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24-05041

Public Utilities Commission of Nevada
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Filed For: Interwest Energy Alliance

In accordance with NRS Chapter 719,
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by: /s Dallas Harris

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October 18, 2024

Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 E. William Street
Carson City, NV 89701

Re: Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.
Docket No. 24-05041

Dear Ms. Osborne:

Please find enclosed the Prepared Direct Testimony of Mark Detsky on behalf of Interwest Energy Alliance ("IEA") in the above-referenced docket.

If you have any questions regarding this filing, please do not hesitate to contact me.

Sincerely,

/s/ Dallas A. Harris
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Nevada Bar No. 14718
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Of Attorneys for Interwest Energy Alliance

Enclosure

BEFORE THE PUBLIC UTILITIES COMMISSION OF NEVADA

Joint Application of Nevada Power Company d/b/a NV Energy and Sierra Pacific Power Company d/b/a NV Energy for approval of their joint 2025-2044 integrated resource plan, for the three-year Action Plan period 2025-2027, and the Energy Supply Plan period of 2025-2027.	Docket No. 24-05041

PREPARED DIRECT TESTIMONY OF

MARK DETSKY

ON BEHALF OF

INTERWEST ENERGY ALLIANCE

October 18, 2024

I. Introduction and Purpose

Q.1. State your name, position, and business address.

A.1. My name is Mark Detsky. I am an attorney and partner at Dietze and Davis, P.C. My address is 2060 Broadway, Suite 400, Boulder, Colorado 80302.

Q.2. On whose behalf are you testifying in this proceeding?

A.2. I am testifying on behalf of Interwest Energy Alliance (Interwest).

Q.3. Please introduce Interwest.

A.3. Interwest is a non-profit trade association of utility-scale renewable energy developers and manufacturers. Interwest's members include developers building solar, wind, storage, and transmission resources in Nevada. Interwest promotes the growth of utility-scale renewable energy and storage markets in Nevada and five other Intermountain West and Desert Southwest states. Interwest also advocates for improvements in regional coordination of electricity providers, including in transmission and regional markets planning forums. Interwest is not a market participant; it is neither a bidder nor a developer of generation projects. Interwest has been an active participant for many years in regulatory proceedings in Nevada, as well as in Arizona, Colorado, New Mexico, Utah, and Wyoming, giving it broad and ongoing experience with Western electricity generation and transmission markets.

Q.4. Please summarize your qualifications and work experience.

A.4. I have twenty years' experience representing clients in Colorado, including in Integrated Resource Plan (IRP) proceedings of Public Service Company of Colorado (PSCo), Black Hills Colorado Electric, and Tri-State Generation and Transmission Association. I have also participated in rulemakings, certificates of public convenience and necessity (CPCNs), transmission-related applications, as well as legislation related to resource and transmission planning. I was endorsed as an expert in resource planning in the Georgia Power IRP in 2019 and in the Alabama Power IRP in 2020. In 2023, I testified on behalf of Interwest in the Sierra Pacific Power Company d/b/a NV Energy (SPPC) and Nevada Power Company d/b/a NV Energy (NPC) (collectively NV Energy or the Company) Fourth Amendment to the 2021 IRP.[1] My CV is included as **Exhibit MDD-1.**

My legal practice includes the representation of Independent Power Producers (IPPs), including an IPP trade association in Colorado. In addition to resource planning, I have experience in generation project development, including offtake and purchase and sale agreements, and Large Generator Interconnection Procedures and Agreements (LGIAs/LGIPs). My regulatory experience includes proceedings for utilities of different sizes, as well as in ratemaking, in regions that are not part of any Regional Transmission Organization (RTO). In 2020, I co-authored a report analyzing best practices in IRPs, provided as **Exhibit MDD-2**.[2]

Q.5. Have you testified before the Nevada Public Utilities Commission?

A.5. Yes, I testified in NV Energy's 2023 application for a Fourth Amendment to its 2021 IRP (the "Fourth Amendment")[3].

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1 Docket No. 22-11032 Docket No. 22-11032, Testimony of Mark D. Detsky on behalf of Interwest Energy Alliance, Nevada Public Utilities Commission (hereinafter "Interwest 2021 IRP Fourth Amendment Testimony").

2 Detsky, M., Lehr, R., Wilson, J, and O'Boyle, M., *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement,* Energy Innovation and the Southern Alliance for Clean Energy (April 2020), available at https://cleanenergy.org/wp-content/uploads/All-Source-Utility-Electricity-Generation-Procurement-Best-Practices_EI_SACE.pdf.

3 Interwest 2021 IRP Fourth Amendment Testimony.

Q.6. What is the purpose of your testimony?

A.6. The purpose of my testimony is to provide Interwest's recommendations for the Commission Order in this IRP. The Commission and the Nevada legislature have in recent years made clear the need for homegrown Nevada resource development. Part and parcel of this priority is to ensure that Nevada ratepayers get the best value out of NV Energy's resource acquisitions. To accomplish this, Nevada needs a robust generation development market, and that in turn depends on certainty and transparency in resource acquisition and transmission planning processes.

Q.7. Please summarize your testimony.

A.7. My testimony supports the three proposed power purchase agreement (PPA) resource acquisitions that were selected from a competitive solicitation, or Request for Proposals (RFP) process, and supports the Company's request for continued investment and development of the Greenlink Transmission Project (Greenlink). My testimony does not take a position on the Company's request for two natural gas-fired, hydrogen-capable, combustion turbines (CTs) at the North Valmy Generating Station totaling 411 MW nameplate capacity (the "North Valmy Units") but identifies questionable modeling and selection methodology employed by NV Energy in selecting the North Valmy Units for its preferred portfolio. My testimony argues that the proposed addition of the North Valmy Units may warrant additional Commission review.

I also show that NV Energy's RFP timing and procedures are not well-suited to allowing robust market participation from a wide array of developers and projects in those RFPs. In particular, the disconnected nature of NV Energy's RFPs and IRPs creates long lead times from project proposal to project approval, resulting in excessive generation project risk.

The Company presents PPAs for approval here that were priced and bid 14 months ago. In addition, the RFP analysis process remains opaque and lacks competitiveness. The bids into the 2023 Open Resource RFP (2023 RFP), like the three before it, were not evaluated using best bid evaluation practices for RFPs, such as testing bids using the PLEXOS LT capacity expansion model upon which the IRP is based.

In addition to the uncertain competitiveness of NV Energy's RFP practices, NV Energy's portfolio selection procedures show evidence of interference, with NV Energy circumventing its planning model and hand selecting new resources via a screening process the Company conducts after capacity expansion modeling. This screening process substitutes model-selected placeholder resources for the Company's preferred generation projects[4], calling into question whether the Company's selected portfolio is optimal, including in its selectin of the North Valmy Units.

The Commission has an opportunity to address recent shortcomings of NV Energy's resource selection process by adding structure to NV Energy's upcoming 2024 All-Source RFP ("the 2024 RFP"). [5] NV Energy has disclosed that it will release the 2024 RFP this year.[6] I recommend that the Commission require the timely issuance of the 2024 RFP, provide limited direction to NV Energy on the terms, conditions, and scope of the 2024 RFP, and set a deadline for the Company to file a First Amendment to this IRP that includes requests for approval for

[4] *See* Supply Plan, Application, Vol. 8 at 227–38 (explaining that potential projects were "developed from a combination of self-development efforts, request for proposal bid responses, and bilateral negotiations," and that screening cases "were developed by adding these projects individually to the Base Case, then adjusting placeholder resources to achieve similar open positions and similar amounts of renewable energy in each screening case.").

[5] Staff 63, **Exhibit MDD-3** ("NV Energy is currently planning to issue an all source (formerly open resource) RFP in August 2024. NV Energy is not currently involved in bilateral negotiations with any renewable project developers.").

[6] Email from Rainie Mitchell, Renewables and Origination, NV Energy, to Sam Johnston, Interwest (Aug. 14. 2024), attached as **Exhibit MDD-16.**

2024 RFP winning bids. This action will ensure that the upcoming RFP is fair and transparent and that it selects the best available resources, while timing constraints will ensure project success. I discuss options for the Commission to integrate the 2024 RFP as an Action Plan element.

Several factors make a timely and successful Company RFP imperative, including the Company's remaining open position in summer 2028, the Company's need to meet resource sufficiency tests or face penalties after joining the Western Resource Adequacy Program (WRAP), the increased chances of a high load growth scenario, and the need for contingency projects should projects in the pipeline withdraw. In addition to those compelling reasons for the Company to conduct an effective and robust procurement process, the Company's upcoming solicitation offers the Commission the opportunity to compare the Company's North Valmy Units proposal with other available resources. Best resource planning practices would allow the Commission to have that opportunity, and the 2024 RFP presents such an opportunity.

This IRP and the upcoming 2024 RFP face the challenge of the difficult economic environment for new generation projects, as evidenced in the five amendments to the 2021 NV Energy IRP. The state of the generation market is such that, since 2020, generation and storage demand and supply cost trends have trended upward as utilities and renewable developers alike deal with significant cost increases on equipment and labor, international trade issues and other supply chain bottlenecks, and increasing demand – all while trying to decarbonize the electric system.[7] The Commission can adapt to this challenging environment by accelerating the Company's resource acquisition pipeline and integrating the Company's planned 2024 RFP

[7] *See e.g.,* Lazard Levelized Cost of Energy Analysis 2023 at 9 (Attached as **Exhibit MDD-4).**

into the IRP framework. Meanwhile, taking this action would give the Commission the valuable opportunity to review the soundness of the process behind the North Valmy Units proposal, a review that could inform future resource planning decisions.

Q.8. How is your testimony organized?

A.8. My testimony first details Interwest's recommendations. Section III discusses deficiencies with the current RFP process, including how it increases the risk of project failure. Section IV discusses Interwest's proposal for the 2024 RFP and a First Amendment to the 2024 IRP. Section V supports certain of the proposed Supply Plan additions including the PPAs and Greenlink and other transmission investments. I also share my concerns about the North Valmy Units selection process.

Q.9. Are you submitting exhibits along with your testimony?

A.9. Yes, I am submitting 16 exhibits along with my testimony as shown in the table below.

Exhibit Number	Description
MDD-1	Mark Detsky CV
MDD-2	2020 Energy Innovation *et. al*. paper: "Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement."
MDD-3	Response to Data Request Staff 63
MDD-4	Lazard Levelized Cost of Energy Analysis 2023
MDD-5	Response to IEA-002
MDD-6	Response to IEA-006
MDD-7	Response to Staff 69
MDD-8	National Infrastructure Advisory Council draft report, "Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Grid" dated June 2024
MDD-9	Response to IEA – 005 Attachment 1 (2023 RFP)
MDD-10	Staff 115 Attachment 1
MDD-11	IEA-001 Attachment 1
MDD-12	IEA-018
MDD-13	Staff 99

MDD-14	IEA 3-02
MDD-16	Email from Rainie Mitchell, NVE, to Sam Johnston, Interwest

II. Summary of Recommendations

Q.10. Please detail your recommendations.

A.10. I recommend that the Commission order the following in its decision:

1. Approve the NV Energy Action Plan and Supply Plan in part, as follows:
    a. Approve the PPAs for the three "Clean Energy Units", defined as:
        - Dry Lake East PV and BESS PPA for 200 MW of renewable energy and 200 MW of storage with an in-service date (ISD) of December 2026 ("Dry Lake").
        - Boulder Solar III PV and BESS PPA for 127.9 MW of renewable energy and 127.9 MW of storage with an ISD of June 2027 ("Boulder III").
        - Libra Solar PV and BESS PPA for 700 MW of renewable energy and 700 MW of storage with an ISD of December 2027 ("Libra").
    b. Approve the Company's continued development and capital investment in the full Greenlink project, and other transmission investments in the Supply Plan.
    c. Approve the Corsac geothermal PPA.
2. Consider a closer review of the North Valmy Units together with the available options in the market based on responses to the 2024 RFP.
3. Approve the 2024 RFP as an Action Plan element. Consider options for integrating the RFP results as potential Supply Plan additions either via an IRP amendment or another process.
4. Order that the 2024 RFP be modified and integrated into the IRP as follows:

a. If the RFP has not been released, require the release of the 2024 RFP.

b. Order that the bid submission due date be set by the Company as on or before sixty (60) days from when the Commission's 2024 IRP order becomes final (if released) or 60 days from release, based on the Commission's order.

c. If the 2024 RFP has been released, require the Company to update the RFP documents with direction approved by the Commission. Include in the 2024 RFP approval a proposed capacity acquisition amount. One possible amount could be the capacity identified by the Company sufficient to close the open position as of summer 2028.

d. Require the Company to employ best practices in resource planning bid evaluation, including using PLEXOS LT software to test 2024 RFP shortlisted bids in capacity expansion portfolios.

e. Order that the results of the Company's 2024 RFP be presented to the Commission within a time certain, for instance, 120 to 150 days after bid submission, subject to input from NV Energy as to the amount of time the Company requires, to ensure timely review while bids are still viable.

f. Direct the Company to include in its 2024 RFP, prior to evaluation via resource planning software modeling, an opportunity for shortlisted bids to reprice and provide "best and final" proposals that allow bid price increases. This repricing opportunity would also apply to Company proposed candidates.

Q.11. Please provide a draft timeline for the 2024 RFP and First Amendment.

A.11. The following recommended proposal is subject to Company and stakeholder input, as explained in Section IV:

Table MDD-1: Recommended 2024 RFP and First Amendment timeline

Event	Date
RFP Released/Updated	Commission Final Order in IRP + 14 days
RFP bids due	+ 60 days from RFP release
RFP results presented in First Amendment to IRP	+ 4-5 months of RFP bid deadline
Commission decision on 2024 RFP First Amendment	+120 days from RFP filing (indicative of expedited review)

III. NV Energy's RFP Process Increases Project Failure Risk

Q.12. Please describe the purpose of this section.

A.12. This section sets forth Interwest's concerns with NV Energy's current RFP solicitation process and supports the recommendation to direct NV Energy to conduct the 2024 RFP and for the Commission to include it in the approved Action Plan. NV Energy's RFP process adds uncertainty and risk of delay to project development. The process can be improved by the opportunity presented by the 2024 RFP.

A. NV Energy's RFP process is too long and disjointed from IRP filings

Q.13. How does NV Energy characterize its RFP and resource acquisition process?

A.13. NV Energy testified that the RFP is one part of its "multi-prong" strategy to explore options that also include self-build plans, unsolicited offers, or bilateral negotiations in the absence of an RFP.[8]

Q.14. What are your concerns with NV Energy's use of RFPs as a prong of its strategy?

[8] Direct Testimony of Jimmy Daghlian, Application, Vol. 4, at 26.

A.14. My concerns are first that NV Energy treats RFPs as a single tool employed completely within its own discretion, along with self-build plans, unsolicited offers, or bilateral negotiations. The RFP is clearly the Company's least preferred tool given that the Company has only brought forward resources for approval in one of its last four RFPs. RFPs should instead not only be the Company's central resource acquisition tool, but the Commission's preferred tool to foster competition and transparency.

The Company also fails to follow accepted competitive procurement features in the conduct of its RFPs. Competitive procurements require fair opportunity to compete, which includes congruent information among all bidders and the entity conducting the RFP, predictable outcomes, and prohibition of process circumvention by contracting outside of the procurement process.[9] Instead, the timing of RFP releases, contents, bid evaluation, and bid selection remain entirely within NV Energy's shifting discretion. This IRP contains little information about the terms and conditions of the 2023 RFP, even though three of the five requested generators come from the 2023 RFP.

Q.15. What are your concerns with respect to the Company's RFP approach in this IRP?

A.15. The 2023 RFP is badly mistimed with this IRP approval request. The 2023 RFP did not communicate to the market the resource adequacy (RA) needs, the size and scope of the acquisition, the correct approval timeline, or direction from an IRP order. Worse, it appears that the 2024 RFP will continue these practices; Although it is not yet released, the 2024 RFP has no clear pathway to Commission review or approval.

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9 *See* Exhibit MDD-2.

Q.16. How is the 2023 RFP disconnected in terms of timing of the IRP?

A.16. The timing of when bids were requested and received is not reasonably connected to the time when bids were brought forward for approval. As a result, generation developers have been made to hold their pricing for well over a year from the time bids were submitted, without the ability to account for inflation or changes in market conditions, such as international tariffs. In today's high inflation environment, that is a big problem.

The most recent RFP was released January 17, 2023.[10] Bids were due March 14, 2023, except that solar and storage PPA bids (that were ultimately selected) were originally disallowed. Solar and storage PPA bids were later given the ability to bid by email dated July 19, 2023, and the bid deadline was extended to August 17, 2023. Although bids were given the ability to "refresh" with best and final pricing, that was only allowed to *reduce* pricing.[11]

The Company performed due diligence and executed PPAs prior to the IRP. Having executed PPAs will help projects move forward quickly after approval. However, these executed PPAs were awarded RFP bids based on pricing they provided last August. The PPAs will not be considered approved by the Commission until after the final Order in this IRP, approximately 18 months from their bid submission (estimated at January 2025). This timing estimate assumes no requests for rehearing (RRR) or court appeals involving or impacting the selected PPAs. Eighteen months is not a commercially reasonable amount of time in this economic environment for a renewable and/or storage developer to hold pricing developed in July 2023 to move forward in February 2025.

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10 **Exhibit MDD-9.**

11 *Id.* at 45.

Q.17. When did the 2023 RFP indicate to bidders that approvals would be made?

A.17. Table 2 in the 2023 RFP listed the expected PUCN approval to be May 3, 2024.[12] The 2023 RFP was released while the Fourth Amendment was ongoing. After bids were submitted, the Company put forward the Fifth Amendment to its 2021 IRP (the "Fifth Amendment")[13], but did not include any resources from the 2023 RFP. In other words, the Company's IRP filings could have accommodated a May 3, 2024, approval as the 2023 RFP communicated to the market, but the Company chose not to integrate its RFP with the Fifth Amendment.

Q.18. Have the Clean Energy Units' PPAs been delayed pending the outcome of this case?

A.18. While I am not in communication with these developers, I would opine that it is likely that the Clean Energy Units are "on hold" on major contract milestones until the PPAs are approved by the Commission. This is because under each PPA, there is a "Condition Precedent" in Section 16 where NV Energy, as Buyer, is not committed to the project and therefore the contract is not guaranteed, until the Commission approves the PPA, with conditions acceptable to the Company in its discretion.[14] The Condition Precedent is not satisfied until RRRs are concluded and the decision is not appealed to the courts (if applicable to the project).[15] This is standard practice as neither sophisticated renewable developers, financiers, nor the utility will move forward prior to addressing the regulatory risk that the contract would not be approved until such decision is final and without a right of appeal. NV

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12 *Id.* at 13 on Exh. MDD-9 supra.

13 Docket No. 23-08015, 2021 IRP Fifth Amendment, filed on August 21, 2023.

14 Dry Lake East, Vol. 23 at 86-87; Boulder Solar III, Vol. 24 at 65-66; Libra, Vol. 25 at 178-179. I assume that the Company may move forward before RRR's are decided if a given PPA is not impacted, however that is not explicit in each PPA.

15 *Id.*

Energy did not start that process for the Supply Plan PPAs until June 2024, and the complex nature of the IRP decision-making will likely last into the first quarter of 2025.

Q.19. What is the effect of the Condition Precedent in Section 16 of each PPA?

A.19. With the same caveat that I am not in contact with these project developers, in my experience a PPA, or any offtake agreement, will include a "Notice to Proceed" (NTP) or similar written approval to allow for construction and financing once condition precedents have been met. Lenders may not close financing on a project before that time. Developers may in turn wait for an NTP to finalize equipment orders and transmission studies, to acquire construction permits, and to build the facility.

If the Condition Precedent in Section 16 of the PPAs has not been met, then it is likely that the Clean Energy Unit developers have not closed financing of their project. Additionally, the Clean Energy Unit developers may not have procured solar panels or transmission equipment or executed labor contracts. Each of these cost areas are subject to inflationary pressure, meaning that each day of delay may adversely affect their ability to construct the projects.

Q.20. Could the Condition Precedent also affect the Clean Energy Units' Commercial Operation Dates (CODs)?

A.20. Yes. Delays in regulatory approval and NTP could negatively impact the CODs for these projects. For example, NV Energy produced a table showing that the Boulder Solar III PPA has a development timeline to COD that is "29 months following PUCN approval."[16]

[16] **Exhibit MDD-10,** Tab: Project Differences, Cell: D14.

Assuming that Commission approval occurs in January 2025, 29 months would be July 1, 2027. This is one month after the contracted COD.

It is reasonable to assume that the generation project developers planned as-bid CODs based on the approval deadline communicated to bidders by NV Energy in the 2023 RFP, estimated to be May 3, 2024. Contracted CODs are a dance of regulatory approvals, financing, equipment, permits, labor and construction. Pressure on any element increases the risk of on time COD.

Q.21. Are you saying that the Clean Energy Units will not be built?

A.21. No. But I am saying that NV Energy has exacerbated the risks to the Clean Energy Unit developers both in terms of project cost and COD project delivery through the RFP delay in approval. NV Energy no doubt was aware of the current inflationary pressures these developers are feeling when it released an RFP in January 2023. In addition, this span of 18 – 24 months between bid submittal (August 2023) and NTP (January or February 2025) not only puts significant pressure on the developers' ability to meet their contracted ISD; it also risks NV Energy's ability to meet its forecasted RA need.

Q.22. Is there evidence that project delays and past RFPs exacerbate these RA risks?

A.22. Yes. The Company put forward three RFPs between 2019 and 2022 and did not bring forward a project from any of those RFP bids.[17] As I showed in my testimony to the Fourth Amendment, this was reflected in the low number of bids received in 2022.[18] The 2023 RFP

[17] Docket No. XX_ XXX, Phase 1 Order ¶¶ 34 and 35 regarding 2020; Docket No. 22-11032 , Exhibit MDD – 15 regarding 2022.

[18] Interwest 2021 IRP Fourth Amendment Testimony.

increased the bid pool compared to 2022, but still one-third of bids were eliminated by the Company for transmission deficiencies. The Company received 84 bids representing 31 individual projects. The Company shortlisted 28 bids.[19] A similarly timed RFP released by PSCo in Colorado received over 1000 bids from over 200 projects.[20]

B. The NV Energy RFP Did Not Communicate RA Needs to The Market

Q. Are there concerns other than the delay risk that you identified in prior RFPs?

A. Yes. In addition to delay risk, there is transparency risk where the Company continues to fail to communicate its resource needs to the market with adequate specificity.

Q. Please explain what you mean by transparency risk.

A. The 2023 RFP did not disclose the Company's RA need. For example, the 2023 RFP purpose section indicates only that the Company was soliciting resources over 20 MW and does not mention the open position or the amount of capacity it sought to acquire from individual projects, among individual technology types or in the aggregate.[21] In the IRP, the Company expresses disappointment that it did not receive Idaho wind bids where its base case suggested nearly 1,000 MW would be economic.[22] If the base case had been approved prior to an RFP and the market had been aware of a gigawatt need for wind, such bids may have materialized. But the 2023 RFP did not mention that type of bid being sought, and the Company did not receive bids that its model found optimal.

19 Docket No. 24-05041, IEA 007 and Attachment 1. **Exhibit MDD-15.**
20 *See generally,* Public Service Company of Colorado ERP in Proceeding 21A-0141E (COPUC).
21 IEA-005 Attach 005-1 (2023 RFP) **Exhibit MDD-9.**
22 Supply Plan, Application, Vol. 8 at 232

If the market had specific information on RA need and the goals of the IRP, including project sizes, technologies, areas needing additional generation or ancillary transmission services, it is likely that generation developers would offer projects calibrated to those needs.

C. NV Energy's Bid Evaluation Process Remains Opaque

Q.23. Please explain how NV Energy conducts bid evaluation in the RFP.

A.23. NV Energy conducts RFP bid evaluation through a confidential tabletop exercise where it selects projects that it feels meet the criteria it has put in place in its discretion and eliminates projects based on transmission evaluations or other flaws. NV Energy does not test RFP bids in capacity expansion runs using PLEXOS LT.[23]

Q.24. How does the Company use the PLEXOS LT module if not to optimize from available bid choices?

A.24. The Company conducts its base case PLEXOS LT optimization runs for scenarios that make generic (placeholder) renewable resources as available "candidates" one megawatt at a time until an optimal capacity is reached.[24]

NV Energy then proceeds to a screening stage in which NV Energy substitutes PLEXOS LT-selected placeholder projects with projects hand-picked by NV Energy from among an unknown pool of resources it states that it selected from the 2023 RFP, self-build options, and bilateral negotiations.

Q.25. Are there additional concerns with NV Energy's modeling approach?

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[23] IEA 006. Exhibit MDD-6.

[24] Docket No. 24-04051, Supply Plan, Application, Vol. 8, at 224.

A.25. Yes. NV Energy's approach with the North Valmy Units shows an undue favoring of self-build projects where such projects do not have to compete in an RFP nor are they ever subject to selection in a portfolio optimization model run. Rather, Company-owned proposed units are hard coded into the model. In its "screening cases" and the "combination cases" that followed, the Company simply inserted the North Valmy Units in one run and other CT proposals at approximately 400 MW in capacity for other runs.[25] I discuss problems with NV Energy's methodology related to selecting the North Valmy units in more detail in Section V.

Q.26. Does PLEXOS LT select projects the Company identifies in screening?

A.26. No. The resources available to select in screening come from a pool created by NV Energy from RFPs, bilateral discussions, and self-build activity; the Supply Plan does not include any information regarding the criteria NV Energy uses to develop this pool. The near-term acquisitions proposed here are sourced entirely from that screening pool, meaning those decisions were entirely hardwired. With respect to the PWRR portfolio comparisons, the difference between portfolios may have more to do with the "tail" of the model, or what happens in future IRPs, because there are no near-term decisions made. Further, NV Energy states that the Company makes "placeholder adjustments" in the "combination cases" prior to developing the alternative plans. These adjustments, the Company says, keep the open position the same throughout the planning period. This means that NV Energy manually adjusts the capacity expansion *outputs* of generic resources as well as manually adjusting the *inputs*. This practice would materially change the PWRR of portfolios, because each unit change comes with a cost that is reflected in the PWRR. In the end, this analysis approach makes it unclear

[25] Docket No. 24-05041, IEA-001 Attachment 1 (showing combination cases). **Exhibit MDD-11.**

whether Figure EA-17, showing the relative PWRR rankings of PLEXOS LT combination case runs over 26 years, shows optimized modeling results at all.

Q.27. What do you conclude with respect to RFP process and evaluation by NV Energy?

A.27. NV Energy's RFP evaluations are not transparent. The lack of structure or standards in NV Energy's evaluation of RFPs results in arbitrary unforced errors like initially prohibiting and then only picking solar/battery energy storage systems (BESS) PPA bids. RFP bid submissions are not properly evaluated with capacity expansion resource planning software. NV Energy does not communicate information about its resource needs to the market to sufficiently elicit bids that actually suit its RA needs. Bidders also face a high degree of uncertainty when investing resources in Nevada projects with the hope of bidding into an NV Energy RFP: bidders have no guarantee of timing of RFP selection or Commission approval if selected, and projects are only brought to the Commission for approval 25% of the time. Over time, this can chill market interest in RFPs because of the lack of certainty and at worst, the perception that NV Energy will gain price discovery and project information to leverage for its self-build projects or in future bilateral negotiations.

Q.28. Can anything be done to improve the success of generation acquisition?

A.28. Yes, the Commission can add structure to the Company's procurements by directing the Company to conduct the 2024 RFP and providing limited direction on its scope and timeline.

IV. The Commission Should Require NV Energy to Conduct the 2024 RFP and Integrate It with the IRP

Q.29. Please describe the purpose of this section.

A.29. In this section, I argue why requiring an RFP is in the public interest and provide Interwest's recommendation that the Commission require the Company to conduct the 2024 RFP with certain conditions. Interwest supports the issuance of the Company's 2024 RFP and proposes that the Commission: (1) direct NV Energy to conduct the RFP and include the RFP in the approved Action Plan, (2) direct NV Energy to return to the Commission with RFP results and analysis in a First Amendment as a Supply Plan addition, among other options, and (3) consider additional findings and direction to the Company regarding the scope of the RFP.

Q.30. What are the additional findings on RFP scope that you recommend?

A.30. I recommend that the Commission consider each of the following as separate potential findings:

1. The Company should evaluate shortlisted bids using its resource planning software, including testing bids in PLEXOS LT capacity expansion runs.
2. The Company should continue to allow "best and final" pricing prior to computer modeling to capture any cost increases (or decreases) between bid submission and computer modeling, to help ensure that developers can maintain pricing through Commission approval.

Q.31. Does your proposal address potential timing concerns with the 2024 RFP?

A.31. Yes. The primary reason for the Commission to adopt Interwest's RFP proposal is to address the project delay concerns I discussed in Section III.A., above. The recommendations are also intended to address modeling deficiencies I discussed in Section III.C., and to address the RA need through the Action Plan period.

A. Requiring the issuance of the 2024 RFP Under the Action Plan is in the Public Interest.

Q.32. Why is it in the public interest for the Commission to order NV Energy to conduct a 2024 RFP that includes certain terms and conditions?

A.32. Conducting an RFP as soon as possible will help the Commission address Nevada's resource adequacy concerns and stem the recent tide of NV Energy IRPs and IRP amendments, many of which have proposed large new gas generation additions based on arguments related to an urgent capacity need. Seeding more development activity ahead of any resource adequacy crisis will put NV Energy back on the front foot for addressing resource adequacy and closing the open position, rather than consistent reactionary filings. And conducting an RFP that includes best practice timing characteristics will alleviate the risk of delay articulated in Section III. Finally, the RFP provides an opportunity for the Commission to test the methodology involved in selecting the North Valmy Units. Conducting the 2024 RFP under certain terms and conditions will help alleviate concerns related to RFP timing and its connection with the IRP.

Q.33. Please explain how the Commission's approval of Interwest's proposals could address the timing concern you showed above?

A.33. If the Commission does not approve the 2024 RFP under the Action Plan, then there are two potential concerns that could negatively affect ratepayers. First, NV Energy may conduct the 2024 RFP but fail to request Commission approval of any 2024 RFP winning bids within a commercially reasonable period time, or within 4-6 months from bid submittal, for bidders to hold pricing.

The second reason is that if the Commission's proposed rules under AB 524[26] become final and 2024 RFP resources cannot be brought forward in an IRP amendment, then NV Energy will have to wait until its next IRP to bring forward any resource amount greater than 70 MW from the 2024 RFP. This means either NV Energy, the Commission, and stakeholders would face the enormous burden of a 2025 IRP filing to secure timely project approvals, or face a 2026 IRP that includes 2024 bids that will at that time no longer be viable.

1. Conducting a 2024 RFP will help NV Energy close its open position and address resource adequacy concerns.

Q.34. Are there other reasons for the Commission to direct NV Energy to conduct the 2024 RFP as part of the Action Plan?

A.34. Yes. There are clear reasons why conducting a successful 2024 RFP is in the public interest. NV Energy has disclosed that a high load growth scenario may be more likely due to new demands.[27] Additionally, projects approved in the last three years face significant economic headwinds.. The Company hedges that Sierra Solar is still being "evaluated", despite its approval in the 2021 IRP Fifth Amendment.[28] The RFP could provide a source of backup projects if there are further project withdrawals.

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[26] Proposed Regulations of the Public Utilities Commission of Nevada, Docket No. 23-07026, Nevada Legislative Counsel Bureau File No. R160-24, *available at* https://www.leg.state.nv.us/Register/2024Register/R160-24I.pdf

[27] Supply Plan, Application, Vol. 8, at 129 describing inquiries for loads of addition 6,000 MW.

[28] IEA 0018. **Exhibit MDD-12.** The project remains early enough in development where the Company can move forward with EPC contracts for ancillary buildings but hedge on full financial commitment. That will soon change, however, as the ISD gets closer.

But the biggest driver is that even if the Preferred Plan is approved, the Company's open position continues to grow[29], and will only grow more rapidly if high load growth due in part to new high load factor data center development continues. The Company states that monthly deficiency for the WRAP initial compliance period is approximately 540 MW in September 2028.[30] This deficiency would have to be met by unidentified short-term purchases. However, the Company states that "there is a risk in relying on market purchases to meet the resource sufficiency requirements of in [the] WRAP" because "it may not always be possible to close shortfalls with contractual supplies where those contracts must be firm and provided to WRAP seven-months ahead of time."[31] Seven months is indeed a long lead time for a short-term capacity purchase.

Q.35. Please explain the Company's open position during the Action Plan.

A.35. NV Energy states that the Balanced Plan and Renewable Plan "achieve the 750 MW open position target by 2028 and maintain it through the study period."[32]

Q.36. Did the Company present an alternative plan that closes the open position during the Action Plan period?

A.36. No. The Company presents an alternative plan called the "No Open Position Plan". The No Open Position Plan closes the open position starting in 2028 through the entire planning

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29 Application Summary, Vol. 5 at 10

30 *Id.* at 12

31 Staff 99 **Exhibit MDD-13** (explaining the need to limit the open position to 750 MW in 2028 and thereafter).

32 Direct Testimony of Kimberly Williams, Application, Vol. 4, at 102.

period of 26 years, after the Action Plan period, by disallowing market purchases in PLEXOS LT.[33]

Q.37. Does the No Open Position alternative plan portray the PWRR of closing the open position during the Action Plan period?

A.37. No. The No Open Position Plan continues to close the open position during the remaining 23 years of the planning period, and therefore does not present a portfolio that looks at closing the open position specific to the instant Action Plan period.[34] Figure EA-23 shows how the No Open Position Plan portfolio goes deeply long on generation in the 2030s. This model run puts a thumb on the out years of the portfolio scale by including many additional resources in the out years of the planning period. The No Open Position Plan therefore does not provide insight as to the cost of closing the open position by 2028. It does, however, greatly influence the PWRR of the portfolio for comparative purposes and is easily dismissed by NV Energy as a result. Not surprisingly, it is the most expensive plan option, but not in a way that is relevant to the Supply Plan decisions here.

Q.38. Does the Preferred Plan modeling indicate what it would take to close the open position only during the Action Plan period, or into 2028?

A.38. Yes. The Company states that the No Open Position Plan portfolio keeps the same resources as Balanced Plan and the same named placeholder resources, so it starts out the same as the Balanced Plan. Because the No Open Position Plan portfolio is designed to close the open position starting in 2028, we can review the model's selections to indicate what might be

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33 Supply Plan, Application, Vol. 8, at 243
34 Williams-Direct, Vol. 4, at 102.

needed in 2028 to close the open position at the end of this Action Plan period or summer 2028 (although we don't have the PWRR).

Figure EA-21 lists the PLEXOS LT buildout for each alternative plan. It shows that in 2028, the No Open Position Plan would add a 225 MW solar PV resource for NPC and a 358 MW BESS resource for SPPC.[35] Both the Balanced Plan and the No Open Position Plan select 925 MW of Idaho wind in 2029. As a result, it would be prudent for these types of resources to be the focus of an RFP during the Action Plan period.

Q.39. Does the No Open Position Plan select additional CTs?

A.39. It does, but not until 2030 with the Harry Allen CTs. So, that decision is outside the Action Plan period and can be examined in the next IRP. At that time, more information will be available about the WRAP and day-ahead market development for 2030, and the result of the 2024 RFP, if such is approved, will be integrated in the IRP.

Q.40. Could the Company economically and reliably close the NV Energy open position through 2028 with the 2024 RFP?

A.40. In requiring NV Energy to conduct the 2024 RFP and associated analysis, the Commission has the opportunity to determine if this is possible.

Q.41. Would closing the open position in 2028 be in the public interest?

A.41. Yes, there are key drivers to close the open position, including for market participation and providing additional renewable resources. However, we don't know the cost-benefit analysis of closing the open position in 2028 absent an RFP and PLEXOS modeling. I will

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[35] Supply Plan, Application, Vol. 8, at 246.

note that in this IRP, as in the 2021 IRP, NV Energy has repeated its concern that it is, to paraphrase, behind the ball in keeping up with its RA obligations. If the 2024 RFP provides direction to the generation development market regarding a solicitation consistent with closing the open position as modeled by the Company, then the RFP could solicit valuable information for the Commission.

Q.42. Would the RFP solicit PPA projects and not Company-owned generation?

A.42. No. The Company would be free to solicit build-transfers or submit its own bids.

Q.43. Does the IRP show that there are RA drivers to the 2024 RFP beyond closing the open position?

A.43. Yes, NV Energy asks for approval of its load forecast as accurate for purposes of the IRP, but it also testifies that it has had multiple gigawatts of new customer inquiries, with 5,900 MW of data centers being studied that are "scaled down in the retail forecast."[36] Coupled with transportation electrification and beneficial electrification, there is a greater likelihood in this IRP, versus those prior, that a high load growth scenario emerges on top of the 540 MW open position. If a high load growth scenario emerges in actuality, then NV Energy's 750 MW open position could grow significantly over the short term.

Q.44. How does the WRAP affect the 2024 RFP decision point?

A.44. According to NV Energy, the WRAP binding period is the winter 2027-2028.[37] By that time, NV Energy must show that it has control of its entire open position on a seven-month

[36] Application Summary, at 24
[37] Supply Plan, Application, Vol. 8, at 215.

forecasted basis, so without short term market purchases. The WRAP binding commitment will ramp up to involve severe penalties akin to building the next marginal unit on its system.

2. Requiring NV Energy to conduct 2024 RFP will allow the Commission to evaluate the North Valmy Units in the context of market available resources.

Q.45. How can the Commission's order the Company to develop more information on its North Valmy Units proposal in the upcoming 2024 RFP?

A.45. The Commission can require the Company's 2024 RFP analysis to utilize PLEXOS resource planning models that allow model selection of one, rather than two, North Valmy CT, both CTs, or other options like the Harry Allen CTs, and to evaluate those options in the context of RFP shortlisted bids. The Company should then be able to present the Commission with a clear picture of whether the North Valmy Units are the most cost-effective and best options for filling the Company's RA need, in addition to testing the value of filling the open position during the Action Plan period. I discuss issues with the Company's modeling that resulted in its selection of the North Valmy units in Section V.

B. Proposed Process for Requiring a 2024 RFP

Q.46. Please describe the proposed process for the 2024 RFP.

A.46. If the Commission directs the Company to conduct the RFP and integrates it into the Action Plan, I recommend the following process in **Table MD-1**.

Event	Date
RFP Released/Updated	Commission Final Order in IRP + 14 days
RFP bids due	+ 60 days from RFP release
RFP results presented/First Amendment to IRP filed	within + 4-5 months of RFP bid deadline

Commission decision on 2024 RFP	+120 days from RFP filing (indicative of expedited review)

Table MD-1: Recommended RFP Timeline

Q. Would this approach align with IRP best practices?

A. In my view, yes. This would align with the five best practices for evaluating RFPs and integrating the same with RA needs and new unit decisions as described in the Executive Summary of the report provided as Exhibit MDD-2.

1. The Commission has options for incorporating the RFP into the existing IRP framework.

Q. What is the purpose of this section?

A. There is not a direct discussion in the Nevada Administrative Code or Nevada Revised Statutes regarding the role of an RFP in the IRP process. I propose some options for the Commission relevant to its consideration of Interwest's RFP proposals here.

Q.49. How do the IRP regulations authorize resource acquisition requirements?

A.49. Under NAC § 704.9489, the IRP must include a three-year Action Plan that must "specify … actions that are to take place during the 3 years commencing with the year following the year in which the resource plan is filed" to meet its demand and energy requirements.[38] The Action Plan must include a "specific timetable for acquisition of options for the supply of electric energy."[39]

[38] NAC § 704.9066

[39] *Id.* at subsections (d) and (3).

Under NAC § 704.9385, the IRP must also include a Supply Plan. A Supply Plan is defined as a utility's plan for using existing and proposed resources to meet its forecasted demand and energy requirements.[40] In addition to comprehensive descriptions of existing and proposed facilities, the Supply Plan must include a comprehensive discussion of alternative strategies if any preferred resource or facility were not available. NAC § 704.944. A Supply Plan must identify sources from which the utility has contracted to buy, or has plans or potential opportunities to buy, electric power, using defined criteria.[41]

Q.50. Can an RFP qualify as an element of an Action Plan?

A.50. Yes, an RFP fits the plain language and scope of an Action Plan. Interwest's recommendation here for the Commission to approve the 2024 RFP, if adopted, would allow the RFP to proceed on an identified timetable for review of options and acquisition during the Action Plan 3-year period. An RFP can and should be issued for an identified range of procurement capacity with desired planned project ISDs. Importantly, with Commission guidance, the RFP can take place on a specific timetable.

Q.51. Can an RFP qualify as an element of a Supply Plan under the NAC?

A.51. Yes, an RFP is designed to identify potential opportunities to buy electric power during the Action Plan term. However, if an RFP is approved as part of an Action Plan, then the RFP selected resources are obviously not known at the time of the Commission's IRP Order and do not provide known CODs, prices, and locations.

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[40] NAC §704.9166.
[41] NAC §704.9166; NAC §704.937

Historically, NV Energy has used RFPs *prior* to the IRP rather than *prospective* RFPs in IRPs, however this practice does not disqualify using a prospective RFP. In fact, given today's market conditions and NV Energy's process, a prospective RFP is more likely to mitigate project risk and provide system benefits than a prior RFP.

2. The Commission has multiple options under statute and rule for integrating the 2024 RFP into this IRP.

Q.52. What are some options for the Commission in considering whether to integrate the RFP into its final order in this IRP?

A.52. Interwest has identified three options to incorporate the RFP as an Action Plan element and for potential Supply Plan additions during the Action Plan period. The Commission has more tools than these to explore, but these are readily identifiable:

1. Approve discrete supply objectives in the 2024 RFP as a Supply Plan "placeholders" under the draft AB 524 Rules.
2. Amend the Commission's draft AB 524 Rules to allow RFP acquisitions in IRP amendments as an exception to the Rules' significant deviation standard. This is Interwest's preferred approach.
3. Direct the Company to file the RFP in a new proceeding.

Q.53. Please explain Option 1.

A.53. In its decision on the Fifth Amendment, the Commission found that the Company should identify planned projects it had identified but was not bringing forward for approval as placeholders.[42] The Company has called these "named placeholders"[43] in this IRP. The

[42] 2021 IRP Fifth Amendment, Order, Ordering ¶ 6.
[43] Supply Plan, Application, Vol. 8 (defining a placeholder resource as a generic unit identified in its base case PLEXOS LT modeling).

Company states that named placeholders represent "reasonably known projects in progress or requested, and to reflect anticipated company-owned projects."[44]

In Docket No. 23-070026, creating regulations to implement AB 524, the Commission defined the parameters of an IRP amendment to allow for Supply Plan modifications to add generating capacity greater than 70 MW nameplate only where the resources are "placeholder generating resources".[45] The term "placeholders" is otherwise not defined in the NAC. The Commission could find that the 2024 RFP results constitute limited, but identifiable, Supply Plan additions that are placeholders under AB 524 draft rules which can be added in an IRP amendment.

Q.54. Are the Company's identified named placeholders actual projects?

A.54. Not entirely. Only some of the placeholders are specifically identified, like Amargosa. Some projects are potential future additions to existing generation. And some, like the Idaho Wind placeholder, are not specific projects at all, but instead conceptual opportunities, not unlike an RFP with a defined amount of capacity to be solicited.

Q.55. What is the concern if the RFP outcome does not qualify for an IRP amendment?

A.55. In that event, the Company could not bring forward projects from the 2024 RFP unless it also brings forward an entirely new IRP. A new IRP would involve compliance with the full suite of NAC requirements, including load forecasting, the Distributed Resources Plan, Demand Side Management and Energy Efficiency, Transportation Electrification Plan, and other studies that frankly might not need to be revisited on the same cadence as an RFP. For

44 Supply Plan at 89
45 Draft rules implementing AB 524

the 2024 RFP, there would be no timetable or regulatory vehicle to approve selected resources, rendering the outcome moot from the start.

Q.56. Please describe Option 2.

A.56. Instead of defining the RFP results as a placeholder under the AB 524 rules, the Commission can amend its AB 524 rules to create an exception to the rules' significant deviation standard to allow resources selected in an RFP as part of an approved Action Plan to be proposed for approval in an IRP amendment regardless of capacity acquisition size. This is Interwest's preferred approach.

Q.57. Please describe Option 3.

A.57. The Commission could order a new type of proceeding that addresses the proposed resources acquired via the RFP. In that proceeding, the Commission could review RFP documents, bid evaluation procedures, and a report on the results of the RFP, and approve any resources selected.

Q.58. What are some of the pros and cons of these three options?

A.58. Option 1, to define RFP resources as placeholders, has the benefit of fitting within the draft AB 524 Rules and aligns with both how NV Energy has defined named placeholders and the reasons for proposing placeholders.[46] Option 2 requires changes to the draft AB 524 Rules but would provide clear and unambiguous policy direction regarding RFPs. For this reason,

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[46] Supply Plan at 128 (The Company explains that named placeholders "…meet several business and policy objectives including: 1) support closing the Companies' open capacity positions, 2) comply with the Nevada RFP while providing additional security against PPA cancelations, delays and shortfalls, 3) meet customers' sustainability goals to be carbon-free, 4) reduced exposure to market price volatility, 5) progressing towards the State of Nevada's 2050 clean energy goal…and 6) long-term customer benefits [after depreciation]")

this is Interwest's preferred approach. Option 3 creates the most optionality for the Commission and a clear separation from the IRP. However, there would still be a need to integrate any selected resources into the Supply Plan. Without an amendment to the IRP or clear means to integrate the proceeding with the IRP, a separate proceeding approach might not solve the delay or timing issues I discussed above.

Q.59. Does statute prohibit proposing placeholder resources without specific resource characteristics?

A.59. No. Nev. Rev. Stat. Section 704.741(4) requires concrete energy resources proposed in each proposed scenario to include a list of defined characteristics but is silent on resources for which the Company is not yet requesting approval. This is borne out by accepted practice; each proposed scenario included by NV Energy in this IRP includes placeholder resources in years outside of the Action Plan window. Nev. Rev. Stat. Sec. 704.741(4) does not require those out-year resources to include the listed characteristics and thus would also not require a proposed RFP to include specific proposals for resource technology, location, ownership, and other listed characteristics.

Q.60. Would approval of an RFP as an Action Plan element require the Commission to approve in advance whatever resources are eventually selected?

A.60. No, there is nothing in the NAC or statute that would require the Commission to accept any resources presented in an IRP amendment or create a presumption that any action taken as a result of an RFP was prudent absent Commission review, and the Commission has the ultimate say as to which resources and actions in the IRP are approved, approved with conditions, or rejected. In one possible approach, the Commission can maintain the opportunity for a final prudence review of RFP-selected resources by approving the RFP but only approving any resources selected in the RFP conditional on the Commission determining that the RFP was conducted fairly and in a manner that selected resources in the public interest. This would balance the interests of maintaining the opportunity for final Commission review with giving the Company regulatory certainty to proceed with negotiations and contracting.

V. The Commission Should Approve PPA and Transmission Investments in the Action Plan

Q.61. Please describe the purpose of this section.

A.61. In this section, I discuss Interwest's support of certain Supply Plan additions and recommended review of the North Valmy Units addition in the Company's Preferred Plan, also referred to as the Balanced Plan. Interwest supports the following additions:

1. Approval of the three Supply Plan addition PPAs are referred to as the "Clean Energy Units".
2. Approval of the Corsac Generating Station 2 PPA for 115 MW of geothermal capacity.
3. Approval of requests NV Energy has made to continue progress toward the Greenlink transmission project.
4. Approval of transmission investments detailed in the Supply Plan additions for network upgrades to interconnect and deliver energy from these new projects, and to allow for future interconnection capacity.

Interwest does not take a position on the other requests of the Joint IRP Action Plan, except as set forth below.

Q.62. What is Interwest's position on the addition of the North Valmy Units?

A.62. Interwest does not oppose the acquisition of CTs by the Company, but Interwest has identified concerns that should give the Commission some pause in its consideration of those units as I introduced above. The Commission should consider whether a closer review of the assumptions around the selection of the North Valmy Units is warranted.

Q.63. What are your concerns with the selection of the North Valmy Units?

A.63. Over the course of the 2021 IRP, the Company made several proposals for the Valmy station, aimed at solving a voltage problem in the area. Two separate proposals included solving the transmission issue with solar/BESS generation. Despite the Commission's request in the Fourth Amendment, the Company has not presented a comprehensive analysis of the transmission and economic impacts of options for solutions to the retirement of the Valmy coal plant.[47] Rather, in the Fifth Amendment, the Company proposed a partial solution to transition the Valmy coal plant to be repowered with natural gas combustion, resulting in a 522 MW gas addition to the Valmy station (the "Valmy Repower"). Now, the Company proposes, out of the context of that recent addition, the North Valmy as needed to prevent a must-run condition at the Valmy Repower station.[48]

My first concern is that, in my review of the Supply Plan transmission narrative and the testimony, there is no evidence presented regarding the claimed must-run condition of the Valmy Repower, only statements that the condition exists. Further, there is no evidence as to how the must-run condition would be addressed by the construction of the North Valmy Units, including how the North Valmy Units and the Valmy Repower work together to address that

[47] Docket N. 22-11032, Order, Nevada Public Utilities Commission, at ¶ 128

[48] Supply Plan, Application, Vol. 8, at 175; *see generally* Supply Plan, Application, Vol. 8 (supply plan refers to Valmy must-run condition at numerous points in the narrative).

condition. Meanwhile, the voltage issue the Company raised in the Fifth Amendment is not mentioned by any witness or narrative in the IRP at all. It is apparently no longer a concern.

My second concern is that the modeling assumptions and conventions that led the Company to select the North Valmy Units do not provide adequate support for the conclusion that the North Valmy Units are "the most cost-effective or reasonable resource decision."[49] The Company did not model the North Valmy Units as against other solutions available in the market, and the Company's modeling skews the analysis of whether another configuration, such as only CT, would be optimal.

The result is that there are unanswered questions about whether the North Valmy Units provide the best value for this IRP. Some of these questions have persisted since the 2021 IRP and the selection of Hot Pot and Iron Point solar/BESS projects.

