Exhibit 300

BEFORE THE PUBLIC SERVICE COMMISSIONOF OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES BY APPROXIMATELY $140.2 MILLION PER YEAR OR 21.6 PERCENT AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM	DOCKET NO. 20000-633-ER-23 RECORD NO. 17252

DIRECT TESTIMONY AND EXHIBITS
OF RONALD J. BINZ

ON BEHALF OF
SIERRA CLUB

August 14, 2023

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I. INTRODUCTION, SUMMARY OF FINDINGS, AND RECOMMENDATIONS

Q: Please state your name, position, and address.

A: My name is Ronald J. Binz. I am a Principal with Public Policy Consulting, a firm specializing in energy policy and regulatory matters. I primarily provide regulatory consulting services to public-sector and private-sector clients in the energy and telecommunication industries. My business address is 333 Eudora Street, Denver, Colorado 80220-5721.

Q: On whose behalf are you testifying in this case?

A: I am testifying on behalf of Intervenor Sierra Club.

Q: Please discuss your relevant experience, professional expertise, and educational background.

A: I have been involved in energy regulation since 1979. From 1995 to 2006, and from 2011 to the present, I have served as a principal of Public Policy Consulting. My focus in recent years has been on performance-based regulation and energy regulatory policy, including integrated resource planning ("IRP"), fuel cost proceedings, clean technology, smart grid, and climate issues.

From 2007 to 2011, I was Chair of the Colorado Public Utilities Commission ("Colorado PUC"). In that capacity, I helped implement Colorado's vision for a "New Energy Economy" and its 30% Renewable Energy Portfolio Standard, participated in the Governor's Climate Action Plan, rewrote the Colorado PUC's IRP rules, and improved the Colorado PUC's operations. As Chair, I presided over implementation of the Colorado Clean Air-Clean Jobs Act, examining proposals of electric utilities to reduce pollutants from their fleets of coal fired power plants. I also presided over the modification and approval of an electric utility resource plan that involved the early closure of two coal power plants and added a substantial amount of new wind capacity and additional energy efficiency savings.

In addition to my experience as a commissioner, I have held a number of positions in the field of energy and utility regulation, with a focus on protecting consumer interests. From 1984 to 1995, I was first director of the Colorado Office of Consumer Counsel, Colorado's (new at the time) state-funded utility consumer advocate office. During my tenure, the office was a party to more than two hundred legal cases before the Colorado PUC, the Federal Energy Regulatory Commission ("FERC"), the Federal Communications Commission ("FCC"), and the courts. I negotiated rate settlement agreements with utilities, regularly testified before the Colorado General Assembly, and presented to professional business and consumer organizations on utility rate matters,

From 1996-2003, I served as President and Policy Director of the Competition Policy Institute, an independent non-profit organization based in Washington, D.C., advocating for state and federal policies to advance competition in the energy and telecommunications markets for consumers' benefit.

From July 2011 to July 2013, I was Senior Policy Advisor at the Center for the New Energy Economy ("CNEE") at Colorado State University. Founded by former Colorado Governor Bill Ritter, CNEE assists policymakers, governors, regulators, and other decision-makers in developing roadmaps to accelerate the nationwide development of a new energy economy.

Since the start of my career in 1979, I have participated in more than 150 regulatory proceedings before FERC, the FCC, the U.S. Supreme Court, the Eighth

Circuit, Tenth Circuit, and D.C. Circuit Courts of Appeal, state and federal district courts, and state regulatory commissions in California, Colorado, Georgia, Hawai‘i, Idaho, Maine, Massachusetts, Missouri, Montana, New York, North Dakota, Rhode Island, North Carolina, South Carolina, Texas, Utah, Washington, Wyoming, and the District of Columbia. I have filed testimony in more than sixty proceedings before these bodies, addressing technical and policy issues in electricity, natural gas, telecommunications, and water regulation. I have also testified before U.S. House and Senate Committees sixteen times.

I have authored or co-authored numerous publications on energy and regulatory matters, including Risk-Aware Planning and a New Model for the Utility-Regulator Relationship (July 2012).[1]

My educational background includes an M.A. degree in Mathematics from the University of Colorado (1977), course requirements met for Ph.D., graduate coursework toward an M.A. in Economics from the University of Colorado (1981-1984), and a B.A. with Honors in Philosophy from St. Louis University (1971).

A copy of my professional resume, which includes my employment history, education, Congressional testimony, selected regulatory testimony, reports and publications, and professional associations and activities, is attached as Exhibit 301 to this testimony.

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[1] Ron Binz & Dan Mullen, *Risk-Aware Plan. and a New Model for the Util.-Regul. Relationship* (2012), *available at* http://www.rbinz.com/Binz%20Marritz%20Paper%20071812.pdf.

Q: Have you previously testified before this Commission?

A: Yes. I testified before the Wyoming Public Service Commission in four cases: Docket No. 20000-379-EK-10 (August 2011); Docket No. 20000- ET-03-205 (January 2004); Docket No. 20000-ER-03-198 (January 2004); and Docket No. 20000-ER-02-184. November 2002

Q: What is the focus of your current work?

A: In recent years, I have focused on how cost-effective renewable energy resources can offset rate pressure from the retirement of aging grid infrastructure. In addition, I've worked with regulators and legislators on the use of securitization to recover undepreciated investment in closing fossil and nuclear plants. Finally, I have testified about the importance of utility planning and how, based on my work on the Colorado PUC, all-source competitive bidding can result in very low prices for added resources.

Q: What is the purpose of your testimony?

A: Sierra Club retained me to examine a proposal from PacifiCorp d/b/a Rocky Mountain Power ("RMP" or "Company") to eliminate the fuel cost sharing mechanism that is now part of the energy cost adjustment mechanism ("ECAM") in Wyoming. In that context, I examined:

1. The reasons behind the price spike evidenced in this case;
2. The risk inherent in fossil fuel resources and the related purpose of a risk-sharing mechanism;
3. The changing role of renewables in the Extended Day-Ahead Market ("EDAM") regime; and
4. The benefits of all-source competitive bidding for renewable resources, particularly for PURPA compliance.

Q: What documents did you review in preparing this testimony?

A: I reviewed the net power cost section of Rocky Mountain Power's filing; portions of the discovery adduced in the case, and selected testimony from other Commission proceedings.

Q. Please summarize your findings and recommendations in this case.

A:

- Fuel cost sharing is a valuable element of the ECAM in Wyoming. It serves as a corrective to some of the poor incentives of traditional regulation and partially levels the regulatory playing field between fossil generation and zero-cost renewable generation.

- The anticipated EDAM does not replace or moot out the importance of fuel cost risk sharing. Cost risk sharing will add to the benefits of EDAM, and entering EDAM does not lessen value of sharing.

- An ECAM without the sharing mechanism will present Rocky Mountain Power with a classic "moral hazard:" it will take risks with fossil fuel resources because the Company knows it will be made whole by the regulator. The Commission should not eliminate the 80/20 sharing mechanism; in fact, the Commission should consider restoring the previous sharing level of 70/30.

- The Commission should examine and adopt competitive bidding as a superior method for Public Utility Regulatory Policies Act ("PURPA") compliance. Competitive bidding can improve outcomes that benefit the utility, consumers, and independent power producers alike.

- The Commission should use the occasion of the IRP to study supply portfolio variations, especially in view of the changed incentives brought by the Inflation Reduction Act ("IRA") and EDAM; the Commission should test whether deployment of more low-cost renewables will keep Wyoming's costs and rates in check.

II. Fuel Cost Adjustment Mechanisms and Rocky Mountain Power's Rate Case Application

Q: Please discuss the history and theory of regulatory tools like ECAM.

A: Fuel cost adjustments ("FCAs") first originated in the mid-1970s.[2] Before that time, fuel costs were included in base rates and the levels remained fixed until the next rate case when total rates, including the cost of fuel, would be reset. Fuel costs were relatively stable and there usually was not a "true-up" mechanism.

All of that changed with the 1973 Oil Embargo, which caused market prices for generation fuels to become much more volatile.[3] Because of rapidly increasing fuel prices, many utilities filed "pancaked" rate cases, with new cases filed before the pending ones were settled. Indeed, I witnessed this and other developments firsthand in my role as a consulting utility rate analyst. These pancaked rate cases led to proposals to defer fuel costs that were above the levels included in base rates, and then collect those deferred amounts at a later date, oftentimes in the following month. FCAs helped to address these issues and lighten the regulatory load by mitigating the need for frequent rate cases.

Unsurprisingly, there was a lot of resistance among customer groups and consumer advocates to FCAs. Those opponents argued that FCAs were "single issue ratemaking," that they were overly generous to the utilities, that they relieved much of the pressure on the utilities to be efficient and shifted all fuel cost risk to customers. Despite this opposition, FCAs became a feature of most state regulatory systems, often enshrined in enabling legislation. In the decades following the adoption of FCAs, numerous other

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[2] *RRA Regul. Focus, Adjustment Clauses, A State by State Overview*, S&P Glob. Mkt. Intel. at 2 (Sept. 12, 2017), *available at* https://www.spglobal.com/marketintelligence/en/documents/adjustment-clauses-state-by-state-overview.pdf.
[3] *Id.*

"adjustment clauses" were adopted across the country: for pension benefits, inflation tracking, changes in labor costs, environmental compliance costs, and capital investment, to name a few.

This array of adjustment clauses altered cost-of-service regulation in a way that weakened or removed one of the main incentives for utilities to become and remain efficient as business firms: pressure from cost changes. Recognizing that a cost tracker for fuel and purchased power reduces utilities' incentives toward efficiency, some states began adding features to these fuel clauses, rewarding the utilities for specific actions, such as reducing the heat rate at fossil plants or increasing load factors for their plants. In my view, these *ad hoc* adjustments to the fuel clauses have been only partially successful.

Interestingly, Rocky Mountain Power operated in Wyoming without a "fuel clause" until after 2001. The Company was apparently willing to do business with the upside of profits from selling power without the assurance of a cost-of-service floor that would protect the Company from variation in its power costs.

Q: Please explain what Rocky Mountain Power is seeking in this case.

A: RMP has filed a general rate case so there are numerous issues raised by the filing. Focusing on Net Power Costs ("NPC"), the Company is seeking to raise base rates to reflect sharply higher power costs. The NPC was established in the 2020 General Rate Case at a total of $1.431 billion. The following table, taken from Rocky Mountain Power witness Mitchell's testimony summarizes the changes to elements of NPC, which grew by 78% to a new total of $2.355 billion.

Table 1: Comparison of Forecasted Net Power Costs in Wyoming 2020 General Rate Case and Current Rate Case

Net Power Cost Reconciliation ($)		
	($ millions)	**$/MWh**
WY 2020 GRC Final Forecast	**1,431**	**23.67**
Increase/(Decrease) to NPC:		
Wholesale Sales Revenue	(256.4)	
Purchased Power Expense	788.6	
Coal Fuel Expense	45.5	
Natural Gas Fuel Expense	514.2	
Wheeling and Other Expense	30.3	
Total Increase to NPC	**1,122.2**	
WY 2023 GRC Initial Forecast	**2,553**	**38.32**

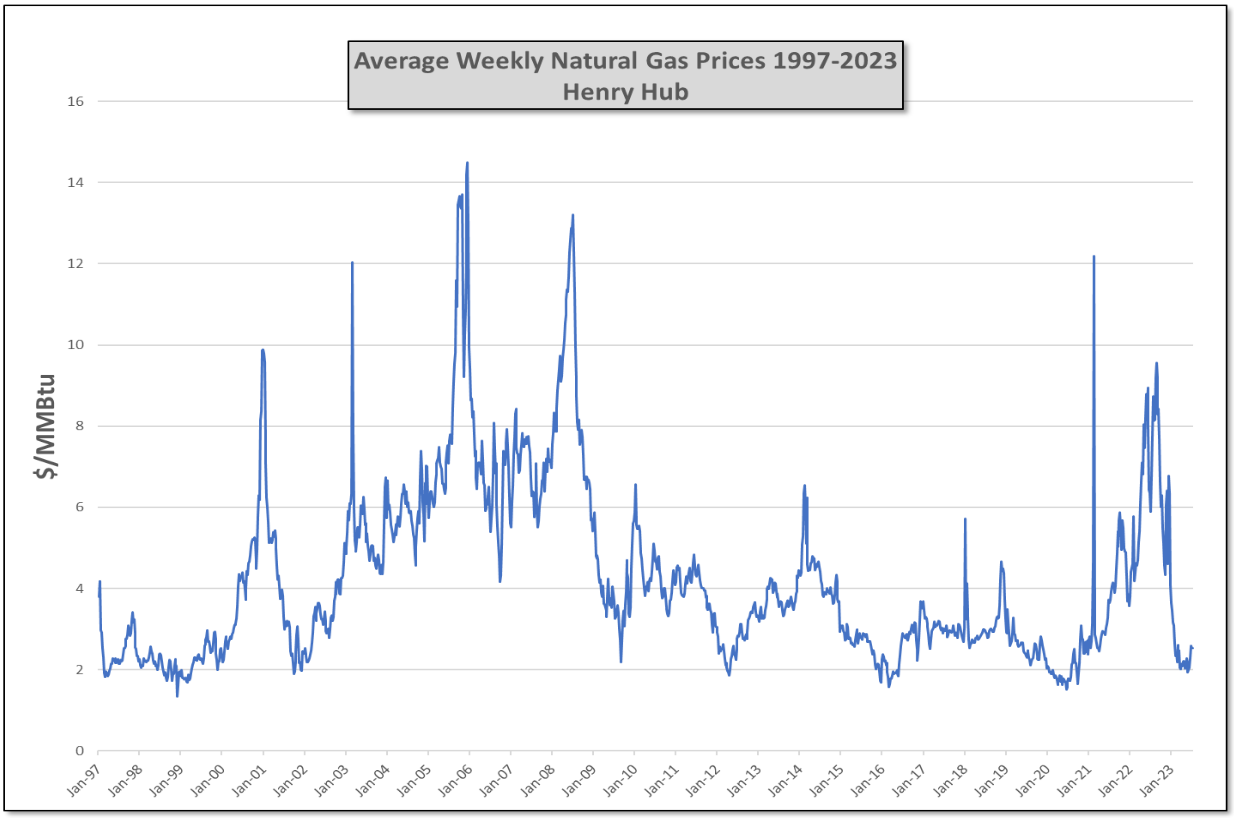
The two largest changes in cost – Natural Gas Fuel and Purchased Power Expense – account for virtually all of the change to NPC. As I will discuss later, both of those factors are driven by changes in the wholesale price of natural gas.

As part of the filing, Rocky Mountain Power asks the Commission to modify the adjustment mechanism that applies to Net Power Costs, the ECAM, through which the utility is permitted to charge customers a majority (but not all) of the difference between forecast NPC and the actual NPC. Currently, after calculating the over/under amount, the balance is split 80/20 between customers and the Company. The Company is proposing to eliminate that cost sharing.

Q: What has happened to generation fuel prices in the past two years?

A: After a period of relatively stable prices in the period 2016 to 2020, natural gas prices became much more volatile and increased sharply, especially during 2022. The following chart shows the cost of natural gas at the Henry Hub price point for the years 1997 to date.

Figure 1: Average Weekly Natural Gas Prices 1997-2023, Henry Hub



Q: What does it mean for prices to be volatile?

A: In everyday usage, "volatile" means the tendency to change quickly and perhaps unpredictably. We might speak of someone's personality being "volatile" or the Dow Jones Industrial Average exhibiting "volatility." For commodities like natural gas or coal, "volatility" describes how quickly the price of the commodity changes over time. The term has loose, informal meanings. But it also has technical, economic meanings. In finance the term is well-defined and can be measured. Officially, “volatility” is the standard deviation of changes in value of a variable over time.

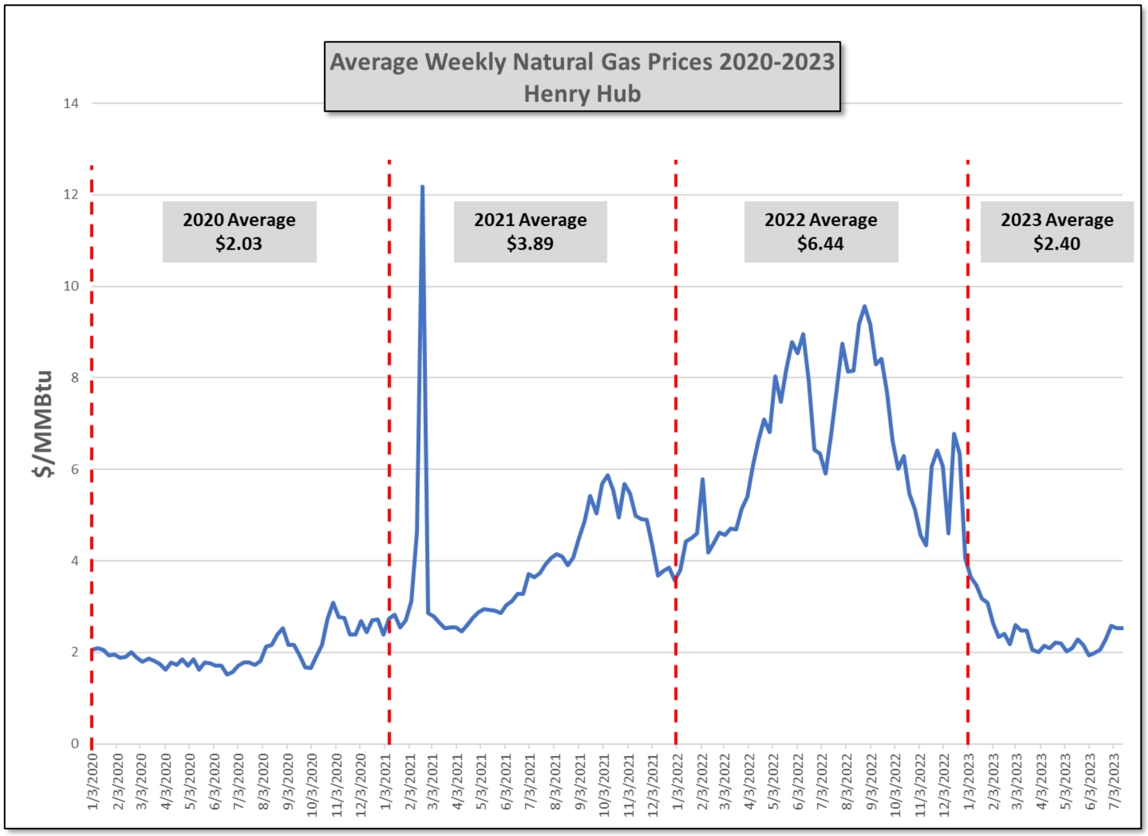
Rising prices do not necessarily signal high volatility. Volatility measures the rate of price changes, both up and down. A slowly rising price might have low volatility; a downward trending price may or may not be volatile. Further, prices that are very volatile in one period might not be volatile in another period. However, in the past two years, the prices of both natural gas and coal have been volatile and increasing.

Q: What does figure 1 show?

A: Over the past 44 years, the price of natural gas has shown itself to be quite volatile, swinging both up and down. I clearly recall the day when the price of natural gas reached a price of over $13.00/MMBtu in early July 2008, one of the highest price levels ever seen. I was Chair of the Colorado Public Utilities Commission, and we were very worried about residential heating costs in the upcoming winter season. We issued a Consumer Alert warning about the coming price increases. As it turned out, the price of gas fell consistently for the next six months, arriving at a price of $3.88 by the end of winter. Happily, the heating season was relatively normal, notwithstanding that natural gas prices had reached record levels only months before. In this case, volatility worked to the customers’ advantage when the price of natural gas fell so rapidly.

Most relevant to this case, it is helpful to examine the natural gas price history on a shorter time scale. Figure 2 is a chart with the same data as Figure 1, limited to the range of 2020-2023. Figure 2 also shows the calculated average of average weekly prices at Henry Hub for each of the calendar years 2020 to 2023.

Figure 2: Average Weekly Natural Gas Prices 2020-2023, Henry Hub



Looking at the average annual price of natural gas in 2021 and 2022, it is not surprising that Rocky Mountain Power's estimate of NPC in 2020 was so far off base in 2021 and 2022, as the average weekly price of natural gas increased over 217% between 2020 and 2022. Higher natural gas prices affect almost every element of the NPC calculation. Clearly, an estimate of future NPC made in 2020 could not have anticipated the huge increase in natural gas prices in 2021 and especially not the "black swan" events in 2022, such as the war in Ukraine. Finally, I note that the price of natural gas so far in 2023 has returned approximately to the price in 2020.

Q: Do you agree with Mr. Mitchell's explanation for differences between forecast NPC and actual NPC?

A: Only partially. Mr. Mitchell cites several reasons why he thinks the estimate for NPC is often wrong. Among others, he lists the ongoing drought's effect on hydro generation, the asymmetric relationship of cost changes for increases and decreases along the supply curve, the cost of natural gas, and the proliferation of "weather dependent generation." These and other factors undoubtedly affect the level and volatility of market prices. But these factors have various levels of influence.

I do not think that Mr. Mitchell stresses enough the role of natural gas prices as a factor. As I will show, most of the fluctuation in NPC stems from changes in the price of natural gas, which directly affect Rocky Mountain Power's generation costs. But higher gas prices also affect the market price of electricity and the costs of most power purchase contracts.

The takeaway is this: natural gas prices are inherently volatile and difficult to predict. This translates directly to unpredictable market prices and unpredictable generation costs.

Q: Does Mr. Mitchell blame renewable energy on the RMP system for the difficulty in predicting future prices?

A: That is certainly one of the conclusions one can draw from his testimony, which states:

> . . . I address how the evolving energy industry's landscape makes it near impossible to model forecasted NPC accurately. The drivers of this diminished model accuracy are shown to be ongoing and recent increases in region-wide adoption of weather dependent generation and the associated impacts to the prices observed in the regional forward power markets. Additional discussion on the asymmetry in the regionwide supply

> stack that results from weather dependent generation provides further support for continued expectations of diminished model accuracy.[4]

At the same time, Mr. Mitchell recognizes the benefit of wind generation and states that the regionwide NPC would be considerably higher were it not for those resources:

> Without these new wind resources and the associated transmission lines to move the generation to load, the 2024 NPC forecast would be $343 million higher on a total-Company basis, approximately $47 million on a Wyoming-allocated basis.[5]

Even if there were tensions between increased renewable generation making forecasting NPC more difficult and renewable generation lowering NPC, the reduction of costs due to renewable energy is quite significant. According to Mr. Mitchell's own numbers, wind savings alone have lowered NPC by 13.5%. Fortunately, the tension is more perceived than real.

Q: What is your response to Mr. Mitchell's observation about the difficulty to accurately predict NPC?

A: I agree with him that the western grid is getting more complicated. He is also correct that it is difficult to predict wind and solar generation in the short run. But there are two things working in the consumer's favor. First, it has been shown in theory and in practice that there is a great benefit for wind and solar generation if there is geographic diversity. While the wind may die down at one site, it might pick up at a geographically distant site. This smoothing of wind generation is very helpful to control room operators who can use the geographic diversity to their advantage.

Second, it is incorrect to blame wind and solar generation initially for unpredictable moves in market prices. To be sure, there is some effect, but it is small and

[4] Ex. 10.0, Direct Test. of Ramon J. Mitchell (March 2023) at 37:1-7 [hereinafter "Ex. 10.0"].
[5] Ex. 10.0 at 52:16-19.

swamped by variability in the price of natural gas. I have prepared the attached 3-page Exhibit 302 that illustrates this effect. The first page shows a hypothetical supply stack. As can be seen, the generation resources are ordered according to their marginal cost of generation. Renewable resources have almost zero marginal cost; next is nuclear; next is coal generation; following coal are combined cycle gas turbines ("CCGT"); and last are the costliest on a marginal cost basis – gas combustion turbine generators.

Q: What does the second page of Exhibit 302 illustrate?

A: The second page illustrates what happens to the system clearing price if all wind and solar resources stopped producing when the system is at average load. This is an extreme assumption with near-zero probability, especially considering the likely geographic diversity of the renewable resources. Nevertheless, we see that removing all of the renewable generation in this illustration shifts the supply curve left, putting a more expensive CCGT plant on the margin. But the new marginal plant is also a combined cycle plant, whose cost difference with the previous marginal plant is small. We see that the effect of all solar and wind disappearing is a minor change in the marginal cost of the last plant, which sets the clearing price in the market.

Q: Please explain the third page of the exhibit.

A: The third page shows what happens when the price of natural gas moves from $2.40/MMBtu (the average price at Henry Hub in 2023) to $6.44 (the average Henry Hub price in 2022). In this case, the supply curve moves up, by about $25/MWh for the combined cycle plants and by about $32/MWh for the gas turbines. CCGTs have a heat rate of about 7000Btu/kWh. This means that a $2.00 change in the price of a MMBtu of gas will change the cost of electricity by about $14.00/MWh. Recall Figure 1 above that shows the volatility of natural gas prices as they move from a weekly average low of $1.34 to a high of $14.49, a swing of almost 11-fold.

Q: What can be understood from this exhibit?

A: The takeaways from this illustrative exhibit are these:

- The variable output of wind and solar generation can affect the market clearing price to a degree. The cost of wind and solar does not change, but variable output can affect which gas plant sets the clearing price of the market. In most circumstances the effect is likely to be small.
- The price of natural gas drives the clearing price in this illustrative market. A change in that price can have a very large effect on the clearing price, and actual experience in the years 2020 to 2023 demonstrates the dominant effect of natural gas price volatility.

III. RISK SHARING MECHANISMS IN FUEL ADJUSTORS

Q: In your view, what are the merits of Wyoming's ECAM sharing mechanism?

A: I have testified in several states about the benefits of a risk-sharing fuel cost mechanism. First, this approach is fairer to utility customers who, without a sharing mechanism, shoulder all the risk of fluctuations in fuel costs and bear all the cost of a resource decision that they were not party to. While future gas prices are difficult to predict; that gas prices are unpredictable is not. Armed with this information, the utility – not its customers – determine how exposed it should be to gas price fluctuations. Unfortunately, in most states, regulation has moved from a point where utilities bore this risk of fuel cost changes – they had to file a rate case to increase fuel prices – to the point where utilities are now fully shielded from that risk. When I was the Consumer Counsel in Colorado in the 1990s, consumer advocates across the country objected to fuel cost pass-throughs and other "adjustment clauses." Their argument was that, by automating the recovery of those costs, regulators and legislators were removing the primary incentive the utilities have to become and stay efficient – cost pressures. That argument – about utility incentives – is not updated to apply to the utility's incentives in resource choices. Wyoming is one of a handful of states that allocates the over/under risk between customers and the utilities. Basic fairness suggests that the utility should share the risk of higher prices, as is currently the practice in Wyoming.

Second, a risk-sharing mechanism is a signal or a reminder to the utility of the risks of including natural gas generation in their portfolio. It is not a prohibition on using natural gas; instead, it simply requires the utility to factor in a known risk of reliance on gas fuel when determining an appropriate mix of generation resources. In other words, it is an equalizing factor when comparing natural gas generation to other energy resources such as energy efficiency or renewable generation, neither of which have fluctuating costs. Without a risk-sharing mechanism, the utility is incentivized to ignore gas price volatility because it knows that, regardless of price fluctuations, it will be made whole. This is a classic example of "moral hazard."

Q: Please expand on this last idea.

A: In economics, finance, and insurance theory, a situation might arise where one party engages in risky behavior or fails to act in good faith because it knows the other party bears the economic consequences of their behavior. This situation is called a "moral hazard." As one well-known example, economists largely agree that the 2008 Great Recession was ushered in when banks took risks they thought the federal government would cover. From Investopedia:

> The financial crisis of 2008 was, in part, due to unrealistic expectations of financial institutions. By accident or design - or a combination of the two - large institutions engaged in behavior where they assumed the outcome had no downside for them. By assuming the government would opt as a

> backstop, the banks' actions were a good example of moral hazard and behavior of people and institutions who think they are given a free option.[6]

In this case, Mr. Mitchell recommends dropping risk-sharing, meaning that its customers will "opt as a backstop." Rocky Mountain Power would be entirely shielded from fuel cost risk by passing through all changes in Net Power Costs to consumers, leaving Rocky Mountain Power whole.

The concept of moral hazard comes home to roost with utility resource selection. If dollar-for-dollar cost recovery for gas or coal is a foregone conclusion, utilities do not appropriately account for the risk of fossil fuel resource acquisition, especially not when compared to the much lower risk of low-cost solar and wind generation, which do not suffer from fluctuating costs.

Q: Aren't ratepayers protected against this moral hazard because a utility's regulators could find that its failure to account for price volatility in its resource selection was imprudent?

A: No, they are not. Utilities assume that they will be compensated for their expenses and capital outlays as long as those expenditures are not egregiously imprudent. In theory, imprudent expenditures are disallowed, and ratepayers are protected from unreasonable decision making by the utility. However, while the idea is discussed in textbooks, the actual number and value of "disallowances" for imprudent expenditures in utility regulation is vanishingly small. Utilities such as Rocky Mountain Power are well aware of this.

[6] Investopedia, *How Did Moral Hazard Contribute to the 2008 Fin. Crisis* (Oct. 29, 2021), *available at* https://www.investopedia.com/ask/answers/050515/how-did-moral-hazard-contribute-financial-crisis-2008.asp.

Q: Why does Rocky Mountain Power oppose retaining the risk sharing mechanism?

A: RMP offers three arguments for eliminating the sharing mechanism:

1. Joining EDAM beginning in 2025 means a loss of control for Rocky Mountain Power's economic dispatch; this makes ECAM sharing unnecessary.

2. Company argues that NPC "will be driven as low as the EDAM can achieve" and "out of the Company's control" so that risk sharing can be set aside.

3. ECAM objectives will be met automatically by EDAM even if ECAM sharing is removed.

Q: What is your response to Rocky Mountain Power's first argument?

A: The first argument – that EDAM will control Rocky Mountain Power's economic dispatch – overstates the effect of EDAM on Net Power Costs. It's true that EDAM will be dispatching the participating units in the short run, but much of that dispatch would have happened anyway. In fact, the predicted impact of EDAM on the eastern RMP region indicates higher generation levels, with increased sales. Lower costs for power in Wyoming should allow more Wyoming sales as EDAM presents new sales opportunities.

