Energy Artisans
8060 Main Street
Ellicott City, MD 21043
p: 443.286.1397
f: 410.630.5161

February 20, 2025

RE: Testimony for HB 1397 – Maryland 2025 Legislative Session

Chair Wilson, Vice Chair Crosby, and Members of the Economic Matters Committee:

The Energy Artisans are pleased to provide this written testimony for HB 1397 of the 2025 Maryland legislative session. As a Maryland based entity with extensive experience working in all aspects of energy load and generation in the United States and Canada, and with specific expertise in PJM and Maryland, we are well informed to provide this testimony regarding the potential impacts and necessity of HB 1397.

Background

The state of Maryland continues to face significant electric generation deficiencies, as it is overly reliant on out of state resources to provide electricity to Maryland consumers. This has been a long-standing issue. The impact is two-fold as time-of-use generation must be imported through high-voltage transmission lines, adding congestion, losses, other locational related costs, and eventual reliance on uneconomic in-state generation, as well as increased reliability costs via the PJM capacity and transmission processes. One path towards easing the electric generation deficit is for the accommodation of additional out-of-state capacity via new high-voltage transmission lines. One of the gating items for transmission construction is a Certificate of Public Convenience and Necessity (CPCN) from the Public Service Commission (PSC).

Conditions of CPCN

Under a CPCN, the PSC leads a holistic public review and comment period to ensure the applying entity meets a number of aspects and measures. Notably, current regulations take the following into consideration for high-voltage electric transmission: recommendation of local governing body, stability and reliability of electric system, economics of the project, esthetics, impact on historic sites, aviation safety, air quality if applicable, effect of climate change, need to meet existing and future demand, and alternative routes that were considered. The last two conditions, the need to meet existing and future demand and alternative routes, apply specifically for high-voltage transmission projects. Taken in total, there appears to be a comprehensive set of conditions for a project to meet save for one glaring omission, alternatives to the building the project itself.

Impacts of Transmission Infrastructure

High-voltage transmission infrastructure is a capital-intensive endeavor with long lasting, if not permanent results with both visual and monetary impact. While standard distribution level utility poles extend about 35 feet above ground, lower voltage transmission infrastructure may be, at minimum, 50 feet above ground. This poses a difficulty in covering, protecting, or otherwise shielding the visual impact that lower capacity generation resources are able to contribute. Additionally, required easements and setbacks on high-voltage transmission limit usable acreage on Marylander's property, thus imposing economic difficulty on those a project is intended to help. Further, transmission owners are allowed to collect a return on their investment as allocated by

Energy Artisans 8060 Main Street
Ellicott City, MD 21043 p: 443.286.1397
f: 410.630.5161

PJM. This ultimately increases the aggregate transmission rate paid by consumers. Under these impacts it is imperative that, under the review of these projects as necessity, that grid related alternatives are considered.

Alternatives

House Bill 1397 suggests the inclusion of two alternative "Grid Enhancing Technologies" to be considered in the CPCN process for high-voltage transmission projects. The first, high performance conductors, have been used by utilities and transmission owners in the past decade to increase line ratings and reliability. Focus on this technology greatly increased in the past year, as recently as this past November when the National Association of Regulatory Utility Commissioners (NARUC) passed a resolution highlighting the ability for high performance conductors to provide benefits to consumers[1]. This past May, twenty-one states, including Maryland, joined the "Federal-State Modern Grid Deployment Initiative"[2], an effort to accelerate improvements to the electric transmission and distribution network. Among the suggested technologies are high performance conductors. It's worth noting that with the recent change in Federal administration, the status of this initiative is unclear, however a February 14, 2025 executive order[3] under the Trump Administration does, widely, consider improvements to energy infrastructure. Expanding the capacity of our regional transmission and distribution grid would greatly increase viable locations for larger generation sources to be built in-state, further facilitating progress to shrinking the generation deficit.

The second alternative for consideration is storage as transmission. This methodology is currently in practice as merchant facility operators seek to capitalize on market arbitrage, congestion, and other types of ancillary services in markets such as ERCOT and CAISO, but also at a grid level in CAISO, MISO, PacifiCorp, among others. A "Storge as Transmission Asset Market Study"[4] was completed in 2023 for NYISO which found significant benefits from reduced congestion, grid support, lower curtailment, and improved deliverability. This has also gained popularity recently as storage costs have decreased and system controls have improved[5]. Further, advances in safety protocols have made their adoption more agreeable among utilities and grid operators focused on reliability. Storage applications have been sought after due to their favorable siting requirements (low acreage footprint) and timeline to implementation. The ability for storage applications to provide this level of grid support should be reasonably considered when evaluating new transmission projects.

Conclusion

Taken in totality, the suggested amendments to the Public Utilities article meet the intention of the bill and provide for the consideration of additional alternatives to high voltage transmission projects. In order to properly ensure transmission projects are evaluated to prevent undue costs on

[1] NARUC, Resolutions Passed by the NARUC Board Of Directors, NARUC Annual Meeting and Education Conference, November 10-13, 2024

[2] "Federal-State Modern Grid Deployment Initiative", May 2024

[3] "Establishing the National Energy Dominance Council", Executive Order, February 14, 2025 (https://www.whitehouse.gov/presidential-actions/2025/02/establishing-the-national-energy-dominance-council/)

[4] "Storage as Transmission Asset Market Study", Quanta Technology, January 2023

[5] LCOE+ 2024 Report", Lazard, June 2024

Energy Artisans 8060 Main Street
Ellicott City, MD 21043 p: 443.286.1397
f: 410.630.5161

Maryland consumers and confirm their necessity under the CPCN process, the Energy Artisans support House Bill 1397.

Patrick D. Welch, Jr.
Founding Member
Energy Artisans

President
Terrapin Energy and Environment, LLC

SUPPORTING DOCUMENTS

Resolutions

Passed by the NARUC Board of Directors

at the

November 10-13, 2024
NARUC Annual Meeting and Education Conference

In Anaheim, California

If you are interested in this resolution, you should read the <u>entire</u> draft and <u>not</u> rely on the truncated description in the Table Contents.

If you have any questions, call or email Brad Ramsay – NARUC GC at 202.257.0568 or jramsay@naruc.org

TABLE OF CONTENTS

costs through coordination; and (iii) encourages collaboration across infrastructure industries, call before you dig program administrators, federal agencies, utility commissions, and state broadband authorities to ensure that facility locates will be accurately and timely performed once requested to prevent damage to existing infrastructure and minimize delays.

Resolution Encouraging the Federal Communications Commission to Investigate the Sale and/or Brokering of Toll-Free and Non-Toll-Free Telephone Numbers to Ensure Number Resource Optimization **Page 13**
Sponsor: (Sarah Freeman) ***PASSED THE BOARD***

Resolution urges FCC to use audit authority to determine how companies are brokering or auctioning toll-free and other numbers via their websites and to determine how these companies obtain these telephone numbers, to ensure that the numbering rules are followed, and to prevent premature number exhaust.

Resolution to File an Amicus Brief with the Supreme Court of the United States in "Consumers' Research v. FCC" **Page 15**
Sponsor: Commissioner Schram ***PASSED THE BOARD***

Resolution authorizes NARUC to file an amicus brief supporting the FCC if the Supreme Court grants certiorari of a 5th Circuit ruling that finds the FCC's Universal Service surcharge mechanism is unconstitutional.

Resolution Adopting NARUC Subcommittee on Accounting and Finance's latest Revisions of the Uniform System of Accounts Reports for Water & Wastewater Utilities. **Page 16**
Sponsor: Commissioner Hughes ***PASSED THE BOARD***

*Resolution adopts and recommends the Uniform System of Accounts for Water Utilities and the Uniform System of Accounts for Wastewater Utilities – as revised by the NARUC Staff Subcommittee on Accounting and Finance - to member Commissions for consideration and for adoption in their respective jurisdiction, as may be deemed warranted, and as may be in the public interes*t.

Resolution Honoring Connecticut Public Utilities Regulatory Authority Vice Chairman John W. "Jack" Betkoski III ***Page 17***
Sponsor: Commissioner Ziegner ***PASSED THE BOARD***

Whereas wildfires, including grassland and forest fires, are increasing in frequency and intensity across North America, resulting in greater public safety hazards and more significant destruction for communities, as well as the utilities that serve them;

Whereas significant wildfires are occurring even in areas previously deemed low risk by the Federal Emergency Management Agency;

Whereas wildfires create significant risks to the energy grid and reliable operations, as well as the financial stability of electric utilities;

Whereas electric utilities are obligated to serve all customers in their service territories, regardless of the wildfire risk profile of the landscape that the infrastructure must traverse to provide that service;

Whereas electric utility infrastructure, such as distribution and transmission lines, is susceptible to damage that can lead to an ignition or contribute to an existing ignition during high wind events or other high fire risk weather, even when lines and rights of way are well maintained, creating public safety risk as well as the significant potential for associated liability;

Whereas electric utilities, as a last resort to protect public safety, may need to deenergize lines to prevent lines from igniting fires or contributing to an existing ignition in high wind events or other high fire risk conditions, to avoid the risk of infrastructure failure, damage and liability, to avoid arcing caused by wildfire smoke, or at the direction of emergency personnel;

Whereas electric utilities risk mitigation through de-energization events, including public safety power shut offs, enhanced recloser safety settings, and emergency de-energizations, may negatively and significantly impact customer reliability, creating the potential for repeated health, safety and financial consequences for communities and individual customers, particularly the most vulnerable customers, the elderly, and functional needs customers;

Whereas reduction of fire consequences, and thus the risk to public safety and the liability associated with an ignition, is a function of multiple factors, including community and property owner fire risk reduction efforts, weather, vegetation and forest management, and fire response capabilities, limiting utility risk mitigation options primarily to ignition prevention;

Whereas management of fire risk and consequences, including electric utility liability, on public lands requires extensive, proactive cooperation between electric utility companies and many federal, state, and local land management agencies to deliver healthy lands and reliable electricity;

Whereas the scale of claims and damages, including non-economic damages, awarded against electric utilities in civil proceedings, regardless of fire investigation findings of cause or utility adherence to a formal wildfire mitigation plan, are financially destabilizing for all utilities, including small utilities as well as very large utilities, with concomitant harms to customers;

Whereas the unique risks of utility-caused ignitions during extreme weather events followed by large civil damages judgements has, in part, led credit ratings agencies to downgrade the electric utility sector[1], impacting 28 percent of the investment grade, long-term corporate debt in the United States[2];

Whereas the demand for utility capital investment in resources, participation in long-term contracts for resources, and grid reliability investments, including deployment of ignition prevention measures, is rapidly increasing in order to meet projections for growing loads, to reduce climate impacting emissions, and to improve reliability in the face of extreme weather;

Whereas access to capital at historically advantageous prices is declining despite strong growth in the electric sector, raising the cost of capital for electric utilities or limiting their access to financing altogether, and thus increasing costs to utility customers;

Whereas electric utilities that have traditionally relied on private insurance, reinsurance, mutual insurance, and self-insurance products, are increasingly unable to obtain such insurance at reasonable cost, or face a lack of availability, due to the substantial risk of wildfire and large claims and civil damage awards;

Whereas the risk of wildfires, and particularly wildfires that become urban conflagrations such as those seen in Santa Rosa, Greenville, and Paradise, California, Lahaina, Hawaii, and Boulder, Colorado, is also significantly impacting the cost of home insurance, a crucial tool that underpins the mortgage market, resulting in rapidly escalating home insurance premiums or the lack of available insurance altogether in a growing number of communities;

Whereas the State of California, in response to the safety and financial risks of wildfires for participating electric utilities and their customers, has created a comprehensive wildfire mitigation program, that includes a requirement for all electric utilities in the state to develop wildfire mitigation plans, as well as the creation of a wildfire fund, that allows compliant large utilities that participate in the state utility wildfire fund with access to a financial backstop and risk pooling mechanism for utilities and their customers, and limits cost recovery and fund reimbursement requirements to address wildfire damage;

Whereas electric utilities across the west, and nationally, are working to address their wildfire risk through increased situational awareness and grid investments to reduce the likelihood of their infrastructure causing an ignition and limiting impacts to customers;

Whereas although the State of California wildfire mitigation plans and wildfire fund have helped reduce ignitions and has mitigated some financial risk for participating large electric utilities, the costs of implementing these additional wildfire measures have contributed significantly to bill increases for utility customers in California;

Whereas electric utilities across the west, and nationally, are working to address their wildfire risk through increased situational awareness and grid investments to reduce the likelihood of their

---

1 Outlook for North American Investor-Owned Regulated Utilities Weakens, Gabriel Grosberg, S&P Global Ratings, 2/14/2024.

2 The ratio of total US outstanding corporate debt, excluding the financial sector, with 10 to 30 year maturities and A and B ratings as compared to utility corporate debt of the same type, as calculated from Bloomberg data, 9/27/2024.

infrastructure causing an ignition or contribute to an existing ignition and limiting impacts to customers;

Whereas~~-~~recognizing the significant risks associated with wildfires, engagement by state regulators and policy makers together with utilities and other interested stakeholders can help identify national and state strategies that allow electric utilities regardless of size to better manage both financial risks and costs associated with wildfires and provide incentives to invest in improved safety outcomes, which could in turn, result in lower overall costs to all customers;

Whereas substantially lowering financial and insurance risks and incentivizing improved safety outcomes by creating minimum safety standards and a federal wildfire funding mechanism, could assist in stabilizing access to capital markets as well as the insurance market for all electric utilities and, to some degree homeowners; *now therefore be it*

Resolved that the Board of Directors of the National Association of Regulatory Utility Commissions, convened at its 2024 Annual Meeting and Education Conference in Anaheim, California, encourages the following~~:~~

(1) Engagement with utilities, state and federal policy makers to develop strategies, including a voluntary solution, to address risks associated with wildfire that could promote stable financial and insurance markets that could lead to lower costs and mitigated wildfire risks, including reduced costs for customers; and

(2) Rapid and significant coordination of utilities and federal land management agencies to allow utilities access to rights-of-ways to reduce fuel loads and mitigate the risk of high consequence fire on public lands.

Passed by the Energy and Environmental Resources Committees on November 11, 2024.
Adopted by the NARUC Board of Directors on November 13, 2024

Resolution on Urging Clarification of Utility Recovery Bond Classification by the SEC to Lower the Cost to Energy Customers

Whereas utility recovery bonds, also referred to as 'ratepayer-backed bonds,' ' utility securitization bonds,' or 'stranded cost bonds,' are financial tools authorized by specific state legislation to help regulated utilities finance critical projects such as climate adaptation, disaster recovery and asset retirement;

Whereas many states have passed enabling legislation for regulators and investor-owned utilities to use this type of financing, and other states are actively contemplating it;

Whereas these bonds receive the highest credit ratings (AAA/Aaa) from their state legislative, regulatory, and federal constitutional protections, which are designed to reduce costs for utility customers, offering a more efficient financing method compared to traditional utility financing;

Whereas utility recovery bonds have advantages for consumers and utilities by reducing the immediate financial burden of large utility costs; realizing lower ratepayer costs of capital: lowering utility credit risk; providing more predictable and stable utility bills; and enabling utilities to access large amounts of capital for significant projects without waiting for traditional rate recovery processes.

Whereas high inflation has resulted in energy rates increasing over the last five years by over 24 percent cumulatively, and that utility recovery bonds have lowered costs for many customers over the same period;

Whereas utility recovery bonds are fundamentally different from asset-backed securities (*e.g.,* credit card bonds, collateralized debt obligations, etc.) such as those that were problematic during the financial crisis of 2008-09 in terms of the issuer type, the nature of the collateral backing, the role of the state and regulators, the risk of the underlying assets, and the source and use of funds;

Whereas since the bonds were first used by regulators and utilities, the Internal Revenue Service (IRS) recognizes the bonds as corporate debt of the parent utility and the Financial Accounting Standards Board, as well as the Securities Exchange Commission (SEC) Office of Chief Accountant have treated the bonds as corporate debt on the consolidated balance sheet of the parent utility;

Whereas from June 2016 through August 2022, the bonds were recognized as corporate utility bonds by Barclays Index Services the predecessor to Bloomberg Index Services, Ltd. which greatly expanded the potential market for and competition among investors for the bonds which leads to lower borrowing rates:

Whereas in August 2022 Bloomberg Index Services Ltd reclassified utility recovery bonds as "asset backed securities" and in July 2024 an interpretation by the staff of the SEC Division of Corporation Finance may imply a similar reclassification.

Whereas these reclassifications (i) are contrary to a common sense understanding of the bonds and lack any investor protection benefit or rationale on how these bonds meet the definition of asset-backed securities and (ii) will severely limit the market for utility recovery bonds, negatively affect investors perception of the complexity and risk of the bonds and therefore lead to inefficient market outcomes by directly increasing utilities' borrowing costs, resulting in higher energy rates for millions of American households;

Whereas the actions of reclassifying utility recovery bonds as asset-backed securities have not sufficiently considered the impact on energy consumers, and do not align with the principles of serving the public interest; *and*

Whereas the Governors of eight states have signed a letter requesting the SEC Chairman act in the public interest and to address this problematic reclassification of utility recovery bonds by index providers and staff interpretations; *now, therefore be it*

Resolved that the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2024 Annual Meeting and Education Conference in Anaheim, California, urge index providers and the SEC to clarify that utility recovery bonds should be classified as corporate bonds, not asset-backed securities, for purposes of Regulation AB or for purposes of the Securities Exchange Act of 1934 to prevent unnecessary increases in energy costs for consumers in states that choose to use this form of financing and to maintain fair and efficient markets as per the SEC's mission.

Passed by the Consumers and Public Interest Committee on November 11, 2024.
Adopted by the NARUC Board of Directors on November 13, 2024.

