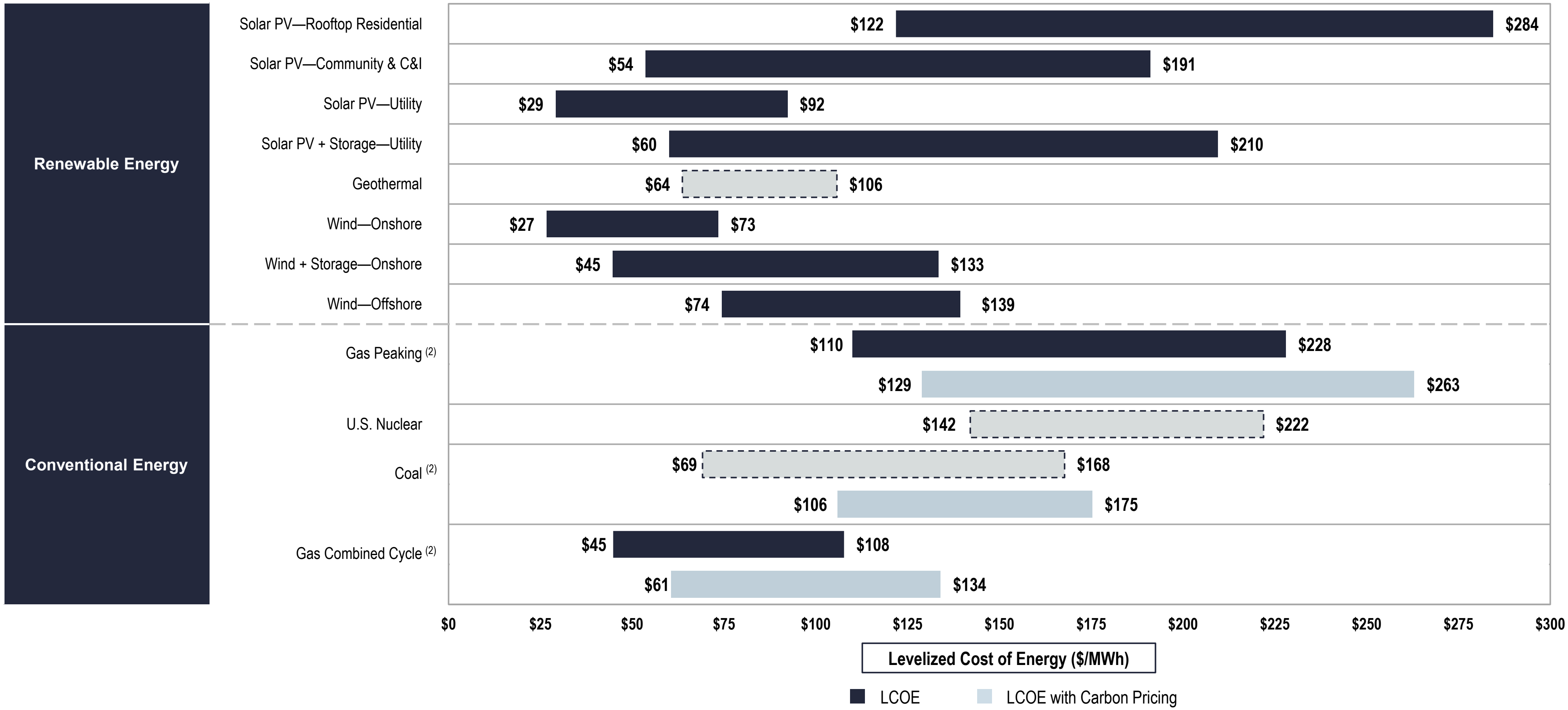
(1) Assumes a fuel cost range for gas-fired generation resources of \$2.59/MMBTU – \$4.31/MMBTU (representing a sensitivity range of ± 25% of the \$3.45/MMBTU used in the LCOE).

(2) Assumes a fuel cost range for nuclear generation resources of \$0.64/MMBTU – \$1.06/MMBTU (representing a sensitivity range of ± 25% of the \$0.85/MMBTU used in the LCOE).

(3) Assumes a fuel cost range for coal-fired generation resources of \$1.10/MMBTU – \$1.84/MMBTU (representing a sensitivity range of ± 25% of the \$1.47/MMBTU used in the LCOE).

Levelized Cost of Energy Comparison—Sensitivity to Carbon Pricing

Carbon pricing is one avenue for policymakers to address carbon emissions; a carbon price range of $40 – $60/Ton[1] of carbon would increase the LCOE for certain conventional generation technologies, as indicated below

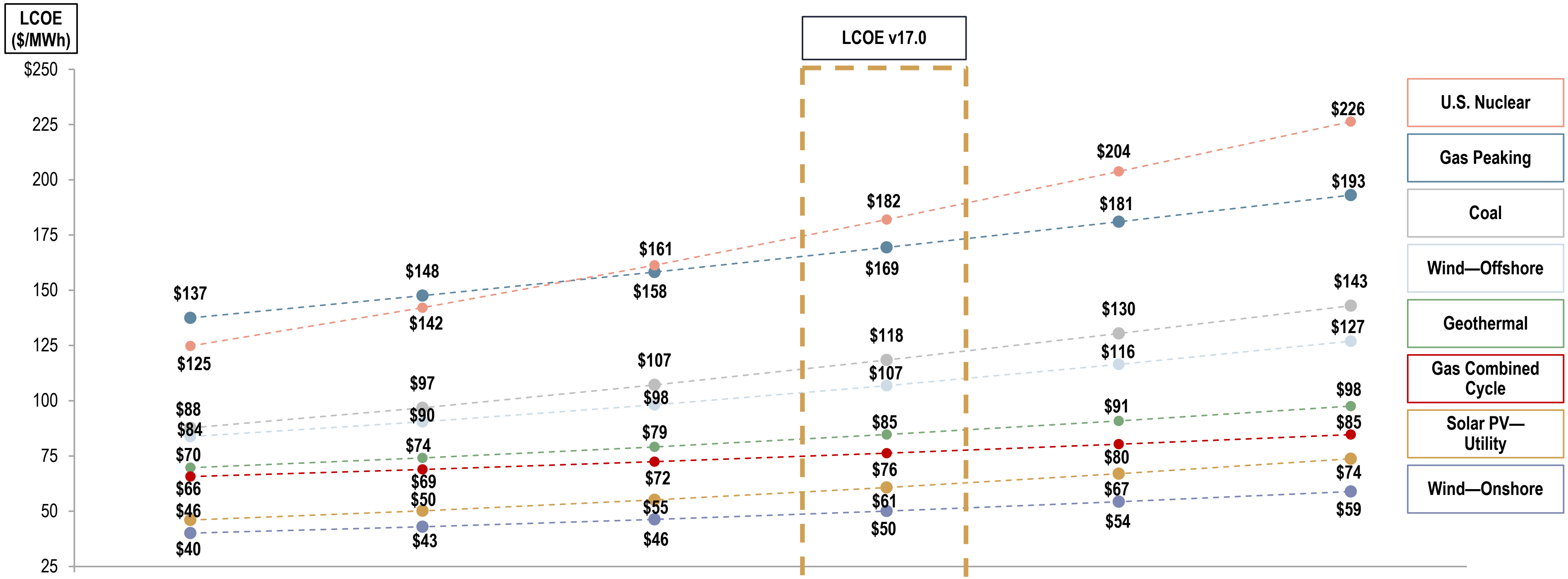


Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled "Levelized Cost of Energy Comparison—Version 17.0".
(1) In November 2023, the U.S. Environmental Protection Agency proposed a $204/Ton social cost of carbon.
(2) The low and high ranges reflect the LCOE of selected conventional generation technologies including an illustrative carbon price of $40/Ton and $60/Ton, respectively.

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration in determining the LCOE for utility-scale generation technologies is the cost, and availability, of capital[(1)]—in practice, this dynamic is particularly significant because the cost of capital for each asset is directly correlated to its specific operational characteristics and the resulting risk/return profile

Average LCOE[(2)]



After-Tax IRR/WACC	4.2%	5.4%	6.5%	7.7%	8.8%	10.0%
Cost of Equity	6.0%	8.0%	10.0%	12.0%	14.0%	16.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

Source: Lazard and Roland Berger estimates and publicly available information.

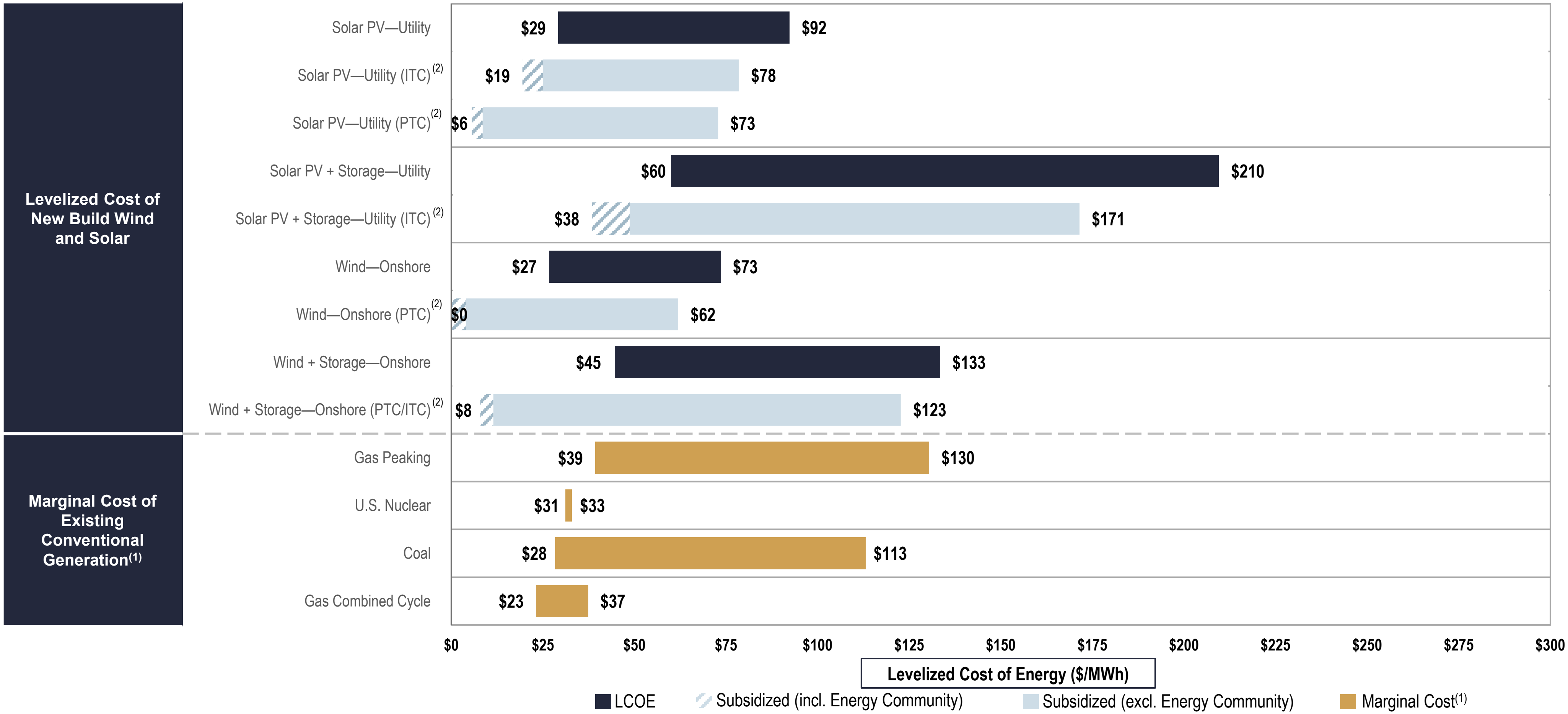
Note: Analysis assumes 60% debt and 40% equity. Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on the page titled "Levelized Cost of Energy Comparison—Version 17.0".

(1) Cost of capital as used herein indicates the cost of capital applicable to 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—New Build Renewable Energy vs. Marginal Cost of Existing Conventional Generation

Certain renewable energy generation technologies have an LCOE that is competitive with the marginal cost of selected existing conventional generation technologies—notably, as incremental, intermittent renewable energy capacity is deployed and baseload gas-fired generation utilization rates increase, this gap closes, particularly in low gas pricing and high energy demand environments



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on page titled "Levelized Cost of Energy Comparison—Version 17.0".