Rocky Mountain Power's NPC is dominated by coal and gas (56%) and purchased power (23%). The mix of resources in RMP's generation fleet available to meet load is largely what determines NPC, not the daily dispatch of those resources. This is because, while RMP has some ability to ramp its resources up or down depending on load, it cannot change out those resources – it must "go to war with the army it has." In that sense, at the point of cost reimbursement, it is too late to affect the resource mix; that comes at the time the IRP. The sharing mechanism conveys the risk that resource choices can make. Utilities can compare lower-risk portfolios with a fossil portfolio that is known to have fluctuating costs to which the utility is exposed.

Rocky Mountain Power, and not EDAM, will determine how that mix of resources (and their associated costs) evolves over time. While RMP cannot control market prices for gas, coal, or power produced by others, it can shape its NPC by a judicious resource expansion. As I will discuss later, adding more wind and solar will be key to lowering NPC. In short, EDAM will not be running the Company: RMP will still be in control of resource selection and subject to the incentives of cost-of-service regulation.

Q: What about Mr. Mitchell's next two arguments – that EDAM will drive costs lower with or without the sharing mechanism in ECAM?

A: My response is that the Company can push costs even lower than those produced by the market. EDAM will function to optimize dispatch of multiple generation resources across the market footprint and optimize the use of the transmission grid. The result will be lower total costs of power production. Neither RMP nor any single market participant can accomplish this optimization: it requires an operative, the EDAM, with the authority to dispatch plants in reliability-constrained merit order. The savings achieved by this optimization will flow through to each participating entity through a lowering of the market price, compared to what would have been. Mr. Mitchell is correct that these results will occur whether or not Wyoming Commission requires differences between predicted NPC and actual NPC to be shared between RMP and its customers.

But that is not the end of the story: EDAM does not prevent RMP, through its short- and long-run management choices, from lowering power costs even further. Most of these savings beyond EDAM will not occur in a timeframe of hours or days. They will occur as a result of whether RMP makes least-cost resource decisions, whether RMP operates its units optimally, and how RMP interacts financially with the EDAM market. There is simply no reason to stop with the cost improvements resulting from EDAM.

Q: What do you recommend the Commission do with the sharing mechanism?

A: I recommend the Wyoming Commission retain the sharing mechanism. It still serves a valuable and equitable role by putting part of the fuel cost risk on the utility. A fuel cost sharing mechanism gives the Company some "skin in the game." Further, customers see a sharing mechanism as fundamentally fairer than customers shouldering all the risk. I was not involved in the Commission decision to move the sharing percentage from 70/30 to 80/20, but these same arguments support a move back to the 70/30 split, especially as utilities have progressively more ways to limit their risk by using renewables such as solar with storage.

IV. THE ROLE OF RENEWABLE ENERGY IN REDUCING NPC

Q: Why should Wyoming regulation encourage more zero-cost resources and storage?

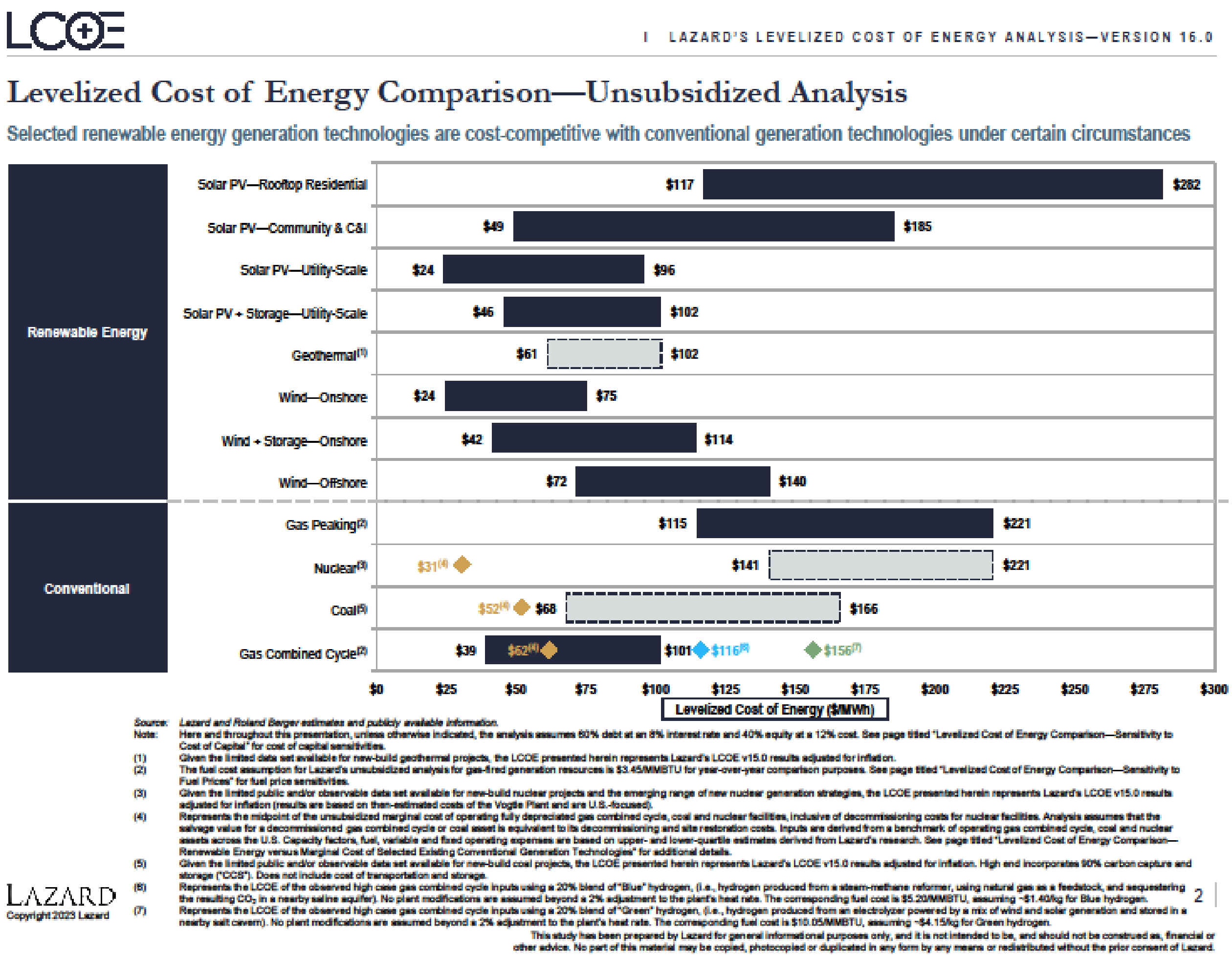
A: Wyoming is coal country, but it can also be solar country and wind country. There are multiple reasons why the Commission should promote more adoption of low-cost renewable resources:

- Wind and solar costs are now often lower than any fossil resource.
- Wyoming has exceptional wind and solar resources.
- Low-cost wind and solar in Wyoming can be very profitable in EDAM.
- New tax policies in the Inflation Reduction Act will boost renewable production.

Q: Please explain your first point.

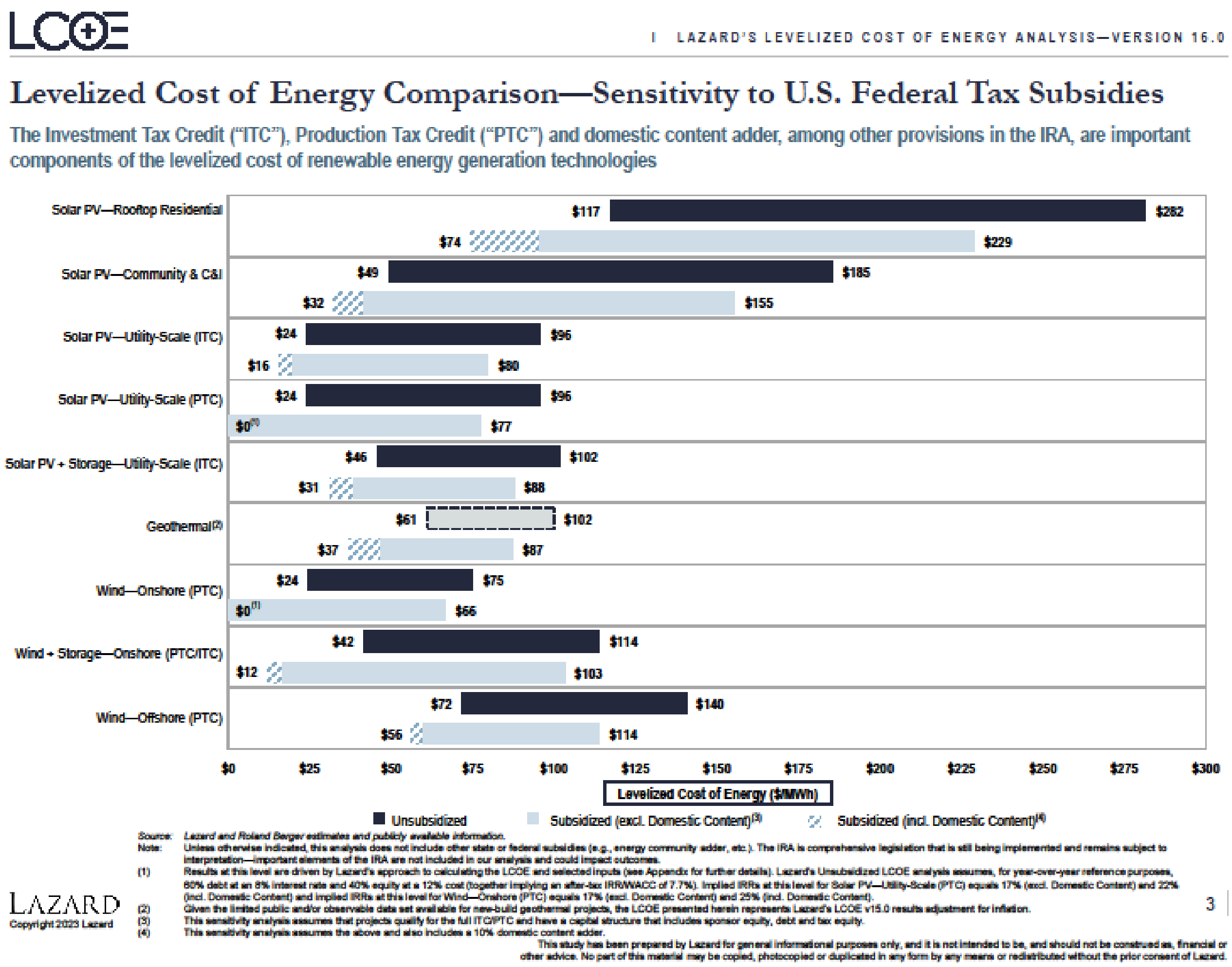
A: First, renewable resources are now often lower cost than gas generation and sometimes coal generation. In many places geothermal energy is also now a competitive baseload option. I am attaching as Exhibit 303 a copy of the Lazard's 2023 Levelized Cost of Energy Analysis, the 16th edition of this comprehensive report. The report shows the range of costs – overnight and levelized – that characterize every significant electric energy source. As the Commission can see on page 2 of the report, renewable energy – chiefly wind and utility scale solar – is competitive with fossil and nuclear generation on **<u>an unsubsidized basis</u>**. That page is reproduced below as Figure 3.

Figure 3: Levelized Cost of Energy Comparison – Unsubsidized Analysis



But the current federal administration has championed the Inflation Reduction Act that extends and increases the federal tax credits for renewables and storage. Page 3 of the Lazard report shows how federal tax credits affect each major resource type. This page is also reproduced below as Figure 4.

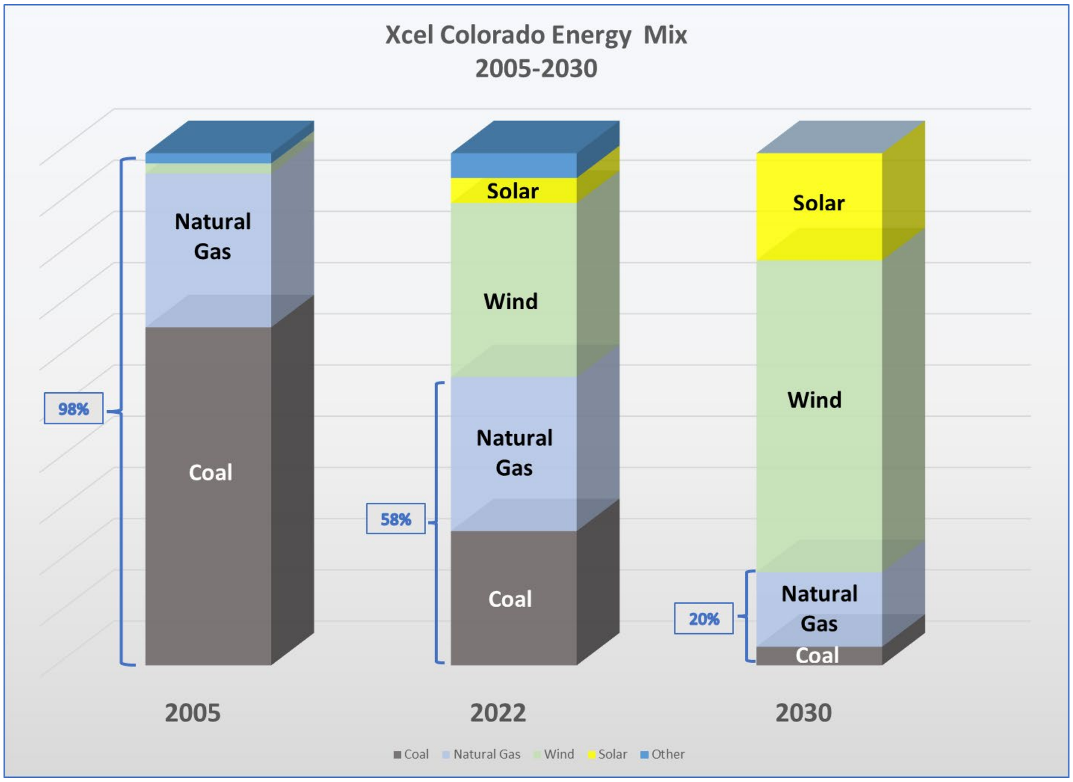
Figure 4: Levelized Cost of Energy Comparison – Sensitivity to U.S. Federal Tax Subsidies



Q: How are these low prices and new tax policies affecting investor-owned utilities?

A: The low cost of renewables has changed how many utilities are doing business. Xcel Energy Colorado provides a good example. The following figure shows the change in generation fuel mix since 2005 and what is planned for 2030, only 7 years from now. To be clear, the chart below measures the fuel sources behind energy (MWh) production. Xcel separately arranges capacity to cover its peak demand.

Figure 5: Xcel Colorado Energy Mix 2005-2030



Utilities like Xcel can use renewables, both wind and solar, in a "fuel-saving" mode. This means that the resources provide energy that allows Xcel to throttle back their gas and coal plants. The fossil plants remain in service for capacity, but are used much less often for energy. With competitive bidding, Xcel has been able to obtain wind and solar (including with storage) at rock-bottom prices. Below, Table 2 shows the bid prices for wind and solar Xcel Colorado received in its 2016 IRP. Following this summary, the bids were evaluated, ranked, and contract negotiations continue followed.

There are several key features of this matrix. First note that the prices quoted for wind and solar are *median* prices. In other words, half the bids were cheaper than the quoted number. This means that half of the 42 wind bids were cheaper than $18.10/MWh.

Similarly, half of the 59 bids for solar with storage were cheaper than $36.00/MWh. As it turns out, Xcel contracted with NextEra for 300 MW of wind energy at the near-unbelievable price of $10.07 per MWh[7].

Table 2: Xcel Energy RFP Responses by Technology, 2016

RFP Responses by Technology

Generation Technology	# of Bids	Bid MW	# of Projects	Project MW	Median Bid Price or Equivalent	Pricing Units
Combustion Turbine/IC Engines	30	7,141	13	2,466	$ 4.80	$/kW-mo
Combustion Turbine with Battery Storage	7	804	3	476	6.20	$/kW-mo
Gas-Fired Combined Cycles	2	451	2	451	[redacted]	$/kW-mo
Stand-alone Battery Storage	28	2,143	21	1,614	11.30	$/kW-mo
Compressed Air Energy Storage	1	317	1	317	[redacted]	$/kW-mo
Wind	96	42,278	42	17,380	$ 18.10	$/MWh
Wind and Solar	5	2,612	4	2,162	19.90	$/MWh
Wind with Battery Storage	11	5,700	8	5,097	21.00	$/MWh
Solar (PV)	152	29,710	75	13,435	29.50	$/MWh
Wind and Solar and Battery Storage	7	4,048	7	4,048	30.60	$/MWh
Solar (PV) with Battery Storage	87	16,725	59	10,813	36.00	$/MWh
IC Engine with Solar	1	5	1	5	[redacted]	$/MWh
Waste Heat	2	21	1	11	[redacted]	$/MWh
Biomass	1	9	1	9	[redacted]	$/MWh
Total	430	111,963	238	58,283		

Further, the solicitation by Xcel led to a vast number of bids. While the target solicitation was about 1200 MW, Xcel got bids for 58,283 MW – forty-three times the amount sought. The "incredibly low" prices caught the attention of Utility Dive.[8]

Part of the value of Xcel renewable play is that wind and solar are immune to fuel cost risk. The marginal cost of operating wind and solar is only the variable operation and maintenance costs ("VO&M"), which are near zero. These resources can be owned by the

[7] Mich. Pub. Serv. Comm'n, *MI Power Grid Phase II, Advanced Plan. Evaluator and All-Source Mtg.* (Feb. 2021), *available at* https://www.michigan.gov/-/media/Project/Websites/mpsc/workgroups/comp-proc/Feb_18_Competative_Procurement_Presentation_.pdf?rev=c0dfd06533714ee9991658e2f8c145f2.

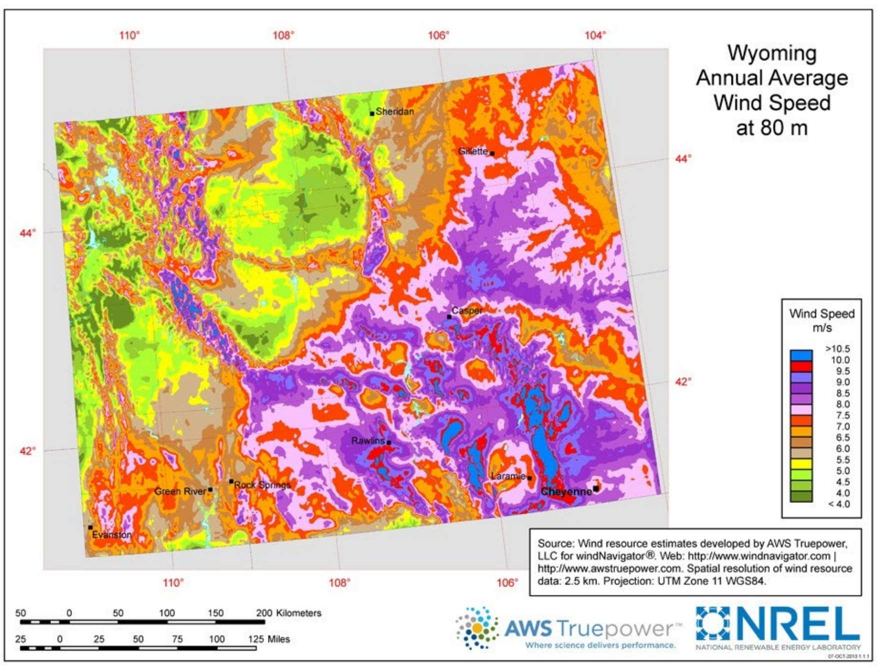
[8] *See* Herman K. Trabish, *Xcel's Record-Low-Price Procurement Highlights Benefits of All-Source Competitive Solicitations*, Util. Dive (June 1, 2021), *available at* https://tinyurl.com/y4d4re5c.

utilities or purchased under contract from independent power producers. Those contracts may or may not have an annual price escalator, but there are no provisions, as with fossil power contracts, that permit passing through increased operating costs similar to fuel costs with fossil resources. There will be no "price surprises" with these resources.

Q: What about your second point – Wyoming's renewable resources?

A: Wyoming has excellent solar and wind resources, and is, in fact, already experiencing low-cost clean energy development. As the Commission knows, Carbon County is the site of the world's largest windfarm. A look at the wind resource map prepared by the National Renewable Energy Lab ("NREL") shows how rich the wind resource is.

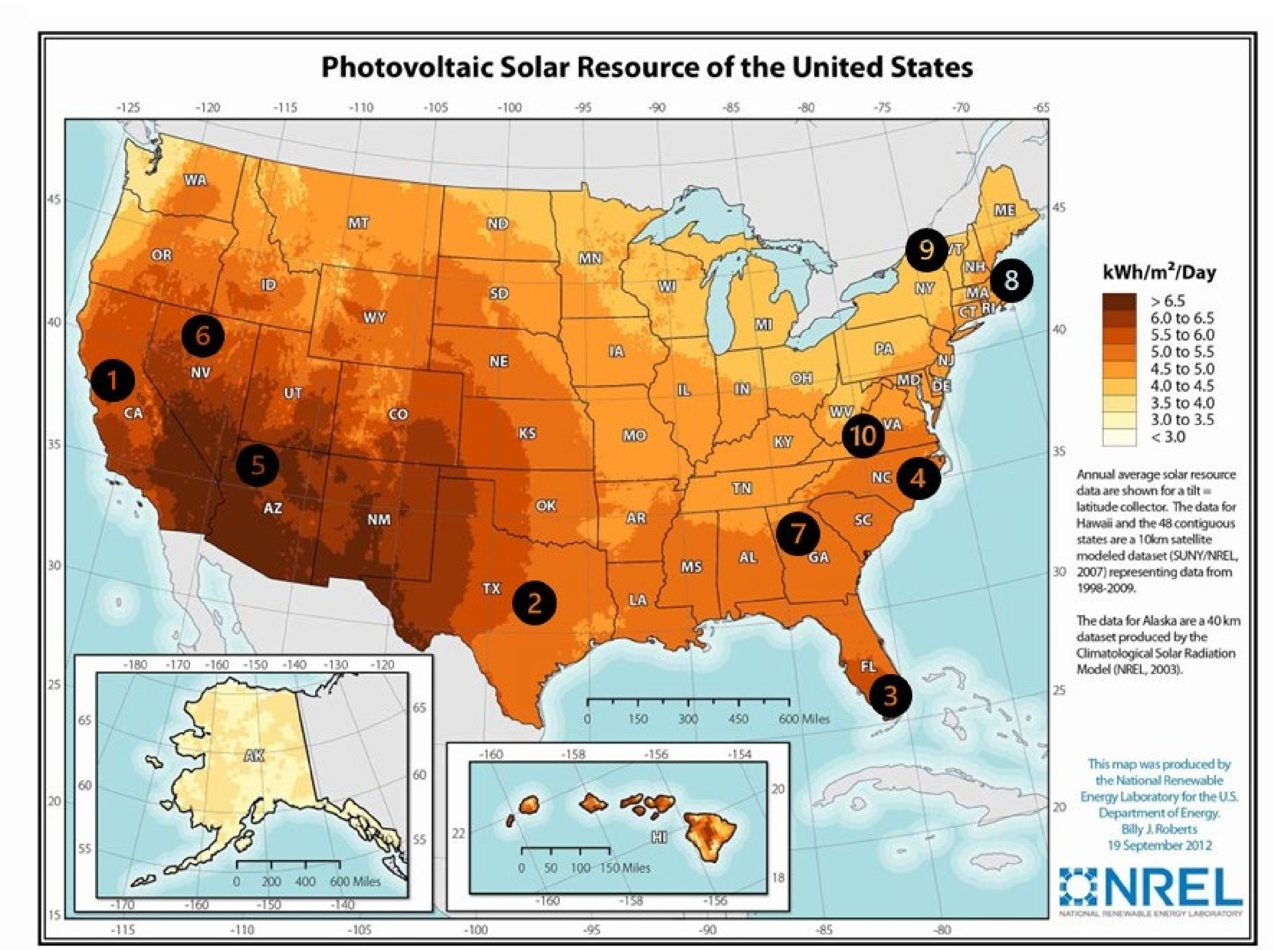
Figure 6: Wyoming Wind Resource Map



Much of the state is endowed with Class 6 and 7 wind resources. Neither Texas nor Iowa, the Number 2 and 3 wind states behind California, have resources this good.

Wyoming also has very good solar resources. Its average insolation is on par with Texas, the second-largest solar state. Four more of the top ten solar states – Florida, North Carolina, Georgia, Virginia – all have insolation levels that are inferior to Wyoming's levels. The following chart shows the top ten solar states and illustrates their relative solar resources.

Figure 7: Photovoltaic Solar Resources of the United States



Q: Please explain your third point concerning renewables in EDAM.

A: These low-cost renewable resources could be very profitable in the EDAM market. The all-in costs of stand-alone photovoltaic solar generation are often in the 20 cents per kwh range. Recall that Lazard (Figure 4 above) prices solar with federal tax credits at $0 to

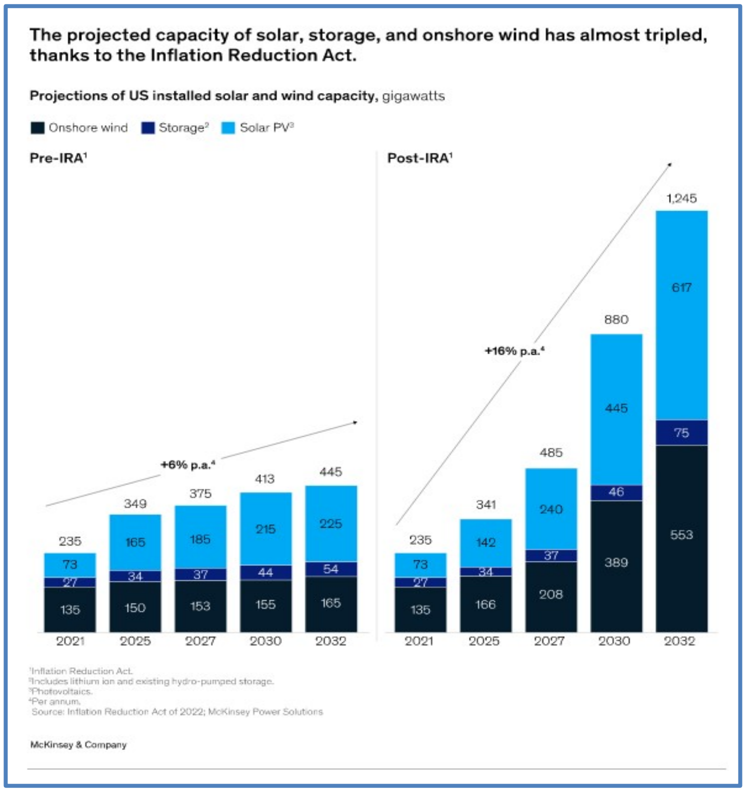
$16/MWh. Wind costs are even lower. While Wyoming may not need this renewable energy for its own residents, companies and customers in other states do need it. If the mid-day market price of energy is, for example, $40/MWh, then energy produced at half that cost (as is the case for many new renewable energy projects) will be very profitable when sold through EDAM.

Q: Are there any other factors that the Commission should consider relating to renewable energy development in Wyoming?

A: Yes. My fourth point is that the Commission should consider the impact that the Inflation Reduction Act ("IRA") will have on solar and wind development. The IRA contains many provisions designed to increase renewable deployment. The provisions concerning federal subsidies for solar have been modified in ways that will make solar investment more directly beneficial to utilities, among other changes. McKinsey & Company issued a recent report that estimates the Inflation Reduction Act will nearly triple the development of wind and solar generation in the next ten years. See Figure 8.

This means that there will be plenty of market for Wyoming solar generation to grow into. RMP will be able to reach much of that market through the EDAM structure. Bottom line, Wyoming's solar potential is large and could be very profitable to the state's utilities that participate in the EDAM.

Figure 8: Impact of IRA on Projected Solar, Storage, and Onshore Wind



V. PURPA AND NET POWER COSTS

Q: Are PURPA-related costs a driver of the proposed increase in the fuel rider?

A: Yes, they are. As shown in Mitchell Exhibit 10.1, QF costs for qualifying facilities comprise $305 million – about 22% of RMP's total power purchase expenses. The Company appears to acquire some renewable resources under the PURPA avoided cost tariff and others through PPA contracts.

Q: How are PURPA requirements met in Wyoming?

A: Rocky Mountain Power appears to meet its PURPA requirements in Wyoming by offering a combination of "avoided cost" tariffs (Schedule 37) and a negotiated pricing regime (Schedule 38) under which the Company will purchase renewable energy from qualified facilities ("QFs"). However, based on my experience as Chair of the Colorado Public Utilities Commission, I think there is a better approach to QF purchases that will benefit the utility, its customers, and independent power producers alike: all-source competitive bidding.

Q: Please explain.

A: Colorado initially managed its PURPA obligations by buying QF power at a set tariff rate based on "avoided cost." There was a predictable amount of regulatory jockeying, conflicting studies about avoided cost, and eventually lawsuits. There seemed never to be a consensus on what constituted "avoided cost" and whether the utility was obliged to buy the power when evidence showed it wasn't needed.

In the early 1990s, the Colorado Commission scrapped the avoided-cost-tariff system and replaced it with a different approach. Only the smallest projects (less than 100 kW) were handled by a tariff offering. QFs larger than 100 kW were required to offer their projects into a competitive bidding process that was tied to a utility's periodic IRP proceeding. The first phase of the IRP process established the need for additional power and a schedule of acquisition of resources over a five-year implementation period. The theory of this practice is that competitive bids would reveal the cost of the next resources required by the utility in a manner that was superior to estimating avoided cost.