Resolution Supporting the Integration of Advanced Transmission Technologies in the Electricity Transmission System

Whereas North American Electric Reliability Corporation (NERC) in its 2023 Long-Term Reliability Assessment found growth rates of forecasted peak demand and energy have risen significantly since the 2022 assessment, projecting peak demand for electricity to increase by 9.19% over the next ten years;

Whereas according to market monitor data from annual market reports, transmission congestion costs across the seven organized markets in the U.S. have risen significantly over the past eight years, more than doubling since 2016;

Whereas Lawrence Berkeley National Laboratory data shows that there are over 2,000 gigawatts of generation and storage projects waiting to connect to the grid, with queue times more than doubling from below two years in 2008 to over five years in 2022;

Whereas the U.S. Department of Energy (DOE) National Transmission Needs study found that the U.S. needs to expand regional transmission capacity by 20-128%, and interregional capacity by 25-412% by 2035;

Whereas the US economy requires 24/7 low-cost, reliable electricity to maintain competitiveness in global markets;

Whereas Advanced Transmission Technologies (ATTs), which include, but are not limited to advanced power flow controls, dynamic line rating, and topology optimization, commonly referred to as Grid Enhancing Technologies (GETs), and High-Performance Conductors (HPCs), which include carbon and composite core conductors and superconductors, offer affordable, innovative technological solutions to reduce costs by unlocking critical transmission capacity in the near term;

Whereas the 2024 DOE Innovative Grid Technology Liftoff Report found ATTs are commercially available and have been deployed internationally for years and that GETs and HPCs provide multiple benefits to consumers, including that GETs can increase utilization on new and existing transmission lines by 16% or more; reduce congestion by 50% or more; and save over $5 billion in production cost savings annually, while DOE also found reconductoring with HPCs could double the capacity of existing transmission lines at approximately half the cost of building a new transmission line, and if deployed nationally could meet NERC's 10-year peak load growth projections;

Whereas the federal government, States, and industry can work together to accelerate the use of these new innovative technologies to affordably expand the transmission capacity needed to maintain reliability and meet growing electricity demand; *now, therefore be it*

Resolved that the Board of Directors of the National Association of Regulatory Utility Commissioners, convened at its 2024 Annual Meeting and Education Conference in Anaheim, California, recognizes the need to ensure the reliability and cost-effectiveness of the transmission system, that there are technical potential and benefits to utility ratepayers of the holistic deployment of ATTs such as GETs and HPCs across their systems, and supports Congress appropriating sufficient funds to support utilities, Regional Transmission Organizations/Independent System Operators, and States with the deployment of ATTs, such as through the Grid Resilience and Innovation Partnerships

Programs, for deployments, technical assistance, and research, after funding from the bipartisan Infrastructure Investment and Jobs Act is exhausted in 2025.

____

Passed by the Committees on Electricity and Energy Resources and the Environment on November 11, 2024.
Adopted by the NARUC Board of Directors on November 13, 2024.

Resolution Supporting Communication and Coordination on Underground Infrastructure Safety during Broadband Deployment

Whereas the Bipartisan Infrastructure Law included $42.5 billion for the Broadband Equity, Access and Deployment (BEAD) program for telecommunications and broadband providers to expand infrastructure, particularly in rural areas where investments in internet connectivity have been limited;

Whereas excavation damage, including from broadband installation, is a leading cause of accidents and service disruptions involving underground facilities and has resulted in loss of life, injury, environmental damage, property damage, and disruption of vital services;

Whereas as broadband infrastructure construction work increases, protection of existing infrastructure will be paramount, to include existing buried gas, electric, telecommunications, and water infrastructure;

Whereas some form of call before you dig notification system has been developed in almost every state, and call before you dig notification systems have proven to be important elements in efforts to reduce or prevent damage caused by excavation activity, and thereby reduce or prevent harm to the public associated with such damages when used diligently and properly;

Whereas costs to locate existing buried utilities have the potential to be significant, particularly as requests increase for underground infrastructure operators to identify underground infrastructure, as telecommunications and broadband providers begin construction;

Whereas this volume of locate requests is expected to increase with implementation of BEAD and other federal and state funding programs over the next several years;

Whereas unexpected delays in construction, including delays in obtaining infrastructure locates, will result in additional cost to broadband providers deploying BEAD funding, and will result in additional public cost as well as delays in obtaining sorely needed broadband infrastructure;

Whereas the cost of service to locate infrastructure under call before you dig programs may be borne by infrastructure operators with existing underground infrastructure and ultimately passed on to customers of the existing underground infrastructure;

Whereas state agencies administering broadband funding seek to maximize efficiency in the broadband deployment process, while simultaneously minimizing costs to both broadband providers and existing utility providers;

Whereas a streamlined locate process can prevent delays in network deployment and ensure a provider's ability to meet deadlines associated with funding grants;

Whereas federal broadband funding could be used to cover increased costs to locate existing infrastructure associated with awarded broadband deployment projects. Specifically, the National Telecommunications and Information Administration (NTIA), an agency under the Department of Commerce administering the BEAD Program in coordination with state governments, indicated that costs related to location services are eligible uses of program funding;

Whereas state agencies can play a role in lowering costs for customers by encouraging underground infrastructure operators under their jurisdiction to leverage federal funding for broadband deployment to assist in funding utility locates and call before you dig programs;

Whereas the significant expansion of broadband access must also prioritize the importance of safe digging practices and incident prevention, to include complying with applicable state safe digging programs;

Whereas timely and open coordination and communication between existing utility providers and incoming telecommunications and broadband providers as to the objectives and timelines of construction will be essential for maximizing efficiencies in the construction process; *now, therefore be it*

Resolved that the Board of Directors of the National Association of Regulatory Commissioners, convened at its 2024 Annual Meeting and Education Conference in Anaheim, California, supports the federal government providing specific guidance on the use of federal funding for the payment or reimbursement of qualified infrastructure locating services to support broadband projects; *and be it further*

Resolved that NARUC encourages its member commissions and federal agencies to collaborate with and educate state agencies administering BEAD funding to address eligible uses of funding, including infrastructure locating services and methods for reimbursing public utilities for such costs using federal funding, as well as to identify opportunities to minimize locate request costs through coordination; *and be it further*

Resolved that NARUC encourages collaboration across infrastructure industries, call before you dig program administrators, federal agencies (particularly, the NTIA, Federal Communications Commission, Department of Treasury, Department of Agriculture, and Pipeline and Hazardous Materials Safety Administration), utility commissions, and state broadband authorities on these goals. Such collaboration should address industry and excavator education on call before you dig and damage prevention requirements; data collection and analysis to monitor risks and trends; federal and state grant funding policies and procedures; the use of federal broadband funding (to include BEAD) for infrastructure locating services; and methods of coordination on construction timelines, processes, and objectives in order to minimize locate costs and unnecessary delays; *and be it further*

Resolved that NARUC encourages all owners of existing buried infrastructure to take all necessary steps to ensure that facility locates will be accurately and timely performed once requested in order to prevent damage to existing infrastructure and minimize delays.

Passed by the Committees on Gas, Telecommunications, and Water on November 11, 2024
Adopted by the NARUC Board of Directors on November 13, 2024

Resolution Encouraging the Federal Communications Commission To Investigate the Sale and/or Brokering of Toll-Free and Non-Toll-Free Telephone Numbers to Ensure Number Resource Optimization

Whereas the North American Numbering Plan (NANP), the plan for telephone numbering in North America and the Caribbean, is currently projected to run out of telephone numbers (TN) between 2049 and 2054 (NANPA Website) and potentially sooner if current trends in telephone number usage continue;

Whereas according to industry numbering rules, the North American Numbering Plan Administrator (NANPA) will begin work on an expansion plan when the NANP is within 15 years of exhaust: (Section 6.2 of the NPA Allocation Plan and Assignment INC Guidelines);

Whereas based on current projections, planning for a NANP expansion could begin in just 13 years, in 2037; (ITN Report[3] Appendix);

*Whereas t*ransitioning to an expanded plan after number exhaustion would require moving to 12-digit dialing at an estimated societal cost of up to $270 billion; (Internet of Things Notice);

Whereas State Commissions, in their efforts to ensure that telephone numbers are used efficiently and legally, are facing issues caused by service providers that appear to fail to comply with federal numbering rules, industry guidelines, and the numbering authority delegated to the States;

Whereas a number of State Commissions have reported that some telecommunications carriers, including Voice over Internet Protocol (VoIP) service providers, appear to be transferring telephone numbers to companies that warehouse these numbers or engage in their sale or licensing;

Whereas one of these companies claims to have access to nearly 73 million telephone numbers for sale or auction;

Whereas at least one of these companies has applied for direct access to numbering resources;

Whereas some of these companies have websites that offer an auction capability to buy vanity numbers—sometimes for millions of dollars;

Whereas the NANC asked the Alliance for Telecommunications Industry Solutions (ATIS) Industry Numbering Committee (INC) to investigate the brokering of geographic telephone numbers as long ago as September 30, 2015, following credible reports of numbers being sold; (INC Guidelines relating to such transactions apply to service providers, not individual users.[4]);

Whereas nine years after the NANC's request for action, these companies appear to have continued to broker and warehouse telephone numbers at the expense of area codes, particularly those edging towards exhaust.

---

[3] Report and Recommendation on the Feasibility of Individual Telephone Number (ITN) Pooling Trials and Alternative Means for Conserving Numbering Resources (ITN Report)

[4] "Telephone numbers are North American Numbering Plan (NANP) resources that are considered a public resource and are not owned by the assignees. Consequently, resources cannot be sold, brokered, bartered, or leased by the assignee for a fee or other consideration." ATIS-0300070, *Guidelines for the Administration of Telephone Numbers*, section 1.0.

Whereas the FCC rules regarding number conservation include: counting service providers' number utilization (including obtaining growth codes) only for assigned numbers;[5] placing a 180-day limit on holding numbers in "reserved" status, [6] and requiring sequential number assignment, which imposes limits on a service provider's ability to provide customers with "vanity" numbers;[7]

Whereas ATIS guidelines prohibit end users from selling numbers[8] and some local exchange tariffs and/or customer agreements include language indicating that the customer has no property right to TNs;

Whereas on February 28, 2023, the NANC approved the ITN Report recommending, among other things, further detailed study on the brokering of geographic numbers, and a review of industry guidelines and policies be performed to determine the impact of these processes on number resource utilization and the need for clarification/modification of numbering rules;

Whereas the ITN Report recommended that the FCC consider using its audit processes to address the brokering and mischaracterization of numbers;

Whereas NARUC has reconstituted its Numbering Subgroup to increase State Commission focus and participation on numbering issues;

Whereas despite the funding the NANC has approved to audit companies to ensure compliance with its numbering rules and guidelines, there has not been a numbering audit of a telecommunications carrier or Voice over Internet Protocol service provider in at least 15 years; (47 CFR 52.15(k) and ITN Report); *and*

Whereas as numbering resources dwindle, State Commissions need more tools and resources to enforce both state and federal numbering rules; *now therefore be it*

Resolved that the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC), convened at its 2024 Annual Meeting in Anaheim, California, urges the FCC to use the audit authority outlined in 47 CFR 52.15(k) to determine how companies are brokering or auctioning toll-free and other numbers via their websites and to determine how these companies obtain these telephone numbers, to ensure that the numbering rules are followed, and to determine if additional rules are needed to prevent premature number exhaust.

Passed by the Committee on Telecommunications on November 11, 2024.
Adopted by the NARUC Board of Directors on November 13, 2024.

---

5 *See generally* 47 CFR § 52.15 (h); *see also VoIP Direct Access Order*, FCC 15-70, ¶ 32 (clarifying "that the terms „end users" and „customers" [in „assigned numbers"] do not include telecommunications carriers and non-carrier voice or telecommunication service providers).

6 47 CFR § 52.15 (f); *Number Resource Optimization*, 17 FCC Rcd 252, ¶¶ 121-22 (2001) ("limit[ing] the amount of numbers that are set aside for use by a particular customer but are not being used to provide service on a regular basis.").

7 47 CFR § 52.15 (j).

8 ATIS-0300119, *Thousands-Block (NPA-NXX-X) & Central Office Code (NPA-NXX) Administration Guidelines*, § 2.1.

***Resolution to File an Amicus Brief with the Supreme Court of the United States in* Consumers' Research v. FCC**

Whereas on July 24, 2024, U.S. Circuit Court of Appeals for the Fifth Circuit held in *Consumers' Research v. FCC* that the current funding mechanism for the federal Universal Service Fund is unconstitutional, and remanded the matter to the Federal Communications Commission ("FCC");

Whereas on September 30, 2024, the FCC and the United States Department of Justice filed with the Supreme Court of the United States a petition for writ of certiorari of the 5th Circuit's decision;

Whereas if certiorari is granted, the impact of the Supreme Court's decision in *Consumers' Research* could have far-reaching implications for the future of the Universal Service Fund and, therefore, the telecommunications industry;

Whereas, the Universal Service Fund subsidizes the development and maintenance of telecommunications infrastructure, to the benefit of consumers and the telecommunications industry as a whole;

Whereas the FCC Universal Service Fund subsidies for telecommunications and broadband services are distributed to the entire country, the states have an interest in ensuring that they are not discontinued, since such action would be contrary to the interests of consumers, the communications industry, and the states;

Whereas the Universal Service Fund also provides much-needed funding for programs such as Lifeline and E-Rate, which many states rely upon to support their residents; *now, therefore, be it*

Resolved, that the Board of Directors of the National Association of Regulatory Utility Commissioners ("NARUC"), convened at its 2024 Annual Meeting and Education Conference in Anaheim, California, finds that if the petition for writ of certiorari filed with the Supreme Court of the United States in *Consumers' Research v. FCC* is granted, NARUC should file an amicus brief in this matter for the purpose of advocating for the interests of NARUC and its member states.

Passed by the Committee on Telecommunications on November 11, 2024.
Adopted by the NARUC Board of Directors on November 13, 2024.

Resolution Adopting the NARUC Subcommittee on Accounting and Finance's latest Revisions of the Uniform System of Accounts Reports for Water and Wastewater Utilities.

Whereas at its Summer Meeting held in Los Angeles, California from July 22 to 25, 1996, the National Association of Regulatory Utility Commissioners (NARUC) Executive Committee (now, Board of Directors) unanimously adopted the Uniform System of Accounts for Water Utilities and the Uniform System of Accounts for Wastewater Utilities reports (collectively, the USoA Reports);

Whereas the NARUC Staff Subcommittee on Accounting & Finance (SSAF) recommends updates to USoA Reports periodically, and recently adopted changes to the USoA reports on October 8, 2024;

Whereas the USoA reports are meant to be guides for how water and wastewater utilities account for their operations;

Whereas the USoA reports include a uniform system of accounts recommended to NARUC member commissions for consideration and for adoption, as may be deemed warranted, and as may be in the public interest;

Whereas the uniform system of accounts contained in the USoA reports are not meant to supersede the authority of any jurisdiction, as the regulating body has final authority on the accounting procedures used by the regulated public utilities subject to their jurisdiction;

Whereas if the uniform system of accounts contained in the USoA reports contradict the practice within a given jurisdiction, regulated public utilities should defer to the regulating body's laws, regulations, and orders;

Whereas the SSAF has offered the updated USoA reports for review and approval by both the NARUC Committee on Water and the NARUC Board of Directors, *now therefore be it*

Resolved the NARUC Board of Directors, convened in its 2024 Annual Meeting and Education Conference in Anaheim, California, hereby adopts and recommends the Uniform System of Accounts for Water Utilities and the Uniform System of Accounts for Wastewater Utilities to member Commissions for consideration and for adoption in their respective jurisdiction, as may be deemed warranted, and as may be in the public interest.

___

Passed by the NARUC Committee on Water November 11, 2024.
Adopted by the NARUC Board of Directors November13, 2024.

Resolution Honoring Connecticut Public Utilities Regulatory Authority Vice Chairman John W. "Jack" Betkoski III

Whereas John W. Betkoski was appointed to the Connecticut Department of Public Utility Control in 1997 and elected Vice Chairman of that body in 2007. When Public Utilities Regulatory Authority ("PURA") was established on July 1, 2011 as the State's new regulatory authority, Betkoski was appointed a Director by Governor Dannel P. Malloy and elected as Vice Chairman of the new authority;

Whereas Vice Chairman Betkoski served as Chairman of the National Association of Regulatory Commissioners ("NARUC") Committee on Water from July 2001 to July 2004 and served as an active member of the NARUC Committee on Consumer Affairs;

Whereas the NARUC Constitution was amended to establish the Subcommittee on Education & Research through a resolution sponsored by the Executive Committee at the Annual Convention in November 2006, with Vice Chairman Betkoski chairing the Subcommittee's inaugural meeting in February 2007;

Whereas Vice Chairman Betkoski led the Subcommittee in a busy three-year period that included creating a NARUC New Commissioner training course, implementing a standardized system concerning use of the NARUC name and logo for events organized by other institutions, conducting a survey of Commissioner and Commission staff interest in advanced degree programs, monitoring the transition process of the National Regulatory Research Institute, enhancing the institutional relationships with NARUC endorsed regulatory training providers;

Whereas Vice Chairman Betkoski was appointed as NARUC's representative to the International Confederation of Energy Regulators to chair the Working Group 4 on Training, Education and Best Practices in November 2009, thereby allowing him to focus his efforts to enhance sound regulatory training and research practices around the world;

Whereas Vice Chairman Betkoski is the former President of the New England Conference of Public Utilities Commissioners and the NARUC;

Whereas Vice Chairman Betkoski is currently a member of NARUC's Board of Directors;

Whereas Vice Chairman Betkoski is currently Chairman of the Connecticut Water Planning Council, a member of the American Water works Association Research Foundation's Public Council on Drinking Water Research, and a member of the Environmental Protection Agency's National Drinking Water Advisory Council, serving on its Water Security Working Group;

Whereas prior to his service at the PURA, Vice Chairman served as a member of the Connecticut General Assembly, representing the 105th District (Ansonia, Beacon Falls, and Seymour) as a State representative for 1987-1997, co-chairman of the legislature's Commerce Committee from 1993 to 1997;

Whereas Vice Chairman Betkoski received a Bachelor of Arts degree from Sacred Heart University, a Master of Science and a Sixth Year Diploma in Advanced Studies in Administration and Supervision from Southern Connecticut State University; *now therefore be it*

Resolved that the Board of Directors of the National Association of Regulatory Commissioners, convened at its 2024 Annual Meeting and Education Conference, in Anaheim, California, congratulates Vice Chairman for all his years of dedicated public service and leadership; *and be it further* that all National Association of Regulatory Commissioners members convey their best wishes for Vice Chairman Betkoski in all his future endeavors.

Passed by the Committee on Electricity on November 11, 2024.
Adopted by the NARUC Board of Directors on November 13, 2024.

Federal-State Modern Grid Deployment Initiative

May 2024

The White House
Washington

Table of Contents

Federal-State Modern Grid Deployment Initiative Principles

In the face of growing needs for modernization of the U.S. electrical grid, the Biden-Harris Administration in May 2024 will launch the Federal-State Modern Grid Deployment Initiative (“the Initiative”) to accelerate improvements to the electric transmission and distribution network, which are critical to meeting the country’s objectives for affordable, clean, reliable, and resilient power. Grid stakeholders are increasingly looking for opportunities to meet those objectives, while facing a variety of challenges around projected electric load growth, line congestion, interconnection delays, siting and permitting, variability in power prices for consumers, and increasing reliability risks from extreme weather events due to climate change. Fundamentally, the Biden-Harris administration recognizes that more modern, more dynamic approaches to power system management are needed to keep pace with the scale of changes happening across the country.