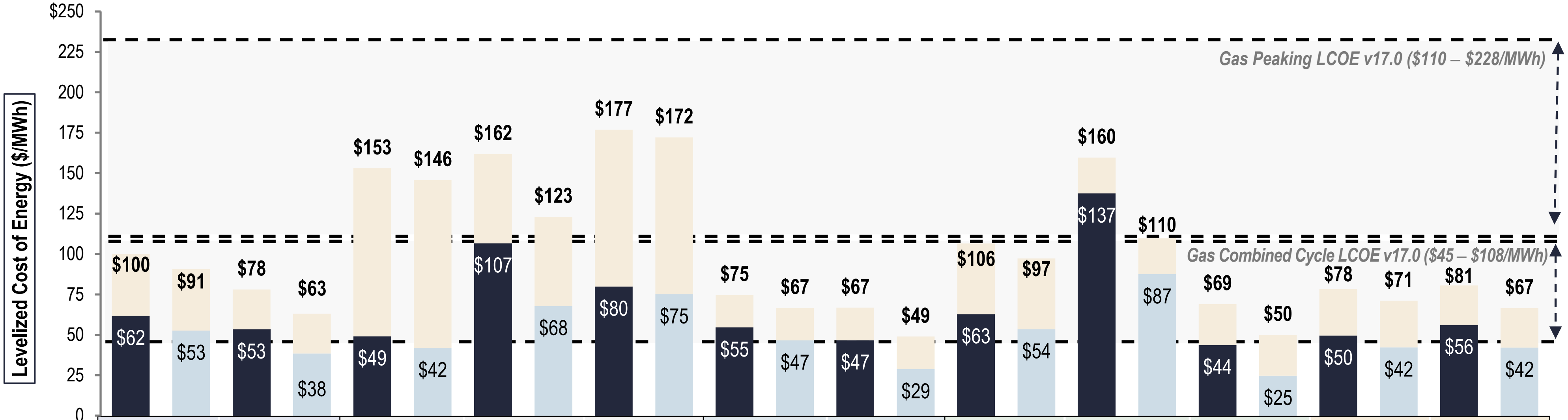
(1) Reflects the marginal cost of operating fully depreciated gas, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent to its decommissioning and site restoration costs. Inputs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

(2) See page titled "Levelized Cost of Energy Comparison—Sensitivity to U.S. Federal Tax Subsidies" for additional details.

Levelized Cost of Energy Comparison—Cost of Firming Intermittency

The incremental cost to firm[(1)] intermittent resources varies regionally—as such is defined by the relevant reliability organizations using the current effective load carrying capability ("ELCC")[(2)] values and the current cost of adding new firming resources

LCOE Including Levelized Firming Cost ($/MWh)[(3)]



	Solar	Wind	Solar	PV + Storage	Wind	Solar	Wind	Solar	PV + Storage	Wind	Solar	Wind
ELCC	39%	26%	8%	51%[(4)]	14%	57%	19%	42%	72%[(4)]	21%	38%	25%
Capacity Factor	18%	34%	23%	23%	23%	21%	39%	18%	18%	42%	23%	33%
Resource Penetration	6%	25%	52%	52%	20%	1%	58%	7%	7%	7%	21%	44%
	MISO		CAISO			SPP		PJM			ERCOT	

■ LCOE [(3)] ■ Subsidized (excl. Energy Community)[(3)] ■ Firming Cost [(1)]

Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Total LCOE, including firming cost, does not represent the cost of building a 24/7 firm resource on a single project site, but, instead, the LCOE of a renewable resource and the additional costs required to achieve the resource adequacy requirement in the relevant reliability region based on the net cost of new entry ("Net CONE"). ISO ELCC data as of April 2024.

(1) Firming costs reflect the additional capacity needed to supplement the net capacity of the renewable resource (nameplate capacity * (1 – ELCC)) and the Net CONE of a new firm resource (capital and operating costs, less expected market revenues). Net CONE is assessed and published by grid operators for each regional market. Grid operators use a natural gas peaker as the assumed new resource in MISO ($8.22/kW-mo), SPP ($8.56/kW-mo) and PJM ($10.20/kW-mo). In CAISO, the assumed new resource is a 4-hour lithium-ion battery storage system ($18.92/kW-mo). For the PV + Storage cases in CAISO and PJM, assumed storage configuration is 50% of PV MW and 4-hour duration.

(2) ELCC is an indicator of the incremental reliability contribution of a given resource to the electricity grid based on its contribution to meeting peak electricity demand. For example, a 1 MW wind resource with a 15% ELCC provides 0.15 MW of capacity contribution and would need to be supplemented by 0.85 MW of additional firm capacity in order to represent the addition of 1 MW of firm system capacity.

(3) Reflects the average of the high and low of Lazard's LCOE v17.0 for each technology using the regional capacity factor, as indicated, to demonstrate the regional differences in project costs.

(4) For PV + Storage cases, the effective ELCC value is represented. CAISO and PJM assess ELCC values separately for the PV and storage components of a system. Storage ELCC value is provided only for the capacity that can be charged directly by the accompanying resource up to the energy required for a 4-hour discharge during peak load. Any capacity available in excess of the 4-hour maximum discharge is attributed to the system at the solar ELCC. ELCC values for storage range from 90% to 95% for CAISO and PJM.

Levelized Cost of Energy Comparison—Historical LCOE Comparison

Lazard's LCOE analysis indicates significant historical cost declines for utility-scale renewable energy generation technologies, which has begun to level out in recent years and slightly increased this year

Selected Historical Average LCOE Values[1]

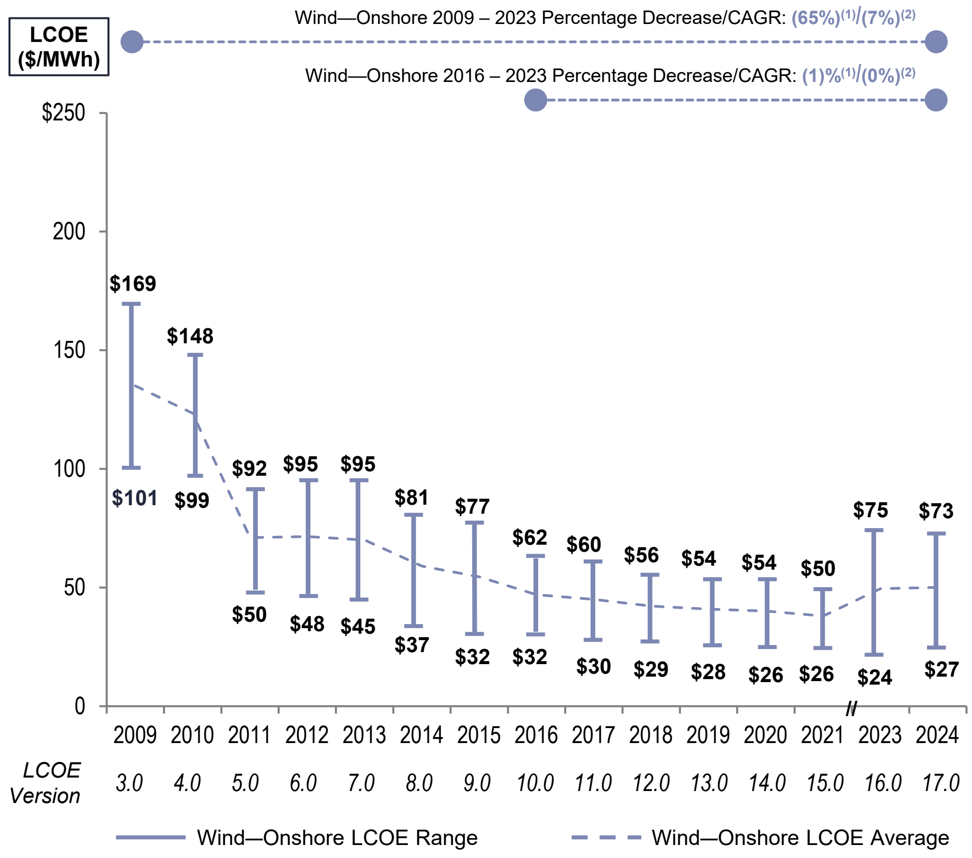
Source: *Lazard and Roland Berger estimates and publicly available information.*

(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 v3.0.

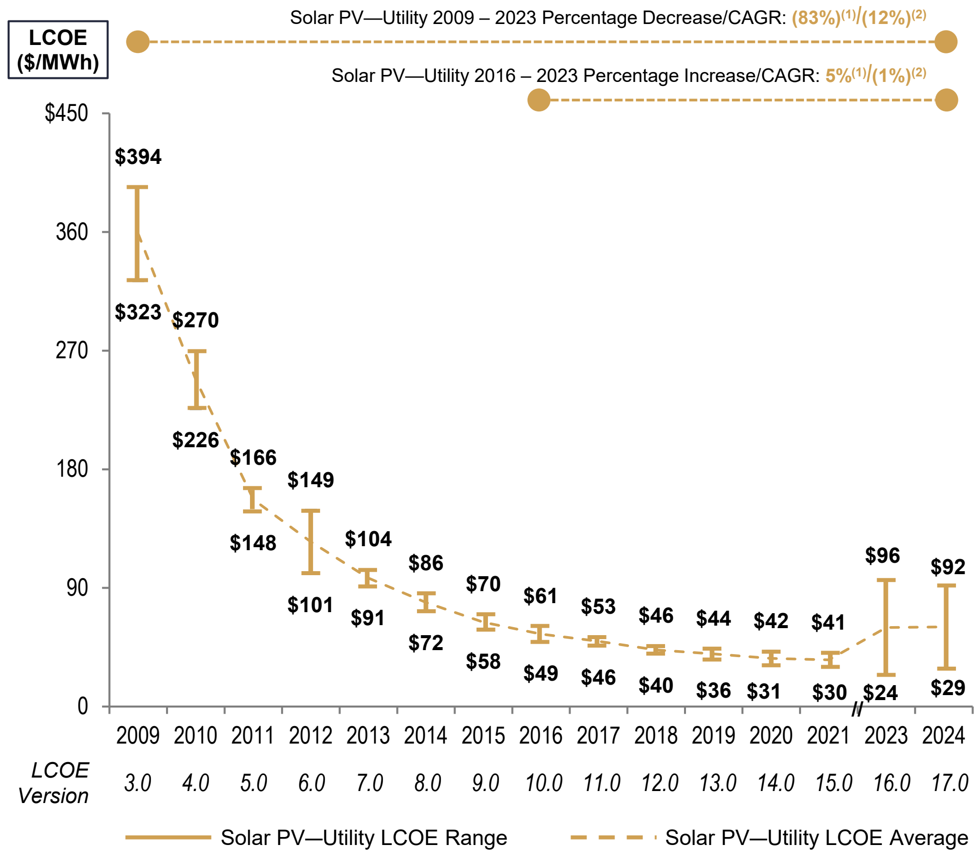
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

While the low end of the LCOE for both wind and solar has increased slightly, reflecting current market conditions, the average has remained nearly flat and the overall range has narrowed, reflecting, among other things, reconciliation of the supply chain challenges that were notable last year

Wind—Onshore



Solar PV—Utility



Source: Lazard and Roland Berger estimates and publicly available information.

(1) Reflects the average percentage increase/(decrease) of the high end and low end of the LCOE range.

(2) Reflects the average compounded annual rate of decline of the high end and low end of the LCOE range.