Q.64. How did the Company address the transmission need at the Valmy station?

A.64. In the Fourth Amendment, the Company proposed using solar/BESS generation for dynamic voltage support in the Carlin Trend load pocket after the retirement of the Valmy coal-fired units, and general capacity benefit.[50] In the Fifth Amendment, the Company proposed the gas repower of Valmy because it needed a resource at Valmy for "voltage regulation" and "contingency-related voltage issues on the Sierra system."[51] The Company also stated that Greenlink could provide voltage support.[52]

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49 *Id.* at ¶ 129.

50 Note that Company witness Mr. Atkins refers to support in the Transmission Narrative, but no such narrative was found in the filing. There was some discussion in the Narrative to the Fourth Amendment, Vol. 1 at 39, e.g. and a 200 MW 4-hour BESS met the criteria at that time as a completely different approach than CTs.

51 Nevada Public Utilities Commission Docket No. 23-08015, (2021 IRP Fifth Amendment), Application, Vol. 1, at 138 and Vol. 3 at 12.

52 2021 IRP Fifth Amendment, Application, Vol. 1 at 139.

The Company here claims that the North Valmy Units are now needed to solve a must-run condition at the to-be-constructed Valmy Repower plant. The must-run status is treated as a given. The Company also claims that, without the North Valmy Units, the Valmy Repower unit will have to run "in perpetuity".[53] The must-run designation for the Valmy Repower implies that the North Valmy Units address resource adequacy issues, but that is not discussed in the testimony or narrative, so we are left to guess.

Q.65. Would a delay of the North Valmy Units lead to a "must-run" condition at the Valmy station "in perpetuity"?

A.65. No. In resource planning, no decision is made "in perpetuity". Resource planning is meant to do the opposite, that is, to select options to best optimize the system on a going-forward basis. NV Energy witness Mr. Atkins testifies that the North Valmy Units are expected to run between 12 to17 percent of the year for only two years, and then their usage will slip to only a 7 percent net capacity factor.[54] This indicates that the Company anticipates reliability in the Valmy area will be partially met from other sources as soon as 2030. This might also indicate that system changes will mitigate the must-run condition, rather than it lasting "in perpetuity." Again, the record is silent on this point with no analysis presented by the Company.

Q.66. Please explain your concern with the modeling assumptions around the selection of the North Valmy Units.

A.66. The North Valmy Units proposal was tested in a limited fashion via the PLEXOS LT model. The Company tested various Company-owned CT proposals of similar capacity that

[53] *Id.*
[54] Atkins Direct, Application, Vol. 2 at 107.

were hard-coded into the PLEXOS LT model and used the capacity expansion module to test those units in isolated 'screening analyses.'[55] Noticeably absent, however, was that: (1) the Company never tested whether one gas-fired unit would be sufficient, in any location,[56] (2) the Company never tested whether the model would select CTs given the Clean Energy Units or versus other shortlisted bids from the 2023 RFP,[57] and (3) the Company testifies that Idaho Power will own half of the repowered Valmy generation, but does not explain how the ownership arrangement might restrict NV Energy's ability to use the entire 522 MW capacity of the Valmy Repower. For instance, it is possible, but NV Energy does not discuss, that NV Energy's agreement with Idaho Power includes flexibility to use Valmy Repower's full capacity to meet ancillary service transmission requirements at certain times or under certain conditions.

Q.67. Do you have concerns with the Company's modeling assumptions for CTs in general?

A.67. Yes. The PLEXOS LT module "base case" optimization runs could only select CT candidate resources in increments of 440 MW (a set of two individual combustion turbine peaking units) with an ISD beginning in 2027.[58] The base case also had a total build limit of 880 MW, meaning that no more than 4 CTs could be selected in the planning period.[59]

Once the base case selected 440 MW CTs in 2027, in the cases that followed to develop the alternative plans, either the North Valmy Units or other Company units were hand input in place of the generic CTs in the base case. This means that first, NV Energy prevented the

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55 Supply Plan, Application, Vol. 8, at 229–33.

56 **Exhibit MDD-5** ("NV Energy did not consider a resource combination or alternative resource plan that included only one CT at any candidate location").

57 **Exhibit MDD-6.**

58 Supply Plan, Application, Vol. 8, at 224.

59 *Id.*

model from selecting one CT, or less than 400 MW of CTs. Second, the capacity expansion model never meaningfully evaluated the relative benefit of the various screened configurations and locations of two CTs.[60]

Q.68. What question did the Company actually answer in its modeling?

A.68. The Company answered the question of what capacity the model would build *after* the Action Plan period assuming the North Valmy Units are in-service, versus other model runs that assumed other gas plants the Company hand-selected were built instead.

Q.69. But didn't the base case run prove that the gas CTs were needed in the first place, and isn't that need met by the North Valmy Units?

A.69. The base case run did select 420 MW of gas CTs in 2027.[61] However, because of the model's constraints of *only* being able to select two CTs at 440 MW, the base case raises a question about the amount of CT capacity that is needed on the system. Recall first that the 440 MW amount is the least amount of CT capacity made available to the model.[62] This is contrasted by how the Company modeled renewable generation, which was in 1 MW linear expansion increments until the model finds the optimal project size.[63] This means that if the model saw a need for CTs, it could not select a capacity it found optimal, it had to select 2 CTs for a total of 440 MW capacity.

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60 IEA 1-02, supra

61 Supply Plan, Application, Vol. 8, at 226.

62 The Company states that "combustion turbine peaking unit size is modeled in 440 MW unit sizing, . . . and is available to be in-service beginning in 2027," and has a total build limit of 880 MW. Supply Plan, Application, Vol. 8, at 224. However, the Base Case run appears to have selected 420 MW of CTs for SPPC in 2027. *Id.* at 226. This appears to contradict the Company's assertion related to unit sizing limits, but is close enough in size that perhaps one figure or the other is a misstatement.

63 Supply Plan, Application, Vol. 8, at 224.

After 2027, the base case run did not select another gas unit for nearly 20 years.[64] That strongly suggests that CT capacity was over-selected by the model and that the model then found the system was significantly long on gas generation, because the next "firm dispatchable units" were not selected until 2045, even though firm generation was made available to the model after 2040 due to planned CT retirements.[65] The Company explained that CTs were available the entire planning period and that the firm dispatchable designation indicates a placeholder for new clean firm dispatchable technologies to hopefully come, but for purposes of this modeling were just generic CTs.

The model may have selected less CT capacity had it had the opportunity. The evidence suggests that the Commission needs more information on the assumptions underlying the selection of gas CTs in 2027 in the base case model, and whether configurations such as one CT would be better for ratepayers.

Q.70. What does Interwest recommend based on this analysis of the selection of the North Valmy Units?

A.70. Interwest recommends the Commission conduct a closer review of the North Valmy Units so that it understands the basis for the selection both for the transmission or RA need in the area and can be confident that the modeling produced a robust defense of the selection. Interwest concludes that there are unanswered questions as to the scope of the transmission problem to be addressed by the North Valmy Units, whether the modeling provided sufficient options for the Commission to consider, and whether the proposed solution offers a complete and final solution for the stated issue or if more proposed gas generation additions loom in

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64 *Id.*, Figure EA-6, Buildout for 2024 Joint IRP Base Case, at 226–7.

65 **Exhibit MDD-7**.

future filings. As I discussed in Sections III and IV, requiring the issuance of a 2024 RFP would provide an opportunity to conduct this review in a formal proceeding.

A. The PPAs in the Supply Plan are in the Public Interest

Q.71. Why are the PPAs in the Action Plan in the public interest?

A.71. Each of the "Clean Energy Units" was selected out of the 2023 RFP. The resources acquired thus result from a competitive process which, although not held recently, may still represent viable projects. The PPAs were effective as of January 31, 2024 (Dry Lake) and May 3, 2024 (Libra and Boulder III).

Second, the fact that these projects are each PPAs means that construction and operation risk is contracted to the responsibility of the relevant IPPs and not with NV Energy ratepayers. These projects will generate large amounts of clean energy onto the system, and the substantial storage capacity will provide reliability and capacity benefits. The Clean Energy Units represent a significant investment in Nevada's renewable energy landscape, which NV Energy ratepayers and state policy have requested of the Company.

Q.72. Do you agree with the Company's analysis of the energy landscape in Nevada?

A.72. Yes, I agree with NV Energy witness Mr. Schlag that there are converging headwinds that have "created a challenging and complex landscape" facing the Company as it seeks to meet its RA needs.[66] This includes global supply chain problems, coupled with new load growth trajectories, coupled with increased costs to meet that load, compounded by extreme weather events including wildfires becoming year-round, normal occurrences. This period

[66] Direct Testimony of Nick Schlag, Application, Vol. 4, at 162–3.

would be challenging to plan for even if there were not the simultaneous, urgent global need to decarbonize the electric grid.

Although Interwest is not a market participant, the organization represents the renewable energy, storage, and transmission development industry across multiple states and therefore has unique insight into the energy landscape. Interwest members and other utilities agree on the complexity of the current energy landscape. In particular, the solar and storage energy industry, as well as the transmission component industry, continue to be hard hit in the supply chain, changes which began during the COVID pandemic and since have resulted in one hurdle after another. More recently, global demand for transmission components and tariffs on solar panels have created extensive delays in project development throughout the West. Finally, there are multiple initiatives underway seeking to create or expand RTOs in the West where they have not been established previously. All of these issues affect this IRP.

Q.73. What steps does the Supply Plan take to mitigate these complexities?

A.73. The Supply Plan acquires large amounts of PV generation and storage capacity where supply agreements are in hand and recommits to transmission expansion through Greenlink and other network upgrades. NV Energy has taken steps to address its renewable energy standard, selected projects with favorable transmission, and honored the continued requests of its ratepayers for additional clean energy supplies. The Company also states that the PPA terms are favorable to project delivery.

Q.74. Why does Interwest support the Corsac project acquisition?

A.74. The Corsac project will provide baseload geothermal power the cost of which should be largely allocated to its Clean Transition Tariff (CTT) customer.[67] The innovative rate

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67 Williams Direct, Application, Vol. 4, at 83.

structure proposed is potentially an appropriate method of cost recovery. Interwest intends to participate in the Commission's docket related to the CTT to complete its review, but at first blush Interwest supports NV Energy's intention to lead on new uses for clean energy to meet a large sector of load growth.

B. NV Energy Should Continue to Invest in the Greenlink Transmission Project.

Q.75. Please explain why Interwest supports continued investment in the Greenlink Project.

A.75. There are two main reasons for Interwest's continued support of the entire Greenlink Project despite cost estimates continuing to rise. The first is that continued renewable energy to meet load growth requires a strong transmission "backbone", not just across Nevada but throughout the region. Renewable energy provides greater system value through diversity of resources and location of resources. Transmission access increases reliability while decreasing long term system costs by avoiding long generation tie-lines and smaller scopes of interconnection upgrades required by new generators. The second is that interregional transmission is needed to facilitate the growth of markets in the West, which relates to the ability to have resource diversity and market downward pressure on energy delivery.

Q.76. Is that true even with the significant cost increases that the Company is reporting?

A.76. Yes. One truth about transmission development is that it is cheaper to do it today than it will be tomorrow. Of course, no one is pleased to see year-over-year cost estimates rise, but this is the unfortunate global trend as electric systems around the world are transforming and growing at the same time. This has put international pressure on transmission component demand on top of the high inflationary environment on both equipment and labor cost.[68] These

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68 *See e.g.,* **Exhibit MDD-8.**

are market realities rather than mismanagement. With current economic trends, further delay of Greenlink will likely add to its as-built cost while not diminishing its long term need to strengthen the connection between Nevada's load centers. Thus, continued progress is needed to bring this project to fruition.

NV Energy has passed a key milestone in achieving its federal land use permit. As the Company points out, Greenlink not only shores up a crucial north-south reliability segment, but also will allow for large amounts of Nevada based renewable generation to interconnect to the grid, not just in this IRP but for IRPs to come.[69] Investments in the bulk transmission grid enable reduced cost and timing of new generation interconnections.

Q.77. Don't third party developed projects need to pay their own way onto the grid?

A.77. Yes. The distinction of the "bulk" transmission network are high voltage lines that connect to multiple delivery points on the system or collect from multiple sources to load and allow network upgrades for multiple generator interconnections. Generation developers filing interconnection requests are responsible to pay for network upgrades to connect and mitigate impacts from their project to the system. Upgrades from the project to the low side of the transformer connecting to the substation are referred to as Interconnection Customer Interconnection Facilities (ICIF).

Renewable developer projects must often finance and pay the initial cost to construct network upgrades to the bulk transmission system that are caused by the electrical impacts of their project or the substation built for their project. These are transferred to utility ownership after construction and repaid to the developer over a negotiated amortization period. These are

69 Direct Testimony of Jimmy Daghlian, Application, Vol. 4, at 25.

called Transmission Provider Interconnection Facilities (TPIF). An IPP project will finance both ICIF and TPIF, and retain ownership of the ICIF.

Q.78. How do upgrades on a project-by-project basis relate to Greenlink?

A.78. The majority of transmission projects in the Supply Plan are meant to interconnect individual generators or to mitigate localized reliability needs. These types of project-by-project interconnections are generally not intended to improve the transfer capacity across the system. Third party developer interconnections are focused on upgrades limited to that project.

Upgrades to the transmission system like Greenlink are much broader and intended to mitigate overloads due to a variety of outage conditions across the system as increasing amounts of load and generation are added. In addition, large new lines have been made necessary as new generation transitions away from the large coal stations of the twentieth century.[70] The more redundancy that exists because of large trunk circuits, the fewer upgrades and operating restrictions are needed for new renewable generation.

Q. Do you agree with the Company's assessment that its system will suffer negative impacts if Greenlink is not constructed? 79.

A.79. Without commenting on the hypothetical resource changes modeled, I agree at a high level that project development in Nevada will be riskier and more expensive without Greenlink and Nevada will have less transfer capacity to effectively use market structures.

Q.80. Can the Company meet its RA need without Greenlink?

A.80. Over the Action Plan period, yes, it is plausible as Greenlink is not fully online in the model until 2028. However, beyond that the Company would see impacts that require more

[70] *See,* discussion of planning challenges of E3 in ECON-5.

generation or transmission or both. As it is, the Company is in a high-growth period along with potential market entry that is putting pressure on its RA needs. Greenlink is necessary for the large amount of energy the Company will need to manage to address load growth and market development. In addition, Greenlink is the key to unlocking Nevada-based generation. Renewable generation in particular has consistently relied on transmission expansion to unlock new areas for development.

Q.81. Do you agree with the other transmission projects in the action plan?

A.81. I have not reviewed the underlying transmission studies supporting each addition. However, it is notable that the Company is contemporaneously bringing forward transmission network upgrades with the generation addition requests. This is not the standard practice, and in my opinion, it is ahead of the curve for the integration of generation and transmission in IRPs. I applaud this area where NV Energy is showing initiative and thorough review. This will assist projects in meeting their target ISDs. The Company also uses a zonal transmission model in PLEXOS using system path ratings as transmission constraints.[71]

Q.82. Does Interwest support NV Energy's proactive approach to interregional and internal transmission planning?

A.82. Yes. NV Energy has led on regional market engagement. NV Energy's push to complete Greenlink is essential to Nevada's clean energy future. Greenlink will enable the addition of needed renewables in diverse Nevada locations while providing additional interregional connectivity. Ratepayers will benefit by getting Greenlink in service as fast as

71 ECON-8 at Vol. 28 at 379.

reasonably possible, enabling more renewables to meet capacity needs. On the other hand, additional delay will almost certainly continue to increase the cost of the project.

Q.83. Do you anticipate that Greenlink will be the last large-scale transmission addition to the NV Energy system?

A.83. No. NV Energy should continue to investigate additional large transmission projects. NV Energy's zonal model offers a positive step in integrating generation and transmission planning. The Company should continue to integrate more specific transmission planning modeling into generation modeling.

Q.84. Does this conclude your testimony?

A.84. Yes, thank you.

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SELECTED PUBLICATIONS

- with John Wilson, Mike O'Boyle and Ron Lehr, *Making the Most of the Power Plant Market: Best Practices for All-Source Electric Generation Procurement*, Energy Innovation and the Southern Alliance for Clean Energy (April 2020).
- with Gabriella Stockmayer and KC Cunilio, *Electric Vehicles: Plugging into Colorado Regulation*, Colorado Lawyer (February 2020).
- *Electric Vehicles: Rolling Over Barriers and Merging with Regulation,* William and Mary Environmental Law and Policy Review, Vol. 40, No. 2 (March 2016).
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- with Jeffrey J. Kahn, *Ditch Rights: The Law of Irrigation Easements and Rights of Way*, in COLORADO WATER LAW BENCH BOOK, Colorado Bar Association (2006).

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MAKING THE MOST OF THE POWER PLANT MARKET: **BEST PRACTICES FOR ALL-SOURCE ELECTRIC GENERATION PROCUREMENT**

BY JOHN D. WILSON, [1] MIKE O'BOYLE,[2] RON LEHR, [3] AND MARK DETSKY[4] ● APRIL 2020

It is a golden age for power plant procurement. Utilities are paying less to acquire new power plants, whether they are powered by the sun, wind, water, fossil fuels, or operate as storage facilities. The global market to supply utilities with power plants is by any measure competitive.

And yet, market competition has surprised utility executives and generated heavy media attention with unexpectedly inexpensive and diversified responses to utility all-source procurements. A Colorado utility called the low solar and wind prices "shocking," but why are utility executives surprised by all-source procurement outcomes? More importantly, how can other utilities replicate these results?

All-source procurement means that whenever a utility (and its regulators) believe it is time to acquire new generation resources, it conducts a unified resource acquisition process. In that process, the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market. Most vertically integrated utilities either voluntarily, or are required by regulators, to conduct competitive procurement through requests for proposals (RFPs) as part of the process selecting adequate generation resources. In an RFP, the utility describes the resources it wishes to procure, and may also offer self-build options to compete against market offers.

About half of the United States' utility sector operates in organized regional wholesale markets. In most utilities that operate in two of these markets, the Midcontinent Independent System Operator (MISO) and Southwest Power Pool (SPP), and in the other half of the sector that does not participate in markets, vertically integrated utilities retain market power. State franchises for such utilities grant vertically integrated utilities rights and responsibilities, including exclusive service territory and an obligation to serve all customers. These utilities typically control the bulk

[1] Southern Alliance for Clean Energy https://cleanenergy.org/ and Resource Insight, Inc. http://resourceinsight.com/

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of transmission assets in their service areas, allowing them to discriminate against competitive generation that would challenge the asset values of utility owned generation. These vertically integrated utilities are not only *monopolies* - sole sellers of power to customers - but they are also *monopsonies* - the single buyers of wholesale power within their service territories.

Vertically integrated utilities thus have market power: As sole buyers, they have control over inputs to and methods for conducting resource planning, as well as methods and assumptions used to evaluate bids received in competitive procurement processes. With the acquiescence of their regulators, these utilities can:

- Control information and impose biases on procurement processes, which can discourage or disfavor otherwise competitive procurement opportunities
- Exercise arbitrary or unfair decision making, which may result in competitive projects being rejected or saddled with unreasonable costs or delays
- Impose terms and conditions that may result in sellers having to accept below-market prices or onerous contract requirements in order to remain active in the market

When these practices occur, utilities may retain or procure uneconomic resources. As both monopolies and monopsonies, vertically integrated utilities are financially incentivized to seek opportunities that invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement.

At the time of this report's writing, many utilities are engaging in a rush to acquire new natural gas-fired capacity and clinging onto coal-fired generation when substantial costs and environmental impacts could be avoided by embracing clean alternatives. Utilities' preferences for gas-fueled generation may be at odds with economics, but it is not surprising. Preference for gas-fueled plants may be related to financial bias towards over-procurement of capacity and self-built generation, as well as an organizational culture and rate design that favors gas-fueled generation.

In order to better understand how regulators currently address these utility market power issues, we evaluated four cases of resource procurement by vertically integrated utilities: Xcel Colorado, Georgia Power, Public Service Company of New Mexico (PNM), and Minnesota Power. We also include brief comments on six other relevant cases.

Our case studies suggest that many vertically integrated utilities have adopted or are moving towards adopting all-source procurement processes.[5] They illustrate that utilities procure resources through all-source, comprehensive single-source, or restricted single-source RFPs. In contrast to an all-source procurement, in comprehensive and restricted single-source

[5] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources might also be integrated into a unified, resource-neutral bid evaluation process. The diversity of regulatory practices with respect to demand-side resource acquisition is substantial and would require additional case studies to fully explore.

procurements, the resource mix is determined in a prior phase and the utility conducts resource-specific procurements for each resource to meet the identified need or needs.

We recommend regulators adopt or revisit five best practices to run an all-source procurement process, and we describe a model bid evaluation process. These recommendations closely follow Xcel Colorado's approach, which has most successfully motivated both the utility as well as potential bidders to engage in a serious, vigorous competitive market process.

1. **Regulators should use the resource planning process to determine the technology-neutral procurement need.** Most all-source procurements were initiated without regulatory review and approval of the need. We recommend that Commissions use resource planning proceedings to make an explicit determination of need – but define that need in terms of the load forecast that needs to be met, and existing plants that may need to be retired. This approach offers advantages over a specific, numeric capacity target and technology specification.
2. **Regulators should require utilities to conduct a competitive, all-source procurement process, with robust bid evaluation.** Four of our case studies (Xcel Colorado, PNM, Northern Indiana Public Service Company, and El Paso Electric) demonstrated that the market for generation projects can provide robust responses to all-source RFPs. These utilities' system planning models appear to be capable of simultaneously evaluating multiple technologies against each other. The optimum mix of solar, wind, storage, and gas resources is more effectively selected based on actual bids, rather than in a generic evaluation prior to issuing single-source RFPs.
3. **Regulators should conduct advance review and approval of procurement assumptions and terms.** Even though the majority of all-source procurements were initiated without regulatory review and approval, our study suggests that Colorado's practice of a full regulatory review process in advance of procurement is best. After-the-fact review creates a number of problems. Out of all the case studies, Xcel Colorado best demonstrates how utility regulators can proactively ensure that resource procurement follows from utility planning.
4. **Regulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding.** Most resource procurement practices we reviewed appeared to include regulatory requirements or utility codes of conduct that restrict information sharing with utility affiliated firms that might participate in the procurement. However, examples of bias toward self-build projects remain. An all-source procurement creates opportunities for large, self-built gas plants to compete against independently developed renewable or storage plants. Regulators should renew procedures that define appropriate utility participation when utility ownership is contemplated, considering that more complex bid evaluation processes can create additional opportunities for bias.
5. **Regulators should revisit rules for fairness, objectivity, and efficiency.** Considering new challenges presented by more diverse, complex, and competitive power generation markets, it is also worth revisiting regulatory practices that provide for fair, objective, and

efficient procurement processes. Public Utility Commissions (PUCs) generally require the use of an independent evaluator. Nonetheless, we observed opportunities for utility leverage in their control over contract terms, use of confidentiality to precluding parties from review, and submitting recommendations on tight timeframes. We also saw limited transparency regarding the results of the procurements."

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INTRODUCTION

It is a golden age for power plant procurement. By any measure, utilities are paying less for power plants whether they are powered by the sun, wind, water, or fossil fuels. Prices for battery storage are dropping fast. Developers and supply chains are diversified. There is ample public information about technology pricing and performance. The global market for power plants is by any measure competitive.

And yet, market competition has surprised utility executives and generated heavy media attention with unexpectedly inexpensive and diversified responses to utility all-source procurements. A Colorado utility called their recent low solar and wind prices “shocking.” And an Indiana utility executive was surprised that wind and solar were “significantly less expensive than new gas-fired generation.” Why were these two all-source procurement outcomes so surprising? More importantly, how can other utilities replicate these results?

All-source procurement means that whenever a utility (and its regulators) believe it is time to acquire new generation resources, it conducts a unified resource acquisition process. In that process, the requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market. Procurement practices for any electric utility are important. Considering the market power that vertically integrated electric utilities have, this paper is focused on how regulators of these utilities can update rules and practices to enable effective all-source procurements.

Access to the power plant development market occurs under market rules set by a regulator and through business practices set by utilities. A less competitive market enhances utilities’ opportunities to invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement. Greater openness to competition can take advantage of rapidly declining prices for clean energy technologies and innovative new use-cases from third-party developers, even within a regulated monopoly marketplace.

Most vertically integrated utilities are either required by regulators or voluntarily conduct competitive procurement through RFPs as part of their process for ensuring adequate generation resources. In RFPs, utilities describe resources they wish to procure, and may also offer self-build options to compete against market offers. Generally, utility procurements follow many recommendations outlined in a 2008 National Association of Regulatory Utility Commissioners (NARUC) report on competitive procurement.[i] Yet today’s market is more diverse, complex and competitive than it was at that point in time.

Rules that may have been designed for single-source competitive procurements can disadvantage or even exclude cost-effective renewable energy, storage, and energy efficiency resources from utilities’ resource procurements. Vertically integrated utilities, with acquiescence of their regulators, can:

1. Control information and impose biases on procurement processes, which can discourage or disfavor otherwise competitive procurement opportunities

2. Exercise arbitrary or unfair decision making, which may result in competitive projects being rejected or saddled with unreasonable costs or delays
3. Impose terms and conditions that may result in sellers having to accept below-market prices or accept onerous contract requirements in order to remain active in the market

When these practices occur, utilities may retain or procure uneconomic resources.

Utilities have control over inputs to and methods for conducting resource planning, and if regulators allow it, can use that control to their advantage.[6] Prevailing regulatory practices give utilities little financial incentive to pursue technologies (such as weather-dependent wind and solar) that force them to change their operating methods or accept lower levels of investment, even where ratepayers and the public interest could benefit.

Arguably, these are among the potential problems that organized competitive wholesale markets are intended to solve. Market rules established by regional transmission organizations (RTOs or ISOs) establish more transparent processes for new generation resources to participate in markets.

Yet roughly half of U.S. electricity load is served by vertically integrated utilities: One-third in traditional bilateral wholesale markets and one-fifth with access to competitive wholesale markets in the MISO and SPP regions[7]. Few regulators of vertically integrated utilities have revisited competitive procurement rules to address these increasingly diverse, complex and competitive markets. Accordingly, we have developed five best practices that regulators should use to update their competitive procurement rules.

1. Regulators should use the resource planning process to determine the technology-neutral procurement need
2. Regulators should require utilities to conduct a competitive, all-source procurement process, with robust bid evaluation
3. Regulators should conduct advance review and approval of procurement assumptions and terms
4. Regulators should renew procedures to ensure that utility ownership of generation is not at odds with competitive bidding
5. Regulators should revisit rules for fairness, objectivity, and efficiency

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[6] As noted in the executive summary, the scope of this paper does not extend to rules and practices related to inclusion of demand-side resources in resource planning. Colorado, for example, requires that utility resource plans include demand-side resources. There is also a need for many regulators to update practices to more optimally tap the increasingly sophisticated market for demand-side resources.

[7] Our simple metric identifies utilities that are regulated by states, rather than organized markets, when making resource procurement decisions. One recent review of multistate regional transmission organizations noted that, "In SPP and MISO, states have more input in resource adequacy decisions." Jennifer Chen and Gabrielle Murnan, *State Participation in Resource Adequacy Decisions in Multistate Regional Transmission Organizations*, Nicholas Institute for Environmental Policy Solutions, Duke University, NI PB 19-03 (March 2019), p. 15.

For vertically integrated utilities, especially in traditional bilateral-only wholesale markets, best practices for cost-effective procurement of power plants are modeled in Colorado.

COLORADO EFFECTIVELY ENGAGES THE MARKET

In 2018, the Colorado PUC captured the electric utility industry's attention with a low-cost, high-renewables portfolio of generation plants submitted as a multi-party settlement advanced by Xcel Energy in Colorado. Xcel Colorado (also known as Public Service Company of Colorado) operates the state's largest investor-owned utility and serves approximately 65 percent of energy load in the state. With wind and solar costs dropping rapidly, Colorado structured a workable, all-source competitive procurement process that provided unrestricted access to current market prices for available resources.

Xcel Colorado's most recent procurement, referred to as the Clean Energy Plan, included a portfolio of wind, solar, battery storage, and gas turbine resources to replace two coal plants. A total of 2,458 megawatts (MW) of nameplate resources were procured, resulting in 1,100 MW of firm capacity replacing 660 MW of coal plants. Other than the relatively small amount of gas turbine resources, the Clean Energy Plan represents a real-world example of what the Rocky Mountain Institute (RMI) has described as a *clean energy portfolio*: a mix of technologies that, together, can provide the same services as a thermal power plant,[ii] though RMI's framework would expand Xcel's approach to include strategic demand reductions from efficiency and demand response.

The competitiveness of this market example resulting in a clean energy portfolio is demonstrated by what the utility called "shockingly" low wind and solar prices – *median* bid prices of $18 per MWh for wind, $30 per MWh for solar, as shown in Table 1.[8] Wind and solar coupled with storage were marginally higher, but remarkably affordable,[9] and more than four hundred bids were submitted – both good metrics for judging a workably competitive process. Getting those competitive results requires concentrated attention from regulators, utilities, and stakeholders.

[8] These prices include federal tax credits for wind and solar.

[9] Stand-alone storage costs are difficult to analyze based on the Xcel Colorado report to the PUC, since amounts of storage bid are not documented.

Table 1: Resource Prices in the 2018 Xcel Colorado Clean Energy Plan

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		

Source: Xcel Colorado, *2016 Electric Resource Plan: 2017 All Source Solicitation 30-Day Report*, COPUC Proceeding No. 16A-0396E (December 28, 2017).

Although not yet public, ultimate costs of the wind and solar projects are likely to be below median bid prices. These low costs mean that Xcel Colorado consumers' long-term generation costs will be lower and less risky as the company pursues its "steel for fuel" business model and climate mitigation goals.[iii]

It is also worth noting that Xcel Colorado is allowed to own projects that result from and to participate in its own RFPs.[iv] Subject to PUC discretion, Colorado utilities may target 50 percent utility ownership.

Much of the credit for this market-driven outcome can be given to Colorado's competitive resource acquisition model. Colorado regulators require planning and bidding, encourage early coal retirements and clean replacements, and solicit stakeholder support. The remarkable results are a credit to Colorado policymakers and to Xcel's managers and employees.[10]

UTILITY PLANNING AND PROCUREMENT CONCEPTS

In order to understand how Colorado's regulation of the generation market differs from some other state regulatory approaches, it is important to understand integrated resource planning and the system planning models used by utilities.

[10] Credit has to be shared with the renewable energy industry, wind and solar developers, and firms that provide financial backing for renewables projects. Their growing sophistication and business acumen deserve mention.

INTEGRATED RESOURCE PLANNING

In two-thirds of states, procurement processes are linked to a regulated planning process, often called integrated resource plans (IRP). In these proceedings, utilities propose, and their regulators consider long-term power generation and demand side needs. [11, v] Future demands are projected and resources to meet them are considered. These IRPs are intended to inform utility investment decisions and allow regulators and the public to understand relative economics of different approaches, as well as operational and reliability tradeoffs associated with different resource mixes.

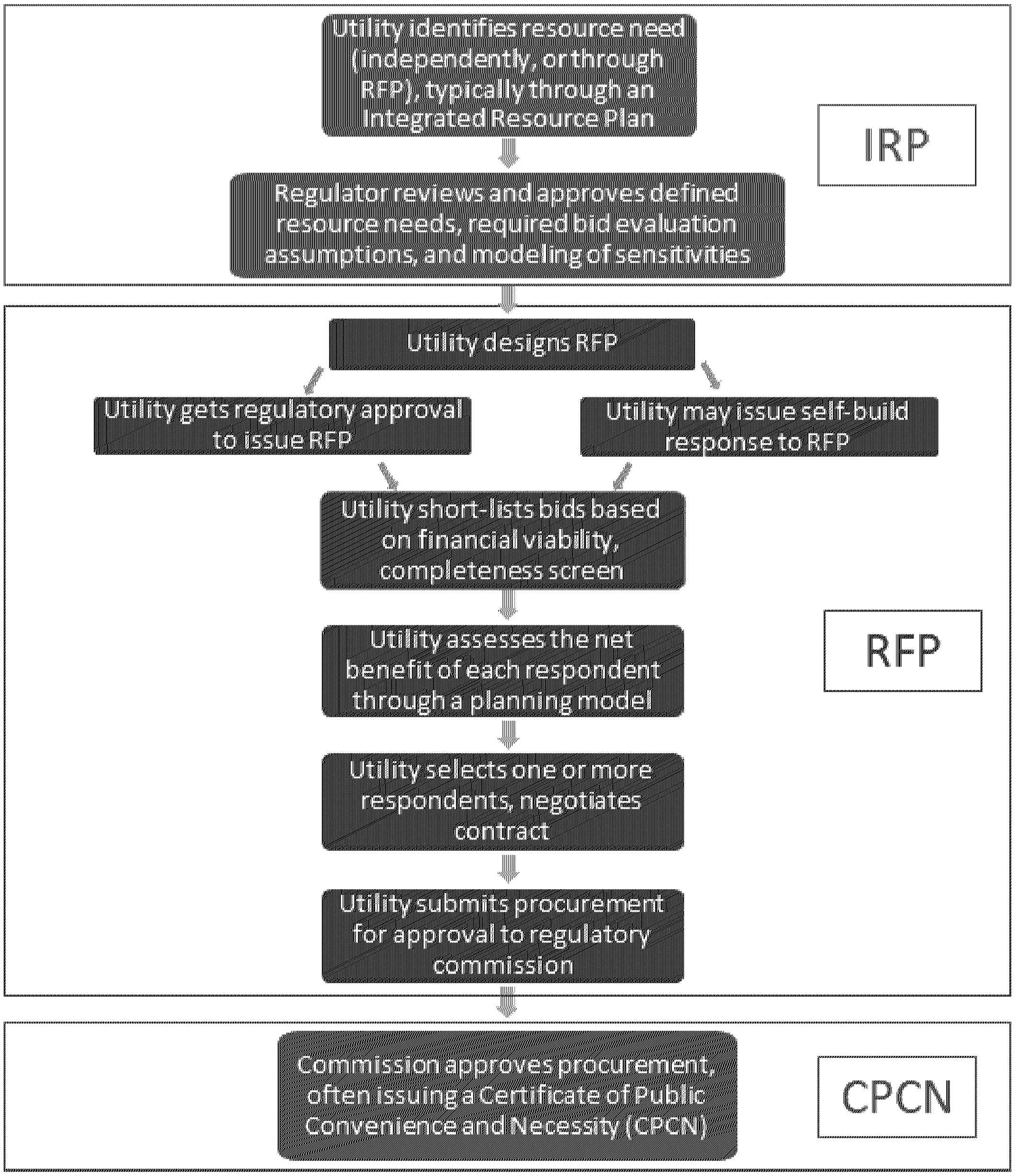
In states with traditional, or partially restructured, bilateral wholesale markets,[12] IRPs typically lead to discrete resource approvals through a certificate of public convenience and necessity (CPCN). Often, regulators require utilities to issue an RFP as part of that process. Regulators practice widely varying levels of review of IRPs. Some states, such as Colorado, require the IRP to be approved prior to proceeding to an RFP. In other states, the IRP review process may not include specific approvals – or, the submission of an IRP may be simply acknowledged or accepted, without leading to meaningful regulatory action.

Where regulators require the IRP to be reviewed prior to an RFP, utilities and regulators may proceed in a logical order, with regulators approving the need for new resources in the IRP, followed by the RFP, and leading to the CPCN. An idealized sequence is provided in Figure 1. However, some states, such as Florida, allow RFPs to be conducted by utilities first, with IRPs being submitted as part of CPCN process.

[11] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources might also be integrated into a unified, resource-neutral bid evaluation process. The diversity of regulatory practices with respect to demand-side resource acquisition is substantial and would require additional case studies to fully explore.

[12] If the state policy allows retail choice within organized competitive wholesale markets, then any required resource planning process would inform a market procurement to supply customers who remain on the default service (if they have not elected a retail electric provider). Such procurements are not within the scope of this paper.

Figure 1: Illustrative sequencing of utility planning and procurement*



*This represents an idealized sequence - some or all steps may not occur, potentially reducing regulatory oversight opportunities.

SYSTEM PLANNING MODELS

Utilities use complex planning models to evaluate cost-effectiveness of current and prospective generation resources. Often, utilities use a capacity expansion model to evaluate which resource choices to invest in to meet customer requirements.[vi] For example, if a utility forecasts that future demand will exceed its resources by 1,000 MW in a given year, the capacity expansion model will suggest that the resources should be, for example, some mix of solar, wind, gas turbine, or combined cycle plants based on the plants' relative economics and on forecasted customer energy demand.

Utilities often identify several capacity plan options, and then screen those options using a more detailed production cost model, which simulates how generation and market supplies will operate on an hourly basis. These models are generally licensed for use by utilities from vendors and often come with significant restrictions on access for regulators and other parties that may wish to inspect the utility's modeling practices.

System planning models are driven by complex algorithms which vary from vendor to vendor and by necessity, simplify real-world operating practices. For example, software may be configured to have a "must run" requirement for a power plant in a critical location, even though system operators may have other options to maintain system reliability. Also, IRPs may assume a level of energy efficiency program impacts, when it is possible to establish energy efficiency program levels by optimizing in the system planning model.[vii]

More recently, system planning models have struggled to accurately model battery storage, particularly if storage resources will be used to provide a mix of short- and long-term grid services. The Washington State Utilities and Transportation Commission recently noted that "traditional hourly IRP models are becoming increasingly inadequate," and urged a transition to sub-hourly models.[viii] The Commission also noted that IRP models remain unable to consider the distribution and transmission benefits of resources.

Furthermore, utilities' modeling practices can have a significant impact on modeling outcomes. Utilities may place constraints on certain resources that implicitly express utility preferences. These constraints are based on utilities' assumptions about resource capabilities and costs. Detailed analysis of how utilities use these models, employ current and outdated information, correct and incorrect assumptions, and adjust model variables is an extremely resource-intensive process. Regulators and other stakeholders who wish to review those decisions can be at a substantial disadvantage relative to utilities.

CAPACITY CREDIT

System planning models are typically designed to optimize resources to achieve a resource adequacy target (enough capacity to meet demand, even with generation outages). In some models, thermal generation resources are assumed to deliver their full nameplate capacity at the system's peak, regardless of actual past performance. Other models partially or fully consider significant risks of outages. But in all models, variable energy resources (solar and wind) are assumed to deliver less than nameplate capacity at system peak. To recognize these operating issues, system planning models will assign a capacity credit to resources, which is the "percentage of a generating technology's nameplate capacity that can be counted toward meeting resource adequacy requirements."[ix]

Ideally, system planning models will rely on probabilistic methods to calculate capacity credits of solar, wind, and traditional resources, and are increasingly developing these methods for energy storage resources.[x] Effective load carrying capacity (ELCC) and load duration curve (LDC) are a few methods used to measure capacity credit.[xi] If a utility uses a method that assigns an unreasonably low capacity credit to a resource, then system planning models will evaluate that resource as contributing less to resource adequacy than is merited.

Not only is it possible to assign an unreasonably low capacity credit to a single resource, but system planning models can also undervalue combinations of resources. The combination of solar and storage, for example, create “diversity benefits” in that their combined capacity credit is greater than the sum of their individual values.[xii]

DOMINANCE OF NATURAL GAS AND SOURCES OF BIAS IN UTILITY RESOURCE PROCURMENT

Colorado’s procurement is notable for its relatively low portion of gas-fueled generation. By contrast, even though some forecasts suggest wind and solar power development will roughly equal gas plant development over the next three decades, these national forecasts suggest that gas-fueled generation will continue to dominate.[xiii] This is particularly true for vertically integrated utilities. For example, as shown in Table 2, gas-fueled plants are forecast to be over half of all new generation in the Southeast, while solar power will represent about a third of new generation brought online between 2018 and 2025.[13]

Table 2: Forecast Power Development, Southeast Utilities, 2018-25

	New Capacity	Annual Generation	Generation Share
Gas	21 GW	75 TWh	53 %
Solar	20 GW	45 TWh	31 %
Nuclear	2.2 GW	17 TWh	12 %
Wind	0.3 GW	1 TWh	1 %
Other	1.7 GW	4 TWh	3 %

Preference for gas-fueled power plants is at odds with economics of power plant development, which in 2019 clearly favors renewable energy in terms of cost.

[13] The Southern Alliance for Clean Energy tracks utility integrated resource plans, public announcements of power plant development, and other similar sources to construct the forecast relied upon here. The Southeast includes non-RTO utilities serving customers in Alabama, Florida, Georgia, South Carolina, and parts of Kentucky, Mississippi, and North Carolina. Consistent with prevailing utility practice in the region, where a capacity need is not explicitly identified as gas generation, gas generation is generally assumed.

- For 2018, Lawrence Berkeley National Laboratory (LBNL) reports the levelized cost of energy (LCOE) for wind power averaged $36 per megawatt-hour (MWh), with subsidies and project financing terms driving contract prices down below $20/MWh.xiv
- For 2018, LBNL reports the median LCOE for utility-scale solar projects was $54/MWh, with subsidies and project financing terms driving average contract prices to $31/MWh, with some below $20/MWh."xv
- The most recent results from utility bidding processes, such as those discussed in the appendix, document renewable energy prices lower than those reported by LBNL.

In comparison, gas-fueled combined cycle plants have an average LCOE in the $44-68/MWh range.[xvi] Thus, wind and solar have a cost advantage of at least $8/MWh but more often at least $20/MWh. This cost advantage is one reason that RMI found "an optimized clean energy portfolio is more cost-effective and lower in risk" than gas-fueled power plants.[xvii]

The utility preferences for gas-fueled generation may be at odds with economics, but it is not surprising. Utilities own and operate numerous gas-fueled combined-cycle and combustion-turbine plants (about 1,900 units as of 2018[xviii]). Their preference for gas-fueled plants may be related to

- A financial bias towards over-procurement of capacity
- A financial bias towards self-built generation
- An organizational culture and rate design that favors gas-fueled generation.

That consumers bear the risk of fossil fuel costs through fuel cost rate riders in most states provides additional incentive for utilities to low-ball fuel cost projections and saddle consumers with risks that fuel costs will exceed projected values.

FINANCIAL BIAS TOWARDS OVER-PROCUREMENT OF CAPACITY

Financial theory suggests that utilities are incentivized to adopt practices leading toward over procurement of capacity (versus energy), which helps explain the current prevalence of natural gas in resource planning. The well-established Averch-Johnson effect demonstrates that a "firm has an incentive to acquire additional capital if the allowable rate of return exceeds the cost of capital."[xix] For example, one author has suggested that utilities that favor building large-scale nuclear plants "will deliver greater per-share stock price gains to their present investors than they would under any other resource strategy."[xx] In contrast, investments in energy efficiency programs or contracts with competitive renewable energy suppliers do not offer the utility opportunities to acquire and earn profits on additional capital. Utility practices that may lead to over-procurement of capacity include over-forecasting of peak load or arbitrarily limiting market imports in resource planning.

The concept of capacity is often defined bluntly in utility planning and procurement and system planning models demonstrate a tendency to plan for singular capacity events; sometimes evaluating just a single peak hour in a year. Yet it has been noted that "capacity is vague as to what energy or reliability service is being provided," and the North American Electric Reliability

Corporation has not identified capacity as an "Essential Reliability Service."[xxi] The practice of emphasizing capacity as a planning goal may be better aligned with utilities' financial interests than with the obligation to provide reliable service to their customers.

FINANCIAL BIAS TOWARDS SELF-BUILT GENERATION

Prevailing regulatory structures provide financial incentives for utilities building and owning new generation. State regulators grant utilities an authorized return on invested equity, so about half of typical gas plant investment costs are returned to shareholders. If a self-built plant has a larger investment scale, a lower risk, or a higher return than an alternative, such as energy efficiency or contracting for renewable energy, these investments will tend to drive utilities' stock prices up.[xxii]

Since regulators do not typically allow utilities to consider stock price impacts when making decisions, this would indirectly express bias within utility planning practices. For example, utilities may offer a pretext for excluding solar, wind, and storage resources from acquisition - perhaps by citing an unsubstantiated expectation that future price reductions warrant delay.

UTILITY CULTURAL BIAS AND RATE DESIGN FAVORS FUEL-BASED GENERATION

Utilities' organizational cultures may value existing operating practices designed around fuel-based resources, such as methods to control ramping or other grid management capabilities. Or utilities may simply default to the relative ease of substituting one fuel-based, dispatchable thermal resource for another. In an environment of relatively flat load growth,[xxiii] new generation needs are primarily driven by thermal generation retirements – aged coal and gas-fueled steam generation, as well as some nuclear plants. Gas-fueled thermal generation plants are traditional and well-understood, making operators comfortable with adding additional units.

This cultural bias can be bolstered behind prevailing rate design practices and least-cost planning arguments. Utilities may shift costs, risks, and potential liabilities (like coal ash disposal problems) onto customers by preferring resources with fuel prices to those, like solar and wind, without fuel price and related risks.

Gas fuel costs are automatically passed through directly to consumers using fuel adjustment rate riders, so utility customers bear costs and risks that gas prices will spike unpredictably, such as when weather impacts gas production and delivery. Yet utility planning practices may discount such risks by emphasizing the median forecasted fuel cost.[xxiv] By diminishing the utility's consideration of cost risks that are entirely borne by their customers, the utility's cultural bias towards fuel-based generation can be presented as a cost-saving preference.

Utilities' organizational cultures become meaningful in their system planning practices and they make critical assumptions and forecasts that determine whether their models reasonably consider economics of selecting alternatives such as wind, solar, storage, demand-side resources, imports, and exports. Utility planning staff may:

- Effectively exclude new or unfamiliar technologies from consideration by using outdated or unreasonable performance and cost assumptions, or by using software that lacks capability to properly model those technologies[xxv]
- Underestimate, arbitrarily cap, or ignore specific capabilities of resources such as wind, solar, storage, and demand-side resources[xxvi]
- Discount potential for regional markets or balancing authorities to provide reliability services[xxvii]
- Fail to consider whether existing power plants should be retired in favor of lower cost alternatives; instead assume that existing plants should remain in service until the end of their estimated useful lives[xxviii]

Beyond these specific model manipulations, utility planning itself may be organized around the existence of large, thermal generation plants. Transmission planning will tend to favor replacing coal plants with a similar resource in order to meet reliability standards, even though different transmission and generation approaches could also provide lower cost reliable service.

It is unclear whether corporate or regulatory environmental goals can overcome utilities' cultural biases. Some state laws or regulations have required that carbon reduction and other externalities be introduced into resource planning processes. In California, legislation has imposed a price on carbon,[xxix] prohibited regulated utilities from signing long-term contracts with coal-fired power plants,[xxx] and directed regulated utilities to procure clean energy resources in a "loading order."[xxxi] And in Colorado, recent state legislation directs the PUC to employ a federally determined social cost of carbon in planning.[xxxii] Of course, renewable portfolio standards requiring utilities to increase the share of renewable generation have been the strongest drivers of renewable energy deployment.[xxxiii]

In other states, some utilities have professed decarbonization goals without recommending regulatory action. Southern Company and Duke Energy, for example, have public "net zero" carbon decarbonization goals, yet both firms are investing heavily in gas-fueled generation and other natural gas infrastructure.[xxxiv] It seems that planning practices at many utilities have not shifted commensurate with the changing economics of resource planning.[14]

REGULATION OF UTILITY PROCUREMENT

Before 1978, vertically integrated utilities provided most of their own power by owning generation. Enactment of the Public Utility Regulatory Policies Act compelled utilities to purchase power from co-generators and small power producers. Then, the Energy Policy Act of 1992 further opened up regulated wholesale power markets.

[14] Some utilities have initiated distribution resource planning to better align investments in the grid with distributed energy resources. It remains to be seen whether this will better align utility investments with resource planning economics, or whether new planning practices will result in additional barriers to alternative investment paths.

Vertically integrated utilities, however, retained market power as regulated monopolies exempt from federal antitrust laws. State franchises for such utilities grants them rights and responsibilities, including exclusive service territory and an obligation to serve all customers. State franchises may not require a vertically integrated monopoly to purchase power from a competitive market, unless states have established a competitive wholesale market subject to federal regulation.

Vertically integrated utilities are thus not only *monopolies* - sole sellers of power to customers - but they are also *monopsonies* - the single buyers of wholesale power within their service territory. Co-generators and independent power producers generally have a right to purchase access to utilities' transmission systems to access markets outside utilities' exclusive service territories, but this is a limited right that often comes with significant burdens and high costs.

Courts often define market power in terms of ability to control prices or exclude competition.[xxxv] Vertically integrated utilities, as both monopolies and monopsonies, often have substantial market power in their relevant generation markets due to monopolies on transmission services as well as the ability to exclude competitors from supplying electricity to utility customers. Utility regulators may maintain a singular focus on monopoly issues and overlook the market effects caused by regulated utilities' monopsony power.

Monopsony power gives vertically integrated utilities greater ability to act on monopolistic biases towards self-generation and over-procurement of generation. As sole (or dominant) buyers of power in a particular market, vertically integrated utilities have at least three tools they can use to constrain markets, shift risks to sellers, and force generation prices below long-term market rates.[15]

- Utilities' abilities to control information and impose biases on procurement processes can discourage or disfavor otherwise competitive procurement opportunities
- Utilities' arbitrary or unfair decision making may result in competitive projects being rejected or saddled with unreasonable costs or delays
- Utilities' abilities to impose terms and conditions may result in sellers having to accept below-market prices or onerous contract requirements in order to remain active in the market

The third tool, forcing sellers to accept below-market prices, might appear to help consumers by driving down power costs, but below-market prices are of course unsustainable. If utilities utilize all three tools, it may stifle competition enough to drive sellers to exit markets. Less competitive markets enhance utilities' opportunities to invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement.

[15] These three tools are further explained in a companion paper, John D. Wilson, Ron Lehr, and Michael O'Boyle, *Monopsony Behavior in the Power Generation Market* (forthcoming).

Even though utility regulators are well acquainted with the tendencies of utilities to procure excessive resources, they tend to view these tendencies through the lens of monopoly behavior. For example, as sole power sellers, utilities can exercise pricing power to subsidize demand for their products at the expense of other providers. Perhaps because competitive procurement is a relatively new phenomenon (emerging over the past three or four decades), regulators have paid less attention to potentials for monopsony market power to result in over-procurement and less than competitive results.