The Initiative reaffirms President Biden’s commitment to ensuring the United States has the electric grid it needs to continue outperforming other countries and to help local communities thrive. Building on the Biden-Harris Administration’s legislative accomplishments and executive actions in tackling the grid modernization challenge, the Initiative aims to bring together states, federal entities, and power sector stakeholders to help the grid adapt quickly and cost-effectively to meet the challenges and opportunities that the power sector faces in the twenty-first century.

Grid modernization can be encumbered by legacy policies and technologies designed for a time when electricity demand was much more static than it is today. The resurgence of American domestic manufacturing along with the rapid adoption of electric vehicles and growth of large data centers, among other factors, require a collective shift in perspective about the grid to more proactive, innovative approaches that are better suited to tackle the accelerating pace of innovation. While progress has been made to address challenges to building new grid assets such as transmission and distribution lines, additional options are needed—particularly tools that can provide more immediate impact and solutions.

To that end, modern grid technologies, including high performance conductors and grid enhancing technologies (“GETs”, such as dynamic line ratings), are proven, commercially-available solutions that can be rapidly and affordably deployed at-scale today to improve line capacity, performance, and resilience. They can be beneficial for both new and existing transmission and distribution projects. For new projects, they can help get new generation and loads interconnected faster, with less disruption, and also protect against future demand increases. For existing infrastructure, modern grid technologies can be even more valuable, by significantly reducing deployment costs, permitting times, and build times. Their deployment additionally helps accelerate job creation and investment opportunities.

★ ★ ★ ★ ★ ★

Although these solutions have strong operational track records in several countries around the globe and many of the top technologies come from U.S.-based companies, widespread deployment in the U.S. continues to lag. The Federal-State Modern Grid Deployment Initiative aims to drive efforts to speed up adoption and deployment of those tools to ensure that the electric grid remains a source of strength for continued progress and economic vitality of the states individually and the country as a whole. States participating in this Initiative will advance the following commitments to accelerate modern grid solutions, with support and collaboration from the federal government to ensure collective progress toward these shared goals.

Mutual Federal-State Commitments

Meeting the shared challenges and opportunities of increased load growth, a rapidly changing energy landscape, aging infrastructure, and new grid enhancing technologies – while delivering reliable, clean, and affordable energy to consumers – the Federal government and the states jointly commit to:

- Explore ways to accelerate the near-term deployment of more advanced, commercially-available grid technologies to expand grid capacity and build modern grid capabilities on both new and existing transmission and distribution lines;
- Recognize that the deployment of modern grid technologies is part of a holistic energy strategy, complementing the need to build out new transmission and distribution lines;
- Recognize that there will not be a "one-size-fits-all" approach to maximizing the opportunities and overcoming the challenges each state may be facing with their grid;
- Work to increase state and Federal cooperation for both intraregional and interregional transmission planning efforts across regions, including Regional Transmission Organizations and Independent Service Operators;
- Work collaboratively with solution providers, industry, labor organizations, and trusted validators to build a diverse workforce and ensure grid owners and operators have access to the training and equipment needed to support modern technology deployment;
- Work to provide opportunities for stakeholders and communities within and across regions to share how to most effectively improve siting, regulatory, and economic structures;
- Explore opportunities to establish innovative partnership models, pool resources, and jointly plan transmission and distribution infrastructure development.

State Commitments

State governments recognize that innovative grid technology deployment bolsters the capacity of our electric grid to more effectively meet current and future demand, maximizes benefits of new and existing transmission infrastructure, increases grid resilience to the growing impacts of climate change, and better protects consumers from variability in energy prices. Enhanced coordination within and across states can accelerate utilization of modern grid solutions and ensure the power system is built for the future. The state governments commit to:

- Prioritize or accelerate efforts that support the adoption of modern grid solutions to cost-effectively meet growing electric grid needs, including efforts that increase capacity and maximize utilization of existing infrastructure;
- Explore opportunities at the executive and legislative levels to address capacity challenges facing the grid in an expedient manner;
- Explore pathways to facilitate adoption of high-performance conductors and grid enhancing technologies, which may include considering these technologies in grid planning, financial incentives, performance standards, and updated cost-effectiveness criteria;
- Maximize the use of available Federal financial and technical assistance;
- Help assess and communicate the potential benefits of modern grid technologies to partners and stakeholders within and across states, including local governments and the public;
- Share successes, challenges, lessons learned, and best practices with other states.

Federal Commitments

The Federal government's role in the Initiative is rooted in its recognition that a robust electric grid is essential for delivering the country's economic, social, climate, and strategic objectives. In order to promote economic competitiveness, grow the country's manufacturing capacity, and place the United States in a position to continue creating good-paying jobs, the Federal government commits to:

- Maintain the national focus on grid innovation and promote awareness of power challenges as a strategic and economic priority nationwide;
- Ensure Federal agencies and lawmakers are informed of the value and opportunities created by grid innovation, and the criticality of reform;
- Make technical assistance programs available from the U.S. Department of Energy's Grid Deployment Office, Office of Electricity, and National Labs for regions and states that are seeking additional support. This can also include assistance with decision frameworks between technologies and policies;
- Ensure states are aware of available financial assistance resources to support local projects, such as competitive funding from U.S. Department of Energy's Grid Resilience and Innovation Partnership program (GRIP) and low-cost loans from the Title 17 Energy Infrastructure Reinvestment program;
- Encourage Power Marketing Administrations to consider modern grid technologies and collaborate with related power authorities in the regions they respectively serve;
- Promote ongoing dialogue between partner states, industry leaders, labor organizations, and trusted technical validators (domestically and globally) to explore strategies to accelerate deployment;
- Continue to source, track, evaluate, and disseminate information on state-of-the-art technologies and policies.

###

Storage as Transmission Asset Market Study

White Paper on the Value and Opportunity for Storage as Transmission Asset in New York

Prepared for NY-BEST January 2023 Prepared by Quanta Technology

Storage as Transmission Asset Market Study

White Paper on the Value and Opportunity for Storage as Transmission Asset in New York

PREPARED BY

Quanta Technology

William Brown
Henry Chao
Arnold Schuff
Steven Wang

PREPARED FOR

New York Battery and Energy Storage Technology (NY-BEST) Consortium

ACKNOWLEDGEMENTS

NY-BEST gratefully acknowledges the financial contributions of the New York State Energy Research and Development Authority (NYSERDA) and NY-BEST members who supported the study.

DISCLAIMER

This white paper was prepared by Quanta Technology, LLC (Quanta) for NY-BEST as part of an engagement in which Quanta assessed the technical feasibility and operational practicality of storage projects to perform transmission functions in New York. The white paper's contents are for informational purposes and are provided "as is," without representation or warranty of any kind, including, without limitation, accuracy and completeness. Quanta assumes no responsibility to the reader for the consequences of any errors or omissions and may revise the whitepaper at any time under NY-BEST's guidance without notice to the reader.

NY-BEST | New York, NY

Quanta Technology | Raleigh, NC

Acronyms and Abbreviations

AVCE	Automatic voltage controlling equipment
BESS	Battery energy storage system
CLCPA	Climate Leadership and Community Protection Act
FERC	Federal Energy Regulatory Commission
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan (regional planning process)
MW	Megawatt
MWh	Megawatt-hour
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordination Council
NWA	Non-wire alternative
NYCA	New York Control Area
NYSPSC	New York State Public Service Commission
NYSRC	New York State Reliability Council
NYISO	New York Independent System Operator
PAR	Phase angle regulator
PPTN	Public policy transmission need
ROW	Right-of-way
SATA	Storage as Transmission Asset
SATOA	Storage as Transmission-Only Asset
TO	Transmission owner
TSL	Transmission security limit
UPME	Unidad de Planeación Minero Energética

Table of Contents

Executive Summary

Energy storage projects are becoming competitive as an alternative to traditional transmission lines. Not only does an energy storage project typically have a smaller land disturbance and shorter development, permitting, and construction timelines—meaning additional savings—but energy storage can also be added incrementally to address any uncertainties in transmission needs. Beyond increasingly utilizing existing transmission networks, energy storage is suited for low or uncertain load growth scenarios and spiky peak-shaving applications to mitigate grid congestion, reduce renewable curtailment, and defer the uncertain need for new power lines.

In this study, we first discuss how grid planners and operators are currently proposing and implementing batteries as alternatives to traditional transmission. For example, Germany plans to spend €348M on its Grid Booster project. Likewise, the Midcontinent Independent System Operator's (MISO) 2020 transmission expansion plan included its first energy storage project. MISO concluded that installing an $8.1M, 2.5MW/50 MWh battery in the Waupaca area would be more cost-effective than rebuilding double 115 kV transmission lines for $11.3M. In this study, we demonstrate the economic and environmental value of Storage as Transmission Asset (SATA) through a series of global use cases.

Second, we illustrate three use cases for potentially applying SATA to the currently planned New York State transmission grid to increase grid operations and utilization efficiency. The three use cases for New York support the State's transmission upgrade pursuits by demonstrating the potential for SATA to deliver renewable energy to consumers using a cost-effective alternative to traditional transmission. SATA has the potential to reduce the grid upgrade effort, completion time, and cost, estimated to be on the order of several billion dollars in the coming decades. Finally, in addition to renewable curtailment reduction and cost savings, using SATA will greatly reduce land disturbance and thus minimize impacts on land resources and the environment.

Ultimately, the three SATA use cases illustrate viable applications and offer the following benefits:

- Use Case 1 demonstrates that SATA is a viable alternative to transmission wire solutions because it reduces congestion and cost-effectively improves transfer capability.
- Use Case 2 demonstrates that SATA is beneficial because it provides the technical advantage of grid voltage support, improving transmission capability and renewable energy deliverability.
- Use Case 3 demonstrates that SATA can improve capacity deliverability and reduce local capacity requirements beyond its role as a transmission asset.

Notably, the study focuses on storage deployed to cost-effectively improve transmission system reliability and efficiency and hence is justifiable to recover the cost through regulated rate schedules in the same manner as traditional transmission. Under certain circumstances and with changes to transmission tariffs, such storage could be a bulk power resource participating in the New York Independent System Operator's (NYISO) grid and market operations if the storage market participation does not conflict with its designed applications and services. For example, if a one-hour duration asset sufficiently supports reliable operation of the grid, a longer-duration asset could provide other grid services, including energy adequacy to improve system resilience during high demand times, synthetic inertia, frequency regulation, voltage support, and more.

The following table summarizes the cost savings of the three use cases compared to traditional transmission solution costs.

Use Case	Battery Size	Estimated SATA Capital Cost ($M)	Estimated Wire Solution Capital Cost ($M)	Local Area Annual Cost Saving ($M)	NYCA-Wide Congestion Annual Cost Saving ($M)
#1	200 MW/200 MWh	120	700	9.9*	13.1
#2	50 MW/50 MWh + 1,500 MVAr Reactive Power Capacity	250	615	51**	55
#3	200 MW/200 MWh	120	533	30.4***	17.8

*   Congestion cost saving for Zone K
**   Congestion cost saving for the Central East interface
***   Zone J LCR saving and congestion cost saving

The use cases in this study show that SATA projects can provide significant cost savings compared to traditional transmission solutions. New York State is transforming its electric system into one that is cleaner and more resilient under the direction of the Climate Leadership and Community Protection Act (CLCPA) with projected multi-billion dollar spending on transmission expansion; however, present transmission planning rules and tariffs do not allow the use of SATA to optimize these investments. Done properly and permissibly, SATA could greatly reduce the impact on New York ratepayers by avoiding overbuilding wire-only solutions.

Introduction

As the New York State Public Service Commission (NYPSC) and other key policymakers have reiterated, achieving the State's clean energy transition goals will require diversified, innovative technologies that enable clean energy resources to benefit customers. But current transmission planning processes do not consider how SATA, as opposed to traditional transmission, can offer reliability, economics, and environmental benefits for customers. Specifically, SATA deployment allows a more cost-effective use of the existing transmission system and land conservation; hence, it is likely to receive more stakeholder support than traditional wire buildout. This study examines SATA use cases from other territories and details the analysis and results for three proposed SATA use cases in New York State. These use cases show where and how SATA can facilitate achieving policy goals, reduce renewable curtailment, and decrease energy and investment costs.

In Part 1, we evaluate SATA's potential through a series of use cases from other jurisdictions where battery storage has been deployed as a substitute for traditional transmission. We also explain how SATA has reliably met climate policy objectives.

In Part 2, we examine three potential use cases on New York transmission systems to illustrate the scale of the opportunity and benefits of SATA in unlocking clean, cost-effective generation. These use cases evaluate techno-economic feasibility, capital requirements, and permitting and compliance advantages of realizing greater system transfer capability through the SATA applications.

1. Part 1 – Value of SATA and Use Cases

Energy storage systems can decrease the cost of achieving climate targets and should be integral to the transmission planning process. One challenge is deciding the appropriate tariff structure and the affected ratepayer group(s). Part 1 focuses on potential SATA use cases, SATA facilities currently planned or operated, their respective operating schemes, and how they satisfy reliability needs and climate policy objectives.

As the demand for transmission systems to achieve climate, environmental, curtailment, and economic policy objectives grows, shifting market conditions are eroding traditional wire transmission solutions' value relative to more flexible alternatives, especially with more elastic demand due to demand-side activities, such as distributed energy resources. One flexible alternative is SATA, a storage-based application that can be repurposed and reused for different functions. Furthermore, SATA can be used at different locations as a transmission upgrade deferral asset, wherein the project price is assessed against the transmission upgrade's avoided capital cost. Thus, potential use cases for SATA providing value to the transmission grid include the following:

1. **To increase transmission transfer capability** over major bulk transmission interfaces[1] – SATA can balance individual transmission interface line loadings and mitigate system voltage or stability issues under normal or contingency conditions. Such capabilities enable the grid to carry higher power flows over the transmission interface.
2. **To provide stability services** – SATA can provide voltage control and inertia, critical attributes for the grid to maintain constant frequency and voltage. While many synchronous generators are retiring due to today's environmental constraints and climate targets, this situation allows SATA to become a viable option to avoid otherwise-necessary costly transmission upgrades.
3. **To meet grid operation flexibility needs** with existing transmission infrastructure – As fossil peaking generators are retiring, the power grid is losing operating flexibility in affected areas. As such, expanding localities' remote access to flexible system transmission resources becomes necessary. Siting SATA in the affected areas avoids building expansive transmission lines and makes the intermittent locational resources capable of responding to grid dispatch needs. In this case, SATA would primarily control power flows to achieve better balances among transmission facility loadings, enabling more efficient use of existing transmission facilities.
4. **To address lumpiness and provide grid-forming support** beyond that of a traditional transmission project – Traditional transmission projects are lumpy[2] and uneconomic or inflexible to address small, incremental grid needs and thus fail in project justification at the planning stage or results and require a lengthy permitting process. By contrast, storage can be planned flexibly and built incrementally with less environmental disturbance and shorter permitting time, reducing the cost of foreclosing the option of congestion mitigation. Faster project development enables shorter time periods than the cost recovery period required for a traditional transmission project, minimizing the risk of stranded assets and preventing overbuilding transmission infrastructure. Additionally, energy storage's grid-forming technologies can provide voltage and frequency regulation capabilities for grid stability.

[1] A transmission interface consists of a set of parallel transmission facilities that separate two parts of transmission networks within a transmission system. The transfer capability for the transmission system is a measure of the ability of the bulk power, typically a high-voltage transmission system, to move electric power from one part to the other over the defined set of facilities for overall system resource adequacy requirements.

[2] Due to the nature of a transmission line project that can only be built in certain sizes, the investment often is lumpy. The cost is fixed over a sizable range. Within the range in capacity, there are no returns to scale.

5. **To reduce renewable curtailment** by managing congestion on non-bulk transmission networks – This potential use case is similar to 1) above but focuses on a non-bulk, lower voltage transmission system where renewable output is limited by the thermal ratings of a single transmission facility. Using SATA can help the transmission facility avoid thermal rating exceedance under normal and contingency conditions.
6. **To allow optionality in transmission planning** – Energy storage projects can be deployed in a piecemeal fashion, allowing the project to be augmented over time as needs develop and providing valuable planning and cost optionality to transmission operators.

The following sections introduce examples of energy storage being implemented in the U.S. and globally. Among the examples, the storage-based solution is consistently more cost-effective or preferred alternative to traditional transmission because of physical or societal constraints.

1.1 Energy Storage Application in Germany

In Germany, "more and more electricity from renewable energy needs to be transported from the windy northern part of the country to the [load] centers of demand in the south and west."[3] Thus, the German power grid is reaching its limits. To address this, "a 1,300 MW portfolio of energy storage known as GridBooster was proposed in 2019 to ensure grid stability and lower network (i.e., redispatch) costs. As a first phase, three projects totaling 450 MW have been approved for procurement by TransnetBW and TenneT to provide backup transmission capacity, as opposed to the grid operators maintaining an entire additional transmission line on standby to provide N-1 contingency relief."[4]

In addition to building new transmission lines, full use of the existing transmission lines enabled by using new technologies triggered the German Federal Network Agency (BnetzA) to approve two innovative pilot facilities for grid boosters in the Network Development Plan in December 2019. The project,[5] known as Grid Booster (in German, Netzbooster), is to be completed in 2025 and has the following features:

- At 250 MW/250 MWh, the planned battery storage unit in Kupferzell, a major German transmission grid hub, helps better use existing powerlines in normal operations without having to secure potential contingency conditions. During normal system operation, the storage will be charged and remain so. During contingency situations or grid failure, the storage will intervene within seconds to inject or absorb power into the line to which it is connected and will mimic power flow on transmission lines, enabling time for grid operators to redispatch generation.
- The project's cost is part of the €348M budgeted for the Grid Booster initiative. While grid boosters cannot replace the grid expansion needed after 2030, they can defer and delay the costly immediate transmission upgrades, providing optionality to the system. Further, "if the pilot facilities work well, other technical solutions will also be feasible rather than large-scale centralized storage units. For example, there could be lots of distributed storage units, or 'flexible loads,'"[6] according to Germany's Federal Ministry for Economic Affairs and Climate Action.