The Colorado Commission carefully designed the competitive bidding process, overseeing the language of the solicitation, the model contract language and importantly, employing an Independent Evaluator to check the selection and negotiation processes.[9] It

[9] 4 Colo. Code Regs. § 723-3-3611-3613.

was important to the Commission that the process be transparent and give assurance to all players that the results would be fair.

As the years passed, competitive bidding was applied to renewable energy projects (PURPA-affected or not) that utilities began to purchase to meet renewable energy targets. By 2016, the system and the market had matured into a remarkable combination where the utilities were swamped with very low-cost wind, solar, and storage projects. Anyone will tell you that the process has been a resounding success.

Q: What are the advantages of using competitive bidding to acquire PURPA resources?

A: I would cite four major advantages;

1. All-source competitive bidding eliminates the nettlesome problem of determining a utility's "avoided cost" with all its variations for resource size, quality, geography, etc. Competitive bidding sorts out those variables.
2. With a well-designed regime, industry participants will be treated equitably and will trust the process. There will be winners and losers, but probably not litigious losers.
3. Competitive bidding brings out many bidders on equal terms and the acquisition can stretch over three or four years.
4. And most importantly, the utility is able to buy the economically correct amount of energy resources, at economically correct prices; fixed tariffs and negotiations are liable to buy too much or too little energy.

Earlier I discussed the results of Xcel Colorado's competitive bidding for resources. It's fair to say that everyone, including Xcel and the electricity trade press, were quite surprised at the outcome of that solicitation. The resource request for proposal ("RFP") drew interest from hundreds of bidders, who collectively offered 410 proposals. But most surprising were the rock-bottom prices that the solicitation produced. At the time of that solicitation, prices for wind and solar with storage were the lowest seen in the country.

Rocky Mountain Power Wyoming is a smaller playing field than Xcel's Colorado territory, but I predict comparable results if the Commission instructs the state's utilities to fulfill their PURPA needs by using all-source competitive bidding. And, as discussed earlier, adding more low-cost wind and solar resources can replace gas burn in units and position Rocky Mountain Wyoming to profit from EDAM.

Q: In addition to changes to acquiring PURPA resources, do you have any recommendations regarding Rocky Mountain Power's IRP?

A: Yes. I recognize that the IRP regime in Wyoming is different than the Colorado IRP process. Colorado holds hearings on the IRP, approves a plan and then requires competitive bidding to acquire the resources indicated by the plan. In contrast, I understand that RMP files an IRP that informs the Commission of its plans. The Commission does not "approve" the IRP, but accepts its filing.

Even though the Wyoming PSC does not approve the IRP, the Commission could use the opportunity of the IRP submission to examine how different portfolios could affect RMP and its customers. This will be especially important as RMP enters EDAM since selling low-cost renewable generation into the EDAM market could be very profitable and lower RMP's Net Power Costs. The Commission could specify what type of portfolio it would like for RMP to examine and require that the analysis be included with the IRP filing. The utility is never better prepared to explore a Commission-specified option than when an IRP is being prepared.

Q: What sort of portfolios would you recommend the Wyoming Commission require RMP to evaluate at the time of its IRP?

A: As the economics of electric power in the Western Interconnection continue to change, the Commission should ensure that RMP is looking at supply portfolios that take advantage of the changes. My recommendation is that, at a minimum, the Commission require a portfolio that maximizes the use of federal tax credits available to RMP from the Inflation Reduction Act. The Commission should also direct the Company to run a sensitivity increasing the level of renewable generation on RMP's system in order to test whether deployment of more low-cost renewables will keep Wyoming's costs and rates in check due to their low cost and also the ability to sell these resources on the market through EDAM.

VI. CONCLUSION

Q: Please summarize your findings and recommendations.

A:

- Fuel cost sharing is a valuable element of the ECAM in Wyoming. It serves as a corrective to some of the poor incentives of traditional regulation and partially levels the regulatory playing field between fossil generation and zero-cost renewable generation.
- EDAM does not replace or moot out the importance of fuel cost risk sharing. Sharing will add to the benefits of EDAM; entering EDAM does not lessen value of sharing.
- An ECAM without the sharing mechanism will present Rocky Mountain Power with a classic "moral hazard." It will take risks with fossil fuel resources because the Company knows it will be made whole by the regulator. The Commission should not eliminate 80/20 sharing mechanism; instead, the Commission should consider restoring the previous sharing level of 70/30
- The Commission should use the occasion of the IRP to study supply portfolio variations, especially in view of the changed incentives brought by the IRA and EDAM; the Commission should test whether deployment of more low-cost renewables will keep Wyoming's costs and rates in check.

- The Commission should examine and adopt competitive bidding as a superior method for PURPA compliance. Competitive bidding can improve outcomes that benefit the utility, consumers, and independent power producers alike.

Q: Does this complete your testimony at this time?

A: Yes.

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RECORD NO.: 17252
WITNESS: RONALD J. BINZ
EXHIBIT: 301

DIRECT TESTIMONY AND EXHIBITS OF RONALD BINZ
ON BEHALF OF SIERRA CLUB

EXHIBIT 301
PROFESSIONAL RESUME OF RONALD J. BINZ

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Employment History

2011-present Principal, Public Policy Consulting

Following my four-year term on the Colorado Public Utilities Commission, I resumed my consulting practice in energy policy and regulation. My focus is on climate, clean tech, regulatory reform, utility business models, integrated resource planning and smart grid.

Current and recent clients include Millennium Challenge Corporation, National Renewable Energy Laboratory, Nikola Power, Southern Environmental Law Center, Vote Solar, Hewlett Foundation, the U.S. Department of Energy, Northeast Clean Energy Council, Climate Policy Initiative, Steffes Corporation, Posigen, Sunshare LLC, Vivint Solar, Tendril Networks, Dow Solar, Lawrence Berkeley National Laboratory, Ceres, the Energy Regulatory Commission of Mexico, Environmental Defense Fund, Earthjustice, Blue Planet Foundation, the Future of Privacy Forum, American Efficient, and Conservation Colorado, among others.

International Engagements

In recent years, I have had assignments in energy policy and regulation in several foreign countries, including Jordan, Liberia, Malawi, Mexico, Nepal, Sierra Leone, and Tanzania. The activities include developing policy and regulatory roadmaps (Mexico, Nepal), reviewing and drafting legislation (Nepal, Tanzania), advising on electric market structure (Nepal, Malawi) hosting a technical conference (Mexico), designing regulatory agencies (Malawi, Sierra Leone, Nepal, Mexico), advising on natural gas regulation (Tanzania) and developing Smart Grid policy (Mexico).

2013 Nominee, Federal Energy Regulatory Commission

I was nominated by President Obama on June 27, 2013, to serve on the Federal Energy Regulatory Commission and, upon confirmation, to be designated as Chairman. My nomination was vigorously opposed by the coal industry and certain conservative political groups. Following a confirmation hearing, it appeared unlikely that my nomination would be reported favorably by the Senate Energy and Natural Resources Committee. I therefore asked that my name be withdrawn from further consideration.

2011-2013 Senior Policy Advisor, Center for the New Energy Economy

The Center for the New Energy Economy (CNEE) at Colorado State University is headed by former Colorado Governor Bill Ritter, Jr. The Center provides policy makers, governors, planners, and other decision makers with a road map to accelerate the nationwide development of a New Energy Economy.

2007-2011 Chairman, Colorado Public Utilities Commission

I was appointed by Governor Bill Ritter, Jr. in January 2007. As Chairman, I helped implement the Governor's and Legislature's vision of Colorado's New Energy Economy, implementing the state's 30% Renewable Energy Portfolio Standard, fulfilling the Commission's role in the Governor's Climate Action Plan, streamlining telecommunications regulation, promoting broadband telecommunications investment, and improving the operation of the Commission.

Here are some major accomplishments during my term on the Commission:

- **Implementing the Clean Air-Clean Jobs Act (2010).** Following passage of this new law in 2010, the Commission worked under a very compressed time schedule to examine proposals by XcelEnergy and Black Hills Energy to reduce pollutants from their coal fired generation plants. The contentious Xcel proceeding involves thirty-four legal parties, testimony from sixty-one witnesses and the consideration of more than a dozen contending compliance plans. The case required the close cooperation between the Commission and the Colorado Department of Public Health and Environment, the first such collaboration.

- **Implementing dozens of new energy, transportation, and telecommunications laws.** In each legislative session during the term of Governor Ritter, the general assembly passed numerous sweeping utility-related laws. Many of these new laws required the Commission to adopt rules, compile reports, or conduct hearings. Rarely in Colorado history has there been this much activity required of the Commission.

- **Modifying and approving the electric resource plan of XcelEnergy (2009)**. After extensive hearings, the Commission approved a plan that includes large amounts of new wind capacity, the early closure of two coal power plants to reduce carbon and other emissions, the acquisition of 200-600 megawatts of solar thermal capacity, and substantial amounts of new energy efficiency savings. The target portfolio would reduce CO_2 emissions per megawatt-hour by 22% from current levels over eight years. The Commission decision required competitive acquisition for new resources.

- **Adopting new, aggressive energy efficiency requirements (2008)** for Colorado gas and electric utilities. The Commission's requirements for electric utilities go well beyond the statutory minimum levels enacted in 2007. The Commission's policies also provided for rapid cost recovery of energy efficiency spending and bonus incentives for superior performance for the utilities.

- **Rewriting the Commission's electric resource planning rules (2007)** to require full consideration of future costs for carbon emissions, new clean energy resources and environmental and economic externalities. Retained and refined the requirements for competitive acquisition of new resources.

- **Improving communications with stakeholders.** I successfully sought legislation to modify the Commission's enabling statute, allowing the use of a "permit-but-disclose" communications process like the one employed successfully by the Federal Communications Commission and the FERC. The result has been much greater exposure of the Commissioners and staff (outside the hearing process) to the thinking of consumers, utilities, environmental advocates, large customers, advocates for new technologies, etc.

- **Organizing meetings of Western state regulators on regional transmission issues**. We discussed coordination in our efforts to add transmission capacity, especially to renewable energy zones. In future meetings we will discuss a goal of eliminating "pancaked" transmission pricing in the intermountain west.

- **Conducting hearings in eight towns around the state** on a "road trip" to collect consumer opinions about energy rates, distributed generation, the future of the energy sectors, and support for moving toward a more environmentally sensitive utility industry.

- **Reorganizing the PUC's staff** to create a Research and Emerging Issues section. As chairman, I worked to improve deployment of the agency's modest staff so that the Commissioners could stay apprised of new technology and policy alternatives and be able to investigate and implement new regulatory approaches.

- **Reaching out to consumers and interest groups.** I frequently speak at meetings of consumer organizations, environmental groups, business and professional associations, legal seminars, etc. The two-way-street communications improves my understanding and conveys to the public the immense challenges we face in energy policy with climate change.

1995-2006 President, Public Policy Consulting

Consultant, specializing in energy and telecommunications regulatory policy issues. Assignments include strategic counsel to clients and research and testimony before regulatory and legislative bodies. In addition, I produced several research reports about the impact on rates of adding significant amounts of wind and solar capacity to utility systems. These reports are listed below.

I had a wide range of clients, including consumer advocate offices, rural electric utilities, senior citizen advocacy groups, environmental groups, industrial electric users, homebuilders, building managers, telecommunications resellers, incumbent local exchange companies, low-income advocacy organizations, and municipal utilities. I testified as an expert witness before regulatory commissions in twelve states.

1996-2003 President and Policy Director, Competition Policy Institute

Competition Policy Institute was an independent non-profit organization that advocated for state and federal policies to bring competition to energy and telecommunications markets in ways that benefit consumers. Duties included: determining the organization's policy position on a wide range of telecommunications and energy issues; conducted research, produced policy papers, presented testimony in regulatory and legislative forums, hosted educational symposia for state regulators and state legislators.

1984-1995 Director, Colorado Office of Consumer Counsel

Director of Colorado's first state-funded utility consumer advocate office. By statute, the OCC represents residential, small business and agricultural utility consumers before state and federal regulatory agencies. The office was a party to more than two hundred legal cases before the Colorado Public Utilities Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission, and the courts.

Managed a staff of eleven, including attorneys, economists, and rate analysts who conduct economic, financial, and engineering research in public utility matters. Testified as an expert witness on subjects of utility rates and regulation. Negotiated rate settlement agreements with utility companies. Regularly testified before the Colorado general assembly and spoke to professional business and consumer organizations on utility rate matters. Consulted with advisory board of consumer leaders from around the state.

Held leadership roles in National Association of State Utility Consumer Advocates. Member of high-level advisory boards to Federal Communications Commission (Network Reliability Council and North American Numbering Council) and Environmental Protection Agency (Acid Rain Advisory Council). Frequent witness before congressional committees and invited speaker before national industry and regulatory forums.

1977-1984 Consulting Utility Rate Analyst

Represented clients in public utility rate cases and testified as an expert witness in utility cases before regulatory commissions in Utah, Wyoming, Colorado, and South Dakota. Clients included state and local governments, low-income advocacy groups, irrigation farmers and consumer groups. Testimony spanned topics of telephone rate design, electric cost-of-service studies, avoided cost valuation of nuclear generation, electric rate design for irrigation customers and municipal water rate design.

1975-1984 Instructor in Mathematics

Taught mathematics at the University of Colorado, Denver, and Boulder campuses. Nominated three times for outstanding part-time faculty member.

1971-1974 Manager, Blue Cross, and Blue Shield

Managed major medical claims processing department. Responsibilities included budgets, hiring, training, managing supervisors, and coordinating with medical peer review committee.

Other Business Interests

1994-2011 Managing Partner, Trail Ridge Winery

Managing Partner and Secretary/Treasurer of Trail Ridge Winery. Trail Ridge Winery was located in Loveland, Colorado, and produced a variety of award-winning wines from Colorado-grown grapes.

Education

M.A. (Mathematics) 1977. University of Colorado. Course requirements met for Ph.D.

Graduate courses toward M.A. in Economics 1981-1984. University of Colorado. Twenty-seven hours including Economics of Regulated Industries, Natural Resource Economics, Econometrics.

B.A. with Honors (Philosophy) 1971. St. Louis University.

Professional Associations and Activities

Selected Current and Recent:

Board of Directors, Nikola Power

Board of Directors, GRID Alternatives Colorado

Board of Directors, GRID Alternatives (national)

Board of Directors, Western Resource Advocates (WRA)

Board of Directors, Southwest Energy Efficiency Project (SWEEP)

Board of Directors, Smart Electric Power Alliance (SEPA)

Advisor, Sunshare, LLC.

Brookings Institution, Non-resident Senior Fellow, 2013-2014

Harvard Electric Policy Group, John F. Kennedy School, Harvard University 1994-present

Advisory Council to the Board of the Electric Power Research Institute (EPRI) 2008-2011

Keystone Energy Board 2009-2012

Aspen Institute for Humanistic Studies, Communications and Society Programs 1986-present

Selected Past:

National Association of Regulatory Utility Commissioners
- Member, Energy Resources and Environment Committee 2007-2011
- Member, International Relations Committee 2007-2011
- Chair, NARUC Task Force on Climate Policy 2010-2011
- President, Western Conference of Public Service Commissioners, 2010-2011

Acid Rain Advisory Council to the Environmental Protection Agency, circa 1991
American Association for the Advancement of Science
American Vintners Association (*now* WineAmerica), Executive Committee, Membership Chair
Colorado Common Cause, Board Member
Colorado Energy Assistance Foundation, Board Member, Past President
Colorado Legislative Task Force on Information Policy, Gubernatorial Appointee 2000-2001
Colorado Public Interest Research Foundation, Board Member
Colorado Telecommunications Working Group, Gubernatorial Appointee
Colorado Wine Industry Development Board, Chairman
Council on Economic Regulation, Past Fellow
Denver Mayor's Council on Telecommunications Policy
Exchange Carriers Standards Association Network Reliability Steering Committee
Legislative Commission on Low-Income Energy Assistance, Past President
National Association of State Utility Consumer Advocates
- President 1991-1992, Vice-President 1990, Treasurer 1987-1989
- Chair, Telecommunications Committee 1992-1995

Network Reliability Council to the Federal Communications Commission
New Mexico State University Public Utilities Program, Faculty and Advisory Council
North American Numbering Council to Federal Communications Commission, Co-Chair
Outreach Committee, Western States Coordinating Council Regional Planning Committee
Total Compensation Advisory Council to the State of Colorado Department of Personnel
Who's Who in Denver Business

Selected Regulatory Testimony

From 1977 to date, Mr. Binz participated in more than 150 regulatory proceedings before the Federal Communications Commission, the Federal Energy Regulatory Commission, State and Federal District Courts, the 8th Circuit, 10th Circuit and D.C. Circuit Courts of Appeal, the U.S. Supreme Court and 22 state regulatory commissions: in Arizona, California, Colorado, the District of Columbia, Georgia, Hawaii, Idaho, Indiana, Massachusetts, Maine, Michigan, Missouri, Montana, New York, North Dakota, South Carolina, South Dakota, Texas, Utah, Washington, and Wyoming. He has filed testimony in more than sixty proceedings before these bodies. His testimony and comments have addressed a wide variety of technical and policy issues in telecommunications, electricity, natural gas, and water regulation.

Before the Public Service Commission of South Carolina. Application of Dominion Energy South Carolina, Inc. for Mid-Period Adjustment to Increase Base Rates for the Recovery of Electric Fuel Costs. October 2022.

Before the Public Service Commission of South Carolina. In Re: Annual Review of Base Rates for Fuel Costs of Duke Energy Carolinas, LLC For Potential Increase or Decrease in Fuel Adjustment. Docket No. 2022-3-E . September 2022.

Before The North Carolina Utilities Service Commission. Application Of Duke Energy Progress, LLC Pursuant To G.S. 62-133.2 And Commission Rule R8-55 Relating To Fuel And Fuel-Related Charge Adjustments For Electric Utilities. Docket No. E-2, Sub 1292. August 2022.

Before The Utilities And Transportation Commission of the State of Washington. Washington Utilities And Transportation Commission, Complainant, v. Puget Sound Energy, Respondent. Docket UE-220066 and Docket UG-220067. July 2022.

Before The Georgia Public Service Commission. Docket No. 44160. Georgia Power Company's 2022 Integrated Resource Plan. May 2022.

Before The Public Service Commission of Indiana. Cause No. 45546, Joint Petition of Indiana Michigan Power Company (I&M) and AEP Generating Company (AEG) For Certain Determinations with Respect to the Commission's Jurisdiction Over the Return of Ownership of Rockport Unit 2. July 2021.

Before the Nevada Public Service Commission. Docket No. 19-06008. Rulemaking to amend, adopt, and/or repeal regulations in accordance with Senate Bill 300 (2019). January 2021.

Before the Public Service Commission of Michigan. Case Nos. U-20713 and U-20851. In the matter, on the Commission's own motion, regarding the regulatory reviews, revisions, determination and/or approvals necessary for regulated electric providers to comply with Section 61 of 2016 PA 342. December 2020.

Before the Public Utilities Commission of Colorado. In the Matter of the Implementation of § 40-3-117, C.R.S. Regarding an Investigation into Performance- Based Ratemaking. March 2020.

Before the Public Service Commission of Montana. Electric Utility Rate Review NorthWestern Energy. Docket No. D2018.2.12. February 2019.

Before the Public Utility Commission of Hawaii. Instituting a Proceeding to Investigate Performance- Based Regulation. Docket No. 2018-0088. November 2018.

Before the Public Utilities Commission of South Carolina. Joint Application and Petition of South Carolina Electric & Gas Company and Dominion Energy, Incorporated for Review and Approval of a Proposed Business Combination between SCANA Corporation and Dominion

Energy, Incorporated, as May Be Required, and for a Prudency Determination Regarding the Abandonment of the V.C. Summer Units 2 & 3 Project and Associated Customer Benefits and Cost Recovery Plan. Docket Nos. 2017-370-E; 2017-305-E; 2017-207-E. November 2018.

Before the Public Utilities Commission of Rhode Island In Re: National Grid Application to Change Electric and Gas Distribution Revenue Requirements and Associated Rates. Docket No. 4780. April 2018.

Before the Public Utility Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of General Rate Case and Revised Rate Schedules and Rules. Docket No. 2016-0328. Topic: Proposal for Incentive Based Regulation.

Before the Massachusetts Department of Public Utilities. Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00. April 2017. Topic: Proposal for Incentive Based Regulation.

Before the Public Utilities Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC., MAUI ELECTRIC COMPANY, LIMITED, and NEXTERA ENERGY, INC., For Approval of the Proposed Change of Control and Related Matters. "Testimony of Ronald J. Binz." January 2016. Topic: Conditions to be attached to merger approval.

Before the Public Service Commission of New York. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Case 14-M-0101. "Statement of Ronald J. Binz on Behalf of Earthjustice in Reply to Parties' Initial Comments on the Staff Straw Proposal" October 2014. Topic: Regulatory approach in the Commission's REV proposal.

Before the Public Service Utilities Commission of Hawaii. Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited. Docket No. 2013-0141. "Declaration of Ronald J. Binz." September 2014. Topic: Proposal for Incentive Regulation of HECO.

Before the Public Utilities Commission of California. Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements. Rulemaking 13-09-011. Comments and oral testimony of Ronald J. Binz before the Administrative Law Judge. August 2014.

Before the Public Service Commission of Wyoming. In the Matter of Rocky Mountain Power's Confidential Contract Filing Docket No. 20000-379-EK-10 of a Purchase Power Agreement between PacifiCorp and Pioneer Wind Park I. Binz Affidavit on behalf of Northern Laramie Range Alliance. Record No. 12618 (August 2011)

Before the West Virginia Public Service Commission. In the Matter of the Petition of Verizon West Virginia, Inc. To Cease Rate Regulation of Certain Workably Competitive Telecommunications Services. Case No. 06-0481-T-PacifiCorp (June 2006)

Before the Utah Public Service Commission. In the Matter of The Division's Annual Review and Evaluation of Electric Lifeline Program, HELP Rate Design Testimony. Docket No. 04-035-21 (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Rebuttal Testimony. Docket No. 05F-167G. (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Direct Testimony. Docket No. 05F-167G. (June 2005)

Before the Michigan Public Service Commission. Testimony on behalf of the Michigan Attorney General. In the Matter of SBC Michigan's Request for Classification of Business Local Exchange Service as Competitive Pursuant to Section 208 Of the Michigan Telecommunications Act. Case No. U-14323. (March 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel. In the Matter of the Combined Application of Qwest Corporation for Reclassification and Deregulation of Certain Part 2 Products and Services and Deregulation of Certain Part 3 Products and Services. Docket No. 04A-411T. (February 2005)

Before the Utah Public Service Commission. In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Rate Design Testimony. Docket No. 04-035-42. (January 2005)

Before the Utah Public Service Commission. In the Matter of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Revenue Requirements Testimony. Docket No. 04-035-42. (December 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Building Owners and Managers Association of Metropolitan Denver (BOMA) in the Matter of The Investigation and Suspension of Tariff Sheets Filed by Public Service Company of Colorado with Advice Letter No. 1411—Electric Docket No. 04S-164E (October 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of The Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. Docket No. 04A-214E (filed: September 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of the Application of Public Service Company of Colorado for an Order

Authorizing It to Implement a Purchased Capacity Cost Adjustment Rider in Its PUC No. 7 – Electric Tariff. Docket No. 03A-436E. (Filed: March 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of Wyoming Industrial Energy Consumers (WIEC) and AARP In the Matter of the Application of PacifiCorp for Approval of a Power Cost Adjustment Mechanism. Docket No. 20000- ET-03-205 (filed: January 2004).

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel Regarding the Unbundling Obligations of Incumbent Local Exchange Carriers Pursuant to The Triennial Review Order – Initial Commission Review. Docket No. 03I-478T. (January 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of The Application of PacifiCorp for A Retail Electric Utility Rate Increase Of $41.8 Million Per Year Docket No. 20000-ER-03-198 (January 2004).

Before the Wyoming Public Service Commission. Public hearings testimony on behalf of AARP in the matter of an application by Kinder Morgan to modify the provider selection process in its Choice Gas Program. (December 2003).

Before the Public Service Commission of North Dakota. Testimony on behalf of AARP in the matter of In the Matter of the Notice of Montana-Dakota Utilities Co. for an Electric Rate Change. Case No. PU-399-03-296. (October 2003)

Before the Colorado Public Utilities Commission. Testimony in the matter of Public Service Company of Colorado's Advice Letter No. 598 – Natural Gas Extension Policy. Docket No. 02S-574G. (March 2003)

Before the Colorado Public Utilities Commission. Testimony in the remand hearings in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (January 2003)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning a Proposed General Rate Increase and Surcharge for Previous Power Costs. (November 2002).

Before the Colorado Public Utilities Commission. Comments on behalf of the Colorado Energy Assistance Foundation. Docket No. 02R-196G. In the Matter of the Proposed Repeal and Reenactment of the Rules Regulating Gas Utilities. (November 2002)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Assistance Foundation and Catholic Charities of the Archdiocese of Denver. Docket No. 02A-158E. In the Matter of the Application of Public Service Company of Colorado for an Order to Revise its Incentive Cost Adjustment. (April 2002)

Before the Idaho Public Utilities Commission. Testimony on behalf of Astaris, in the matter of Case No. IPC-E-01-43 concerning the buy-back rates under an electric load reduction program. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in matter of the investigation of Advice Letters 579 and 581 of Xcel Energy on behalf of Homebuilders Association of Denver. Dockets 01S-365G and 01S-404G. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (August 2001)

Before the Colorado Public Utilities Commission. Testimony in the matter of the investigation and suspension of Advice Letter No. 566 of Xcel Energy on behalf of the Homebuilders Association of Metropolitan Denver. Docket No. 00S-422G. (November 2000)

Before the American Arbitration Association. In the Matter of Univance Telecommunications, Inc. v. Venture Group Enterprises, Inc. Arbitration No. 77 Y 147 00099 00 (November 2000)

Testimony of Ronald Binz at FCC Public Forum on SBC/Ameritech merger (May 1999)

Docket No. 97-106-TC -- Testimony of Ron Binz before New Mexico State Corporation Commission on Investigation Concerning USWest's Compliance with Section 271(c) of the Telecommunications Act (July 1998)

Before the Colorado Public Utilities Commission. Testimony Concerning the Investigation of Telephone Numbering Policies. (March 1998)
Docket No. 6717-U □ Testimony before the Georgia Public Service Commission Concerning the Service Provider Selection Plan of Atlanta Gas Company. (January 1997)

Case 96-C-0603 and Case 96-C-0599--Testimony of Ronald J. Binz on behalf of CPI before the New York State Public Service Commission concerning the Bell Atlantic/NYNEX Merger (November 1996)

Docket No. 96-388 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of the Office of the Public Advocate (October 1996) State of Maine, Public Utilities Commission Joint Petition of New England Telephone and Telegraph Company and NYNEX Corporation for Approval of the Proposed Merger of a Wholly-Owned Subsidiary of Bell Atlantic Corporation into NYNEX Corporation.

Application No. 96-04-038 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of Intervener, Utility Consumers Action Network (September 1996) Before the Public Utilities Commission of the State of California in the Matter of the Joint Application of Pacific Telesis Group (Telesis) and

SBC Communications (SBC) for SBC to Control Pacific Bell (U 1001 C), Which Will Occur Indirectly as a Result of Telesis' Merger with a Wholly Owned Subsidiary of SBC, SBC Communications (NV) Inc.

Presentation to Federal-State Joint Board on Universal Service (April 12, 1996)

Testimony before the Texas Public Utility Commission on the Integrated Resource Planning Rule (March 1996)

Congressional Testimony

Mr. Binz has appeared sixteen times before U.S. House and Senate Committees. In addition, he has testified numerous times before state legislatures in several states. Here is a list of his U.S. Congressional testimony and statements:

United States Senate Energy and Natural Resources Committee, 2013. Statement in support of my nomination to the Federal Energy Regulatory Commission.

United States House of Representatives Commerce Committee, Energy Subcommittee, 2008. Testimony concerned a proposal to adopt a federal renewable energy standard.

United States House of Representatives Judiciary Committee, November 1999. Testimony concerning H.R. 2533, The Fairness in Telecommunications License Transfer Act of 1999.

United States Senate Judiciary Committee; Antitrust, Business Rights and Competition Subcommittee, April 1999. Testimony concerning S.467, The Antitrust Merger Review Act.

United States Senate Commerce Committee, Telecommunications Subcommittee, May 1998. Testimony in oversight hearings concerning the performance of the Common Carrier Bureau of the Federal Communications Commission.

United States Senate Judiciary Committee, Washington, D.C., September 1996. Presented testimony on behalf of the Competition Policy Institute on the competitive impact of proposed mergers of Regional Bell Operating Companies.

United States House of Representatives Subcommittee on Telecommunications and Finance of the Committee on Commerce, May 1995. Testimony presenting NASUCA’s position on H.R. 1555 by Representative Fields.

United States Senate Subcommittee on Antitrust, Washington, D.C., September 1994. Testimony presenting NASUCA's position on S. 1822 by Senator Hollings.

United States House of Representatives Subcommittee on Telecommunications and Finance of the House Energy and Commerce Committee, Washington, D.C., February 1994. Presented testimony on H.R. 3636.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., October 1992. Supplemental testimony presenting NASUCA's position on legislation concerning the Modified Final Judgment introduced by Representative Brooks.

United States House of Representatives Subcommittee on Telecommunications and Finance, Washington, D.C., October 1991. Testimony on RBOC entry into telecommunications manufacturing and information services.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., August 1991. Testimony presenting NASUCA's position on possible federal legislation concerning the Modified Final Judgment.

United States Senate Subcommittee on Energy Regulation and Conservation, Denver, Colorado, April 1991. Testimony presenting NASUCA's position on federal legislation concerning regulation of the natural gas industry, introduced by Senator Wirth.

United States Senate Communications Subcommittee, Washington, D.C., February 1991. Testimony on behalf of NASUCA concerning S.173, telecommunications legislation introduced by Senator Ernest Hollings.

United States Senate Communications Subcommittee, Washington, D.C., July 1990. Testimony on behalf of NASUCA concerning S.2800, telecommunications legislation introduced by Senator Conrad Burns.