Lazard's Levelized Cost of Storage Analysis—Version 9.0

Introduction

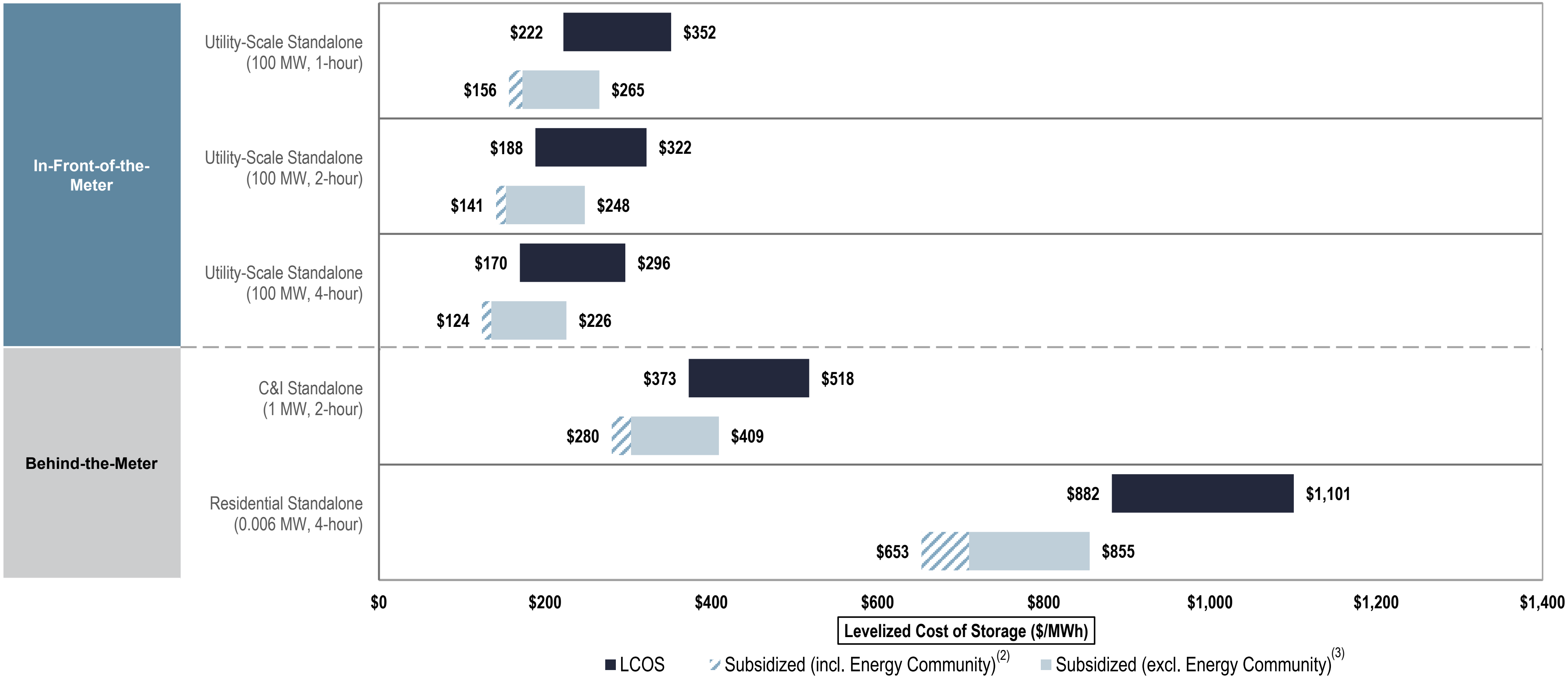
Lazard's Levelized Cost of Storage analysis addresses the following topics:

- LCOS Analysis:
  - Comparative LCOS analysis for various energy storage systems on a $/MWh basis
  - Comparative LCOS analysis for various energy storage systems on a $/kW-year basis
- Energy Storage Value Snapshots:
  - Overview of potential revenue applications for various energy storage systems
  - Overview of the Value Snapshot analysis and identification of selected geographies for each use case analyzed
  - Results from the Value Snapshot analysis
- Appendix Materials, including:
  - An overview of the use cases and operational parameters of selected energy storage systems for each use case analyzed
  - An overview of the methodology utilized to prepare Lazard's LCOS analysis
  - A summary of the assumptions utilized in Lazard's LCOS analysis

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, may include: implementation and interpretation of the full scope of the IRA; economic policy, transmission queue reform, network upgrades and other transmission matters, congestion; curtailment or other integration-related costs; permitting or other development costs, unless otherwise noted; and costs of complying with various regulations (e.g., federal import tariffs or labor requirements). This analysis also does not address potential social and environmental externalities, as well as the long-term residual and societal consequences of various energy storage system technologies that are difficult to measure (e.g., resource extraction, end of life disposal, lithium-ion-related safety hazards, etc.). This analysis is intended to represent a snapshot in time and utilizes a wide, but not exhaustive, sample set of Industry data. As such, we recognize and acknowledge the likelihood of results outside of our ranges. Therefore, this analysis is not a forecasting tool and should not be used as such, given the complexities of our evolving Industry, grid and resource needs.

Levelized Cost of Storage Comparison—Version 9.0 ($/MWh)

Lazard's LCOS analysis evaluates standalone energy storage systems on a levelized basis to derive cost metrics across energy storage use cases and configurations(1)



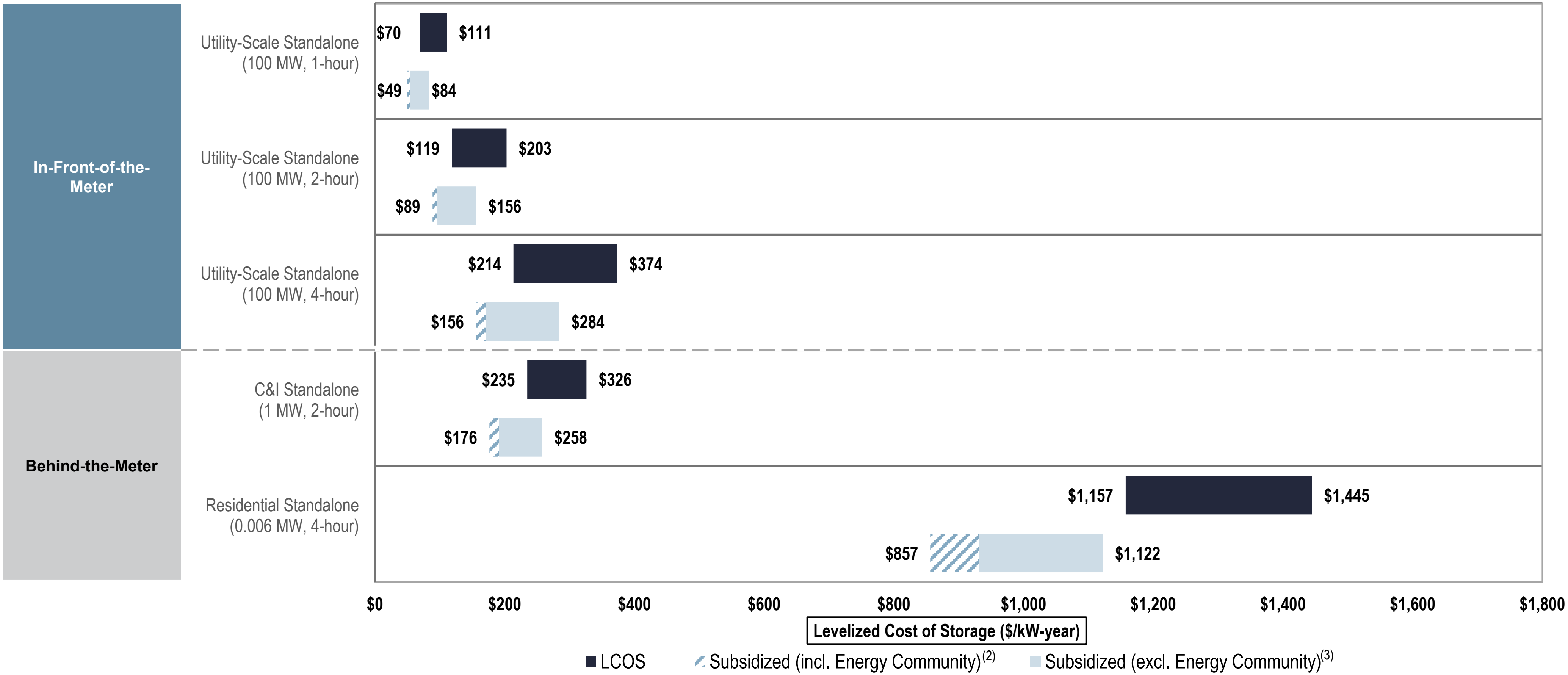
Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Here and throughout this section, unless otherwise indicated, the analysis assumes 20% debt at an 8% interest rate and 80% equity at a 12% cost, which is a different capital structure than Lazard's LCOE analysis. Capital costs are comprised of the storage module, balance of system and power conversion equipment, collectively referred to as the energy storage system, equipment (where applicable) and EPC costs. Augmentation costs are not included in capital costs in this analysis and vary across use cases due to usage profiles and lifespans. Charging costs are assessed at the weighted average hourly pricing (wholesale energy prices) across an optimized annual charging profile of the asset. See Appendix B for charging cost assumptions and additional details. The projects are assumed to use a 5-year MACRS depreciation schedule.

(1) See Appendix B for a detailed overview of the use cases and operation parameters analyzed in the LCOS.
(2) This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity and also includes a 10% Energy Community adder.
(3) This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity.

Levelized Cost of Storage Comparison—Version 9.0 ($/kW-year)

Lazard's LCOS analysis evaluates standalone energy storage systems on a levelized basis to derive cost metrics across energy storage use cases and configurations[(1)]



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: Here and throughout this section, unless otherwise indicated, the analysis assumes 20% debt at an 8% interest rate and 80% equity at a 12% cost, which is a different capital structure than that used in Lazard's LCOE analysis. Capital costs are comprised of the storage module, balance of system and power conversion equipment, collectively referred to as the energy storage system, equipment (where applicable) and EPC costs. Augmentation costs are not included in capital costs in this analysis and vary across use cases due to usage profiles and lifespans. Charging costs are assessed at the weighted average hourly pricing (wholesale energy prices) across an optimized annual charging profile of the asset. See Appendix B for charging cost assumptions and additional details. The projects are assumed to use a 5-year MACRS depreciation schedule.

(1) See Appendix B for a detailed overview of the use cases and operation parameters analyzed in the LCOS.

(2) This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity and also includes a 10% Energy Community adder.

(3) This sensitivity analysis assumes that projects qualify for the full ITC and have a capital structure that includes sponsor equity, debt and tax equity.

Value Snapshots—Revenue Potential for Selected Storage Use Cases

The numerous potential sources of revenue available to energy storage systems reflect the benefits provided to customers and the grid

- **The scope of revenue sources is limited to those captured by existing or soon-to-be commissioned projects—revenue sources that are not clearly identifiable or without publicly available data have not been analyzed**

		Description	Use Cases(1): Utility-Scale Standalone	Utility-Scale PV + Storage	Utility-Scale Wind + Storage	Commercial & Industrial Standalone	Commercial & Industrial PV + Storage	Residential PV + Storage	Residential Standalone
Wholesale	Demand Response—Wholesale	• Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand				✓	✓		
Wholesale	Energy Arbitrage	• Storage of inexpensive electricity to sell later at higher prices (only evaluated in the context of a wholesale market)	✓	✓	✓				
Wholesale	Frequency Regulation	• Provides immediate (4-second) power to maintain generation-load balance and prevent frequency fluctuations	✓	✓	✓				
Wholesale	Resource Adequacy	• Provides capacity to meet generation requirements at peak load	✓	✓	✓				
Wholesale	Spinning/ Non-Spinning Reserves	• Maintains electricity output during unexpected contingency events (e.g., outages) immediately (spinning reserve) or within a short period of time (non-spinning reserve)	✓	✓	✓				
Utility	Demand Response—Utility	• Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand				✓	✓	✓	✓
Customer	Bill Management	• Allows reduction of demand charge using battery discharge and the daily storage of electricity for use when time of use rates are highest				✓	✓	✓	✓
Customer	Backup Power	• Provides backup power for use by residential and commercial customers during grid outages				✓	✓	✓	✓
Customer	Incentives	• Payments provided to residential and commercial customers to encourage the acquisition and installation of energy storage systems				✓	✓	✓	✓

Source: *Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.*
(1) Represents the universe of potential revenue streams available to the various use cases. Does not represent the use cases analyzed in the Value Snapshots.