RECOMMENDED BEST PRACTICES

Less competitive markets enhance utilities' opportunities to invest their own capital in generation, even at above-market prices, and even to the point of costly over-procurement. To avoid procurements that are excessive (or even unnecessary), too costly, or not optimal, regulators of vertically integrated utilities need to address potential biases towards over-procurement, self-generation, and fuel-based generation. These biases are most likely to be advanced by utilities exercise market power through their ability to control information, engage in arbitrary or unfair decision making, and impose terms on sellers.

In order to better understand how regulators address these utility market power issues, we evaluated Xcel Colorado and three other significant cases of resource procurement by vertically integrated utilities (Georgia Power, PNM, and Minnesota Power). We also include brief comments on six other relevant cases. Due to the varying scope and characteristics of each case study, it was not possible to evaluate each procurement case across all characteristics. Detailed descriptions, especially of the four full evaluations, are provided in the appendix.

Our case studies suggest that many vertically integrated utilities have adopted or are moving towards adopting all-source procurement processes. [16] Our case studies illustrate that utilities procure resources through all-source, comprehensive single-source, or restricted single-source RFP processes, as summarized in Table 3.

- An all-source procurement is a unified resource acquisition process where requirements for capacity or generation resources are neutral with respect to the full range of potential resources or combinations of resources available in the market[17]
- A comprehensive single-source procurement uses a planning process to select amounts of different resource technologies to be procured; utilities conduct separate

[16] Demand-side resources, including demand response and energy efficiency, are also considered in some utility planning processes, which might be called "all-resource planning." The scope of this paper does not extend to all aspects of utility resource planning. Nor did we examine how demand-side resources might also be integrated into a unified, resource-neutral bid evaluation process. The diversity of regulatory practices with respect to demand-side resource acquisition is substantial and would require additional case studies to fully explore.

[17] While this study is focused on case studies of supply-side resource procurements, demand-side and distributed resources could also be included in such procurements. Practices required to include those additional resource types are beyond the scope of this study but merit development.

procurements for each resource to meet the acquisition goal, each stated as a specific megawatt goal for a class of technology (e.g., solar or combined cycle gas).

- Single-source RFPs are generally developed internally and have no obvious linkages to consideration of other resource alternatives. (We did not identify any cases where a utility does not at least attempt an RFP before proceeding to self-build, but likely such practices continue) Utilities may be procuring other resource technologies, but those acquisition goals are developed in a separate process.

Numbers of bids received in each case study suggests that a regulatory requirement for use of an independent evaluator and significant staff scrutiny provide for a meaningful engagement of the market.

Table 3: Summary of RFPs Conducted in Case Studies (See Appendix for details)

Utility	RFP Type	Status	Bids
PNM	All-Source RFP	Pending 2020	735
Xcel Colorado	All-Source RFP	Approved 2018	417
Georgia Power	Comprehensive single-source RFPs	2015 Gas / 2017 RE Pending 2020	221 TBD
Minnesota Power	Comprehensive single-source RFPs	Approved 2018	115
NIPSCO	All-Source RFP	Announced 2018	90
El Paso Electric	All-Source RFP	Pending 2020	81
California	All-Source RFP	Various	(varied)
Florida	Single-source RFPs	Approved 2016	0 or few
Dominion Energy Virginia	Single-source RFP	Suspended 2019	n/a
Duke - North Carolina	Comprehensive single-source RFPs	Pending	n/a

These case studies support our recommendation that regulators adopt or revisit five best practices to run an all-source procurement process, and we describe a model bid evaluation process. These are based on Xcel Colorado's approach, which has most successfully motivated both the utility as well as potential bidders to engage in a serious, vigorous competitive market process.[xxxvi] Examples and evidence in support of these practices are mostly drawn from case studies in the Appendix, where assertions are explained, and citations are provided.

REGULATORS SHOULD USE THE RESOURCE PLANNING PROCESS TO DETERMINE THE TECHNOLOGY-NEUTRAL PROCUREMENT NEED.

Most all-source procurements were initiated without regulatory review and approval of the need. By “need,” utilities conventionally specify a numeric capacity need, and often also specify technology eligibility, either by name or by restrictive performance standards. In contrast, the Colorado PUC makes an advance determination of need that, counter-intuitively, does not establish the specific capacity or technology to be procured.

Consistent with the process Colorado followed, we recommend that regulators use resource planning proceedings to make an explicit determination of need – but define that need in terms of the load forecast that needs to be met, and existing plants that may need to be retired. Ideally, the determination of need would ensure that the procurement is open to any technology, and any siting location. This approach offers advantages over a specific, numeric capacity target and technology specification.

The Xcel Colorado case study shows how a need can be defined in terms of a load forecast and retirement of specific units without setting a specific, numeric capacity target or specifying a desired technology. In that case, the Colorado PUC approved two load-forecast scenarios, and several different generation scenarios, including both with and without retirement of two coal units. Xcel Colorado used the scenarios to construct several alternative portfolios of bids for the PUC to review. By using a flexible need, the Colorado PUC proactively ensures that resource procurement follows from utility planning.

When regulators lack a process for advance approval of the resource need,

- Parties are limited to challenging the utility’s own determination of need after the RFP has been conducted, such as during a CPCN proceeding
- The utility’s procurement may not consider retirements of existing power plants that would otherwise be out-competed by RFP bids
- The regulator may be presented with an up-or-down decision, rather than a range of options

While commissions may have good reasons for establishing a numeric capacity target for an RFP, our recommendation is that regulators establish need by approving the load forecast(s) and identifying which (if any) existing units should be considered for retirement. The resulting portfolio should satisfy the need created by the forecast and retirement options, with the utility procuring any amount of nameplate capacity of a mix of technologies based on cost-effectively meeting the need.

As in Colorado’s process, the final determination of need can be made by the regulator when the utility presents alternative portfolios to the commission. In Colorado, the result is that the assessment of need and alternatives is largely absent from CPCN decisions.[xxxvii] If the commission determines need and reviews alternatives during the resource planning and all-source procurement steps, then a CPCN proceeding does not need to further consider these issues. As a result, the CPCN proceeding will be primarily related to reviewing project-specific financial or technical issues that would not have arisen in the previous proceedings. By determining need concurrent with reviewing the RFP portfolio results, the regulator can consider not only the need associated with a load forecast but may also take advantage of opportunities to replace existing plants and achieve a more cost-effective or cleaner resource mix.

Colorado's approach generated a robust, cost-effective portfolio, and the portfolio did not require a hearing for review due to extensive advance review. It also validated the recommendation to retire two coal units, which is a relatively new consideration in a procurement process. Where procurements fill a retirement need, they are generally in response to a firm retirement schedule. Otherwise, utilities usually assume that existing plants should remain in service until the end of their estimated useful lives.

Several of our case studies illustrate less robust approaches to need determination.

North Carolina: North Carolina utilities often simplify system planning models by making assumptions that existing generating units will continue to operate until they are fully depreciated. Recently, the North Carolina Utilities Commission ordered Duke Energy to remove such assumptions, and "model the continued operation of these plants under least cost principles."[xxxviii] However, this evaluation is confined to the IRP process for now, as the Commission has not ordered Duke to include existing plants in its procurement processes.

New Mexico: The New Mexico Public Regulation Commission (PRC) does not have a routine process for regulatory oversight of the need determination. Even though there was agreement between the utility and other parties about PNM's resource need, this success can be largely attributed to a one-time settlement related to environmental regulation issues. Neither the PNM or El Paso Electric case indicates that New Mexico regulators have a clear process for determining the need for generation procurement.

Virginia: An even less effective process occurred in Virginia, where the utility initiated an RFP based on an unapproved IRP after receiving a clear caution about its resource investment plans in the previous IRP.

Georgia: The Georgia Public Service Commission (PSC) has a clear process for approving resource needs in a resource planning proceeding, in advance of resource procurement. Over the past decade, the PSC developed a practice of multiple, single-source RFPs – together representing a relatively comprehensive procurement from the generation market. The potential for optimizing the mix through the bid evaluation process, rather than in Georgia Power's IRP, was challenged in the 2019 proceeding. Parties contested the insistence on "firm" capacity and lack of clarity on whether "firm" capacity included energy and how it could be supplied. These were not directly addressed in the PSC's order and instead were left to private negotiations between PSC staff and the utility.

California: Although California Public Utilities Commission policy has included all-source procurement for many years, the process has been constrained. A 2014 all-source procurement was mostly determined by localized capacity constraints which practically excluded many market options. The recent 3.3 gigawatt (GW) all-source procurement appears more promising, but does have a specific capacity target, in part because the procurement will serve a complicated mix of related entities.

REGULATORS SHOULD REQUIRE UTILITIES TO CONDUCT COMPETITIVE, ALL-SOURCE BIDDING PROCESSES, WITH ROBUST BID EVALUATION.

Many jurisdictions require or encourage utilities to acquire new resources through bidding. Often regulators rely on independent evaluators to provide assurance of fairness and rigor in the process.[18] But in some cases, utilities have simply built the next generation plant they have planned, either skipping or "winning" the bid process. This behavior is adequately explained by reference to utilities' financial incentives to increase capital spending, which should be recognized.[19] When the outcome of a bid process is neither predestined nor requiring an adversarial intervention to obtain a reasonable outcome, the bid process is likely to be competitive.

As discussed above, Xcel Colorado, PNM, NIPSCO and El Paso Electric all used all-source procurement processes, received large numbers of bids representing a wide range of technologies, development and ownership approaches, and competitively evaluated those bids within a system planning model to construct optimal portfolios. Bid evaluation was then fully explained in a regulatory proceeding. While few issues were raised after Xcel Colorado's review process because of thorough advance review, all four utilities had to fully explain their bid evaluation in some form of regulatory hearing.

In addition to restricting technology eligibility, single-source RFPs tend to leave meaningful issues unresolved and use a ranking process for bid evaluation. All-source procurements rely on market data and system planning models to make decisions about the scale and mix of resources. The equivalent decisions by utilities that use single-source procurements are made within those utilities' resource planning processes, which may or may not be subject to close regulatory oversight.

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[18] Notably, both Georgia Power and Xcel Colorado use Accion Group as the independent evaluator for their respective RFPs, but the procurement practices are significantly different.

[19] Regulators allow utilities to earn on equity investment as their major financial incentive. Not surprisingly, utilities, paid to invest, take whatever steps they can to make and justify these investments, including creating pre-determined bid processes that result in choosing the utility's own projects as bid winners. Steve Kihm et al., *Moving Toward Value In Utility Compensation: Part 1 - Revenue and Profit*, America's Power Plan (June 2015).

Insufficient oversight of bid evaluation practices may leave meaningful issues unresolved.

The case studies suggest that regulators do not exercise strong oversight of bid evaluation practices for most vertically integrated utilities. While the discussion above explains how the best approach is advance review, even during after-the-fact reviews the level of oversight is often insufficient to resolve meaningful technical or policy issues.

Utilities need this oversight because their behavior often aligns with their interests in exerting control over the "quantity procured, generation profile, project siting, and reliability" of resources that they acquire.[xxxix] This exertion of utility control can lead to utilities imposing biases on the procurement process, which can disfavor an otherwise competitive procurement - and, if utilities are allowed to exercise arbitrary or unfair decision making, otherwise beneficial projects can be rejected.

Colorado regulators provide the only example of strong, comprehensive oversight. The resource planning process includes a clear need determination, as well as review of draft requests for proposals, bid evaluation criteria, and proposed purchase agreements. Xcel Colorado's RFP was not challenged by intervenors on these issues. In contrast, the following examples highlight different types of gaps in oversight.

Georgia: Georgia Power's resource plan was challenged on its valuation of renewable energy and lack of clarity on whether "firm" capacity included energy and how it could be supplied. The assumptions and methods used in the planning process were also to be used during bid evaluation. Many issues raised in the Georgia Power case were not directly addressed in the PSC's order and instead were left to private negotiations between PSC staff and the utility. On the other hand, Georgia Power's RFP process does include close oversight of the bid evaluation process by PSC staff, including bid evaluation by both staff and the independent evaluator.

Minnesota: Intervenors criticized Minnesota Power's procurements for being rushed, including unrealistic requirements, disallowing otherwise qualified proposals due to a Federal Energy Regulatory Commission (FERC) ruling, negotiating for a single project, and using unreasonable and biased modeling assumptions and constraints, undervaluing clean alternatives. Although regulators expressed concerns about many of these issues, Minnesota Power's recommended projects were approved.

Bid evaluation practices vary from relying on models, to ranking based on costs.

Those vertically integrated utilities that have adopted or are moving towards adopting all-source procurement processes are also using their system planning models to create optimal portfolios and select winning bids. Xcel Colorado, PNM, NIPSCO, and El Paso Electric all demonstrate this practice.

It is difficult to imagine how an all-source procurement might be conducted without using system planning models to evaluate all bids together. This is the key distinction between all-source procurement utilities and utilities that use comprehensive single-source procurement or single-source RFP to acquire resources. In general, utilities that do not use all-source procurements simply rank qualified bids based on cost or, somewhat better, net benefits.[20]

For example, Minnesota Power used a net benefits approach that compares costs with a calculated estimate of project benefits. Yet even though Minnesota Power calculated project benefits of its preferred gas plant using its system planning model, it did so in comparison to generic resources, not actual bids it had received in its single-source RFPs. Only after selecting and evaluating projects did Minnesota Power combine winning projects from all its RFPs together in a portfolio analysis.

Georgia Power also uses a net benefits approach, the scope of which has led to several technical challenges to its evaluation method. While many of these challenges continue due to the PSC's deferral to its staff, some are a result of the utility's preference for ranking bids based on one-by-one evaluation rather than a comprehensive system planning model driven selection.

Restricted single-source RFPs do even less comparative analysis by basing procurement on an internal need assessment. The IRP sets the allocation between resource technologies, meaning that the critical decision about which resources are invested in depends on utilities' assumptions regarding cost and performance, rather than the results of the RFP. All too often, these RFPs result in few or no independent alternatives to a self-build proposal and can never result in a meaningful alternative to utilities' IRP modeling analysis.

REGULATORS SHOULD CONDUCT ADVANCE REVIEW AND APPROVAL OF PROCUREMENT ASSUMPTIONS AND TERMS.

Colorado's practice of reviewing all aspects of the procurement process in advance of the RFP is relatively unusual. Most of the RFP processes we reviewed did not require advance review and approval of the assumptions, bid evaluation process, and key bid documents, including contract terms and conditions. This results in a number of problems that may not be resolved due to the focus on making an up-or-down decision on the final procurement request.

In a better approach, the Colorado PUC uses its Phase 1 process to approve required bid evaluation assumptions and modeling of sensitivities, and relevant policy decisions such as carbon cost criteria. Xcel Colorado is held accountable for quality of its planning efforts prior to an RFP being issued. After the utility bid report is submitted to the Colorado PUC, hearings are generally not required to obtain approval.

In addition to a less contentious and ultimately smoother process, the advance approval approach used in Colorado also ensures that potential bidders receive adequate information about what, where and when the utility really needs to acquire additional resources - including capacity and energy, and potentially ancillary services.

[20] Another method is to use a scoring rubric that includes multiple metrics. This approach was not used by any of the utilities in our case studies.

Most all-source RFP processes reviewed do not require advance review and approval.

Colorado's Electric Resource Planning process uses a two-phase approach to provide this explicit link. The first phase considers the utility's planning study findings, and results determine objectives of an all-source procurement and how bids will be evaluated. This first phase influences, but does not constrain, technology choices in the all-source RFP process. The second phase considers results of all-source procurement. Remarkably, of all-source procurement processes we reviewed, Xcel Colorado's may be the only one that did not require a hearing for regulatory approval of RFP results.

The other three all-source procurements at PNM, NIPSCO, and El Paso Electric, were initiated by utilities without advance regulatory review of planning conclusions or RFP materials. In the cases of PNM and NIPSCO, there were prior utility filings and proceedings that informed procurement process, but specific terms of all-source procurement were not reviewed in advance.

Some single-source RFP procurements generally exhibit greater advance oversight of assumptions used for bid evaluation and terms of the RFP. The Georgia PSC requires approval of all bid evaluation practices and documents prior to final release. Although Minnesota Power procurement derived from the preceding IRP, the final procurement arguably departed from the Minnesota PUC's order in key respects.

Problems that occur when regulators don't require advance review and approval

Regulators should conduct advance review because resource plans rely on models that in turn include assumptions and criteria that directly affect both resources procured and overall costs of resource acquisition. We see evidence that failure to conduct these advanced reviews enables utilities to control information and impose biases on procurement processes.

If advance review and approval doesn't occur, then regulators may review these key decisions when utilities present RFP results for certification of resource acquisitions. In our case studies, these after-the-fact reviews occurred in proceedings marked by substantial challenges to assumptions and criteria used to define need and evaluate bids, as well as contract terms. These after-the-fact reviews created at least five problems:

- Alternative resources being excluded from planning or procurement, or being effectively excluded by using outdated or unreasonable performance or cost assumptions
- A choice between accepting a potentially flawed procurement, or accepting delays and additional costs of re-doing RFPs
- Decisions on specific project portfolios often result in failure to set clear policy for future procurement practices
- Emerging technologies may be undervalued or excluded if new procurement practices are not developed
- RFPs themselves may be less competitive due to utilities withholding information from bidders

Furthermore, after-the-fact review may create more work for regulators, as shown in the following examples. Regulators may be concerned about the resources required to hold two or three proceedings. However, dealing with all the issues in a single proceeding may result in a more complex decision, which is either even more resource intensive, or results in issues being left unaddressed or unresolved.

Minnesota: Difficult choices between accepting a flawed procurement and ordering a re-do is illustrated in Minnesota. The Minnesota PUC explicitly refused to proactively approve Minnesota Power's procurement of a gas plant, but the utility proceeded to issue a gas plant RFP, thus excluding alternative resources from consideration beyond limited amounts in separate single-source procurements. When the PUC reviewed results of this gas plant RFP, neither it nor intervening parties were able to propose specific, credible alternatives other than issuing a new RFP. Thus, when a regulator feels compelled to focus on immediate needs for action, it may defer policy decisions to further consultations between the utility and its staff, and clear policy may not be set.

New Mexico: In the PNM case, the New Mexico PRC conducted an extensive after-the-fact review of both significant technical issues with the utility's system planning model as well as policy issues related to application of the recently enacted Energy Transition Act. Some of these same issues are being raised in ongoing El Paso Electric resource acquisition proceedings. Since the PRC enabled intervenors to address those issues using the utility's system planning models, viable alternative portfolios were suggested during an after-the-fact review - a very unusual situation. However, since no decision has been reached in the PNM case, it is unclear whether this after-the-fact review will enable the PRC to resolve technical and policy disputes without delaying contracts.

Georgia: Even if regulators explicitly approve the RFP process in advance, they may not rule on critical assumptions and criteria as part of that approval. For example, in Georgia, these decisions are handled during RFP review, and the PSC staff recommends their approval as part of the RFP solicitation's final review . However, while influenced by the PSC staff review, the methods, assumptions, and criteria for evaluating bids are primarily determined by Georgia Power and for the most part, disclosed to bidders only in "illustrative" format. Bidders can only view and contest project-related assumptions, and they cannot view or contest the system-related assumptions that affect evaluation of their bids.

A more general problem we observed across many of the case studies is that while utilities have generally acknowledged the value of grid services, those values may not be recognized for new technologies in the same way that they are taken for granted from gas-fueled generation. Or, if compensation terms are unclear, then bidders will need to build in pricing risk to include in their bid costs. In either case, failure to clearly articulate value of grid services for new technologies puts bids for those resources at a disadvantage. For example, bidders in the cases we studied have little or no indication of the value that vertically integrated utilities have for "flexible" and "quick start" generation resources, like energy storage or reciprocating engines. Additional steps are needed to capture value of multiple grid services that renewable and storage resources can provide.[xl]

REGULATORS SHOULD RENEW PROCEDURES TO ENSURE THAT UTILITY OWNERSHIP IS NOT AT ODDS WITH COMPETITIVE BIDDING.

Regulators often allow utilities to participate in their own RFPs, either directly or via an affiliate owned by the corporate holding company. They may also buy out developers using a "build-transfer" contract or, as in the case of Minnesota Power, take ownership stakes in the project. Most resource procurement practices we reviewed appeared to include regulatory requirements for utility codes of conduct that restricted information sharing with affiliates who might participate in procurements.

However, some examples of bias toward self-build project remain. An all-source procurement creates opportunities for large, self-built gas plants to compete against much smaller, independently developed renewable or storage plants. Or, more often, utilities may simply propose a single-source RFP that creates a favorable opportunity for their own self-build proposals. Regulators should renew those procedures, considering whether more complex bid evaluation processes will create additional opportunities for bias.

When utilities have the right to self-build, a competitive bid process provides utilities with concrete incentives to reduce costs, encourage technology development, and promote new business and financial approaches. Otherwise, the utility's bids will be uncompetitive. For example, in the case of El Paso Electric, the utility self-built 226 MW of the 370 MW procurement target, but also found it cost effective to exceed its target and procure 350-550 MW of market-supplied resources. One might speculate that El Paso Electric might simply have built a 370 MW peaker plant in the absence of an all-source procurement. Certainly, the NIPSCO comments cited above indicate a degree of surprise at results delivered by engaging the market.

In contrast, Florida's history of utilities selecting themselves as the winner of every RFP suggests that meaningful competition can be discouraged by an ineffective procurement process. Similarly, the suspended Dominion Energy Virginia RFP was accused of bias towards self-build projects. We did not review Florida or Virginia RFP proceedings comprehensively, so we do not suggest what specifically causes this lack of meaningful competition.

It is a responsibility of regulators to proactively address structural bias and prevent improper self-dealing by utilities. Regulators should not wait for independent power producers to invest in futile bids in the hope that their challenges to bid procedures will result in a commission-ordered remedies. The 2008 NARUC report on competitive procurement[xli] suggests that regulators use the following methods:

- Involvement of an independent monitor or evaluator
- Transparent assumptions and analysis in a procurement process
- Detailed information provided to potential bidders
- Utility codes of conduct to prohibit improper information sharing with utility affiliates

- Careful disclosure and review of “non-price” factors and attributes, particularly if they may advantage self-build or affiliate bids

Our recommended best practices build on those in the 2008 NARUC report, and we observed that they are often effectively applied within the context of current planning and procurement processes. However, the evidence of some degree of structural biases and improper self-dealing, as well as new challenges in all-source procurements, suggests that these best practices need renewed attention as regulators update rules and practices.

When regulators enforce requirements for utility codes of conduct that restrict information sharing with affiliates who might participate in the procurement, a fair process still gives the utilities opportunities to provide equity earnings. Opportunities for utilities to own new resources acquired through market procurements can allow them to avoid “hollowing out rate base” and maintain earnings per share for their investors.

REGULATORS SHOULD REVISIT RULES FOR FAIRNESS, OBJECTIVITY, AND EFFICIENCY.

Considering new challenges presented by more diverse, complex and competitive power generation markets, it is also worth revisiting NARUC’s recommendation that procurement processes should be fair, objective, and efficient. As discussed above, regulators should revisit safeguards against preferential treatment of any offers, especially from regulated utilities or their affiliates. Regulators should also ensure that utilities do not engage in unfair, biased, or inefficient processes that result in developers seeing bids rejected, saddled with unreasonable costs or delays, or forced to accept contract terms that drive pricing to below-market levels.

To ensure that all-source procurement is conducted with fairness, objectivity, and efficiency, regulators should:

- Require use of an independent monitor or evaluator
- Require pre-approval of contract terms and directly monitor the utility’s use of any remaining flexibility
- Provide for a process that affords all parties a reasonable opportunity to influence outcomes
- Establish methods to address unforeseen circumstances
- Establish reasonable protections for confidential information (not just deferring to the utility)

Most resource procurement practices we reviewed appeared to include regulatory requirements for an independent evaluator. We saw evidence that independent evaluators had adequate authority and impact in the Xcel Colorado, Minnesota Power, and Georgia Power cases. PNM used a third-party to assist in administering the RFP process, but it was not clear whether it was truly “independent.”

We also saw evidence that many vertically integrated utilities retain a high degree of control over contract terms with potential resource developers. Contract terms are only reviewed after parties have negotiated power contracts for Minnesota Power, PNM, NIPSCO, El Paso Electric, Dominion Energy Virginia, Florida utilities, and Duke Energy in North Carolina. For example, Dominion Energy Virginia's contract terms were stated to be only available on a confidential basis and specified that proposed revisions "may" be considered. Furthermore, while Dominion claimed that battery storage technologies would be considered in the RFP, no contract terms were available. The Xcel Colorado and Georgia RFPs demonstrated a better approach where regulators reviewed and approved contract terms when authorizing final RFP documents.

We are not convinced that many regulators give all parties have a reasonable opportunity to influence outcomes, or that Commissions had established procedures for addressing unforeseen circumstances. Colorado provides bidders with clear rights and opportunities to review the bid-specific assumptions the utility has determined prior to bid evaluation. Other parties who may have a legitimate interest in the outcome of the procurement are also at a disadvantage when there is no opportunity to review aspects of the procurement process. For example, legislative requirements to consider carbon emissions in California and localized economic impacts of plant retirements in New Mexico present legitimate interests in verifying the fairness of bid evaluation practices. A utility's use of confidentiality to restrict review and make unilateral decisions can go as far as to leverage the process to obtain a preferred outcome.

Some commission practices allow utilities to leverage the process to obtain a preferred outcome.

Regulated procurement processes can result in less than optimal outcomes: Under the pressure of a thumbs up or down decision and using imprecise regulatory standards, commissioners and staff experts may feel pressure to render what might be termed "constructive" decisions. Under such pressure, regulators may overlook actions that resulted in bids being rejected, developers facing terms with unreasonable costs, delays, or onerous terms. If the utility advances its recommendation at a time when the need precludes consideration of otherwise cost-effective alternatives, this only exacerbates pressure on regulators.

- In Minnesota, commissioners may have revised their legal standards or shortcut evidentiary review in the interest of approving a gas-fueled power plant that had been discussed for several years. Rejection would have created very tight timelines for procurement.
- Also in Minnesota, the utility's handling of a FERC ruling that affected some bids raised questions that were not answered in the final order.
- In Georgia, IRP and RFP proceedings are almost always settled through bilateral negotiation between PSC staff and the utility followed by PSC approval. While some policy intervention by the PSC does occur in its final order, this practice results in fewer opportunities for other parties to influence outcomes than in states with more direct engagement by the PSC on critical practices.

Time pressures, unforeseen circumstances, development of customs, or practices that lead to negotiated deals are inevitable in the regulatory process. These tendencies should be checked by regulators in advance. For example, regulators can ensure that procurement processes are designed to create reasonable alternatives to the utility's preferred portfolio, and that a public interest standard is applied to selection among those alternatives.

Some utilities offer little transparency.

To demonstrate the impact of a fair, objective, and efficient procurement process, some utilities provide detailed bid reports. These reports include specific information on numbers of bids; average, median, or ranges of prices, and reasons for selecting bids. See, for example, summaries from Xcel Colorado (Table 1), and PNM (Table 5). Other utilities often do not report average, median, or ranges of bid prices publicly.

The lack of transparency makes it more difficult to resolve other issues. As discussed above, some key technical issues are often left unresolved by regulators, with the additional implication being that the utility's technical choices may be considered confidential. Furthermore, it is difficult for other parties to use confidential RFP results to question the utilities' modeling analyses and resulting allocation of resources among various technologies. The heavy use of confidentiality in most of RFP processes we reviewed limits opportunities for public evaluation of both IRP planning and RFP process effectiveness.

Furthermore, if public scrutiny does not lead to clear understanding of what generation resources the market is offering, then intervenors and staff are unable to respond with better options. This in turn can diminish policymakers' confidence in the cost-effectiveness of alternatives.

MODEL PROCESS FOR BID EVALUATION

a. After the commission has determined the need, or several need scenarios, the utility (or regulatory staff, as appropriate) should:

   i. Select an independent evaluator.

   ii. Revise and publish the RFP and model power purchase agreement (PPA) documents as permitted by the commission's order, with input from relevant parties and potential bidders. The utility may issue separate forms for renewable, hybrid (renewable with storage), and fully dispatchable generation. Renewable resources should be allowed to submit multi-part bids for must take, curtailable, and flexible contract options for the same generation project. The RFP should specify the methods for considering end effects if contracts are of differing lengths.

b. The utility should screen bids for minimum compliance. If necessary due to bid volume, similar projects may be ranked against each other and least competitive bids may be removed from consideration.

c. The utility should evaluate the bids using system planning models.

   i. All off-model adjustments to reflect resource-specific costs and benefits authorized by the commission should be made prior to input in models if possible.

   ii. The capacity expansion model should optimize among bids of all technologies to fill approved system energy needed during the resource acquisition period (e.g., through 2028). Capacity values for renewable and storage technologies should be used as assumptions in the capacity expansion model, and thermal technologies should include forced outage rates and other applicable constraints on capacity.[21]

   iii. The utility should use model results to create and compare multiple bid portfolios. Regulators may add specific objectives that should be satisfied by alternative optimized portfolios, and they may encourage portfolios based on sensitivity analyses to cost, load, or other uncertainties.

d. The utility should further study costs of top performing optimized portfolios using a production cost model to run sensitivities as approved by regulators. If there are concerns about reliability, utilities could also conduct resource adequacy studies on top performing optimized portfolios.

e.	Results of evaluations should be summarized in a report, with all model evaluation data made available for review by regulatory staff and qualified intervenors. The independent evaluator's report should be included.
f.	After soliciting comments on the bid evaluation report from parties, regulators should approve or modify a resource portfolio. If the Commission authorized multiple need scenarios, the decision should also explicitly identify the need scenario that it is relying upon.

CONCLUSIONS

With these suggestions in mind, utilities, regulators and consumers can all benefit from competitive processes that reveal the best resource options available in the market at the time. Xcel Colorado's recent bid results ratify the notion that these results can be accomplished, if the right planning procedures are followed, regulators regulate utility monopsony power in the public interest, and competitors are motivated by adequate information and transparent process to risk their capital by submitting many bids at low costs. These outcomes are not the work of a day or a week, but by paying attention to the lessons already learned, the pattern that works in Colorado can provide guidance toward a cleaner electric sector.

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[21] It may be appropriate to use seasonal capacity values and more sophisticated methods as they evolve.

APPENDIX

Table 4: Summary of RFPs Conducted in Case Studies

Utility	RFP Type	Status	Bids
PNM	All-Source RFP	Pending 2020	735
Xcel Colorado	All-Source RFP	Approved 2018	417
Georgia Power	Comprehensive single-source RFPs	2015 Gas / 2017 RE Pending 2020	221 TBD
Minnesota Power	Comprehensive single-source RFPs	Approved 2018	115
NIPSCO	All-Source RFP	Announced 2018	90
El Paso Electric	All-Source RFP	Pending 2020	81
Florida	Single-source RFPs	Approved 2016	0 or few
Dominion Energy Virginia	Single-source RFP	Suspended 2019	n/a
Duke - North Carolina	Comprehensive single-source RFPs	Pending	n/a

ALL-SOURCE RFP CASE STUDY: XCEL COLORADO DEMONSTRATES A PROVEN SOLUTION –

As discussed in the report, in 2018 the Colorado PUC approved Xcel Colorado's portfolio of wind, solar, battery storage, and gas turbine resources to replace two coal plants, referred to as the Clean Energy Plan. A total of 2,458 MW of nameplate resources were procured, resulting in 1,100 MW of firm capacity replacing 660 MW of coal plants.

The cost-effectiveness of the portfolio was driven by what the utility called "shockingly" low wind and solar prices -- *median* bid prices of $18 per MWh for wind, $30 per MWh for solar.[22] Wind and solar coupled with storage were marginally higher, but remarkably affordable.[23] Although not public, the ultimate cost of the wind and solar projects are likely to be below the median bid prices. Much of the credit for this market-driven outcome can be given to the Colorado competitive resource acquisition model.

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[22] These prices include federal tax credits for wind and solar.

[23] Stand-alone storage costs are difficult to analyze based on the Xcel Colorado report to the PUC, since amounts of storage bid are not documented.

Colorado's Planning Process Creates the Market

Since 2004, Colorado's PUC has relied on a two-phase process motivating the utility and potential bidders to participate effectively in supplying a cost-effective mix of resources to serve Xcel Colorado's customers. Colorado utilities must submit an electricity resource plan ("ERP") every four years.

In Colorado, procurement policy shifted towards bidding for new resources in the wake of Xcel Colorado's rate case including about $1 billion in new costs for the Pawnee coal plant in the early 1980s. A billion dollars dropped into a rate case for a new power plant did not give the Colorado PUC or ratepayers time to consider options due to construction timelines, with insufficient notice to participate in decision making. The utility responded to these complaints by producing a hefty binder of planning information, inviting the PUC and interested parties to a single afternoon discussion about planning. Then, in 1989, Xcel Colorado's system was overwhelmed with the interest of nearly 1,000 MW of qualified facilities in response to avoided costs related to the Pawnee unit. In response, the Commission approved a moratorium on QF contracts.

Solutions began to emerge. One commissioner had been looking into bidding constructs that might be applied to the unique circumstances of a monopoly utility.[xlii] NARUC, through its Energy Conservation Committee, had developed "integrated resource planning" during the late 1980s based on a Nevada rule, developed by Jon Wellinghoff.

Drawing on these resources during the early 1990s, the Colorado PUC wrote the Colorado Electric Resource Planning (ERP) rules.[24] Each successive application of these rules has led to changes and improvements.[25] The current PUC is continuing to develop the Colorado planning rules to incorporate distribution planning, additional attention to transmission and market issues, and to conform its planning rules with recently legislated aggressive carbon reduction goals.[xliii]

The Colorado ERP proceeding occurs in two phases, planning and procurement, followed by a CPCN proceeding for utility-owned facilities. In the most recent proceeding, the entire process took about three years. The planning process took about one year, the all-source RFP took 16 months, and most of the CPCNs were issued within 14 months. This proceeding establishes the market rules by which Colorado's investor-owned utilities procure power.

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[24] The process began with a QF only solicitation that morphed into integrated resource planning starting in 1996.

[25] Colorado's ERP rules initially focused on RFPs for PURPA qualifying facilities, but the rules were revised to an all-source process beginning in 1996. Prior to competitive bidding, there had been consistent controversy over PURPA enforcement, resulting in a QF moratorium. Actual bidding in Colorado began after bidding rules were negotiated and then jointly proposed by Public Service Company of Colorado and the newly formed Colorado Independent Energy Association (CIEA). The Commission accepted those jointly proposed rules in 1991. However, the utility then balked at complying, and CIEA battled for a number of years to get the transparent bidding rules followed, and to have an independent evaluator included in the bidding process.

Colorado ERP Phase 1: Utility Planning

Generation procurement in Colorado begins with planning. In Phase 1 of the ERP proceeding, like many IRPs, the Commission reviews all planning related data and information. Phase 1 also includes review of the utility's draft request for proposals, bid evaluation criteria, and proposed power purchase agreements. Thus, the Colorado ERP process links planning and competitive bidding from the very beginning.

Xcel Colorado relies on capacity expansion and production cost modeling to arrive at an approved resource need, taking into consideration load forecasts, fuel costs, renewable integration (including costs and effective load carrying capacity), carbon cost, reserve margin, and other study results. Demand side management and distributed generation are also input to the ERP, as they determined in separate proceedings based on the PUC's view that markets for supply and demand side resources are not conveniently bid together. Like many IRPs, the PUC conducts hearings to review this determination of resource need, including definition of the capacity shortfall, required modeling of sensitivities, and other technical findings. However, unlike most IRP proceedings, in Phase 1, the Colorado PUC neither approves a utility's "base case" nor decides what technologies should fill a capacity need.

The Colorado PUC's 2017 determination of need is relatively unique. Instead of approving a "single MW estimate of resource need," the RFP was authorized to fill a range of different need scenarios, including the following.

- A zero-need scenario, which considered the possibility that Xcel Colorado would have a minimal need. Nevertheless, the PUC anticipated that the portfolio might include "wind resources (and perhaps solar resources) and would not preclude the potential acquisition of low-cost gas-fired resources."[xliv]
- A 450 MW need scenario, based on the demand forecast. (The PUC directed that a post-hearing load forecast be used for the most updated information.)
- An alternative scenario in excess of the calculated resource need that provides benefits to customers over the planning period.
- A "Clean Energy Plan" scenario, which increased the need to allow for the early retirement of two coal units.[xlv]

Thus, although the Phase I decision gave Xcel Colorado clear direction as to what needs to consider in its procurement process, it did not give advance approval of a specific amount or type of capacity resource.

In addition to the need determination, Colorado's Phase 1 review includes RFP documents, model contracts, modeling assumptions that will be used to conduct the all-source RFP bid evaluation, the process by which transmission costs are factored in to bids, the surplus capacity credit (how to handle bids that aren't perfectly matched to need), backfilling (how to compare bids of various length) and other procurement policy matters.[xlvi] Thus, the PUC's 2017 Phase 1 decision aligned the utility's identified resource needs, planning assumptions, and bid evaluation criteria in advance of Xcel Colorado's all-source RFP.

Colorado ERP Phase 2: Resource Procurement

In Colorado's Phase 2, the utility issues an all-source RFP. The 2016 Xcel Colorado RFP included three bidding forms for intermittent, dispatchable and semi-dispatchable resources. The use of three different bidding forms facilitated the initial screening process, in which bids are categorized by resource in order to be reviewed for minimum eligibility criteria. Initial screening also includes an economic screen, based on an "all-in" levelized energy cost ("LEC"), meaning all costs and benefits included.

> **Colorado Electric Resource Planning Rule**
>
> It is the Commission's policy that a competitive acquisition process will normally be used to acquire new utility resources. The competitive bid process should afford all resources an opportunity to bid, and all new utility resources will be compared in order to determine a cost-effective resource plan (i.e., an all-source solicitation). 4 CCR 723-3-3611(a)

From that initial review process, bidders are notified whether their projects will proceed to the modeling phase and, if so, the specific assumptions that will apply to their project, with opportunity for dispute within a limited time window. In 2016, 160 of 417 eligible bids received by Xcel Colorado were included in the system planning model analysis.[xlvii]

All bids that are forwarded to modeling are modeled together[26] under the assumptions approved in Phase 1. The rules ensure that the utility's portfolio development phase will include a sufficient quantity of bids across various generation resource types such that alternative resource plans can be created.

The utility develops multiple portfolios in the model analysis including the utility's preferred portfolio, a least-cost portfolio, and other portfolios that address varying strategies as identified in the Phase 1 decision, such as increasing amounts of renewables or differing plant retirement decisions. In 2016, Xcel Colorado included 11 portfolios in its Phase 2 Report.[xlviii] Then, using a production cost model, the selected portfolios are evaluated under varying assumptions.[27] These "sensitivity analyses" include variations in fuel cost, carbon cost, financial criteria, etc.

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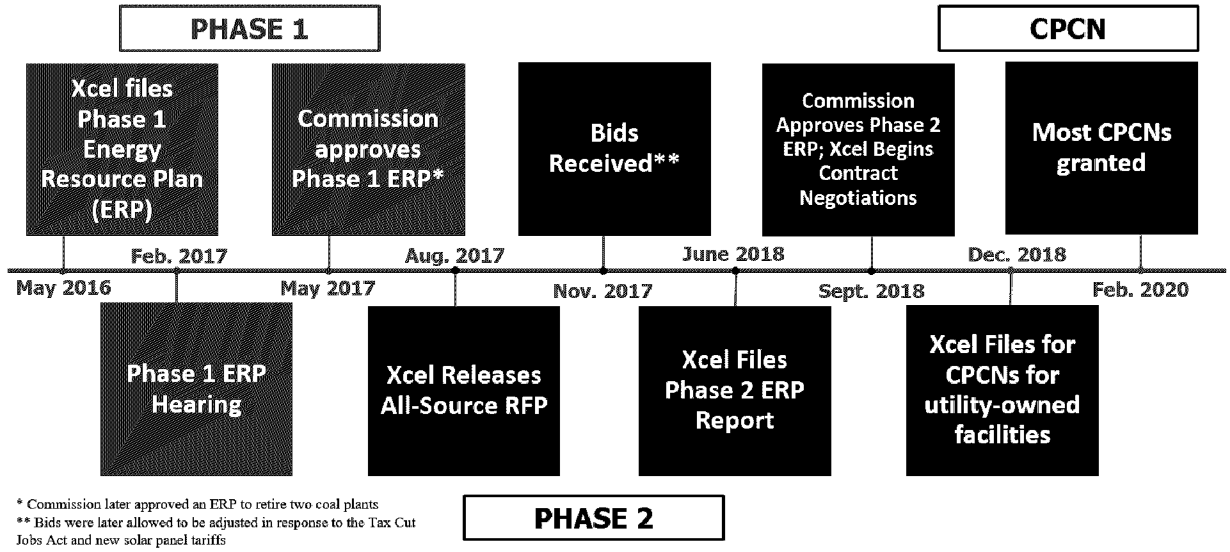
[26] Even though there are three bidding forms for intermittent, dispatchable and semi-dispatchable resources, all of these projects "compete" in the model by being modeled simultaneously.

[27] In addition to production cost models, Xcel Colorado also conducts power flow analyses to estimate transmission upgrade costs associated with each portfolio. Power flow analyses are done for portfolios, not for individual projects.

Figure 2: From IRP to Procurement: How long does it take to do all-source procurement the Colorado Way?



It is important to highlight that the outcome of the modeling of specific bids in Phase 2 can result in very different outcomes than for generic resources evaluated in Phase 1. In 2016, Xcel Colorado's recommended portfolio was substantially different than predicted by the system planning model in the Phase 1 planning study. For example, Xcel Colorado's base case had not predicted any storage resources would be selected. When real world competition was brought to bear, the resource mix was different than anyone had anticipated, both in terms of generation units selected and cost.[xlix]

The entire all-source RFP process is explained in the utility's bid report, which is filed 120 days after bids are submitted. The utility's report is submitted for review, along with model data, by PUC staff and parties. After receiving comments, the PUC issues its Phase 2 Decision, usually without a hearing. The Phase 2 Decision ratifies (or changes) the recommended resource portfolio, authorizing the utility to proceed to bid negotiations, contract awards, construction and operation.

Finally, it is worth noting that implementation of all-source procurement practices has enabled the Colorado PUC to establish that plan approval results in a rebuttable presumption that utility actions taken in concert with approved plans are prudent for purposes of inclusion in PUC-approved consumer rates. This provides value to power providers, utility customers, and the utility itself.

Key Advantages of Colorado's All-Source Procurement Practices

Colorado's all-source procurement practices demonstrate several important approaches to regulating a monopsony utility and achieving a more cost-effective generation solution than a single-source RFP.[l]

- The Colorado PUC reviewed and approved a range of need scenarios for acquiring new power, but did not specific a specific capacity quantity or technology.
- The Colorado PUC reviewed and approved the conditions for acquiring new power. Xcel Colorado was required to conduct an all-source solicitation open to projects regardless of technology, nameplate capacity, location, or transmission requirements to fill the identified capacity and energy need. The terms of the order establish substantial transparency, affording potential bidders clarity as to requirements their bids must meet.
- Xcel Colorado operates a process that allows for fair competition between IPPs and utility ownership proposals. It must consider all bids that meet specified minimum criteria based on cost, schedule, and other relevant performance factors. This addresses bidder concerns about arbitrary decision making and reduces risk premiums that bidders might otherwise feel compelled to include in their bids.
- Xcel Colorado allows for flexible technology outcomes by using its capacity expansion model to optimize resource portfolios based on the best bids in combination. It does not simply evaluate and rank bids individually. This approach benefits utility customers by attracting a maximum diversity of bids since there is potential for any project to fill a niche.
- The Colorado PUC reviews and discloses contract terms in advance, removing uncertainty for bidders.

As suggested above, the Colorado PUC's procurement practices demonstrate robust attention to potential abuses of the utility's market power without compromising the utility's obligation to meet system reliability needs.

ALL-SOURCE RFP CASE STUDY: PNM - EFFECTIVE ENGAGEMENT OF STAKEHOLDERS, BUT AFTER THE RFP

In its 2017 integrated resource plan, PNM recommended abandoning its interest in the San Juan coal plant and replacing it with projects procured in an all-source RFP process. In New Mexico, IRPs are not approved by the New Mexico PRC, and so PNM relied on its IRP to issue an RFP without a determination of need by the PRC.[li]

However, the PRC was not entirely disengaged from determining the need filled by the RFP and approved the process for considering abandonment of the San Juan coal plant in a 2015 stipulation related to environmental concerns. [lii] The stipulation also referenced stakeholder review of the IRP and inclusion of "renewable resource options beyond" those identified in the IRP. Based on those agreed conditions, the resulting abandonment proceeding included review of most of the modeling assumptions and bid evaluation practices used in PNM's procurement process.[liii]

After the PRC ordered the proceeding, New Mexico enacted the Energy Transition Act on March 22, 2019.[28] In addition to gas, solar, and battery storage resources intended to replace the San Juan coal plant, PNM's application also included the securitization component of the ETA, which helped PNM propose a revenue requirement that was lower than its 2017 IRP forecast.[liv]

The RFP resulted in 345 bids, plus 390 bids in the supplemental storage RFP.[lv] PNM contracted with an "owner's engineer," whose role included serving as an "independent resource to review, summarize, and evaluate bid information."[lvi] However, other aspects of the owner's engineer role may not have reflected the usual understanding of an "independent evaluator."[lvii]

Bid prices were very cost-effective, as shown in Table 5. In some cases, such as wind, the prices were similar to the Xcel Colorado prices (see Table 1). But for solar and battery hybrid projects, the prices were more than 40 percent lower, indicating rapid price changes in the market.

As of publication of this report, the PRC has not ruled on PNM's proposal. However, the proceeding is noteworthy because intervening parties were able to, and in fact did, propose alternative portfolios and challenge the utility's technical assumptions in evaluating those portfolios. The PNM portfolio is compared to the portfolio recommended by the Coalition for Clean Affordable Energy, an environmental and consumer advocacy organization, in Table 5 below.

[28] The Energy Transition Act sets aggressive clean energy goals for the state (50 percent carbon free by 2030, 100 percent by 2045) and provides for financial assistance to transition communities reliant on coal. This meant securitization for San Juan to reduce the rate impact to ratepayers and $40 million to assist plant employees and mine workers with retraining and severance pay.

Table 5: Comparison of Portfolios Recommended by PNM and Coalition for Clean Affordable Energy (CCAE) to replace San Juan Coal Plant[lviii]

	PNM Portfolio	CCAE Portfolio	Resource price
Wind (already under contract)	140 MW	140 MW	$17 / MWh
Solar / Battery Hybrid	350 / 60 MW	650 / 300 MW	$19-20 / MWh + $7-10 / kw-mo
Standalone Battery	70 MW	0	$1,211-1,287/kW + $9-10 / kw-year
Gas Turbine	280 MW	0	$680 / kW + $3 / kw-year + fuel costs
Energy Efficiency in 2023	53 MW	69 MW	$263 / first-year MWh
Demand Response in 2023	38 MW	69 MW	$95 / kw-year
2022-2038 System CO_2 emissions	21.9 million tons	20.3 million tons	
Forecast System Cost 2022-2038 (net present value)	$5.26 billion	$5.33 billion[lix]	

Key Issues in the Review of PNM's Replacement Portfolio

Timing of the Proceeding

The scheduling of the abandonment, financing, and resource replacement proceeding was the subject of significant litigation. PNM sought to delay the proceeding until June 2019, arguing that its decision to abandon the San Juan coal plant superseded the approved stipulation agreement. The PRC forcefully disagreed, stating that PNM had already delayed the proceeding, an action that "may have already negated a significant portion of the Commission's abandonment authority - the practical ability to deny PNM's abandonment ..."[lx] The PRC further noted that the delay, "potentially legitimizes the concerns ... that PNM may be seeking to gain an advantage and box in parties that oppose PNM's choices with a time limit."[lxi]

PNM challenged the order in the New Mexico Supreme Court, which stayed the deadline of March 1, 2019 for filing of the proceeding. The court rejected PNM's challenge, which resulted in PNM filing its application on July 1, 2019, nevertheless effectively achieving PNM's original schedule objective. PNM's filing of a consolidated abandonment, financing and resource replacement proceeding was not what had been originally contemplated by the PRC, but the PRC accepted the filing as "responsive" to its order and adjusted the schedule to allow for a 15-month review period.[lxii]

Consideration of Factors Included in Energy Transition Act

The Energy Transition Act provided that "cost, economic development and the ability to provide jobs with comparable pay and benefits to those lost due to the abandonment of the qualifying generation facility are to be considered in evaluating replacement resources." Among other factors and considerations, replacement resources were also to be those "with the least environmental impacts, and those higher ratios of capital costs to fuel costs."[lxiii]

PNM argued that its preferred portfolio, which was developed on the basis of reliability and cost, met the ETA policy factors.[lxiv] It argued that the ETA did not alter "PNM's general planning practices."[lxv] PNM also explored these factors by creating three additional portfolios that focused on replacement generation located in the school district, having high renewable energy content, and making progress towards zero-carbon goals. The additional portfolios that PNM evaluated for increased consideration of those factors did not result in any changes to its recommended portfolio.[lxvi]

The CCAE portfolio was one of the portfolios suggested by intervenors that sought to achieve these goals by placing solar and battery storage projects in the school district rather than the gas turbine projects favored by PNM. According to CCAE, this would increase investment in the school district from $210 million to $447 million, and construction jobs from 375 to at least 500 compared to PNM's proposal.[lxvii]

Technical Problems with RFP Evaluation Modeling

Intervenors raised several technical issues related to PNM's RFP modeling. Some of the issues with greater impact on the results included:

- Inaccurate or constrained energy efficiency and demand response programs and costs
- An inflated forced outage rate at a power plant
- Consideration of correlated outages of gas generators
- Excessive limits on power imports during peak periods
- Effective load carrying capabilities for wind and battery resources were too low
- Relationship between renewable generation output patterns and weather variations
- Use of an unsanctioned reliability metric for system flexibility
- Failure to use a social cost of carbon

Although PNM did accept one technical critique of its modeling, it generally disagreed with the intervenors.[lxviii] In addition to arguing that the higher cost of the intervenor portfolios was significant, PNM also argued that many of the technical adjustments made by intervenors would result in higher reliability risks. Thus, much of the argument about which portfolio was best justified by general planning practices and the ETA factors hinged on whether PNM or intervenor witnesses' testimony is deemed more reliable.