United States House of Representatives Subcommittee on Telecommunications and Finance, July 1988. Testimony on the FCC Price Cap proposal.

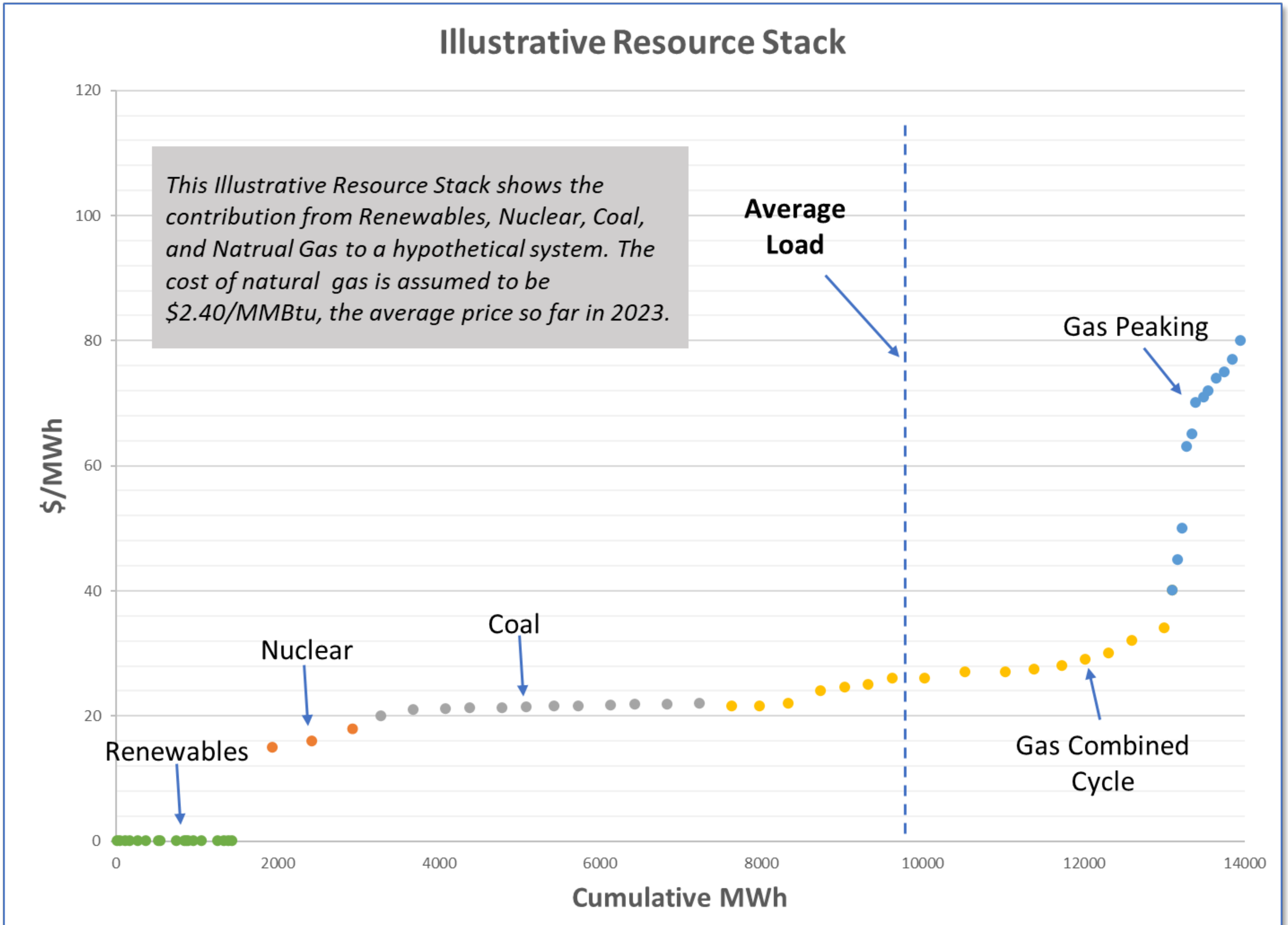
Reports and Articles

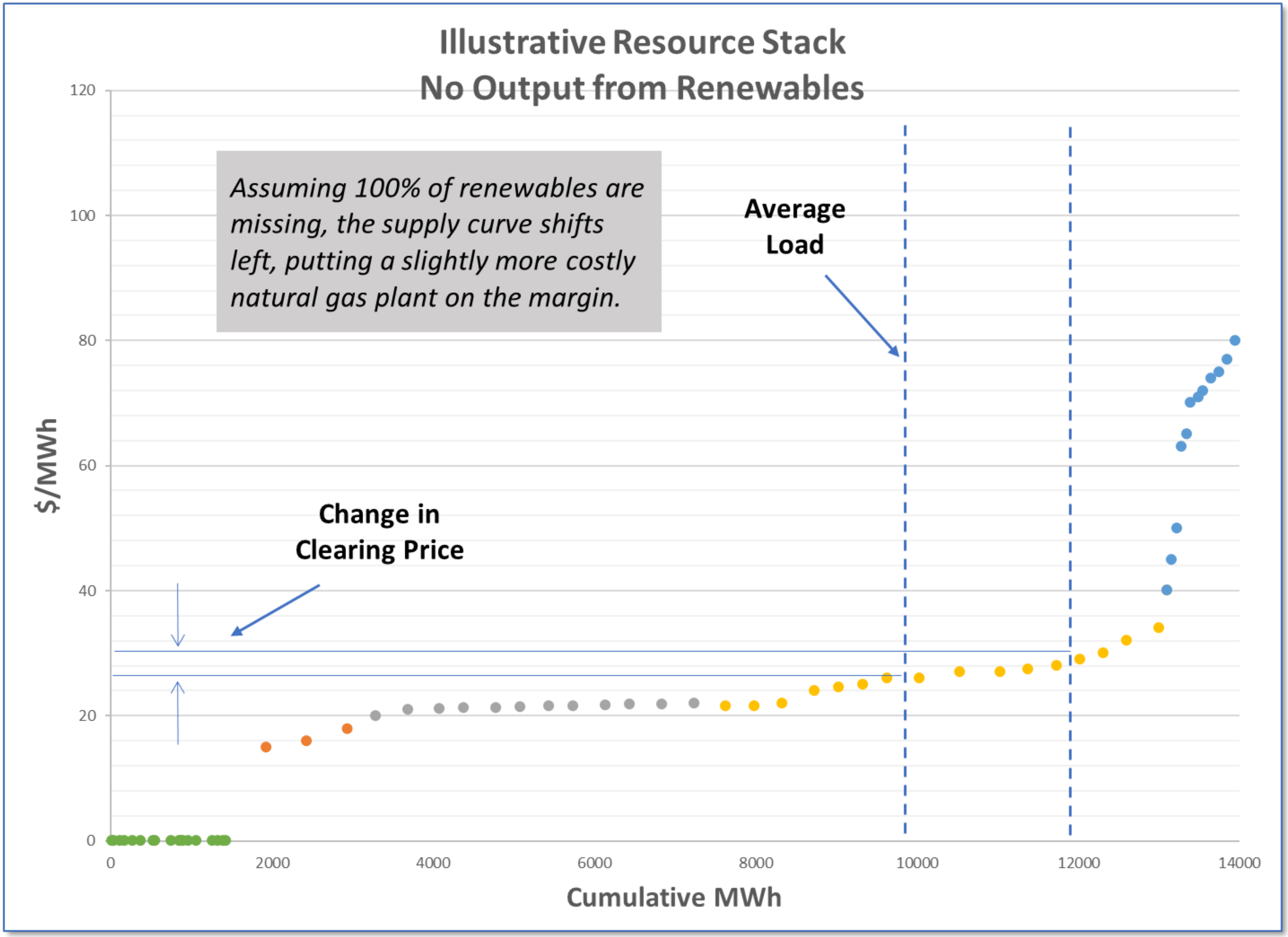
Title	Publisher	Date
Considerations for the Governance of a Western Regional System Operator	Public Policy Consulting	March 2016
Practicing Risk Aware Electricity Regulation: 2014 Update	Ceres	November 2014
Priorities after FERC Overture	EnergyBiz Magazine	Jan-Feb 2014
Risk-Aware Planning and a New Model for the Utility-Regulator Relationship	ElectricityPolicy.com	July 2012
Practicing Risk Aware Electricity Regulation: What Every State Regulator Needs to Know	Ceres	April 2012
Conquering Consumer Resistance: Time to cross the bridge to time-of-use rates	EnergyBiz Magazine	March-April 2012
Cap and Innovate: An alternative approach to climate regulation.	Public Utilities Fortnightly	June 2010
Wind on the Public Service Company of Colorado System: Cost Comparison to Natural Gas	Interwest Energy Alliance (with Jane Pater)	August 2006
The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado	Public Policy Consulting	September 2004
The Impact a Renewable Energy Portfolio Standard on Retail Electric Rates in Colorado	Public Policy Consulting	February 2004
Qwest, Consumers and Long-Distance Entry: A Discussion Paper	Public Policy Consulting	October 2001
Addressing Market Power: The next step in electric restructuring	Competition Policy Institute	June 1998
Navigating a Course to Competition: A consumer perspective on electric restructuring	Competition Policy Institute	August 1997

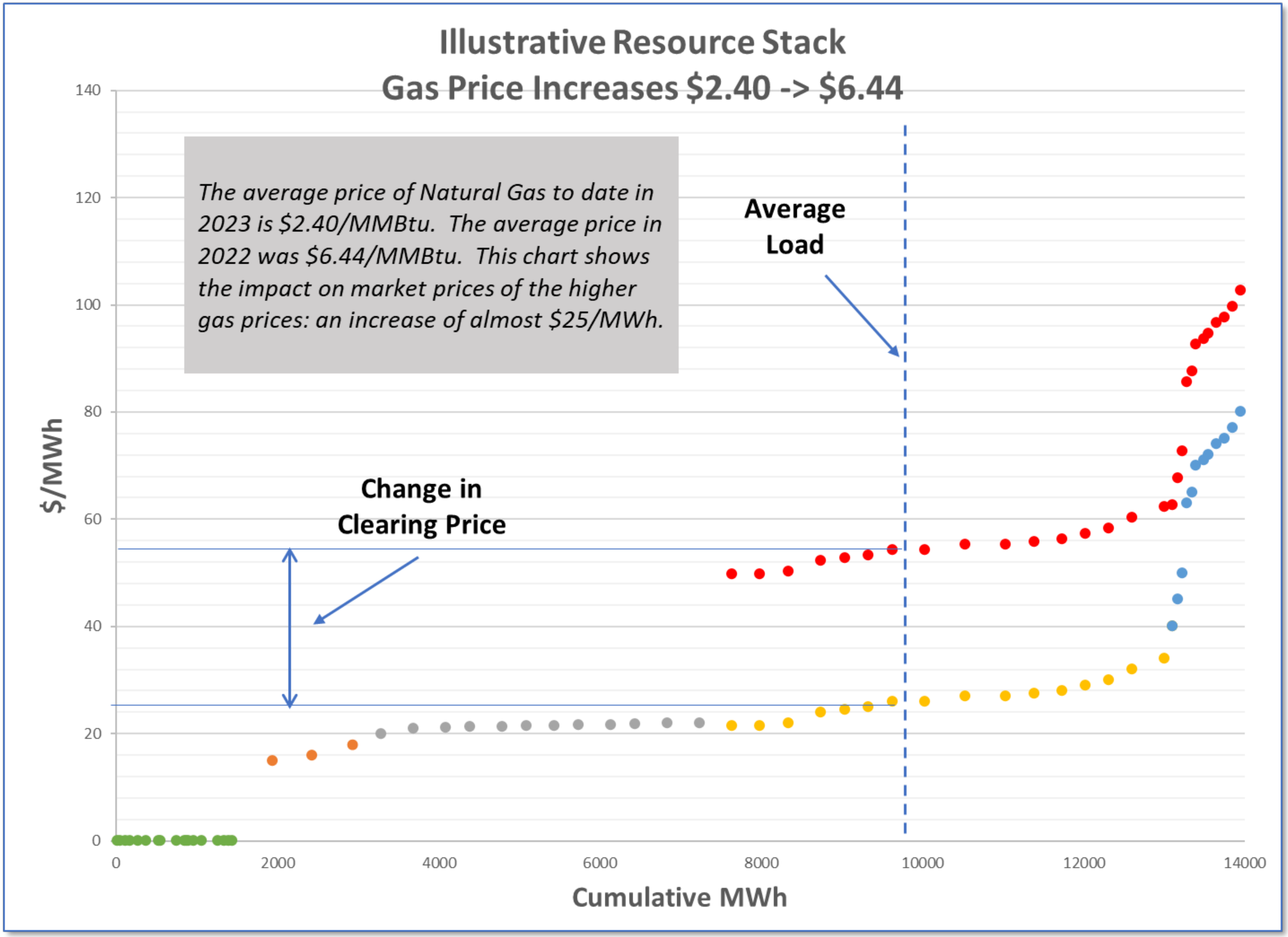
DOCKET NO.: 20000-633-ER-23
RECORD NO.: 17252
WITNESS: RONALD J. BINZ
EXHIBIT: 302

DIRECT TESTIMONY AND EXHIBITS OF RONALD BINZ ON BEHALF OF SIERRA CLUB

EXHIBIT 302
ILLUSTRATIVE RESOURCES STACK


Illustrative Resource Stack
This Illustrative Resource Stack shows the contribution from Renewables, Nuclear, Coal, and Natrual Gas to a hypothetical system. The cost of natural gas is assumed to be $2.40/MMBtu, the average price so far in 2023.
Average Load
Gas Peaking
Coal
Nuclear
Renewables
Gas Combined Cycle
$/MWh
120
100
80
60
40
20
0
0
2000
4000
6000
8000
10000
12000
14000
Cumulative MWh


Illustrative Resource Stack
No Output from Renewables
Assuming 100% of renewables are missing, the supply curve shifts left, putting a slightly more costly natural gas plant on the margin.
Average Load
Change in Clearing Price
$/MWh
120
100
80
60
40
20
0
0
2000
4000
6000
8000
10000
12000
14000
Cumulative MWh



Illustrative Resource Stack
Gas Price Increases $2.40 -> $6.44
The average price of Natural Gas to date in 2023 is $2.40/MMBtu. The average price in 2022 was $6.44/MMBtu. This chart shows the impact on market prices of the higher gas prices: an increase of almost $25/MWh.
Average Load
Change in Clearing Price
$/MWh
0
20
40
60
80
100
120
140
0
2000
4000
6000
8000
10000
12000
14000
Cumulative MWh

DOCKET NO.: 20000-633-ER-23

RECORD NO.: 17252

WITNESS: RONALD J. BINZ

EXHIBIT: 303

DIRECT TESTIMONY AND EXHIBITS OF RONALD BINZ
ON BEHALF OF SIERRA CLUB

EXHIBIT 303
LAZARD 2023 LEVELIZED COST OF ENERGY ANALYSIS

Exhibit 303

APRIL 2023

LCOE+

LAZARD

With support from Roland Berger

Exhibit 303

Table of Contents

Exhibit 303

APRIL 2023

I Lazard's Levelized Cost of Energy Analysis—Version 16.0

LAZARD

Introduction

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

- **Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities 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 utility-scale generation technologies**
- **Illustration of the historical LCOE declines for onshore wind and utility-scale solar technologies**
- **Comparison of capital costs on a $/kW basis for various generation technologies**
- **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**
- **Considerations regarding the operating characteristics and applications of various generation technologies**
- **Appendix materials, including:**
  - An overview of the methodology utilized to prepare Lazard's LCOE analysis
  - A summary of the assumptions utilized in Lazard's LCOE analysis

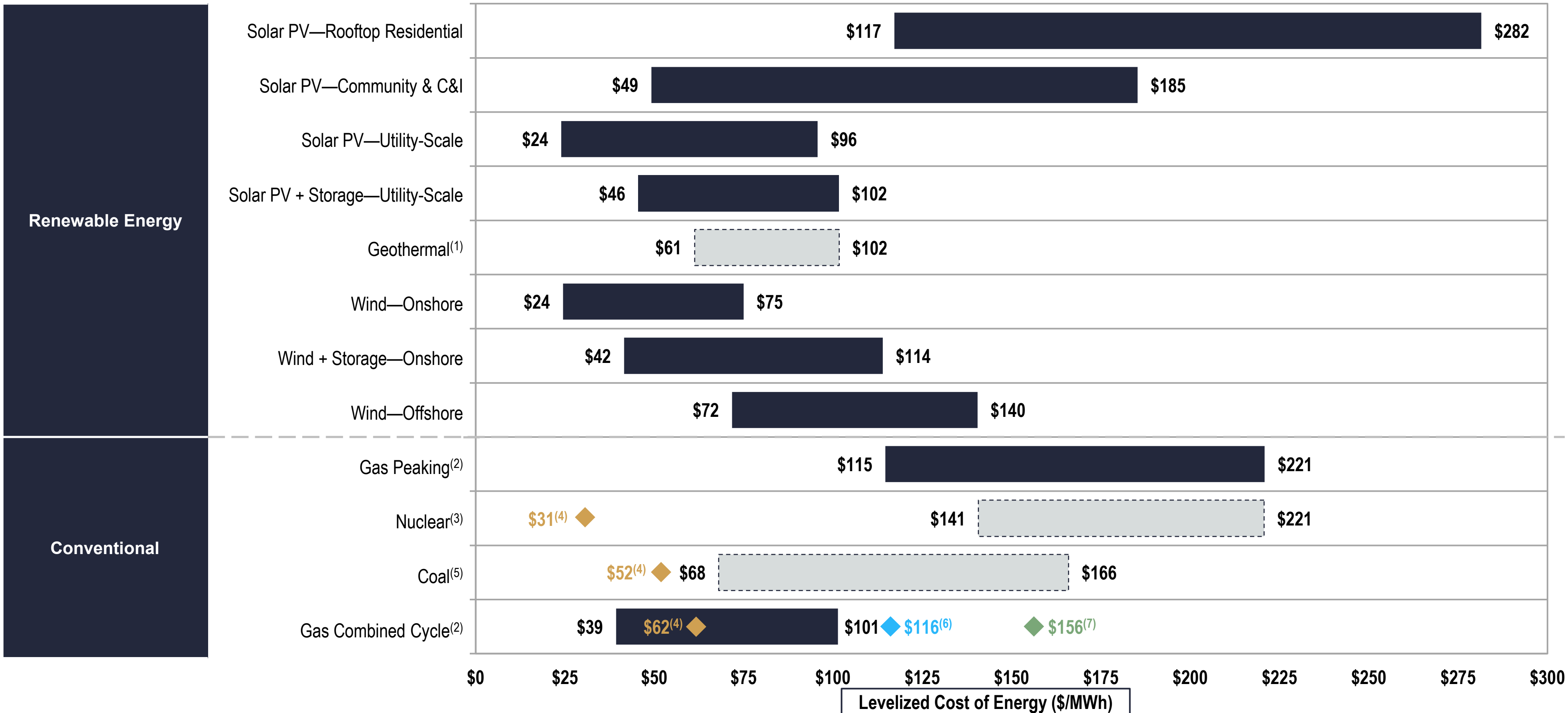
Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: implementation and interpretation of the full scope of the Inflation Reduction Act ("IRA"); network upgrades, transmission, congestion 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 also does not address potential social and environmental externalities, including, for example, the social costs and rate consequences for those who cannot afford distributed generation solutions, as well as the long-term residual and societal consequences of various conventional generation technologies that are difficult to measure (e.g., nuclear waste disposal, airborne pollutants, greenhouse gases, etc.)

LAZARD

Note: This report has been compiled using U.S.-focused data.

Levelized Cost of Energy Comparison—Unsubsidized Analysis

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



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

Note: Here and throughout this presentation, 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 data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.

(2) The fuel cost assumption for Lazard's unsubsidized analysis for gas-fired generation resources is $3.45/MMBTU for year-over-year comparison purposes. See page titled "Levelized Cost of Energy Comparison—Sensitivity to Fuel Prices" for fuel price sensitivities.

(3) Given the limited public and/or observable data set available for new-build nuclear projects and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation (results are based on then-estimated costs of the Vogtle Plant and are U.S.-focused).

(4) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, 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—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies" for additional details.

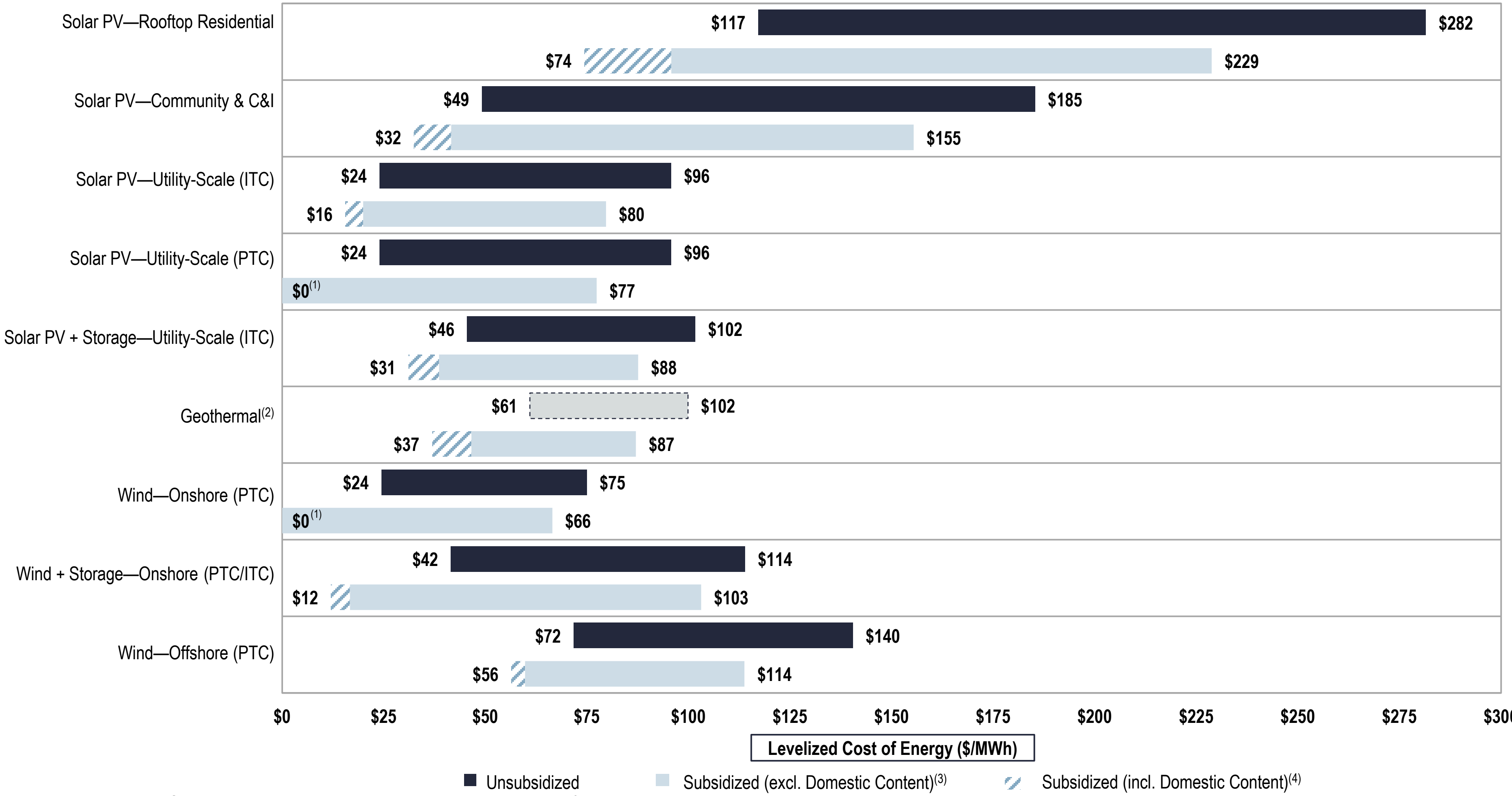
(5) Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation. High end incorporates 90% carbon capture and storage ("CCS"). Does not include cost of transportation and storage.

(6) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Blue" hydrogen, (i.e., hydrogen produced from a steam-methane reformer, using natural gas as a feedstock, and sequestering the resulting CO_2 in a nearby saline aquifer). No plant modifications are assumed beyond a 2% adjustment to the plant's heat rate. The corresponding fuel cost is $5.20/MMBTU, assuming ~$1.40/kg for Blue hydrogen.

(7) Represents the LCOE of the observed high case gas combined cycle inputs using a 20% blend of "Green" hydrogen, (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% adjustment to the plant's heat rate. The corresponding fuel cost is $10.05/MMBTU, assuming ~$4.15/kg for Green hydrogen.

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

The Investment Tax Credit ("ITC"), Production Tax Credit ("PTC") and domestic content adder, among other provisions in the IRA, are important components of the levelized cost of renewable energy generation 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., energy community 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) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Lazard's Unsubsidized 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 Solar PV—Utility-Scale (PTC) equals 17% (excl. Domestic Content) and 22% (incl. Domestic Content) and implied IRRs at this level for Wind—Onshore (PTC) equals 17% (excl. Domestic Content) and 25% (incl. Domestic Content).

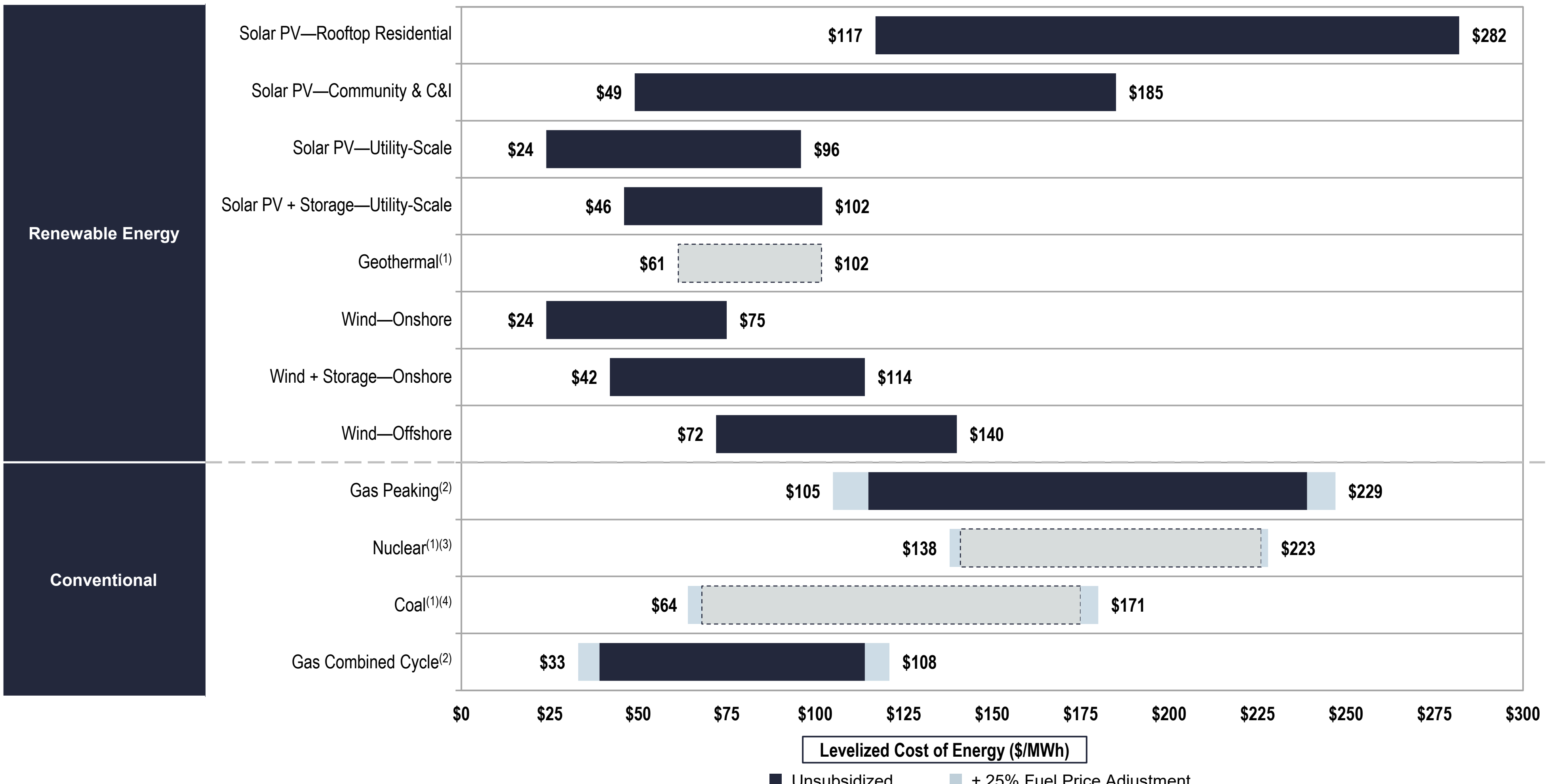
(2) Given the limited public and/or observable data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjustment for inflation.

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

(4) This sensitivity analysis assumes the above and also includes a 10% domestic content adder.