Value Snapshot Case Studies—Overview

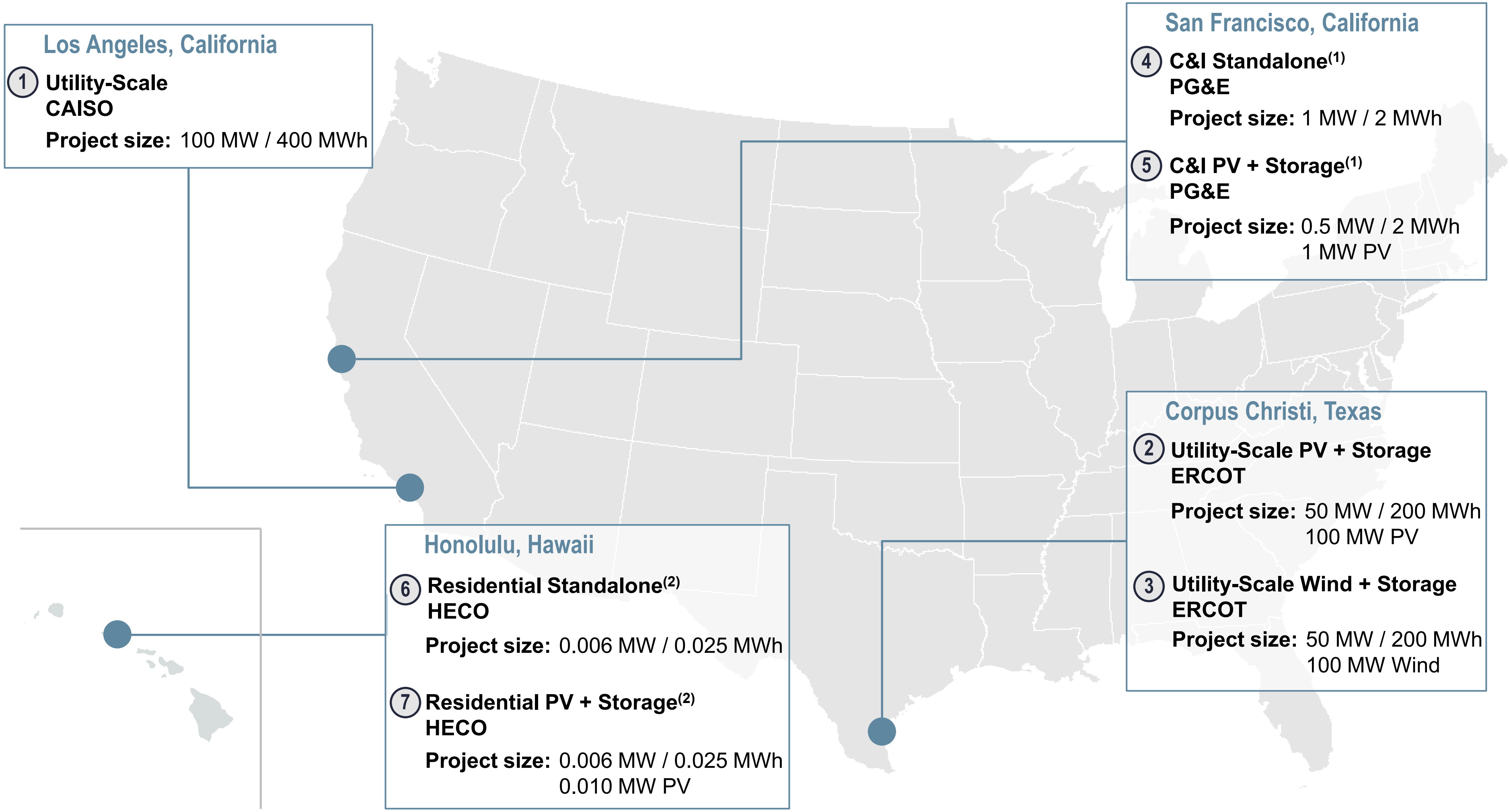
Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases

		Location	Description	Storage (MW)	Generation (MW)	Storage Duration (hours)	Revenue Streams
In-Front-of-the-Meter	1 Utility-Scale Standalone	CAISO[1] (SP-15)	Large-scale energy storage system	100	–	4	• Energy Arbitrage • Frequency Regulation • Resource Adequacy • Spinning/Non-Spinning Reserves
	2 Utility-Scale PV + Storage	ERCOT[2] (South Texas)	Energy storage system designed to be paired with large solar PV facilities	50	100	4	
	3 Utility-Scale Wind + Storage	ERCOT[2] (South Texas)	Energy storage system designed to be paired with large wind generation facilities	50	100	4	
Behind-the-Meter	4 Commercial & Industrial Standalone	PG&E[3] (California)	Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I energy users	1	–	2	• Demand Response—Utility • Bill Management • Incentives • Tariff Settlement, Demand Response Participation, Avoided Costs to Commercial Customer and Local Capacity Resource Programs
	5 Commercial & Industrial PV + Storage	PG&E[3] (California)	Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for C&I energy users	0.5	1	4	
	6 Residential Standalone	HECO[4] (Hawaii)	Energy storage system designed for behind-the-meter residential home use—provides backup power and power quality improvements	0.006	–	4	• Demand Response—Utility • Bill Management • Tariff Settlement • Incentives
	7 Residential PV + Storage	HECO[4] (Hawaii)	Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation	0.006	0.01	4	

Source: *Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.*
Note: Actual project returns may vary due to differences in location-specific costs, revenue streams and owner/developer risk preferences.
(1) Refers to the California Independent System Operator.
(2) Refers to the Electricity Reliability Council of Texas.
(3) Refers to the Pacific Gas & Electric Company.
(4) Refers to the Hawaiian Electric Company.

Value Snapshot Case Studies—Overview (cont'd)

Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases



Source: Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.

Note: Project parameters (i.e., battery size, duration, etc.) presented above correspond to the inputs used in the LCOS analysis.

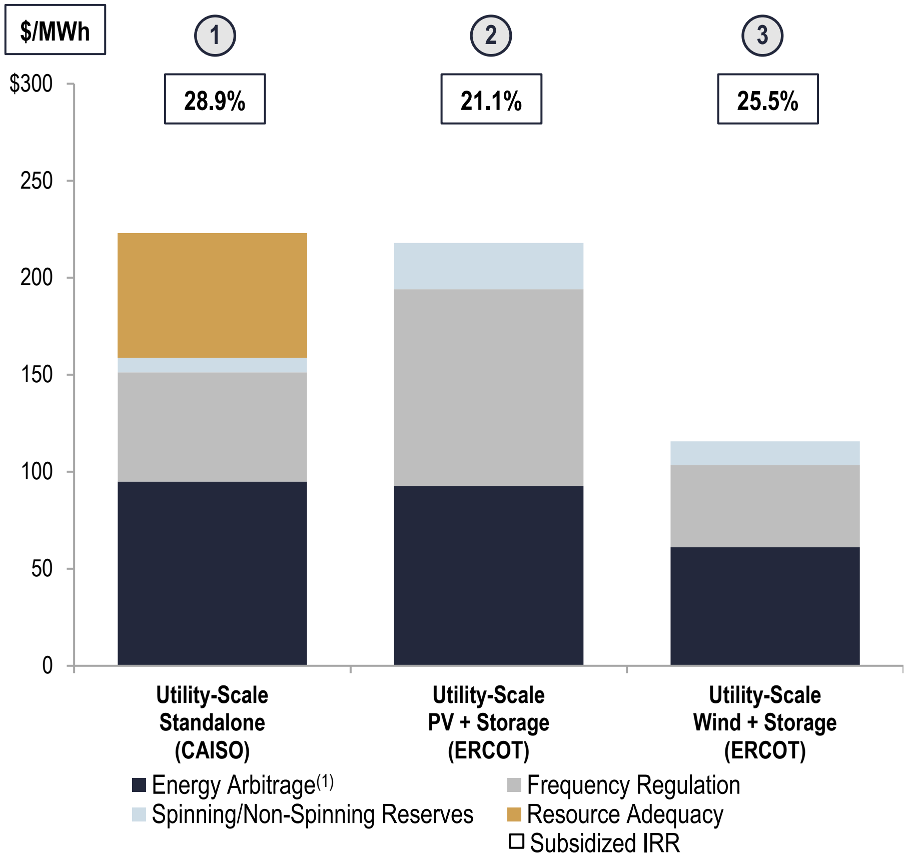
(1) Assumes the project provides services under contract with PG&E.

(2) Assumes the project provides services under contract with HECO.

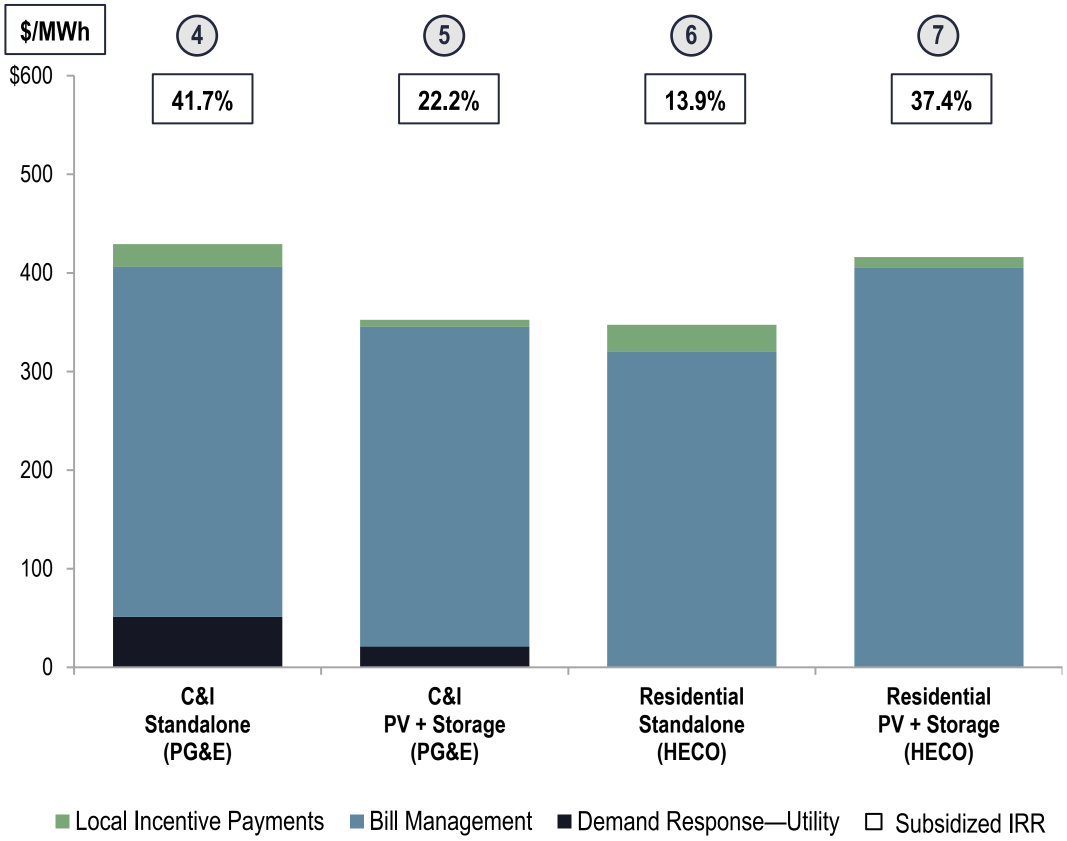
Value Snapshot Case Studies—Results

Project economics evaluated in the Value Snapshot analysis continue to evolve year-over-year as costs change and the value of revenue streams adjust to reflect underlying market conditions, utility rate structures and policy developments

In-Front-of-the-Meter Revenue



Behind-the-Meter Revenue



Source: *Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.*

Note: Levelized costs presented for each Value Snapshot reflect local market and operating conditions (including installed costs, market prices, charging costs and incentives) and are different in certain cases from the LCOS results for the equivalent use case on the page titled "Levelized Cost of Storage Comparison—Version 9.0 ($/MWh)", which are more broadly representative of U.S. storage market conditions as opposed to location-specific conditions. Levelized revenues in all cases are gross revenues (not including charging costs). Subsidized levelized cost for each Value Snapshot reflects: (1) average cost structure for storage, solar and wind capital costs, (2) charging costs based on local wholesale prices or utility tariff rates and (3) all applicable state and federal tax incentives, including 30% federal ITC for solar and/or storage, $27.50/MWh federal PTC for wind and 35% Hawaii state ITC for solar and solar + storage systems. Value Snapshots do not include cash payments from state or utility incentive programs. Revenues for Value Snapshots (1) – (3) are based on hourly wholesale prices from the 365 days prior to December 15, 2023. Revenues for Value Snapshots (4) – (7) are based on the most recent tariffs, programs and incentives available as of December 2023.

(1) In previous versions of this analysis, Energy Arbitrage was referred to as Wholesale Energy Sales.