Post-RFP Constraints on Battery Storage

PNM issued its supplemental RFP for energy storage in April 2019, partially in response to the ETA enactment. After determining the optimal portfolio might include as much as 170 MW of battery storage, PNM raised several concerns about the 150 MW storage component of the winning solar-plus-storage bid.[lxix]

- Investment tax credit rules would prevent the storage facility from "recharging with cheap excess wind energy from the grid at night"
- New storage created technology risk and risk of non-performance due to this being larger than any previously built battery storage facility, and the bidder never having constructed a battery storage facility
- The location, far from the Albuquerque load center, is disadvantageous from a system balancing perspective. More optimal locations would allow deferral of T&D facilities and provision of ancillary services.
- Investing now would forgo future price decline and technology innovation opportunity
- By not owning the facility, PNM would not gain operational knowledge of a new technology[lxx]

Based on these concerns, in June 2019, PNM limited total battery storage to 130 MW and individual projects to 40 MW.[lxxi] This occurred about one month after PNM received bids in its supplemental storage RFP,[lxxii] and PNM's evaluation of those bids was only conducted under the limitations set in June 2019.[lxxiii]

Intervenors challenged the battery storage limitations, citing more extensive industry experience with the technology than given credit by PNM, PNM's study by the Brattle Group recommending roughly twice as much battery deployment, a failure to value the locational benefits of storage, and a misunderstanding of the economic value of immediate procurement.[lxxiv]

Access to PNM's Modeling Software

The PRC required PNM to make its models available to seven intervenors without charge.[lxxv, lxxvi] PNM used two primary models in its work, EnCompass for capacity expansion and SERVM for reliability (it also used PowerSimm). PNM made the modeling software available using either PNM running the models using resource portfolios selected by the parties, or by purchasing a license for parties to use the models on their own. Access to the models resulted in a relatively clear distinction being drawn between the parties' positions.

COMPREHENSIVE SINGLE-SOURCE RFP CASE STUDY: GEORGIA POWER PROCURES RESOURCES SEPARATELY

In its 2019 IRP proceeding, the Georgia PSC authorized six single-source RFP processes.[lxxvii] This case study will focus on two near-term utility scale procurement processes, a capacity-based RFP primarily targeted at gas-fueled plants and a renewable energy RFP.[lxxviii] The Commission also authorized smaller-scale procurements, including distributed generation solar resources,[lxxix] biomass,[lxxx] and battery storage.[lxxxi] Georgia's procurement processes rely on RFPs with a number of relatively robust requirements, including an independent evaluator, disclosure of contract terms in advance, and close scrutiny by PSC staff.[lxxxii] Intervening parties recommended the use of all-source procurement; however, this recommendation was not implemented. While not specified in the order, affiliate, self-build and turnkey projects are generally allowed by the PSC.[lxxxiii]

The capacity procurement, primarily targeted at gas-fueled plants, was proposed to address two needs. First Georgia Power proposed to retire Plant Bowen Units 1-2, with a capacity of 1,450 MW of coal-fired generation for economic reasons. Georgia Power anticipated that the retirement would trigger a need for 1,000 MW of replacement capacity in 2022. Second, Georgia Power identified an unspecified capacity need in 2026-28.[lxxxiv]

The renewable energy procurement, primarily targeted at solar plants, was proposed by Georgia Power in response to analysis that showed it would reduce system costs to add additional solar power. Georgia Power initially proposed a total of 1,000 MW and agreed to a larger amount in negotiations with PSC staff. The PSC raised the total amount of renewable energy procurements to 2,260 MW, including smaller-scale procurements mentioned above.

Georgia Power's use of concurrent, single-source procurements emerged over the past decade as solar procurements emerged as a significant component of the utility's resource strategy. Georgia Power's most recent capacity RFP was initiated in 2010 (known as the "2015 RFP"), and it resulted in 47 proposals.[lxxxv] In 2017, a solar procurement resulted in 174 proposals.[lxxxvi]

Capacity Procurement Issues in the Georgia IRP Proceeding

The Georgia PSC largely ratified Georgia Power's proposal for "firm" capacity to replace coal plants and meet a 2028 capacity need in its 2019 IRP decision.[29] According to utility witnesses, the procurements will limit participation to "combined cycle units, combustion turbines, and renewable resources combined with storage."[lxxxvii]

Intervenors challenged this narrow eligibility standard on two grounds. First, several intervenors provided evidence that renewable energy and storage could contribute to meeting the capacity need. Second, the intervenors pointed out that the retirement would lead to a need for both

[29] "Firmness" is defined by Georgia Power to mean providing "capacity and energy ... from specific, dedicated generating unit(s) on an unencumbered first-call basis and priority." Georgia Power, *2015 Request for Proposals*, Georgia PSC Docket 27488 (April 20, 2010), p. 7.

energy and capacity, and that the energy need not be fully supplied by a "firm" capacity resource. Their recommended remedy of an all-source procurement was not adopted in the final order.

Capacity Value of Renewable Energy and Storage

In the Georgia Power IRP proceeding, several intervenors advanced three arguments that renewable energy and storage could contribute to meeting the capacity need.

First, intervenors argued that renewable energy does provide capacity value. For example, the PSC's advocacy staff had recommended that "all types of generation resources that can provide capacity be permitted to bid."[30] Utility witnesses agreed that the "capacity equivalents" for solar power considers "the reliability improvement of that resource compared to the reliability improvement [of a] dispatchable resource."[lxxxviii] Georgia Power uses an approved method to determine the capacity value of renewable energy projects in its procurements.

Second, intervenors submitted evidence that proven technology could enhance renewable energy's capacity value.[lxxxix] Large-scale solar and wind power plants can be built with the capability to receive a dispatch signal from the control center or to respond directly to grid conditions.[xc] For example, in partnership with the National Renewable Energy Laboratory and the California Independent System Operator, First Solar demonstrated that its 300 MW solar PV plant could follow dispatch signals from the grid operator with greater accuracy than a gas-fired power plant, providing important reliability services in the process.[xci] Counter-intuitively, application of intentional pre-curtailment of solar results in *less* overall curtailment.[xcii] In addition to reducing curtailment, the intentional curtailment practices used in the "full flexibility" mode of solar dispatch provide operating reserve services including downward and upward regulation.[xciii] This evidence pointed towards an opportunity for additional value, beyond that accepted by Georgia Power.

Third, intervenors argued that storage projects need not be dependent on co-located renewable energy plants, and that their operation could achieve greater benefits than the utility was acknowledging. In the past, Georgia Power has required that energy storage bids must be co-located at a renewable energy plant site, charged solely from the renewable energy plant, and must operate to provide only one storage use.[31] Georgia Power witnesses did agree that multiple

[30] This recommendation was linked to a provision stating, "... language should be included in the RFP that would permit the Company to reject all bids at its discretion. This language would give the Company and the Commission more options to address future capacity needs." While the stipulation appears to have used a narrower eligibility standard, the broad discretionary language is included in the stipulation. *See* Tom Newsome et. al., *Direct Testimony on Behalf of the Georgia Public Service Commission Public Interest Advocacy Staff*, GPSC Docket No. 42310 (April 25, 2019), p. 114; *and* Georgia Public Service Commission, *Order Adopting Stipulation as Amended*, Docket No. 42310 (July 29, 2019), Stipulation p. 4.

[31] The storage use options allowed by Georgia Power are smoothing (minimize moment-to-moment variations in energy output), firming (guaranteeing the daily energy output profile), and shifting (delivering energy in more valuable hours, with delivery decisions made by either the seller or Georgia Power). Georgia Power, *2020/2021*

storage uses could be provided by the same facility, but expressed concern over accounting impacts that might occur if Georgia Power assumed operational control over a stand-alone storage project.[xciv]

At the end of the IRP proceeding, it appeared that Georgia Power did not accept the intervenors' evidence in favor of updating its concept of "firm" capacity value. The utility maintained its position that stand-alone renewable energy projects cannot bid into its capacity RFP, even if updated to provide "full flexibility" capability, and also its position that storage projects would need to be co-located at a renewable energy site with operational control by the project owner.

Procurement of Capacity and Energy

Some of the intervenors also advanced the argument that even in a capacity RFP, the utility was also procuring energy, and that it should consider resources that only offered energy in the interest of procuring an optimal mix of capacity and energy resources. Even though a large part of Georgia Power's requests is based on the need to replace energy from Plant Bowen Units 1-2,[32] Georgia Power's RFP considers only capacity for firm, or "guaranteed," generation.[xcv]

Georgia Power's witnesses speculated on what the capacity RFP would likely procure, pointing out that gas plants were coming off contract capable of delivering low cost bids to meet the assumed capacity need,[xcvi] which appeared to refer to over 1,000 MW of gas turbine PPAs.[33] Gas turbine energy generation is among the most expensive energy resources, usually dispatched for reliability and ancillary services at very limited utilization rates. The three plants whose contracts are expiring have been used less than 7 percent of the time.[xcvii] In effect, these gas turbine units would meet the firm capacity needs defined by Georgia Power, but could not supply cost-effective energy to substitute for the energy need.

The actual amount of energy needed from the procurement is not public. Georgia Power redacted all meaningful planning data in its IRP related to what services, such as energy, they might need beyond 1,000 MW of capacity. For example, it is unclear whether Georgia Power's bid evaluation will favor units that mimic the 2017 dispatch of Plant Bowen Units 1-2 or will have some other preferred dispatch. This means that it remains unclear to bidders what types of energy resources might perform cost-effectively in the bid evaluation process.

Renewable Energy Development Initiative, Request for Proposals for Utility Scale Renewable Generation, GPSC Docket No. 40706 (December 10, 2018), p. 15-16.

[32] In 2017, Plant Bowen Units 1-2 generated 5.3 million MWh, representing an annual combined capacity factor of 42 percent (51 percent for Unit 1 and 33 percent for Unit 2), which is typical of these units since 2012. Direct Testimony of Mark Detsky, on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association, Georgia PSC Docket No. 42310 (April 25, 2019), p. 26.

[33] The expiring peaking combustion turbine PPAs: MPC Generating - 301 MW GT; Walton County Power - 436 MW GT; Washington County Power - 302 MW GT. See, Stipulation in Docket No. 22528-U, dated Nov. 2, 2006.

Renewable Energy Valuation Issues in the Georgia IRP Proceeding

The PSC expanded three renewable energy procurements proposed by Georgia Power (utility-scale solar, distributed generation solar, and battery storage), and added a fourth for biomass. The stipulation approved by the PSC also deferred several issues related to the valuation of renewable energy to consultation between the utility and Commission staff, primarily adjustments to the capacity equivalency of solar power that affect capacity value.

The issues related to valuation are critical because prior RFPs have specified price plus any costs for renewable energy must not exceed the projected avoided cost on a levelized basis.[xcviii] These values are calculated on a project-specific basis, using a process known as the Renewable Cost Benefit (RCB) Framework,[xcix] and are not disclosed to bidders. Not only are bidders competing against each other, but they must also keep costs below an unknown ceiling.

The RCB Framework is essentially an enhanced version of conventional avoided cost methods. Georgia Power's RCB Framework is relatively comprehensive in that it supports calculation by resource (e.g., wind, utility-scale, and distributed solar) at the project level. The calculations consider several measurable system costs or benefits, generally relies upon utility-specific hourly data, and is updated based on new and improved data.[c]

However, Georgia Power's methods for evaluating renewable energy resources in its resource planning and procurement processes were heavily critiqued by other parties. The issues included the date of the next generation capacity need, the methods for assessing the system benefits of renewable energy, and several modeling issues including claims that basic statistical concepts were misapplied.[ci]

The critiques raised by experts for parties other than the PSC staff were generally not addressed in the PSC order approving the stipulation. Few of these concerns can be raised during the process for approving the renewable or capacity RFPs, or approving any resulting procurement plans.

There is a direct connection between the decision to evaluate renewable resource bids outside the baseline resource plan and the use of separate procurements for capacity, renewable and storage resources. This is because it is impossible to construct an ideal portfolio mix when evaluating bids one-by-one. A bid ranking process could end up with all solar projects, which would not be an effective portfolio. Furthermore, because the operation of energy storage projects depends on the resources with which they are paired, the RCB Framework is "not well-suited to evaluating energy storage resources … and may also require portfolio-level modeling."[cii] Georgia Power's planning practices appear to be diverging into three separate processes,[34] with inefficient overall optimization.

[34] This commentary does not address the energy efficiency planning process, which is a fourth separate process.

Bid Evaluation - Primarily Based on Economic Analysis

After receiving Commission approval in an IRP proceeding, Georgia Power conducts its RFPs with a focus on an economic comparison between bids. There are some differences in the methods for evaluating capacity and renewable energy bids.

- Capacity bids - ranked on net cost ($/MW) considering:[ciii]
  - Fixed costs - such as purchase price, capacity cost payment, fixed O&M, fuel pipeline costs
  - Equity costs - for a capital lease, cost impact to the utility balance sheet
  - Production costs - a production cost model simulation is conducted for each proposal, based on cost and operating characteristics of the unit compared to a reference simulation without the bid
  - Transmission costs - model simulated impacts on the transmission system, including system upgrades and impact on energy losses
- Renewable energy bids - ranked on net benefit ($/MWh) considering:[civ]
  - Bid costs
  - Projected avoided costs, according to the RCB Framework
  - Transmission and distribution costs

With the exception of the capital lease issue in the capacity RFP, the two evaluation methods appear very similar in their general approach to bid ranking, other than the evident difference in ranking based on cost per capacity (MW) and per energy (MWh). Both evaluations consider more than just the simple price of the bid, reaching a net cost (or benefit) result after considering impacts on the overall system dispatch costs.

The overall system dispatch costs are therefore very important factors for bidders to consider in developing competitive bids. However, bidders are provided very little specific information about the production, transmission, and other cost model simulations.

- In a capacity RFP, bidders were informed that, "proposals located in areas of major load (net of generation) would tend to receive a more favorable transmission facilities cost evaluation (since power export capability from the area will not be required) than proposals located in areas that have generation significantly in excess of area load where power export capability from the area may be required."[cv] However, no information about where these locations might be was offered, nor were specific cost multipliers made available.
- In a renewable energy RFP, bidders were provided with relative avoided energy costs for typical days by month. For example, the peak hour was 2:00 p.m. on an August day, while avoided energy costs were represented as 60 percent of that value for 2:00 p.m. on a November day.[cvi] These values are, of course, averages over sunny and cloudy days within the same month.

In these RFPs, although several non-price evaluation factors are noted, such as bidder development experience and specific facility location issues, these appear to be relatively straightforward and not likely to exhibit bias. If the bidder is proposing to sell the unit to Georgia Power, then there would be due diligence on the operating costs. Contracts of varying lengths are accepted.

After evaluating individual bids, Georgia Power assembles several portfolios from the best performing individual bids. Production and transmission costs are re-evaluated for each portfolio in order to identify the best combination of bids.[cvii] The Georgia PSC has a longstanding RFP rule that requires an independent evaluator, extensive staff involvement throughout the process, and PSC approval of the final RFP.

COMPREHENSIVE SINGLE-SOURCE RFP CASE STUDY: MINNESOTA POWER CONSTRAINS ITS RFPS

In 2018, the Minnesota PUC approved Minnesota Power's portion of the Nemadji Trail Energy Center (NTEC), a 525 MW natural gas combined cycle plant in Wisconsin. Minnesota Power would operate and own its share of the plant through agreements with an affiliate and a cooperative utility partner. The NTEC plant was selected in a single resource (gas) RFP, even though the RFP proceeded from an IRP in which the MPUC clearly contemplated an all-source procurement.

Consideration of the NTEC plant came out of Minnesota Power's 2015 IRP. In that IRP, the PUC approved up to 100 MW of solar power, 300 MW of wind power, and a demand response competitive bidding process, exceeding the utility's requests in each instance.[cviii] Minnesota Power was also authorized to idle two coal units, make certain transmission investments, and enter into short term contracts. Minnesota Power was denied approval of certain pollution control equipment at a coal plant. However, Minnesota Power was also authorized to "pursue an RFP to investigate the possible procurement of combined-cycle natural gas generation, with no presumption that any or all of the generation identified in that bidding process will be approved . . . ."

While the RFP was specifically authorized for gas generation, the PUC's order also emphasized that "Minnesota Power's evaluation of replacement generation should not be limited to one resource." Accordingly, the PUC required that the next resource plan include a "full analysis of all alternatives." This requirement was in response to parties who had argued that the solicitation should be fuel-neutral, considering renewables, demand-response measures, or customer-owned generation. As discussed below, this did not happen. A lack of clarity in the order ultimately disappointed parties who believed that the PUC intended for the results of the RFP to be submitted with an updated IRP.

Minnesota Power 2015-16 RFPs

Minnesota Power conducted five RFPs in 2015 and 2016 to develop its 2017 EnergyForward Resource Package. Two of the RFPs, for solar and wind, were relatively uncontroversial, and led to procurements as described above. The customer co-generation RFP did not receive any responses.[cix] The demand response RFP only received one response and did not result in procurement,[cx] and intervenors challenged its effectiveness due to its short response time (less than two months, with the first information session occurring only six weeks before the deadline), the requirement to participate at up to 800 hours per year (creating a large risk), and uncertainties about participation requirements.[cxi]

The gas resource RFP sought “up to 400 MW of dispatchable natural-gas-fired capacity and associated unit-contingent energy.”[cxii] The RFP required PPA pricing for a minimum term of 20 years with a purchase option and requested additional buy-out options. Bidders were required to provide pricing, cost and performance details in their bid. In some cases, the independent evaluator used an outside expert to estimate certain costs.

Fifteen gas resource proposals were deemed qualified.[cxiii] However, two bids were later eliminated based on a FERC ruling on transmission that made resources outside of the local resource zone more “problematic.”[cxiv] The two “problematic” bids were apparently not provided an opportunity to address the issue.

The independent evaluator used results from Minnesota Power’s dispatch model to calibrate its own bid evaluation models used in its assessment. Each bid was individually evaluated to estimate the net impact on Minnesota Power’s system production costs. Minnesota Power shortlisted two projects, including the NTEC bid from Minnesota Power’s affiliate and an unspecified independent PPA. The independent evaluator agreed with Minnesota Power’s selection of a 250 MW proposal for the NTEC plant from the utility’s affiliate.

Minnesota Power’s modeling of NTEC occurred in its capacity-expansion model. In the first step, the utility compared the NTEC plant to a number of generic resource alternatives covering a wide range of technologies.[cxv] Notably, neither bid alternatives to the NTEC plant from the gas resource RFP nor any of the selected or bid alternatives for the solar or wind RFPs were included in this step. In the second step, the NTEC plant was combined with the results of the solar and wind RFPs and compared to two renewable capacity portfolios and one gas peaker portfolio.

Minnesota Power was criticized for delays in its negotiations, which resulted in the estimated need being revised twice. Only the NTEC bidder was allowed to revise the proposal, “in essence MP/ALLETE pursued a single source rather than issuing a new RFP consistent with the revised needs or allowing all bidders the opportunity to address the new need.”[cxvi] The public advocate identified a need to create a “formal, Commission-approved resource acquisition process.”[cxvii]

The gas resource RFP received the most extensive challenges from intervenors, and the administrative law judge agreed that “Minnesota Power used unreasonable assumptions in its modeling, failed to analyze a reasonable range of resources, and placed constraints on the model that resulted in [a bias] in favor of NTEC.”[cxviii] For example, intervenor witnesses challenged the use of winter peaking constraints (MISO is a summer peaking system), the use of capacity values for renewable energy that are lower than standard in MISO, and the use of unnecessarily large sizes for generic resources.[cxix] Nonetheless, the MPUC overruled the administrative law judge and approved the NTEC plant agreements.

The wind RFP received a total of 94 bids, and the solar RFP received 83 bids plus two self-build projects.[cxx] After evaluating the initial solar RFP bids, Minnesota Power decided to pursue a 10 MW project and invited bidders to resubmit at that size. The Commission reviewed the results of those RFPs in separate proceedings. Issues were raised in those proceedings that related to the quality of the renewables RFPs and the fulfillment of the IRP goals. After the winning bid from the wind RFP was selected, the utility and the developer agreed to a "repricing mechanism" was added to address some uncertainties that had developed, and Minnesota Power also agreed to consider taking an equity interest in the project. In the solar RFP, some of the terms and conditions were questioned by the public advocate. Because the utility had reduced solar procurement from the RFP goal of 100 MW to 10 MW, the Commission ordered Minnesota Power to further discuss its modeling of solar resources with the public advocate.

Minnesota Commission Discussion of All-Source Procurement

In contrast to the Georgia decision, the Minnesota commissioners engaged in substantial discussion of issues related to the suitability of Minnesota Power's procurement practices. Despite a lack of evidence from Minnesota Power demonstrating their consideration of clean alternatives to the gas-fired power plant, ultimately the PUC authorized NTEC's procurement.

Key at issue was the burden of proof Minnesota Power faced to justify NTEC as the optimal resource to meet future system needs. The PUC's procedural order established that, "Minnesota Power bears the burden of proving that the proposed gas plant … is needed and reasonable based on all relevant factors …" Among the relevant factors was consideration of alternatives such as wind and solar, storage, demand response, and energy efficiency. Yet when presented to the PUC, the case focused on the gas plant's approval, as there were no alternatives that could be selected if determined more reasonable.[cxxi]

In its final decision on the NTEC plant, the PUC voted 3-2 to reverse the administrative law judge who found that Minnesota Power had not met its burden of proof to justify the procurement of NTEC. The dissenting commissioners felt that the NTEC plant was not needed for capacity, and was not cost-effective as an energy resource.[cxxii] There was significant disagreement among the parties regarding what the prior order required -- one commissioner explained that he believed the order had called for the RFP to seek "intermediate capacity needs" rather than being limited to a gas resource.[cxxiii]

Approval of the RFP thus appeared to depart significantly from the order authorizing the RFP. In reversing, the PUC did not explicitly find that Minnesota Power had met its burden of proof. Instead, it evaluated evidence "based on the totality of the record"[cxxiv] by the Department of Commerce which supported a finding NTEC was "needed and reasonable based on all relevant factors."[cxxv] By applying a lower burden of proof than the IRP standard, it appears concerns expressed by intervenors regarding the burden of proof had been realized.

In considering the NTEC plant decision, there are several relevant lessons that may be considered when developing practices for all-source procurement.

- Utility proposals to transact with affiliates and own specific resources may justify higher burdens of proof such as requiring monopsony utilities to test the market for clean energy portfolios that provide the same service.
- Competent and transparent analysis can provide regulators with strong evidence for a decision. Regardless of one's perspective on the correct decisions in this matter, the record is clear that the administrative law judge and all five commissioners were well-informed by all the experts who testified in the proceeding.
- Commission decisions are more constrained when considering the results of a single-source RFP. The thumbs up/down nature of the decision raises the stakes of rejecting the utility's recommendation, requiring the utility to start from scratch on a potentially accelerated timeline if procurement is denied.
- Commission orders directing all-source procurements need to be clearly worded and establish the statutory standard of review up front. Once the utility has proceeded to conduct an RFP, a regulator will find it difficult to remedy any discrepancies with its initial order.

The only matter which the record of this case leaves uncertain is whether the gas resource RFP was truly competitive. Neither the utility nor the independent evaluator provided much evidence regarding how robust the responses were, as no details regarding alternative gas resources were provided outside of trade secret seals.

ALL-SOURCE RFP CASE STUDY: NIPSCO "SURPRISED" BY LESS EXPENSIVE RENEWABLES

NIPSCO used an all-source RFP for its 2018 IRP, and it began implementation in 2019. The all-source RFP was one of several process improvements that NIPSCO implemented based on feedback from its 2016 IRP.[cxxvi] While the 2016 IRP had called for only two unit retirements in 2023, in the 2018 IRP NIPSCO determined that it could move forward with retiring all its coal plants. The key development was evaluation of "the all source Request for Proposal (RFP) solicitation that NIPSCO ran as part of its 2018 Integrated Resource Plan process – which concluded that wind and solar resources were shown to be lower cost options for customers compared to other energy resource options."[cxxvii]

NIPSCO received 90 total proposals in response to its RFP.[cxxviii] Those proposals were evaluated in its system planning models in two steps. First, NIPSCO evaluated eight different coal retirement portfolios, with varying retirement timings up to and including full retirement in 2023.[cxxix] Second, after selecting the preferred retirement path, NIPSCO evaluated six different replacement generation scenarios.[cxxx] The evaluation considered several metrics, and included stochastic evaluation of various cost driver uncertainties (e.g., fuel cost).

NIPSCO concluded that it should proceed to acquire 1,053 MW of solar, 92 MW of solar plus storage, 157 MW of wind, 50 MW of capacity market purchase, and 125 MW of demand side management resources, along with the retirement of all coal plants by 2028.[cxxxi] The selected portfolio maximized renewables and utilized longer duration contracts relative to the other portfolios. The selected portfolio is projected to have roughly 1 million tons of carbon emissions in 2030, compared to 18.2 million tons in 2005.[cxxxii] (The retirement portfolio analysis did not include carbon emissions.) Other replacement generation portfolios studied had up to 3.1 million tons of emissions. As shown in Table 6, relative to the 2016 IRP Scenario, NIPSCO was able to reduce forecast costs by $1.1 billion, or nearly 10 percent.

Table 6: NIPSCO 2018 IRP / RFP Evaluation of Alternate Portfolios (30-year net present value)[cxxxiii]

Portfolio	Description	System Revenue Requirement
Base	Coal in service through end-of-life	$ 15.4 billion
2016 IRP Scenario	40% coal in 2023	$ 12.9 billion
Preferred Retirement Path	15% coal in 2023	$ 11.3 billion
Average-Low Carbon	More renewables, longer contracts	$ 11.8 billion
Savings vs 2016 IRP Scenario		**$ 1.1 billion**

In a recent webinar, Mike Hooper, NIPSCO senior vice president explained that NIPSCO "ran an RFP process inside of the integrated resource plan to get a better indication of what the real market data looked like." He further explained that, "We kind of made an assumption that as the results came back it would be very much similar to 2016, particularly where we sit in the world, that natural-gas generation would be the most cost-effective option. ... And as we ran this RFP and got our results back, we were surprised to see that wind ...and then solar ... were significantly less expensive than new gas-fired generation."[cxxxiv]

ALL-SOURCE RFP CASE STUDY: EL PASO ELECTRIC FINDS VALUE

Although the public record is sparse, the 2017 El Paso Electric RFP is a good example of a utility finding unexpected value through an all-source procurement process. In 2017, El Paso Electric issued an all-source RFP for 370 MW of generating capacity. Utilizing an independent evaluator, the utility received and evaluated 81 bids from a variety of resources.[cxxxv]

El Paso Electric evaluated the proposals using a two-stage process. First, viable proposals were evaluated based on levelized cost, grouped by resource type (conventional/dispatchable, renewable, load management, or energy storage) and type of proposal being offered (PPA, purchase, or equity participation). The utility then selected the top-ranking proposals from each group to shortlist.[cxxxvi] Of those, only the top ranked solar and storage bids were modeled in a staged portfolio process to determine the winning bids.[cxxxvii]

In 2018, the utility announced that it would meet the capacity needs with 200 MW of solar, 100 MW of battery storage, and a new 228 MW gas peaker plant. While El Paso Electric appears to have expected to obtain mainly peaking units to meet the 370 MW summer peak need, the utility ended up procuring 528 MW (nameplate) of generating resources.[cxxxviii]

SINGLE SOURCE RFP CASE STUDY: FLORIDA BIAS TOWARDS SELF-BUILD GENERATION

A general review of Florida's history with utility RFPs raises the issue of bias towards self-build options. The authors are unaware of any Florida utility RFP process that resulted in selection of a competitive bid: RFP "winners" have always been the utility's own self-build option. Private communications by one of the authors with attorneys who represent independent power producers suggest that there is a widespread perception that the Florida RFP evaluation process does not generally offer an opportunity for meaningful competition.

In one instance, Duke Energy Florida did reverse course with a "last minute acquisition" of Calpine's Osprey plant.[cxxxix] In that proceeding, two independent power producers submitted testimony stating that Duke Energy Florida's bid evaluation process was "oversimplified and structurally biased"[cxl] and "[biased] in favor of DEF's self-build projects."[cxli]

The Duke Energy Florida reversal does not prove that the Florida PSC ensures meaningful competition. In that reversal, the independent power producer had to invest relatively few resources to challenge the utility because the plant was already in operation. Although cost information is redacted from the docket, it appears that the cost advantage offered by Calpine over the self-build option was substantial.

Even after that reversal, developers appear uninterested in developing new project proposals in Florida, perhaps because new project bids require greater investment than bidding an existing facility. Just one year after Calpine obtained a reversal of Duke Energy Florida's self-build option, Florida Power & Light conducted an RFP. FPL reported, "No RFP submission received satisfied the minimum requirements of the RFP."[cxlii]

ALL-SOURCE RFP CASE STUDY: CALIFORNIA'S LOADING ORDER IS A SLOW PATH TO ALL-SOURCE PROCUREMENT

In 2003, California's energy agencies ruled that utilities must procure resources using the "Loading Order," which mandates that energy efficiency and demand response be pursued first, followed by renewables, and lastly clean-fossil generation.[cxliii] Though it took years to get up and running, a marquee case to apply the loading order occurred in 2013 and 2014, when Southern California Edison (SCE) announced it would pursue an all-source procurement including preferred resources to replace the local resources once provided by the San Onofre Nuclear Generating Station.

However, SCE's procurement was not truly "all-source." SCE established a minimum set-aside for preferred resources, implying that gas was going to be a major part of any selected portfolio. This procurement was also limited to local resources, in order to supply generation to a capacity-constrained area.[cxliv]

After a highly anticipated reverse auction, SCE procured 1,382 MW of gas-fired generation, with a smaller yet significant portion of utility-scale batteries (263 MW), efficiency (136 MW), renewables (50 MW), and demand response (70 MW).[cxlv] Reactions to the procurement were mixed - the storage procurement was unprecedented in size, attracting national attention and praise for innovative approach.[cxlvi] Allowing demand-side management to meet some of the need also represented a new application of the loading order. On the other hand, advocates were dismayed at the selection of local natural gas generation, critiquing both SCE's evaluation and the PUC's approval for failing to observe the loading order.[cxlvii]

The next opportunity for an all-source procurement in California is an ongoing proceeding at the CPUC. In November 2019, the CPUC directed SCE and several other related entities to undertake a 3.3 GW all-source procurement.[cxlviii] The procurement is for both "system resource adequacy and renewable integration capacity," and permits both existing and new resources to participate. The utility is required to conduct the "all-source solicitation in a non-discriminatory manner, with resources delivering the same attributes being valued in the same manner. SCE will be required to show its bid comparison metrics to the CPUC to justify its requested procurement."[cxlix]

Even as a leader in renewable integration with a 100 percent clean energy standard on the books, the CPUC is struggling to create rules and standards allowing the replacement of existing gas with new clean energy alternatives. For example, the CPUC is conducting a full examination of capacity credit of hybrid resources - combinations of renewables, storage, and other generation. But until that examination is complete, the CPUC is using an interim method for capacity credit of hybrid resources, which may constrain the availability of clean energy alternatives that can compete with existing gas-fueled resources.

The interim capacity credit method proposed by the CPUC assigns a hybrid resource the greater of the capacity credit values assigned to individual component resources.[cl] Under this framework, solar will most likely receive nearly no capacity credit (due to the excess of solar already on the grid) and four-hour storage barely qualifies for capacity credit. Behind-the-meter resources also receive no credit. Advocates hold that this will likely result in 50-60 year-old gas-fired power plants continuing to operate and receive capacity revenue after the procurement.[cli]

SINGLE-SOURCE RFP CASE STUDY: DOMINION ENERGY VIRGINIA CONSTRAINS THE MARKET

A recent Dominion Energy Virginia RFP demonstrates several issues related to over-procurement, self-build, transparency, and fairness. In November 2019, Dominion Energy Virginia initiated an RFP for up to 1,500 MW of new peaking resources.[clii] Resources must be "new and fully dispatchable." The resource need was identified by Dominion in its 2019 integrated resource plan, which selected a gas peaker plant.[cliii] Notably, the 2019 IRP was an update to a 2018 IRP that had been first rejected, then a refiled version approved with a strong caveat that the Commission did not "express approval . . . of the magnitude or specifics of Dominion's future spending plans."[cliv]

In response, LS Power asked the Virginia State Corporation Commission and Attorney General to suspend the RFP process.[clv] Among the complaints cited by LS Power are the requirement for resources to be "new," a lack of transparency regarding how Dominion's self-build alternatives will be evaluated (including potential disparity in risk of changes to environmental laws), and the lack of an independent evaluator. LS Power did not specifically complain about the exclusion of resource alternatives to gas peaker plants.

In December, Dominion Energy Virginia suspended the RFP without giving an explanation. A news article speculated that the suspension was in response to reports that the utility had over-forecasted demand for years.[clvi]

COMPREHENSIVE SINGLE-SOURCE RFP CASE STUDY: RESOURCE EVALUATION STIRRINGS IN NORTH CAROLINA

Commission interest in allowing competition between a wide array of resources to replace existing coal is emerging in North Carolina. A recent order by the North Carolina Utilities Commission (NCUC) identified similar concerns in a ruling on 2018 IRPs.[clvii]

- With respect to storage resources, the NCUC re-asserted its direction from a prior order in which it indicated that Duke Energy's "evaluations of [battery storage] technology … have not been fully developed to a level to provide guidance as to the role this technology should play going forward."
- With respect to energy efficiency resources, the NCUC noted that "Duke simply accepts its presently established levels of [energy efficiency and demand-side management] for planning purposes, and plugs those amounts into its IRP," and directed improved modeling of those resources.
- The NCUC further ordered that future IRPs "explicitly include and demonstrate assessments of the benefits of purchased power solicitations, alternative supply side resources, potential [energy efficiency and demand-side management] programs, and a comprehensive set of potential resource options and combinations of resource options."
- The NCUC ordered Duke Energy to "remove any assumption that their coal-fired generating units will remain in the resource portfolio until they are fully depreciated. Instead, the utilities shall model the continued operation of these plants under least cost principles …"

The NCUC decision on Duke Energy's IRPs illustrates concerns about issues that also appear in other utility all-source procurement practices.

[i] Susan Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, Analysis Group (July 2008).

[ii] Dyson, Mark, Jamil Farbes, and Alexander Engel, *The Economics of Clean Energy Portfolios: How Renewable and Distributed Energy Resources Are Outcompeting and can Strand Investment in Natural Gas-Fired Generation*, Rocky Mountain Institute (2018).

[iii] Ronald L. Lehr and Mike O'Boyle, *Steel for Fuel: Opportunities for Investors and Customers*, Energy Innovation Policy and Technology LLC (December 2018).

[iv] Colorado General Assembly, Colorado Senate Bill 19-236, *Sunset Public Utilities Commission,* Section 5 (May 2019).

[v] As of 2014. US Environmental Protection Agency, State Climate and Energy Program, *Energy and Environment Guide to Action* (2015), p. 7-10. See also Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (2013), p.5.

[vi] US Environmental Protection Agency, State Climate and Energy Program, *Energy and Environment Guide to Action* (2015), p. 7-24.

[vii] John Shenot et. al., *Capturing More Value from Combinations of PV and Other Distributed Energy Resources*, Regulatory Assistance Project (August 2019).

[viii] Washington State Utilities and Transportation Commission, *Report and Policy Statement on Treatment of Energy Storage Technologies in Integrated Resource Planning and Resource Acquisition*, Docket No. UE-151069 (October 11, 2017), p. 12.

[ix] Andrew D. Mills and Pia Rodriguez, *Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities*, Lawrence Berkeley National Laboratory (October 2019).

[x] Regional power markets have developed mechanisms for capturing the value from solar, wind and other distributed energy resources. *See* John Shenot et. al., *Capturing More Value from Combinations of PV and Other Distributed Energy Resources*, Regulatory Assistance Project (August 2019).

[xi] Andrew D. Mills and Pia Rodriguez, *Drivers of the Resource Adequacy Contribution of Solar and Storage for Florida Municipal Utilities*, Lawrence Berkeley National Laboratory (October 2019).

[xii] Energy and Environmental Economics, Inc., *Planning Reserve Margin and Capacity Value Study*, Nova Scotia Power (July 2019), p. 64.

[xiii] US Energy Information Administration, *Annual Energy Outlook 2019* (January 24, 2019), p. 92.

[xiv] Ryan Wiser and Mark Bolinger, *2018 Wind Technologies Market Report*, US Department of Energy (August 2019).

[xv] Mark Bolinger, Joachim Seel and Dana Robson, *Utility-Scale Solar*, Lawrence Berkeley National Laboratory (December 2019).

[xvi] Lazard, *Lazard's Levelized Cost of Energy Analysis - Version 13.0* (November 2019).

[xvii] Dyson, Mark, Jamil Farbes, and Alexander Engel, *The Economics of Clean Energy Portfolios: How Renewable and Distributed Energy Resources Are Outcompeting and can Strand Investment in Natural Gas-Fired Generation*, Rocky Mountain Institute (2018).

[xviii] US Energy Information Administration, *Annual Energy Outlook 2019* (January 24, 2019), Table 4.1.

[xix] Harvey Averch and Leland Johnson, "Behavior of the Firm under Regulatory Constraint," *American Economic Review* (December 1962).

[xx] Steven Kihm, "When Revenue Decoupling Will Work … And When It Won't," *The Electricity Journal* (October 2009).

[xxi] Rob Granlich and Michael Goggin, *Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform*, Grid Strategies LLC (November 2019), p. 11.

[xxii] Steven Kihm, Peter Cappers and Andrew Satchwell, *Considering Risk and Investor Value in Energy Efficiency Business Models*, ACEEE Summer Study on Energy Efficiency in Buildings (2016).

[xxiii] US Energy Information Administration, *Annual Energy Outlook 2019* (January 24, 2019), p. 89.

[xxiv] Ron Binz et. al., *Practicing Risk-Aware Electricity Regulation*, Ceres (November 2014).

[xxv] Tyler Comings et. al., *Review of Duke Energy's North Carolina Coal Fleet in the 2018 Integrated Resource Plans* (March 7, 2019).

[xxvi] Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (2013).

[xxvii] Brendan Kirby, *Direct Testimony on Behalf of Southern Alliance for Clean Energy*, NCUC Docket No. E-100, Sub 158 (June 21, 2019).

[xxviii] Twenty states' IRP rules are "silent with respect to unit retirements." Rachel Wilson and Bruce Biewald, *Best Practices in Electric Utility Integrated Resource Planning*, Regulatory Assistance Project (2013).

[xxix] California Assembly Bill No. 32 (September 2006).

[xxx] California Senate Bill No. 1368 (September 2006)

[xxxi] California's loading order expresses a preference for energy efficiency, demand response, and renewable energy before considering fossil generation as a last resort. Sylvia Bender et al., *Implementing California's Loading Order for Electricity Orders*, California Energy Commission (July 2005).

[xxxii] Colorado General Assembly, Colorado Senate Bill 19-236, *Sunset Public Utilities Commission,* Section 13 (May 2019).

[xxxiii] Galen L Barbose, *U.S. Renewables Portfolio Standards: 2019 Annual Status Update*, Berkeley Lab, (July 2019).

[xxxiv] Heather Pohnan, Maggie Shober, and John D. Wilson, *Tracking Decarbonization in the Southeast: 2019 Generation + CO2 Emissions Report*, Southern Alliance for Clean Energy (July 2019); and Bruce Biewald et. al., *Investing in Failure: How Large Power Companies Are Undermining their Decarbonization Targets*, Synapse Energy Economics for Majority Action (March 2020).

[xxxv] See *United States v. E.I. du Pont de Nemours & Co.*, 351 U.S. 377, 391-92 (1956).

[xxxvi] The practices suggested here presume a market design and bidding process that is common across the United States. A wider range of potential procurement practices is discussed in IRENA, *Renewable Energy Auctions: A Guide to Design* (June 2015).

[xxxvii] Public Utilities Commission of Colorado, *Cheyenne Ridge Wind Project CPCN*, Decision No. C19-0367 (April 24, 2019), CoPUC Proceeding No. 18A-0905E, p. 13.

[xxxviii] North Carolina Utilities Commission, *2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans,* Order in Docket No. E-100, Sub 157 (August 27, 2019), p. 90-91.

[xxxix] Claire E. Kreycik et. al., *Procurement Options for New Renewable Electricity Supply*, National Renewable Energy Laboratory Technical Report NREL/TP-6A20-52983 (December 2011).

[xl] Maureen Lackner et al., "Policy Brief - Using Lessons from Reverse Auctions for Renewables to Deliver Energy Storage Capacity: Guidance for Policymakers," *Review of Environmental Economics and Policy*, (Winter 2019).

[xli] Susan Tierney and Todd Schatzki, *Competitive Procurement of Retail Electricity Supply: Recent Trends in State Policies and Utility Practices*, Analysis Group (July 2008).

[xlii] Ronald L. Lehr and Robert Touslee, "What Are We Bid? Stimulating Electric Generation Resources Through the Auction Method," *11 Public Utilities Fortnightly* (12 November 1987).

[xliii] Colorado Public Utilities Commission, *Amendments to Electric Rules, 4 CC 723-3*, Proceeding No. 19R-0096E.

[xliv] Colorado Public Utilities Commission, *2016 Electric Resource Plan Phase I*, Decision No. C17-0316 (March 23, 2017), Proceeding No. 16A-0396E, p. 15.

[xlv] Colorado Public Utilities Commission, *Phase II Decision*, Decision No. C18-0761 (August 27, 2018), Proceeding No. 16A-0396E, p. 16.

[xlvi] Colorado Public Utilities Commission, *2016 Electric Resource Plan Phase I*, Decision No. C17-0316 (March 23, 2017), Proceeding No. 16A-0396E, pp. 40-44.

[xlvii] Xcel Energy Colorado, *2016 Electric Resource Plan, 120-Day Report*, CoPUC Proceeding No. 16A-0396E (June 6, 2018), pp. 78, 84

[xlviii] Xcel Energy Colorado, *2016 Electric Resource Plan, 120-Day Report*, CoPUC Proceeding No. 16A-0396E (June 6, 2018), p. 41.

[xlix] Mark Detsky, *Direct Testimony on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association*, GPSC Docket No. 42310 (April 25, 2019), pp. 21-22.

[l] Mark Detsky, *Direct Testimony on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association*, GPSC Docket No. 42310 (April 25, 2019).

[li] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 52.

[lii] New Mexico Public Regulation Commission, *Order Initiating Proceeding on PNM's Abandonment of San Juan Generating Station*, NMPRC Case No. 19-00018-UT (January 30, 2019), pp. 6-7

[liii] One project, a 140 MW wind project, was separately proposed a month earlier in an RPS compliance action. Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00159-UT (June 3, 2019), p. 18.

[liv] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 15.

[lv] Roger W. Nagel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), Exhibit RWN-4, p. 9.

[lvi] Roger W. Nagel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), pp. 4, 33.

[lvii] Roger W. Nagel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 8.

[lviii] Anna Sommer, *Corrected Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (December 13, 2020), p. 4; Justin Brant, *Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (December 27, 2020), pp. 5, 8; Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 24; Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), pp. 11, 56-57, 75-76, 81-82.

[lix] PNM contends that the CCAE portfolio would cost approximately $100 million more if modeling assumptions that it disagrees with are used. Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 23.

[lx] New Mexico Public Regulation Commission, *Order Initiating Proceeding on PNM's Abandonment of San Juan Generating Station*, NMPRC Case No. 19-00018-UT (January 30, 2019), pp. 6-7.

[lxi] New Mexico Public Regulation Commission*Order Initiating Proceeding on PNM's Abandonment of San Juan Generating Station*, NMPRC Case No. 19-00018-UT (January 30, 2019), p. 12.

[lxii] New Mexico Public Regulation Commission, *Corrected Order on Consolidated Application,* NMPRC Case Nos. 19-00018-UT and 19-00195-UT (July 10, 2019), pp. 2-5.

[lxiii] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 7-8.

[lxiv] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 8.

[lxv] Thomas G. Fallgren, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 16.

[lxvi] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 17.

[lxvii] Tyler Comings, *Direct Testimony on Behalf of Coalition for Clean Affordable Energy*, NMPRC Case No. 19-00195-UT (December 13, 2020), p. 19.

[lxviii] Nicholas L. Phillips, *Rebuttal Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (January 13, 2020), pp. 23, 33-44.

[lxix] Nick Wintermantel, *Direct Testimony on Behalf of PNM*, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 22-24.

[lxx] William Kemp, Direct Testimony on Behalf of PNM, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 23-29. Note that PNM has substantial control over the battery storage facilities. Thomas G. Fallgren, Direct Testimony on Behalf of PNM, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 68.

[lxxi] Thomas G. Fallgren, Direct Testimony on Behalf of PNM, NMPRC Case No. 19-00195-UT (December 13, 2019), p. 23.

[lxxii] Tyler Comings, Direct Testimony on Behalf of Coalition for Clean Affordable Energy, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 5.

[lxxiii] Nick Wintermantel, Direct Testimony on Behalf of PNM, NMPRC Case No. 19-00195-UT (July 1, 2019), p. 23-25.

[lxxiv] Mihir Desu, Direct Testimony on Behalf of Coalition for Clean Affordable Energy, NMPRC Case No. 19-00195-UT (July 1, 2019), pp. 20-25, 32-46.

[lxxv] New Mexico Public Regulation Commission, Order Addressing Revised PNM Proposal on Discovery Issues, NMPRC Case No. 19-00195-UT (August 27, 2019), p. 3.

[lxxvi] PNM estimated that the "total cost for modeling-related requests and software [was] $100,000." PNM testimony recommended that parties bear their own costs for this modeling in the future. (v Nicholas L. Phillips, Rebuttal Testimony on Behalf of PNM, NMPRC Case No. 19-00195-UT (January 13, 2020), p. 65.) The cost to PNM for a single EnCompass license (which can be shared by multiple parties) is $5,000, and for SERVM is $2,100 per month, per party. (PNM, Revised Proposal to Provide Parties Access to Resource Planning Models and Information Regarding Requests for Proposals, NMPRC Case No. 19-00195-UT (August 14, 2019), pp. 19-20.) Software license costs negotiated directly by individual parties could be significantly higher than those made available to PNM, and the software will also require purchase or rental of a compatible server environment.

[lxxvii] Georgia Public Service Commission, Order Adopting Stipulation as Amended, Docket No. 42310 (July 29, 2019).

[lxxviii] The capacity-based RFP will solicit bids for two separate capacity needs, one for 2022-23 and one for 2026-28. Originally proposed as two RFPs, Georgia Power has initiated a single RFP process titled "2022-2028 Capacity Request For Proposals." *See* Georgia Public Service Commission, Order Adopting Stipulation as Amended, Docket No. 42310 (July 29, 2019), Stipulation p. 4.

[lxxix] The "DG" RFP will procure customer-sited projects, paid avoided costs. If the RFP is oversubscribed, a lottery will be used to select projects. Georgia Public Service Commission, Order Adopting Stipulation as Amended, Docket No. 42310 (July 29, 2019), p. 15.

[lxxx] The details of the biomass RFP are not yet developed, but presumably this competitive procurement will not cap costs at avoided costs, as testimony during the hearing suggested that biomass would be too expensive. Georgia Public Service Commission, Order Adopting Stipulation as Amended, Docket No. 42310 (July 29, 2019), p. 15-16.

[lxxxi] Georgia Public Service Commission, Order Adopting Stipulation as Amended, Docket No. 42310 (July 29, 2019), Stipulation p. 5.

[lxxxii] Georgia Public Service Commission, Rule 515-3-4-.04(3).

[lxxxiii] Affiliate and turnkey projects were allowed in: Georgia Power, *2020/2021 Renewable Energy Development Initiative*, *Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), p. 16-18. Affiliate and self-build projects were allowed in: Georgia Power, *2015 Request for Proposals*, Georgia PSC Docket 27488 (April 20, 2010), p. 2, 4.

[lxxxiv] Jeffrey R. Grubb et. al., Direct Testimony on behalf of Georgia Power Company, GPSC Docket No. 42310 (March 14, 2019), p. 38.

[lxxxv] Georgia Power Company, Application for Decertification, Certification and Updated Integrated Resource Plan, GPSC Docket No. 34218 (August 4, 2011), p. 25.

[lxxxvi] Georgia Public Service Commission, Order Approving 2018/19 Renewable Energy Development Initiative Power Purchase Agreements, Docket No. 41596 (January 16, 2018), p. 3.

[lxxxvii] Jeffrey R. Grubb et. al., *Direct Testimony on behalf of Georgia Power Company*, GPSC Docket No. 42310 (March 14, 2019), p. 40.

[lxxxviii] Jeffrey R. Grubb et. al., *Georgia Power 2019 Integrated Resource Plan*, GPSC Docket No. 42310, transcript p. 222.

[lxxxix] Arne Olson, *Direct Testimony on behalf of Georgia Large Scale Solar Association*, GPSC Docket No. 42310 (April 25, 2019).

[xc] Arne Olson, *Direct Testimony on behalf of Georgia Large Scale Solar Association*, GPSC Docket No. 42310 (April 25, 2019), p. 53. Clarification relative to wind resources by personal communication.

[xci] Loutan, C., et al. *Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant*, California Independent System Operator, First Solar, and National Renewable Energy Laboratory, Report NREL/TP-5D00-67799 (March 2017).

[xcii] Energy and Environmental Economics, First Solar, and Tampa Electric Company, *Investigating the Economic Value of Flexible Solar Plant Operation* (October 2018), p. 4.

[xciii] Arne Olson, *Direct Testimony on behalf of Georgia Large Scale Solar Association*, GPSC Docket No. 42310 (April 25, 2019), p. 54.