[3] Federal Ministry for Economic Affairs and Climate Action, "What Is a Grid Booster," February 26, 2020, https://www.bmwi-energiewende.de/EWD/Redaktion/EN/Newsletter/2020/02/Meldung/direkt-account.html.
[4] Kiran Kumaraswamy, Achal Sondhi, Pablo Barrague, and Holger Wolfschmidt, "Building Virtual Transmission: Critical Elements of Energy Storage for Network Services," Fluence white paper, https://info.fluenceenergy.com/hubfs/Building%20Virtual%20Transmission.pdf.
[5] https://www.transnetbw.de/de/netzentwicklung/projekte/netzbooster-kupferzell/mediathek.
[6] Federal Ministry for Economic Affairs and Climate Action, "What Is a Grid Booster."

- "To support the transmission network, the [Grid Booster] will deliver a suite of complex grid services, including synthetic inertia, dynamic voltage control, contingency support, and congestion management among others."[7]
- In operation, "the project-operating company gets production losses for which the grid operator is obliged to pay compensation in accordance with §13 and §15 of the Act for the Development of Renewable Energies (Erneuerbare-Energien-Gesetz – EEG)."[8]

1.2 Energy Storage Application in Colombia

The Caribbean region of Colombia is experiencing high rates of load growth exceeding 5.5% annually, thus stressing the transmission infrastructure and leading to severe congestion and unreliable operating regimes. Unlike the rest of the system, the Caribbean region is powered by 90% thermal resources and is interconnected to the Central system using three 500 kV lines with an operational transfer limit of 1,500 MW. The installed generation capacity is 3,000 MW, serving a peak demand of 2,000 MW.

Transmission congestion is frequently encountered during contingencies, such as the loss of a transformer or a line, in what is labeled as N-1 congestion. However, congestion can also occur in normal system conditions if the daily load peaks cause a line to overload, in what is labeled as an N-0 congestion. In the Barranquilla region, Colombia's Mining and Energy Planning Unit (UPME) identified grid violations due to transmission congestion. In the absence of grid expansion solutions, the grid operator must operate two power plants all the time (Tebsa and Flores) to mitigate grid violations, even though one plant would have sufficed had the grid constraints been resolved. Redispatching generation away from the least-cost dispatch to avoid grid constraints is an industry-standard operational practice that is effective but costly.

UPME's integrated resource plan identified several urban sites with congestion on the transmission network that was extremely challenging to resolve with traditional wire solutions with the right-of-ways (ROW) along the river that were subject to environmental or societal oppositions. UPME further examined the efficacy of using energy storage to resolve the grid constraints to reduce land use and impact and of using storage to shave local peak load. The system benefits were the reduced number of grid violations, lower generation cost under both N-0 and N-1 operating conditions, and less cost compared to traditional solutions.

In January 2021, UPME launched an RFP for a minimum of 45 MW/45 MWh BESS. In July 2021, the RFP was awarded to Canadian Solar at $19M. Compared to the traditional wire solution, which was determined to be cost-prohibitive, the storage solution is effectively the only viable alternative to improve reliability and reduce consumer costs.

1.3 Energy Storage Application by MISO

MISO proposed incorporating storage devices owned by transmission owners as Storage as Transmission-Only Assets (SATOAs). The MISO proposal was to make energy storage projects eligible, under certain circumstances, for selection in the MISO transmission expansion plan (MTEP) and to provide cost-based recovery for such projects on the same basis as other MTEP projects. The SATOA

[7] Yusuf Latief, "Grid Booser: World's Largest Storage-as-Transmission Project Gets Green Light," *Smart-Energy*, October 9, 2022, https://www.smart-energy.com/storage/grid-booster-worlds-largest-storage-as-transmission-project-gets-green-light/.
[8] Rotorsoft, "EisMan & Redispatch 2.0," https://www.rotorsoft.de/en/features/eisman-redispatch-20/.

can "resolve a discrete, non-routine transmission need that only can be addressed by storage under MISO's functional control, and not by a resource operating in MISO's markets,"[9] with the following tariff specifications:

- "MISO's discretion in selecting SATOAs is 'appropriately bounded' by [its MTEP process]."
- "Prevents SATOAs from being included in its expansion plan when they cannot be shown to solve a particular non-routine transmission need."
- "SATOAs are most likely to qualify as baseline reliability projects or other projects for which transmission owners maintain a right of first refusal to build."[10]
- SATOA is excluded from market participation. Energy transactions are settled to the extent necessary to provide transmission services. Annual net market revenues are used to offset transmission revenue requirements.

The MTEP process developed a SATOA project to improve local load serving reliability and grid voltage performance. The Waupaca area in Northern Wisconsin involves a local 69 kV system supported by a nearby multi-segment 115/138 kV transmission line. When both ends of the 115/138 kV supply line are out of service (planned or forced), the local loads cannot be sustained.

This SATOA project is a hybrid storage project with a total of 14 MVAR capacitors and a 2.5 MW/5 MWh battery to improve customer reliability. It will enhance system reliability and operating flexibility in responding to multiple contingencies and maintenance outages. The storage is largely automated and triggered as a post-contingency action based on transmission line status and other system conditions. Maintaining a proper charge state will be coordinated between the transmission operating utility and MISO.

Whereas the SATOA's capital cost is $8.1M, a traditional solution of rebuilding a 115 kV transmission line to double circuits costs $11.3M. Thus, the SATOA project is more cost-effective.

1.4 National Grid's Nantucket Storage Project

"The island of Nantucket in Massachusetts traditionally receives its electricity from undersea supply cables from the mainland, but . . . summer energy demand has grown dramatically in recent years" because of the island's load growth. "To ensure electric reliability for customers during peak summer months and defer the need for an additional expensive underwater supply cable to the island, National Grid installed a 6 MW/48 megawatt-hour (MWh) battery storage project."[11]

This storage project, "together with the 15 MW diesel generator and a power control house, . . . cost[s] $81 million."[12] Compared to the $200M submarine cable alternative, New England consumers avoided a $120M cost.

---

[9] FERC Docket No. ER20-588, comments filed June 1, 2020, by MISO.

[10] Zach Hale, "MISO's 'Storage-as-Transmission' Proposal Wins FERC Approval," *S&P Global Market*, August 11, 2020, https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/miso-s-storage-as-transmission-proposal-wins-ferc-approval-59872358.

[11] National Grid, "Two National Grid Projects Selected as Energy Storage North America 2019 Innovation Award Winner, *National Grid US*, https://www.nationalgridus.com/News/2019/11/Two-National-Grid-Projects-Selected-as-Energy-Storage-North-America-2019-Innovation-Award-Winner-/.

[12] Iulia Gheorghiu, "There once was a 48 MWh Tesla battery on Nantucket, which saved National Grid $120M in its budget," *Utility Dive*, October 10, 2019, https://www.utilitydive.com/news/Tesla-national-grid-battery-energy-storage-8hour-long-duration-diesel-generation-system-nantucket/564428/.

2. Part 2 – Three Use Cases

Utility and ISO planning goals are driven by conducting transmission system performance assessments to maintain acceptable system performance and demonstrate compliance with the NERC and regional planning standards (NERC, NPCC, NYSRC, and TO's local rules). As part of the planning process, projects are developed to reliably serve electric customers during normal and emergency operating conditions, and project costs are recovered from the tariffs of responsible TOs or the ISO. Part 2 describes three use cases that illustrate how the transmission planning process could include consideration of SATA with respect to the following:

- Technical grid modeling study and incorporation in grid operations
- Comparison to traditional transmission solutions
- Estimating the opportunity's scale and benefits

The study illustrates how energy storage can function as a transmission substitute to serve the electric grid's reliability needs as identified by the grid planners and operators. In particular, for bulk power transmission, we illustrate three SATA use cases as non-wire alternatives (NWAs) to transmission upgrades:

1) Battery storage at the Shore Rd 345 kV substation to reduce congestion between Lower Hudson Valley (Zone I) and Long Island (Zone K) by discharging the stored energy to keep the Dunwoodie – Shore Road 345 kV (Y-50) cable loading under applicable ratings in the event of a contingency, including the outage of the Spring Brook – East Garden City 345 kV (Y-49) circuit.

2) Battery storage at the Oswego complex or near the Edic 345 kV substation as an automatic voltage controlling equipment (AVCE) to provide voltage support to maintain a consistent Central East interface transfer capability that otherwise would reduce up to 300 MW if the voltage support from the generators in the Oswego complex were not available.

3) Battery storage at the Mott Haven 345 kV substation to increase transmission security limits (TSLs) into New York City (Zone J) to improve local reliability and reduce Zone J's installed capacity requirement.

The cost recovery for the SATA would be similar to traditional transmission asset cost recovery, although wholesale market participation may create additional revenue opportunities. The potential market revenue could reduce the revenue requirement for SATA-based solutions. The use case examples discuss the benefits due to congestion relief, lower installed capacity cost, and reduced renewable production curtailment.

2.1 N-1 Security Constraint Management

This use case evaluates energy storage projects reducing congestion, thereby improving the utilization of existing transmission assets. More concretely, using storage for congestion relief can enhance the transmission system's capacity to overcome emergency situations caused by a contingency. Such situations would otherwise require transmission expansion or less efficient generation dispatch. Therefore, SATA is an NWA solution and mitigates reliability violations from traditional pre-contingency preventive measures to post-contingency corrective actions by taking advantage of the storage technology's fast reaction.

In grid operations, N-1 contingencies must be secured when a wholesale market is cleared to comply with NERC reliability criteria. These N-1 constraints often result in more expensive, out-of-merit generation dispatch to ensure that load is met and that line loadings and generation are within limits under the N-1 conditions. Storage can mitigate these N-1 contingency costs by immediately counterbalancing the overload upon the N-1 contingencies before any transmission facility is damaged. The above thought process is illustrated in Figure 1, where the three transmission lines are each rated at 0.5 MW:

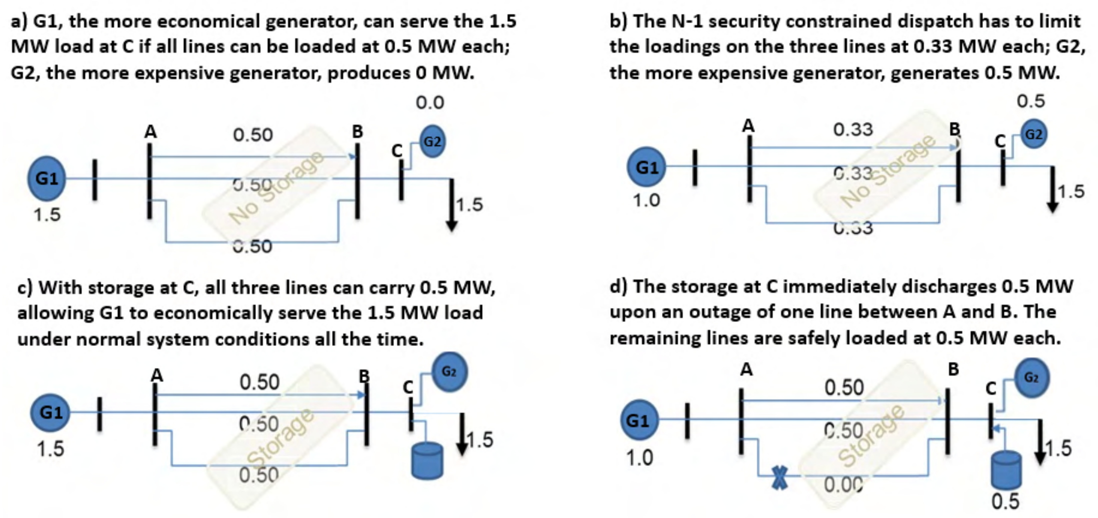


Figure 1. SATA for Transmission Congestion Relief [13]

Applying the same concept to reducing congestion between Zones I & J and Zone K, a SATA consisting of a 200 MW/200 MWh storage could be sited at the Shore Rd 345 kV bus to prevent the Dunwoodie – Shore Road 345 kV (Y-50) circuit from being overloaded under contingency conditions. Currently, transmission between Zones I & J and Zone K is constrained, particularly upon the outage of Y-50's parallel circuit, the Spring Brook – East Garden City 345 kV (Y-49) cable. Additionally, stuck breaker contingencies in Zone I and an outage of the 345/138 kV transformers at Shore Road also constrain the flow from Zones I & J to Zone K.

This SATA use case can be part of the grid operation to secure all the tie lines into Long Island. The other three tie lines (Northport – Norwalk, Jamaica – Valley Stream, and Jamaica – Lake Success) are already automatically controlled by phase angle regulators (PARs). The automatic PAR control would make each of the other three tie lines self-correcting for outages of any tie line over several minutes. With this SATA, the only free-flow tie line, Y-50, will become controllable too, and SATA would react within sub-seconds of the outage of Y-49 or any contingencies discussed above. Two power cases, representing summer peak and winter peak conditions, were created to evaluate if SATA can relieve congestion and increase transfer capability between Zones I & J and Zone K. Table 1 shows the overload on the Y-50 circuit upon the contingency of losing the Y-49 circuit. Under summer and winter peak conditions, Y-50 will be 119% and 117% overloaded, respectively.

Table 2 lists the transfer limits from Zones I & J to Zone K with and without the 200 MW/200 MWh storage at the Shore Road 345 kV substation, which shows that the SATA can increase the transfer limit by approximately 200 MW. The storage is sized to fully resolve the overload on Y-50 with respect to Y-49 related contingencies.

[13] Without the storage at Bus C, the transmission limit between Buses A and B is 1.0 MW; with the storage at Bus C, the limit is 1.5 MW.

Table 1. Overload on Y-50 upon the Loss of Y-49

Overload (%)	Summer	Winter
Y-50 upon the loss of Y-49 (Rate B)	119%	117%
Storage required at the Shore Rd 345 kV bus (MW)	180	170

Table 2. Transfer Limit from Zones I & J to Zone K

Transfer Limit (MW)*	Summer (MW)	Winter (MW)
Zones I & J to Zone K	965.5	1,077.9
Zones I & J to Zone K with 200 MW storage at Shore Rd	1,167	1,280.1

* All transfer limit numbers are set by the most severe contingency, the Y-49 outage.

A production cost simulation evaluated the storage's benefits under 8,760 hours of operation. The SATA has increased the utilization of the interface between Zones I & J and Zone K from 9,614 GWh to 11,161 GWh, an incremental amount of 1,547 GWh. The corresponding annual congestion cost saving for Zone K is $9.9M, and the annual congestion cost saving for the entire New York Control Area (NYCA) operated by the NYISO is $13.1M, shown in Table 3. The saving is primarily attributable to the mitigation of the security constraints associated with Y-50 and Y-49, which have been the major limiting constraints in grid operation over the years.

The $13.1M annual congestion saving is only one of many benefits brought about by a transmission expansion project such as the one required by a public policy transmission need (PPTN) between Zones I & J and Zone K,[14] which is currently under development by the NYISO. The 1,547 GWh of incremental energy over the transmission interface between Zones I & J and Zone K demonstrates the ability of the SATA to unlock the value of the existing transmission without additional ROWs. If renewable resources used the incremental amount, an additional 1,547 GWh of renewable energy would be available from upstate New York to the load in Zone K.

Table 3. Cost Saving without/with the Storage

	Without Storage	With Storage
Zone K Total Congestion Cost ($M)	29.02	19.14
Zone K Congestion Cost Reduction ($M)		9.9
NYCA-Wide Congestion Cost Reduction ($M)		13.1

The capital cost for this SATA is approximately $120M. Compared to adding a new 345 kV tie line from Zone I or J to Zone K to mitigate the congestion between the zones, which would be approximately $700M,[15] this SATA solution could save New York consumers $580M.

[14] http://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B13FE24BB-C966-4719-8ADA-E2A85F59B7C5%7D.

[15] Substations and cable costs. Particularly, over 18 miles of underground and submarine cables will be built at the cost of approximately $47 million and $20.5 million per mile, respectively, according to "Petition of Consolidated Edison Company of New York, Inc. for approval to recover costs of Brooklyn Clean Energy Hub" filed by Con Edison in PSC Case No. 20-E-0197 (April 15, 2022).

2.2 Voltage Support Services Use Case

The Central East interface voltage performance depends on the generator's in-service status in Oswego and Athens. To support the voltage performance and to maintain a consistent Central East interface transfer limit, a SATA can be utilized as AVCE to control the voltage level at major transmission buses. The SATA located at one of the buses observes the bus voltages around the Central East interface and injects or absorbs reactive power into the grid to maintain the voltage within limits. Because the primary focus is to regulate the bus voltages automatically, the requirements for the real power in MW and storage durations for the battery are less important. This AVCE focus makes storage a cost-effective application when the alternative is to build another line or replace the voltage regulation function of the generators in the Oswego complex to stiffen the grid voltage response. Static VAR compensators can provide similar benefits but are relatively expensive and less flexible to meet grid operation needs.

A SATA consisting of a 50 MW/50 MWh battery with a 1,500 MVAR reactive power capability inverter can be sited in the Oswego/Edic complex to participate in grid operations, and it would maintain system voltage between 95% and 105% of the standard rating together with other switched shunt capacitors and available generators and transformer tap changers in the grid. Specifically, when the three generators in the Oswego area are not in service, the Central East interface limit is no longer reduced by approximately 300 MW. The SATA will provide the needed voltage support and control to maintain a consistent power transfer capability over the interface independent of the in-service status of some of the generators in the Oswego area.

A production cost simulation evaluated the SATA benefits under 8,760 hours of operation with the Central East interface limit at a minimal 3,250 MW when up to three generators are not available in the Oswego area. Figure 2 shows the 8,760-hour power flows over the Central East interface with and without the SATA. The SATA has increased the utilization of the Central East interface from 22,000 GWh to 23,000 GWh. Additionally, without the SATA, the Central East interface is congested for 3,037 hours, and the congestion cost is $142M; with the SATA, the total congestion drops to 2,028 hours, and the congestion cost is $91M. Therefore, the congestion saving over the Central East interface is $51M, and the corresponding total NYCA congestion cost saving is $55M.

Table 4 and Table 5 show the total renewable curtailment in upstate New York, Zones A–G, with and without the SATA. The difference shows that this SATA can reduce the renewable curtailment from 102 GWh to 67 GWh, a 35 GWh reduction.

The capital cost of the SATA is approximately $250M, with a major cost spent on the inverter of the solution. Compared to the recently commissioned $615M 345 kV transmission project,[16] this SATA could save $365M in capital investment for New York ratepayers if the Central East interface is further expanded.