Lazard's Levelized Cost of Hydrogen Analysis—Version 4.0

LAZARD

Introduction

Lazard's Levelized Cost of Hydrogen analysis addresses the following topics:

- Comparative and illustrative LCOH analysis for various green and pink hydrogen production systems on a $/kg basis
- Comparative and illustrative LCOE analysis for natural gas peaking generation, a potential use case in the U.S. power sector, utilizing a 25% hydrogen blend on a $/MWh basis, including sensitivities for U.S. federal tax subsidies
- Appendix materials, including:
  - An overview of the methodology utilized to prepare Lazard's LCOH analysis
  - A summary of the assumptions utilized in Lazard's LCOH analysis

Note on Methodology:

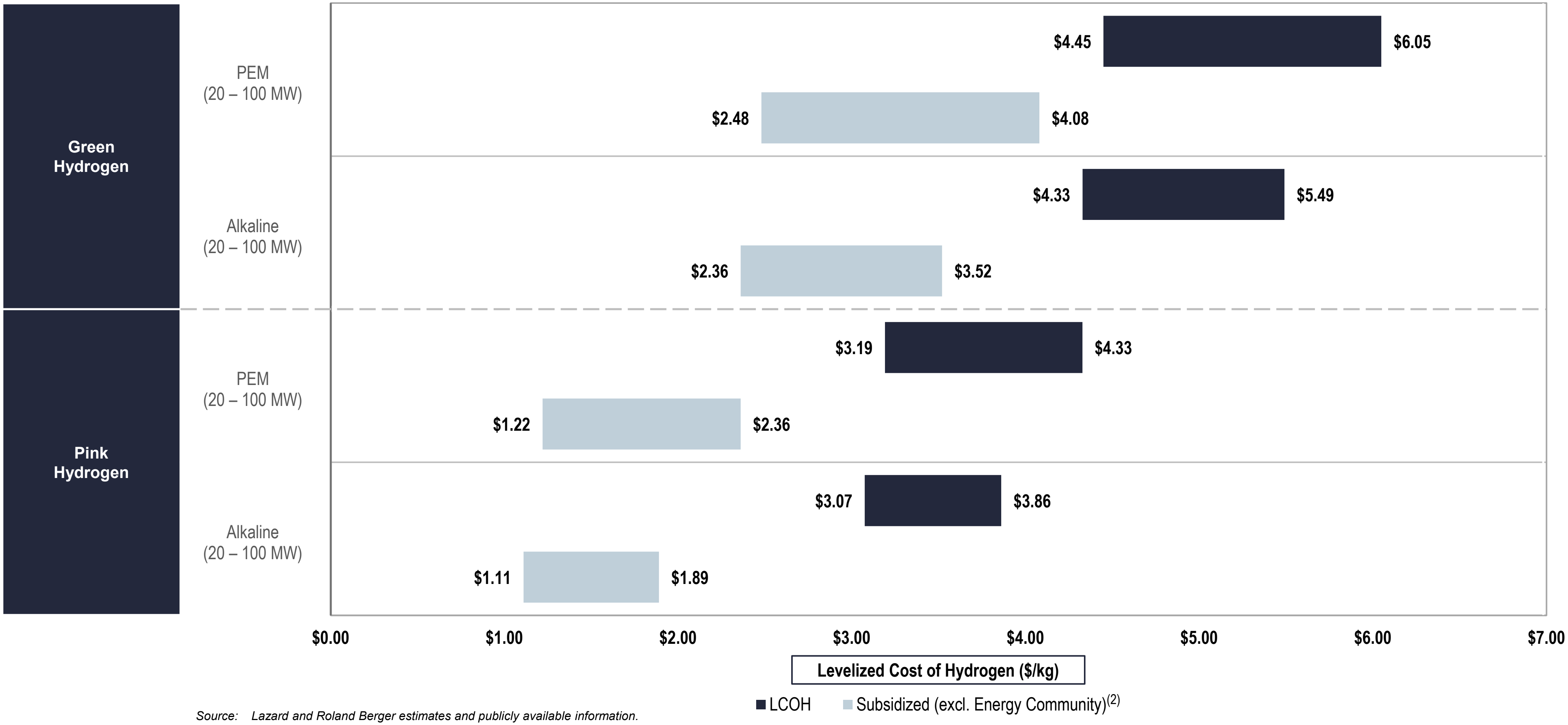
- The analysis within includes storage costs paid to a third party but does not include any expenditures related to the transport, construction of pipeline or construction of storage
- This analysis does not include electrolyzers produced in China, which are currently priced at one third of the price of incumbent electrolyzers, as they struggle to penetrate the U.S. market due to lack of thorough testing and uncertainty around potential tariffs or other trade disruptions with China

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: implementation and interpretation of the full scope of the IRA; development costs of the electrolyzer and associated renewable energy generation facility; conversion, storage and transportation costs of the hydrogen once produced; additional costs to produce alternate products (e.g., ammonia); costs to upgrade existing infrastructure to facilitate the transportation of hydrogen (e.g., natural gas pipelines); electrical grid upgrades; costs associated with modifying end-use infrastructure/equipment to use hydrogen as a fuel source; potential value associated with carbon-free fuel production (e.g., carbon credits, incentives, etc.). This analysis also does not address potential environmental and social externalities, including, for example, water consumption and the societal consequences of displacing the various conventional fuels with hydrogen that are difficult to measure

As a result of the developing nature of hydrogen production and its applications, it is important to have in mind the somewhat limited nature of the LCOH (and related limited historical market experience and current market depth). In that regard, we are aware that, as a result of our data collection methodology, some will have a view that electrolyzer cost and efficiency, plus electricity costs, suggest a different LCOH than what is presented herein. The sensitivities presented in our study are intended to address, in part, such views

Levelized Cost of Hydrogen Comparison—Version 4.0 ($/kg)

Subsidized green and pink hydrogen can reach levelized production costs under $2/kg[1]—fully depreciated operating nuclear plants yield higher capacity factors and, when only accounting for operating expenses, pink hydrogen can reach production costs lower than green hydrogen



Source: *Lazard and Roland Berger estimates and publicly available information.*

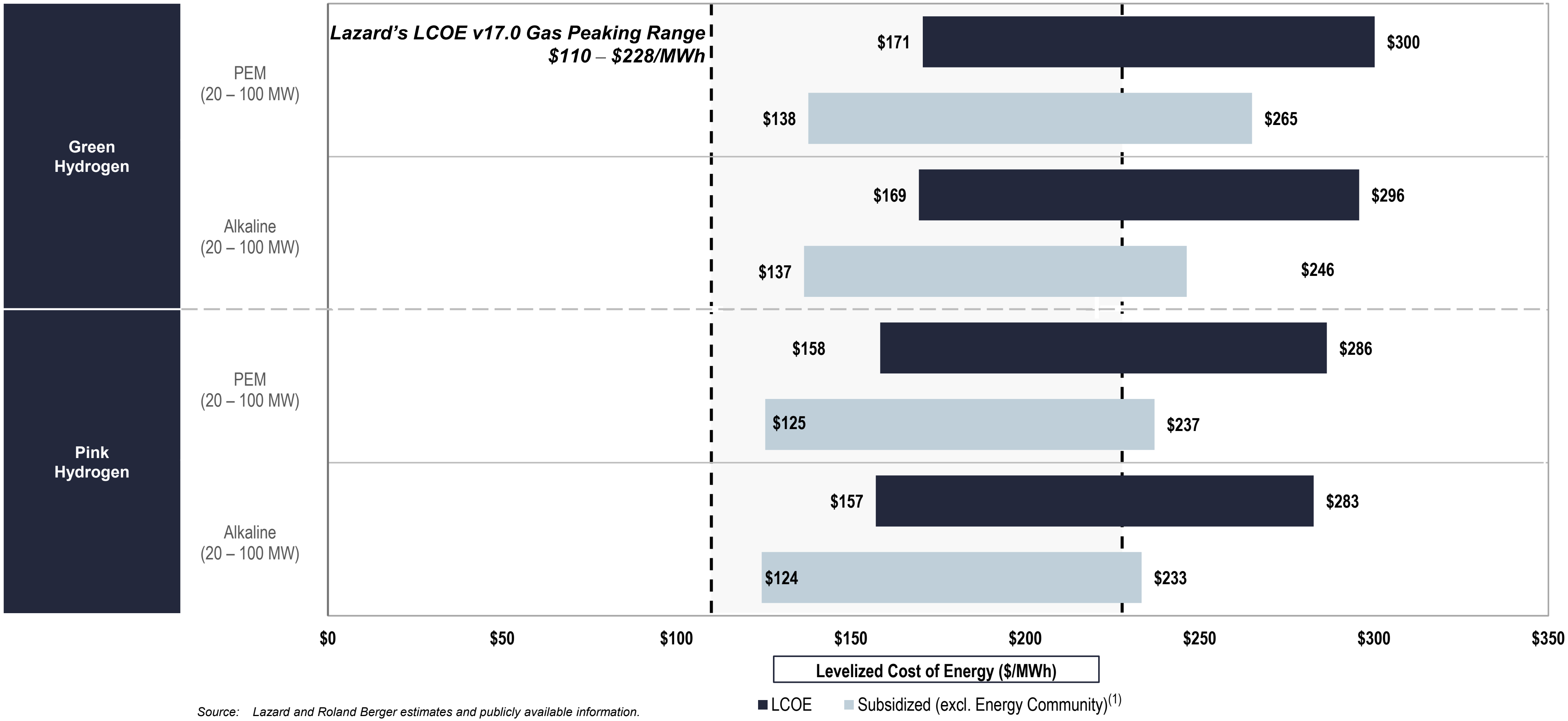
Note: Unless otherwise indicated, this analysis assumes electrolyzer capital expenditure assumptions based on high and low values of sample ranges, with additional capital expenditure for hydrogen storage. Capital expenditure for underground hydrogen storage assumes $20/kg storage cost, sized at 120 Tons for green hydrogen and 200 Tons for pink hydrogen (size is driven by electrolyzer capacity factors). Pink hydrogen costs are based on marginal costs for an existing nuclear plant (see Appendix C for detailed assumptions).

(1) In the U.S., ~$2/kg is the cost to produce gray hydrogen using low-cost natural gas.

(2) This sensitivity analysis assumes that projects qualify for the hydrogen PTC but does not include subsidized electricity costs. This analysis assumes projects have a capital structure that includes sponsor equity, debt and tax equity. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

Levelized Cost of Energy Comparison—Gas Peaking with 25% Hydrogen Blend

While hydrogen-ready natural gas turbines are still being tested, preliminary results, including our illustrative LCOH analysis, indicate that a 25% hydrogen by volume blend is feasible and cost competitive



Source: *Lazard and Roland Berger estimates and publicly available information.*

Note: This analysis assumes a fuel blend of 25% hydrogen and 75% natural gas by volume. Results are driven by Lazard's approach to calculating the LCOE of an illustrative gas peaking plant and selected inputs (see LCOE Appendix for further details). Natural gas fuel cost is assumed to be \$3.45/MMBtu, hydrogen fuel cost based on LCOH \$/kg for case scenarios, assumes 8.8 kg/MMBtu for hydrogen. Analysis includes hydrogen storage costs for a maximum of 8-hour peak episodes for a maximum of 7 days per year, resulting in additional costs of \$120/kW (green) and \$190/kW (pink). Previous versions of this analysis sensitized only the cost of hydrogen—the current version sensitizes both the hydrogen production parameters and the gas peaking plant parameters.