[xciv] Jeffrey R. Grubb et. al., *Georgia Power 2019 Integrated Resource Plan*, GPSC Docket No. 42310, transcript p. 408, 411.

[xcv] Jeffrey R. Grubb et. al., *Georgia Power 2019 Integrated Resource Plan*, GPSC Docket No. 42310, transcript p. 564-566.

[xcvi] Jeffrey R. Grubb et. al., *Georgia Power 2019 Integrated Resource Plan*, GPSC Docket No. 42310, transcript p. 665.

[xcvii] Mark Detsky, *Direct Testimony on Behalf of Southern Alliance for Clean Energy and Southern Renewable Energy Association*, GPSC Docket No. 42310 (April 25, 2019), p. 28.

[xcviii] Georgia Power, *2020/2021 Renewable Energy Development Initiative*, *Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), p. 2-3.

[xcix] Georgia Power, *A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia*, Integrated Resource Plan Technical Appendix Volume 2, GPSC Docket No. 42310 (January 17, 2019).

[c] Georgia Power, *A Framework for Determining the Costs and Benefits of Renewable Resources in Georgia*, Integrated Resource Plan Technical Appendix Volume 2, GPSC Docket No. 42310 (January 17, 2019).

[ci] Jamie Barber et. al., *Direct Testimony on Behalf of the Georgia Public Service Commission Public Interest Advocacy Staff*, GPSC Docket No. 42310 (April 25, 2019), p. 48; Brendan J. Kirby, *Direct Testimony on Behalf of Southern Alliance for Clean Energy*, GPSC Docket No. 42310 (April 25, 2019), pp. 18-26; James F. Wilson, *Direct Testimony on Behalf of Georgia Interfaith Power & Light and Partnership for Southern Equity*, GPSC Docket No. 42310 (April 25, 2019), p. 30; and William M. Cox and Karl R. Rabago, *Direct Testimony on Behalf of Georgia Solar Energy Association and Georgia Solar Energy Industries Association*, GPSC Docket No. 42310 (April 25, 2019), p. 36-37.

[cii] Arne Olson, *Direct Testimony on behalf of Georgia Large Scale Solar Association*, GPSC Docket No. 42310 (April 25, 2019), p. 19.

[ciii] Georgia Power, *2015 Request for Proposals*, GPSC Docket No. 27488 (April 20, 2010), Attachment G.

[civ] Georgia Power, *2020/2021 Renewable Energy Development Initiative*, *Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), Attachment C.

[cv] Georgia Power, *2015 Request for Proposals*, GPSC Docket No. 27488 (April 20, 2010), Attachment G, p. 6.

[cvi] Georgia Power, *2020/2021 Renewable Energy Development Initiative*, *Request for Proposals for Utility Scale Renewable Generation*, GPSC Docket No. 40706 (December 10, 2018), Attachment C, p. 4.

[cvii] Georgia Power, *2015 Request for Proposals*, GPSC Docket No. 27488 (April 20, 2010), Attachment G, p. 7.

[cviii] Minnesota Public Utilities Commission, Order Approving Resource Plan with Modifications, Docket No. E-015/RP-15-690 (July 18, 2016).

[cix] Minnesota Power, 2017 EnergyForward Resource Package, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 3-34.

[cx] Minnesota Power, 2017 EnergyForward Resource Package, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 3-32.

[cxi] Robert R. Stephens, Direct Testimony on Behalf of Large Power Intervenors, MPUC Docket No. E-015/AI-17-568 (January 19, 2018).

[cxii] Sedway Consulting, Inc., "Independent Evaluation Report for Minnesota Power Company's 2015 Gas-Fired Resource Solicitation," 2017 EnergyForward Resource Package, Appendix V, MPUC Docket No. E-015/AI-17-568 (July 28, 2017).

[cxiii] Minnesota Power, 2017 EnergyForward Resource Package, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 6-13.

[cxiv] Minnesota Power, 2017 EnergyForward Resource Package, MPUC Docket No. E-015/AI-17-568 (July 28, 2017), p. 6-14.

[cxv] Eric J. Palmer, Direct Testimony on Behalf of Minnesota Power, MPUC Docket No. E-015/AI-17-568 (November 9, 2017), p. 15-17.

[cxvi] Steve Rakow, Direct Testimony on Behalf of the Division of Energy Resources, MPUC Docket No. E-015/AI-17-568 (January 19, 2018), p. 36.

[cxvii] Steve Rakow, Direct Testimony on Behalf of the Division of Energy Resources, MPUC Docket No. E-015/AI-17-568 (January 19, 2018), p. 37.

[cxviii] Minnesota Public Utilities Commission, Order Approving Affiliated-Interest Agreements with Conditions, Docket No. E-015/AI-17-568 (January 24, 2019).

[cxix] Anna Sommer, Direct Testimony on Behalf of Fresh Energy, et. al., MPUC Docket No. E-015/AI-17-568 (January 19, 2018).

[cxx] Minnesota Public Utilities Commission, Order Approving Power Purchase Agreement, MPUC Docket No. E-015/M-18-545 (January 23, 2019); Minnesota Public Utilities Commission, Order Approving 10 MW Blanchard Solar Power Purchase Agreement and Cost Recovery Method, MPUC Docket No. E-015/M-18-401 (October 2, 2018).

[cxxi] Fresh Energy et. al., Clean Energy Organizations' Comments on Minnesota Power's 2015-2029 Resource Plan, MPUC Docket No. E-015/RP-15-690 (June 30, 2017).

[cxxii] Comments of Commissioner Schuerger, Minnesota Public Utilities Commission, Agenda Meeting, (October 29, 2018).

[cxxiii] Comments of Commissioner Tuma, Minnesota Public Utilities Commission, Agenda Meeting, (September 7, 2017).

[cxxiv] Comments of Commissioner Lipshcultz, Minnesota Public Utilities Commission, Agenda Meeting, (October 29, 2018).

[cxxv] Minnesota Public Utilities Commission, Order Approving Affiliated-Interest Agreements with Conditions, Docket No. E-015/AI-17-568 (January 24, 2019).

[cxxvi] NIPSCO, 2018 Integrated Resource Plan (October 31, 2018), p. 10.

[cxxvii] NIPSCO, NIPSCO Announces Addition of Three Indiana-Grown Wind Projects (February 1, 2019).

[cxxviii] NIPSCO, 2018 Integrated Resource Plan (October 31, 2018), p. 54.

[cxxix] NIPSCO, 2018 Integrated Resource Plan (October 31, 2018), p. 146.

[cxxx] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 171.

[cxxxi] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 172.

[cxxxii] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), p. 171.

[cxxxiii] NIPSCO, *2018 Integrated Resource Plan* (October 31, 2018), pp. 155, 171.

[cxxxiv] Mike Hooper, NIPSCO, *What Happens When Wind and Solar Win on Price?*, Advanced Energy Economy webinar (June 25, 2019).

[cxxxv] Omar Gallegos, *Direct Testimony on Behalf of El Paso Electric*, NMPRC Case No. 19-00349-UT (November 18, 2019), pp. 20-22.

[cxxxvi] El Paso Electric, *2017 All Source Request for Proposals for Electric Power Supply and Load Management Resources* (June 30, 2017), p. 23.

[cxxxvii] Omar Gallegos, *Direct Testimony on Behalf of El Paso Electric*, NMPRC Case No. 19-00349-UT (November 18, 2019), pp. 35-38.

[cxxxviii] El Paso Electric, *El Paso Electric Announces Results of Competitive Bid for New Generation* (December 26, 2018). The utility also announced 50-150 MW of additional wind and solar power "to provide for fuel diversity and energy cost savings." However, the utility did not successfully negotiate those projects. Wayne Oliver, *Direct Testimony on Behalf of El Paso Electric*, NMPRC Case No. 19-00349-UT (November 18, 2019), Exhibit WJO-4, p. 45.

[cxxxix] Florida Office of Public Counsel, *Citizen's Post-Hearing Statement of Positions and Post-Hearing Brief*, FPSC Docket No. 140110-EI (September 10, 2014).

[cxl] Paul J. Hibbard, *Direct Testimony on Behalf of Calpine Construction Finance Company, L.P.*, FPSC Docket No. 20140110-EI (July 14, 2014).

[cxli] *Direct Testimony and Exhibits of Jeffry Pollock on Behalf of NRG Florida, LP*, Florida PSC Docket No. 20140110-EI (July 14, 2014).

[cxlii] Florida Power & Light Company, *Petition for Determination of Need for Okeechobee Clean Energy Center Unit 1*, FPSC Docket No. 150196-EI (September 3, 2015).

[cxliii]Sylvia Bender et al., *Implementing California's Loading Order for Electricity Orders,* California Energy Commission, (July 2005).

[cxliv] California Public Utilities Commission, *Resource Adequacy*.

[cxlv] Jeff McDonald, 'CPUC approves Edison energy deals,' *The San Diego Union-Tribune*, (November 19, 2015).; Peter Maloney, 'Why clean energy advocates are challenging SCE's historic storage buy,' *Utility Drive* (November 16, 2015).

[cxlvi] Eric Wesoff, Jeff St. John, "SCE Announces Winners of Energy Storage Contracts Worth 250MW," *Green Tech Media* (November 5, 2014). Further, to better understand the potential role of distributed energy resources in meeting local reliability needs, SCE began in parallel a preferred resources pilot that has demonstrated 200 MW of DERs "can be an effective means to manage load." Southern California Edison, *SCE Preferred Resources Pilot* (August 1, 2019).

[cxlvii] Peter Maloney, 'Why clean energy advocates are challenging SCE's historic storage buy," *Utility Drive* (November 16, 2015).

[cxlviii] California Public Utilities Commission, *Decision Requiring Electric System Reliability Procurement for 2021-2023*, Rulemaking 16-02-007 (November 13, 2019).

[cxlix] California Public Utilities Commission, *Proposed Decision of ALJ Fitch*, Rulemaking 16-02-007 (September 12, 2019).

[cl] California Public Utilities Commission, *Proposed Decision Granting Motion Regarding Qualifying Capacity Value of Hybrid Resources with Modifications*, Rulemaking 17-09-020, (January 16, 2020).

[cli] Engie Storage et. al, *Joint Comments Regarding Qualifying Capacity Value Of Hybrid Resources*, CPUC Rulemaking 17-09-020 (December 20, 2019).

[clii] Dominion Energy Virginia, *2019 Solicitation for Peaking Power Supply Generation* (November 6, 2019).

[cliii] Dominion Energy Virginia, *Virginia Electric and Power Company's 2019 Update to 2018 Integrated Resource Plan*, VSCC Case No. PUR-2019-00141 (August 29, 2019).

[cliv] Virginia State Corporation Commission, *Integrated Resource Plan Filing*, Final Order in Case No. PUR-2018-00065 (June 27, 2019).

[clv] LS Power, *Doswell Letter to Virginia State Public Utility Commission and Attorney General Urges Suspension of Uncompetitive Solicitation Process for New Power Generation Peaking Resources* (November 21, 2019).

[clvi] Robert Walton, "Dominion suspends plan to add 1.5 GW of peaking capacity as Virginia faces gas glut," *Utility Dive* (December 5, 2019).

[clvii] North Carolina Utilities Commission, *2018 Biennial Integrated Resource Plans and Related 2018 REPS Compliance Plans,* Order in Docket No. E-100, Sub 157 (August 27, 2019), p. 90-91.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	06-21-2024
REQUEST NO:	Staff 63	**KEYWORD:**	issue next open resource RP; current bilateral negotiations renewables
REQUESTER:	Olesky	**RESPONDER:**	Spitzer, Sean (NV Energy)

REQUEST:

Reference: RFP

Question: Please state when NV Energy plans to issue its next open resource RFP. Please state if NV Energy is currently involved in any bilateral negotiations with renewable project developers.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

NV Energy is currently planning to issue an all source (formerly open resource) RFP in August 2024. NV Energy is not currently involved in bilateral negotiations with any renewable project developers.

APRIL 2023

LCOE+

LAZARD

With support from Roland Berger

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Table of Contents

APRIL 2023

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

Introduction

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

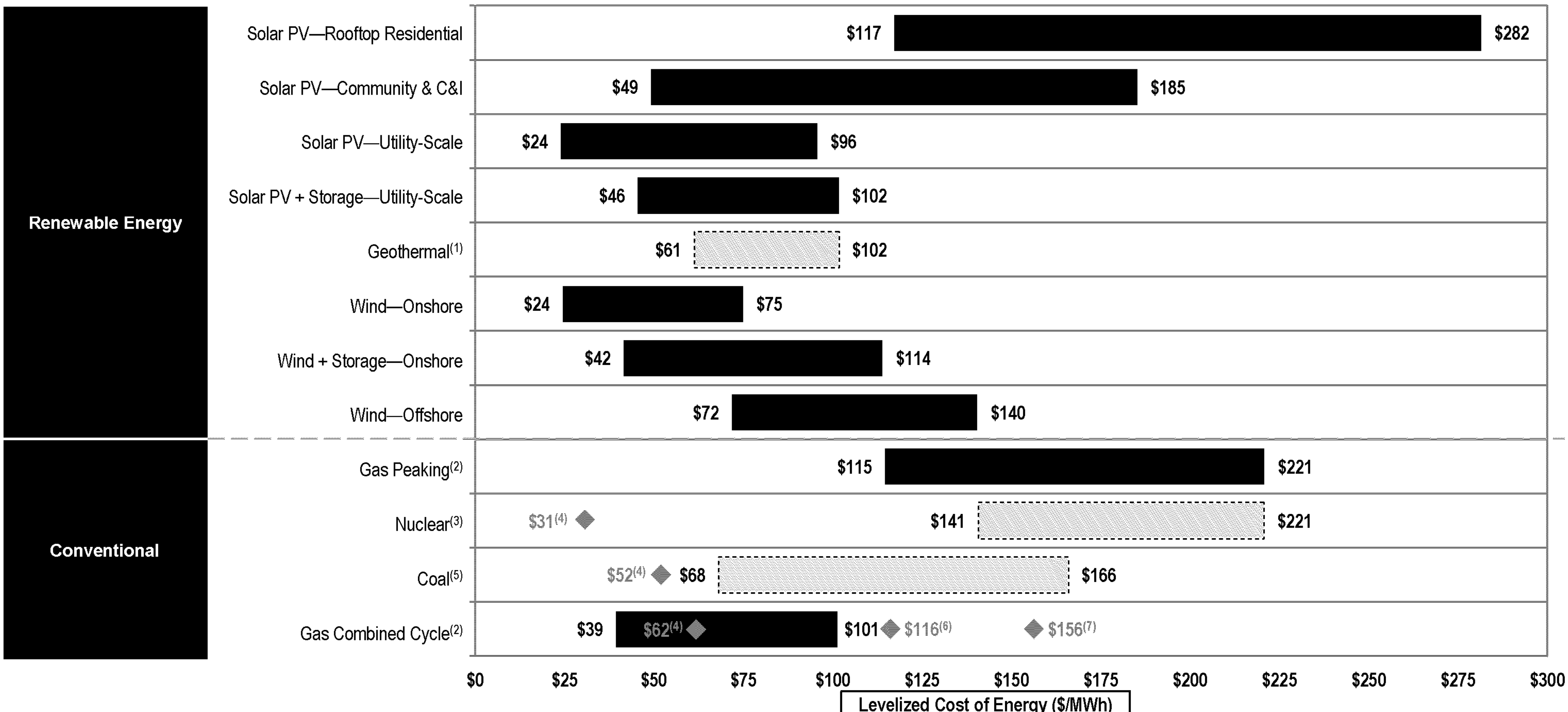
- **Comparative LCOE analysis for various generation technologies on a $/MWh basis, including sensitivities for U.S. federal tax subsidies, fuel prices, carbon pricing and cost of capital**
- **Illustration of how the LCOE of onshore wind, utility-scale solar and hybrid projects compare to the marginal 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.)

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.

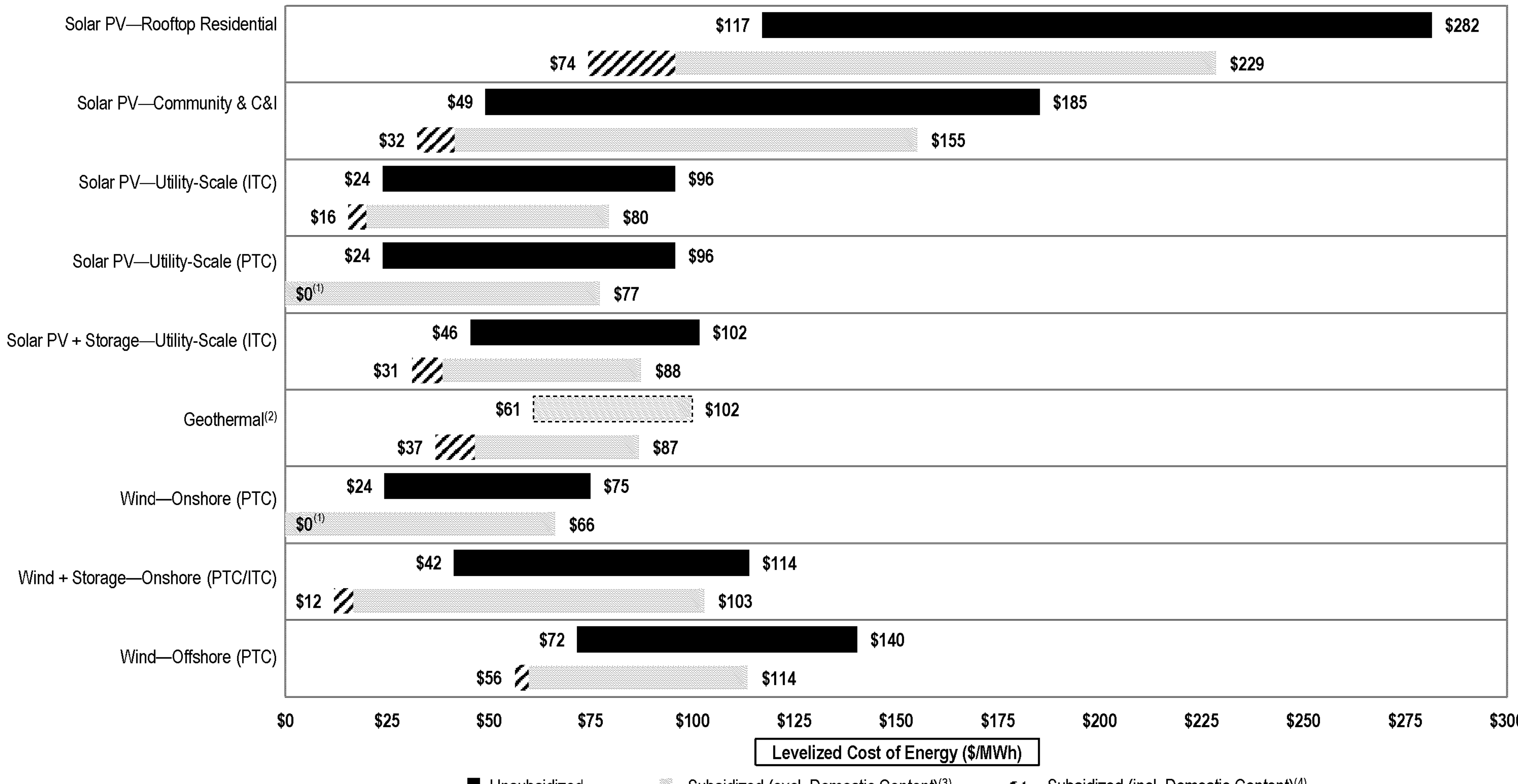
(5) Given the limited public and/or observable data set available for new-build coal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjusted for inflation. High end incorporates 90% carbon capture and storage ("CCS"). Does not include cost of transportation and storage.

(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).

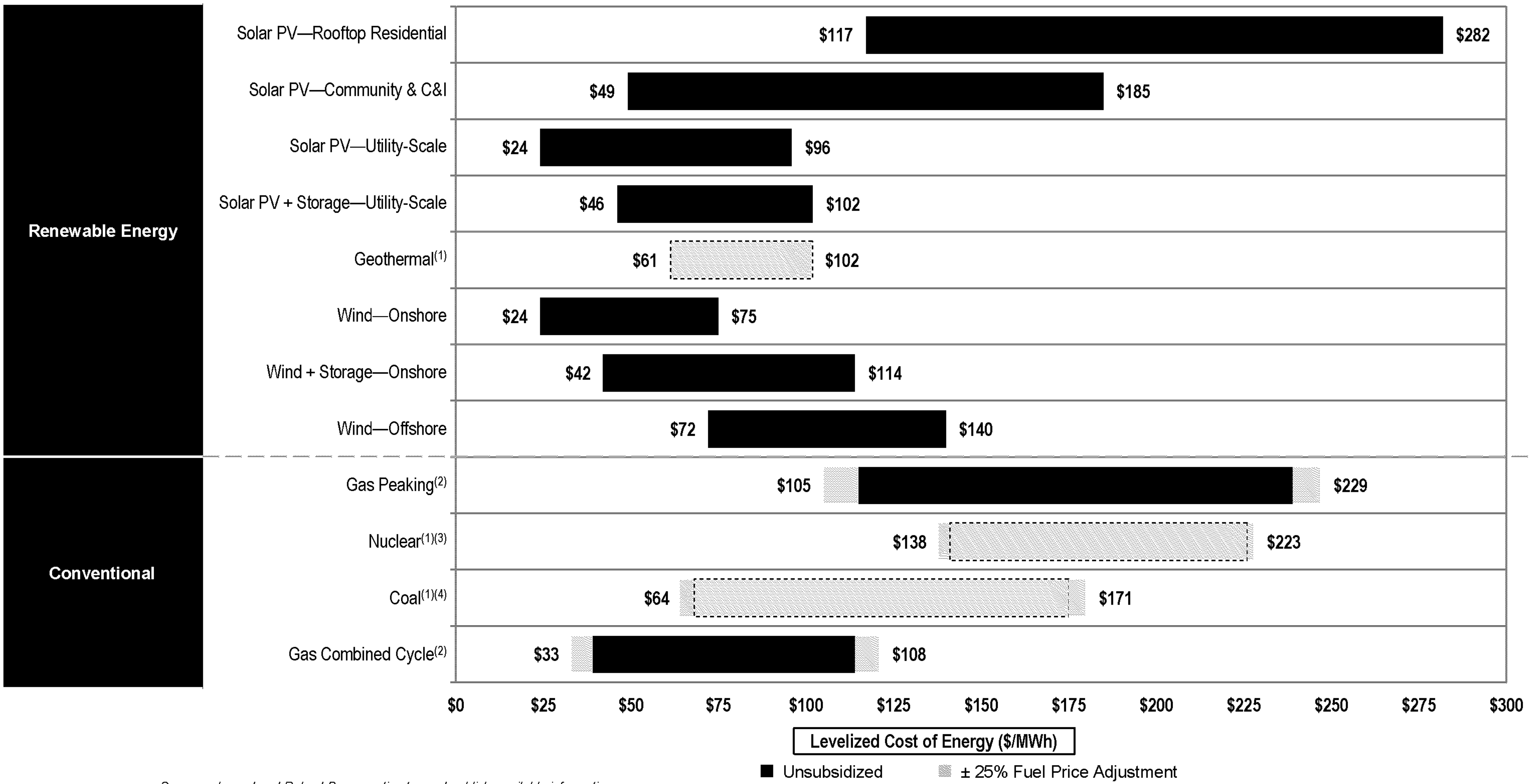
(2) Given the limited public and/or observable data set available for new-build geothermal projects, the LCOE presented herein represents Lazard's LCOE v15.0 results adjustment for inflation.

(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.

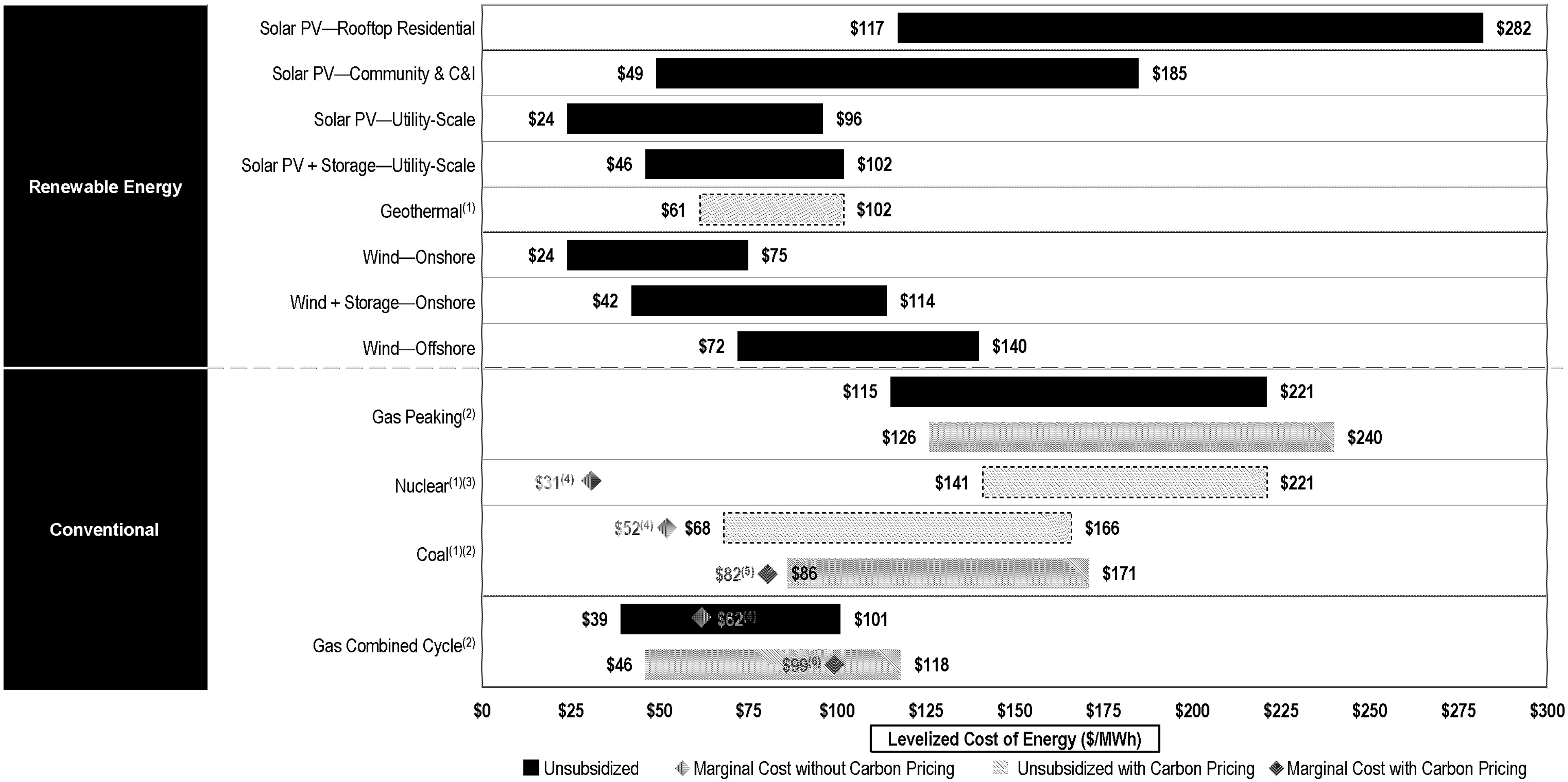
(2) Assumes a fuel cost range for gas-fired generation resources of $2.59/MMBTU – $4.31/MMBTU (representing a sensitivity range of ± 25% of the $3.45/MMBTU used in the Unsubsidized Analysis).

(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.

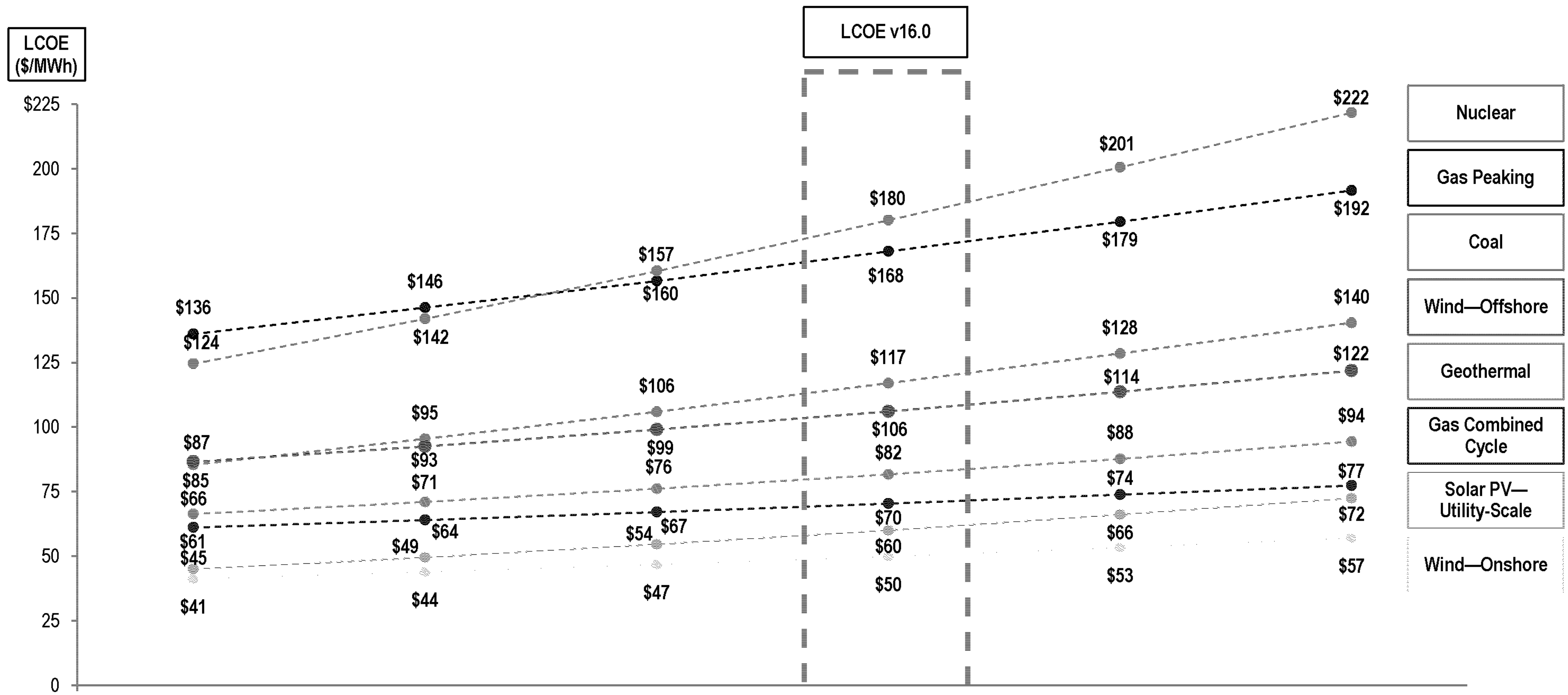
(5) Represents the midpoint of the unsubsidized marginal cost of operating fully depreciated coal facilities with illustrative carbon pricing. Operating coal facilities are not assumed to employ CCS technology.

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

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%

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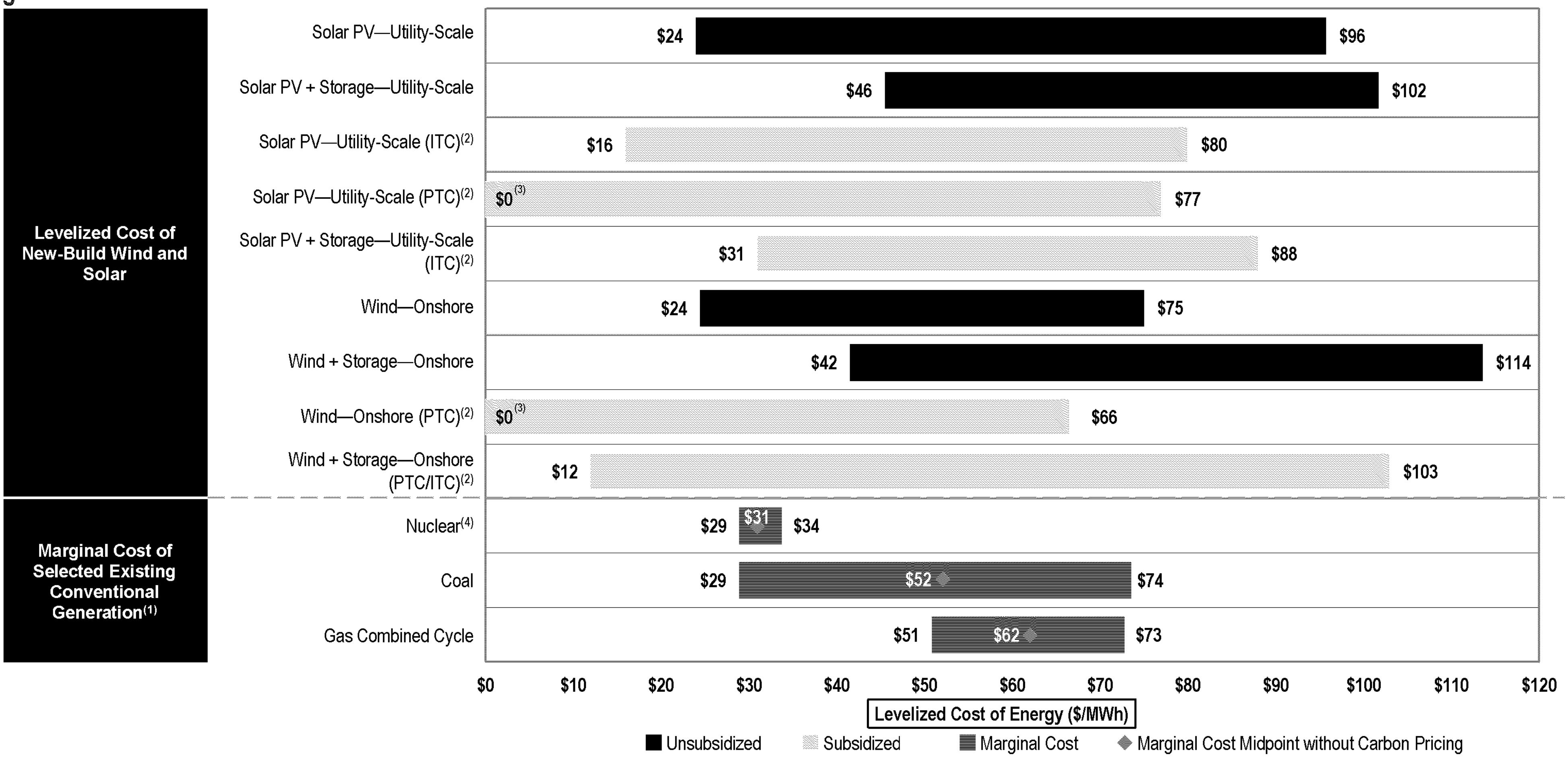
Source: Lazard and Roland Berger estimates and publicly available information.
Note: Analysis assumes 60% debt and 40% equity. Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on the page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".
(1) 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

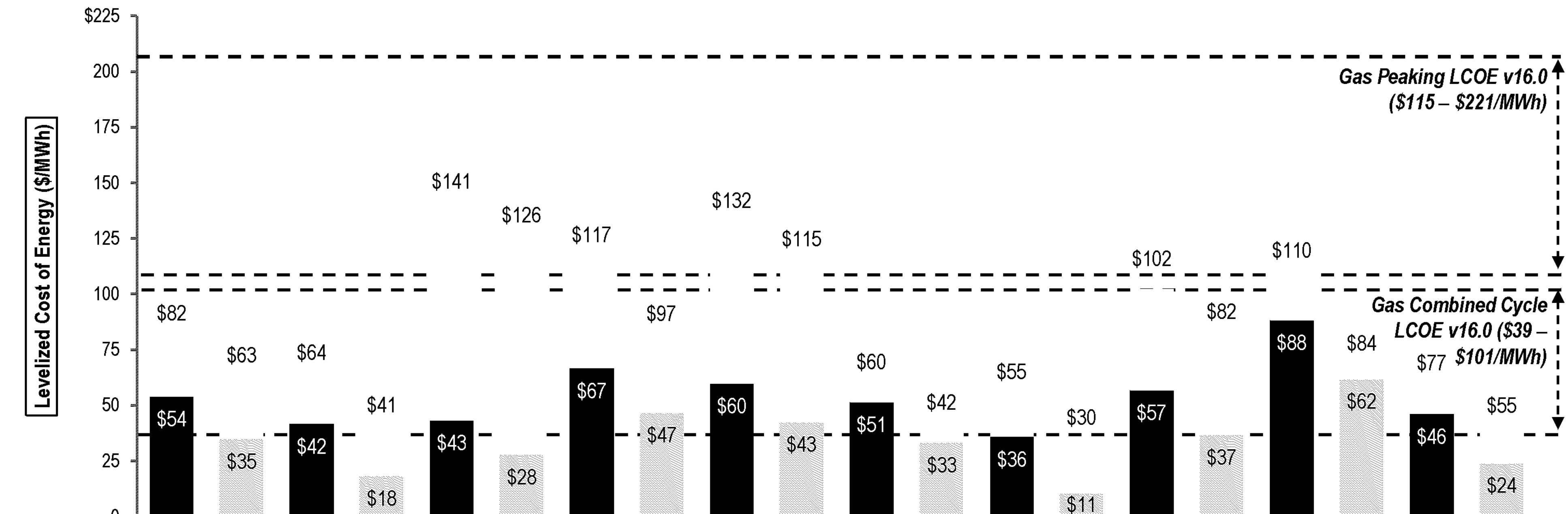


Source: *Lazard and Roland Berger estimates and publicly available information.*
Note: Unless otherwise noted, the assumptions used in this sensitivity correspond to those used on page titled "Levelized Cost of Energy Comparison—Unsubsidized Analysis".
(1) Represents the marginal cost of operating fully 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]



	MISO		CAISO			SPP		PJM		
	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%

■ 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.

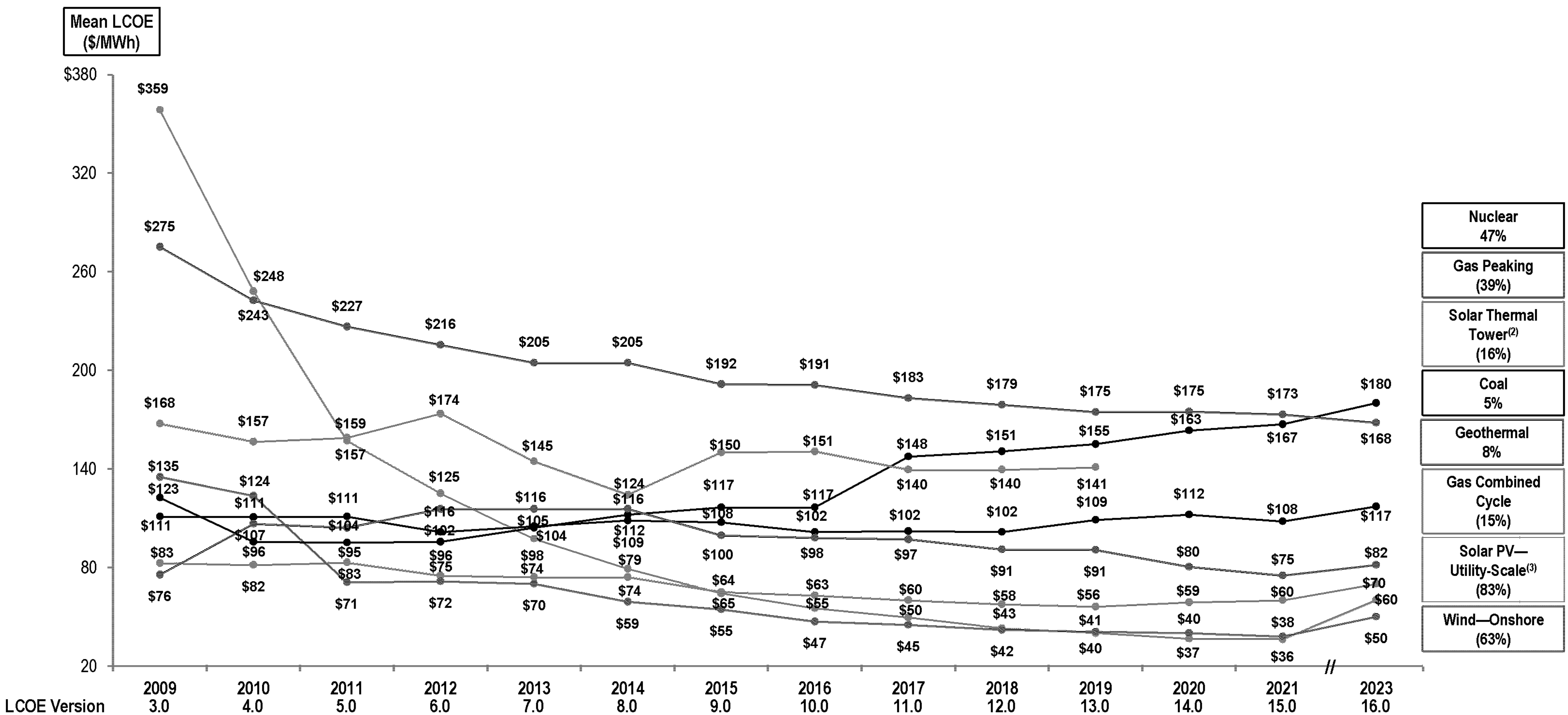
(3) LCOE values represent the midpoint of Lazard's LCOE v16.0 cost inputs for each technology adjusted for a regional capacity factor to demonstrate the regional differences in both project and firming costs.

(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)]

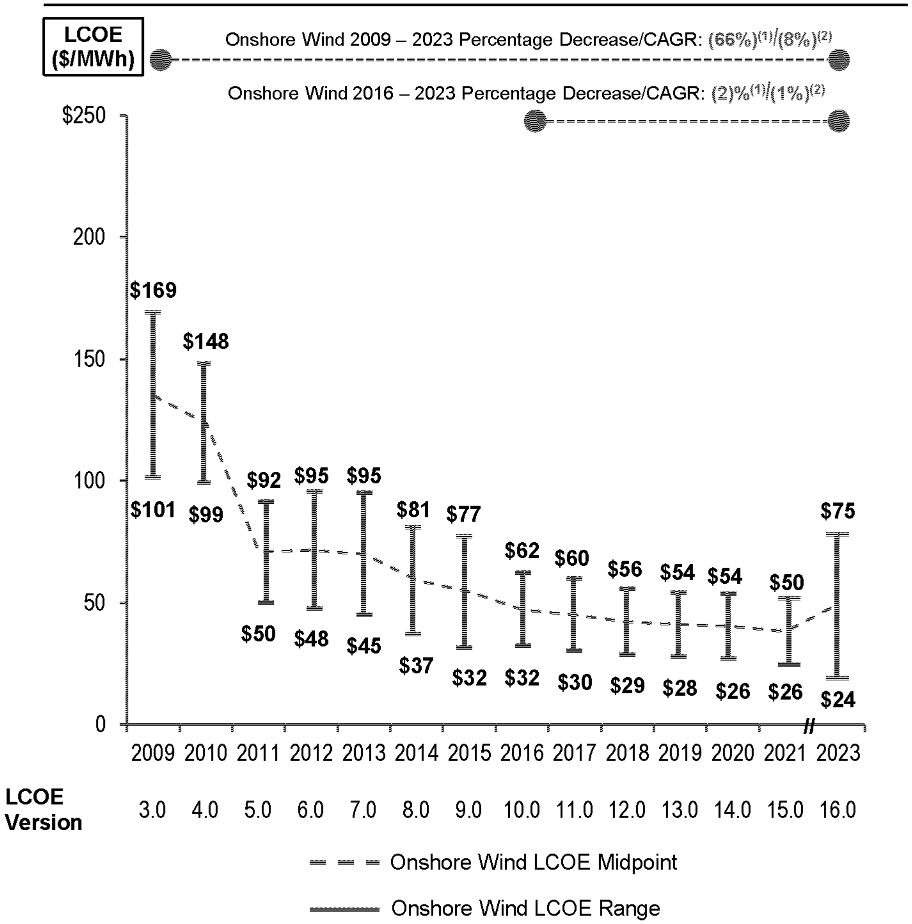


Source: *Lazard and Roland Berger estimates and publicly available information.*
(1) Reflects the average of the high and low LCOE for each respective technology in each respective year. Percentages represent the total decrease in the average LCOE since Lazard's LCOE v3.0.
(2) The LCOE no longer analyzes 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.

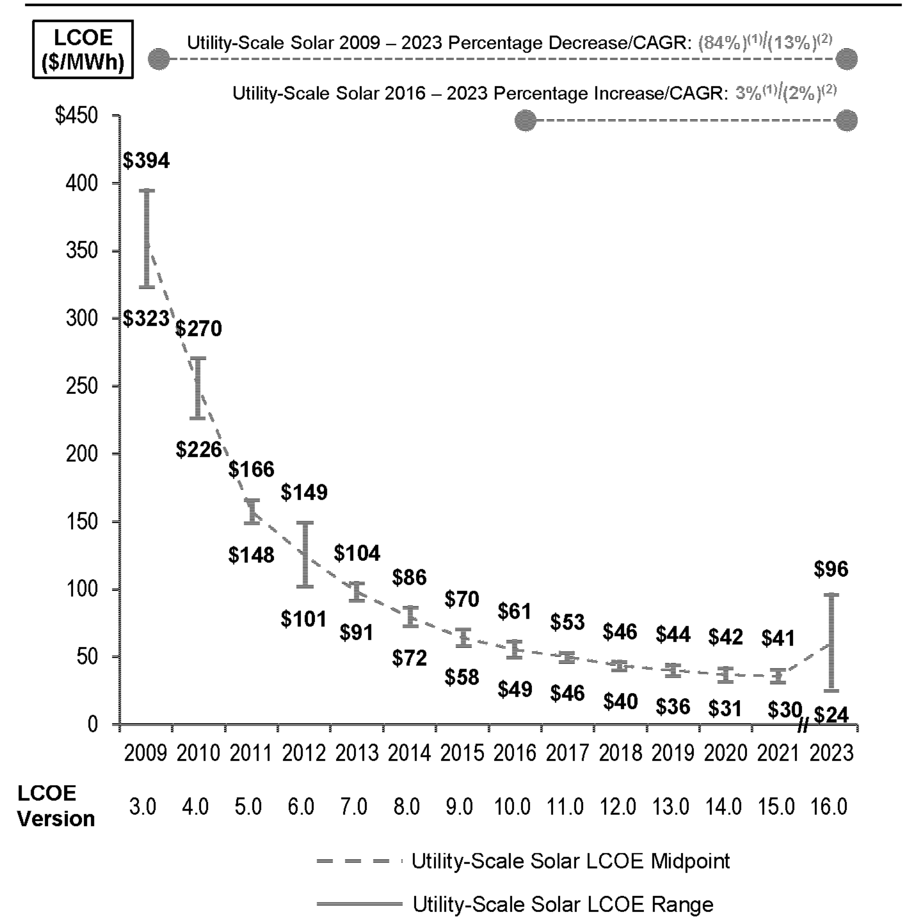
Levelized Cost of Energy Comparison—Historical Renewable Energy LCOE

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



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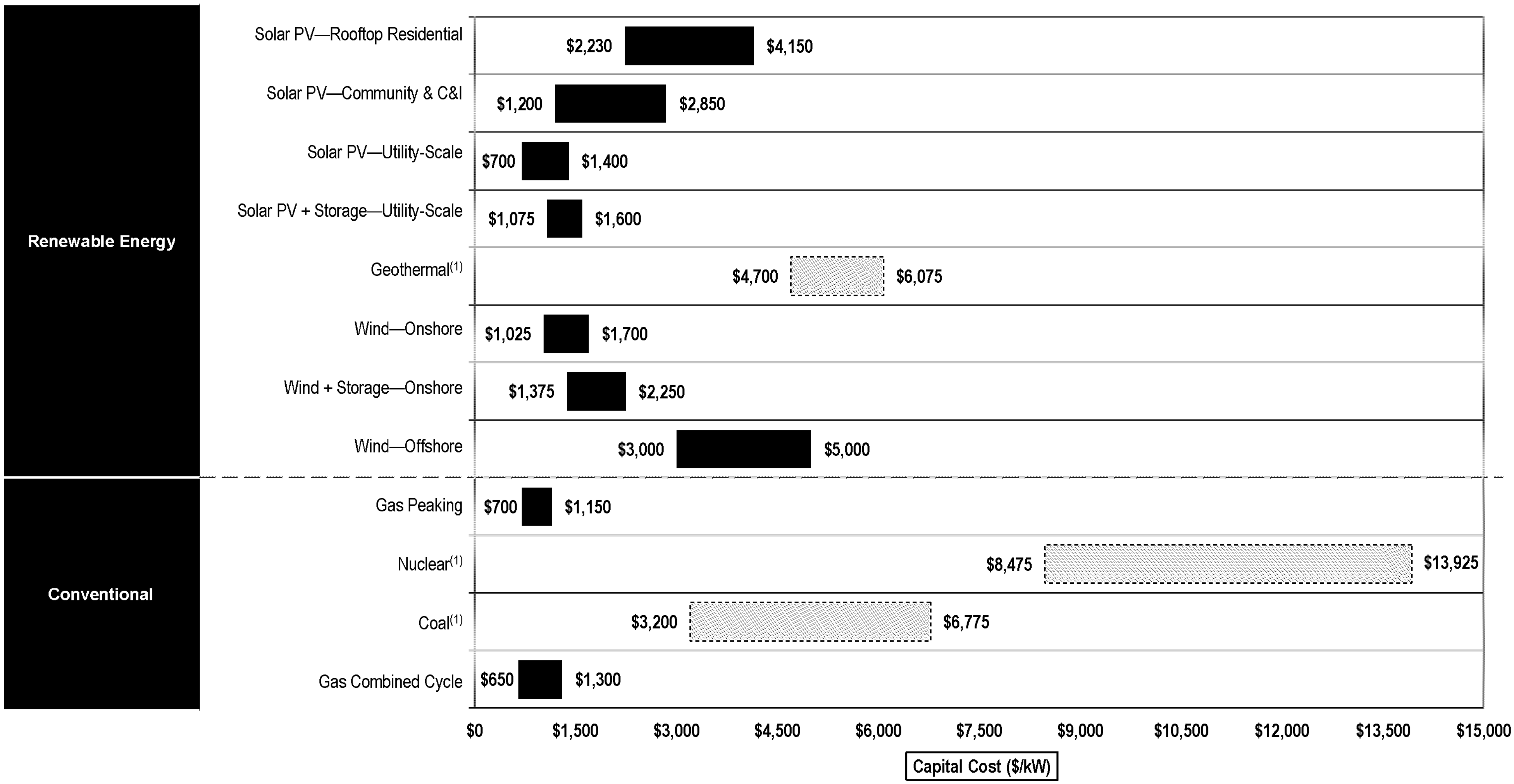
Source: Lazard and Roland Berger estimates and publicly available information.
(1) Represents the average percentage decrease/increase of the high end and low end of the LCOE range.
(2) Represents the average compounded annual rate of decline of the high end and low end of the LCOE range.