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 unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

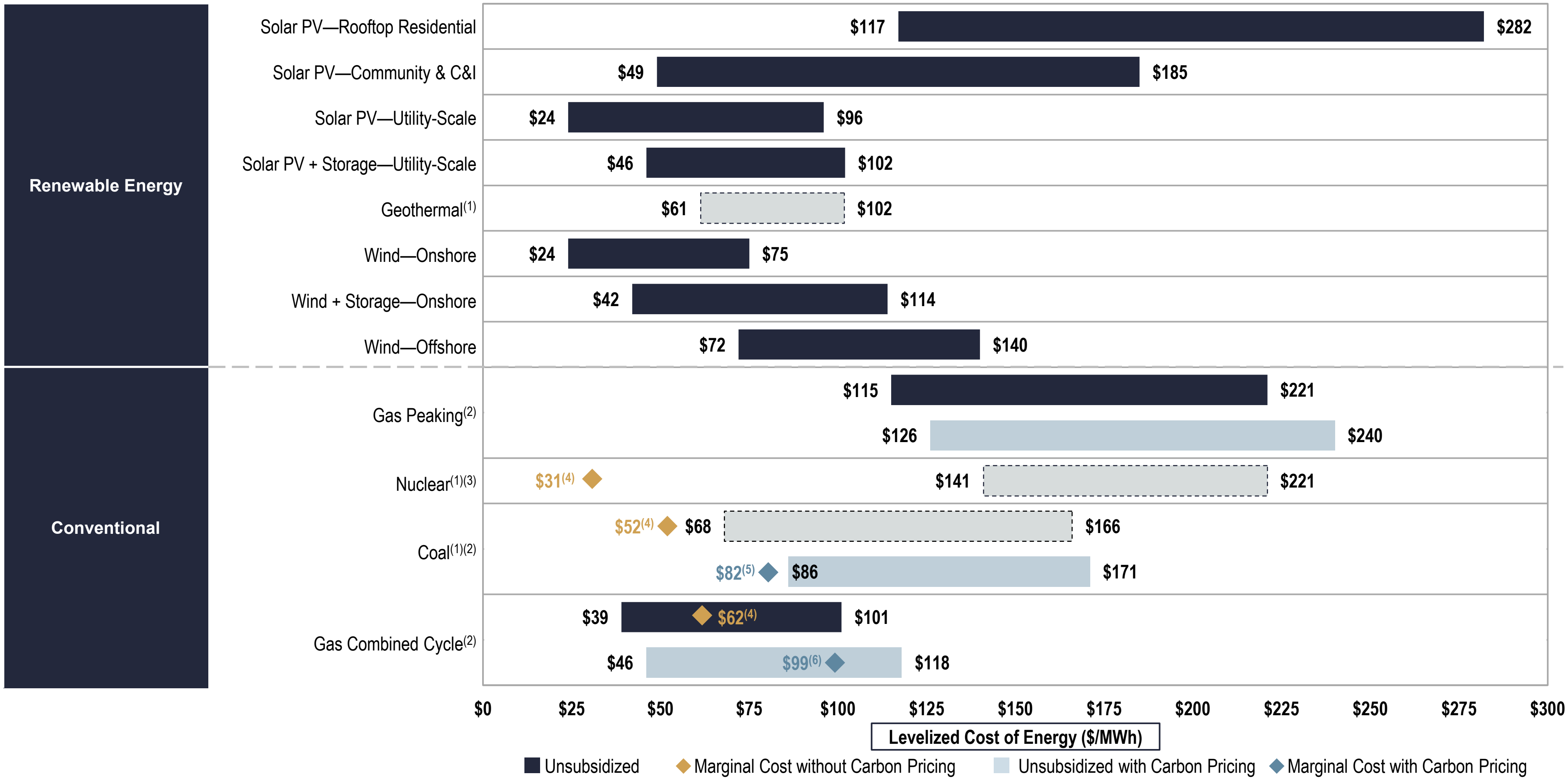
(2) Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a sensitivity range of ± 25% of the $3.45/MMBTU used in the Unsubsidized Analysis).

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

(4) 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 Unsubsidized Analysis).

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 $20 – $40/Ton of carbon would increase the LCOE for certain conventional generation technologies relative to those of onshore wind and utility-scale solar



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 unsubsidized analysis as presented on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

(2) The low and high ranges reflect the LCOE of selected conventional generation technologies including illustrative carbon prices of $20/Ton and $40/Ton, respectively.

(3) The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA (e.g., nuclear subsidies) are not included in our analysis and could impact outcomes.

(4) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle or coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, 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—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies" for additional details.

(5) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated coal facilities with illustrative carbon pricing. Operating coal facilities are not assumed to employ CCS technology.

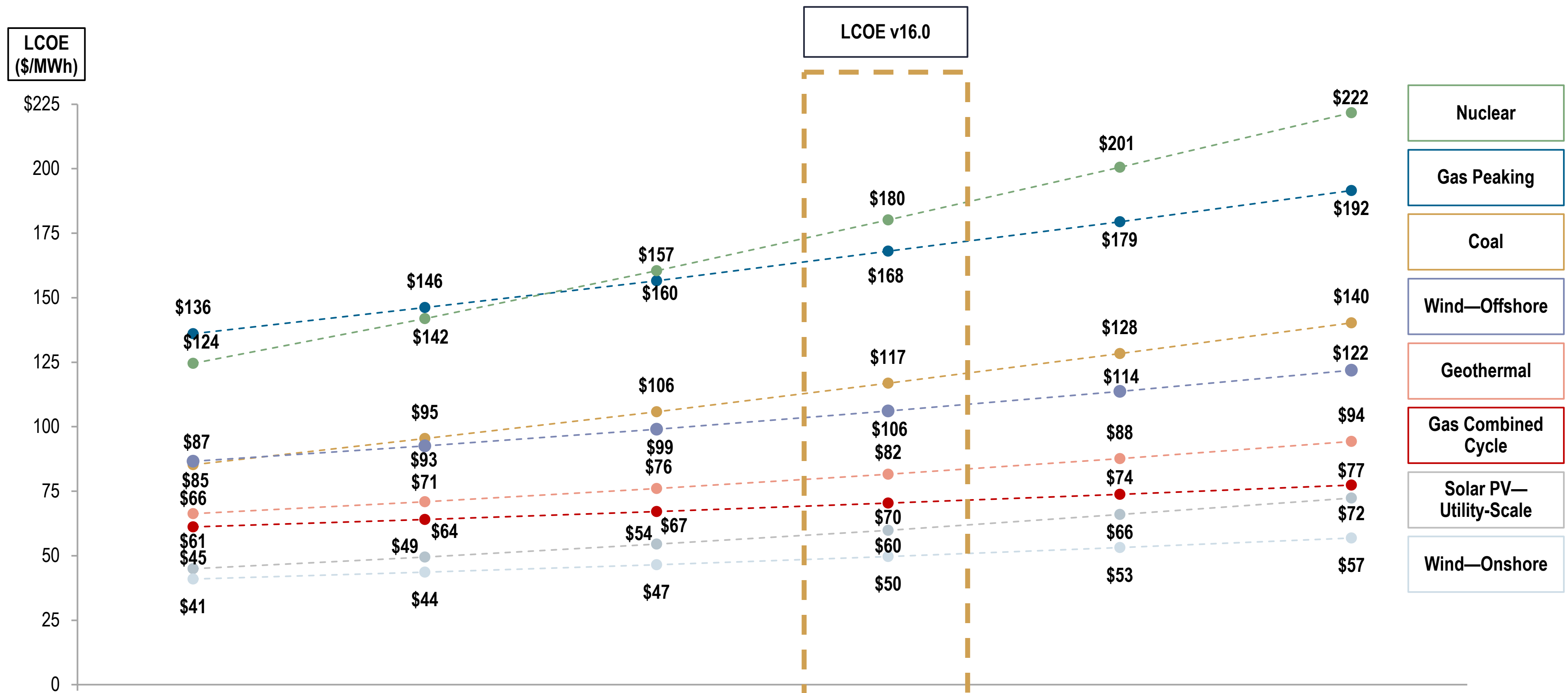
(6) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated gas combined cycle facilities with illustrative carbon pricing.

Exhibit 303

Levelized Cost of Energy Comparison—Sensitivity to Cost of Capital

A key consideration in determining the LCOE values for utility-scale generation technologies is the cost, and availability, of capital[(1)]; this dynamic is particularly significant for renewable energy generation technologies

Midpoint of Unsubsidized 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.

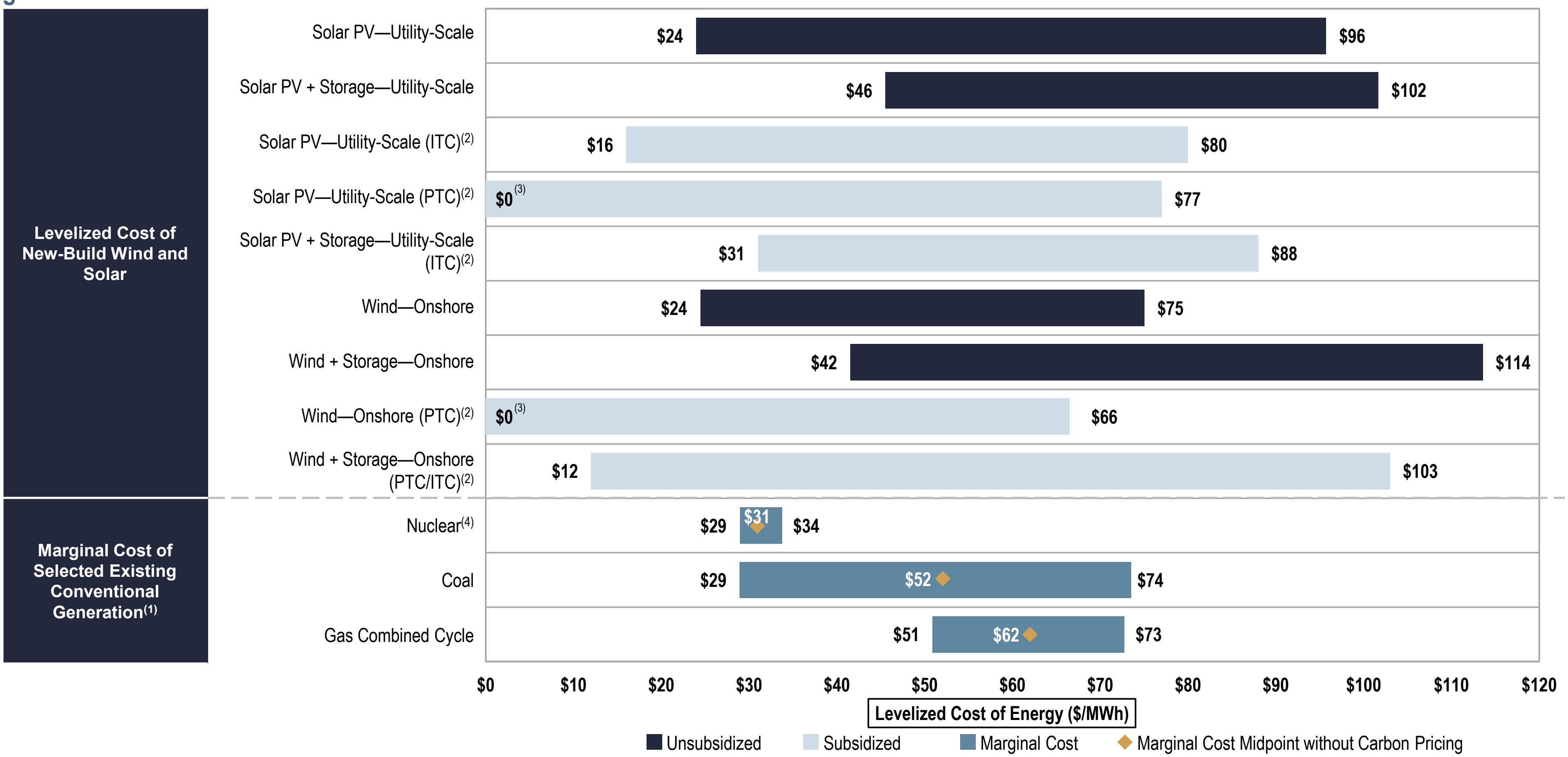
Note: Analysis assumes 60% debt and 40% equity. Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".

(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—Renewable Energy versus Marginal Cost of Selected Existing Conventional Generation Technologies

Certain renewable energy generation technologies have an LCOE that is competitive with the marginal cost of existing conventional generation



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—Unsubsidized Analysis".

(1) Represents the marginal cost of operating fully depreciated gas combined cycle, coal and nuclear facilities, inclusive of decommissioning costs for nuclear facilities. Analysis assumes that the salvage value for a decommissioned gas combined cycle and coal asset is equivalent to its decommissioning and site restoration costs. Inputs are derived from a benchmark of operating gas combined cycle, 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. Assumes a fuel cost of $0.79/MMBTU for Nuclear, $3.11/MMBTU for Coal and $6.85/MMBTU for Gas Combined Cycle.

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

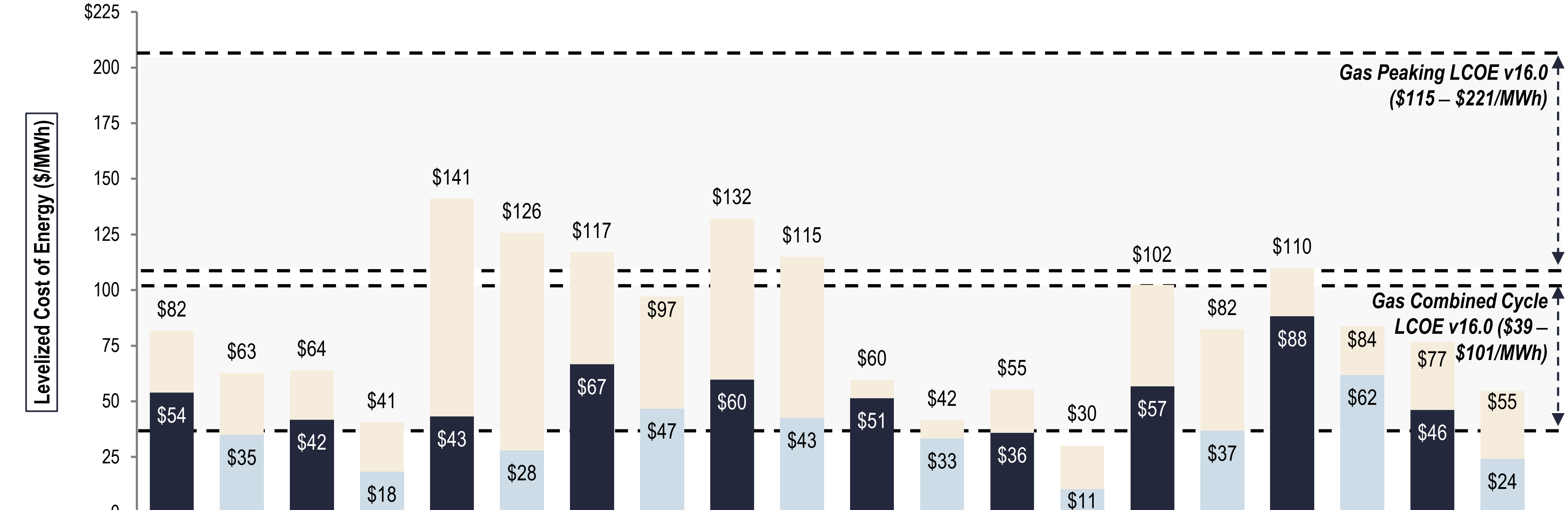
(3) Results at this level are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Lazard's Unsubsidized LCOE analysis assumes, for year-over-year reference purposes, 60% debt at an 8% interest rate and 40% equity at a 12% cost (together implying an after-tax IRR/WACC of 7.7%). Implied IRRs at this level for Solar PV—Utility-Scale (PTC) equals 17% (excl. Domestic Content) and 22% (incl. Domestic Content) and implied IRRs at this level for Wind—Onshore (PTC) equals 17% (excl. Domestic Content) and 25% (incl. Domestic Content).

(4) The IRA is comprehensive legislation that is still being implemented and remains subject to interpretation—important elements of the IRA (e.g., nuclear subsidies) are not included in our analysis and could impact outcomes.

Levelized Cost of Energy Comparison—Cost of Firming Intermittency

The incremental cost to firm[(1)] intermittent resources varies regionally, depending on the current effective load carrying capability ("ELCC")[(2)] values and the current cost of adding new firming resources—carbon pricing, not considered below, would have an impact on this analysis

LCOE v16.0 Levelized Firming Cost ($/MWh)[(3)]



	Solar	Wind	Solar	PV + Storage	Wind	Solar	Wind	Solar	PV + Storage	Wind
ELCC	50%	16%	7%	51%[(4)]	15%	85%	17%	38%	70%[(4)]	15%
Capacity Factor	20%	43%	25%	25%	30%	21%	50%	19%	19%	39%
Resource Penetration	3%	25%	32%	32%	19%	1%	56%	5%	5%	7%
	MISO		CAISO			SPP		PJM		

■ Lazard's Unsubsidized LCOE[(3)] ■ Lazard's Subsidized LCOE[(3)] ■ Firming Cost[(1)]

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

(1) Firming costs reflect the additional capacity needed to supplement the net capacity of the renewable resource (nameplate capacity * (1 – ELCC)) and the net cost of new entry (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 CT 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 reliability contribution of different resources to the electricity grid. The ELCC of a generation resource is 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 with 0.85 MW of additional firm capacity in order to represent the addition of 1 MW of firm system capacity.

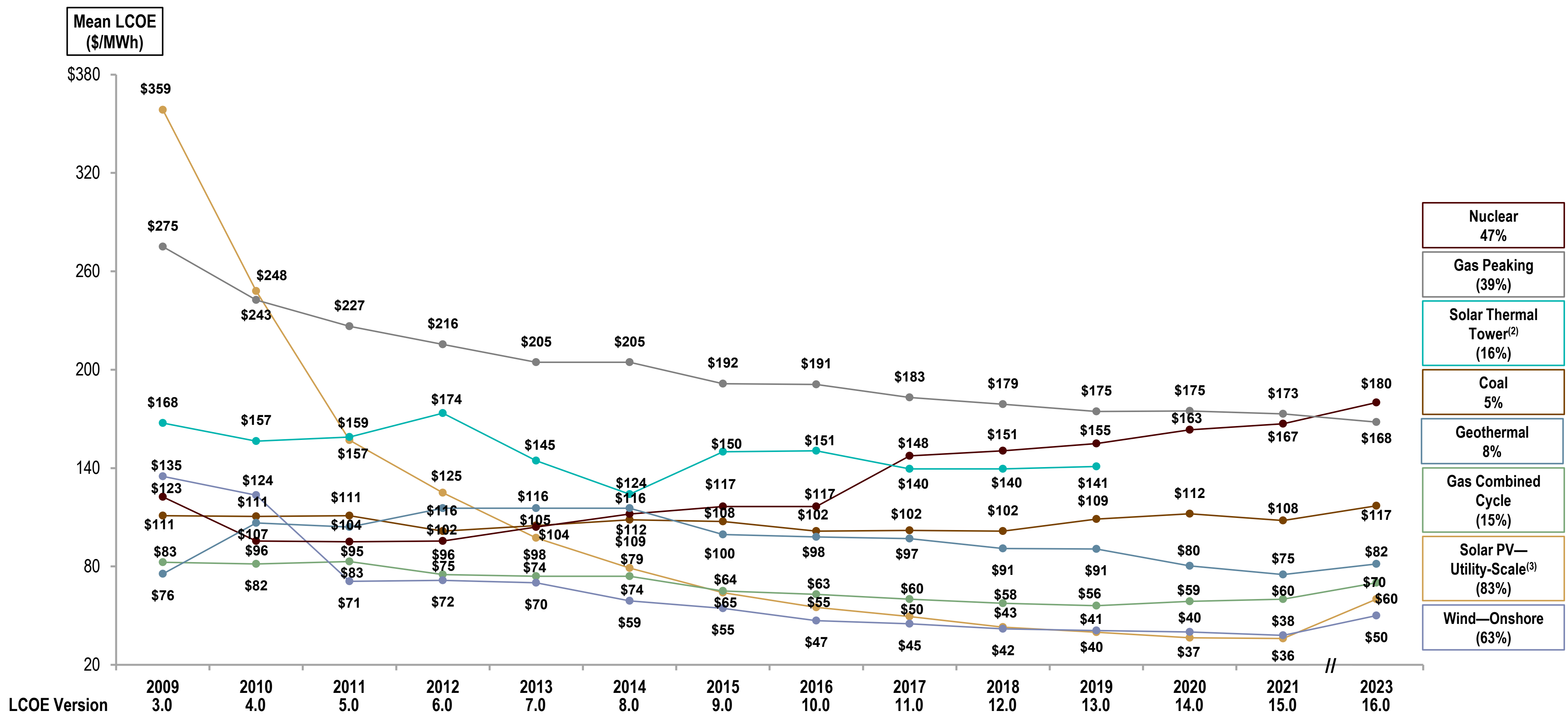
(3) LCOE values represent the midpoint of Lazard's LCOE v16.0 cost inputs for each technology adjusted for a regional capacity factor to demonstrate the regional differences in both project and firming costs.

(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% – 95% for CAISO and PJM.

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

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

Selected Historical Mean Unsubsidized 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.

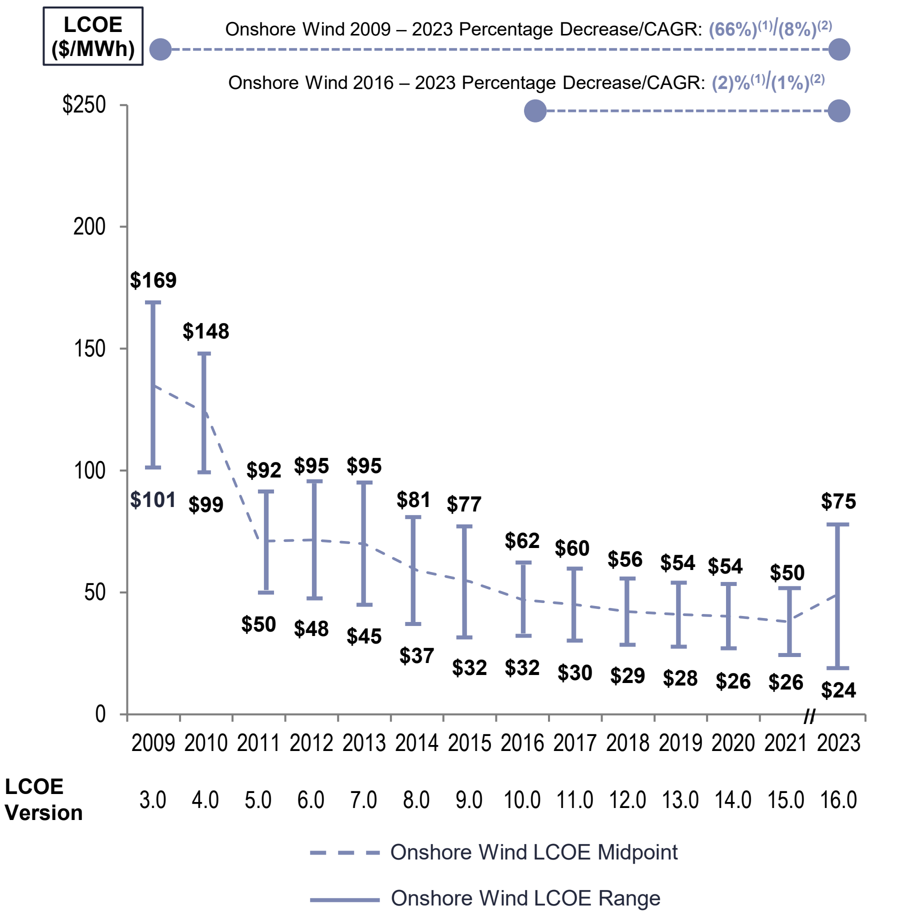
(2) The LCOE no longer analyzes solar thermal costs; percent decrease is as of Lazard's LCOE v13.0.

(3) Prior versions of Lazard's LCOE divided Utility-Scale Solar PV into Thin Film and Crystalline subcategories. All values before Lazard's LCOE v16.0 reflect those of the Solar PV—Crystalline technology.

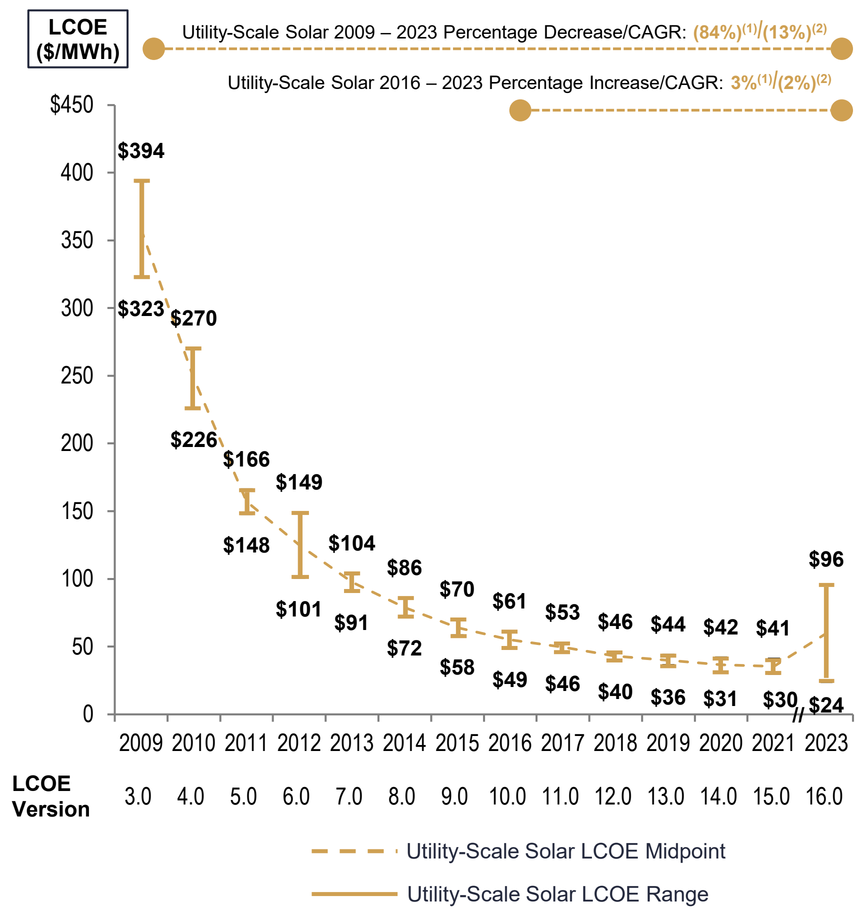
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

Even in the face of inflation and supply chain challenges, the LCOE of best-in-class onshore wind and utility-scale solar has declined at the low-end of our cost range, the reasons for which could catalyze ongoing consolidation across the sector—although the average LCOE has increased for the first time in the history of our studies

Unsubsidized Onshore Wind LCOE



Unsubsidized Solar PV LCOE



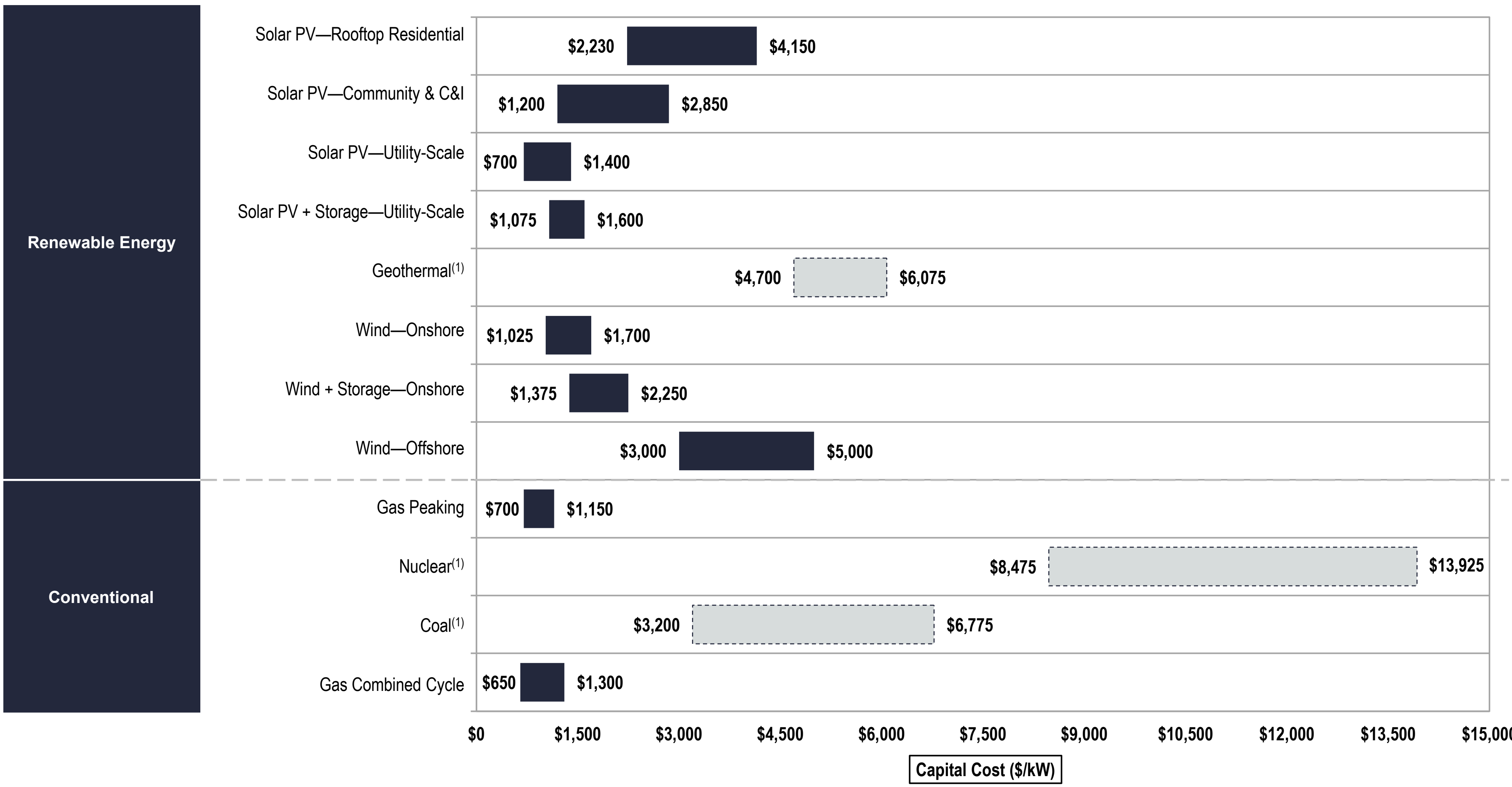
Source: Lazard and Roland Berger estimates and publicly available information.