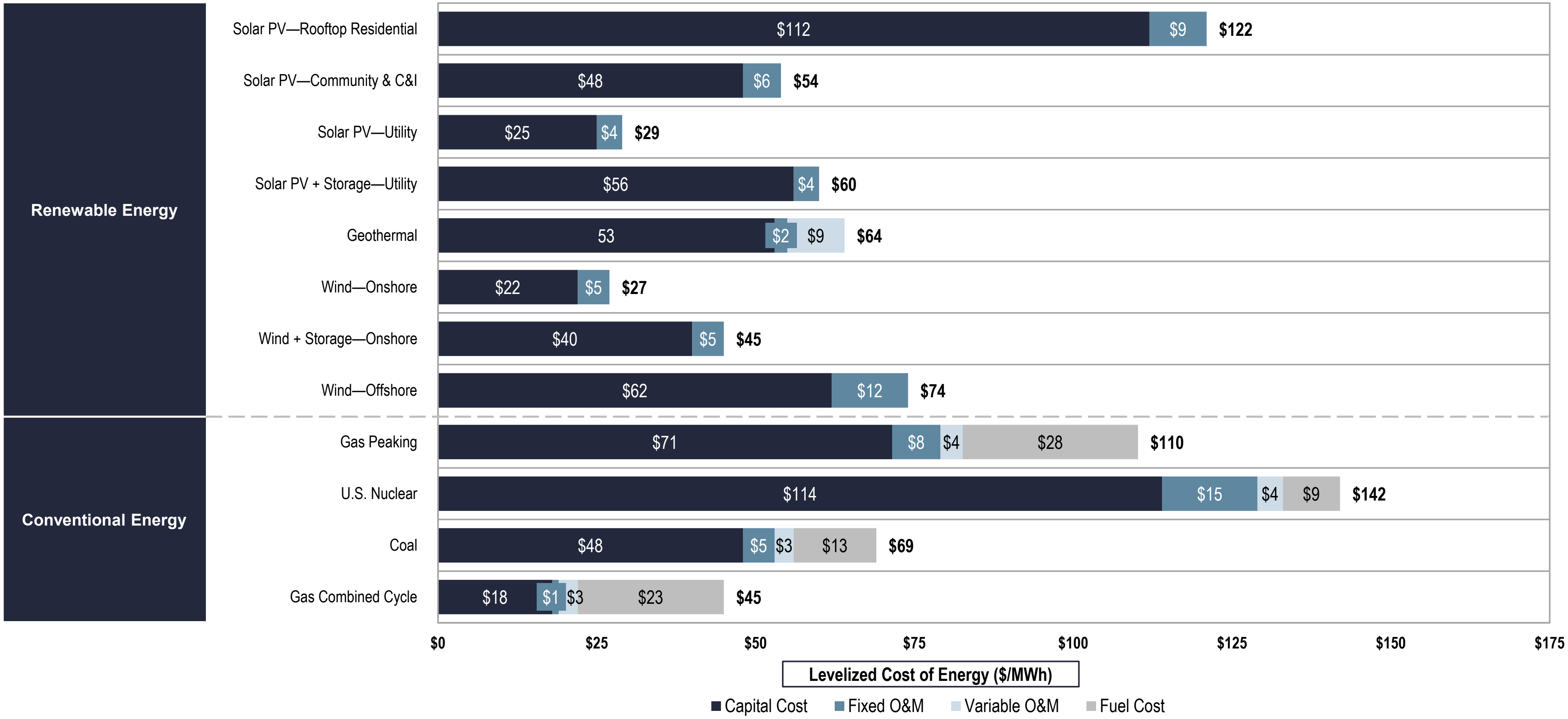
(1) This sensitivity analysis assumes that projects qualify for the hydrogen PTC but does not include subsidized electricity costs. This analysis assumes projects have a capital structure that includes sponsor equity, debt and tax equity. The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA are not included in our analysis and could impact outcomes.

Appendix

LCOE v17.0

Levelized Cost of Energy Components—Low End

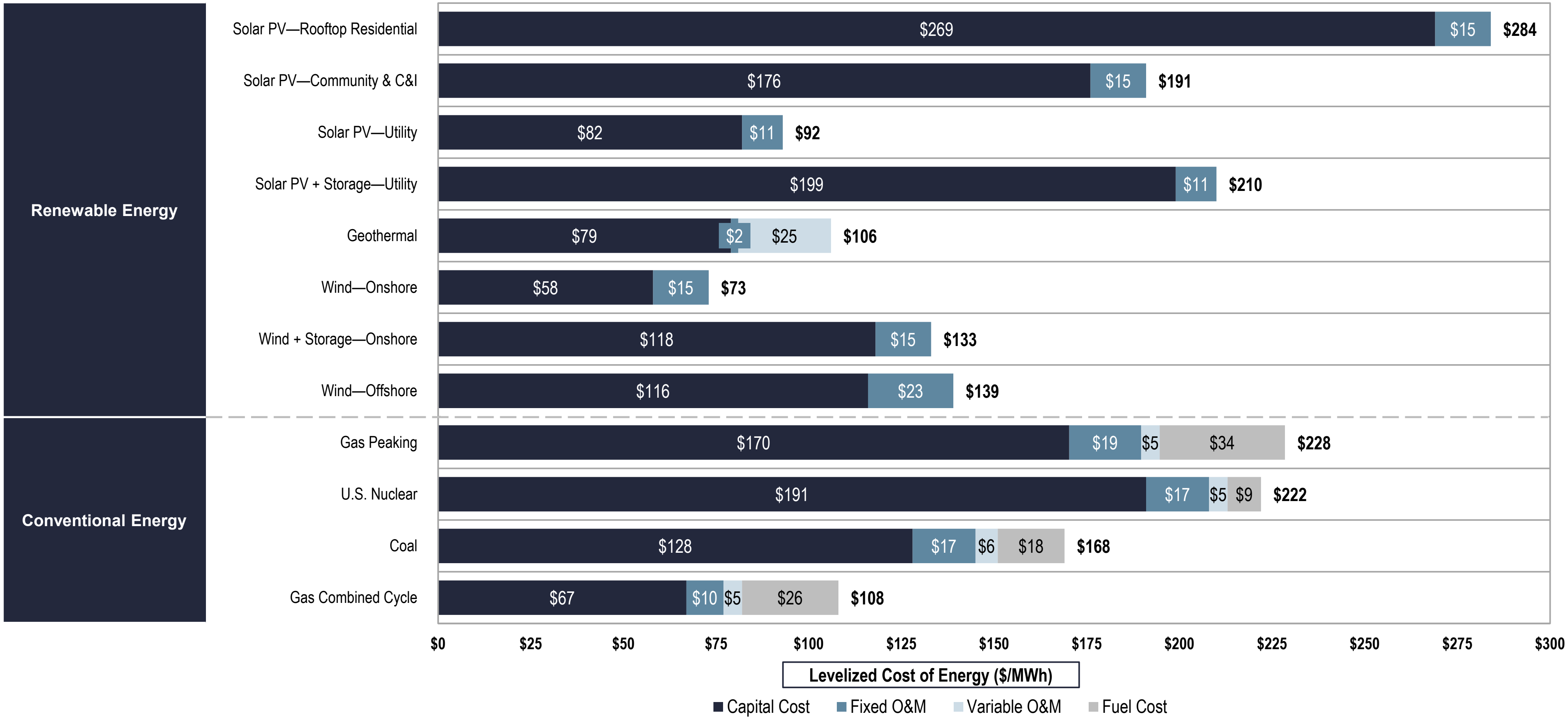
Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and Industry scale to continue lowering operating expenses and capital costs for renewable energy generation technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*
Notes: Figures may not sum due to rounding.

Levelized Cost of Energy Components—High End

Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and Industry scale to continue lowering operating expenses and capital costs for renewable energy generation technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*
Notes: Figures may not sum due to rounding.

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 value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" pages for detailed assumptions by technology)

Unsubsidized Onshore Wind — Low Case Sample Illustrative Calculations

Year [1]		0	1	2	3	4	5	6	7	20
Capacity (MW)	(A)		175	175	175	175	175	175	175	175
Capacity Factor	(B)		55%	55%	55%	55%	55%	55%	55%	55%
Total Generation ('000 MWh)	(A) x (B) = (C)*		843	843	843	843	843	843	843	843
Levelized Energy Cost ($/MWh)	***(D)***		***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***	***$24.4***
Total Revenues	**(C) x (D) = (E)***		**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**	**$20.6**
Total Fuel Cost	(F)		--	--	--	--	--	--	--	--
Total O&M	(G)*		3.5	3.6	3.7	3.7	3.8	3.9	4.0	5.5
Total Operating Costs	**(F) + (G) = (H)**		**$3.5**	**$3.6**	**$3.7**	**$3.7**	**$3.8**	**$3.9**	**$4.0**	**$5.5**
EBITDA	**(E) - (H) = (I)**		**$17.1**	**$17.0**	**$16.9**	**$16.8**	**$16.7**	**$16.7**	**$16.6**	**$15.1**
Debt Outstanding - Beginning of Period	(J)		$107.6	$105.5	$103.2	$100.7	$98.0	$95.1	$92.0	$9.9
Debt - Interest Expense	(K)		(8.6)	(8.4)	(8.3)	(8.1)	(7.8)	(7.6)	(7.4)	(0.8)
Debt - Principal Payment	(L)		(2.1)	(2.3)	(2.5)	(2.7)	(2.9)	(3.1)	(3.4)	(9.9)
Levelized Debt Service	(K) + (L) = (M)		($10.7)	($10.7)	($10.7)	($10.7)	($10.7)	($10.7)	($10.7)	($10.7)
EBITDA	**(I)**		$17.1	$17.0	$16.9	$16.8	$16.7	$16.7	$16.6	$15.1
Depreciation (MACRS)	(N)		(35.9)	(57.4)	(34.4)	(20.7)	(20.7)	(10.3)	0.0	0.0
Interest Expense	(K)		(8.6)	(8.4)	(8.3)	(8.1)	(7.8)	6.3	16.6	(0.8)
Taxable Income	**(I) + (N) + (K) = (O)**		**($27.4)**	**($48.8)**	**($25.8)**	**($11.9)**	**($11.8)**	**($7.6)**	**($7.4)**	**$14.3**
Federal Production Tax Credit Value	(P)		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Federal Production Tax Credit Received	(P) x (C) = (Q)*		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
Tax Benefit (Liability)	**(O) x (tax rate) + (Q) = (R)**		**$11.0**	**$19.5**	**$10.3**	**$4.8**	**$4.7**	**$0.0**	**$0.0**	**$0.0**
Capital Expenditures		**($71.8)**	**($107.6)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow [2]	**(I) + (M) + (R) = (S)**	**($71.8) [3]**	**$17.3**	**$25.8**	**$16.5**	**$10.8**	**$10.7**	**$0.0**	**$0.0**	**($1.4)**
Cash Flow to Equity Investors	(S) x (% to Equity Investors)	($71.8)	$17.3	$25.8	$16.5	$10.8	$10.7	$6.4	$2.1	($1.4)
IRR For Equity Investors		**12.0%**								

Key Assumptions [4]	
Capacity (MW)	175
Capacity Factor	55%
Fuel Cost ($/MMBtu)	$0.00
Heat Rate (Btu/kWh)	0
Fixed O&M ($/kW-year)	$20.0
Variable O&M ($/MWh)	$0.0
O&M Escalation Rate	2.25%
Capital Structure	
Debt	60.0%
Cost of Debt	8.0%
Tax Investors	0.0%
Cost of Equity for Tax Investors	10.0%
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
PTC (+10% for Domestic Content)	$0.0
PTC Escalation Rate	1.5%
Capex	
EPC Costs ($/kW)	$1,025
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$1,025
Total Capex ($mm)	$179
Cash Flow Distribution	
Portion to Tax Investors (After Return is Met)	1%

Technology-dependent

Levelized

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Numbers 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.

Levelized Cost of Energy—Key Assumptions

		Renewable Energy: Solar PV								
	Units	Rooftop Residential			Community and C&I			Utility		
		Low		High	Low		High	Low		High
Net Facility Output	MW		0.005			5			150	
Total Capital Cost	$/kW	$2,300	–	$4,150	$1,300	–	$2,900	$850	–	$1,400
Fixed O&M	$/kW-yr	$16.50	–	$20.00	$13.00	–	$20.00	$11.00	–	$14.00
Variable O&M	$/MWh		—			—			—	
Heat Rate	Btu/kWh		—			—			—	
Capacity Factor	%	20%	–	15%	25%	–	15%	30%	–	15%
Fuel Price	$/MMBTU		—			—			—	
Construction Time	Months		9			12			12	
Facility Life	Years		25			30			35	
Levelized Cost of Energy	$/MWh	$122	–	$284	$54	–	$191	$29	–	$92

Source: Lazard and Roland Berger estimates and publicly available information.

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

	Units	Renewable Energy: Geothermal Low		Geothermal High	Wind—Onshore Low		Wind—Onshore High	Wind—Offshore Low		Wind—Offshore High
Net Facility Output	MW		250			250			1,000	
Total Capital Cost	$/kW	$4,860	–	$6,280	$1,300	–	$1,900	$3,750	–	$5,750
Fixed O&M	$/kW-yr	$14.50	–	$15.75	$24.50	–	$40.00	$60.00	–	$91.50
Variable O&M	$/MWh	$9.05	–	$24.80		—			—	
Heat Rate	Btu/kWh		—			—			—	
Capacity Factor	%	90%	–	80%	55%	–	30%	55%	–	45%
Fuel Price	$/MMBTU		—			—			—	
Construction Time	Months		36			12			36	
Facility Life	Years		25			30			30	
Levelized Cost of Energy	$/MWh	$64	–	$106	$27	–	$73	$74	–	$139

Source: Lazard and Roland Berger estimates and publicly available information.