[16] The $615M projected cost is part of 345 kV Marcy to New Scotland Transmission Upgrade Project. See LS Power, "LS Power Rate Settlement Reduces Transmission Project Cost Estimate by $200+ Million," April 27, 2021, https://www.lspower.com/ls-power-rate-settlement-reduces-transmission-project-cost-estimate-by-200-million/.

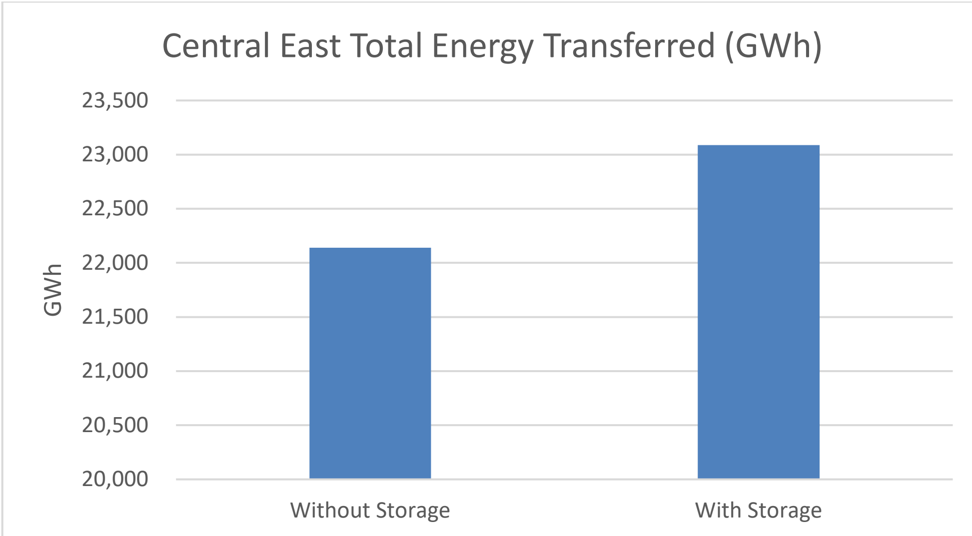


Figure 2. Central East Total Energy Transferred

Table 4. Curtailment in Zones A–G in Production Cost Simulation without SATA

Year 2030	Renewable (GWh)	Curtailment (GWh)	Curtailment %
NYZA	3,770	7	0.2%
NYZB	3,433	11	0.3%
NYZC	5,586	13	0.2%
NYZD	2,561	4	0.1%
NYZE	4,903	59	1.2%
NYZF	2,168	6	0.3%
NYZG	496	1	0.2%
Total	**22,917**	**102**	**0.4%**

Table 5. Curtailment in Zones A–G in Production Cost Simulation with SATA

Year 2030	Renewable (GWh)	Curtailment (GWh)	Curtailment %
NYZA	3,773	4	0.1%
NYZB	3,438	7	0.2%
NYZC	5,593	7	0.1%
NYZD	2,563	1	0.1%
NYZE	4,922	40	0.8%
NYZF	2,168	6	0.3%
NYZG	496	1	0.3%
Total	**22,952**	**67**	**0.3%**

2.3 Example of Reduced Local Capacity Requirement

For the Zone J Locality interface, the TSLs use New York State Reliability Council (NYSRC) Local Reliability Rule G.1-R1. The G.1-R1 rule states that "certain areas of the Con Edison system are designed and operated for the occurrence of a second contingency." Generation and PAR schedules under N-2 conditions are developed to maximize the TSL import capability while maintaining all bulk power system transmission element power flows are within normal ratings (i.e., N-2-0).

Modeling a 200 MW/200 MWh SATA sited at or interconnected to the Mott Haven 345 kV substation illustrates how a SATA can increase the TSLs into Zone J to improve local reliability and reduce the local capacity requirement (LCR) for Zone J.

The TSL improvement is evaluated over the Dunwoodie South interface, and the transfer limit was tested with and without the SATA. The FERC 715 2027 Summer power flow model was used for this analysis. Generation redispatch for the N-2 outage case will recognize the NYISO's ability to redispatch generation in support of maximizing TSLs. The result is shown in Table 6, where the limiting facility is the Dunwoodie – Mott Haven Line 71 with a normal rating of 785 MVA; the limiting contingency is the double outage from Sprain Brook – W49th St 345 kV cables (M51 and M52). The improvement in the TSL is 329.5 MW.

Table 6. TSL Limits with and without the Mott Haven SATA

Dunwoodie South Transfer Results	Contingency Name	Emergency Transfer Limit without SATA (MW)	Emergency Transfer Limit with SATA (MW)	Emergency Transfer Limit Improvement (MW)
Dunwoodie South Interface Limits	M51+M52	2,644.5	2,974	329.5

With the incremental 329.5 MW in the TSL, Zone J can purchase an additional 329.5 MW capacity from upstate New York and reduce the LCR requirement by 329.5 MW. Based on the example in NYISO's "Proposed Updates to the Transmission Security Limit Method for the 2022–2023 Capability Year LCR Determinations," September 9, 2021, the LCR requirement for Zone J would be reduced from the current 77.6% to 74.7% (=(11,217−2,920−329.5+407)/11,217), where the 11,217 MW is Zone J's peak load, 2,920 MW is the existing TSL, and 407 MW is Zone J's resource unavailability amount.

In sum, the 329.5 MW incremental in the TSL could reduce the LCR by 2.9%, resulting in an annual LCR cost saving of $12.6M based on the New York Installed Capacity auction prices in 2022. In addition, the increased transmission capacity would reduce transmission congestion by $17.8M per year for Zone J. In total, this SATA can save New York electricity ratepayers $30.4M annually.

The SATA's capital cost is approximately $120M. Compared to adding a new 345 kV transmission cable from Dunwoodie to Mott Haven, which would cost over $533M,[17] this SATA provides over $400M in savings for New York electric consumers.

[17] Over 11.35 miles of underground cables will be built at the cost approximately $47 million per mile.

3. Conclusions and Discussion

The use cases in this study show that SATA projects can provide significant cost savings compared to traditional transmission solutions. Not only does a SATA project typically have a shorter development, permitting, and construction duration—meaning additional savings—but the SATA can also be added incrementally to address any uncertainties in the transmission needs. In addition to increasing transmission transfer capability by utilizing existing transmission facilities more efficiently, SATA is also well suited for low or uncertain load growth scenarios and spiky peak-shaving applications, as illustrated by the MISO and Colombia use cases, respectively.

While traditional transmission expansion projects can significantly increase the thermal transfer capability across major transmission interfaces, building a transmission line to meet a circuit peak MW loading may not be necessary if the peak's duration is short and there is excess capacity in off-peak hours, resulting in cost savings. One metaphor for this mitigation measure is that building a large pipe trickling water 99% of the time, which is full only 1% of the time, is expensive and inefficient. Instead, running a garden hose 99% of the time but filling a reservoir 1% of the time is cheaper and more efficient. Such a scenario could be applicable in developing transmission projects in response to the PPTN project currently under development by the NYISO. Done properly and permissibly, SATA could save New York ratepayers millions of dollars by avoiding overbuilding wire-only solutions.

This study has specifically performed studies on three use cases for the New York State transmission grid in its 2026 state. The three use cases demonstrate the potential for delivering renewable energy to consumers as required by the CLCPA:

1. Use Case 1 demonstrates that SATA is a cost-effective solution to incrementally increase the transfer capability and reduce congestion between Lower Hudson zones and Long Island.
2. Use Case 2 demonstrates that SATA beneficially and dynamically regulates grid voltage to maintain constant transfer capability for the Central East interface, greatly increasing renewables' energy deliverability in upstate New York.
3. Use Case 3 demonstrates that SATA can improve the TSLs in New York City, hence reducing local capacity requirements and saving consumers' capacity payment.

The following table summarizes the cost savings of the three use cases compared to traditional transmission solution costs.

Use Case	Battery Size	Estimated SATA Capital Cost ($M)	Estimated Wire Solution Capital Cost ($M)	Local Area Annual Cost Saving ($M)	NYCA-Wide Congestion Annual Cost Saving ($M)
#1	200 MW/ 200 MWh	120	700	9.9*	13.1
#2	50 MW/50 MWh + 1,500 MVAr Reactive Power Capacity	250	615	51**	55
#3	200 MW/ 200 MWh	120	533	30.4***	17.8

* Congestion cost saving for Zone K
** Congestion cost saving for the Central East interface
*** Zone J LCR saving and congestion cost saving

SATA can achieve these benefits not only by employing its charging and discharging cycles but also with reactive power injections and withdrawals through its (smart) inverter. The meshed nature of transmission networks allows a single SATA project to ameliorate overloads on a relatively weak link under various contingency conditions. With the advance in technology, a SATA project can be flexibly utilized interactively or combined with transmission circuits and loads as dispatchable resources to address overloads and voltage violations, achieving the highest efficiency possible in timing and cost-effectiveness.

New York is transforming its electric system into one that is cleaner and more resilient under the direction of the CLCPA with projected multi-billion dollar spending in transmission expansion.[18] As renewable resource integration continues, certain portions of the New York State transmission system are becoming more congested. At the same time, new flow patterns caused by the intermittent renewable resources will lead to different power flow patterns and varying utilization of the existing transmission facilities. SATA is uniquely suitable to address these kinds of varying, incremental, and sometimes uncertain transmission capacity needs.

Additionally, though not addressed explicitly in Part 1 or Part 2, SATA will reduce land disturbance and thus enable New York to meet environmental targets through land conservation. For a green field overhead transmission solution, 10 miles of transmission with a 120 ft ROW disturbs 144 acres, potentially more if the ROW is larger. By contrast, 100 MW/400 MWh of SATA doing the same function disturbs less than 10 acres (assuming about 50 MWh per acre with room for switchgear, connecting facilities, perimeter offsets, and stormwater management). Thus, SATA offers New York not only climate and cost-savings benefits but also environmental benefits.

Developing cost-effective SATA in transmission planning processes requires changes in the planning rules and tariff, together with changes in market designs. Current market rules and transmission planning tariffs have resulted in denying SATA applications as well as regulating rate recovery and often inhibiting SATA development. The current planning process should be revised to include SATA at the need and solution assessment stages and to allow SATA cost recovery under the ISO tariff.[19] Additionally, as many ISOs are contemplating new market rules allowing flexible system resources to accommodate renewables and load variability, co-optimal use of SATA facilities as dispatchable resources for the grid operators can lead to a more reliable and resilient electric power grid.

[18] Multiple interveners' comments on NYSPSC Case 20-E-0197.

[19] Alternative regulated solutions selected by the ISO as the more efficient or cost-effective transmission solution to reliability are identified in the Reliability Planning Process, NYISO OATT, Section 31, "Attachment Y - New York ISO Comprehensive System Planning Process."

LAZARD

LCOE+

LEVELIZED COST OF ENERGY+

June 2024

WITH SUPPORT FROM Roland Berger

Table of Contents

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

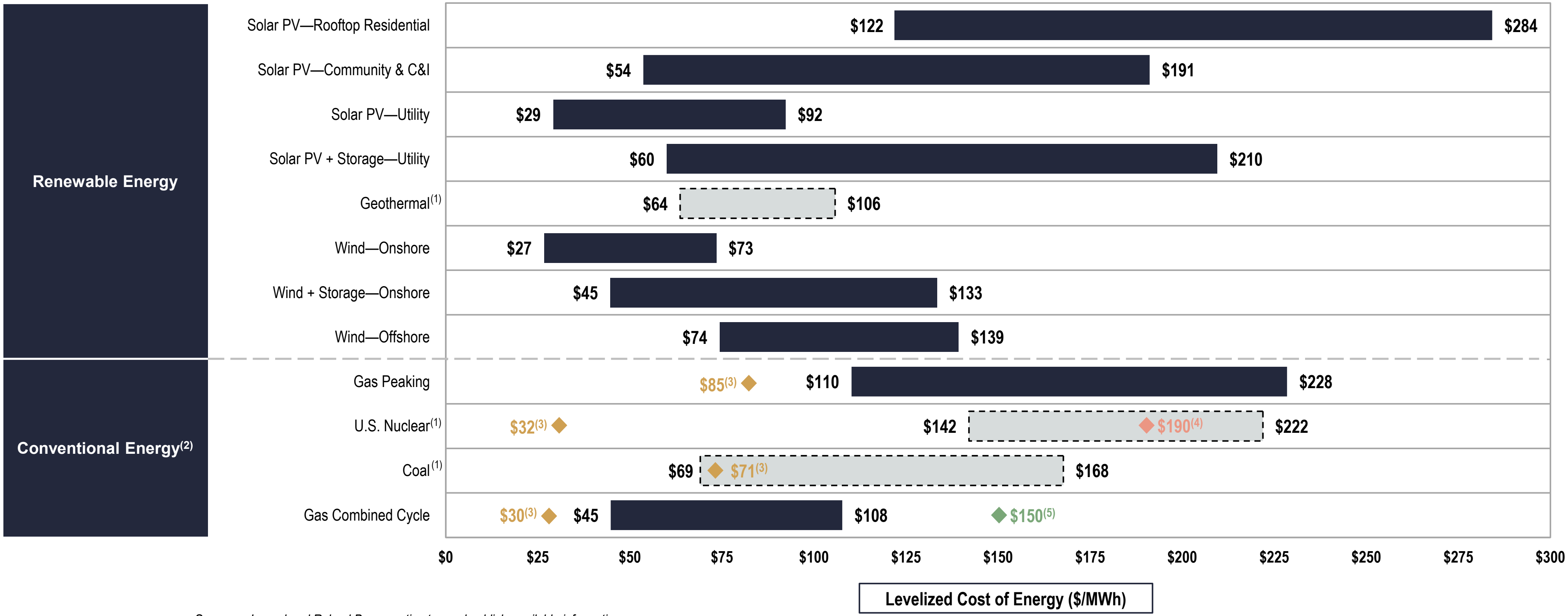
Lazard's Levelized Cost of Energy analysis addresses the following topics:

- 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.

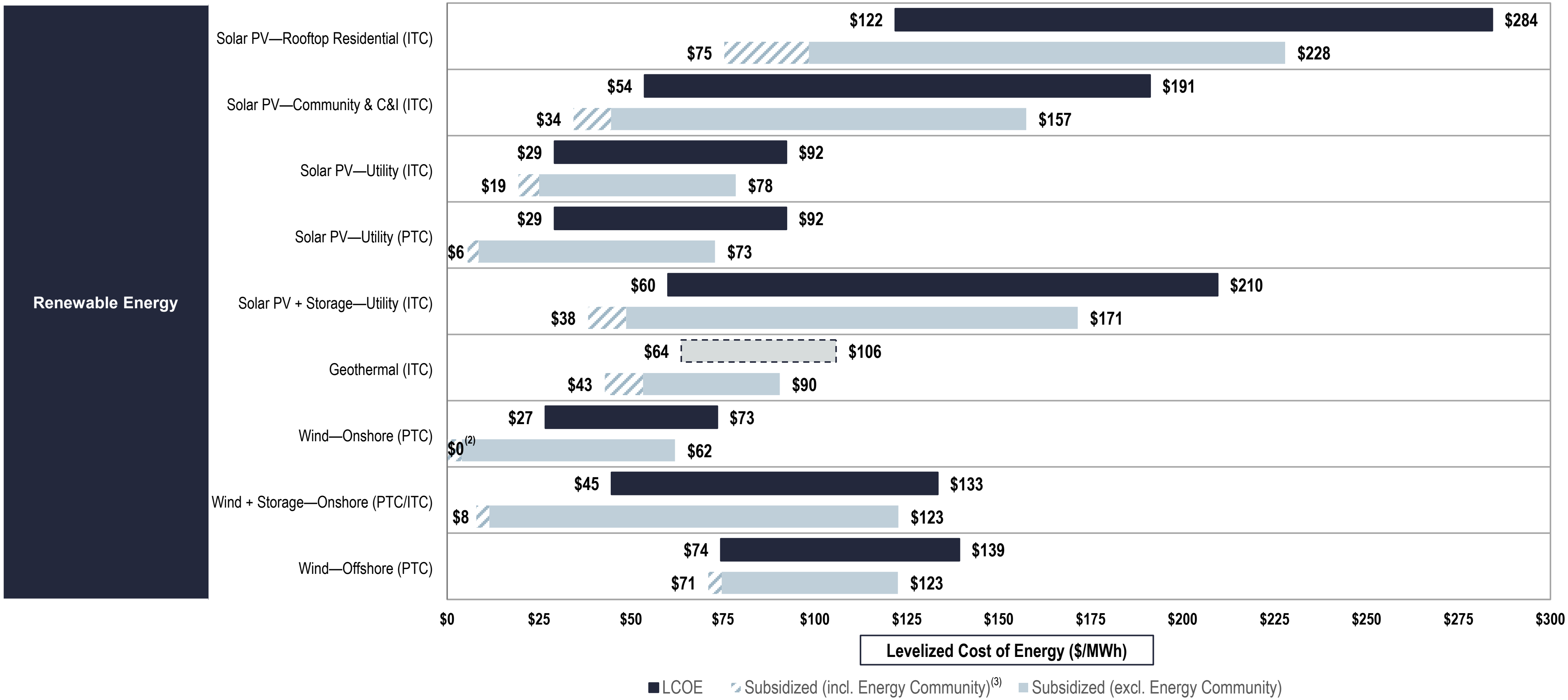
(3) Reflects the average of the high and low LCOE marginal cost of operating fully depreciated gas peaking, gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent 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.