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

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

Levelized Cost of Energy Comparison—Capital Cost Comparison

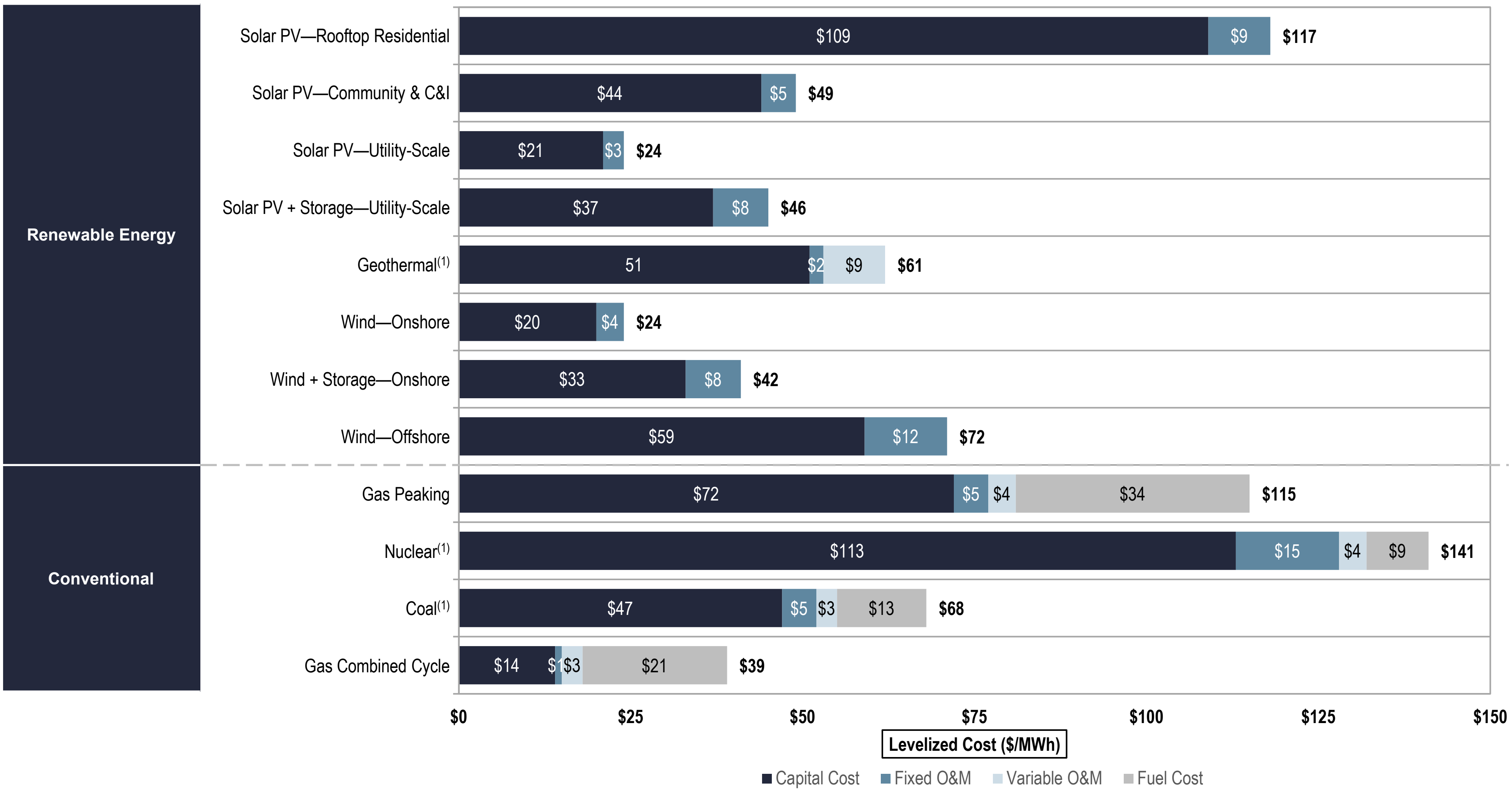
In some instances, the capital costs of renewable energy generation technologies have converged with those of certain conventional generation technologies, which coupled with improvements in operational efficiency for renewable energy technologies, have led to a convergence in LCOE between the respective technologies



Source: *Lazard and Roland Berger estimates and publicly available information.*
Notes: Figures may not sum due to rounding.
(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

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



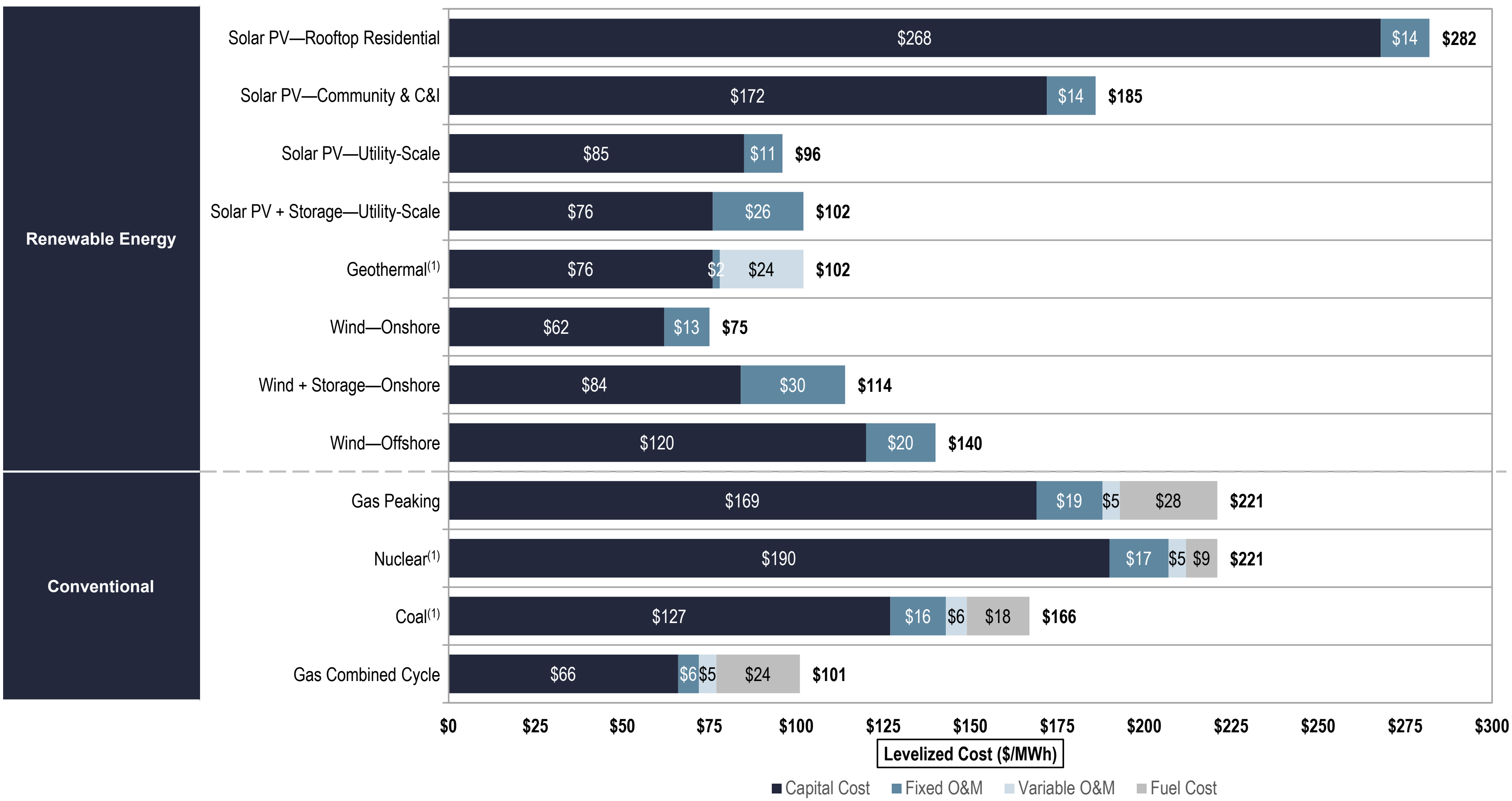
Source: Lazard and Roland Berger estimates and publicly available information.

Notes: Figures may not sum due to rounding.

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

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.

(1) Given the limited public and/or observable data set available for new-build geothermal, coal and nuclear projects, and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation and, for nuclear, are based on then-estimated costs of the Vogtle Plant and are U.S.-focused.

Energy Resources—Matrix of Applications

Despite convergence in the LCOE of certain renewable energy and conventional generation technologies, direct comparisons must take into account issues such as location (e.g., centralized vs. distributed) and dispatch characteristics (e.g., baseload and/or dispatchable intermediate capacity vs. peaking or intermittent technologies)

		Carbon Neutral/ REC Potential	Location			Dispatch			
			Distributed	Centralized	Geography	Intermittent	Peaking	Load-Following	Baseload
Renewable Energy	Solar PV[1]	✓	✓	✓	Universal	✓	✓		
	Solar PV + Storage	✓	✓	✓	Universal	✓	✓		
	Geothermal	✓		✓	Varies				✓
	Onshore Wind	✓		✓	Rural	✓			
	Onshore Wind + Storage	✓		✓	Rural	✓	✓		
	Offshore Wind	✓		✓	Coastal	✓			
Conventional	Gas Peaking	✗	✓	✓	Universal		✓	✓	
	Nuclear	✓		✓	Rural				✓
	Coal	✗		✓	Co-located or rural				✓
	Gas Combined Cycle	✗		✓	Universal			✓	✓

Source: Lazard and Roland Berger estimates and publicly available information.
(1) Represents the full range of solar PV technologies.

APRIL 2023

II Lazard's Levelized Cost of Storage Analysis—Version 8.0

LAZARD

Introduction

Lazard's Levelized Cost of Storage ("LCOS") analysis addresses the following topics:

- **Lazard's LCOS analysis**
  - Overview of the operational parameters of selected energy storage systems for each use case analyzed
  - Comparative LCOS analysis for various energy storage systems on a $/kW-year basis
  - Comparative LCOS analysis for various energy storage systems on a $/MWh basis
- **Energy Storage Value Snapshot analysis**
  - 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
  - Summary results from the Value Snapshot analysis
- **Appendix materials, including:**
  - 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, could include: implementation and interpretation of the full scope of the IRA; network upgrades, transmission, congestion 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.)

Note: This report has been compiled using U.S.-focused data.

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	① 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 report analyzes one-, two- and four-hour durations[2]	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
In-Front-of-the-Meter	② Utility-Scale (PV + Storage)	• Energy storage system designed to be paired with large solar PV facilities to better align timing of PV generation with system demand, reduce curtailment and provide grid support	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
In-Front-of-the-Meter	③ Utility-Scale (Wind + Storage)	• Energy storage system designed to be paired with large wind generation facilities to better align timing of wind generation with system demand, reduce curtailment and provide grid support	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	④ Commercial & Industrial (Standalone)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction for C&I users – Units 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	⑤ Commercial & Industrial (PV + Storage)	• Energy storage system designed for behind-the-meter peak shaving and demand charge reduction services for C&I users – Systems designed to maximize the value of the solar PV system by optimizing available revenue streams and subsidies	• Lithium Iron Phosphate (LFP) • Lithium Nickel Manganese Cobalt Oxide (NMC)
Behind-the-Meter	⑥ 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)
Behind-the-Meter	⑦ Residential (PV + Storage)	• Energy storage system designed for behind-the-meter residential home use—provides backup power, power quality improvements and extends usefulness of self-generation (e.g., PV + storage) – Regulates the power supply and smooths the quantity of electricity sold back to the grid from distributed PV applications	• 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**

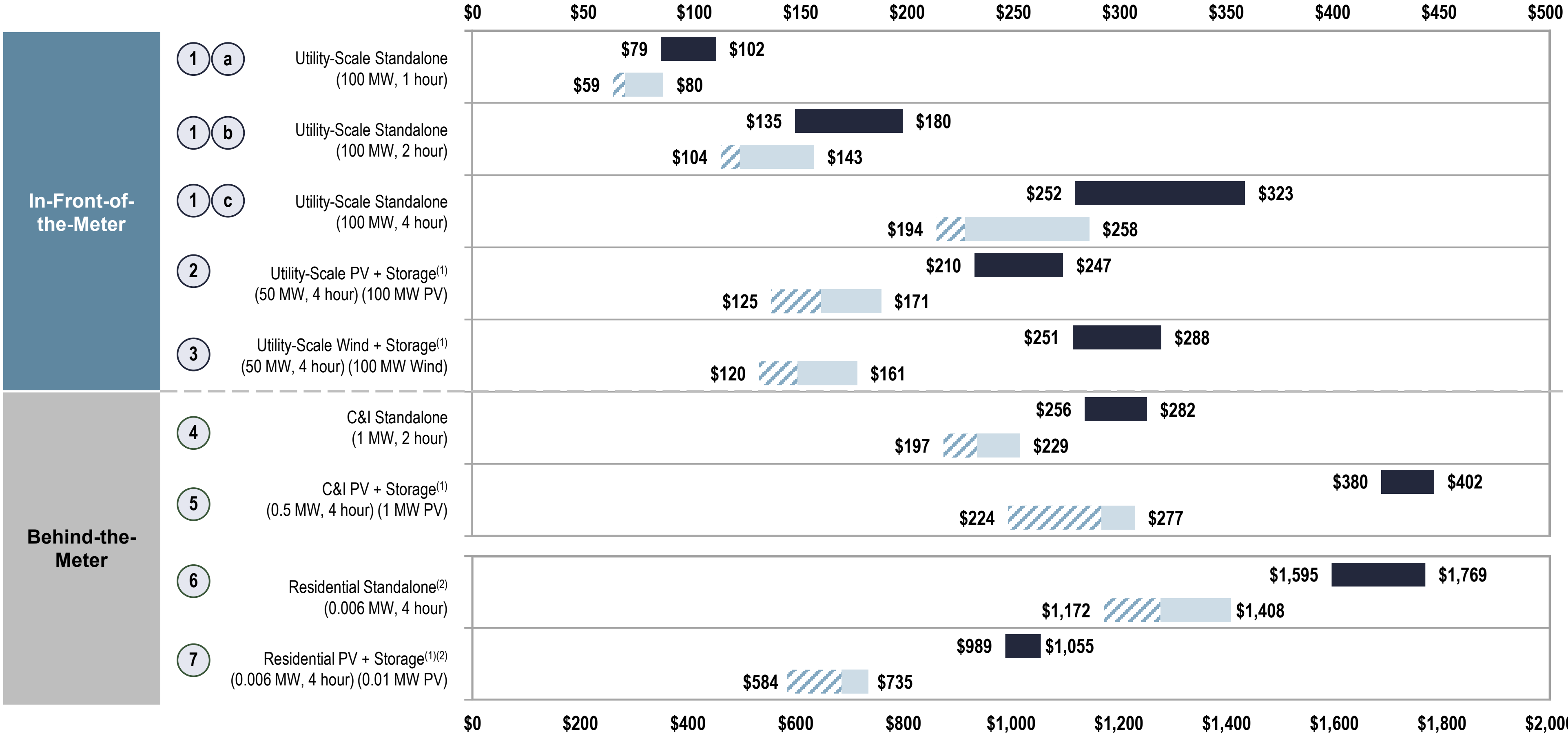
= "Usable Energy"[2]

			A Project Life (Years)	B Storage (MW)[3]	Solar/ Wind (MW)	Battery Degradation (per annum)	C Storage Duration (Hours)	D = B x C Nameplate Capacity (MWh)[4]	E 90% DOD Cycles/ Day[5]	F Days/ Year[6]	G = D x E x F Annual MWh[7]	H = A x G Project MWh
In-Front-of-the-Meter	1 Utility-Scale (Standalone)	a	20	100	–	2.6%	1	100	1	350	31,500	630,000
		b	20	100	–	2.6%	2	200	1	350	63,000	1,260,000
		c	20	100	–	2.6%	4	400	1	350	126,000	2,520,000
	2 Utility-Scale (PV + Storage)[8]		20	50	100	2.6%	4	200	1	350	191,000	3,820,000
	3 Utility-Scale (Wind + Storage)[8]		20	50	100	2.6%	4	200	1	350	366,000	7,320,000
Behind-the-Meter	4 Commercial & Industrial (Standalone)		20	1	–	2.6%	2	2	1	350	630	12,600
	5 Commercial & Industrial (PV + Storage)[8]		20	0.50	1	2.6%	4	2	1	350	1,690	33,800
	6 Residential (Standalone)		20	0.006	–	1.9%	4	0.025	1	350	8	158
	7 Residential (PV + Storage)[8]		20	0.006	0.010	1.9%	4	0.025	1	350	15	300

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) Usable energy indicates energy stored and available to be dispatched from the battery.
(3) Indicates power rating of system (i.e., system size).
(4) 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).
(5) "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.
(6) Indicates number of days of system operation per calendar year.
(7) Augmented to nameplate MWh capacity as needed to ensure usable energy is maintained at the nameplate capacity, based on Year 1 storage module cost.
(8) For PV + Storage and Wind + Storage cases, annual MWh represents the net output of combined system (generator output, less storage "round trip efficiency" losses) assuming 100% storage charging from the generator.

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

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



■ Unsubsidized ■ Subsidized (excl. Domestic Content)(3) ▨ Subsidized (incl. Domestic Content)(4)

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

Note: Here and throughout this presentation, unless otherwise indicated, 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 and therefore numbers will not tie. 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 included as part of O&M expenses in this analysis and vary across use cases due to usage profiles and lifespans. Charging costs for standalone cases are assessed at the weighted average hourly pricing (wholesale energy prices) across an optimized annual charging profile of the asset. No charging costs are assumed for hybrid systems. See Appendix for charging cost assumptions and additional details.

(1) For PV + Storage and Wind + Storage cases, the levelized cost is based on the capital and operating costs of the combined system, levelized over the net output of the combined system.

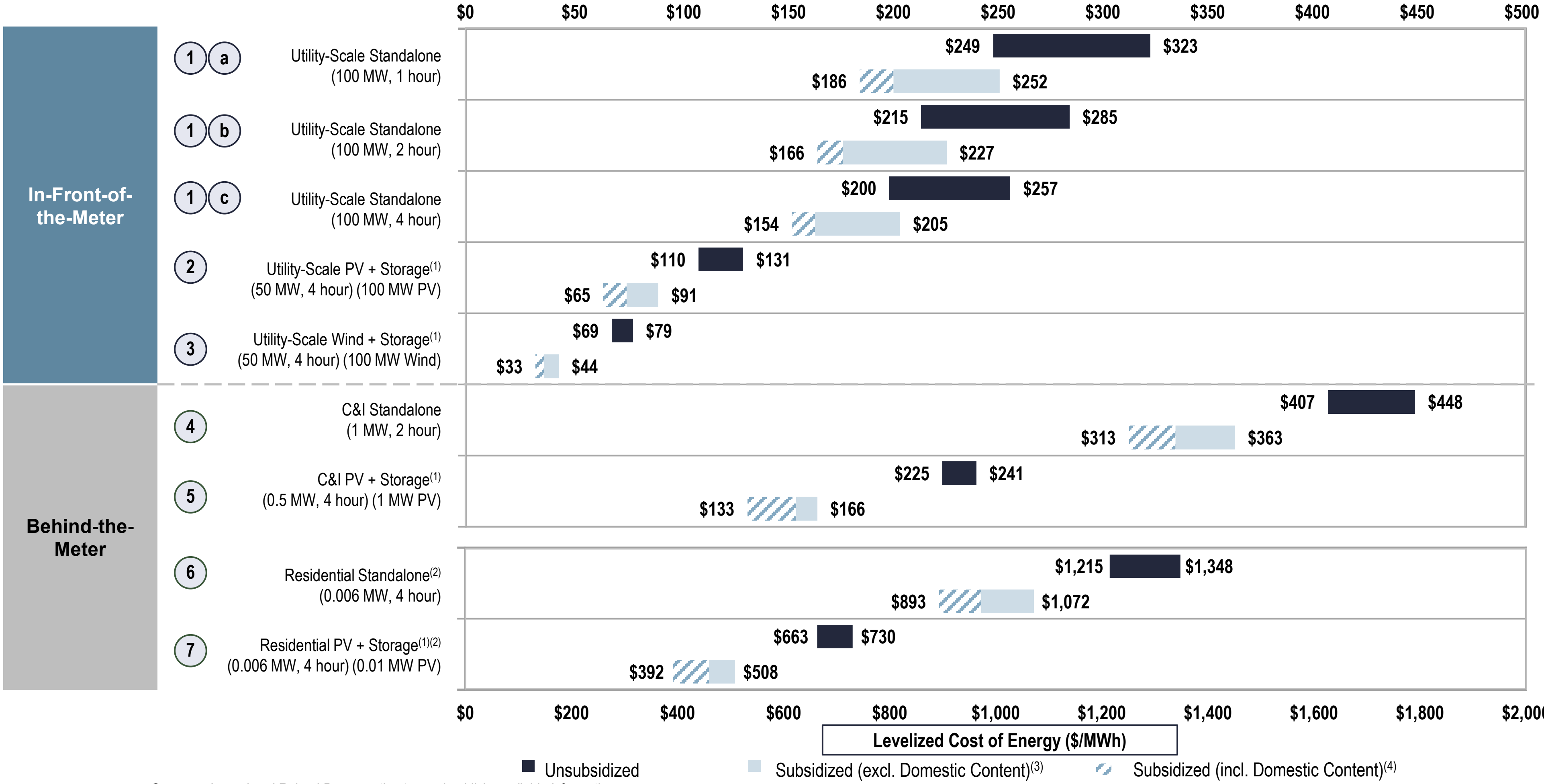
(2) In previous LCOS reports, residential battery storage costs have reflected equipment purchase costs only. For Lazard's LCOE v16.0 and LCOS v8.0, capital costs for residential battery storage projects includes installation/labor, balance-of-system components and warranties.

(3) This sensitivity analysis assumes that projects qualify for the full ITC/PTC and have a capital structure that includes sponsor equity, debt and tax equity. In this analysis only the wind portion of the Wind + Storage system utilizes the PTC.

(4) This sensitivity analysis assumes the above and also includes a 10% domestic content adder.

Levelized Cost of Storage Comparison—Energy ($/MWh)

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



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

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(4) This sensitivity analysis assumes the above and also includes a 10% domestic content adder.

Value Snapshots—Revenue Potential for Relevant Use Cases

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 (S)	Utility-Scale (PV + S)	Utility-Scale (Wind + S)	Commercial & Industrial (S)	Commercial & Industrial (PV + S)	Residential (PV + S)	Residential standalone (S)
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 (four-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				✓	✓	✓	✓

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

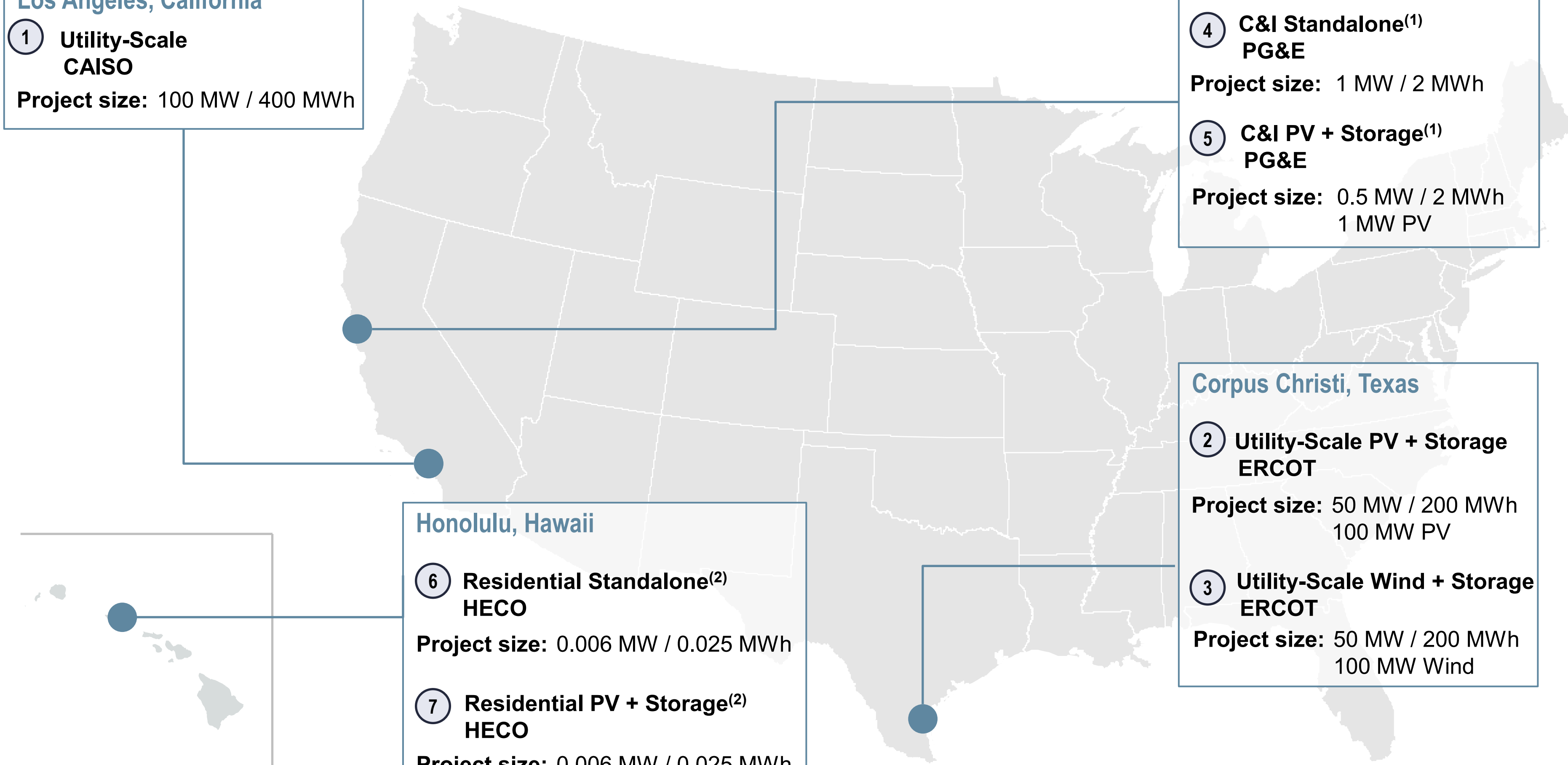
Lazard's Value Snapshots analyze the financial viability of illustrative energy storage systems designed for selected use cases

		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, DR Participation, Avoided Costs to Commercial Customer, Local Capacity Resource Programs and Incentives
	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 Pacific Gas & Electric Company.
(4) Refers to 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



Los Angeles, California

1 **Utility-Scale**
CAISO
Project size: 100 MW / 400 MWh

San Francisco, California

4 **C&I Standalone**[1]
PG&E
Project size: 1 MW / 2 MWh

5 **C&I PV + Storage**[1]
PG&E
Project size: 0.5 MW / 2 MWh
1 MW PV

Corpus Christi, Texas

2 **Utility-Scale PV + Storage**
ERCOT
Project size: 50 MW / 200 MWh
100 MW PV

3 **Utility-Scale Wind + Storage**
ERCOT
Project size: 50 MW / 200 MWh
100 MW Wind

Honolulu, Hawaii

6 **Residential Standalone**[2]
HECO
Project size: 0.006 MW / 0.025 MWh

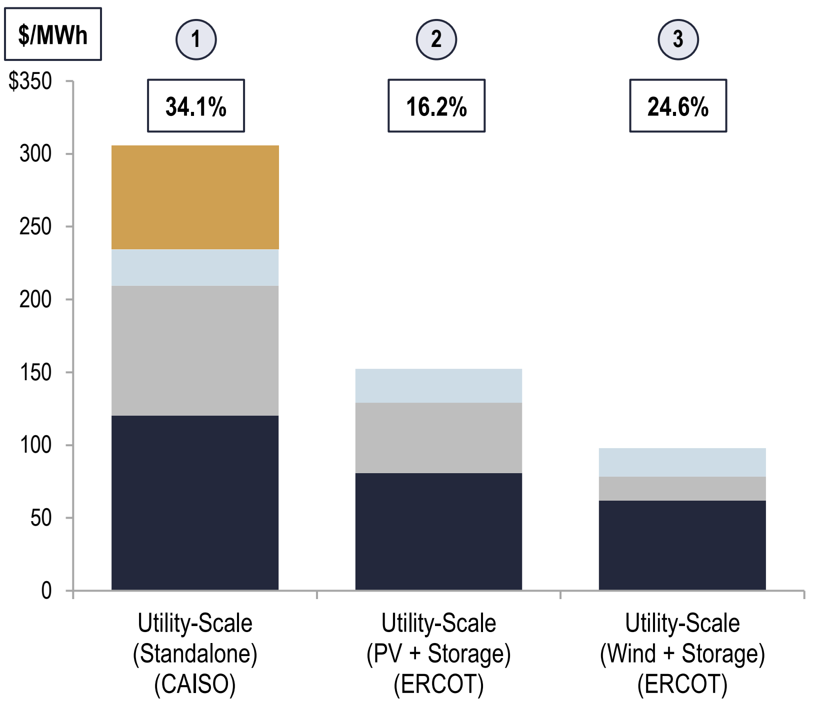
7 **Residential PV + Storage**[2]
HECO
Project size: 0.006 MW / 0.025 MWh
0.010 MW PV

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.