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

	Units	Renewable Energy: Hybrid Generation + Storage					
		Solar PV + Storage—Utility			Wind + Storage—Onshore		
		Low		High	Low		High
Storage							
Power Rating	MW		50			50	
Duration	Hours		4			4	
Usable Energy	MWh		200			200	
90% Depth of Discharge Cycles/Year	%		350			350	
Roundtrip Efficiency	%		91%			88%	
Inverter Cost	$/kW	$30	–	$60	$30	–	$60
Total Capital Cost (excl. Inverter)	$/kWh	$249	–	$421	$249	–	$421
Storage O&M	$/kWh	$3.63	–	$8.18	$3.63	–	$8.18
Generation							
Capacity	MW		100			100	
Capacity Factor	%		30%			55%	
Project Life	Years		20			20	
Total Capital Cost	$/kW	$850	–	$1,400	$1,300	–	$1,900
Fixed O&M	$/kW	$11.00	–	$14.00	$24.50	–	$40.00
Extended Warranty Start	Year		3			3	
Warranty Expense % of Capital Costs	%	0.5%	–	1.5%	0.5%	–	1.5%
Charging Cost	$/MWh		$0.00			$0.00	
Unsubsidized LCOE	$/MWh	$60	–	$210	$45	–	$133

Source: Lazard and Roland Berger estimates and publicly available information.

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

		Conventional Energy											
	Units	Gas Peaking (New Build)			U.S. Nuclear (New Build)			Coal (New Build)			Gas Combined Cycle (New Build)		
		Low		High	Low		High	Low		High	Low		High
Net Facility Output	MW	240	–	50	2,200			600			550		
Total Capital Cost	$/kW	$700	–	$1,150	$8,765	–	$14,400	$3,310	–	$7,005	$850	–	$1,300
Fixed O&M	$/kW-yr	$10.00	–	$17.00	$136.00	–	$158.00	$40.85	–	$94.35	$10.00	–	$25.50
Variable O&M	$/MWh	$3.50	–	$5.00	$4.40	–	$5.15	$3.10	–	$5.70	$2.75	–	$5.00
Heat Rate	Btu/kWh	8,000	–	9,800	10,450			8,750	–	12,000	6,750	–	7,500
Capacity Factor	%	15%	–	10%	92%	–	89%	85%	–	65%	90%	–	30%
Fuel Price	$/MMBTU	$3.45			$0.85			$1.47			$3.45		
Construction Time	Months	24			69			60	–	66	24		
Facility Life	Years	20			40			40			20		
Levelized Cost of Energy	$/MWh	$110	–	$228	$142	–	$222	$69	–	$168	$45	–	$108

Source: Lazard and Roland Berger estimates and publicly available information.

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

		Marginal Cost of Selected Existing Conventional Generation											
	Units	Gas Peaking (Operating)			U.S. Nuclear (Operating)			Coal (Operating)			Gas Combined Cycle (Operating)		
		Low		High	Low		High	Low		High	Low		High
Net Facility Output	MW	240	–	50		2,200			600			550	
Total Capital Cost	$/kW		$0			$0			$0			$0	
Fixed O&M	$/kW-yr	$4.00	–	$6.00	$102.40	–	$109.50	$22.20	–	$27.80	$9.50	–	$12.60
Variable O&M	$/MWh	$2.60	–	$9.10	$3.00	–	$3.50	$2.80	–	$4.80	$1.00	–	$2.00
Heat Rate	Btu/kWh	10,875	–	12,575	10,400	–	10,400	10,350	–	11,175	7,075	–	7,550
Capacity Factor	%	12%	–	1%	96%	–	96%	81%	–	8%	80%	–	41%
Fuel Price	$/MMBtu	$2.60	–	$2.90	$0.80	–	$0.80	$1.70	–	$4.60	$2.50	–	$3.50
Construction Time	Months		24			69			60			24	
Facility Life	Years		20			40			40			20	
Levelized Cost of Energy	$/MWh	$39	–	$130	$31	–	$33	$28	–	$113	$23	–	$37

Source: *Lazard and Roland Berger estimates and publicly available information.*

LCOS v9.0

Energy Storage Use Cases—Overview

By identifying and evaluating selected energy storage applications, Lazard's LCOS analyzes the cost of energy storage for in-front-of-the-meter and behind-the-meter use cases

		Use Case Description	Technologies Assessed
In-Front-of-the-Meter	**Utility-Scale (Standalone)**	• Large-scale energy storage system designed for rapid start and precise following of dispatch signal • Variations in system discharge duration are designed to meet varying system needs (i.e., short-duration frequency regulation, longer-duration energy arbitrage[1] or capacity, etc.) – To better reflect current market trends, this analysis analyzes 1-, 2- and 4-hour durations[2]	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	**Commercial & Industrial (Standalone)**	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I users – Units are often configured to support multiple commercial energy management strategies and provide optionality for the system to provide grid services to a utility or the wholesale market, as appropriate, in a given region	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	**Residential (Standalone)**	• Energy storage system designed for behind-the-meter residential home use—provides backup power and power quality improvements – Depending on geography, can arbitrage residential time-of-use ("TOU") rates and/or participate in utility demand response programs	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)

Source: Lazard and Roland Berger estimates and publicly available information.

(1) For the purposes of this analysis, "energy arbitrage" in the context of storage systems paired with solar PV includes revenue streams associated with the sale of excess generation from the solar PV system, as appropriate, for a given use case.

(2) The Value Snapshot analysis only evaluates the 4-hour utility-scale use case.

Energy Storage Use Cases—Illustrative Operational Parameters

Lazard's LCOS evaluates selected energy storage applications and use cases by identifying illustrative operational parameters[1]

- Energy storage systems may also be configured to support combined/"stacked" use cases

		Project Life (Years) (A)	Storage (MW)[2] (B)	Solar/ Wind (MW)	Battery Degradation (per annum)	Storage Duration (Hours) (C)	Nameplate Capacity (MWh)[3] (D = B x C)	90% DOD Cycles/ Day[4] (E)	Days/ Year[5] (F)	Annual MWh[6] (G = D x E x F)	Project MWh (H = A x G)
In-Front-of-the-Meter	Utility-Scale (Standalone)	20	100	–	2.6%	1	100	1	350	31,500	630,000
		20	100	–	2.6%	2	200	1	350	63,000	1,260,000
		20	100	–	2.6%	4	400	1	350	126,000	2,520,000
Behind-the-Meter	Commercial & Industrial (Standalone)	20	1	–	2.6%	2	2	1	350	630	12,600
	Residential (Standalone)	20	0.006	–	1.9%	4	0.025	1	350	8	158

= "Usable Energy"[7]

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Operational parameters presented herein are applied to Value Snapshot and LCOS calculations. Annual and Project MWh in the Value Snapshot analysis may vary from the representative project.
(1) The use cases herein represent illustrative current and contemplated energy storage applications.
(2) Indicates power rating of system (i.e., system size).
(3) Indicates total battery energy content on a single, 100% charge, or "usable energy". Usable energy divided by power rating (in MW) reflects hourly duration of system. This analysis reflects common practice in the market whereby batteries are upsized in year one to 110% of nameplate capacity (e.g., a 100 MWh battery actually begins project life with 110 MWh).
(4) "DOD" denotes depth of battery discharge (i.e., the percent of the battery's energy content that is discharged). A 90% DOD indicates that a fully charged battery discharges 90% of its energy. To preserve battery longevity, this analysis assumes that the battery never charges over 95%, or discharges below 5%, of its usable energy.
(5) Indicates number of days of system operation per calendar year.
(6) Augmented to nameplate MWh capacity as needed to ensure usable energy is maintained at the nameplate capacity, based on Year 1 storage module cost.
(7) Usable energy indicates energy stored and available to be dispatched from the battery.

Levelized Cost of Storage Comparison—Methodology

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

Subsidized Utility-Scale (100 MW / 200 MWh)—Low Case Sample Calculations

Year[1]		*0*	*1*	*2*	*3*	*4*	*5*	*20*
Capacity (MW)	(A)		100	100	100	100	100	100
Available Capacity (MW)		110	109	106	103	100	110	102
Total Generation ('000 MWh)[2]	(B)*		63	63	63	63	63	63
Levelized Storage Cost ($/MWh)	***(C)***		***$178***	***$178***	***$178***	***$178***	***$178***	***$178***
Total Revenues	**(B) x (C) = (D)***		**$11.2**	**$11.2**	**$11.2**	**$11.2**	**$11.2**	**$11.2**
Total Charging Cost[3]	(E)		(4.4)	(4.5)	(4.6)	(4.7)	(4.8)	(6.3)
Total O&M, Warranty, & Augmentation[4]	(F)*		(0.3)	(0.3)	(0.6)	(0.6)	(4.3)	(0.8)
Total Operating Costs	**(E) + (F) = (G)**		($4.7)	($4.8)	($5.2)	($5.3)	($9.1)	($7.1)
EBITDA	**(D) - (G) = (H)**		**$6.5**	**$6.4**	**$5.9**	**$5.8**	**$2.1**	**$4.1**
Debt Outstanding - Beginning of Period	(I)		$11.7	$11.4	$11.2	$10.9	$10.5	$1.1
Debt - Interest Expense	(J)		(0.9)	(0.9)	(0.9)	(0.9)	(0.8)	(0.1)
Debt - Principal Payment	(K)		(0.3)	(0.3)	(0.3)	(0.3)	(0.3)	(1.1)
Levelized Debt Service	(J) + (K) = (L)		(1.2)	(1.2)	(1.2)	(1.2)	(1.2)	(1.2)
EBITDA	**(H)**		$6.5	$6.4	$5.9	$5.8	$2.1	$4.1
Depreciation (5-yr MACRS)	(M)		(9.9)	(15.9)	(9.5)	(5.7)	(5.7)	0.0
Interest Expense	(J)		(0.9)	2.8	0.0	(0.0)	0.0	0.0
Taxable Income	**(H) + (M) + (J) = (N)**		**($4.4)**	**($6.6)**	**($3.6)**	**$0.1**	**($3.6)**	**$4.1**
Tax Benefit (Liability)	**(N) x (Tax Rate) = (O)**		**$0.9**	**$1.4**	**$0.8**	**($0.0)**	**$0.8**	**($0.9)**
Federal Investment Tax Credit (ITC)	**(P)**		**$17.5**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
Capital Expenditures		**($46.7)**	**($11.7)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow	**(H) + (L) + (O) + (P) = (Q)**	**($46.7)**[7]	**$23.7**	**$6.6**	**$5.5**	**$4.6**	**$1.7**	**$2.1**

IRR For Equity Investors	**12.0%**

Key Assumptions[5]	
Power Rating (MW)	100
Duration (Hours)	2
Usable Energy (MWh)	200
90% Depth of Discharge Cycles/Day	1
Operating Days/Year	350
Charging Cost ($/kWh)	$0.064
Fixed O&M Cost ($/kWh)	$1.30
Fixed O&M Escalator (%)	2.5%
Charging Cost Escalator (%)	1.87%
Efficiency (%)	91%
Capital Structure	
Debt	20.0%
Cost of Debt	8.0%
Equity	80.0%
Cost of Equity	12.0%
Taxes	
Combined Tax Rate	21.0%
Contract Term / Project Life (years)	20
MACRS Depreciation Schedule	5 Years
Federal ITC - BESS	30%
Capex	
Total Initial Installed Cost ($/kWh)[6]	$292
Extended Warranty (% of Capital Cost)	0.7%
Extended Warranty Start Year	3
Total Capex ($mm)	$58

Use-case specific · Global assumptions

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Numbers presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Total Generation reflects (Cycles) x (Available Capacity) x (Depth of Discharge) x (Duration). Note for the purpose of this analysis, Lazard accounts for Degradation in the Available Capacity calculation.
(3) Charging Cost reflects (Total Generation) / [(Efficiency) x (Charging Cost) x (1 + Charging Cost Escalator)].
(4) O&M costs include general O&M (BESS plus any relevant Solar PV or Wind O&M, escalating annually at 2.5%), augmentation costs (incurred in years needed to maintain usable energy at original storage module cost) and warranty costs (0.7% of equipment, starting in year 3).
(5) Reflects a "key" subset of all assumptions for methodology and illustration purposes only. Does not reflect all assumptions.
(6) Initial Installed Cost includes Inverter costs, Module cost, Balance-of-System cost and EPC cost.
(7) Reflects initial cash outflow from equity sponsor.