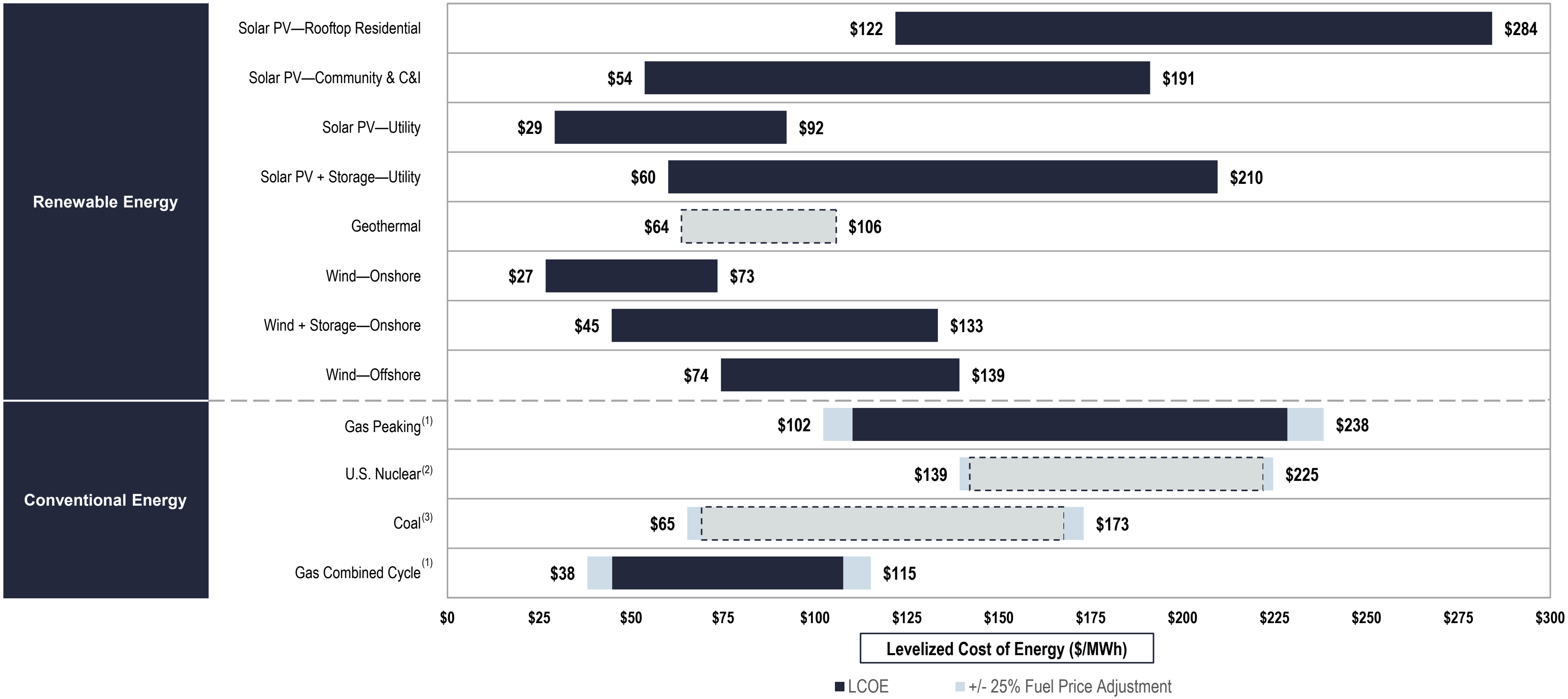
(1) This sensitivity analysis assumes that projects qualify for the full ITC/PTC, have a capital structure that includes sponsor equity, debt and tax equity and assumes the equity owner has taxable income to monetize a portion of the tax credits.

(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".

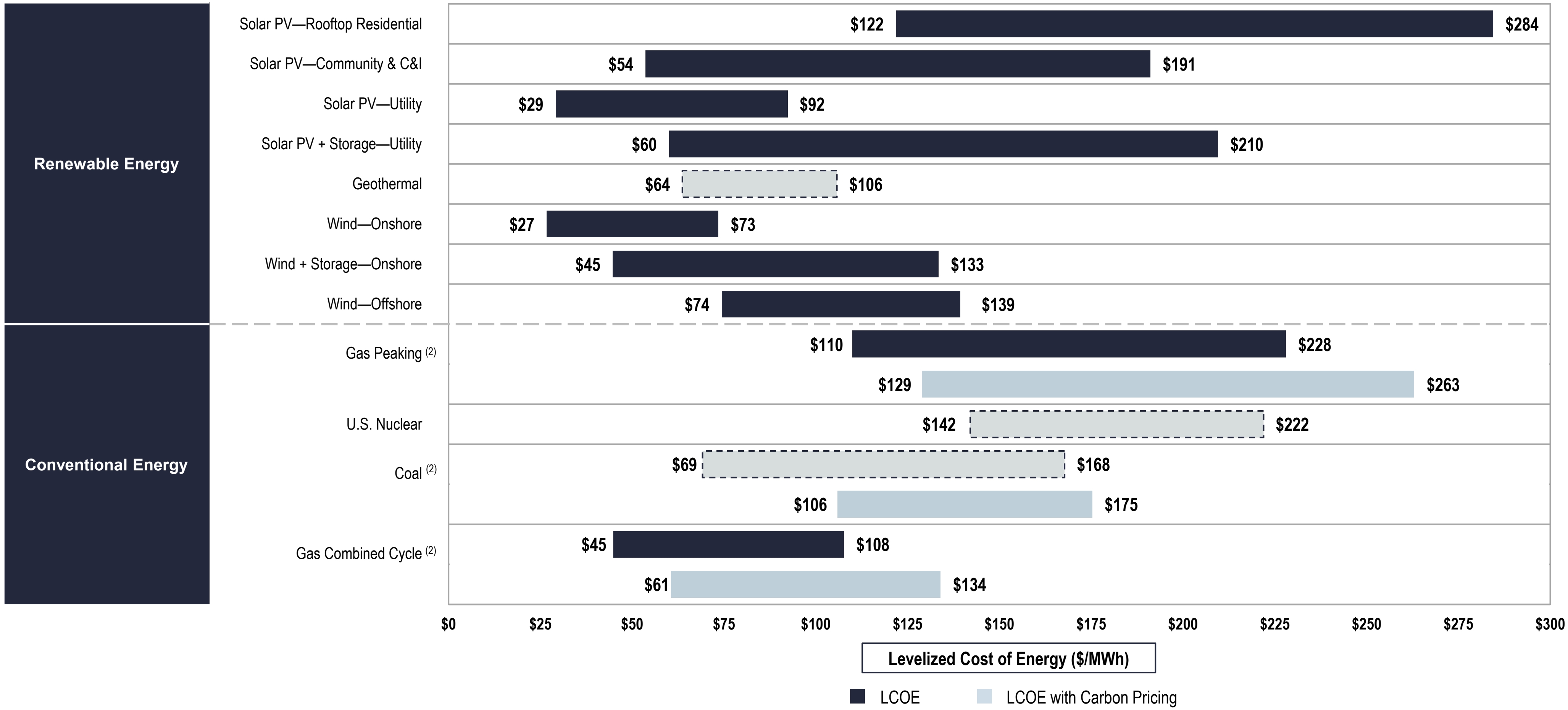
(1) Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a sensitivity range of ± 25% of the $3.45/MMBTU used in the LCOE).

(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

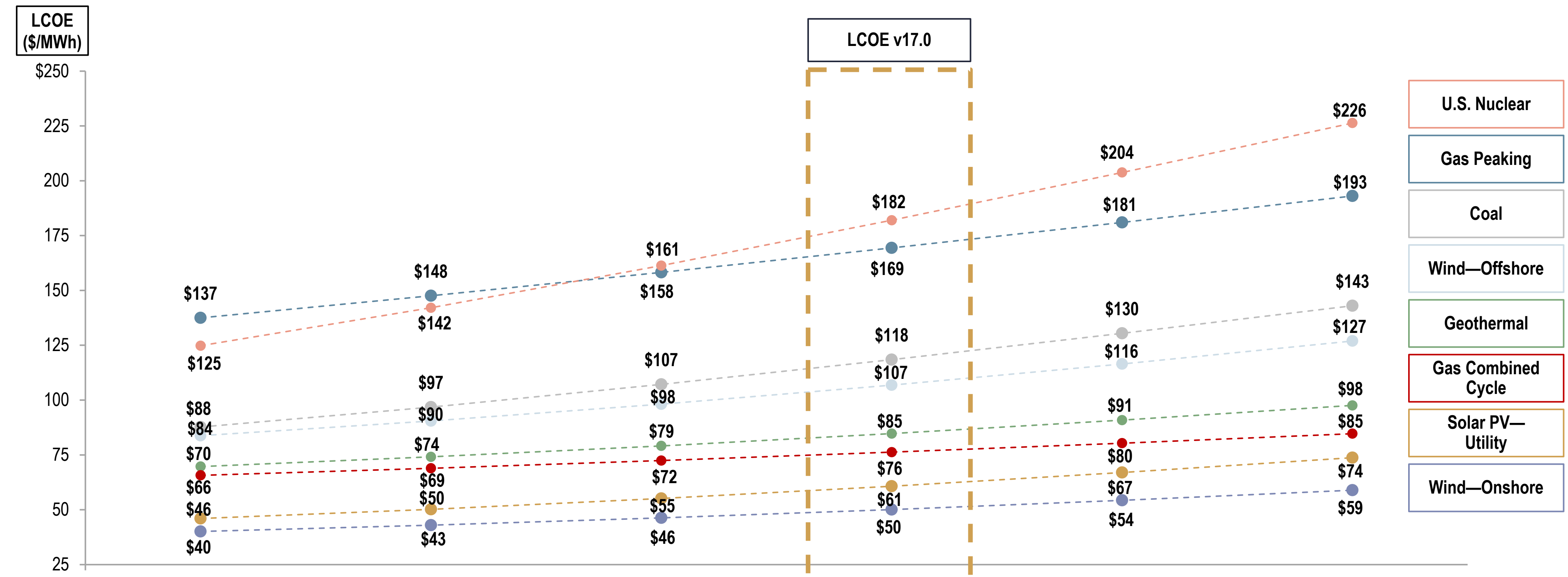


Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used in the LCOE analysis as presented on the page titled "Levelized Cost of Energy Comparison—Version 17.0".
(1) In November 2023, 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)]

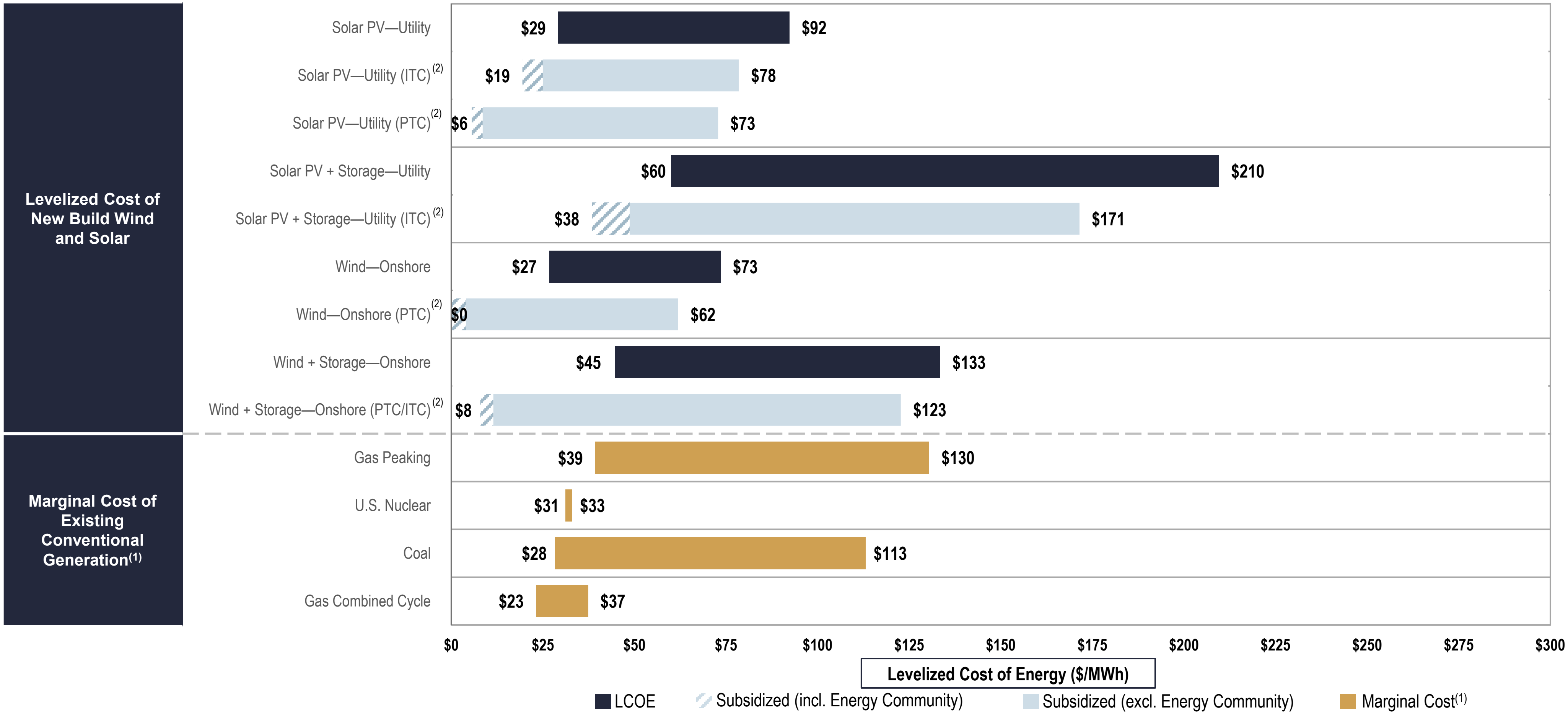


After-Tax IRR/WACC	4.2%	5.4%	6.5%	7.7%	8.8%	10.0%
Cost of Equity	6.0%	8.0%	10.0%	12.0%	14.0%	16.0%
Cost of Debt	5.0%	6.0%	7.0%	8.0%	9.0%	10.0%

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".

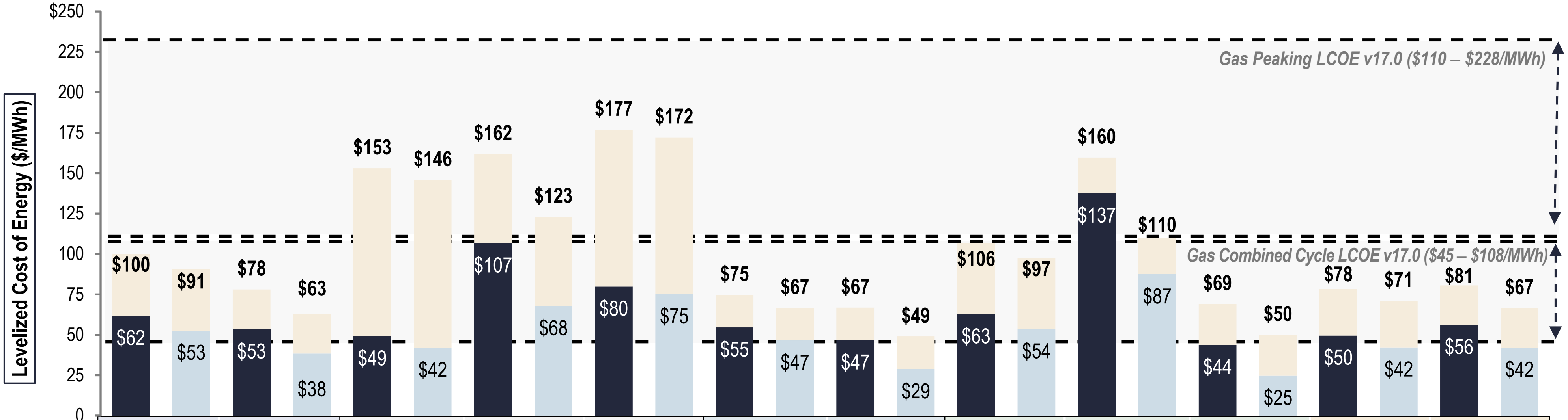
(1) Reflects the marginal cost of operating fully depreciated gas, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas or coal asset is equivalent to its decommissioning and site restoration costs. Inputs 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]

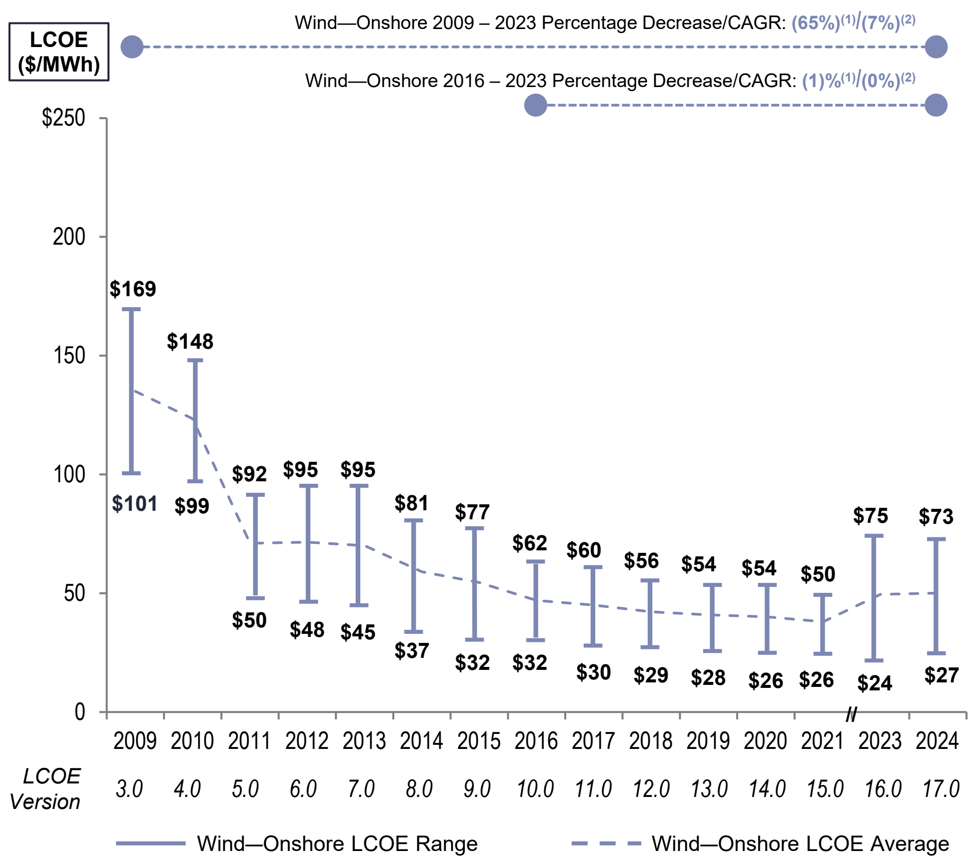
Source: *Lazard and Roland Berger estimates and publicly available information.*

(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.