Levelized Cost of Energy Comparison—Capital Cost Comparison

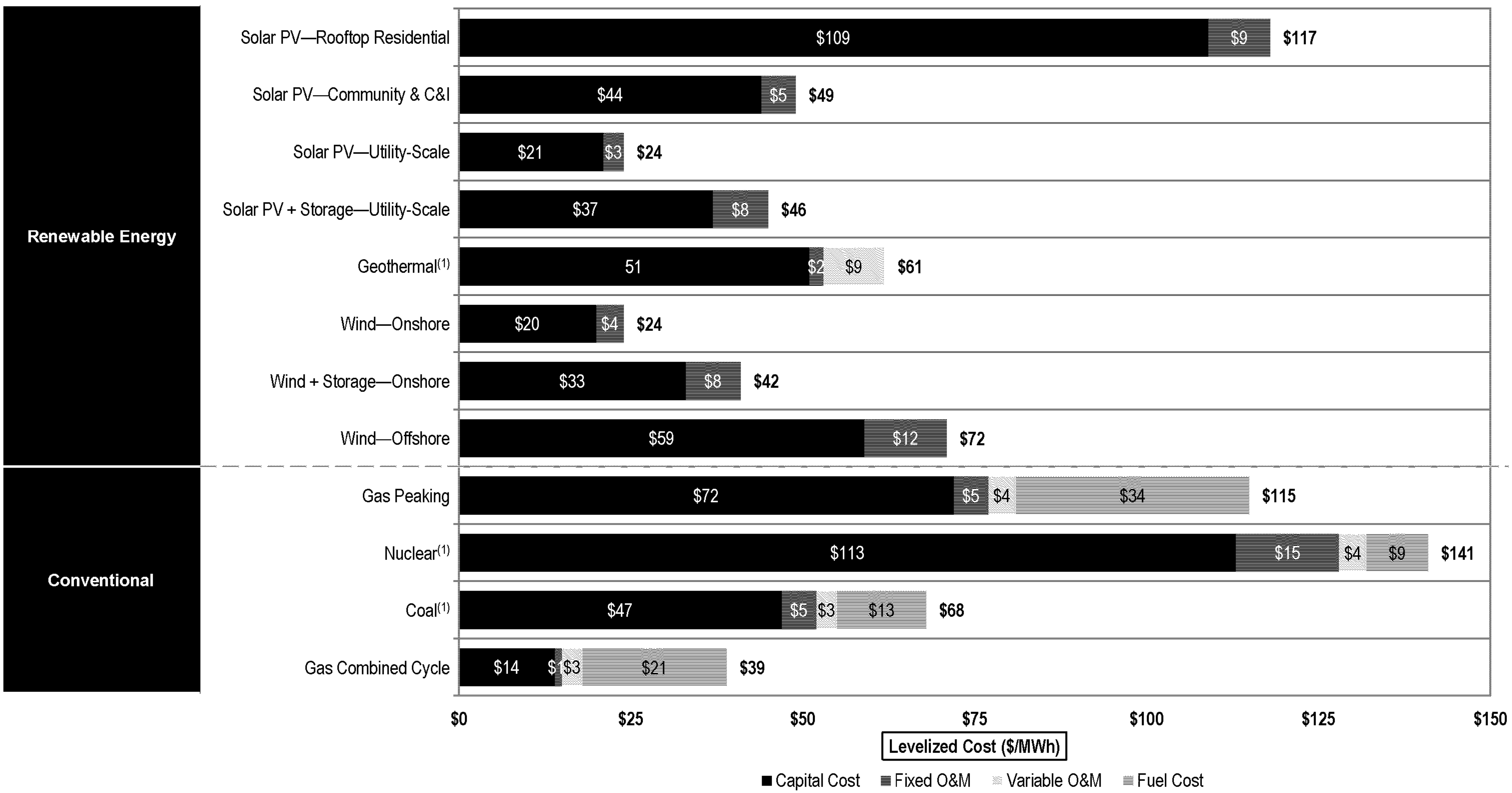
In some instances, the capital costs of renewable energy generation technologies have converged with those of certain conventional generation technologies, which coupled with improvements in operational efficiency for renewable energy technologies, have led to a convergence in LCOE between the respective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

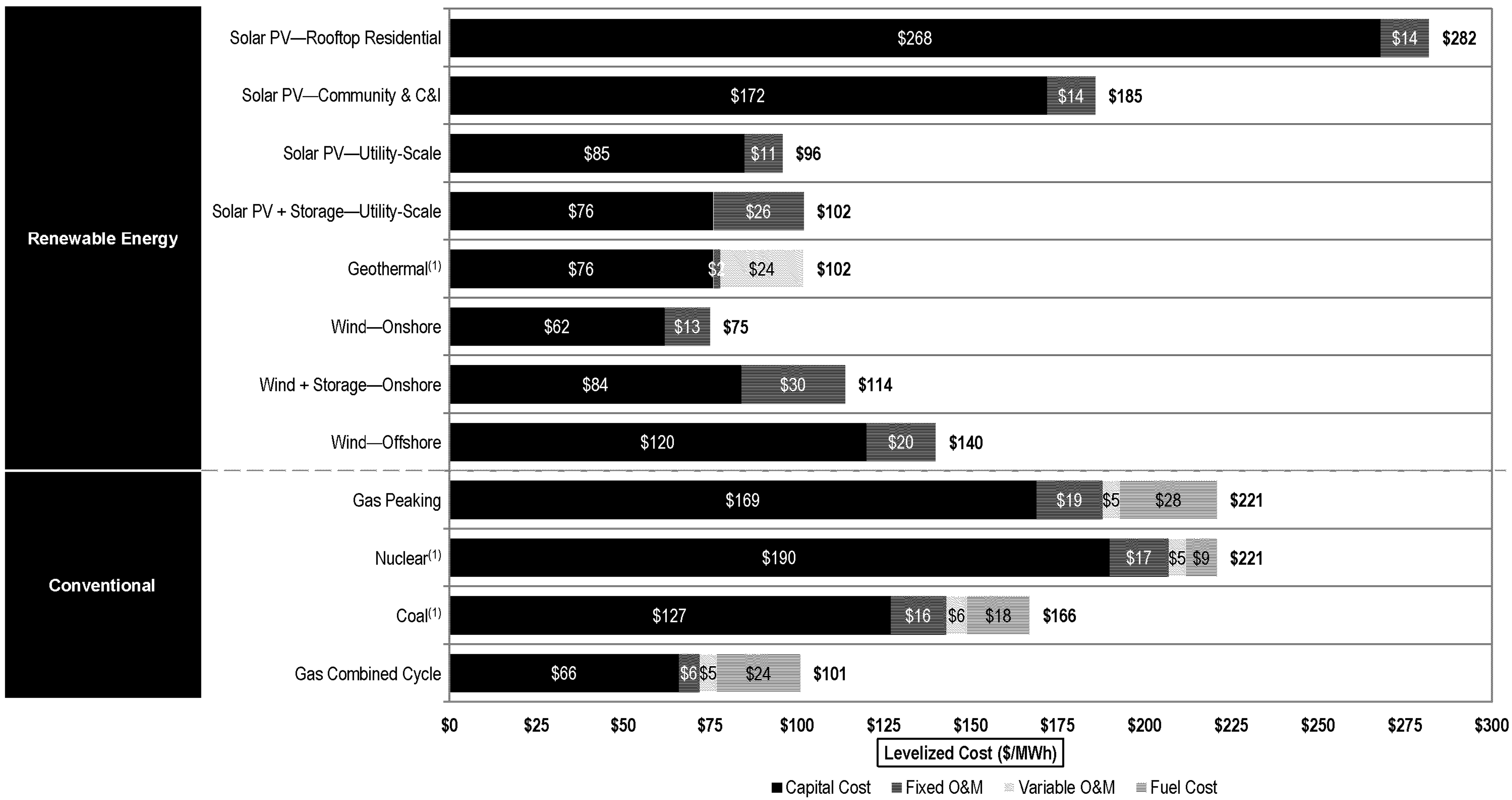
Certain renewable energy generation technologies are already cost-competitive with conventional generation technologies; key factors regarding the continued cost decline of renewable energy generation technologies are the ability of technological development and industry scale to continue lowering operating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

LCOE+

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**

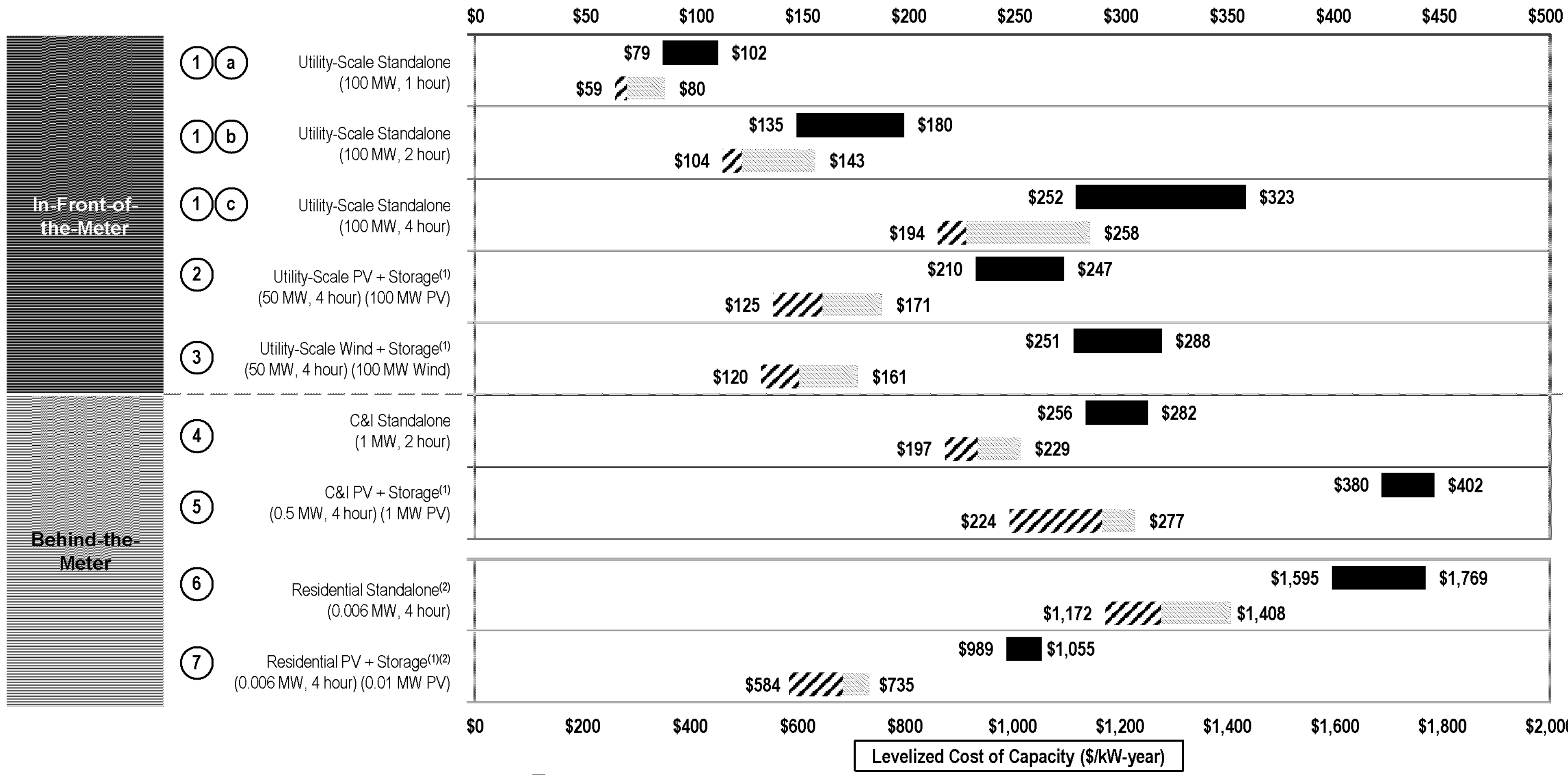
[ ] = "Usable Energy"(2)

			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



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.

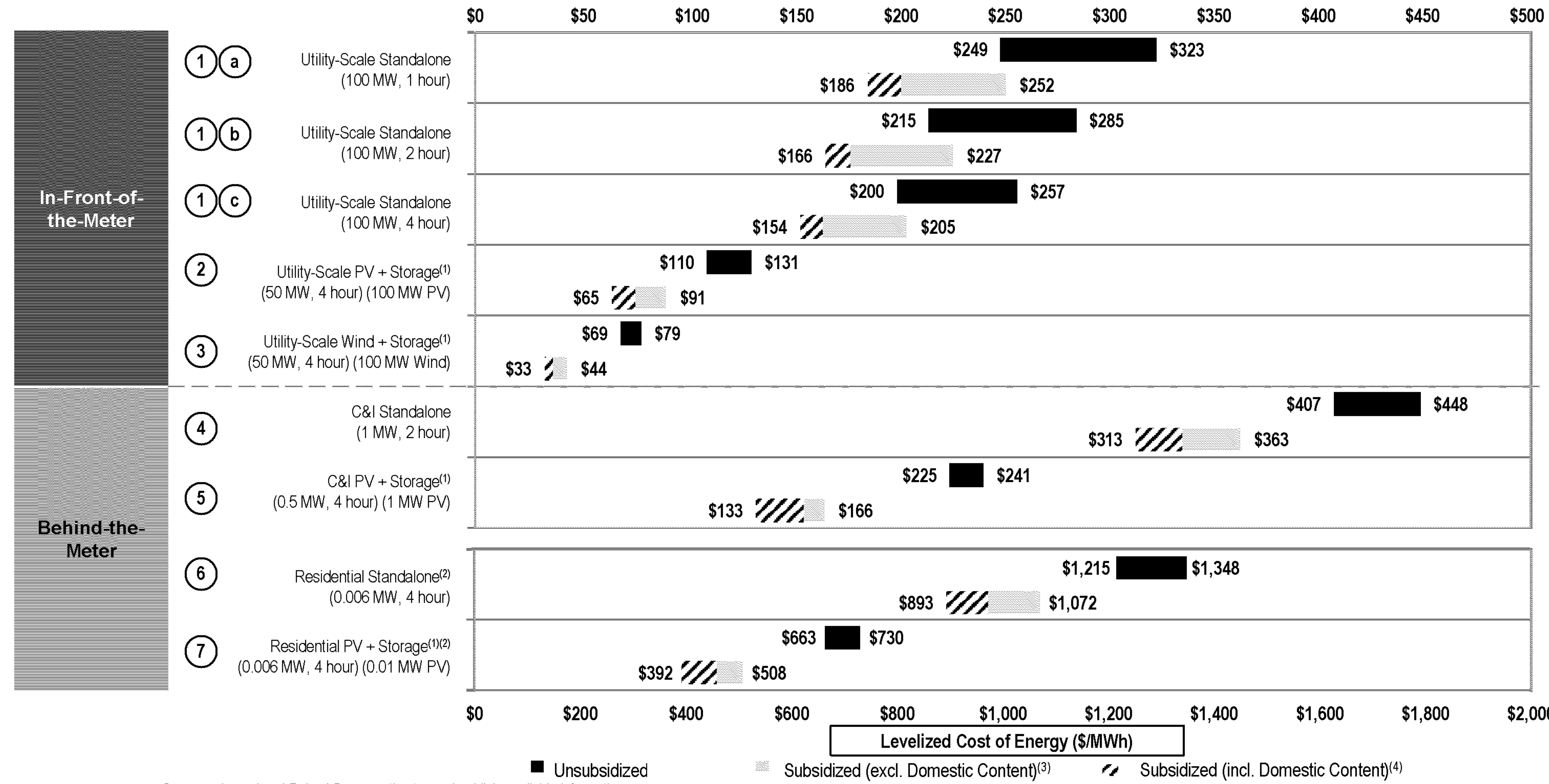
(2) In previous LCOS reports, residential battery storage costs have reflected equipment purchase costs only. For Lazard's LCOE v16.0 and LCOS v8.0, capital costs for residential battery storage projects includes installation/labor, balance-of-system components and warranties.

(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.*

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.

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

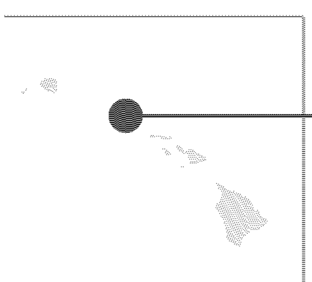
Corpus Christi, Texas

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

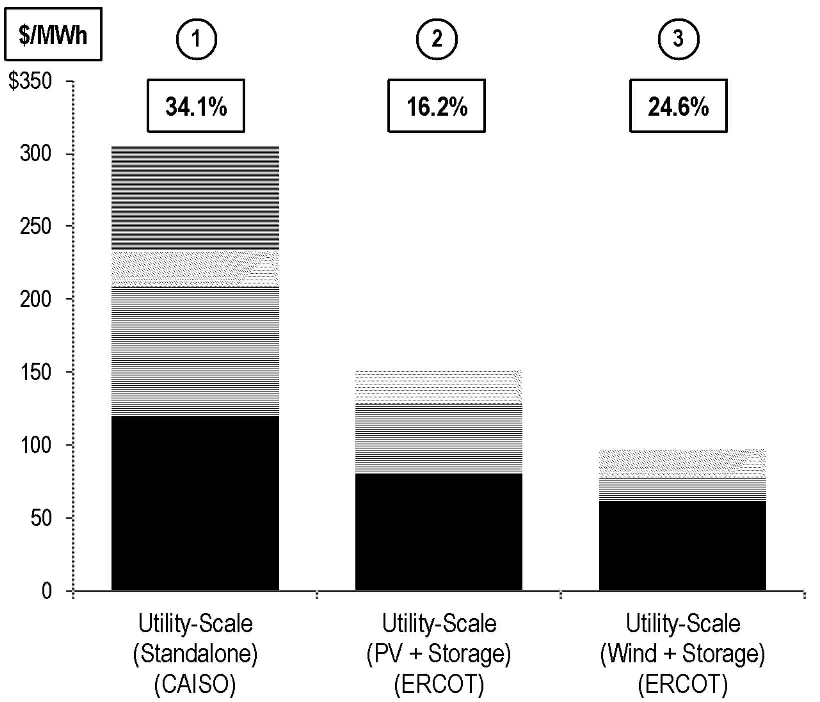
Project size: 0.006 MW / 0.025 MWh
0.010 MW PV

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.

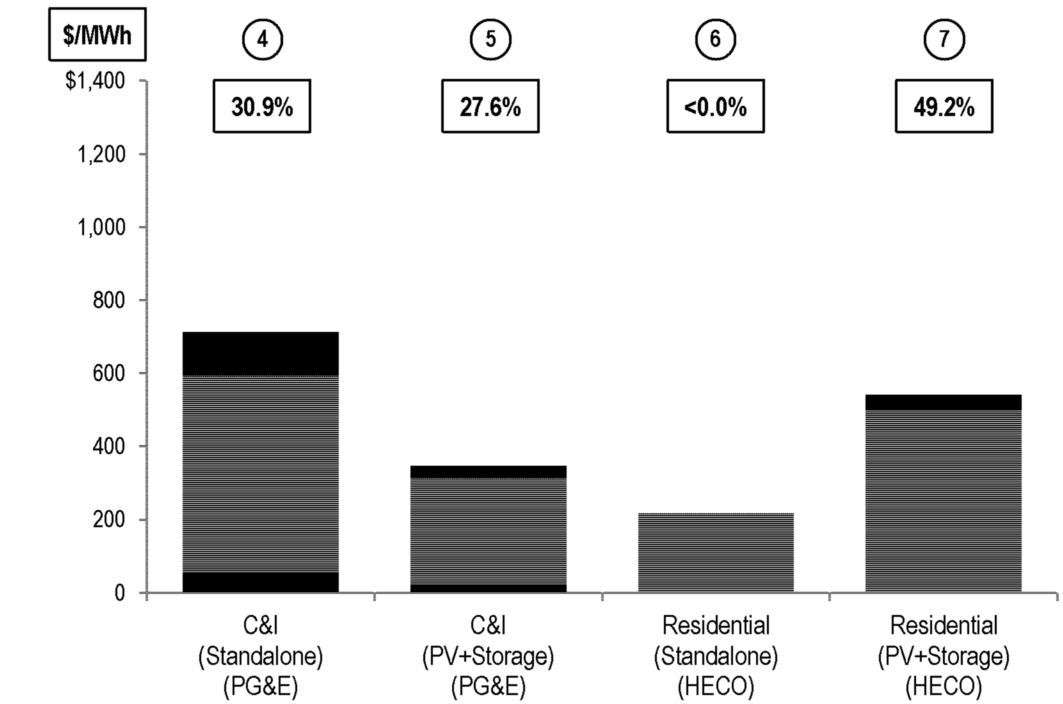
Value Snapshot Case Studies—Summary Results

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.

LCOE+

APRIL 2023

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

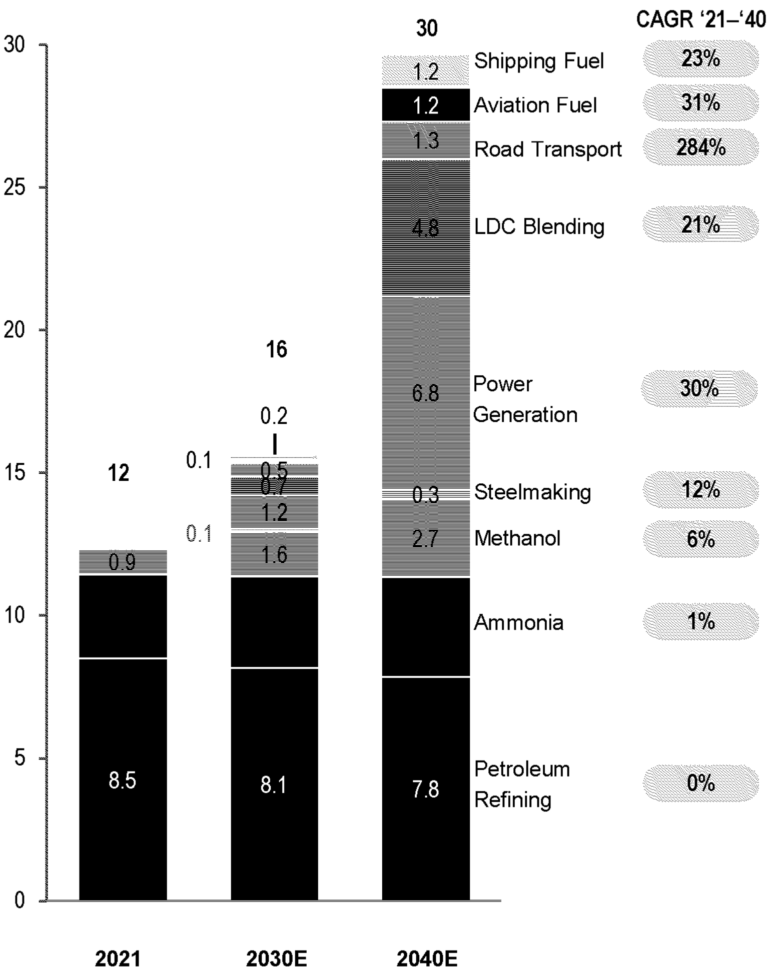
Technology Overview & Commercial Readiness	Hydrogen and Hydrogen Production • Hydrogen is currently produced primarily from fossil fuels using steam-methane reforming and methane splitting processes (i.e., "Gray" hydrogen) • A variety of additional processes are available to produce hydrogen from electricity 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

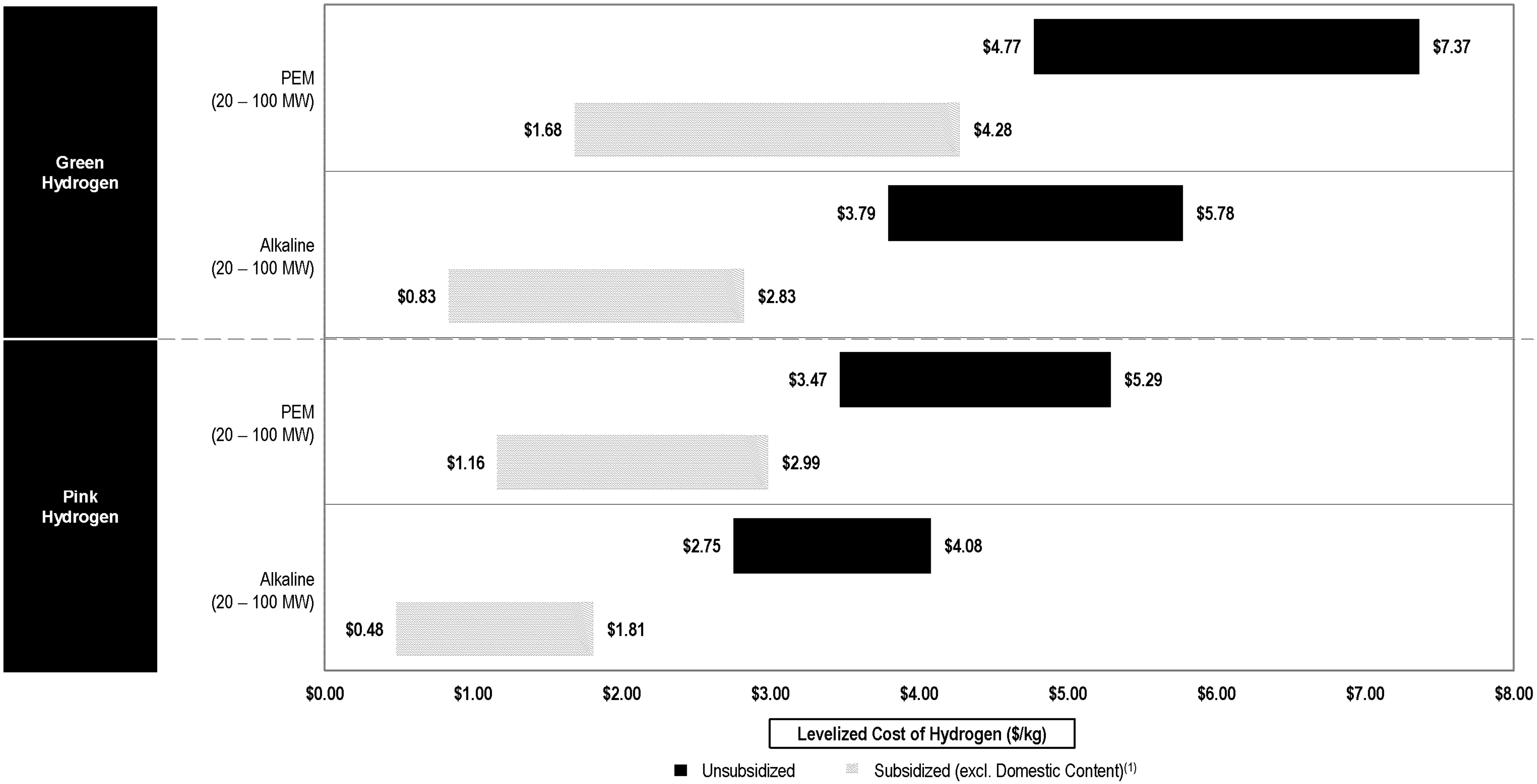
Implications for the Power Sector

- 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



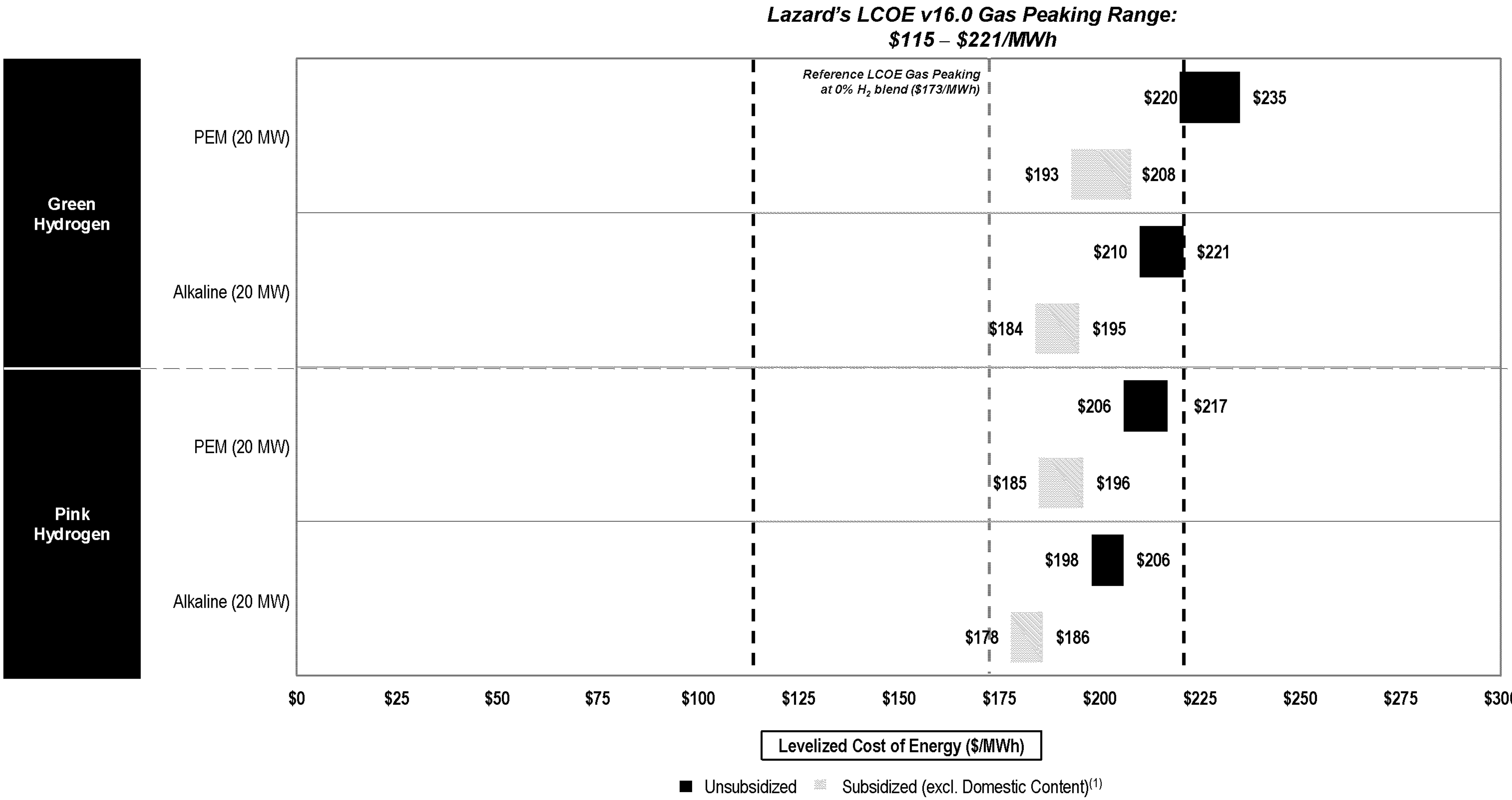
Source: Lazard and Roland Berger estimates and publicly available information.

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

[redacted]

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.

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1 Carbon Capture & Storage Systems

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Lazard's Carbon Capture & Storage Analysis—Executive Summary

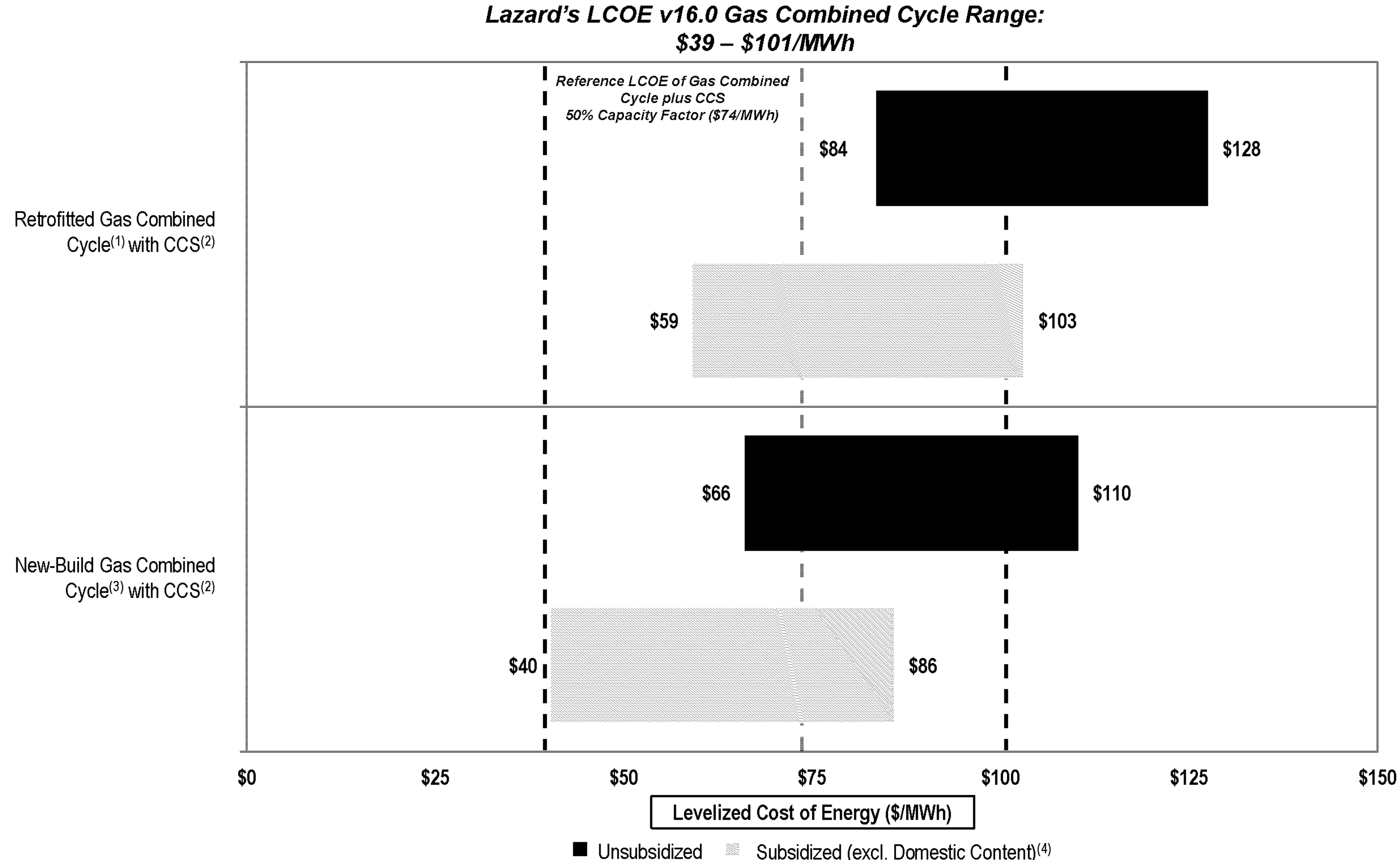
Technology Overview & Commercial Readiness	• CCS refers to technologies designed to sequester carbon dioxide emissions, particularly from power generation or industrial sources • The core technology involves a specialized solvent or other material that enables the capture of carbon dioxide from a gas 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

LCOE 550 MW Gas Combined Cycle Plus CCS System



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.

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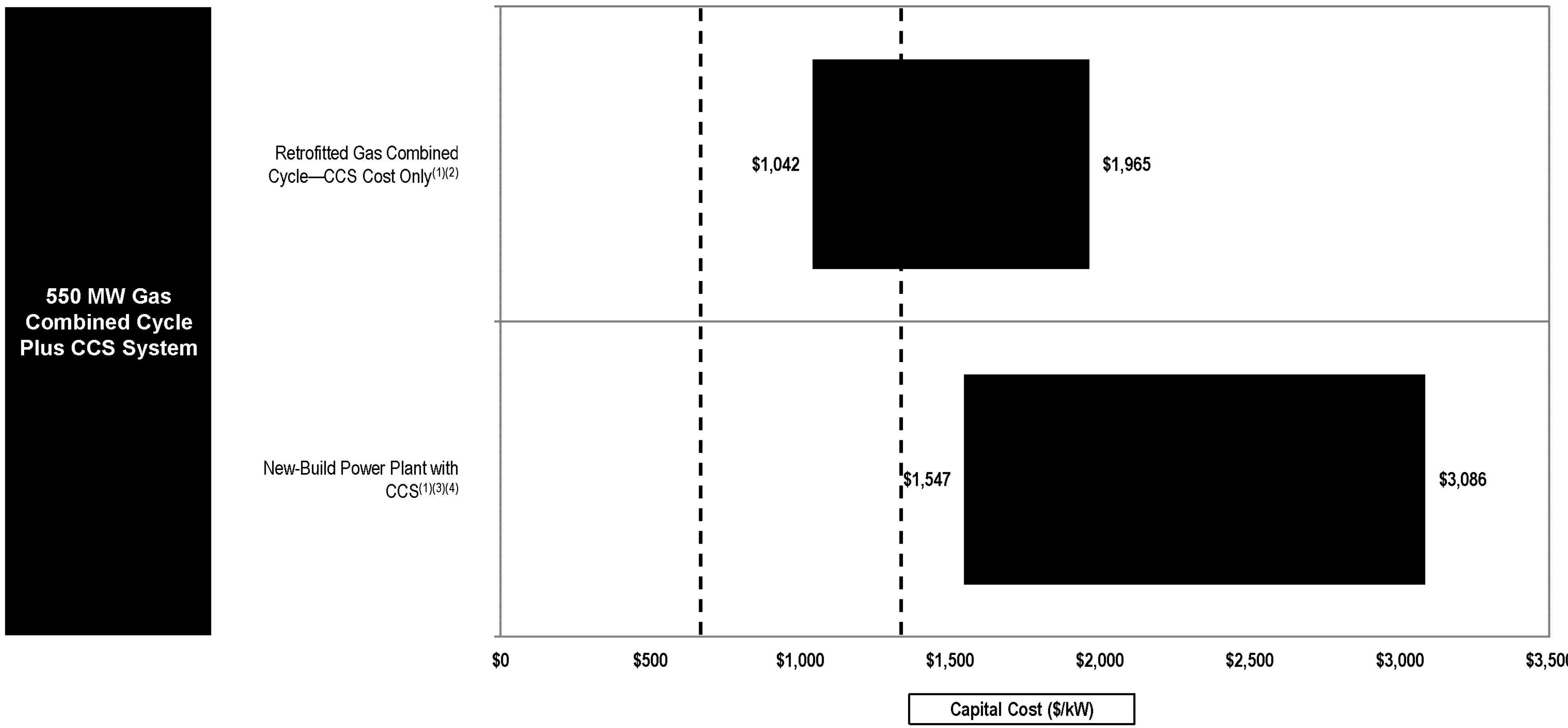
Carbon Capture & Storage Systems—Capital Cost Comparison (Unsubsidized)

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

Lazard's LCOE v16.0 Gas Combined Cycle Capital Cost Range: $650 – $1,300/kW



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

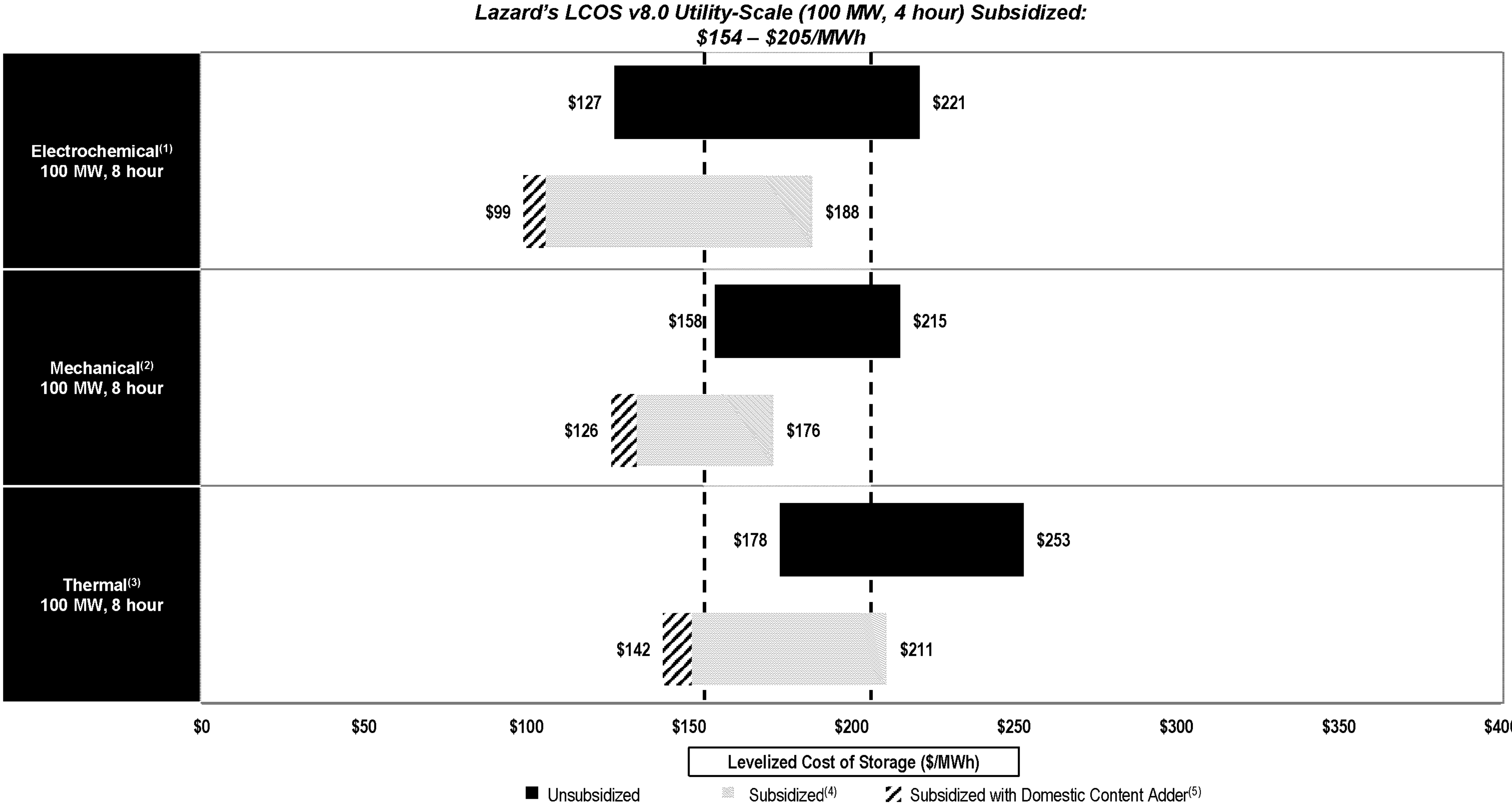
LDES technologies typically fall into three main technological categories that provide unique advantages and disadvantages and also make them suitable (or not) across a variety of use cases

	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.

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B LCOE v16.0

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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.

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.

LCOE

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.

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

	Units	Nuclear (Operating)			Coal (Operating)			Gas Combined Cycle (Operating)		
		Low Case		High Case	Low Case		High Case	Low Case		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

LAZARD

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.

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[redacted]

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.

LCOE

Levelized Cost of Storage—Key Assumptions

	Units	Utility-Scale (Standalone) (100 MW / 100 MWh)	Utility-Scale (Standalone) (100 MW / 200 MWh)	Utility-Scale (Standalone) (100 MW / 400 MWh)	Utility-Scale (PV + Storage) (50 MW / 200 MWh)	Utility-Scale (Wind + Storage) (50 MW / 200 MWh)	C&I (Standalone) (1 MW / 2 MWh)	C&I (PV + Storage) (0.5 MW / 2 MWh)	Residential (Standalone) (0.006 MW / 0.025 MWh)	Residential (PV + Storage) (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.

LAZARD

[redacted]

D LCOH v3.0

Levelized Cost of Hydrogen Comparison—Methodology

($ in millions, unless otherwise noted)

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

LCOE

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.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-06-2024
REQUEST NO:	IEA 002	**KEYWORD:**	vol 4 p96-97 williams direct; resource combination alternative valmy CT
REQUESTER:	Harris	**RESPONDER:**	DeMaggio, Jonai (NV Energy)

REQUEST:

According to Kimberly Williams' testimony, NV Energy evaluated several alternative resource plans, including those with solar/storage resources (Volume 4, pages 96 and 97–100).

a. Did NV Energy consider a resource combination or alternative resource plan that included one of the two Valmy CTs plus a solar/storage resource?

b. Did NV Energy consider a resource combination or alternative resource plan that included only one CT at any candidate location?

c. If the answer to subpart (a) or (b) is yes, please provide the details of this consideration, including the criteria and outcomes of such an analysis.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a. No, NV Energy did not consider a resource combination or alternative resource plan that included only one of the two Valmy CTs plus a solar/storage resource.

b. Assuming the question refers to proposed projects as opposed to placeholder resources, no, NV Energy did not consider a resource combination or alternative resource plan that included only one CT at any candidate location.

c. N/A

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-06-2024
REQUEST NO:	IEA 006	**KEYWORD:**	model 2023 open resources RFP PLEXOS LT
REQUESTER:	Harris	**RESPONDER:**	Williams, Kimberly

REQUEST:

Did NV Energy model resources proposed in the 2023 Open Resource RFP via the PLEXOS LT model such that the PLEXOS LT capacity expansion function was allowed to select from short listed bids?

a. If not, why not?

b. If so, did NV Energy model all proposed resources, shortlist resources, and final selected resources?

c. Provide details of the modeling process and outcomes for each stage.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

a. No, please see response to Interwest DR 003.

b. N/A

c. The economic analysis methodology and the details of the process are described in Subsections B through E of the Economic Analysis Section of the supply side narrative, starting on page 208 of 393 in Volume 8. Outcomes can be found in Subsection F of the Economic Analysis Section of the supply side narrative, starting on page 270 of 393 in Volume 8.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	06-25-2024
REQUEST NO:	Staff 69	**KEYWORD:**	supply plan vol 8 p221; candidate resources, firm dispatchable generation, model
REQUESTER:	Cameron	**RESPONDER:**	Heath, Brandon (NV Energy)

REQUEST:

Reference: Candidate resources

Question: In reference to the new firm dispatchable generation section of the supply plan narrative (pg. 221 of volume 8), NV Energy states "Firm dispatchable resources are available for the model to select beginning in 2040." Please explain in detail why this restriction was put on the model as opposed to allowing the model to select such a resource beginning as soon as one could potentially be constructed.

RESPONSE CONFIDENTIAL (yes or no): No

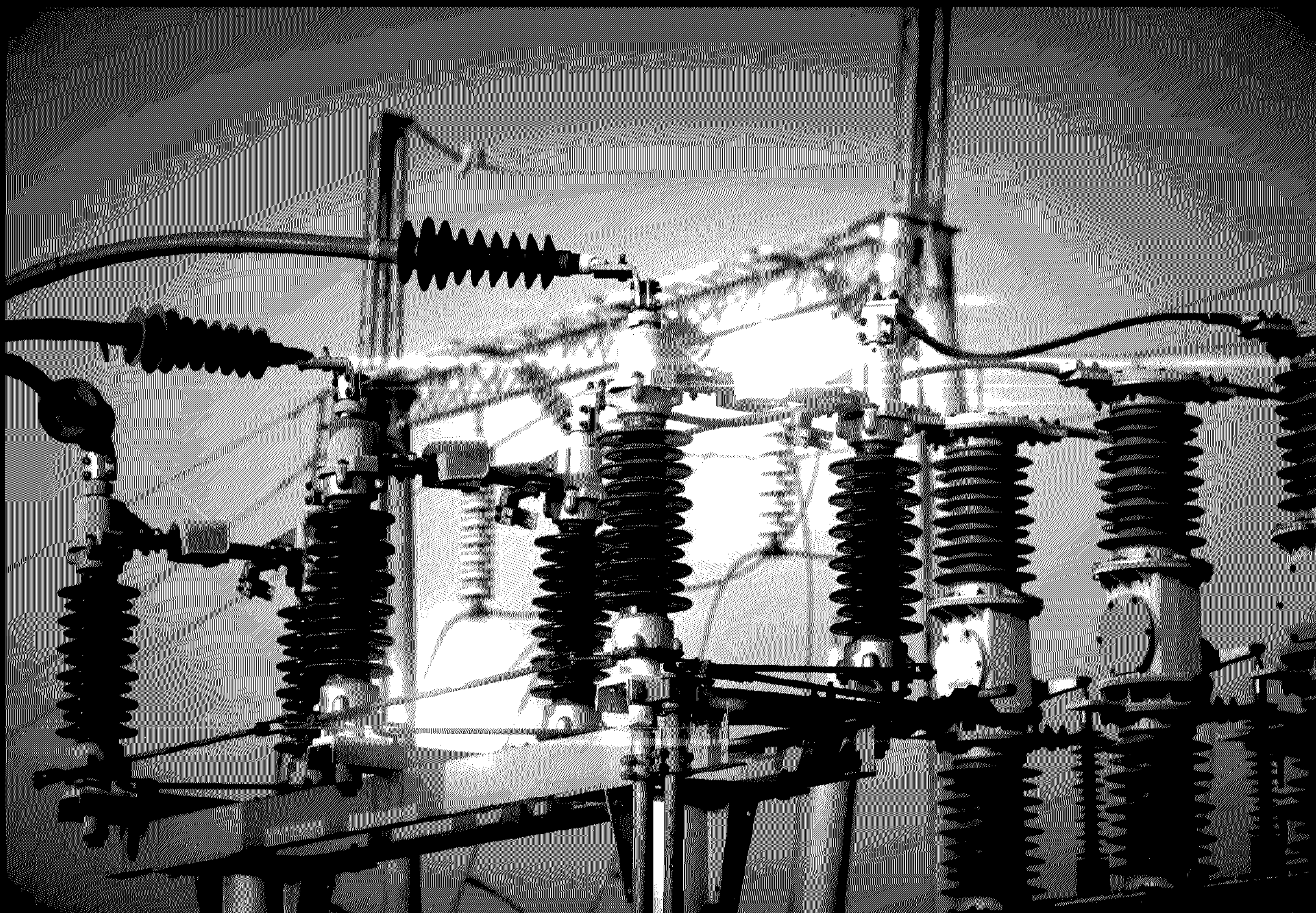
ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

At present, retirement dates for the Companies' currently operating thermal fleet fall in the decade between 2040 and 2050. The year 2040 was thus selected as the first year for the "Firm Dispatchable" candidate resources to be available to be selected in the resource expansion model PLEXOS LT as replacement capacity for the retiring firm dispatchable resources. As discussed in the supply plan narrative on page 219 of 393 in Volume 8, the Companies are not requesting approval to acquire or build any placeholder resources and placeholder resources are subject to change in future filings as the Companies' needs change. Firm dispatchable placeholder resources are intended to represent technologies that can supply electricity reliably on demand for hours, days, or weeks at a time and are modeled today as gas turbines due to the lack of sound data on proven, appropriate low-carbon alternatives. Note that combustion turbine peaking units were specifically made available in the expansion model as early as 2027 as described on page 224 of 393, and only one set of two combustion turbine peaking units was selected in the capacity expansion for the base case.