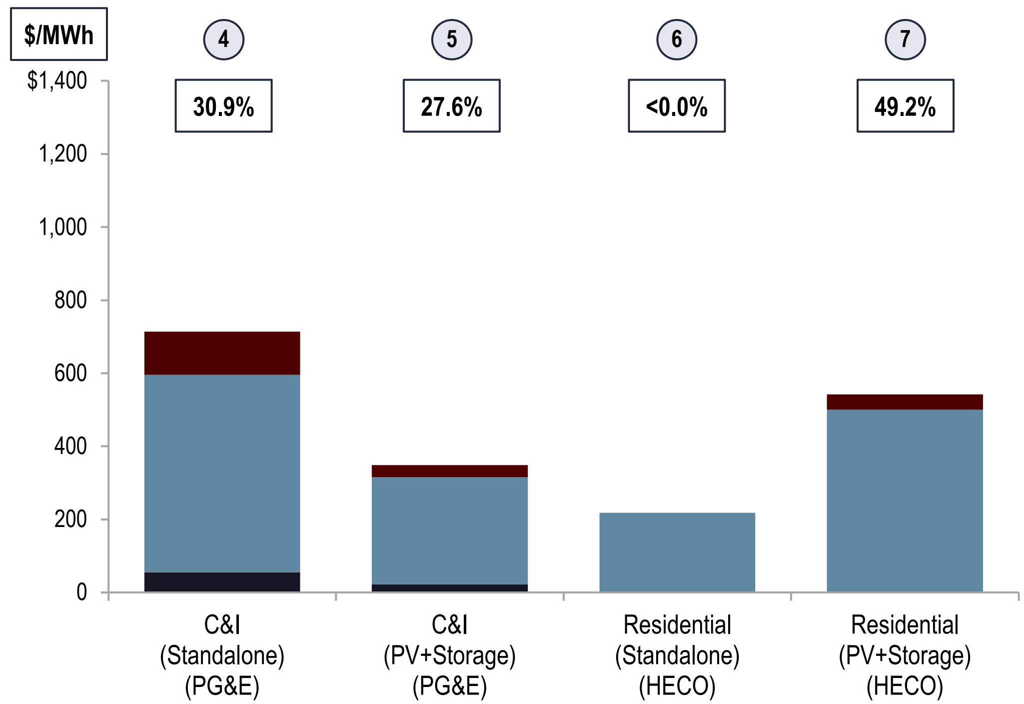
Value Snapshot Case Studies—Summary Results

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



Wholesale Energy Sales | Frequency Regulation | Spinning/Non-spinning Reserves | Resource Adequacy | Demand Response—Utility | Bill Management | Local Incentive Payments | Subsidized IRR

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 pages titled "Levelized Cost of Storage Comparison—Energy ($/MWh)", which are more broadly representative of U.S. storage market conditions versus location-specific. Levelized revenues in all cases show gross revenues (not including charging costs) to be comparable with the levelized cost, which incorporates 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, 30% federal ITC for storage, $26/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 Dec. 15, 2022. Revenues for Value Snapshots (4) – (6) are based on the most recent tariffs, programs and incentives available as of December 2022.

Exhibit 303

APRIL 2023

LCOE+

III Lazard's Levelized Cost of Hydrogen Analysis—Version 3.0

LAZARD

Introduction

Lazard's Levelized Cost of Hydrogen ("LCOH") analysis addresses the following topics:

- **An overview of the current commercial context for hydrogen in the U.S.**
- **Comparative and illustrative LCOH analysis for various hydrogen power production systems on a $/kg basis**
- **Comparative and illustrative LCOE analysis for gas peaking generation, a key use case in the U.S. power sector, utilizing a 25% blend of Green and Pink hydrogen 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

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

Note: This report has been compiled using U.S.-focused data.

Lazard's Levelized Cost of Hydrogen ("LCOH") Analysis—Executive Summary

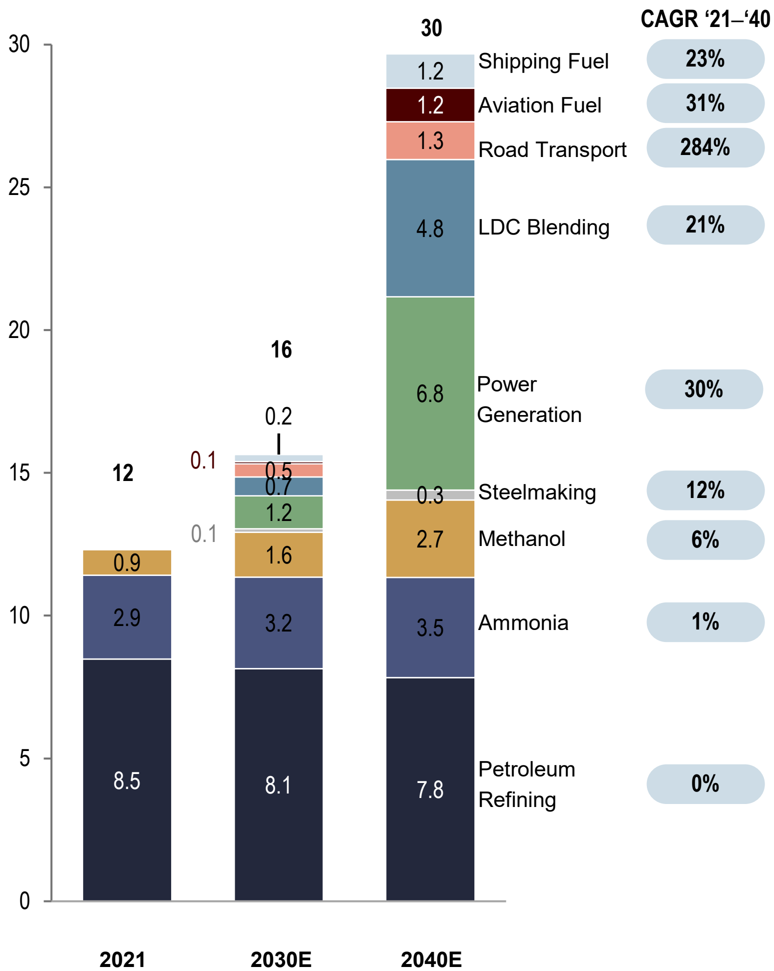
Technology Overview & Commercial Readiness	Hydrogen and Hydrogen Production • Hydrogen is currently produced primarily from fossil fuels using steam-methane reforming and methane splitting processes (i.e., "Gray" hydrogen) • A variety of additional processes are available to produce hydrogen from electricity and water (called electrolysis), which are at varying degrees of development and commercial viability, but the two most discussed forms of electrolysis are alkaline and PEM • Alkaline is generally best for large-scale industrial installations requiring a steady H_2 output at low pressure while PEM is generally well-suited for off-grid installations powered by highly variable renewable energy sources Hydrogen for Power Generation • Combustion turbines for 100% hydrogen are not commercially available today. Power generators are exploring blending with natural gas as a way to reduce carbon intensity • Several pilots and studies are being conducted and planned in the U.S. today. Most projects include up to 5% hydrogen blend by volume, but some testing facilities have used blends of over 40% hydrogen by volume • Hydrogen for power generation can occur via two different combustion methods: (1) premixed systems (or Dry, Low-NOx ("DLN") systems) that mix fuel and air upstream before combustion which lowers required temperature and NOx emissions and (2) non-mixed systems that combust fuel and air without premixing which requires water injection to lower NOx emissions
Market Activity & Policy Support	• Hydrogen is currently used primarily in industrial applications, including oil refining, steel production, ammonia and methanol production and as feedstock for other smaller-scale chemical processes • Clean hydrogen is well-positioned to reduce CO_2 emissions in typically "hard-to-decarbonize" sectors such as cement production, centralized energy systems, steel production, transportation and mobility (e.g., forklifts, maritime vessels, trucks and buses) • Natural gas utilities are likely to be early adopters of Green hydrogen as methanation (i.e., combining hydrogen with CO_2 to produce methane) becomes commercially viable and pipeline infrastructure is upgraded to support hydrogen blends • The IRA provides a distinct policy push to grow hydrogen production through the hydrogen PTC and ITC. In addition, clean hydrogen would see added lifts from tax and other benefits aimed at clean generation technologies
Future Perspectives	• Given its versatility as an energy carrier, hydrogen has the potential to be used across industrial processes, power generation and transportation, creating a potential path for decarbonizing energy-intensive industries where current technologies/alternatives are not presently viable • Clean hydrogen is expected to play a significant role in decarbonizing U.S. energy and other industries, including power generation through combustion, feedstock for ammonia, refining processes and e-fuels
Overview of Analysis	• The LCOH illustratively compares hydrogen produced through electrolysis via renewable power (Green) and nuclear power (Pink) • The analysis also includes the LCOE impact of blending these hydrogen sources with natural gas for power generation • For the analysis, unsubsidized renewables pricing is based on the average LCOE of a wind plant, oversized as compared to the electrolyzer and accounting for costs of curtailment. Unsubsidized nuclear power pricing is based on the average LCOE for an existing nuclear plant • Subsidized costs include the impact of the IRA. 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

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

Hydrogen Applications in Today's Economy

Today, most hydrogen is produced using fossil sources (i.e., Gray hydrogen) and is used primarily in refining and chemicals sectors, but clean (i.e., Blue, Green or Pink) hydrogen is expected to play an important role in several new growth sectors, including power generation

Forecasted U.S. Hydrogen Demand (million tons)



Key Hydrogen Terms and Implications for the Power Sector

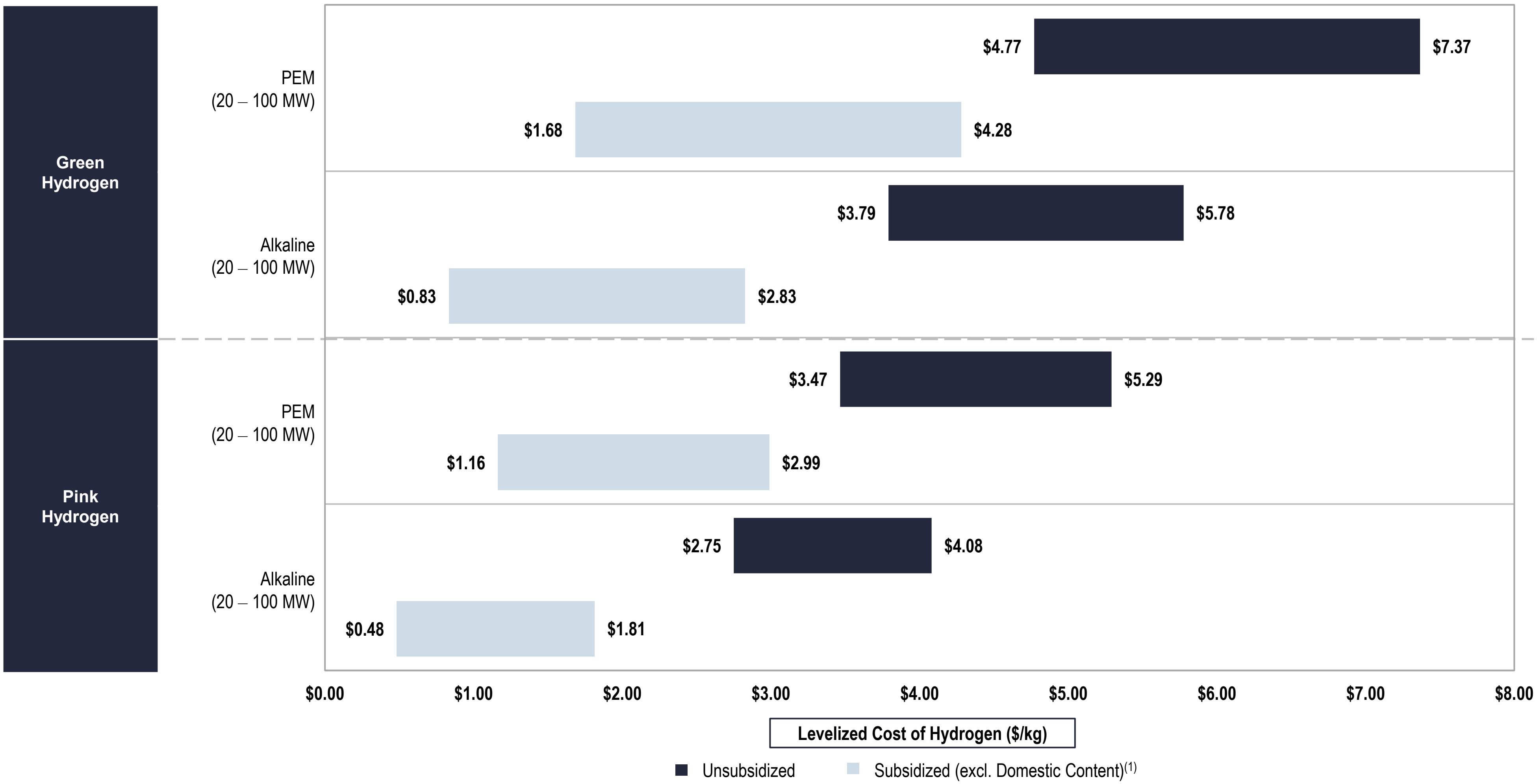
Overview of Hydrogen Color Spectrum	• Hydrogen production can be divided into "conventional" and "clean" hydrogen:
	  • **Conventional**:
	    – **Gray**: Almost all hydrogen produced in the U.S. today is through steam-methane reforming, where hydrogen is separated from natural gas. Carbon dioxide is a byproduct of this process
	    – **Black (or Brown)**: Uses steam and oxygen to break molecules in coal into a gaseous mixture resulting in streams of hydrogen and carbon dioxide
	  • A catch-all, **Yellow** hydrogen is produced through electrolysis using grid electricity
	  • "Clean" hydrogen comes in several colors, which are based on the production process, including:
	    – **Blue**: Black, Brown or Gray hydrogen, but with carbon emissions captured or stored
	    – **Green**: Renewable power used for electrolysis, where water molecules are split into hydrogen and oxygen using electricity
	    – **Pink**: Nuclear power used for electrolysis
	  • Other novel production processes include **Turquoise** hydrogen from methane pyrolysis, which uses thermal splitting of methane into hydrogen and solid carbon and is considered carbon-free if using electricity from renewable sources

Implications for the Power Sector	• Several utilities and developers have started exploring co-firing clean hydrogen with natural gas in combustion turbines to reduce emissions • Clean hydrogen production as a method to store renewable energy could utilize what would otherwise be curtailed renewable load and turn this energy into carbon-free dispatchable load, allowing for higher penetration of intermittent renewable resources, while also impacting capacity market prices and seasonal pricing peaks

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

Levelized Cost of Hydrogen Analysis—Illustrative Results

Subsidized Green and Pink hydrogen can reach levelized production costs under $2/kg—fully depreciated operating nuclear plants yield higher capacity factors and, when only accounting for operating expenses, Pink can reach production levels lower than Green hydrogen



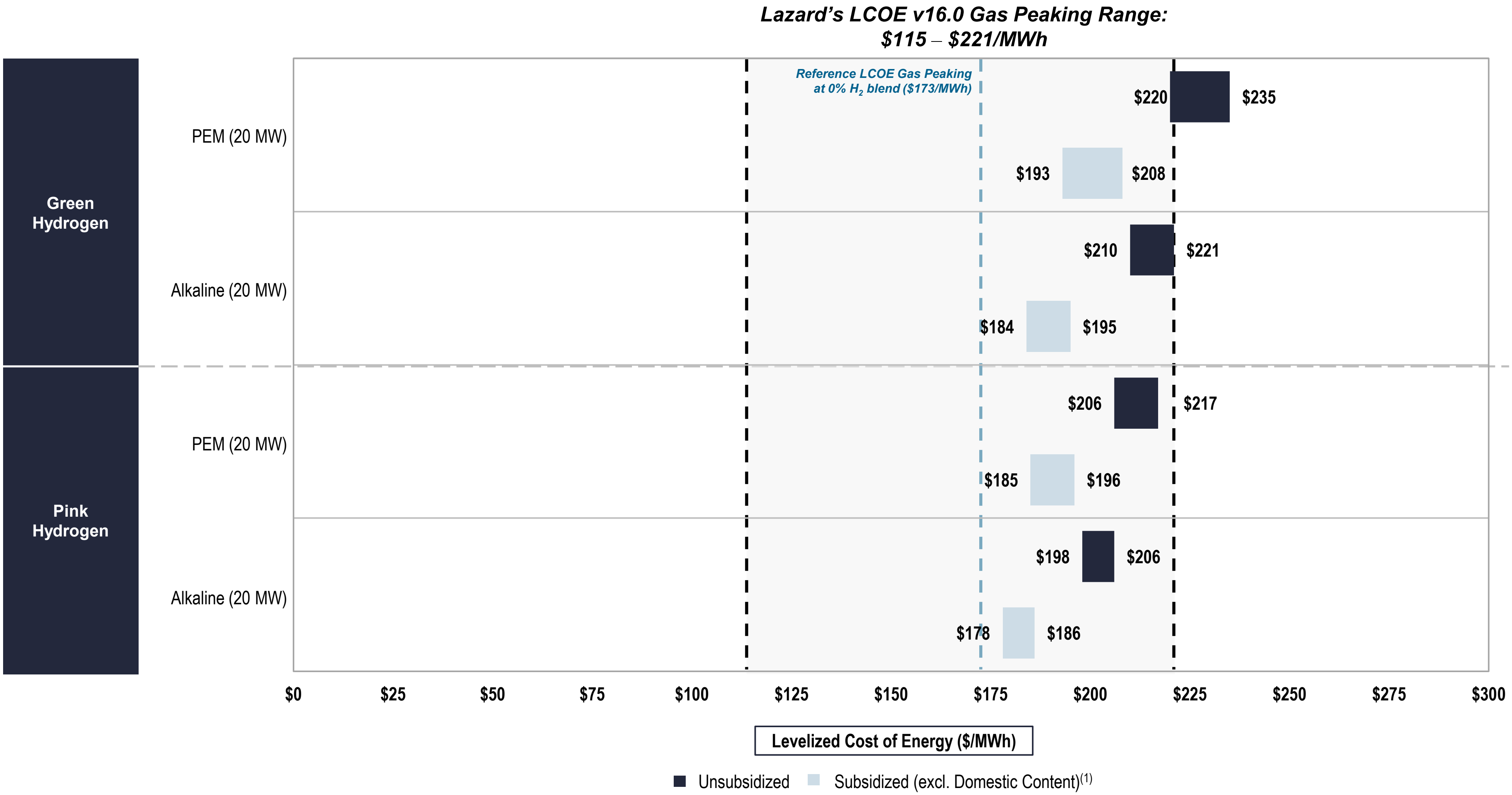
Source: Lazard and Roland Berger estimates and publicly available information.

Note: Here and throughout this presentation, 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 H_2 and 200 tons for Pink H_2 (size is driven by electrolyzer capacity factors). Pink hydrogen costs are based on marginal costs for an existing nuclear plant (see Appendix for detailed assumptions).

(1) This sensitivity analysis assumes that projects qualify for the full PTC and 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—Gas Peaking Plant 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: The analysis presented herein assumes a fuel blend of 25% hydrogen and 75% natural gas. Results are driven by Lazard's approach to calculating the LCOE and selected inputs (see Appendix for further details). Natural gas fuel cost assumed $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).

(1) This sensitivity analysis assumes that projects qualify for the full PTC and 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

A Maturing Technologies

Introduction

Lazard's preliminary perspectives on selected maturing technologies addresses the following topics:

- **Lazard's Carbon Capture & Storage ("CCS") System perspectives**
  - An overview of key findings and observed trends in the CCS sector
  - A comparative levelized cost of CCS for power generation on a $/MWh basis, including selected sensitivities for U.S. federal tax subsidies
  - An illustrative view of the value-add of CCS when included as an element of a new-build and retrofitted combined cycle gas plant
  - A comparison of capital costs on a $/kW basis for both new-build natural gas plants with CCS technology and existing natural gas plants retrofitted with CCS technology
- **Lazard's Long Duration Energy Storage ("LDES") analysis**
  - An overview of key findings and observed trends in the LDES sector
  - A comparative levelized cost for three selected types of LDES technologies, including selected sensitivities for U.S. federal tax subsidies

Other factors would also have a potentially significant effect on the results contained herein, but have not been examined in the scope of this current analysis. These additional factors, among others, could include: implementation and interpretation of the full scope of the IRA; development costs of the carbon capture or LDES system or associated generation facility; conversion, storage or transportation costs of the CO_2 once past the project site; costs to upgrade existing infrastructure to facilitate the transportation of CO_2; potential value associated with carbon-free fuel production (e.g., carbon credits, incentives, etc.); potential value associated with energy storage revenue (e.g., capacity payments, demand response, energy arbitrage, etc.); network upgrades, transmission, congestion 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 environmental and social externalities, including, for example, water consumption and the societal consequences of storing or transporting CO_2, material mining and land use

Importantly, this analysis is preliminary in nature, largely directional and does not fully take into account the maturing nature of the technologies analyzed herein

Note: This report has been compiled using U.S.-focused data.

Exhibit 303

APRIL 2023

1 Carbon Capture & Storage Systems

LAZARD

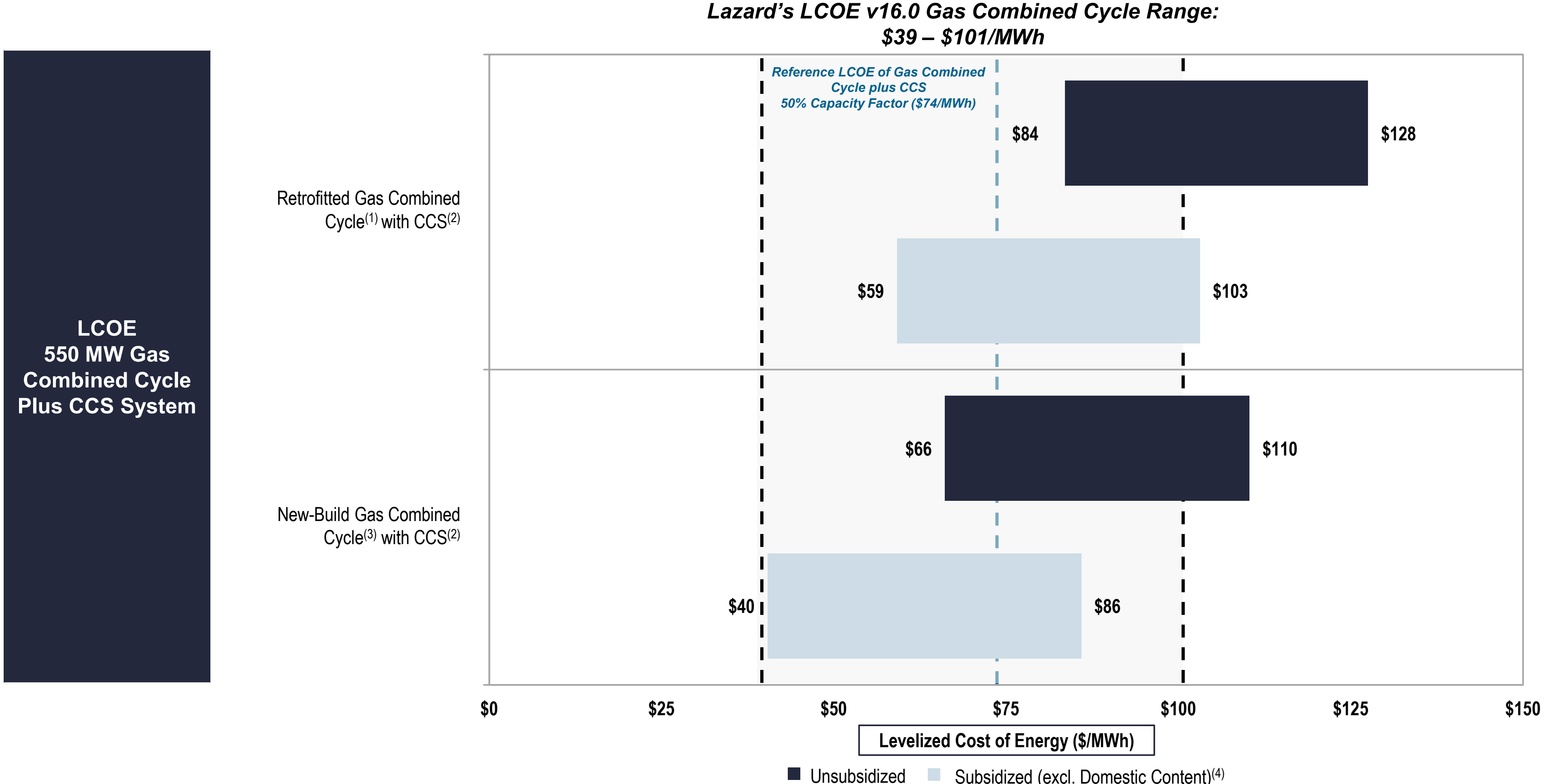
Lazard's Carbon Capture & Storage Analysis—Executive Summary

Technology Overview & Commercial Readiness	• CCS refers to technologies designed to sequester carbon dioxide emissions, particularly from power generation or industrial sources • The core technology involves a specialized solvent or other material that enables the capture of carbon dioxide from a gas stream (usually an exhaust gas) • Oxycombustion is emerging as a potential new type of natural gas power plant design that integrates CO_2 capture in the combustion cycle for a claimed 100% capture rate • In power generation, CCS can be applied as a retrofit to existing coal and gas-fired power plants or incorporated into new-build plants • CO_2 capture rates are currently 80% – 90%, with a near-term goal of 95%+ • Current "post-combustion" CCS technologies require power plants to operate close to full load in order to maintain high capture rates • CCS systems require energy input and represent a parasitic load on the generation unit effectively increasing the "heat rate" of the generator • CCS also requires compression, transportation and either secure permanent underground storage of carbon dioxide or alternate end-use • To date, there are very few completed power generation CCS project examples
Market Activity & Policy Support	• CCS has attracted significant interest and investment from various market participants • Project costs, especially for retrofits, are highly dependent upon site characteristics • The Department of Energy ("DOE")/National Energy Technology Laboratory ("NETL") have provided significant support for the emerging CCS sector by funding engineering studies and collecting cost estimates and performance data • The IRA has increased the tax credit for carbon sequestration to $85/ton, providing a significant subsidy for CCS deployment that can offset much of the increased capital and operating costs of a CCS retrofit or new-build with CCS • A number of power sector CCS projects are being developed to retrofit existing coal and natural gas power plants, some of which are expected to be completed by the middle of the decade
Future Perspectives	• Natural gas power generation will continue to play an important role in grid reliability, especially as renewable penetration increases and more coal retires • CCS has the potential to allow natural gas plants to remain in operation as the U.S. continues to rapidly decarbonize its power grid • CCS costs are still high, and given that the majority of the capital cost of a CCS system consists of balance-of-system components, innovations in solvents and other core capture technologies may not result in significant cost reductions • New technologies such as oxycombustion systems may represent meaningful improvements in capture efficiency and cost • The deployment of any CCS technology depends on the availability of either offtake or permanent CO_2 storage reservoirs (placing geographic limitations on deployment) and the validation of the security of permanent storage (in avoiding CO_2 leakage)
Overview of Analysis	• The illustrative analysis presented herein is limited to post-combustion CCS for power generation • Two cases are included: (1) an amine CCS system retrofitted to an existing natural gas combined cycle plant and (2) an amine CCS system with a new-build natural gas combined cycle plant • CO_2 transportation and storage costs are assumed to be fixed across both cases at $23/ton • Subsidized costs include the impact of the IRA. 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

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

Levelized Cost of Energy—Gas Combined Cycle + CCS System

CCS systems benefit from federal subsidies through the IRA, making the LCOE of a gas combined cycle plant plus a CCS system cost-competitive with a standalone gas combined cycle plant in both a retrofit and new-build scenario



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

Note: The fuel cost assumption for Lazard's analysis for gas-fired generation resources is $3.45/MMBTU.

(1) Represents the LCOE of a combined system, new CCS with a useful life of 12 years and LCOE of Gas Combined Cycle including remaining book value of retrofitted power plant. The low case represents an 85% capacity factor while the high case represents a 50% capacity factor.

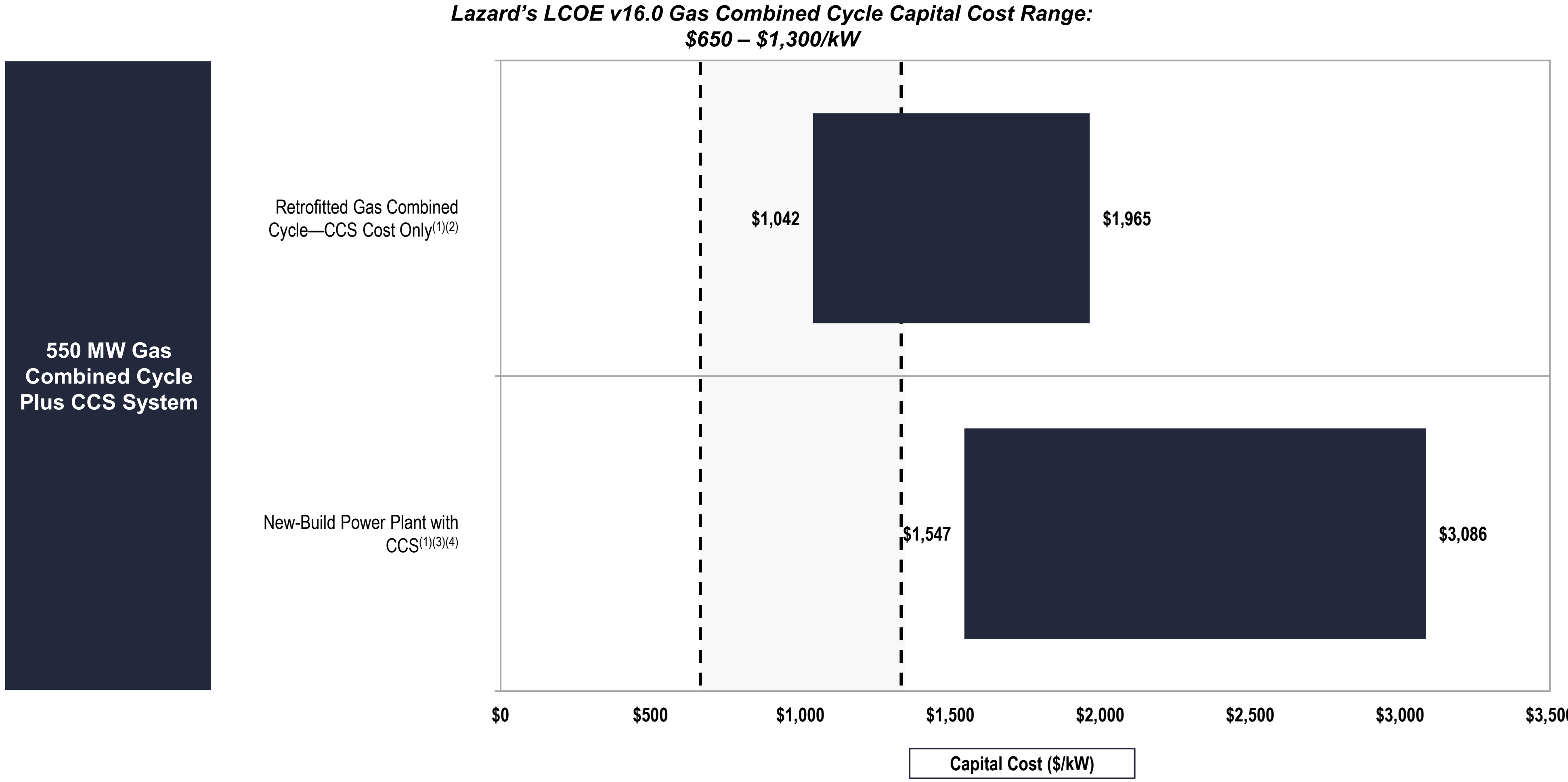
(2) Represents a 2 million-ton CO_2 plant and generation heat rate increases of 11% for the low case (85% capacity factor) and 21% for the high case (50% capacity factor) due to fixed usage of parasitic power by the CCS equipment.