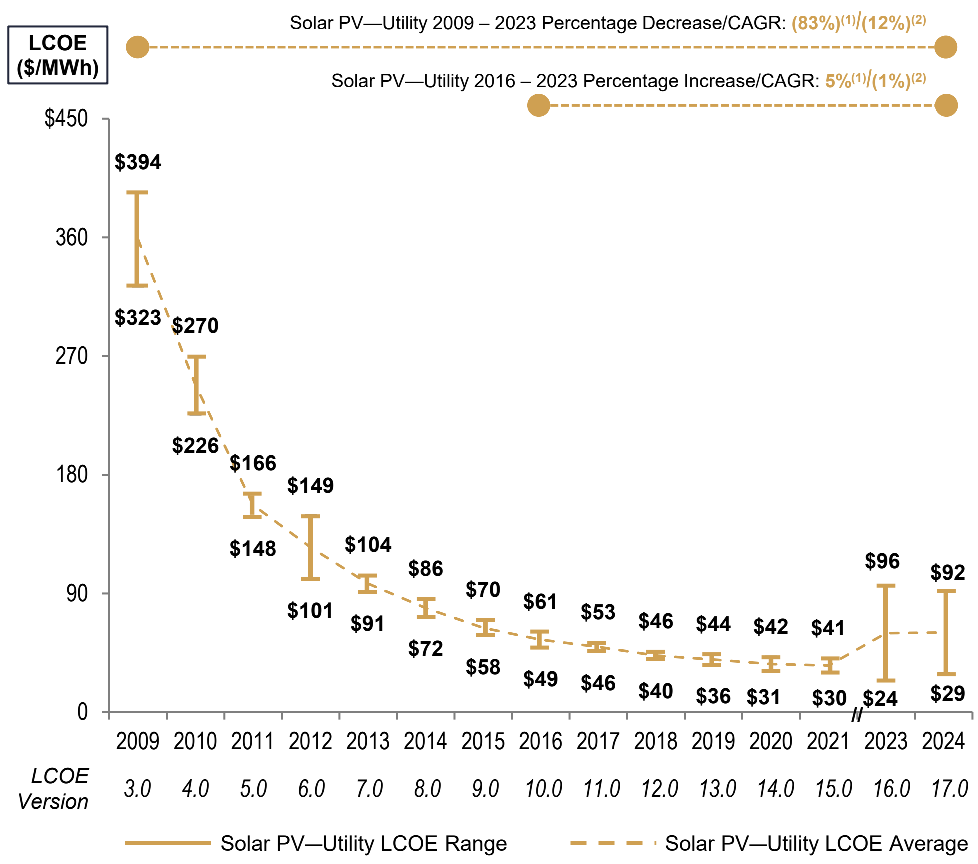
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

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

LAZARD

Introduction

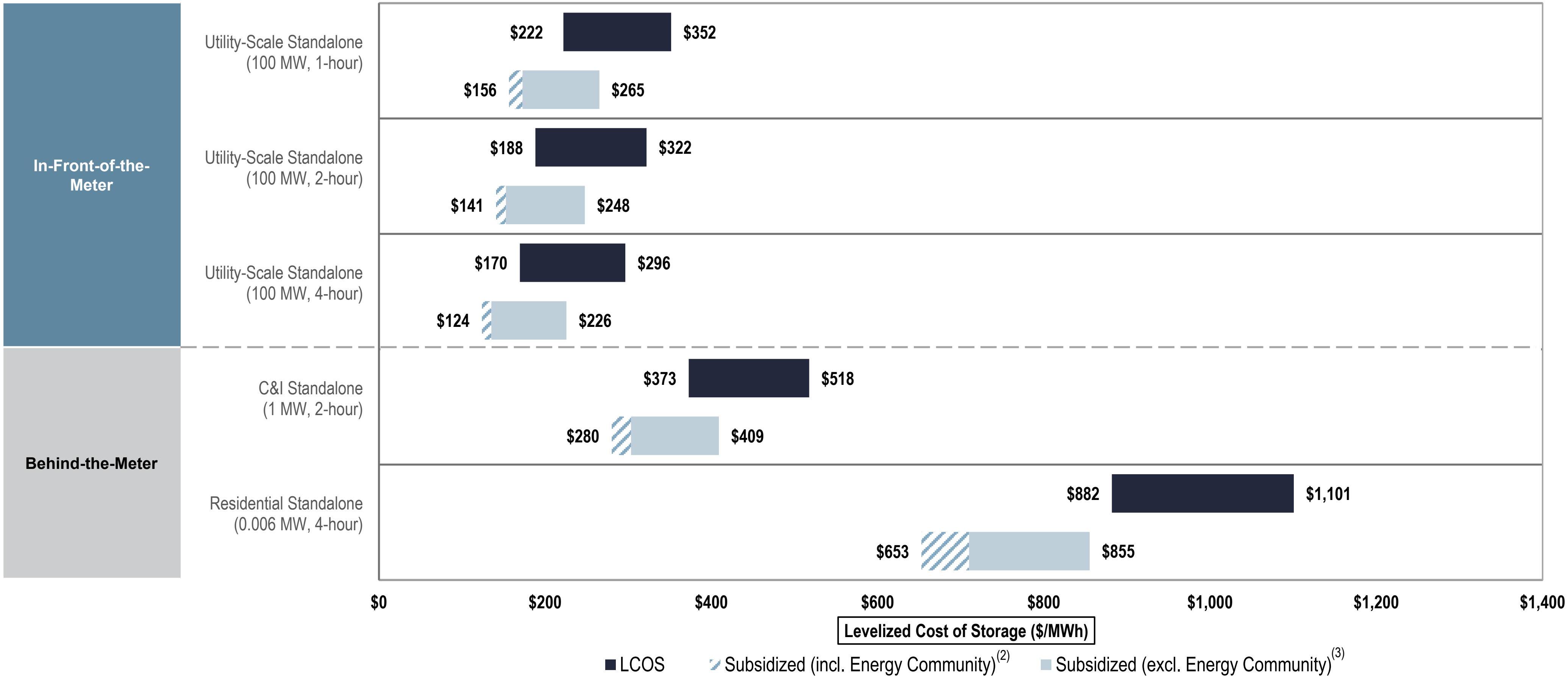
Lazard's Levelized Cost of Storage analysis addresses the following topics:

- 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.

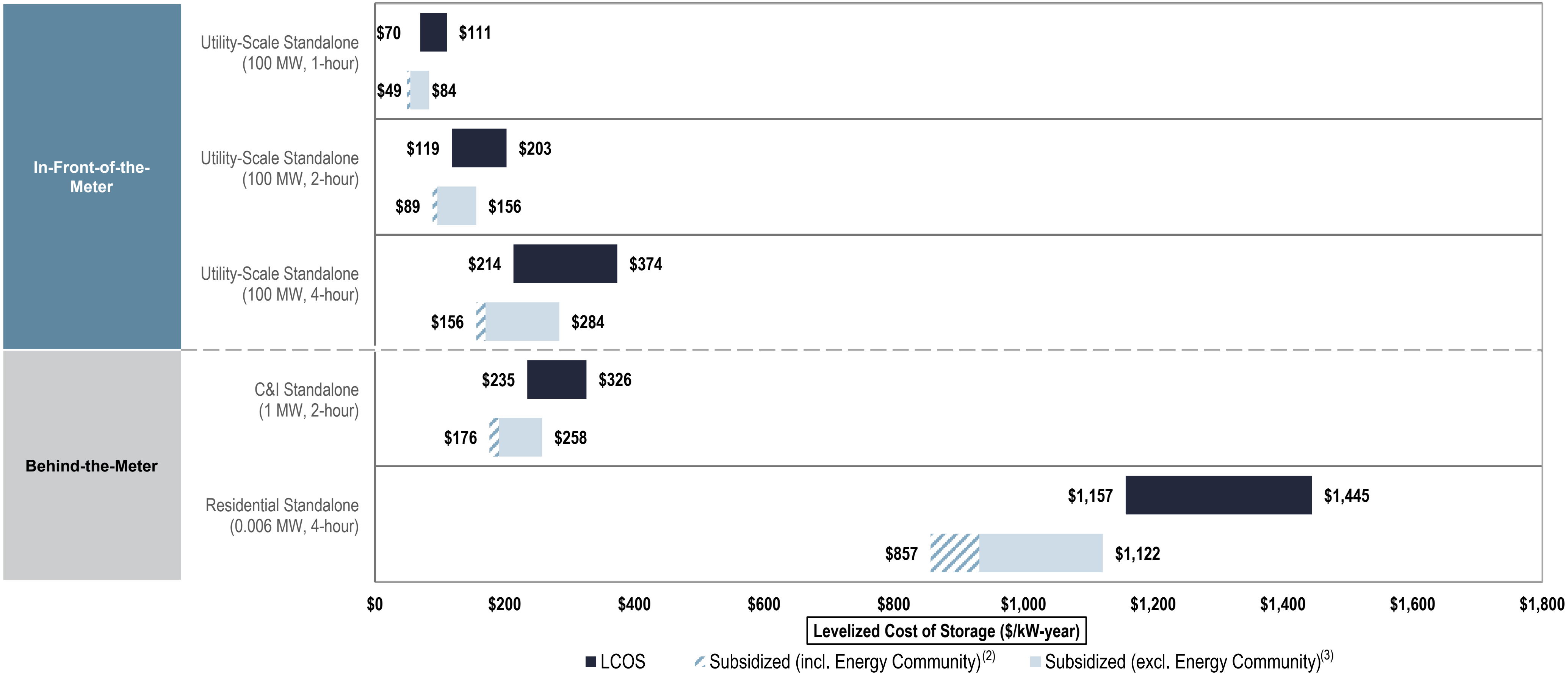
(1) See Appendix B for a detailed overview of the use cases and operation parameters analyzed in the LCOS.

(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**

			Use Cases(1)						
		Description	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

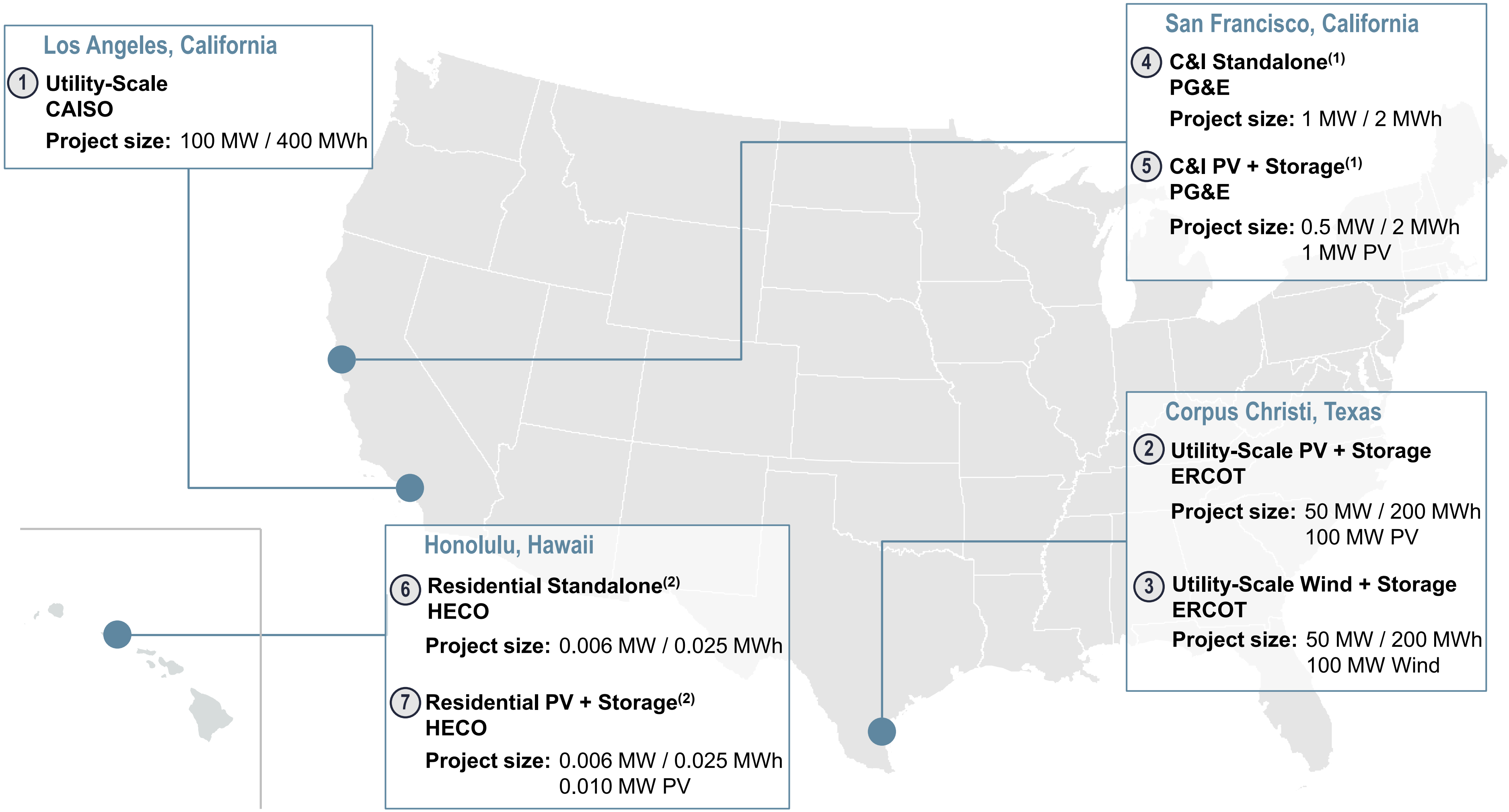
Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases

		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

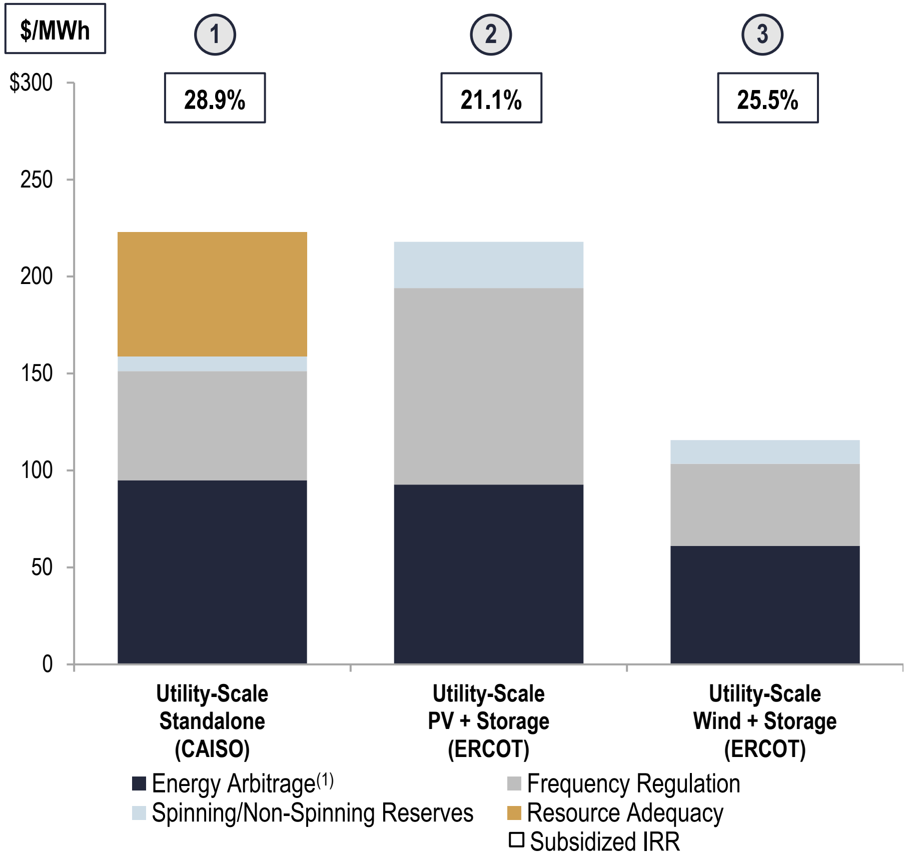


Source: Lazard and Roland Berger estimates, Enovation Analytics and publicly available information.
Note: Project parameters (i.e., battery size, duration, etc.) presented above correspond to the inputs used in the LCOS analysis.
(1) Assumes the project provides services under contract with PG&E.
(2) Assumes the project provides services under contract with HECO.