NIAC The National Infrastructure Advisory Council



Addressing the Critical Shortage of Power Transformers to Ensure Reliability of the U.S. Grid

JUNE 2024

Table of Contents

About the NIAC

The President's National Infrastructure Advisory Council (NIAC or the Council) is composed of senior executives from industry and state and local government who own and operate the critical infrastructure essential to modern life. The Council was established by executive order in October 2001 to advise the President on practical strategies for industry and government to reduce complex risks to the designated critical infrastructure sectors.

At the President's request, NIAC members conduct in-depth studies on physical and cyber risks to critical infrastructure and recommend solutions that reduce risks and improve security and resilience. Members draw upon their deep experience, engage national experts, and conduct extensive research to discern the key insights that lead to practical Federal solutions to complex problems.

For more information on the NIAC and its work, please visit: https://www.cisa.gov/niac.

1. Executive Summary

Electricity is vital to modern life, and transformers are critical components of a stable and resilient electric grid, which, in turn, is a linchpin of United States (U.S.) infrastructure and economic wellbeing. Transformers change the voltage of electricity to enable the efficient flow of power from the source of generation to the end user where the power is consumed. During the COVID-19 pandemic, the transformer manufacturing industry was among those that experienced severe supply chain disruptions – and the impact of those disruptions have only become more pronounced in subsequent years. Currently, an electric utility or generation developer that orders a transformer may have to wait 2 to 4[1] years for it to be delivered, compared to a wait of just months as recently as 2020.[2] One large power transformer manufacturing facility based in the U.S. disclosed a 5-year wait time for new transformer orders.

Wood Mackenzie, a consulting firm, recently reported[3] that "transformer lead times have been increasing for the last 2 years – from around 50 weeks in 2021, to 120 weeks on average in 2024. Large transformers, both substation power and generator step-up transformers, have lead times ranging from 80 to 210 weeks." This data is shown in **Figure 1**.

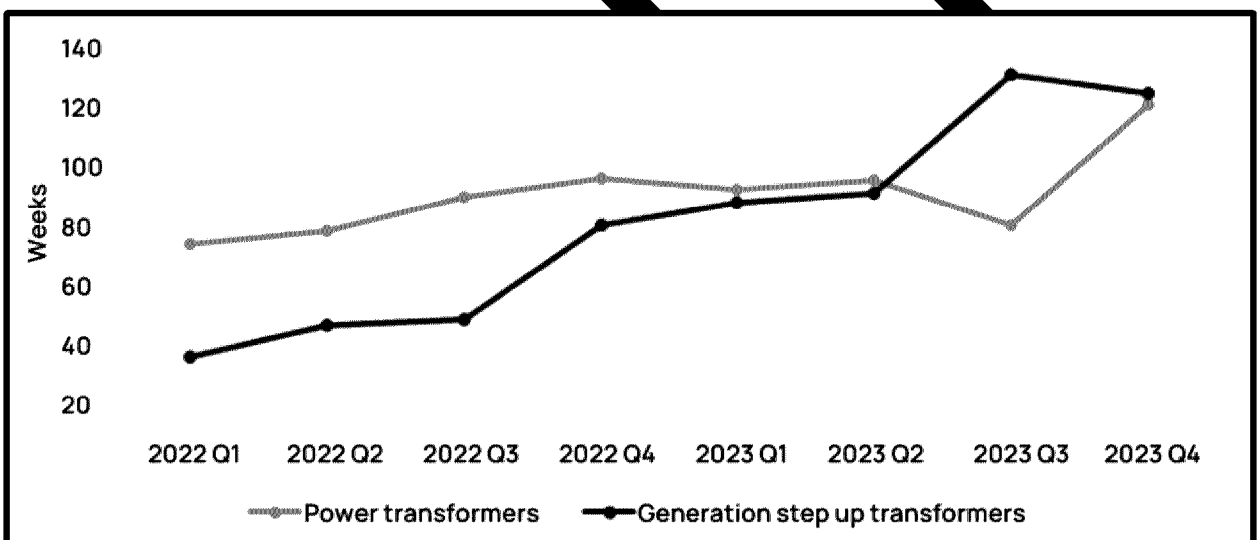


Figure 1: Growth in Large Power Transformer Lead Time

Rising demand for transformers has exacerbated supply chain challenges, driven by increasing electrification across the U.S. and global economy, the build-out of renewable electricity generation, and growth in large-load customers such as data centers. This has led to a sharp increase in prices that is likely to have a ripple effect on the costs of electricity for business and residential consumers.

Figure 2 shows the 10-year price history of large power and distribution transformers scaled to an index of 100 in February 2014. Transformer prices are 80 percent higher since the beginning of the pandemic.

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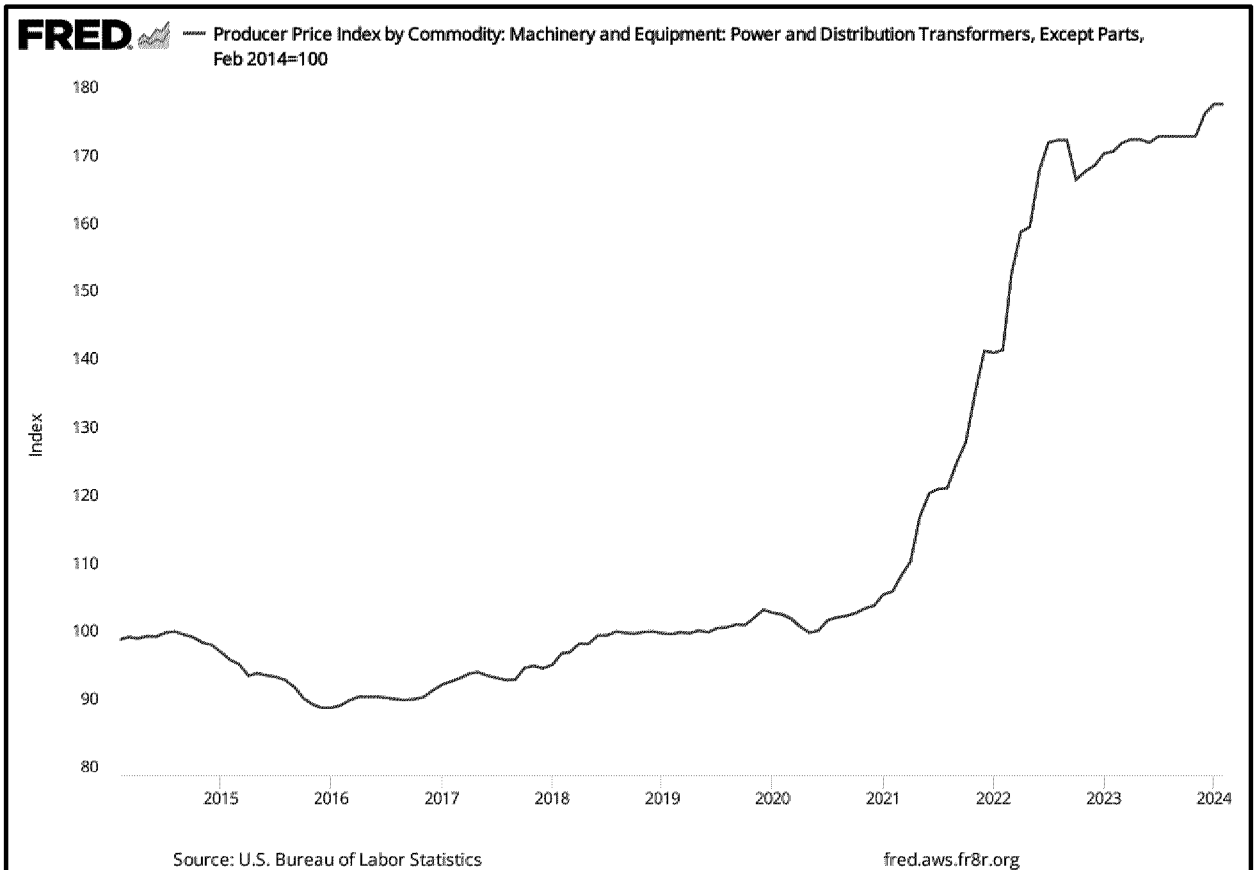
[1] Anthony Allard (Hitachi) and David Garza Herrera (Xignux), April 23, 2024, meeting.
[2] Kann, Shayle. 2024. "Understanding the Electric Transformer Shortage." Latitude Media.
[3] Wood Mackenzie. 2023. "Supply Shortages and an Inflexible Market Give Rise to High Power Transformer Lead Times." The discrepancy between the 210-week lead time cited in the article and the 120-week figure shown in the graph is presumed to be the outside extreme of the range of lead times.



Fi[illegible]: St. Lo[illegible] Federal Re[illegible]k Tra[illegible]mer Price Index

Electric transformers are cri[illegible] to sup[illegible]t grid transf[illegible]ation. Strong action is needed to increase the capacity of tra[illegible]er produ[illegible] to [illegible]siliency [illegible]ational infrastructure, withstand storms, promote st[illegible]th of th[illegible]. electri[illegible] and [illegible] avoid the broad economic disruptions that would re[illegible]rom power o[illegible]es an[illegible]ays in conn[illegible]g homes and businesses to the grid. In addition, transforme[illegible]ill be needed t[illegible]et sta[illegible]d national climate goals by successfully integrating clean energy on the [illegible] such as solar, [illegible]d, and [illegible]ery energy storage system generation. Finally, the industry's current depende[illegible]n foreign-ma[illegible]arge tra[illegible]sformers and key transformer components, such as electrical steel, prese[illegible]a significan[illegible]tional security risk that must be addressed.

From a national security p[illegible]ecti[illegible]creasing domestic production of transformers and critical components presents the be[illegible]n, and this report reflects that as a top priority. Near-shoring certain production to Canada and Mexico is an option with slightly more risk, while friend-shoring production overseas, with transportation of transformers and components via merchant vessels, carries even more risk exposure, though measures could be taken to minimize it.

This report outlines the **causes** of supply chain-related delays in transformer production that have resulted in a transformer shortage and the steep increase in prices. It then offers **seven recommendations** to encourage more domestic production capacity.

Among other challenges, the domestic transformer manufacturing industry has had difficulties attracting and retaining qualified workers.[4] The previous cyclical nature of the industry has made manufacturers wary of increasing capacity despite rising demand, even as it became evident that the recent transformer shortage was not merely the product of a normal cycle.[5] The lack of standardization in transformer design has made automation, assembly optimization initiatives, and other technologies that aid efficient mass production more difficult. Finally, manufacturers have faced cost and regulatory uncertainty concerning electrical steel, which is used to make the core of the transformers and has a limited domestic supply.

These are significant challenges, but they are surmountable.

Based on the briefings and a review of reports pertaining to this issue, the NIAC makes the following recommendations:

1. Craft Federal policies and designate funding targeted [illegible]ing domestic capacity, such as tax credits, grants, accelerated depreciation, funding for new apprentice or training programs, and other incentives, using the Crafting Helpful Incentives to Produce Semiconductors (CHIPS) and Science Act as a model.
2. Achieve greater accuracy in transformer-demand forecasting that provides a more comprehensive outlook across the next 10 to 15 years by convening all parties who drive demand.
3. Encourage long-term contracts/customer commitments between transformer suppliers and the industry sectors driving demand and establish favorable regulatory frameworks to enable them.
4. Establish a strategic virtual reserve of transformers, with the U.S. government as the buyer of last resort.
5. Promote collaboration between design engineers at utilities, engineering firms, trade associations, and domestic and foreign manufacturers to standardize transformer design, reduce complexity associated with customization, and facilitate interoperability through standardized interfaces between transformers and other grid components.
6. Ensure a sufficient supply of electrical steel by coordinating incentives for new domestic supply, government efficiency standards, and trade policy.
7. Grow the pipeline of qualified workers by partnering with universities, community colleges, and trade schools on training programs while working with Federal, state, and local governments to craft [illegible] incentives for workers who enter the field.

While the emphasis of this report is on large power and distribution transformers, some of these seven recommendations also apply to other critical grid components such as conduit, smart meters, switchgear, and high voltage circuit breakers, among others. More domestic or diversified production of this equipment is also needed.

[4] Anthony Allard (Hitachi) and David Garza Herrera (Xignux), April 23, 2024, meeting.
[5] Kann, Shayle. 2024. "Understanding the Electric Transformer Shortage." Latitude Media.

2. Introduction

2.1. The NIAC's Charge

On December 13, 2023, the NIAC's Electrification Subcommittee presented a report to President Joseph Biden on *Managing the Infrastructure Challenges of Increasing Electrification*, highlighting, among other infrastructure-related risks, the national shortage of transformers due to supply chain difficulties. At that time, President Biden asked the NIAC to research the transformer shortage and draft a report to provide recommendations that, if implemented, would increase capacity of domestic transformer production.

The Transformer Production Subcommittee was formed to answer the following questions:

- What steps must the government take to bring transformer manufacturing back to the U.S.?
- How can the private sector be more engaged as a partner to the government?[6]

2.2. Subcommittee Activities

The Subcommittee held meetings on the following dates:

April 3, 2024 – Virtual kickoff meeting.

April 10, 2024 – Subcommittee meeting featured Gene Rodrig[illegible], Assistant Secretary of Energy, U.S. Department of Energy (DOE); and Tom Galloway, President and CEO, North American Transmission Forum.

April 23, 2024 – Subcommittee meeting featured David [illegible] Herrera, board member, Xignux[7]; and Anthony Allard, Executive Vice President, Head of North America, Hitachi Energy.

May 6, 2024 – Subcommittee meeting featured Tim [illegible], CEO of ERMCO[8] and Richard Voorberg of Siemens Energy.

May 10, 2024 – Subcommittee meeting featured Dr. Mo[illegible] Gorman, Deputy Assistant Secretary for Manufacturing, U.S. Department of Commerce.

May 17, 2024 – Subcommittee discussed comments and feedback from members on the initial draft of the report.

2.3. Organization of this Report

The remainder of this report is organized into the following sections:

Current Challenges Related to Transformer Availability: This section provides more detail on the current obstacles to an adequate supply of large power and distribution transformers.

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[6] National Security Council Guidance to the NIAC, January 25, 2024.

[7] Xignux is the parent company of Prolec. Prolec manufactures and distributes a comprehensive range of transformers and other grid products under the Prolec, General Electric, Waukesha, and Celeco brands. It has manufacturing facilities in Louisiana, North Carolina, Texas, Wisconsin, Mexico, and Brazil.

[8] ERMCO is the largest manufacturer of distribution transformers in the U.S. It has manufacturing facilities in Tennessee, Georgia, North Carolina, Canada, and Mexico, among others.

Economic and Environmental Impact of Transformer Shortage: This section offers a perspective on the potential consequences of not encouraging greater domestic transformer manufacturing capacity.

Recommendations: This section presents more detail regarding the NIAC's recommendations.

Call to Action: Based on analysis of the challenges related to transformers, as well as the recommendations aimed at addressing those challenges, this section provides a suggestion of next steps for the Federal government to take.

3. Current Challenges Related to Transformer Availability

At present, there is an extremely tight market for large power and distribution transformers. The following sections discuss the major factors at the heart of these challenges.[9]

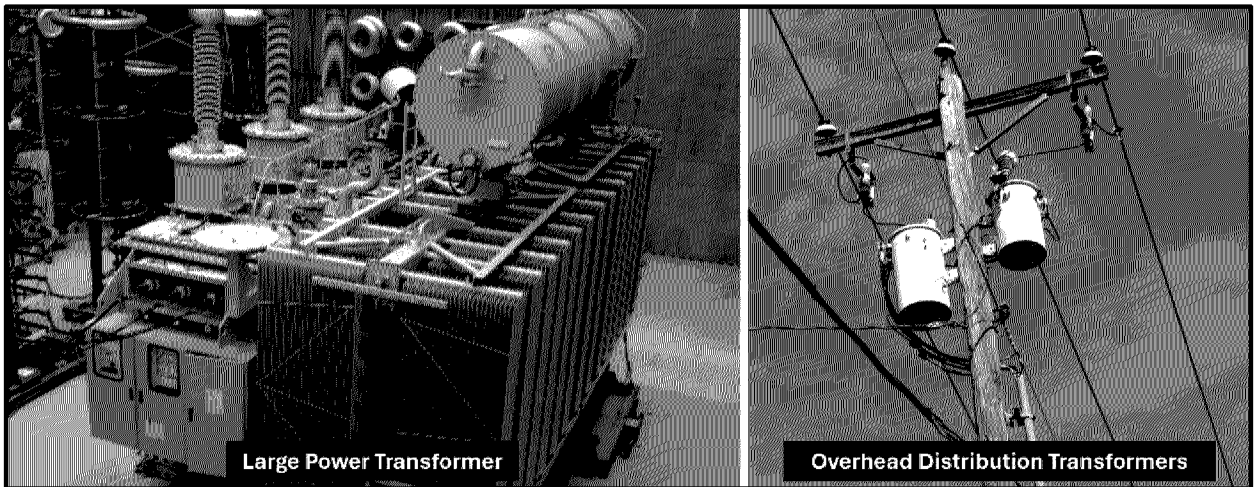

Figure 3: Large Power and Distribution Transformers[10]

3.1. Post-Pandemic Economic Growth

The COVID-19 pandemic disrupted supply chains throughout the world. The grid component sector, including transformers, was no exception as shortages of material, equipment, and labor created slowdowns in both manufacturing and construction. As pandemic restrictions were lifted, projects that had been delayed deliberately, or because of component unavailability, suddenly were resumed. This created supply chain ripple effects that are still subsiding. As measures across the globe were taken to stimulate economies, more disruptions and supply pressures ensued and are still plaguing various industries.

3.2. Grid Modernization

A significant driver of demand is the need to replace aging transformers with new ones. A 2020 study by the U.S. Department of Commerce[11] indicated that the average age of in-service large power transformers was 38 years, which is already near or even past design life. Since the stock of existing transformers in the U.S. has been estimated at over 60 million,[12] replacement alone is sufficient to support considerable annual demand.

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[9] Large power transformers operate at electric transmission voltages above 34.5 kilovolts (kV) whereas distribution transformers operate at 34.5 kV and below.
[10] The large power transformer photo on the left side was excerpted from a Siemens Energy power transformers brochure; the overhead distribution transformers photo on the right side was excerpted from a Duquesne Light Co. overhead line safety announcement.
[11] U.S. Department of Commerce Bureau of Industry and Security Office of Technology Evaluation. 2020. "The Effect of Imports of Transformers and Transformer Components on the National Security."
[12] DOE final distribution transformer rule adds two years for compliance, Utility Dive, April 4, 2024.

According to the Electric Power Research Institute (EPRI), changing duty cycles associated with grid transformation and renewable energy integration may reduce the lifespan of certain transformers or induce capacity deratings, placing further strain on available capacity.[13]

3.3. National Electrification Trend

The national trend toward greater electrification is a large driver of future transformer demand. As transportation, space and water heating, and other economic sectors switch gradually from fossil fuel to electricity, load growth has increased.

In addition, new loads like data centers, electric vehicle charging facilities, heat pumps, and forecasted hydrogen production facilities are all expected to boost U.S. electricity consumption. Rising electrification of homes will increase the load factor on transformers serving those homes. When these transformers are near capacity, they may need to be replaced with larger transformers, further driving demand in that market segment.

A prime example of increasing electrification is the rapid proliferation of large data centers. **Figure 4** shows McKinsey & Company's forecast of data center power consumption in gigawatts by 2030.[14]

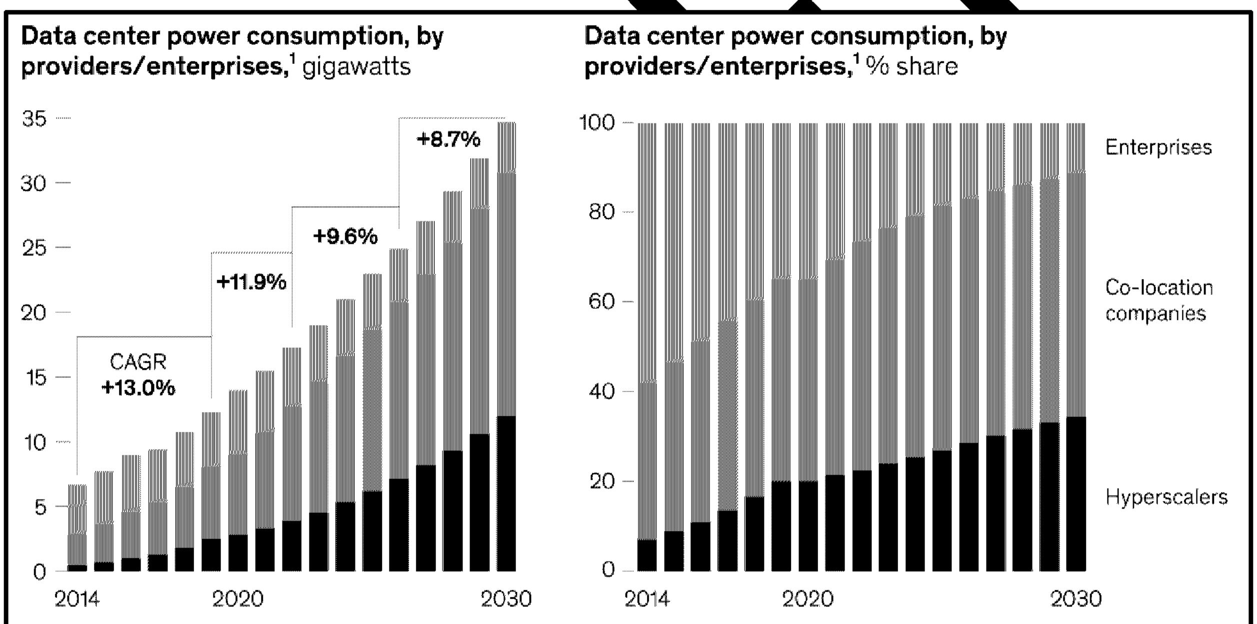

Figure 4: Historical and Forecast U.S. Data Center Power Consumption

The rise in electrification factoring into the growth in demand for transformers is distinct from past trends that have driven demand growth, such as the housing bubble of 2004 through 2007.[15] Rather, increasing electrification is driven both by policy and consumer behavior. There is a buildout of transmission infrastructure already underway that is effectively irreversible, and these actions are driven by the societal

[13] Arshad Mansoor, President of the Electric Power Research Institute.
[14] McKinsey & Company. 2023. "Investing in the Rising Data Center Economy." Hyperscalers are massive data centers for the use of a single owner.
[15] Baker, Dean. 2018. "The Housing Bubble and the Great Recession: Ten Years Later."

urgency of addressing climate change. As such, the demand growth is likely to continue, if not accelerate, making this period distinct from the boom-bust dynamics that the industry has experienced historically.

3.4. Renewable Generation and Transmission Build-Out

Another major driver of future transformer demand is that the annual capacity factors achieved by renewable- and storage-generating resources are much lower than those achieved by conventional thermal plants. Accordingly, the amount of installed transformer capacity required for the same amount of energy production is much higher. For example, a 1,000-megawatt conventional thermal generating plant, operating at 90-percent annual capacity factor, would produce about 7.9 million megawatt-hours annually. It would take 5,000 megawatts of solar photovoltaic capacity, operating at 18 percent annual capacity factor, to produce the same amount of annual energy.

A recent National Renewable Energy Laboratory (NREL) study[16] reveals that the number of distribution transformers required in the U.S. by 2050 will be 160 to 2[illegible]0 percent higher than 2021 levels. This is a compound annual growth rate of installed transformer capacity from 3.7 to [illegible] percent. Many existing transformers will also have to be replaced over the same period, which contributes to the demand for new transformers being much higher than overall U.S. electricity consumption growth rates over the same period. In addition, recent market research suggests that the transformer market will grow at the rate of 5 to 7 percent annually in dollar terms over the next decade.[17]

Figure 5 is excerpted from the Energy Information Administration (EIA) Annual Energy Outlook 2023. The EIA performs detailed modeling on the expected build-out of new electric generating capacity under various scenarios of economic growth, oil and natural gas supply, and low or high zero-carbon technology cost. Regardless of the economic growth, gas production, and/or renewable technology scenario, the EIA forecasts that installed generating capacity in gigawatts will double [illegible] levels. This means that large power and renewable step-up transformer demand will remain very robust.

[16] McKenna, Killian. 2024. "Major Drivers of Long-Term Distribution Transformer Demand." NREL Grid Planning and Analysis Center.

[17] Market research firms sell discrete reports on certain markets or offer a periodic subscription service. However, many market research firms will disclose a few "headline" conclusions from these studies to help attract customers. In developing this report, firms like Grand View Research, Global Market Insights, Allied Market Research, and others estimated that the value of the U.S. transformer market would be growing 5 to 7 percent annually in dollar terms over the next decade.

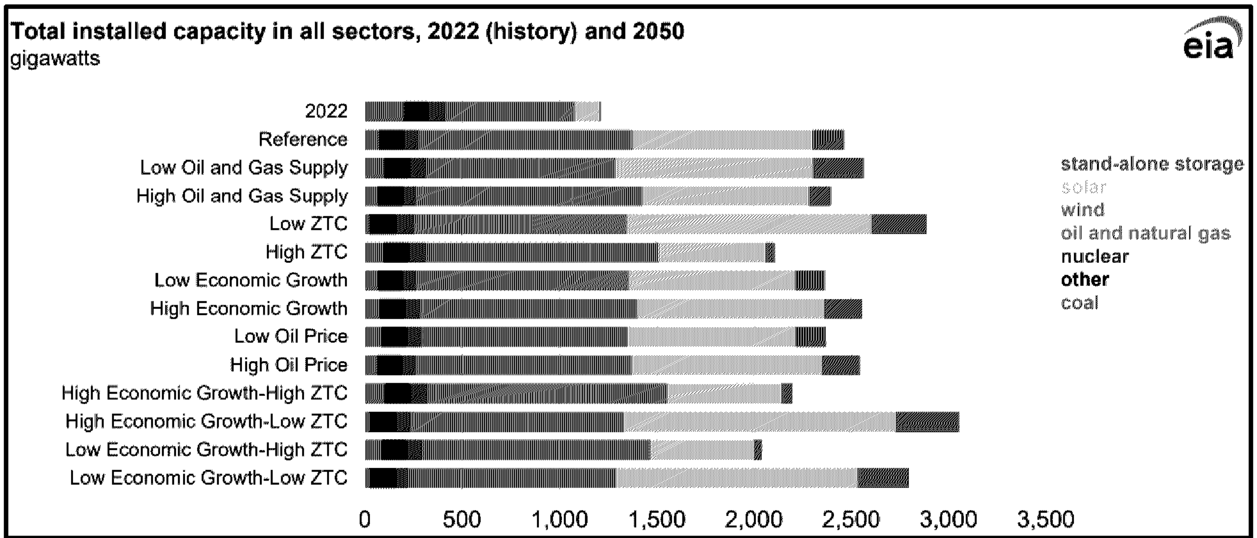

Figure 5: Forecast of Installed [illegible] Generating Capacity in 2050

Figure 6 shows the DOE's forecast of expected bulk power transmission additions by 2035, according to different scenarios such as moderate load growth, high clean energy growth, and both high load and clean energy growth. Depending on the U.S. region, potential growth may be extraordinary. Most regions, excluding California, New York, and the Northwest U.S. under certain scenarios, indicate significant expansion is expected.[18]

[18] U.S. Department of Energy. 2023. "National Transmission Needs Study." Certain designated regions include only portions of states. For example, the Delta region includes the entire State of Louisiana, but only portions of Arkansas, Mississippi, and Texas. The DOE report provides a map indicating the footprint of the regions. Note that under certain scenarios, New York and the Northwest also forecast significant transmission expansion.

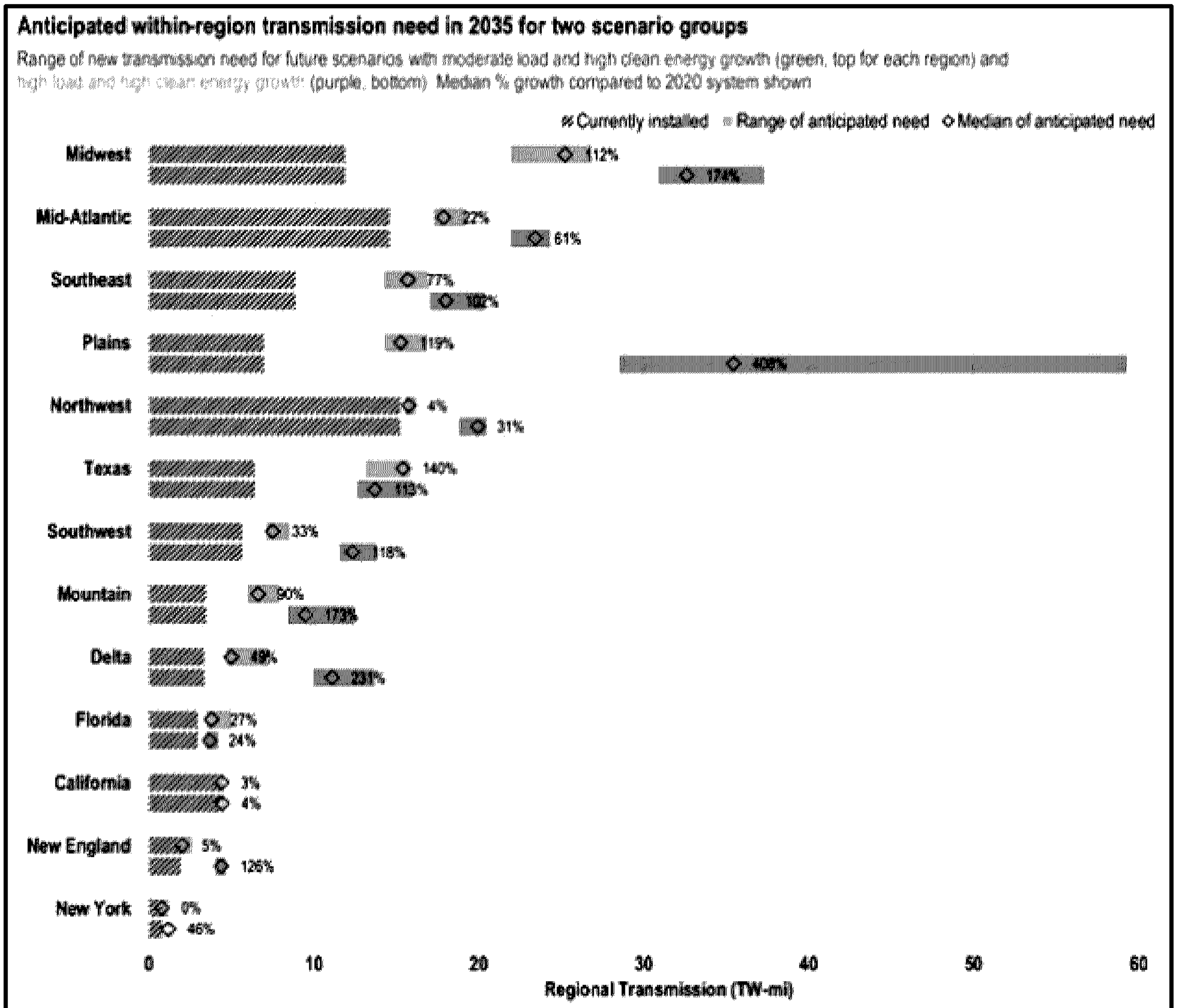

Figure 6: DOE Bulk Power Transmission Expansion Forecast by 2035

3.5. Labor Shortages

The domestic transformer manufacturing industry faces labor shortages due in part to the demands of training, working conditions, and some of the manufacturing facilities being in rural areas that offer a limited regional labor pool. Domestic manufacturers indicated that a lack of workers is one of the largest impediments to expanding capacity. With distribution transformers in particular, manufacturers have found it necessary to add shifts to meet higher demand.

3.6. Historic Industry Cyclicality

The historic cyclical nature of the transformer industry presents yet another challenge. Transformer manufacturers that increased capacity during the housing boom of 2004-2007 experienced severe impact from the 2008 global financial crisis, which has made them wary of increasing capacity despite rising demand. Since there may be opportunities to boost output at certain plants by adding another shift or weekend work, labor shortages may also be blocking an avenue to more production.

Past cyclicality may be tempered by the forecast of strong demand for both distribution and large power transformers over the next several decades.

3.7. Lack of Equipment Standardization

Another challenge is the lack of standardized transformer designs. Many utilities have custom transformer designs and requirements, and they place orders with these unique specifications. This makes mass production impractical, and it has challenged the industry to deploy further automation that could boost production. One large manufacturer suggested that more standardization could boost output at the company's existing plants by a significant factor. The DOE has studied the potential effect of standardization and found that standardization could increase production significantl[illegible]e DOE is also exploring the feasibility of designing a standard transformer that can be mass p[illegible]ed.

The current variety of transformers is primarily a consequen[illegible]llowing (with other special considerations driving variability as well):[19]

1. The need to specify the correct size transfor[illegible]o serve customer l[illegible]
2. The standard high voltage distribution leve[illegible]f each electric utility
3. The low voltage requirements of the customer [illegible] served
4. Whether the load is single phase or three phase
5. Whether the customer is served [illegible]ad or underg[illegible]

3.8. Electrical Steel

Finally, manufacturers have [illegible]gulatory un[illegible]tainty r[illegible]to elect[illegible] steel, which is used to make a transformer's core. Histo[illegible]y, tra[illegible]mers hav[illegible]een[illegible]e w[illegible]ain-oriented electrical steel (GOES), but it is difficult to sourc[illegible]t materia[illegible]mestically[illegible]e same tim[illegible] certain limits on foreign-made steel have made it more expensiv[illegible] purcha[illegible] internation[illegible] In addition, the DOE initially proposed a set of efficiency stan[illegible]hat would[illegible]s steel a[illegible]would require significant changes in the manufactu[illegible]transf[illegible] design. [illegible]ril 20[illegible], the DOE modified the new efficiency standard to allow [illegible]time for ma[illegible]turers[illegible]djust prod[illegible] processes and source key components from other supp[illegible]

[19] As an example, one large domestic manufacturer of single-phase pole-mounted transformers offers 18 different sizes between 0.5 kVa and 500 kVa, 12 different high side voltages (e.g., 2.4 kV, 4.16 kV, etc.), different end use voltages such as 277 or 480 volts, etc. Each of the permutations results in manufacturing complexity.

[20] Distribution voltage levels have tended to increase over the years. While a 4.16 kV or 4.8 kV system might have been standard in the 1940s and 1950s, the current standard might be 13.2 kV or 13.8 kV. However, many utilities still have portions of their service areas where older and lower voltage feeders are still in service. Accordingly, this expands the variety of transformers that must be produced and deployed.

4. Economic and Environmental Impact of Transformer Shortage

In some instances, electric utilities have cautioned local developers that certain new construction projects may be delayed due to the unavailability of transformers and other required grid equipment. Among these utilities are CPS Energy in San Antonio, Texas,[21] and Portland General Electric in Oregon.[22] Other public and investor-owned utilities have experienced similar challenges. Trade groups such as the National Association of Home Builders have also reported construction delays caused by the unavailability of transformers.[23] These delays are disruptive and costly both to builders and to property owners.

Figure 7 is excerpted from a presentation by the DOE's Lawrence Berkeley National Laboratory. The national lab monitors grid interconnection queues of the seven independent system operators (ISO)/regional transmission operators and 44 non-ISO balancing areas, which collectively represent greater than 95 percent of currently installed U.S. electric generating capacity.[24] While many of the proposed generating projects will not be completed, the interconnection queues are a good proxy for the massive grid transformation that is already underway. For a sense of the massive size of the interconnection queue, the total amount of installed utility-scale capacity in the U.S. was about 1,277 gigawatts in 2023, according to an American Public Power Association (APPA) analysis. Therefore, the pending interconnection queue is close to double the installed capacity base.[25]

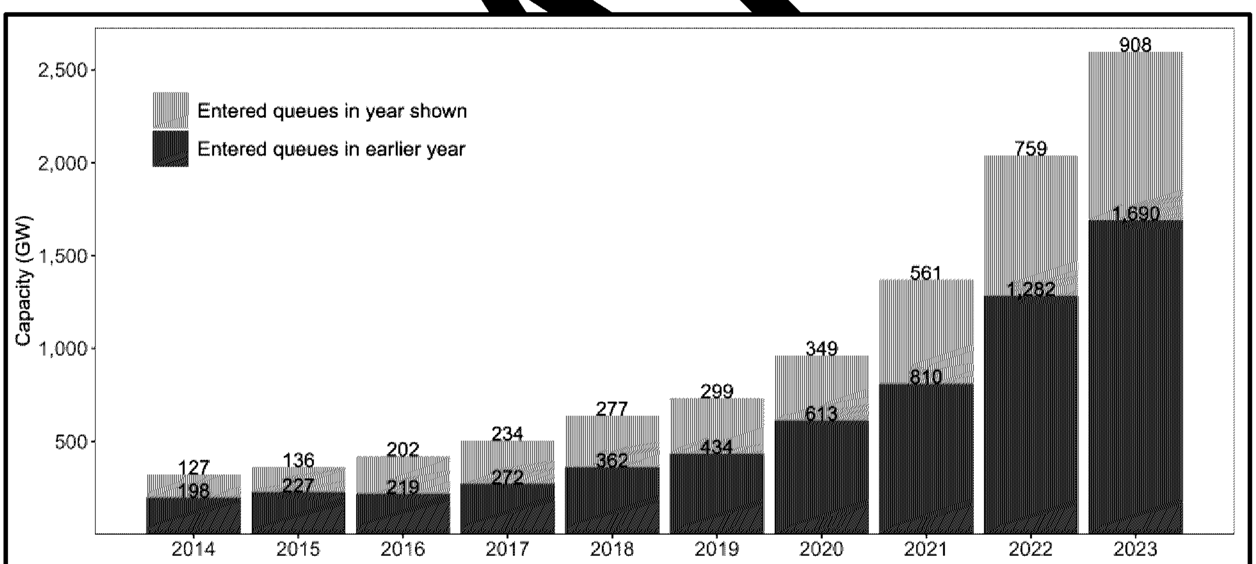

Figure 7. U.S. Generating Capacity Interconnection Queue

According to the Clean Energy States Alliance, 23 states as well as the District of Columbia and Puerto Rico have all enacted legislation or other policies mandating a zero-carbon electricity sector between 2032 and

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[21] CPS Energy. n.d. "Single-Phase Project Queues."
[22] Portland General Electric. 2022. "Nationwide Shortage of Certain Transformers: FAQ for Builders and New Construction."
[23] National Association of Home Builders. 2023. "Electrical Component Shortage is Wreaking Havoc and Demands Action."
[24] Rand, Joseph, et al. 2024. "Queued Up: 2024 Edition, Characteristics of Power Plants Seeking Transmission Interconnection as of the End of 2023."
[25] Buttel, Lindsey. 2023. "America's Electricity Generation Capacity 2023 Update." American Public Power Association.

2050. The map in **Figure 8** shows the 23 states that have such public policy mandates shaded in green.[26] If too many projects are delayed by the lack of transformer or other key electrical grid components, it will inhibit the pace of the energy transition, leading to more greenhouse gases entering the atmosphere and increasing impacts from climate change. Collectively, these 23 states represent an estimated 53 percent of the total U.S. population.

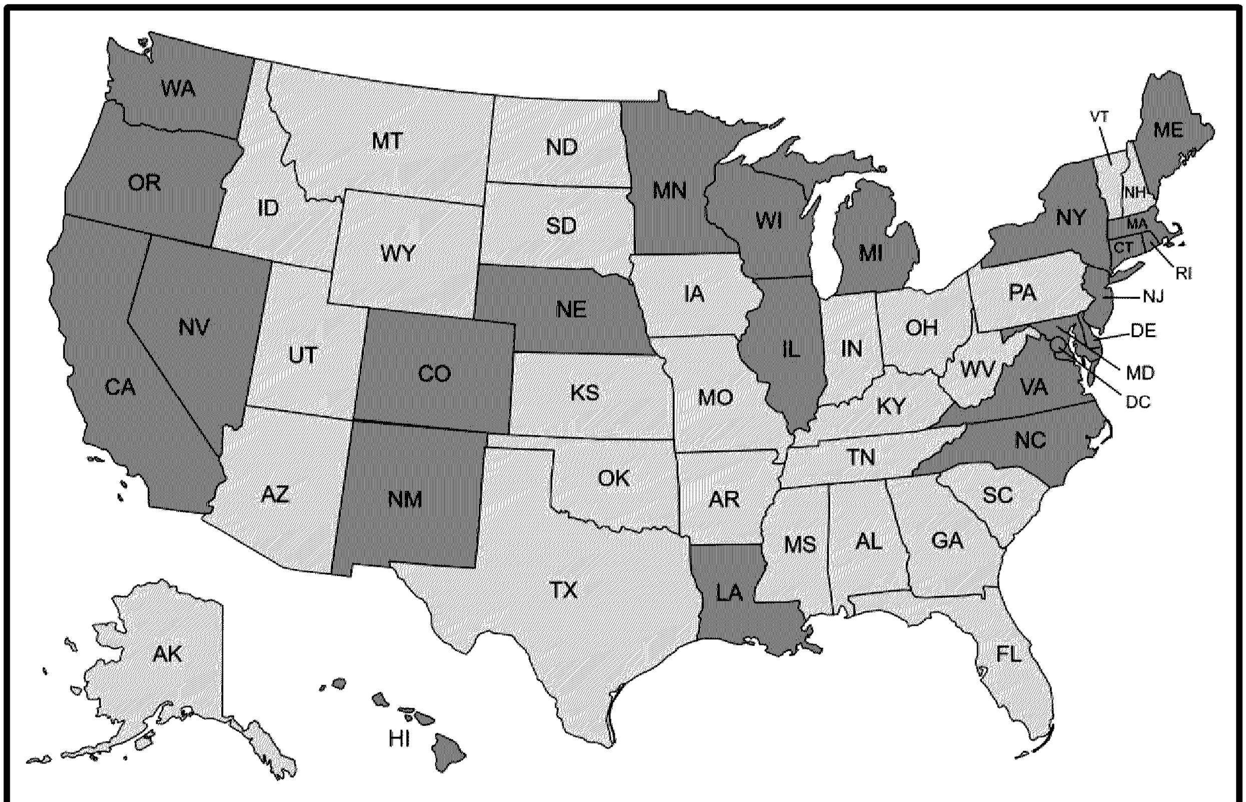

Figure 8: States Enacting Legislation or Policy to Decarbonize the Electric Sector

Extreme weather events are among the most visible, tangible effects of climate change, and a continuing shortage of transformers is likely to impair the resilience of electric grids in affected regions, leading to more frequent, longer lasting outages, thus exacerbating the effect on economies and increasing risks to the health of residents.

Investing in solutions to address the shortage of transformers, however, is not solely about avoiding a set of negative consequences. These investments also have the potential to create value in terms of new jobs, economic growth, and strengthening the nation's energy security.

[26] Detail regarding the legislative or other decarbonization policy of these 23 states is available from the Clean States Energy Alliance website. The map was created using a template from MapChart.

5. Recommendations

The NIAC offers **seven recommendations** to boost domestic production of transformers and promote a closer partnership between the private sector and the government to ensure adequate supply of this critical grid component.

5.1. Expand Domestic Capacity through Federal Policies and Funding Incentives

The NIAC recommends the Federal government craft policies and designate funding targeted at increasing domestic capacity, such as tax credits, grants, accelerated depreciation, funding for new working apprentice and/or training programs, and other incentives, using the CHIPS Act as a model.

Domestic distribution transformer production is still strong in the U.S. This has been attributed, in part, to the degree of customization that utilities have historically required for their distribution transformers. In the case of large power transformers, however, the U.S. is heavily dependent on foreign manufacturers. This dependence creates national security concerns.

The NIAC recommends that the Federal government develop a set of incentives to increase domestic production of electrical steel and expand annual production capacity of both distribution and large power transformers. Incentives could come in the form of grants, investment tax credits, or production-cost tax credits linked to a verifiable and permanent increase in annual production capacity. The capacity increase would be associated with new capital investment to de-bottleneck current production processes, boost automation, and/or expand manufacturing capacity (floor space, assembly bays, production lines, etc.).

Mechanisms like the investment tax and production tax credits available in the Inflation Reduction Act (IRA) to encourage domestic renewable generation projects could be devised to expand permanent domestic transformer production. These incentives would reduce the risk for manufacturers considering capacity expansion.

In a subcommittee briefing with Siemens, a company executive shared that IRA incentives for buying American-made products influenced the company's recent decision to onshore large transformer production at an expanded facility in North Carolina.

The goal is to expand domestic production of large power transformers to 50 percent by 2029 to reduce supply risk and improve national security. Given the current estimated figure of only 20 percent, and with market growth expected, additional capacity will be required. The NIAC recognizes that some manufacturers may elect to produce certain transformer sub-assemblies in other countries with longstanding transformer supply relationships with the U.S., such as Canada, Mexico, and certain European or Asian producers.

The NIAC also recommends that the DOE coordinate a task force to recommend the magnitude of financial support required to induce more domestic production, augmenting work it has already done in this regard.

In addition, an Electric Subsector Coordinating Council Tiger Team should review the supply chain and foreign dependency of other critical grid elements, such as high voltage circuit breakers and switchgear. Increased domestic or diversified production of this equipment is needed. Finally, the Federal government should consider using Defense Production Act funding to support the increased development of large transformer domestic capacity and the gradual conversion of U.S.-based distribution transformers to more efficient methods of transformer production.

5.2. Increase Collaboration to Achieve Greater Accuracy in Transformer Demand Forecasting

The NIAC recommends convening all parties who drive demand to achieve greater accuracy in transformer demand forecasting that will provide a more precise outlook across the next 10 to 15 years.

While most of the large power and distribution transformers in the U.S. are ordered by electric utilities, there are other important market segments, including generation-resource developers, large manufacturers, data center developers, and commercial enterprises. The NIAC recommends that the DOE commence a biannual process to work closely with each transformer market segment to develop a long-term forecast of transformer demand, by type.

This effort would account for how energy policy is shaping market trends. For example, under new transformer efficiency standards,[27] 25 percent of distribution transformers will be made using amorphous steel, which lacks domestic sources of production. The forecasting of transformer demand, then, must reflect the need for sufficient supply of both GOES and amorphous steel.

In addition, the forecasting should account for global supply and demand trends related to utility infrastructure, since those trends have the potential to impact the cost and availability of essential electric equipment like transformers.

By aggregating expected demand from key market participants and factoring in broader global trends related to utility infrastructure, domestic transformer manufacturers will be positioned to make decisions based on more accurate and timely information pertaining to future demand.

The demand forecast should be separated by key market segments, and be as granular as possible on transformer variables such as overhead versus pad-mounted, standard size in kilovolt-amperes (kVA) or megavolt-amperes (MVA), voltage level, distribution versus large power transformers, etc. There are already market research firms that provide forecasts of electric grid equipment demand. The intent is not to displace these activities but rather to encourage all market participants to develop a comprehensive source where all available data can be gathered in a systematic manner.

Much like electric peak load and annual energy forecasts, the DOE should develop scenarios to help industry participants assess the effect of low, base, and high transformer demand forecasts and make its aggregate data sets available publicly. The DOE Annual Energy Outlook is a widely used source of energy forecasts and could serve as a model for this recommendation, recognizing that the transformer outlook will be less complex and not as far-reaching.

[27] U.S. Department of Energy. 2024. "DOE Finalizes Energy Efficiency Standards for Distribution Transformers that Protect Domestic Supply Chains and Jobs, Strengthen Grid Reliability, and Deliver Billions in Energy Savings." DOE final distribution transformer rule adds 2 years for compliance.

5.3. Encourage Commitments Between Transformer Suppliers and the Sectors Driving Demand

The NIAC recommends encouraging long-term contracts/customer commitments between transformer suppliers and the sectors driving demand.

Most electric utilities do not source transformers under long-term contracts. Historically, grid-equipment lead times have been reasonable, and the disparate nature of transformers in terms of size, type, and application makes identifying the needs difficult until the utility's replacement, with the new construction pipeline well-defined. While most electric utilities develop a 5-year capital budget (and sometimes an associated 10-year outlook), only the first several years of the program are known. The out-years of a 5-year budget are typically reasonable in terms of volume, based on typical growth and replacement programs, but are seldom specific regarding discrete projects.