(3) Represents the LCOE of a combined system with a useful life of 20 years. The low case represents an oxycombustion CCS system with a capacity factor of 92.5% and a $10/MWh benefit for industrial gas sales. The high case represents a Gas Combined Cycle + CCS with a capacity factor of 50% and a $2.50/MWh benefit for industrial gas sales.

(4) Subsidized value assumes $85/ton CO_2 credit for 12 years with nominal carbon capture rate of 95% for Gas Combined Cycle + CCS and 100% nominal capture rate for oxycombustion. Assumes an emissions rate of 0.41 ton CO_2 per MWh generated. All costs include a $23/ton CO_2 cost of transportation and storage. There is no domestic content adder available for the CO_2 tax credit. 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.

Carbon Capture & Storage Systems—Capital Cost Comparison (Unsubsidized)

CCS costs are still high and the majority of the capital cost of a CCS system consists of balance-of-system components



Source: Lazard and Roland Berger estimates and publicly available information.
(1) Represents an assumed 2-million-ton CO_2 plant and 550 MW Gas Combined Cycle generation at 85% capacity factor.
(2) Represents an assumed $440 – $550/ton CO_2 of nameplate capacity CCS system.
(3) Represents an assumed $700 – $1,300/kW for Gas Combined Cycle and $400 – $500/ton CO_2 of nameplate capacity for CCS.
(4) New-build range also includes a capital expenditure estimate for a 280 MW oxycombustion project.

2 Long Duration Energy Storage

Lazard's Long Duration Energy Storage Analysis—Executive Summary

Technology Overview & Commercial Readiness	• LDES technologies are emerging alternatives to lithium-ion batteries because they have the potential to be more economical at storage durations of 6 – 8+ hours • Technological categories include electrochemical (including flow batteries and other non-lithium chemistries), mechanical (including compressed air storage) and thermal • A key challenge for LDES economics is the round-trip efficiency or the percentage of the stored energy that can later be output. Currently, LDES technologies have round trip efficiencies, which are varied but generally less than the 85% – 90% for lithium-ion battery systems • LDES technologies generally do not rely on scarce or expensive mineral inputs, but they can require increased engineering, labor and site work compared to lithium-ion, particularly for mechanical storage solutions • Most LDES technologies have not yet reached commercialization due to technology immaturity and, with limited deployments, seemingly none of the emerging LDES technologies have achieved the track record for performance required to be fully bankable
Market Activity & Policy Support	• Emerging LDES technology companies have attracted significant capital investment in the past 5 years • To date, LDES deployments have generally been limited to pilot/early commercial scale • LDES providers are generally seeking to reach commercial manufacturing scale by the end of the decade to be able to support grid-scale deployments that are cost-competitive • The U.S. DOE's concerted funding initiatives, along with the IRA ITC for energy storage resources support and somewhat de-risk LDES deployment • LDES technologies are divorced from the lithium-ion/electric vehicle supply chain, which may confer attractiveness in the short term given increased lithium costs and ongoing supply chain concerns • However, Industry participants are still evaluating the system need for long duration storage as well as appropriate market mechanisms and signals
Future Perspectives	• At increasingly high wind and solar penetrations, there will be a need for resources that can provide capacity over longer durations in order to meet overall capacity and reliability requirements • LDES technologies could potentially serve this function and enable higher levels of decarbonized power generation as a substitute for traditional "peaking" resources • Market structures and pricing signals may be established/adopted to reflect identified value of longer duration storage resources • LDES technologies will compete with, among other things, green hydrogen (generation and storage), natural gas generators with carbon capture systems and advanced nuclear reactors to provide capacity to a decarbonized power grid (assuming viability/acceptability of the relevant LDES technologies)
Overview of Analysis	• The illustrative analysis presented herein includes non-lithium technologies and compares the levelized costs of several flow battery cases along with a compressed air energy system ("CAES") case • All systems are 100 MW, 8 hour systems with one cycle per day at maximum charge and depth of discharge (maximum stored energy output given round trip efficiency) • Subsidized costs include the impact of the IRA. 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

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

Long Duration Energy Storage Technologies—Overview

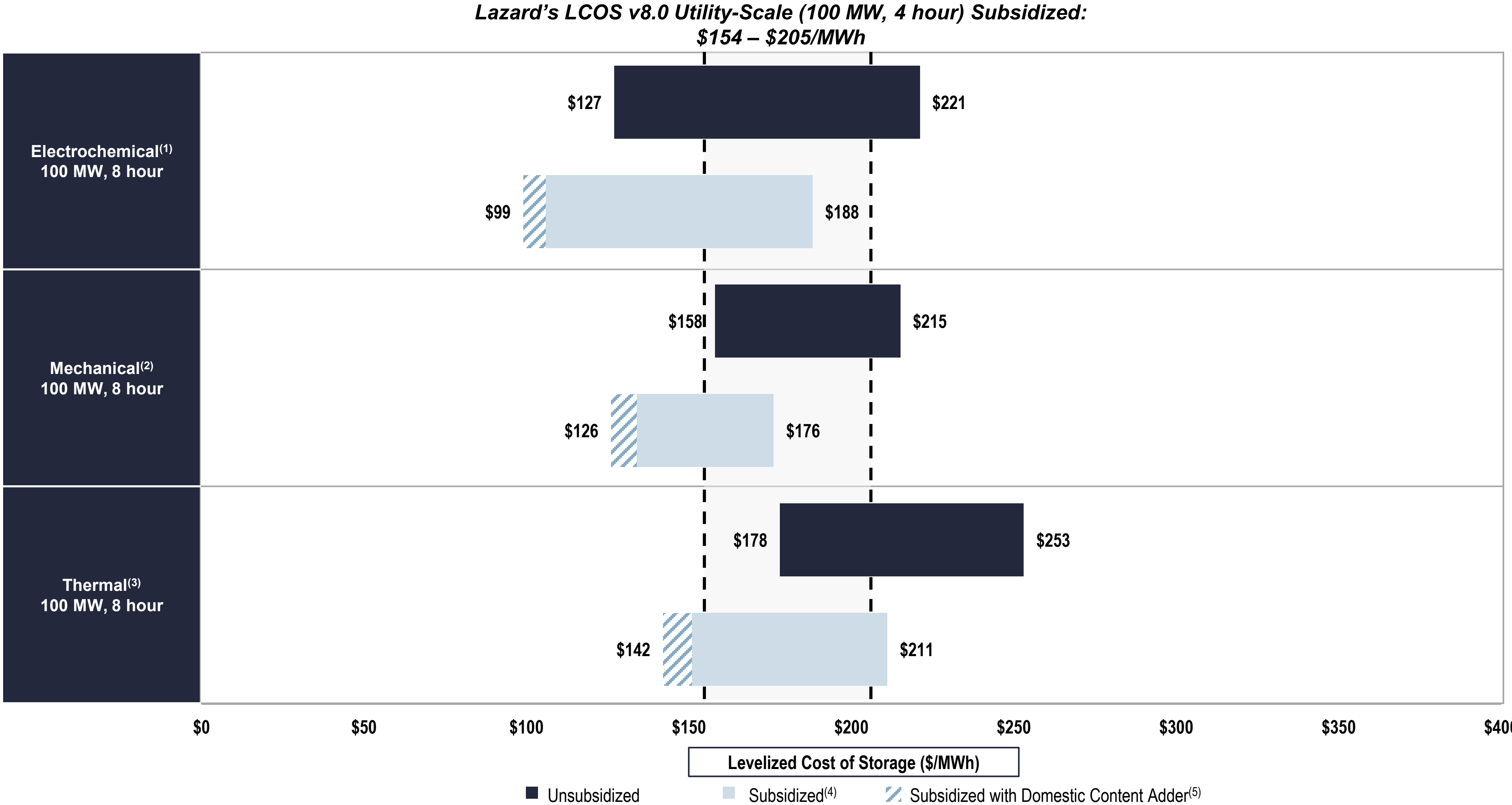
LDES technologies typically fall into three main technological categories that provide unique advantages and disadvantages and also make them suitable (or not) across a variety of use cases

	Electrochemical	Mechanical	Thermal
Description	• Energy storage systems generating electrical energy from chemical reactions	• Solutions that store energy as a kinetic, gravitational potential or compression/pressure medium	• Solutions stocking thermal energy by heating or cooling a storage medium
Typical Technologies	• Flow batteries (vanadium, zinc-bromide) • Sodium-sulfur • Iron-air	• Adiabatic and cryogenic compressed liquids (change in internal energy) • Geo-mechanical pumped hydro • Gravitational	• Latent heat (phase change) • Sensible heat (molten salt)
Selected Advantages	• No degradation • Cycling throughout the day • Modular options available • Considered safe	• Considered safe • Attractive economics • Proven technologies (e.g., pumped hydro)	• Able to leverage mature industrial cryogenic technology base • Inexpensive materials • Power/energy independent • Scalable
Selected Disadvantages	• Membrane materials costly • Difficult to mass produce • Scalability unclear	• Large volumetric storage sites • Difficult to modularize • Cycling typically limited to once per day	• Reduced energy density • Cryogenic safety concerns • Cannot modularize after install
Key Challenges	• Expensive ion-exchange membranes required due to voltage and electrolyte stress • Less compact (lower energy density)	• Geographic limitations of some sub-technologies • Low efficiency of diabatic systems	• Visibility into peak and off-peak • Climate impact on effectiveness • Scale of application (e.g., best for district heating)

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

Levelized Cost of Energy—Illustrative LDES at Scale

The LCOE of LDES technologies is expected to be competitive with lithium-ion for large-scale 8 hour systems in the second half of the decade, with anticipated unit cost advantages at longer durations overcoming lower round-trip efficiency



Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: All cases assume a 20-year system life and 1 cycle per day at maximum depth-of-discharge.
(1) Electrochemical includes flow batteries (vanadium redox, zinc bromine) and non-flow (liquid metal).
(2) Mechanical includes CAES and liquified air energy storage ("LAES").
(3) Thermal includes sensible heat storage solutions (molten salt).
(4) This sensitivity analysis assumes that projects qualify for the full standalone storage ITC.
(5) This sensitivity analysis assumes the above and also includes a 10% domestic content adder. 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.

APRIL 2023

B LCOE v16.0

LAZARD

LCOE

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: Onshore Wind—Low LCOE case presented for illustrative purposes only.

* Denotes unit conversion.

(1) Assumes half-year convention for discounting purposes.

(2) Assumes full monetization of tax benefits or losses immediately.

(3) Reflects initial cash outflow from equity investors.

(4) Reflects a "key" subset of all assumptions for methodology illustration purposes only. Does not reflect all assumptions.

(5) Economic life sets debt amortization schedule. For comparison purposes, all technologies calculate LCOE on a 20-year IRR basis.

LAZARD

Levelized Cost of Energy—Key Assumptions

		Solar PV							
		Rooftop—Residential		Community and C&I		Utility-Scale		Utility Scale + Storage	
	Units	Low Case	High Case	Low Case	High Case	Low Case	High Case	Low Case	High Case
Net Facility Output	MW	0.005		5		150		100	
Total Capital Costs[(1)]	$/kW	$2,230	$4,150	$1,200	$2,850	$700	$1,400	$1,075	$1,600
Fixed O&M	$/kW-yr	$15.00	$18.00	$12.00	$18.00	$7.00	$14.00	$20.00	$45.00
Variable O&M	$/MWh	—		—		—		—	
Heat Rate	Btu/kWh	—		—		—		—	
Capacity Factor	%	20%	15%	25%	15%	30%	15%	27%	20%
Fuel Price	$/MMBTU	—		—		—		—	
Construction Time	Months	3		4	6	9		9	
Facility Life	Years	25		30		30		30	
Levelized Cost of Energy	$/MWh	$117	$282	$49	$185	$24	$96	$46	$102

Source: Lazard and Roland Berger estimates and publicly available information.
(1) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

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

	Units	Geothermal[1] Low Case	Geothermal[1] High Case	Wind—Onshore Low Case	Wind—Onshore High Case	Wind—Onshore + Storage Low Case	Wind—Onshore + Storage High Case	Wind—Offshore Low Case	Wind—Offshore High Case
Net Facility Output	MW	250		175		100		1000	
Total Capital Costs[2]	$/kW	$4,700	$6,075	$1,025	$1,700	$1,375	$2,250	$3,000	$5,000
Fixed O&M	$/kW-yr	$14.00	$15.25	$20.00	$35.00	$32.00	$80.00	$60.00	$80.00
Variable O&M	$/MWh	$8.75	$24.00	—		—		—	
Heat Rate	Btu/kWh	—		—		—		—	
Capacity Factor	%	90%	80%	55%	30%	45%	30%	55%	45%
Fuel Price	$/MMBTU	—		—		—		—	
Construction Time	Months	36		12		12		12	
Facility Life	Years	25		20		20		20	
Levelized Cost of Energy	$/MWh	$61	$102	$24	$75	$42	$114	$72	$140

Source: *Lazard and Roland Berger estimates and publicly available information.*
(1) Given the limited data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.
(2) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

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

	Units	Gas Peaking		Nuclear (New Build) [1]		Coal (New Build) [2]		Gas Combined Cycle (New Build)	
		Low Case	High Case	Low Case	High Case	Low Case	High Case	Low Case	High Case
Net Facility Output	MW	240 –	50	2,200		600		550	
Total Capital Costs [3]	$/kW	$700 –	$1,150	$8,475 –	$13,925	$3,200 –	$6,775	$650 –	$1,300
Fixed O&M	$/kW-yr	$7.00 –	$17.00	$131.50 –	$152.75	$39.50 –	$91.25	$10.00 –	$17.00
Variable O&M	$/MWh	—		$4.25 –	$5.00	$3.00 –	$5.50	$2.75 –	$5.00
Heat Rate	Btu/kWh	—		10,450		8,750 –	12,000	6,150 –	6,900
Capacity Factor	%	15% –	10%	92% –	89%	85% –	65%	90% –	30%
Fuel Price	$/MMBTU	—		$0.85		$1.47		$3.45	
Construction Time	Months	12		69		60 –	66	24	
Facility Life	Years	20		40		40		20	
Levelized Cost of Energy	$/MWh	$115 –	$221	$141 –	$221	$68 –	$166	$39 –	$101

Source: *Lazard and Roland Berger estimates and publicly available information.*
(1) Given the limited public and/or observable data set available for new-build nuclear projects and the emerging range of new nuclear generation strategies, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation (results are based on then-estimated costs of the Vogtle Plant and are U.S.-focused).
(2) High end incorporates 90% CCS. Does not include cost of transportation and storage. Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation.
(3) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

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

	Units	Nuclear (Operating) Low Case		Nuclear (Operating) High Case	Coal (Operating) Low Case		Coal (Operating) High Case	Gas Combined Cycle (Operating) Low Case		Gas Combined Cycle (Operating) High Case
Net Facility Output	MW		2,200			600			550	
Total Capital Costs[1]	$/kW		$0.00			$0.00			$0.00	
Fixed O&M	$/kW-yr	$97.25	–	$120.00	$18.50	–	$31.00	$9.25	–	$14.00
Variable O&M	$/MWh	$3.05	–	$3.55	$2.75	–	$5.50	$1.00	–	$2.00
Heat Rate	Btu/kWh		10,400		10,075	–	11,075	6,925	–	7,450
Capacity Factor	%	95%	–	90%	65%	–	35%	70%	–	45%
Fuel Price	$/MMBTU		$0.79		$1.89	–	$4.33	$6.00	–	$7.69
Construction Time	Months		69		60	–	66		24	
Facility Life	Years		40			40			20	
Levelized Cost of Energy	$/MWh	$29	–	$34	$29	–	$74	$51	–	$73

Source: Lazard and Roland Berger estimates and publicly available information.
(1) Includes capitalized financing costs during construction for generation types with over 12 months of construction time.

Exhibit 303

APRIL 2023

C LCOS v8.0

LAZARD

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" pages 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: Subsidized Utility-Scale (100 MW / 200 MWh)—Low LCOS case 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 ($1.30/kWh, 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 illustration purposes only. Does not reflect all assumptions.

(6) Initial Installed Cost includes Inverter cost of $35/kW, Module cost of $188/kWh, Balance-of-System cost of $30/kWh and EPC cost of $30/kWh.

(7) Reflects initial cash outflow from equity sponsor.

Levelized Cost of Storage—Key Assumptions

	Units	Utility-Scale (Standalone)			Utility-Scale (PV + Storage)	Utility-Scale (Wind + Storage)	C&I (Standalone)	C&I (PV + Storage)	Residential (Standalone)	Residential (PV + Storage)
		(100 MW / 100 MWh)	(100 MW / 200 MWh)	(100 MW / 400 MWh)	(50 MW / 200 MWh)	(50 MW / 200 MWh)	(1 MW / 2 MWh)	(0.5 MW / 2 MWh)	(0.006 MW / 0.025 MWh)	(0.006 MW / 0.025 MWh)
Power Rating	MW	100	100	100	50	50	1	0.5	0.006	0.006
Duration	Hours	1.0	2.0	4.0	4.0	4.0	2.0	4.0	4.2	4.2
Usable Energy	MWh	100	200	400	200	200	2	2	0.025	0.025
90% Depth of Discharge Cycles/Day	#	1	1	1	1	1	1	1	1	1
Operating Days/Year	#	350	350	350	350	350	350	350	350	350
Solar / Wind Capacity	MW	0.00	0.00	0.00	100	100	0.00	1.00	0.000	0.010
Annual Solar / Wind Generation	MWh	0	0	0	197,000	372,000	0	1,752	0	15
Project Life	Years	20	20	20	20	20	20	20	20	20
Annual Storage Output	MWh	31,500	63,000	126,000	63,000	63,000	630	630	8	8
Lifetime Storage Output	MWh	630,000	1,260,000	2,520,000	1,260,000	1,260,000	12,600	12,600	158	158
Initial Capital Cost—DC	$/kWh	$280 – $359	$223 – $315	$225 – $304	$200 – $279	$200 – $279	$429 – $469	$326 – $362	$1,261 – $1,429	$1,150 – $1,286
Initial Capital Cost—AC	$/kW	$35 – $80	$35 – $80	$35 – $80	$20 – $60	$20 – $60	$50 – $80	$50 – $80	$101 – $114	$92 – $103
EPC Costs	$/kWh	$30 – $70	$30 – $70	$30 – $70	$30 – $70	$30 – $70	$59 – $106	$47 – $89	$0 – $0	$0 – $0
Solar / Wind Capital Cost	$/kW	$0 – $0	$0 – $0	$0 – $0	$1,050 – $1,050	$1,350 – $1,350	$0 – $0	$2,025 – $2,025	$0 – $0	$3,175 – $3,175
Total Initial Installed Cost	$	$35 – $51	$54 – $85	$106 – $158	$47 – $73	$47 – $73	$1 – $1	$1 – $1	$0 – $0	$0 – $0
Storage O&M	$/kWh	$1.7 - $9.7	$1.3 - $7.7	$1.2 - $6.7	$1.2 - $6.7	$1.2 - $6.7	$2.5 - $11.2	$1.9 - $8.8	$0.0 - $0.0	$0.0 - $0.0
Extended Warranty Start	Year	3	3	3	3	3	3	3	3	3
Warranty Expense % of Capital Costs	%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.50% - 0.80%	0.00% - 0.00%	0.00% - 0.00%
Investment Tax Credit (Solar)	%	0%	0%	0%	30% - 40%	0%	0%	30% - 40%	0%	30% - 40%
Investment Tax Credit (Storage)	%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%	30% - 40%
Production Tax Credit	$/MWh	$0	$0	$0	$0	$26 - $29	$0	$0	$0	$0
Charging Cost	$/MWh	$61	$64	$59	$0	$0	$117	$0	$325	$0
Charging Cost Escalator	%	1.87%	1.87%	1.87%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Efficiency of Storage Technology	%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	91% – 88%	95% – 90%	95% – 90%
Unsubsidized LCOS	$/MWh	$249 - $323	$215 - $285	$200 - $257	$110 - $131	$69 - $79	$407 - $448	$225 - $241	$1,215 - $1,348	$663 - $730

x

Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Assumed capital structure of 80% equity (with a 12% cost of equity) and 20% debt (with an 8% cost of debt). Capital cost units are the total investment divided by the storage equipment's energy capacity (kWh rating) and inverter rating (kW rating). All cases were modeled using 90% depth of discharge. 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)". Storage systems paired with Solar PV or Wind do not charge from the grid.

APRIL 2023

D LCOH v3.0

LAZARD

Levelized Cost of Hydrogen Comparison—Methodology

($ in millions, unless otherwise noted)

Lazard's LCOH analysis consists of creating a model representing an illustrative project for each relevant technology and solving for the $/kg value that results in a levered IRR equal to the assumed cost of equity (see subsequent "Key Assumptions" pages 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: Unsubsidized Green PEM—High LCOH case 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					
		PEM			Alkaline			PEM			Alkaline		
	Units	Low Case		High Case	Low Case		High Case	Low Case		High Case	Low Case		High Case
Capacity	MW	100	–	20	100	–	20	100	–	20	100	–	20
Total Capex	$/kW	$943	–	$2,265	$740	–	$1,984	$1,013	–	$2,335	$810	–	$2,054
Electrolyzer Stack Capex	$/kW	$341	–	$1,052	$203	–	$652	$341	–	$1,052	$203	–	$652
Plant Lifetime	Years		25			25			25			25	
Stack Lifetime	Hours		60,000			67,500			60,000			67,500	
Heating Value	kWh/kg H2		33			33			33			33	
Electrolyzer Utilization	%		90%			90%			90%			90%	
Electrolyzer Capacity Factor	%		55%			55%			95%			95%	
Electrolyzer Efficiency	% LHV		58%			67%			58%			67%	
Operating Costs:													
Annual H2 Produced	MT	7,788	–	1,558	8,902	–	1,780	12,744	–	2,549	14,568	–	2,914
Process Water Costs	$/kg H2		$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 (Unsubsidized)	$/MWh		$48.00			$48.00			$35.00			$35.00	
Net Electricity Cost (subsidized)	$/MWh		$30.56			$30.56			$30.31			$30.31	
Warranty & Insurance (% of Capex)	%		1.0%			1.0%			1.0%			1.0%	
Warranty & Insurance Escalation	%		1.0%			1.0%			1.0%			1.0%	
O&M (% of Capex)	%		1.50%			1.50%			1.50%			1.50%	
Annual Inflation	%		2.00%			2.00%			2.00%			2.00%	
Capital Structure:													
Debt	%		40.0%			40.0%			40.0%			40.0%	
Cost of Debt	%		8.0%			8.0%			8.0%			8.0%	
Equity	%		60.0%			60.0%			60.0%			60.0%	
Cost of Equity	%		12.0%			12.0%			12.0%			12.0%	
Tax Rate	%		21.0%			21.0%			21.0%			21.0%	
WACC	%		9.7%			9.7%			9.7%			9.7%	
Unsubsidized Levelized Cost of Hydrogen	**$/kg**	**$4.77**		**$7.37**	**$3.79**		**$5.78**	**$3.47**		**$5.29**	**$2.75**		**$4.08**
Subsidized Levelized Cost of Hydrogen	**$/kg**	**$1.68**		**$4.28**	**$0.83**		**$2.83**	**$1.16**		**$2.99**	**$0.48**		**$1.81**
Memo: Unsubsidized Natural Gas Equivalent Cost	***$/MMBTU***	***$41.90***		***$64.65***	***$33.30***		***$50.70***	***$30.40***		***$46.45***	***$24.15***		***$35.80***
Memo: Subsidized Natural Gas Equivalent Cost	***$/MMBTU***	***$14.80***		***$37.55***	***$7.30***		***$24.80***	***$10.20***		***$26.25***	***$4.25***		***$15.90***

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

Levelized Cost of Energy—Gas Peaking Plant with 25% Hydrogen Blend Key Assumptions

		Green Hydrogen						Pink Hydrogen					
		PEM			Alkaline			PEM			Alkaline		
	Units	Low Case		High Case	Low Case		High Case	Low Case		High Case	Low Case		High Case
Capacity	MW		20			20			20			20	
Total Capex	$/kW	$1,412	–	$2,265	$1,230	–	$1,984	$1,482	–	$2,335	$1,300	–	$2,054
Electrolyzer Stack Capex	$/kW	$479	–	$1,052	$186	–	$652	$479	–	$1,052	$186	–	$652
Plant Lifetime	Years		25			25			25			25	
Stack Lifetime	Hours		60,000			67,500			60,000			67,500	
Heating Value	kWh/kg H2		33			33			33			33	
Electrolyzer Utilization	%		90%			90%			90%			90%	
Electrolyzer Capacity Factor	%		55%			55%			95%			95%	
Electrolyzer Efficiency	% LHV		58%			67%			58%			67%	
Operating Costs:													
Annual H2 Produced	MT		1,558			1,780			2,549			2,914	
Process Water Costs	$/kg H2		$0.005			$0.005			$0.005			$0.005	
Annual Energy Consumption	MWh		96,360			96,360			157,680			157,680	
Net Electricity Cost (Unsubsidized)	$/MWh		$48.00			$48.00			$35.00			$35.00	
Net Electricity Cost (subsidized)	$/MWh		$30.56			$30.56			$30.31			$30.31	
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)	%		1.50%			1.50%			1.50%			1.50%	
Annual Inflation	%		2.00%			2.00%			2.00%			2.00%	
Capital Structure:													
Debt	%		40.0%			40.0%			40.0%			40.0%	
Cost of Debt	%		8.0%			8.0%			8.0%			8.0%	
Equity	%		60.0%			60.0%			60.0%			60.0%	
Cost of Equity	%		12.0%			12.0%			12.0%			12.0%	
Tax Rate	%		21.0%			21.0%			21.0%			21.0%	
WACC	%		9.7%			9.7%			9.7%			9.7%	
Unsubsidized Levelized Cost of Hydrogen	$/kg	$5.65		$7.37	$4.53		$5.78	$4.05		$5.29	$3.20		$4.08
Subsidized Levelized Cost of Hydrogen	$/kg	$2.55		$4.28	$1.57		$2.83	$1.74		$2.99	$0.93		$1.81
Natural gas price	$/mmbtu		$3.45			$3.45			$3.45			$3.45	
Peaker LCOE at 0% H2 blend by vol. (unsubsidized)	$/MWh		$173.00			$173.00			$173.00			$173.00	
Peaker LCOE at 25% H2 blend by vol. (unsubsidized)	$/MWh	$220	–	$235	$210	–	$221	$206	–	$217	$198	–	$206
Peaker LCOE at 25% H2 blend by vol. (subsidized)	$/MWh	$193	–	$208	$184	–	$195	$185	–	$196	$178	–	$186
Memo: Unsubsidized Natural Gas Equivalent Cost	*$/MMBTU*	*$49.55*		*$64.65*	*$39.75*		*$50.70*	*$35.50*		*$46.45*	*$28.05*		*$35.80*
Memo: Subsidized Natural Gas Equivalent Cost	*$/MMBTU*	*$22.40*		*$37.55*	*$13.75*		*$24.80*	*$15.30*		*$26.25*	*$8.15*		*$15.90*

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

BEFORE THE PUBLIC SERVICE COMMISSION OF WYOMING

IN THE MATTER OF THE APPLICATION OF ROCKY MOUNTAIN POWER FOR AUTHORITY TO INCREASE ITS RETAIL ELECTRIC SERVICE RATES BY APPROXIMATELY $140.2 MILLION PER YEAR OR 21.6 PERCENT AND TO REVISE THE ENERGY COST ADJUSTMENT MECHANISM	DOCKET NO. 20000-633-ER-23 RECORD NO. 17252

AFFIDAVIT, OATH AND VERIFICATION

Ronald J. Binz (Affiant) being of lawful age and being first duly sworn, hereby deposes and says that:

Affiant is a Principal with Public Policy Consulting and is testifying on behalf of Sierra Club.

Affiant prepared and caused to be filed the foregoing testimony. Affiant has, by all necessary action, been duly authorized to file this testimony and make this Oath and Verification.

Affiant hereby verifies that, based on Affiant's knowledge, all statements and information contained within the testimony and all of its associated attachments are true and complete and constitute the recommendations of the Affiant in his official capacity as a Principal with Public Policy Consulting, testifying on behalf of Sierra Cub.

Dated this 14th day of August, 2023 at Denver, Colorado.

Ronald J. Binz
Principal, Public Policy Consulting
333 Eudora Street
Denver, CO 80220

Certificate of Service

I hereby certify that on this 14th day of August 2023, the **Direct Testimony and Exhibits of Ronald J. Binz on Behalf of Sierra Club** was e-filed with the Wyoming Public Service Commission and a true and correct copy was sent, via mail to the following:

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