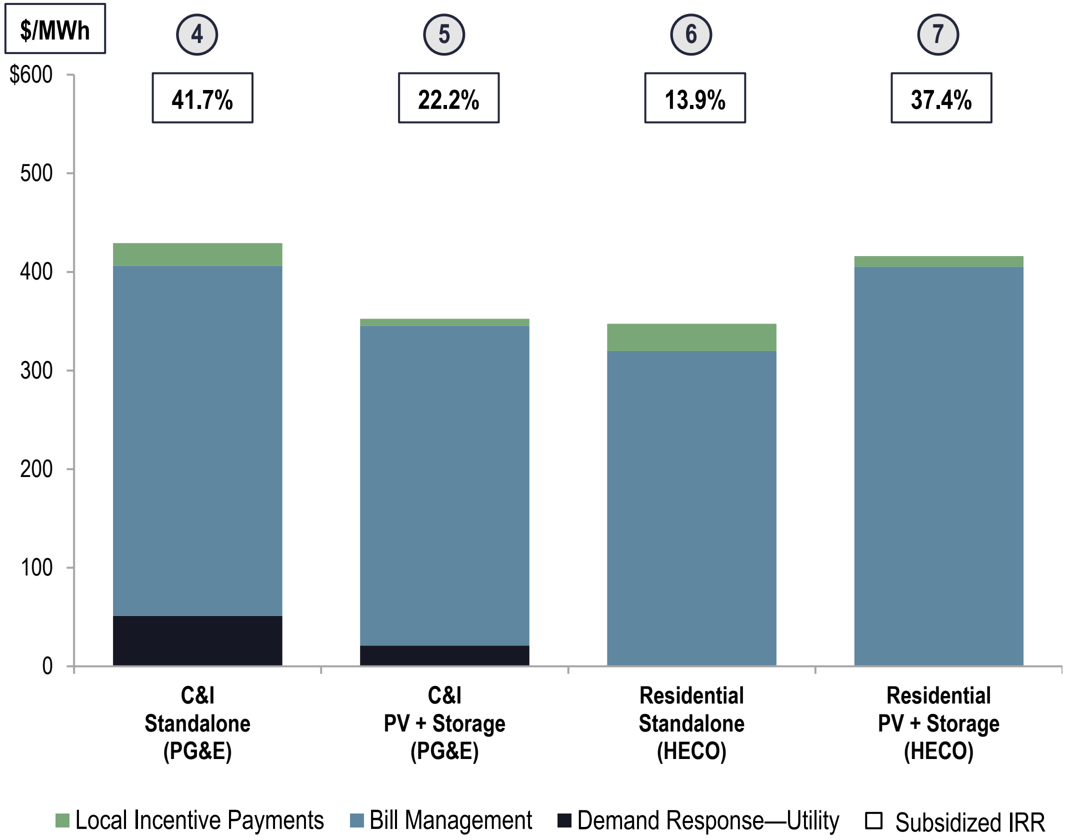
Value Snapshot Case Studies—Results

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

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:

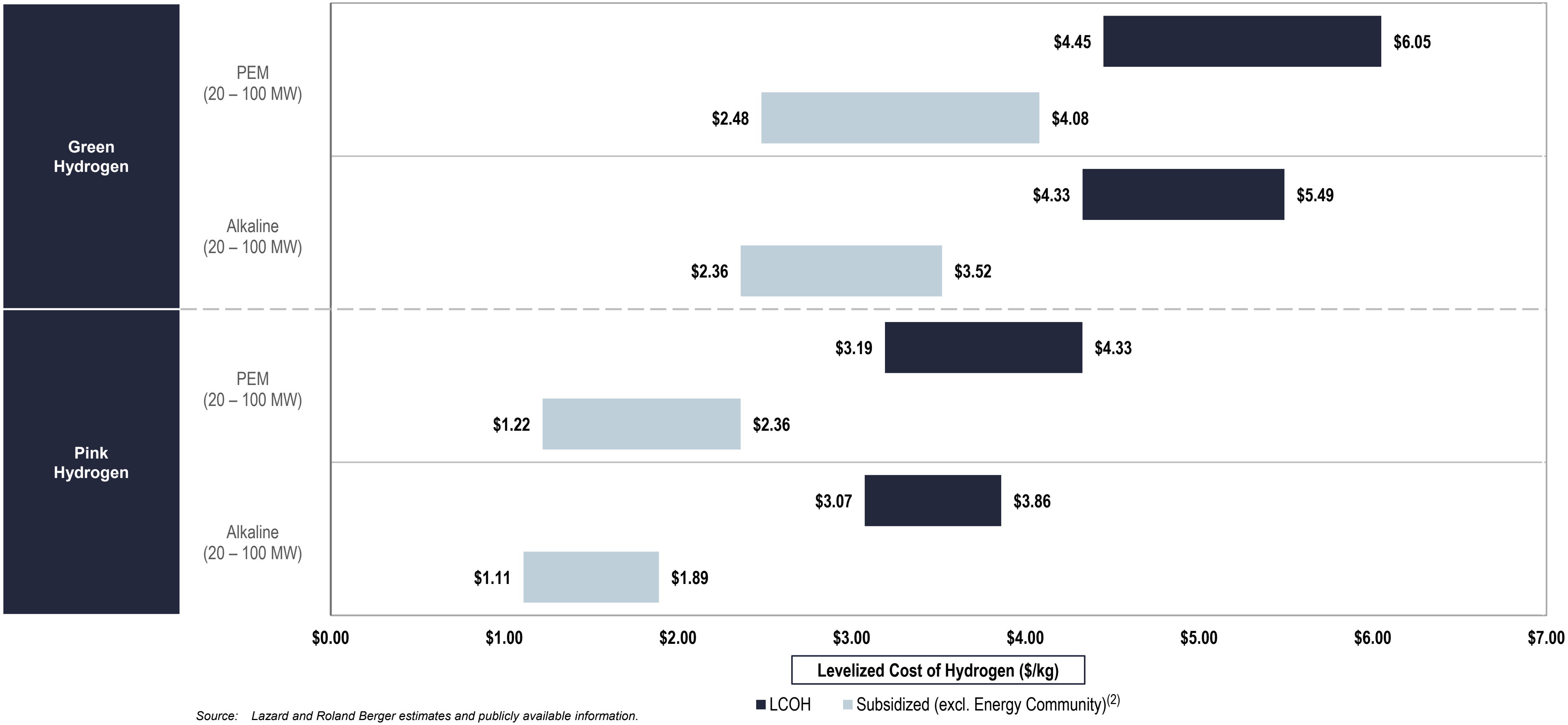
- The analysis within includes storage costs paid to a third party but does not include any expenditures related to the transport, construction of pipeline or construction of storage
- This analysis does not include electrolyzers produced in China, which are currently priced at one third of the price 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.*

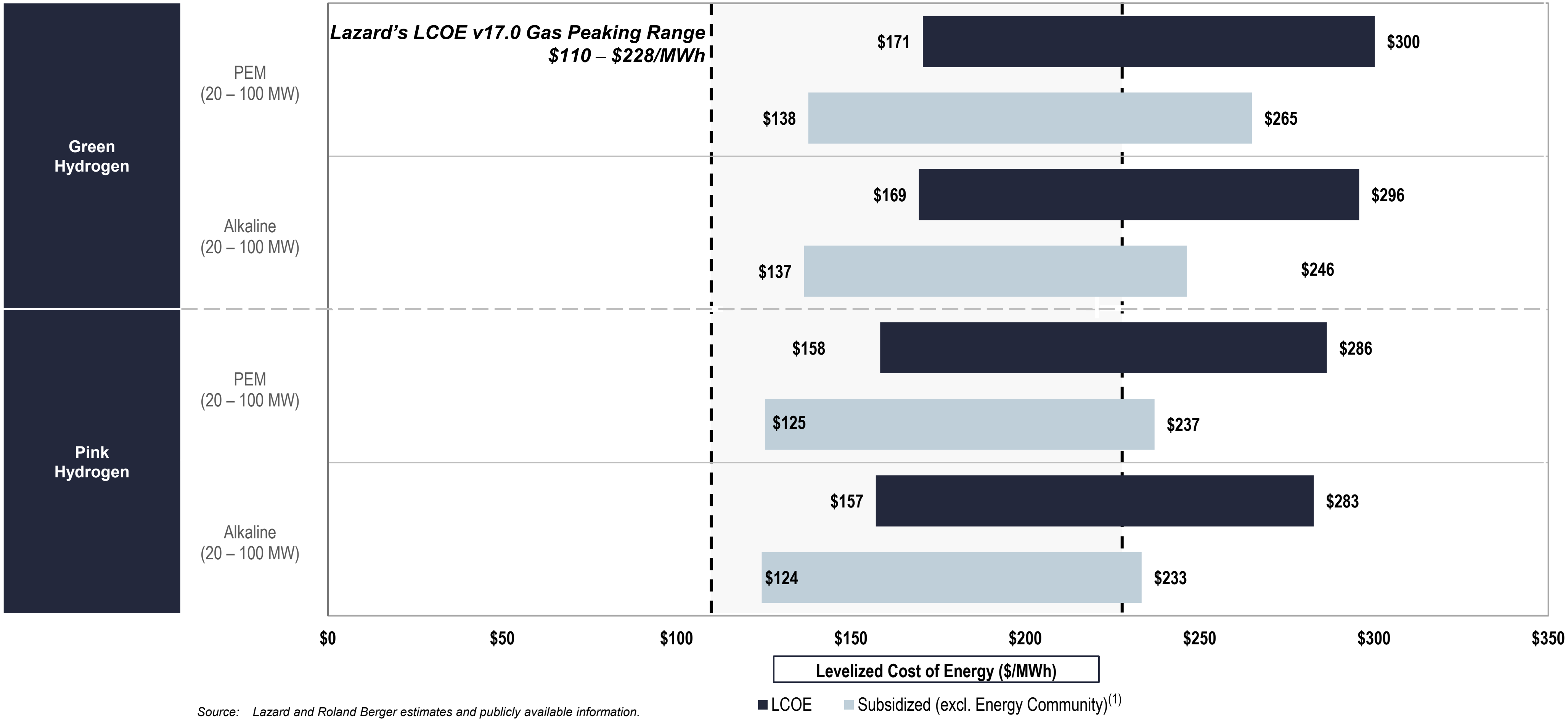
Note: Unless otherwise indicated, this analysis assumes electrolyzer capital expenditure assumptions based on high and low values of sample ranges, with additional capital expenditure for hydrogen storage. Capital expenditure for underground hydrogen storage assumes $20/kg storage cost, sized at 120 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.

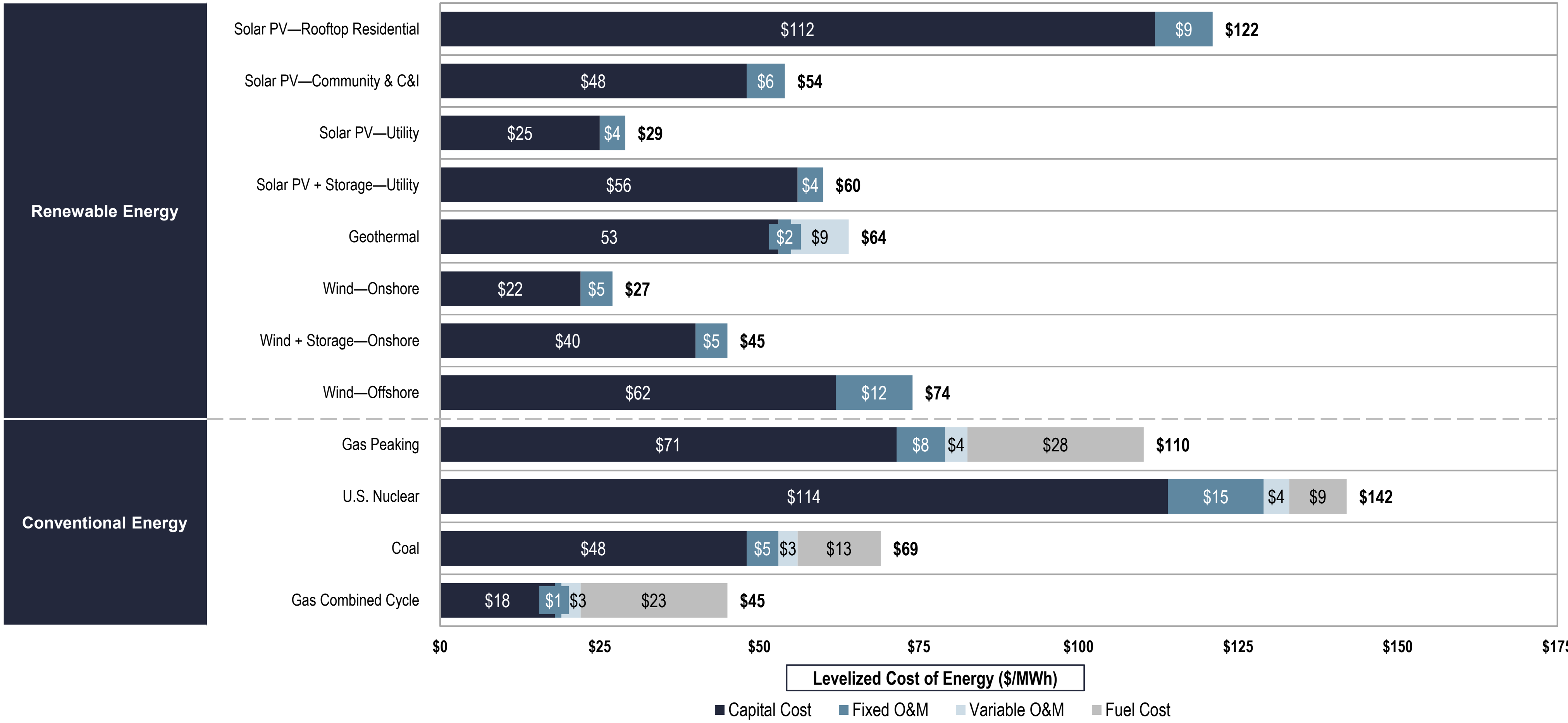
(1) This sensitivity analysis assumes that projects qualify for the hydrogen PTC but does not include subsidized electricity costs. This analysis assumes projects have a capital structure that includes sponsor equity, debt and tax equity. The IRA is comprehensive legislation that is still being implemented 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

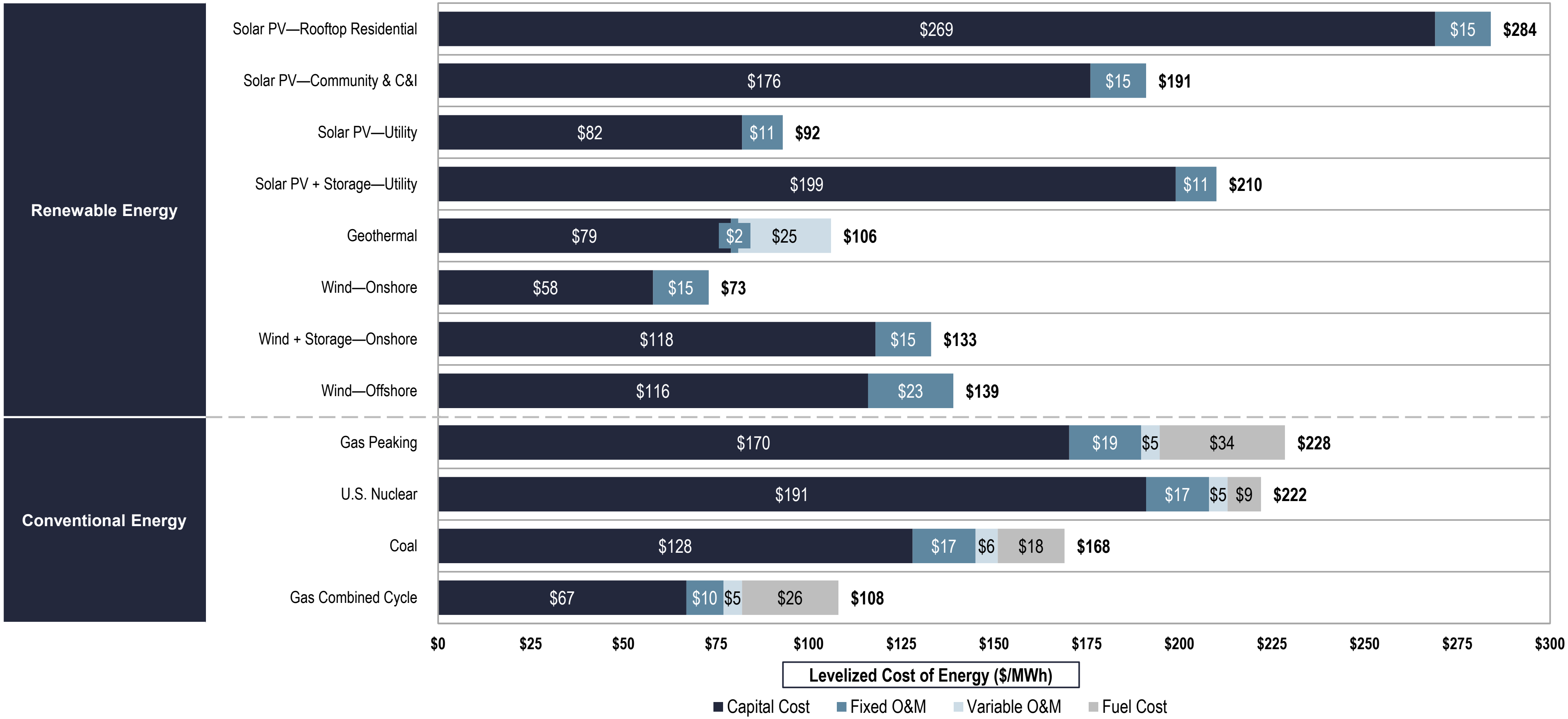
Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and Industry scale to continue lowering operating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

	Units	Renewable Energy: Solar PV								
		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)

		Renewable Energy					
	Units	Geothermal		Wind—Onshore		Wind—Offshore	
		Low	High	Low	High	Low	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)

		Renewable Energy: Hybrid Generation + Storage					
	Units	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

LAZARD

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

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

LCOH v4.0

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

		Green Hydrogen						Pink Hydrogen					
	Units	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.

George Bilicic
Vice Chairman of Investment Banking, Global Head of Global Power, Energy & Infrastructure
Tel: +1 212 632-1560
george.bilicic@lazard.com

Doug Fordyce
Head of Houston Office
Tel: +1 713 236-4640
doug.fordyce@lazard.com

Akshay Dhiman
Managing Director
Tel: +1 212 632-1535
akshay.dhiman@lazard.com

Pablo Hernandez Schmidt-Tophoff
Managing Director
Tel: +1 713 236-4618
pablo.hernandez@lazard.com

Gregory Hort
Managing Director
Tel: +1 212 632-6022
gregory.hort@lazard.com

Frank Daily III
Managing Director
Tel: +1 713 236-4647
frank.daily@lazard.com

Samuel Scroggins
Managing Director
Tel: +1 212 632-6758
samuel.scroggins@lazard.com

Daniel Katz
Director
Tel: +1 212 632-1966
daniel.katz@lazard.com

Mark Lund
Director
Tel: +1 713 236-4639
mark.lund@lazard.com

Gerard Pechal
Director
Tel: +1 713 236-4673
gerard.pechal@lazard.com

Gennadiy Ryskin
Director
Tel: +1 713 236-4624
gennadiy.ryskin@lazard.com

Zac Scotton
Director
Tel: +1 713 236-4652
zac.scotton@lazard.com

Li Wynn Tan
Director
Tel: +1 212 632-1313
li.tan@lazard.com

Mattia Battilocchio
Vice President
Tel: +1 212 632-6389
mattia.battilocchio@lazard.com

Lauren Davis
Associate
Tel: +1 332 204-5527
lauren.davis@lazard.com

Jack Giletto
Associate
Tel: +1 713 236-4655
jack.giletto@lazard.com

Emily Sanchez
Associate
Tel: +1 332 204-5591
emily.sanchez@lazard.com

Vivek Singh
Associate
Tel: +1 332 204-5110
vivek.p.singh@lazard.com

Zain Baquer
Analyst
Tel: +1 917 994-3302
zain.baquer@lazard.com

Quinn Lewis
Analyst
Tel: +1 332 204-5512
quinn.lewis@lazard.com

George Rao
Analyst
Tel: +1 332 204-5512
george.rao@lazard.com

Jack Telle
Analyst
Tel: +1 332 204-5512
jack.telle@lazard.com

Bill Sembo
Senior Advisor
Tel: +1 713 236-4653
bill.sembo@lazard.com

Barbara Burger
Senior Advisor
Tel: +1 713 236-4633
barbara.burger@lazard.com