Levelized Cost of Storage—Key Assumptions

	Units	Utility-Scale Standalone (100 MW / 100 MWh)		Utility-Scale Standalone (100 MW / 200 MWh)		Utility-Scale Standalone (100 MW / 400 MWh)		C&I Standalone (1 MW / 2 MWh)		Residential Standalone (0.006 MW / 0.025 MWh)	
		Low	High	Low	High	Low	High	Low	High	Low	High
Power Rating	MW	100		100		100		1		0.006	
Duration	Hours	1.0		2.0		4.0		2.0		4.2	
Usable Energy	MWh	100		200		400		2		0.025	
90% Depth of Discharge Cycles/Day	#	1		1		1		1		1	
Operating Days/Year	#	350		350		350		350		350	
Project Life	Years	20		20		20		20		20	
Annual Storage Output	MWh	31,500		63,000		126,000		630		8	
Lifetime Storage Output	MWh	630,000		1,260,000		2,520,000		12,600		158	
Initial Capital Cost—DC	$/kWh	$220 –	$311	$159 –	$282	$160 –	$282	$318 –	$430	$984 –	$1,406
Initial Capital Cost—AC	$/kW	$30 –	$60	$30 –	$60	$30 –	$60	$45 –	$80	$0	
EPC Costs	$/kWh	$34 –	$129	$31 –	$116	$29 –	$110	$59 –	$159	$0	
Total Initial Installed Cost	M $	$25 –	$44	$38 –	$80	$76 –	$157	$1		$0	
Storage O&M	$/kWh	$3.7 –	$8.5	$2.9 –	$7.8	$2.8 –	$7.7	$5.5 –	$11.2	$0.0	
Extended Warranty Start	Year	3		3		3		3		3	
Warranty Expense % of Capital Costs	%	0.50% –	1.50%	0.50% –	1.50%	0.50% –	1.50%	0.50% –	1.50%	0.00%	
Investment Tax Credit	%	30.00% –	40.00%	30.00% –	40.00%	30.00% –	40.00%	30.00% –	40.00%	30.00% –	40.00%
Charging Cost	$/MWh	$58		$64		$51		$129		$325	
Charging Cost Escalator	%	1.97%		1.97%		1.97%		1.97%		1.97%	
Efficiency of Storage Technology	%	91% –	88%	91% –	88%	91% –	88%	91% –	88%	91% –	88%
Levelized Cost of Storage	$/MWh	$222 –	$352	$188 –	$322	$170 –	$296	$373 –	$518	$882 –	$1,101

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: All cases were modeled using 90% depth of discharge and 10% overbuild. Wholesale charging costs reflect weighted average hourly wholesale energy prices across a representative charging profile of a standalone storage asset participating in wholesale revenue streams. Escalation is derived from the EIA's "AEO 2022 Energy Source–Electric Price Forecast (20-year CAGR)".

LCOE

LCOH v4.0

LAZARD

Levelized Cost of Hydrogen Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOH analysis consists of creating a model representing an illustrative project for each relevant technology and solving for the $/kg value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" page for detailed assumptions by technology)

Unsubsidized Green PEM—High Case Sample Illustrative Calculations

Year [1]			*1*	*2*	*3*	*4*	*5*	*25*
Electrolyzer size (MW)	(A)		20	20	20	20	20	20
Electrolyzer input capacity factor (%)	(B)		55%	55%	55%	55%	55%	55%
Total electric demand (MWh) [2]	(A) x (B) = (C)*		96,360	96,360	96,360	96,360	96,360	96,360
Electric consumption of H2 (kWh/kg) [3]	(D)		61.87	61.87	61.87	61.87	61.87	61.87
Total H2 output ('000 kg)	(C) / (D) = (E)		1,558	1,558	1,558	1,558	1,558	1,558
Levelized Cost of Hydrogen ($/kg)	***(F)***		***$7.37***	***$7.37***	***$7.37***	***$7.37***	***$7.37***	***$7.37***
Total Revenues	**(E) x (F) = (G)***		**$11.47**	**$11.47**	**$11.47**	**$11.47**	**$11.47**	**$11.47**
Warranty / insurance	(H)		--	--	($0.5)	($0.5)	($0.5)	($0.6)
Total O&M	(I)*		(5.3)	(5.4)	(5.4)	(5.4)	(5.4)	(5.8)
Total Operating Costs	**(H) + (I) = (J)**		**($5.3)**	**($5.4)**	**($5.8)**	**($5.8)**	**($5.9)**	($6.3)
EBITDA	**(G) - (J) = (K)**		**$6.1**	**$6.1**	**$5.6**	**$5.6**	**$5.6**	**$5.1**
Debt Outstanding - Beginning of Period	(L)		$18.1	$17.9	$17.6	$17.3	$17.0	$1.6
Debt - Interest Expense	(M)		($1.4)	($1.4)	($1.4)	($1.4)	($1.4)	($0.1)
Debt - Principal Payment	(N)		($0.2)	($0.3)	($0.3)	($0.3)	($0.3)	($1.6)
Levelized Debt Service	(M) + (N) = (O)		($1.7)	($1.7)	($1.7)	($1.7)	($1.7)	($1.7)
EBITDA	**(K)**		$6.1	$6.1	$5.6	$5.6	$5.6	$5.1
Depreciation (MACRS)	(P)		(6.5)	(11.1)	(7.9)	(5.7)	(4.0)	0.0
Interest Expense	(M)		(1.4)	(1.4)	(1.4)	(1.4)	(1.4)	(0.1)
Taxable Income	**(K) + (P) + (M) = (Q)**		**($1.8)**	**($6.4)**	**($3.7)**	**($1.4)**	**$0.2**	**$5.0**
Tax Benefit (Liability)	**(Q) x (tax rate) = (R)**		**$0.4**	**$1.3**	**$0.8**	**$0.3**	**($0.0)**	**$2.9**
Capital Expenditures		**($27)** [4]	**($18.1)**	**$0.0**	**$0.0**	**$0.0**	**$0.0**	**$0.0**
After-Tax Net Equity Cash Flow	**(K) + (O) + (R) = (S)**		**$4.8**	**$5.8**	**$4.7**	**$4.2**	**$3.9**	**$6.3**
IRR For Equity Investors		**12.0%**						

Key Assumptions [5]	
Electrolyzer size (MW)	20.00
Electrolyzer input capacity factor (%)	55%
Lower heating value of hydrogen (kWh/kgH2)	33
Electrolyzer efficiency (%)	58.0%
Levelized penalty for efficiency degradation (kWh/kg)	4.4
Electric consumption of H2 (kWh/kg)	61.87
Warranty / insurance	1.0%
Total O&M	5.34
O&M escalation	2.00%
Capital Structure	
Debt	40.0%
Cost of Debt	8.0%
Equity	60.0%
Cost of Equity	12.0%
Taxes and Tax Incentives:	
Combined Tax Rate	21%
Economic Life (years) [6]	25
MACRS Depreciation (Year Schedule)	7-Year MACRS
Capex	
EPC Costs ($/kW)	$2,265
Additional Owner's Costs ($/kW)	$0
Transmission Costs ($/kW)	$0
Total Capital Costs ($/kW)	$2,265
Total Capex ($mm)	$45

Technology-dependent

Levelized

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Numbers presented for illustrative purposes only.
* Denotes unit conversion.
(1) Assumes half-year convention for discounting purposes.
(2) Total Electric Demand reflects (Electrolyzer Size) x (Electrolyzer Capacity Factor) x (8,760 hours/year).
(3) Electric Consumption reflects (Heating Value of Hydrogen) x (Electrolyzer Efficiency) + (Levelized Degradation).
(4) Reflects initial cash outflow from equity investors.
(5) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.
(6) Economic life sets debt amortization schedule.

Levelized Cost of Hydrogen—Key Assumptions

	Units	Green Hydrogen						Pink Hydrogen					
		PEM			Alkaline			PEM			Alkaline		
		Low		High	Low		High	Low		High	Low		High
Capacity	MW	100	–	20	100	–	20	100	–	20	100	–	20
Total Capex	$/kW	$1,063	–	$1,975	$1,100	–	$1,831	$1,133	–	$2,045	$1,170	–	$1,901
Electrolyzer Stack Capex	$/kW	$341	–	$862	$269	–	$562	$341	–	$862	$269	–	$562
Plant Lifetime	Years		25			25			25			25	
Stack Lifetime	Hours		60,000			67,500			60,000			67,500	
Heating Value	kWh/kg H_2		33			33			33			33	
Electrolyzer Utilization	%		90%			90%			90%			90%	
Electrolyzer Capacity Factor	%		55%			55%			95%			95%	
Electrolyzer Efficiency	% LHV[(1)]		65%			67%			65%			67%	
Operating Costs													
Annual Hydrogen Produced	MT	8,681	–	1,736	8,902	–	1,780	14,205	–	2,841	14,568	–	2,914
Process Water Costs	$/kg H_2		$0.005			$0.005			$0.005			$0.005	
Annual Energy Consumption	MWh	481,800	–	96,360	481,800	–	96,360	788,400	–	157,680	788,400	–	157,680
Net Electricity Cost	$/MWh		$48.00			$48.00			$35.00			$35.00	
Warranty & Insurance (% of Capex)	%		1.0%			1.0%			1.0%			1.0%	
Warranty & Insurance Escalation	%		1.0%			1.0%			1.0%			1.0%	
O&M (% of Capex)	%		1.5%			1.5%			1.5%			1.5%	
Annual Inflation	%		2.0%			2.0%			2.0%			2.0%	
Capital Structure													
Debt	%		40%			40%			40%			40%	
Cost of Debt	%		8%			8%			8%			8%	
Equity	%		60%			60%			60%			60%	
Cost of Equity	%		12%			12%			12%			12%	
Tax Rate	%		40%			40%			40%			40%	
WACC	%		9.1%			9.1%			9.1%			9.1%	
Levelized Cost of Hydrogen	$/kg	$4.45	–	$6.05	$4.33	–	$5.49	$3.19	–	$4.33	$3.07	–	$3.86
Subsidized Levelized Cost of Hydrogen	$/kg	$2.48	–	$4.08	$2.36	–	$3.52	$1.22	–	$2.36	$1.11	–	$1.89
Memo: Natural Gas Equivalent Cost	*$/MMBTU*	*$39.05*	–	*$53.10*	*$38.00*	–	*$48.20*	*$28.00*	–	*$38.00*	*$27.00*	–	*$33.90*
Memo: Natural Gas Equivalent Cost (Subsidized Hydrogen)	*$/MMBTU*	*$21.80*	–	*$35.85*	*$20.75*	–	*$30.95*	*$10.75*	–	*$20.70*	*$9.70*	–	*$16.60*

Source: *Lazard and Roland Berger estimates and publicly available information.*
(1) "LHV" refers to the lower heating value of the electrolyzer.

Lazard

LCOE+

Lazard's LCOE+ will continue to evolve over time, and we appreciate that there can, and will be, varied views regarding the specifics of our analyses. Accordingly, we would be happy to discuss any of our underlying assumptions and analyses in further detail—and, to be clear, we welcome these discussions as we try to improve our studies over time. In that regard, the studies remain our attempt to contribute in a differentiated and impactful manner to the Energy Transition. Importantly, the Energy Transition is broader in scope than the deployment of renewable energy generation and a cross-sector focus is critical (e.g., energy efficiency, renewable fuels, decarbonization of industry/supply chain, etc.).

More generally, Lazard remains committed to our Power, Energy & Infrastructure Group clients, who remain our highest priority. In that regard, we believe that we have the greatest allocation of resources and effort devoted to this sector of any investment bank. Further, we have an ongoing and intense focus on strategic issues that require long-term commitment and planning. Accordingly, Lazard strives to maintain its preeminent position as a thought leader and leading advisor to clients on their most important matters, especially in this Industry.

If you have any questions regarding this memorandum or Lazard's LCOE+, please feel free to contact any member of the Lazard Power, Energy & Infrastructure Group, including those listed below.

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