Several large power transformer manufacturers have indicated that longer firm commitments by electric utilities (and major renewable and conventional generation developers) would provide more certainty and therefore make capacity expansion decisions easier to justify. Several manufacturers also indicated that European utilities have been making 5- to 10-year equipment purchase commitments and therefore have already reserved significant manufacturing capacity. However, firm commitments for certain types and sizes of transformers may be difficult for U.S. utilities to identify, given risks of tying up too much working capital in inventory or raising concerns from various state public utility commissions. On the other hand, some regulators may be receptive to utilities making longer term commitments if it enables the utility to support growth and/or more rapid renewable and storage capacity deployment.

Given the complex state and federal regulatory overlay of electric utilities, it would be useful to create a model policy whereby the federal government offers recommended guidance regarding commitments for critical infrastructure equipment and building larger power and distribution transformer inventories to cope with unforeseen contingencies. Having the Federal Energy Regulatory Commission support a larger set of critical spares in national transmission rate cases, for example, would set a strong precedent for national [illegible].

5.4. Establish a Reserve of Transformers

The NIAC recommends establishing a strategic reserve of transformers, with the U.S. government as the buyer of last resort.

Various industry participants have advocated that the U.S. government establish a strategic virtual reserve of transformers. The reserve's function would be like that of the U.S. Strategic National Stockpile (SNS) for medical equipment needed to respond to large public health emergencies. The SNS was created in 1999 to help counter potential biological, disease, and chemical threats to civilian populations.[29] The stockpile contains supplies, medicines, and devices for lifesaving care that can be used as a short-term, stopgap buffer when the immediate supply of these materials may not be available or sufficient.

[28] Note that many public power and cooperative utilities are not regulated by state-level public utility commissions. However, a broad national policy regarding increased inventories of critical spares could be considered by their respective governance boards.
[29] Kuiken, Todd and Gottron, Frank. "The Strategic National Stockpile: Overview and Issues for Congress," Updated September 26, 2023. Congressional Research Service, R47400.

Unlike the SNS, however, the transformer reserve would not be created in advance. Rather, a virtual reserve could be created over time where the Federal government would step in as buyer of last resort if domestic manufacturers experienced a slowdown in orders that would result in production below predetermined levels.

As envisioned, the mechanism would function like U.S. Department of Agriculture commodity Price Supports, except that price would not be the trigger; rather, the supports would be activated when plant capacity utilization dips below a particular threshold. The resulting physical reserve could then be stored until production capacity utilization was high and lead times expanded again to unacceptable levels. At that point, the Federal government, working with its private sector partners, would determine a suitable reserve drawdown to alleviate shortages. The virtual reserve, like all stockpiles, would therefore dampen the historical boom/bust cycle of transformer manufacturers and could help improve manufacturing capacity utilization over the cycles. It is likely that any government sales of transformers would occur in periods when market prices are high.

Ideally, the transformer reserve would be set up as a public-private partnership where cooperative-, public-, and investor-owned utilities work closely with other transformer users and the Federal government to ensure that the reserve is eventually stocked with the equipment most likely needed, and withdrawal mechanisms are pre-determined, transparent, and rapid to meet emergency needs.

The concept of a virtual distribution transformer reserve is complicated by the sheer variety of transformers that are available (broad array of different sizes, overhead versus pad-mounted, cooling method, application, specialty units, and so on). The NIAC envisions that a Federally funded virtual reserve program would focus on a smaller subset of transformers in use based on the most common sizes and types. By limiting the type and size of units that would be purchased, the program could also help drive more standardization in transformer specifications.

To ensure readiness, all stored equipment in the reserve would be inspected on a periodic basis to ensure its operability. In addition, given the logistical challenges of transporting large transformers, steps must be taken to ensure that units are stored in multiple locations with suitable inland port, waterway, and/or rail access that enable the transformers to be cost-effectively dispatched to sites where needed.

5.5. Promote Collaboration to Standardize Transformer Design and Reduce Complexity

The NIAC recommends the Federal government promote collaboration between design engineers from utilities, trade associations, and domestic manufacturers with the goal of standardizing transformer design and reducing complexity associated with customization.

Because customer loads and generator sizes are disparate, a broad array of transformer sizes is required to match each application. The use of different distribution and transmission voltages across the U.S. further expands the variety of transformers that must be produced. One estimate indicates there are over 80,000 different distribution transformers available. In addition, the industry could improve interoperability by standardizing the interfaces between transformers and other grid components.

This complexity and customization can complicate the production processes of transformer manufacturers and reduces potential throughput. A potential goal of the standardization effort may be to develop modular transformer components that would allow for faster assembly.

By increasing standardization, manufacturers may be able to boost production and reduce costs at the same time, thereby improving industry profitability.

Historically, standardization has lagged because neither the utility industry nor the manufacturers of transformers had sufficient incentives to pursue it. A study may be needed to test that it is possible to create a standard transformer model that can be widely adopted by utilities, and as a result drive savings in the costs of production. Again, the DOE and EPRI would be natural candidates for sponsoring and assisting this research. Public utility commissions could play an important role in engaging utilities and promoting adoption of standardized equipment.

Gaining broad agreement on standards may be arduous, but an industry-wide effort supported by the utility trade associations, the National Electrical Manufacturers Association, and the Federal government is likely to succeed in reducing the degree of current transformer customization, driving reductions in costs, and boosting productivity. Over time, additional benefits will accrue from standardization, including reduced spare parts complexity and utility training requirements, and better performance analytics to improve reliability of the equipment.

The DOE, the industry trade associations, and a few of the large utilities in the U.S. should be the initial nucleus to launch a standardization effort. According to our briefer from the DOE, the Office of Electricity is actively working to promote standardization of transformers and will continue to need robust support.

It may also be worthwhile to explore the creation of a global inventory of transformers. This strategy has been effective in other industries.[30]

5.6. Coordinate Incentives for Supply, Efficiency Standards, and Trade Policy

The NIAC recommends the federal government ensure a sufficient supply of electrical steel by coordinating incentives for supply, governmental efficiency standards, and trade policy.

The DOE, electric utilities, and transformer manufacturers worked collaboratively over several years to adopt new energy conservation standards for distribution transformers. This effort culminated in a carefully synchronized path to transition gradually to more efficient amorphous steel transformer cores while enabling transformer manufacturers to cultivate new sources of supply and add new production capacity in an orderly way. This approach avoids further supply disruption, undue price escalation, and over-reliance on subcomponent suppliers. At the same time, the new standard will enable the industry to reduce transformer technical losses for the benefit of customers and the environment.

With a 5-year planning horizon and more certainty regarding standards, transformer manufacturers have additional time to expand capacity and migrate to more secure supplies of amorphous steel as the industry shifts from GOES to amorphous steel. It also enables current suppliers of GOES to adjust production gradually and avoid costly and disruptive production facility shutdowns and job losses.

The thrust of the NIAC's recommendation is to continue to allow enough time for amorphous steel production capacity to expand in the U.S. or other near-shore areas of reliable supply. Since it will take years and considerable investment to develop and diversify sources of the more efficient electrical steel, a

[30] International Atomic Energy Agency. 2006. "Potential for Sharing Nuclear Power Infrastructure between Countries."

carefully coordinated and gradual tightening of the efficiency standards will ensure that an orderly transition occurs.

Given the urgency of the supply issue, it may be best to pursue a near-term solution for the shortfall in electrical steel supply, while at the same time advancing a longer-term strategy aimed at increasing its domestic production.

The NIAC believes that the development of alternative supply sources for more domestic amorphous steel or GOES may be a prime candidate for Federal support as discussed in Recommendation 5.1: Expand Domestic Capacity through Federal Policy and Funding Initiatives.

5.7. Grow the Workforce Pipeline through Public and Academic Partnerships

The NIAC recommends the Federal government grow the pipeline of qualified workers by partnering with universities, community colleges, and trade schools on training programs while working with federal, state, and local governments to craft tax incentives for workers who enter the field.

Industry groups have called for the Federal, state, and local governments to encourage universities, community colleges, and trade schools to establish and fund programs to develop a steady pipeline of qualified workers in areas near existing domestic transformer and transformer component manufacturing facilities. As such, the NIAC recommends that the Federal government, coordinated by the DOE, fund the development of training and/or certification programs working closely with transformer manufacturers to ensure that graduates have the requisite skills to be effective employees. Instead of a lengthy classroom-based program, it may be useful to obtain Federal support for initial on-the-job training (e.g., for the 6 to 8 months that it takes to become fully trained and productive).

An ideal approach might be to help fund apprenticeship-type or certification programs that combine shop floor experience with periodic classroom training on tool usage, safety, rigging, welding, and other pertinent skill sets.

Federal consideration of this recommendation should consider careful coordination with another NIAC study, Expanding the Workforce for Critical Infrastructure.

In addition, Federal, state, and local governments should consider offering tax breaks or subsidies to expand the pool of workers who choose to work in this field.

6. Call to Action

The NIAC urges the President to consider these recommendations and move expeditiously to implement them to ensure rapid growth in domestic production of transformers, strengthening the reliability of the U.S. power grid, and securing it against associated risks to national security.

Appendix A: Acknowledgements

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Monica Gorman, Special Assistant to the President for Manufacturing and Industrial Policy, National Economic Council

Appendix B: Definitions

Term	Common Definition
Distribution transformer	Distribution transformers are used to reduce the voltage level of a power supply to that needed by an end-use customer. The electric utility industry defines a distribution transformer as having a high side voltage at or below 34.5 kV.
Grain-oriented electric steel (GOES)	GOES is a specialty steel used for transformer cores because it reduces power losses and makes the device more efficient. It is an iron alloy with silicon instead of carbon as the main component besides iron.
Large power transformer	The Department of Energy uses the term large power transformer to characterize a power transformer with a capacity rating of 100 MVA or higher. As used in this report, a large power transformer is one that is part of the transmission grid and has a low side voltage above 34.5 kV.

Appendix C: Acronyms and Abbreviations

Acronym/ Abbreviation	Definition
CHIPS	Crafting Helpful Incentives to Produce Semiconductors
DOE	Department of Energy
GOES	Grain-Oriented Electric Steel
EPRI	Electric Power Research Institute
EIA	Energy Information Administration
IRA	Inflation Reduction Act
ISO	Independent System Operator
kVA	Kilovolt-amperes
MVA	Megavolt-amperes
NIAC	National Infrastructure Advisory Council
NREL	National Renewable Energy Laboratory
SNS	Strategic National Stockpile

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BID PROTOCOL
2023
OPEN RESOURCE
REQUEST FOR PROPOSALS

Issued: **January 17, 2023**

Responses Due: **March 14, 2023**
4:00 p.m. Pacific Prevailing Time ("PPT")

Bid Event Website: **https://berkshirehathawayenergy.app.jaggaer.com**

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1.0 OVERVIEW

1.1 Purpose and Scope

Sierra Pacific Power Company d/b/a NV Energy ("SPPC") and Nevada Power Company d/b/a NV Energy ("NPC") (collectively "NV Energy" or the "Company") are issuing this 2023 open resource request for proposals ("2023 OR RFP" or "RFP") to interested parties with the intent of securing proposals for the acquisition of long-term dispatchable energy and energy storage resources with a minimum size of 20 MW together with all associated environmental and renewable energy attributes, as applicable.[1] The Company is seeking proposals for conventional and renewable resource types, under various types of agreements.

With this RFP, NV Energy seeks to advance State of Nevada energy policies by procuring new renewable energy projects that produce economic, health and environmental benefits for Nevadans.[2] Renewable energy solidifies the foundation upon which safe, reliable, reasonably priced electric service can be delivered to NV Energy's customers. The renewable resources sought in this RFP will help the Companies to meet the increases in the renewable portfolio standard established by Senate Bill 358, and to meet the needs of a diverse group of stakeholders and policy objectives. Specifically, NV Energy seeks to:

- continue progress towards the 2050 goal of energy production from zero carbon dioxide emission resources equal to the total amount of electricity sold in the State;[3]
- provide lower cost energy and capacity;
- provide customer price stability;
- respond to customer demands for more renewable energy;
- provide for long-term resource adequacy and reliability of Nevada's electric system.

With this RFP, NV Energy also seeks to contract for non-renewable firm capacity and energy assets that may include energy storage and conventional generation to support system peak capacity needs and the continued integration of intermittent renewables.

[1] MW refers to the megawatts of capacity at the point of delivery, alternating current.
[2] Senate Bill 358, 2019 Session of Nevada Legislature, §8(2).
[3] *Id.*

This bid protocol document sets forth the terms, conditions and directives for the 2023 OR RFP. **By responding to this RFP, Bidder agrees to be bound by all the terms, conditions, and other requirements stated in the RFP, including any modifications made to it by NV Energy prior to Bidder's submission of its proposal(s).** Bidders will be notified of any such modifications prior to the proposal submission deadline.

1.2 General Renewable Energy Resource Types and Commercial Structures

NV Energy will consider qualified proposals from Bidders who currently own or have legally binding (e.g. deed, lease agreement, lease option agreement) rights to develop acceptable renewable energy generating resources (including associated substation, transmission lines, water and gas lines, and telecommunication systems, as applicable) with a minimum net power production or storage capacity of 20 MW. For renewable energy proposals, proposals must include all associated environmental and renewable energy attributes as a bundled product, in accordance with this RFP bid protocol document. The Company will not consider demand side, energy efficiency, distributed generation, or portfolio energy credit ("PC")-only proposals, or proposals for assets already under contract with NV Energy.

This 2023 OR RFP is applicable to the purchase of electrical energy from conventional generating assets and qualifying renewable energy facilities as defined in Nevada Revised Statutes ("NRS") Sections 704.7315, 704.7811 and 704.7815, and pursuant to Nevada Administrative Code ("NAC") Sections 704.8831 through 704.8893. Renewable energy proposals shall be compliant with existing Nevada renewable portfolio standards and that provide resource diversification at competitive prices. As described in greater detail below, the Company will consider proposals based on a variety of structures and resource types.

Acceptable renewable energy resource types include solar, geothermal, wind, hydroelectric, biomass, and biogas technologies[4]. Acceptable commercial structures for long-term renewable energy resources include asset purchase agreements ("APA") for existing renewable energy resources, build transfer agreements ("BTA") for projects in development, and, for geothermal (flash and binary), hydroelectric, biomass and biogas and wind, will also include power

[4] All renewable technologies must produce and provide associated renewable energy credits.

purchase agreements ("PPA"). Acceptable commercial structures are further defined in Table 1 below. Pro forma agreements relating to acceptable commercial structures for qualifying renewable energy resource types are included as attachments to this RFP bid protocol document.

The 2023 OR RFP requires that projects be capable of delivering energy to serve load in the Company's retail service territory (http://www.oasis.oati.com/NEVP/).

1.3 Energy Storage Systems

NV Energy will consider energy storage systems ("ESS") that are eligible for the Investment Tax Credit ("ITC"). ESS proposals may stand-alone or associated with Bidder's proposed renewable energy resource.

ESS must have a minimum capacity of 20MW at the point of delivery and designed for three hundred and sixty-five (365) equivalent cycles per year.[5] For purposes of this RFP, ESS systems are not considered a renewable energy resource or a generating facility.

For stand-alone energy storage, the capacity to energy ratio is shall be one to four (4-hour) or one to eight (8-hour) however longer duration proposal options are welcome.[6]

For ESS proposed along with a new solar energy resource, Bidder is encouraged to provide two bids of an AC-coupled ESS such that the relative AC capacities of the proposed solar resource at the point of delivery are 100 and 50 percent that of the ESS capacity, with a 4-hour duration.[7] Bidders are required to submit renewable energy and ESS pricing for both ESS relative sizes, each with a separate Attachment G. Bidders may propose additional ESS designs as alternative bids.

For all other renewable energy resource technologies, bidders are encouraged to include a co-located ESS resource with a 4-hour duration. The relative size of the resource will be proposed

[5] For example, a 50MW energy storage facility would be able to provide 200MWh in four hours to the point of delivery.
[6] For Lithium-Ion battery ESS, compliant bids shall be 4-hour or 8-hour duration however longer duration options are welcome. Proposals for non-Lithium-ion storage technologies Bidders shall propose 4-hour or 8-hour designs if the technology supports however NV Energy welcomes longer-duration proposals that optimize the technology's capability and cost-effectiveness.
[7] For example, a 100-MW solar facility with 100-MW BESS or a 100-MW solar facility with a 200-MW BESS.

by the bidder, taking into consideration NV Energy's desire to discharge the energy to serve evening system peak hours. Bidder will provide information to support the proposed relative size.

1.4 Acceptable RFP Products

NV Energy is seeking the following products and commercial structures (Table 1), located in Nevada, as outlined in more detail in Sections 2.8 through 2.11 below: [8]

[8] See Section 2.7 g for exception for wind energy

Table 1 – RFP Products

Product:	Category:	A	B	C	D
	Commercial Structure	**Renewable** [a]	**Renewable + Storage** [a, b, f]	**Conventional** [h]	**Stand-alone ESS** [i]
	Existing Generating Facility: [c]				
1	APA [d]	X	X	X	X
2	PPA	X	X[g]	X	
3	WSPP Confirm			X	
	New Project:				
4	BTA [d, e]	X	X[g]	X	X
5	PPA	X	X[g]		

Table Notes:

[a] All renewable energy must include unencumbered PCs.

[b] NV Energy will consider projects with one-to-one solar to storage capacity ratio and half-to-one solar to storage capacity ratio where one equals the interconnection capacity. The ESS shall have a four-hour duration. See requirements under Section 1.3.

[c] Proposed projects must not be currently contracted with NV Energy, unless contract expires on or before proposed commercial operation date deadline.

[d] Only solar, solar with energy storage, wind, wind with energy storage, or conventional generation, and energy storage will be considered. Note that the pro forma agreements attached as Attachments D.1 and D.2 are tailored for specific technologies and structures; conforming changes will be required for alternative technologies/structures.

[e] Proposed projects must be constructed to NV Energy engineering, procurement and construction ("EPC") standards

[f] The Large Generator Interconnection Agreement may require action by Bidder to add energy storage. Energy storage dispatch, when paired with renewable energy generation, must not exceed the interconnection agreement's capacity.

[g] Renewable term length is 25 years; ESS term length is 20 years with bidder option to propose one or more five-year options to extend.

[h] Conventional energy products must interconnect to NV Energy's system.

[i] Stand-alone ESS must be 4-hour or 8-hour for Lithium-ion, other durations as optional proposal. Other technologies may be 4-hour or 8-hour but proposals should optimize cost and capability of the technology.

Bidders are invited to submit multiple proposals, incorporating combinations of the products and commercial structures that allow for cost savings. Bidders of solar and wind projects are encouraged to include ESS in their proposals.

Renewable energy resources and if applicable, co-located ESS, must be integrated into the NV Energy system as a network resource for serving load in NV Energy's balancing authority area. **Proposals must allow for a commercial operation date on or before December 31, 2028.** An earlier commercial operation date is preferred to meet customer needs. Proposals must have a point of delivery already identified, and able to interconnect to NV Energy's transmission system. Bidders must demonstrate, through documentation of the completed progress milestones that a Facilities Study has been completed and that a Large Generator Interconnection Agreement ("LGIA") is in place or will be in place that supports the proposed commercial operation date.[9]

For Bidders submitting PPA proposals, the term will be for twenty-five (25) years. PPA proposals must include purchase options in favor of NV Energy for the renewable energy resource, including all energy, capacity and associated environmental and renewable energy attributes, which options are exercisable: (a) at the eighth, fourteenth, and twentieth years following the commercial operation date of the renewable energy resource, and (b) at the end of the term of the PPA. PUCN approval may be required prior to NV Energy exercising such purchase option.

2.0 GENERAL INFORMATION FOR THE 2023 OR RFP

2.1 General Information

NV Energy is seeking proposals for resources as set forth in Section 1.1 of this RFP. NV Energy will evaluate the proposals based on pricing as well as other criteria, including: (a) the greatest economic benefit to the State of Nevada; (b) the greatest opportunity for the creation of new jobs in the State of Nevada; (c) the best value to NV Energy's customers; (d) the financial stability of the Bidder and the ability of the Bidder to financially back the proposal and any warranty or production guarantee; and (e) conformance to the bid criteria and form agreements. NV Energy may select one proposal, multiple proposals, or no proposals as a result of this RFP.

All proposals submitted to NV Energy pursuant to this RFP become the property of NV Energy and may be used by NV Energy, in its sole and exclusive discretion, as it deems appropriate. As part of the RFP process, Bidder is required to sign a Confidentiality Agreement in the form provided in Attachment A to this RFP. However, Bidders shall have no expectation of

[9] An LGIA is applicable to facilities with a net generating facility capacity of greater than 20 MW.

confidential treatment of the executed agreement(s), which will be submitted to the PUCN and become available to the public. Bidders should only mark information as proprietary and confidential that is actually proprietary and confidential.

A proposal may be subject to discovery and disclosure in regulatory or judicial proceedings, including those initiated by a party other than NV Energy. Upon notice from NV Energy of such a discovery or disclosure request or requirement, Bidders may be required to justify the requested confidential treatment under the provisions of a protective order issued in such a proceeding. Except as otherwise provided in the Confidentiality Agreement in the form provided in Attachment A to this RFP, NV Energy may disclose proprietary and confidential information in the course of such proceeding without further notice to Bidders as required by law. If required by an order of the PUCN or any other governmental authority, NV Energy may provide the confidential information without prior consultation or notice to Bidders. Except as otherwise provided in the Confidentiality Agreement in the form provided in Attachment A to this RFP, such information may also be made available under applicable state or federal laws to regulatory commission(s), their staff(s), and other governmental authorities having an interest or jurisdiction in these matters without further notice to Bidder. The Company also reserves the right to release such information to any contractors for the purpose of providing technical expertise to the Company. Such contractors are hereby expressly included within the definition of "Representatives" set forth in the Confidentiality Agreement in the form provided in Attachment A to this RFP.

Bidders will be required to submit bids electronically to the Company using BHE JAGGAER, which is accessible via https://berkshirehathawayenergy.app.jaggaer.com[10]. Bidders are expected to provide a response in each data field represented. The "free text" data field accepts responses that are approximately 1,000 characters. In these fields, Bidders should avoid special formatting and characters, as these can inflate the character count unnecessarily and result in a saving error. In this instance Bidders should simply remove any special characters and formatting, or shorten the answer to save successfully. Bidders should also fill out Excel spreadsheets and provide attachments, to the extent requested by the Company.

[10] To gain access to the event, bidders must follow the directives, as applicable, under the "Steps to Complete" section of the RFP website.

2.2 RFP Schedule

NV Energy has established the target schedule for this RFP as shown in Table 2 below. NV Energy reserves the right to amend the target schedule at any time.

Table 2 – RFP Schedule

RFP Event	Target Schedule
Launch RFP	January 17, 2023
Bidder Questions Deadline (1pm)	March 10, 2023
Bids Due (4pm)	March 14, 2023
Bid Fees Postmark Deadline	March 16, 2023
Initial Shortlist Issued	April 5, 2023
Best and Final Pricing Due	April 7, 2023
Final Shortlist Issued	April 14, 2023
Contract Negotiations Conclude	July 5, 2023
Execution of Contract(s)	July 12, 2023
PUCN Filing for Approval (estimated)	November 21, 2023*
PUCN Approval Timeline (up to 165 Days)	May 3, 2024
Commercial Operation Achieved On or Before	December 31, 2028

*Subject to change to align with NV Energy's regulatory calendar.

2.3 Registration

All parties interested in submitting a bid in response to this RFP must complete and submit a Bidders Registration and Contact Information Form located on the website for this RFP, which can be accessed at www.nvenergy.com/2023ORRFP. Bid numbers will be self-assigned as directed under Section 3.3. Parties registering for this RFP must include both a primary and alternate point of contact and identify one lead negotiator from your organization who will be available to discuss any questions specific to your proposal. This information should be entered in the Corporate Information tab/worksheet of Attachment G.

2.4 Contact Information, Questions, and Answers

This RFP can be accessed at https://berkshirehathawayenergy.app.jaggaer.com. ***All communications between Bidders and NV Energy regarding this RFP will be done using BHE JAGGAER as the messaging system.*** Communication through this system will be monitored by the Company. Communications with NV Energy personnel regarding this RFP outside of the BHE JAGGAER system is grounds to disqualify a Bidder's submission. Any response submitted by mail, facsimile, or email **will not be accepted**. Pre-bidding questions submitted by Bidders, and Company responses, will be posted in BHE JAGGAER for all Bidders to view. At any time during the RFP, a Bidder may log into https://berkshirehathawayenergy.app.jaggaer.com, download the communications, complete the online datasheet information and upload responses. NV Energy requires that all questions concerning this RFP be submitted no later than 1:00 p.m. (PPT) March 10, 2023. Questions submitted after this time may not receive a response.

2.5 Proposal Submittal Instructions

Submitted proposals must be organized in the manner described in Section 3.0 of this RFP and signed by a representative of Bidder who is duly authorized to submit the offer contained in the proposal on behalf of Bidder. Each proposal should specify the self-assigned bid number (see Section 3.3).

Bidders will be required to submit both parts of the proposal (as detailed in Section 3.0) through BHE JAGGAER. Part One of Bidder's proposal, as detailed in Section 3.1 below, will be utilized by NV Energy's credit group in completing a credit review of each Bidder.

In order to consistently analyze responses to this RFP, Bidders are required to prepare their submission within the outlined format. Responses not complying with the format requirements may be considered non-conforming and may be disqualified at the discretion of the Company.

For a proposal to be considered by NV Energy, the proposal must be fully uploaded into BHE JAGGAER by 4:00 p.m. (PPT) onMarch 14, 2023. Proposals, or parts thereof, received after 4:00 p.m. (PPT) on March 14, 2023, will not be accepted. Bidders are strongly encouraged to complete forms and begin uploading files hours in advance of the deadline.

2.6 Bid Fee

Each Bidder must submit the required Bid Fee(s) to NV Energy, by certified check or cashier's check made payable to "Nevada Power Company d/b/a NV Energy" (for projects in southern Nevada) or "Sierra Pacific Power Company d/b/a NV Energy" (for projects in northern Nevada) at the address listed below. The check must reference the 2023 OR RFP and Bidder's bid number(s). The aggregate Bid Fee (as determined below) for each Bidder must be postmarked (or date stamped by delivery service provider) within two (2) business days of submitting the proposal(s) in BHE JAGGAER. Bidder's proposal(s) will not be considered if Bidder fails to submit timely the required Bid Fee(s).

Address for Delivery of Bid Fee:

NV Energy
Renewable Energy & Origination (Bid Fee Processing)
Mail Stop B13RE
P.O. Box 98910
Las Vegas, Nevada 89151-0001

OR

NV Energy
Renewable Energy & Origination (Bid Fee Processing)
Mail Stop B13RE
7155 S. Lindell Road
Las Vegas, NV 89118

The required amount of the Bid Fee for each Proposal is as follows:

(1) $10,000 (base bid fee) for each proposal; and

(2) $2,500 each, for up to two alternative pricing options for same project/proposal.

a. Alternative pricing options may include changes in pricing escalators, COD dates or equipment (e.g. different panels), with all other terms of the proposal being identical[11].

b. Alternative pricing options, beyond two, under a proposal requires a new base proposal fee and, if applicable, up to two alternative pricing options at the fees shown above.

[11] All other terms of the proposal must be identical (i.e. no differences in contract provisions, no change in project size, no change in Delivered Amount (PPA) or as provided in 12x24 or 8760 values of Attachment G, no changes to metering configuration, etc.). A change in AC or DC coupling technology is a significant facility design change as opposed to a vendor or minor specification change, requiring additional due diligence and the change impacts some contract terms and exhibits, therefore, that and similar changes would require a separate $10,000 bid fee.

Bid Fee Exceptions:

(1) If Bidder is proposing a PPA, pricing is required for a 25-year term. Other term lengths may be proposed, but will be considered a separate proposal and require a separate base fee and, if applicable, associated alternative pricing option bid fees.

(2) If Bidder is proposing a solar energy project with co-located ESS, pricing is required for both ESS relative sizes (see Section 1.3). This requirement for two ESS relative sizing options does not require an additional base bid fee. Other ESS relative sizing options may be proposed, but will be considered a separate proposal and require a separate base fee and, if applicable, associated alternative pricing option bid fees. [12]

(3) Other alternative project sizing will be considered a separate proposal and require a separate base fee and, if applicable, associated alternative pricing option bid fees.

(4) Each proposal type/commercial structure (i.e. PPA, WSPP, BTA or APA) is considered a separate proposal.

(5) Bidders may submit a secondary base proposal based on a change in contractual provisions, but must first submit an initial proposal with pricing based on the original pro forma agreement before mark-ups.

Bid Fee Examples:

PPA, WSPP, BTA or APA					
Price Opt 1	*Alt Opt 1*	*Alt Opt 2*	*Alt Opt 3*	*Alt Opt 4*	*Alt Opt 5*
10,000	2,500	2,500	10,000	2,500	2,500

Note: *Limit of two alternative pricing options for each $10,000 base fee*

Co-located ESS (PV Sized – 100%)			**Co-located ESS (PV Sized – 50%)**		
Price Opt 1	*Alt Opt 1*	*Alt Opt 2*	Price Opt 1	*Alt Opt 1*	*Alt Opt 2*
10,000	2,500	2,500	0	0	0

Note: *Limit of four alternative pricing options (i.e. two for each required co-located ESS size)*

[12] For a $10,000 bid fee, bidder proposals for a solar energy project with co-located ESS shall include a base pricing option for each of the required ESS relative sizes to PV (see Section 1.3). In addition, for a fee of $2500 per option, such bidders may propose up to two (2) additional pricing options for the same proposal. All pricing options must be as described above, and all other terms of the proposal must be identical. If such bidder takes full advantage, under a single project/proposal, they will have two additional pricing options for each required ESS relative size (i.e. 4 additional pricing options), plus the base pricing options for a total of 6 pricing options with a bid fee of $15,000. See Bid Fee Examples tables.

A separate Attachment G must be submitted for each pricing option (i.e. base and alternative options). Data contained in Attachment G includes cost model inputs. Model outputs are used to aid in determining the project shortlist. Pricing options included within the proposal, but not in an Attachment G will not be considered. If a co-located ESS system is proposed along with a new renewable energy resource, include both in one Attachment G, under the applicable worksheets/tabs. Follow the proposal numbering and file naming convention in Section 3.3 of this RFP bid protocol document (e.g., the proposal number for the initial Attachment G would be 1.0, and the first alternative pricing option for the same proposal would be 1.1).

The Bid Fees will be used to cover the costs incurred by NV Energy in analyzing the proposals, including the costs of any consultants or legal advisors. Any such costs that are not covered by the Bid Fees will be recovered through fees assessed on Bidders of successful proposals (the "Success Fees"). The Success Fees will be determined by NV Energy once the final amount of Bid Fees and Company costs are known, provided that in no event will a Success Fee exceed $250,000 per successful proposal. **THE BID FEE IS NON-REFUNDABLE. AFTER SUBMISSION OF BIDDER'S PROPOSAL, THE BID FEE WILL NOT BE REFUNDED UNLESS THE PROPOSAL IS WITHDRAWN PRIOR TO THE SUBMITTAL DUE DATE, THE PROPOSAL DOES NOT MEET THE MINIMUM ELIGIBILITY REQUIREMENTS AND THAT DEFICIENCY CANNOT BE CURED, OR THE PROPOSAL IS REJECTED FOR ANY OTHER NON-CONFORMANCE PRIOR TO COMMENCEMENT OF THE SHORTLISTING ANALYSES**.

2.7 Minimum Eligibility Requirements for Bidders

In addition to meeting the proposal organization requirements in Section 3.0, all Bidders must comply with certain minimum eligibility requirements to have their proposals considered in this RFP. Failure to meet the requirements of bulleted items a) through m) will result in rejection of the proposal. Further, any proposal may be deemed non-conforming, and may be rejected by NV Energy, as a result of items n) through ff) of the following:

Minimum Requirements

a) Failure to submit the full proposal in BHE JAGGAER by the due date and time, except where failure was caused by a technical issue with BHE JAGGAER.

b) Failure to provide bid fee(s) by the deadline specified in RFP Schedule (Table 2).

c) Proposal has failed to specify all pricing terms, and include them in Attachment G.

d) Failure to permit disclosure of information contained in the proposal to (i) NV Energy's employees, contractors, consultants, agents or representatives, (ii) relevant regulatory authorities and other governmental authorities, or (iii) non-bidding parties that are party to regulatory proceedings, under appropriate confidentiality agreements.

e) Failure to provide an official Facilities Study or LGIA issued by the NV Energy transmission provider. Projects located outside Nevada must have the equivalent studies and transmission rights delivering energy and associated PCs to NV Energy's balancing authority area.

f) Bidder fails to demonstrate adequate site control for the proposed project, including access to the site, as evidenced through an executed and legally binding title, lease agreement, lease-option agreement, right-of-way, or easement issued by the fee owner or the applicable state or federal land resource agency.

g) For solar, project is not physically located in the state of Nevada – exception for wind, geothermal, hydroelectric and biomass energy proposals which may be located outside Nevada but must have transmission rights per item e) above.

h) Any attempt to influence NV Energy in the evaluation of the proposals outside the solicitation process.

i) Any failure to disclose the real parties of interest in the proposal submitted.

j) Collusive bidding or any other anticompetitive behavior or conduct.

k) Bidder or project being bid is subject to bankruptcy or other insolvency-related proceedings.

l) Failure to provide a copy of Bidder's executed Voluntary Consent Form, as submitted directly to the transmission provider, in the form provided in Attachment B of this RFP.

m) Any proposal, under a partnership arrangement, that does not include evidence documenting that the partnership is legal and binding with an effective period that extends well beyond the expected contract execution date stated in Table 1 (RFP Schedule).

Additional Requirements

n) Any of Bidder, its proposed prime contractor, or any material subcontractor has an Occupational Safety and Health Administration recordable incident rate greater than 1.5 in the last three (3) years or has had any fatalities on projects in the last three (3) years. Please provide relevant supporting documentation.

o) Bidder, or any affiliate of Bidder, either (i) is in current litigation or arbitration with NV Energy or an affiliate of NV Energy, (ii) has, in writing, threatened litigation against NV Energy or an affiliate of NV Energy, with the threatened dispute having an amount in controversy in excess of one million dollars, or (iii) is currently adverse to NV Energy in any material regulatory proceeding before the PUCN or any other governmental authority, without regard to the amount in controversy.

p) Bidder fails to address satisfactorily both the price and non-price factors, as discussed in more detail in Section 5 of this RFP.

q) Failure of Bidder's authorized officer to sign the proposal.

r) Any matter materially impairing Bidder, its proposed prime contractor, any major subcontractor or the project itself, including any matters impairing the output of the generating resource or its energy or environmental attributes.

s) Failure to adhere to Approved Vendors List (Attachment K).

t) For wind: failure to provide one year of viable wind data utilizing at least two anemometers for any wind project to support capacity factors submitted and failure to provide a third-party wind study or equivalent to support the expected capacity factor of the project.

u) For geothermal: failure to provide a minimum of one production well and one injection well flow results to support the viability and capacity of the geothermal resource.

v) For solar: failure to provide Tier 1 solar panel manufacturer resource and technology along with a third-party resource assessment report (i.e. PVSyst) to support the expected capacity factor.

w) For biomass: failure to provide a letter of intent with a biomass fuel source for a period of ten (10) years or greater along with a third-party resource assessment report supporting the expected capacity factor.

x) For biogas: failure to provide a resource assessment report supporting the expected capacity factor. Report to include at a minimum, history of landfill, total volume permitted, volume filled, estimated closure date, organic fraction of the municipal solid waste, moisture levels, temperature and pH of the waste, future waste receipt, increase or decrease and average rainfall in the area.

y) For co-located ESS systems: failure to demonstrate qualification for the ITC, failure to meet all requirements identified in Table 1 and Section 1.3, failure to identify the renewable energy resource, or failure to provide detailed description of required shared facilities and/or equipment with the associated renewable energy project.

z) Failure to provide evidence of adequate development rights, including water rights and associated calculations demonstrating adequate water requirements, permits and information regarding water sources and well systems to support construction and operational phases for each resource. Bidders will also provide all executed contracts or other such documentation (example, water transmission plans, private transactional documents to support the required water rights, etc.).

aa) Failure to identify any and all shared facilities and/or equipment with a third party or under a separate agreement.

bb) For APA or BTA: failure to provide cash flow values required during the development, construction, and operations phase for each resource, including, with respect to build transfer agreements, values and schedules for the EPC Agreement and O&M Agreement. Or completion of cash flow table (Price Input tab) and Financial Inputs tab, both in Attachment G.

cc) Failure to submit an acceptance of the applicable pro forma agreement(s) as written, or a comprehensive mark-up, including comments and revisions, to the applicable pro forma agreement(s) and related exhibits. See Section 3.2.7 for further information.

dd) Failure to submit "audited" financial statements and footnotes, including cash flow statements, for prior three (3) years. If Bidder does not have audited financials, Bidder must provide equivalent financials or the audited financials of the nearest level parent company.

ee) Failure to complete Attachment G in its entirety for each bid and pricing option.

ff) Failure to comply with or satisfy any other requirements specified in this RFP or any attachments hereto, including any requirements in connection with the pro forma agreements and any exhibits thereto. Or any other issue NV Energy deems to be contrary or problematic with the intent of this RFP.

gg) Failure to identify any Inflation Reduction Act ("IRA") incentive benefits that are required for regulatory compliance. Please include a section titled "IRA Incentive Benefits", and include relevant details along with quantification of all incentives that will be applicable to each project being bid.

Evaluation of proposals will follow the process discussed in Section 5. Evaluations to determine the final shortlist of Bidders are targeted to be completed as specified in Section 2.2. NV Energy may choose to engage the final shortlist of Bidders in further discussions and negotiations. Any such discussion or negotiation may be terminated by NV Energy at any time for any reason.

2.8 Proposal for PPA with and without ESS (Product 2 and Product 5)

NV Energy will consider qualifying proposals to enter into PPA for renewable energy resources and renewable energy resources with ESS in accordance with the requirements of Table 1 and in the form attached as Attachment C to this RFP.

Any proposed PPA for renewable energy resources shall have a term of twenty-five (25) full contract years. Bids shall include pricing for the renewable dispatchable facility. Products 2A and 5A are for renewable resources that do not include ESS and are priced with a single dollar per megawatt-hour. Products 2B and 5B are for renewable resources with a single dollar per megawatt-hour energy price and ESS with a dollar per megawatt-month price. Product 2C is for a conventional energy resource that is priced with: (i) a single dollar per megawatt-hour energy and capacity price; or (ii) a single dollar per megawatt-hour energy price, and a monthly capacity fee.

The Facility shall be designed and configured (or modified if Product 2 existing facility) such that it may be operated (dispatched via dynamic signal) at an active power level that is lower than its instantaneous maximum power potential and be capable of delivering ancillary services up to the instantaneous maximum power potential of the facility.

Facilities shall have these capabilities:

- The facility must be capable at all times of being operated, via dynamic signal, at an active power level at or below the instantaneous maximum output of the resource.
- The facility must be capable of reserving a configurable amount of capacity which is continuously available based on operator inputs.
- The instantaneous maximum potential output must be capable of being calculated and provided dynamically and instantaneously to Company.
- The facility must have Automatic Voltage Regulation functionality.
- Bidder must provide operating characteristics of the facility that support automated signal operation, including:
    - Facility capable of operating dynamically on Automated Generation Control (AGC) signal every four seconds
    - Facility minimum active power output when on AGC
    - Facility instantaneous maximum output in real time when on AGC
    - Facility provided maximum and minimum ramp rates when on AGC
    - Facility capable of providing dynamic voltage support at continuously rated maximum output while operating at a Power Factor of 0.95 leading to 0.95 lagging when on AGC
    - Facility capable of providing dynamic frequency response of up to 5% droop when on AGC
    - ESS facility provides each of the above capabilities when state of charge or operating status is available

Bidder's proposal must contain the required documentation listed in Attachment G and any proposed changes to the pro forma PPA (Attachment C) in Microsoft Word format. Bidder's proposal must also contain documentation of the completed process milestones, including demonstrating that a LGIA is in place or will be in place that allows for the proposed commercial operation date of the renewable energy resource. For purposes of this RFP, in determining the Levelized Cost of Energy ("LCOE") of the proposed renewable energy resource, NV Energy will include the transmission and distribution network upgrade costs identified in the LGIA that are to be borne by NV Energy. These costs are to be included in Attachment G. Transmission system losses and One Nevada transmission line available capacity may be considered for both feasibility and other evaluations.

Project development security, if applicable, and operating security will be required from Bidders based on the nameplate capacity of the renewable energy and the associated ESS resource, as applicable, contained in Bidder's proposal(s). Project development security amounts and operating security amounts are non-negotiable. The project development security, if applicable, shall be due within the number of days set forth in the PPA after countersignature of the PPA by NV Energy. The operating security shall be due and payable on the earlier of (a) the commercial operation date of the renewable energy resource and (b) countersignature of the PPA by NV Energy (if the renewable energy resource is then in commercial operation).

Any proposal made for the sale of renewable energy and associated environmental and renewable energy attributes, or the sale of capacity from an ESS system, must be made by Bidder with the understanding that the pro forma PPA attached as Attachment C to this RFP will be the basis for any definitive agreement between Bidder and NV Energy, and the proposal pricing must reflect the terms and conditions as set forth in the original pro forma PPA, prior to any mark-ups by Bidder.

2.9 Proposal for WSPP Agreement (Product 3)

NV Energy will consider qualifying proposals to enter into a confirmation under one of the WSPP confirmations, in accordance with the requirements of Table 1 and in the form attached as Attachment C.3 or C.4 to this RFP.

Bidder's proposal must contain the required documentation listed in Attachment G and any proposed changes to the pro forma WSPP Confirm (Attachment C.3 or C.4) in Microsoft Word format. Bidder's proposal must also contain documentation of the completed process milestones, including demonstrating that a LGIA is in place or will be in place that allows for the proposed commercial operation date of the energy resource. For purposes of this RFP, in determining the Levelized Cost of Energy ("LCOE") of the proposed energy resource, NV Energy will include the transmission and distribution network upgrade costs identified in the LGIA that are to be borne by NV Energy. These costs are to be included in Attachment G. Transmission system losses and One

Nevada transmission line available capacity may be considered for both feasibility and other evaluations.

2.10 Proposal for Asset Purchase Agreement (Products 1A through Product 1D)

NV Energy will consider qualifying proposals to enter into APAs for the sale of existing energy resources, excluding geothermal (flash or binary), hydroelectric, biomass and biogas, in accordance with the requirements of Table 1 and in the form attached as Attachment D to this RFP. Bidder's proposal must contain the required documentation listed in Attachment G and any proposed mark-ups to the pro forma APA (Attachment D) in Microsoft Word format. Bidder shall demonstrate that an active LGIA is in place and transferrable. For purposes of this RFP, in determining the LCOE of the proposed existing energy resource, NV Energy will include its resource integration costs. Transmission system losses and One Nevada transmission line available capacity may be considered for both feasibility and other evaluations.

The pro forma APA contemplates that Bidder will transfer the fee title interest in the relevant site to NV Energy. If Bidder intends for NV Energy to acquire site control through other means (e.g. through a lease agreement, license or otherwise), then this fact should be addressed in Bidder's proposal and Bidder's mark-ups to the form of APA must reflect the intended method by which NV Energy will acquire and maintain site control. The APA, which is specifically for the transfer of fee title, will be subject to further revisions by NV Energy in order to accommodate the change in ownership or site control.

2.11 Proposal for Build Transfer Agreement (Products 4A, 4B, 4C, and 4D)

NV Energy will consider qualifying proposals to enter into BTAs for new stand-alone ESS or energy resources, excluding geothermal (flash or binary), hydroelectric, biomass and biogas, in accordance with the requirements of Table 1 and in the form attached as Attachment E to this RFP. Bidders should note the requirement in Table 1 that the applicable new resource must be constructed to NV Energy's EPC standards. The Facility shall be designed and configured such that it may be operated (dispatched via dynamic signal) at an active power level that is lower than its instantaneous maximum power potential and be capable of delivering ancillary services up to the instantaneous maximum power potential of the facility.

Facilities shall have these capabilities:

- The facility must be capable at all times of being operated, via dynamic signal, at an active power level at or below the instantaneous maximum output of the resource.
- The facility must be capable of reserving a configurable amount of capacity which is continuously available based on operator inputs.
- The instantaneous maximum potential output must be capable of being calculated and provided dynamically and instantaneously to Company.
- The facility must have Automatic Voltage Regulation functionality.
- Bidder must provide operating characteristics of the facility that support automated signal operation, including:
    - Facility capable of operating dynamically on Automated Generation Control (AGC) signal every four seconds
    - Facility minimum active power output when on AGC
    - Facility instantaneous maximum output in real time when on AGC
    - Facility provided maximum and minimum ramp rates when on AGC
    - Facility capable of providing dynamic voltage support at continuously rated maximum output while operating at a Power Factor of 0.95 leading to 0.95 lagging when on AGC
    - Facility capable of providing dynamic frequency response of up to 5% droop when on AGC
    - ESS facility provides each of the above capabilities when state of charge or operating status is available

Bidder's proposal must contain the required documentation listed in Attachment G and any proposed mark-ups to the pro forma BTA (Attachment E) in Microsoft Word format. For the purposes of this RFP, in determining the LCOE of the proposed new renewable energy resource, NV Energy will include its resource integration costs and the transmission network upgrade costs identified in the LGIA that are to be borne by NV Energy. These costs are to be included in Attachment G. Transmission system losses and One Nevada transmission line available capacity will be considered for both feasibility and other evaluations. All applicable security provisions are listed in the applicable pro forma agreement and associated attachments and exhibits.

Bidder's proposal must also contain documentation of the completed process milestones, including demonstrating that a LGIA is in place or will be in place that allows for the proposed commercial operation date.

The pro forma BTA contemplates that Bidder will transfer the fee title interest in the relevant site to NV Energy. If Bidder intends for NV Energy to acquire site control through other means (e.g. through a lease agreement, license or otherwise), then this fact should be addressed in

Bidder's proposal and Bidder's mark-ups to the form of BTA must reflect the intended method by which NV Energy will acquire and maintain site control. The BTA, which is specifically for the transfer of fee title, will be subject to further revisions by NV Energy in order to accommodate the change in ownership/site control.

Any proposal made for the sale of a new renewable energy resource and associated environmental and renewable energy attributes, with or without a ESS system, must be made by Bidder with the understanding that the pro forma BTA attached as Attachment E to this RFP will be the basis for any definitive agreement between Bidder and NV Energy, and the proposal pricing must reflect the terms and conditions set forth in the original pro forma BTA, prior to any mark-ups by Bidder.

2.12 No NV Energy Security; Approvals

PLEASE NOTE THAT NV ENERGY WILL NOT POST SECURITY TO SUPPORT ITS OBLIGATIONS UNDER ANY DEFINITIVE AGREEMENT. BIDDERS WHO WILL REQUIRE SECURITY FROM NV ENERGY SHOULD NOT SUBMIT A PROPOSAL UNDER THIS RFP.

NV Energy reserves the right to update, modify, or revise any or all of the terms and conditions contained in the pro forma agreements attached to this RFP. If a definitive agreement is reached with a Bidder, the agreement will be contingent on the approval of the PUCN and other governmental authorities, as required. NV Energy reserves the right to assign a definitive agreement, or assign or delegate any of its rights and obligations under a definitive agreement, in accordance with the assignment provisions contained in the applicable pro forma agreements attached to this RFP.

2.13 Performance and Reliability Standards

The performance and reliability standards for this RFP are incorporated or referenced in the pro forma agreements attached to this RFP. The Company is seeking performance and reliability standards that will, at a minimum, meet the compliance requirements set forth in NAC Sections 704.8777 through 704.8793, and provide the most value to NV Energy's customers by ensuring the resource is meeting load and is able to provide Nevada portfolio credits to meet its compliance requirements. Such performance and reliability standards are similar to those that NV

Energy has required in prior renewable energy resource RFPs but have been updated to address changes in market circumstances and consistency in contract administration, all with the intent to ensure NV Energy's customers are afforded reliable and cost-effective energy resources.

3.0 SUBMITTAL PREPARATION INSTRUCTIONS

All proposals must comply with the requirements specified in this Section. Specifically, Bidders must organize their written proposals according to the format specified in this Section 3.0, and must provide all applicable information required in Sections 3.1.1 through 3.2.8. In addition, all proposals must be submitted in accordance with the requirements set forth in Section 2.5 of this RFP. *Please note, if you have submitted proposals in one of NV Energy's previous RFPs that some requirements and organization have changed.*

General Organization of the Proposal

All proposals must contain the following information and, to facilitate timely evaluation, must be organized as indicated below. The sections of the proposals must be as follows:

Part One

3.1.1. Cover Letter
3.1.2. Bidder Information

Part Two

3.2.1 Proposal Executive Summary
3.2.2 Technical Information
- 3.2.2.1 Facility and Equipment Description
- 3.2.2.2 Site and Route Characteristics
- 3.2.2.3 Land Permitting/Acquisition, Demonstrated Site Control, Water Rights
- 3.2.2.4 Environmental Permitting, Compliance and Authorization
- 3.2.2.5 Construction and Operating Permits
- 3.2.2.6 Benefits of the Proposed Project to Nevada

3.2.3 Interconnection
3.2.4 Resource Supply
3.2.5 Assurance of Generating Equipment Supply
3.2.6 Project Execution Plan
- 3.2.6.1 Project Schedule
- 3.2.6.2 Safety Program
- 3.2.6.3 Project Controls and Reporting Plan
- 3.2.6.4 Quality Control Program
- 3.2.6.5 Subcontractor Strategy
- 3.2.6.6 Work Site Agreement Plan

3.2.6.7 Staffing Plan
3.2.6.8 Financing Plan
3.2.6.9 Environmental Plan
3.2.6.10 Facility Operation and Maintenance Plan
3.2.7 Contract Terms and Conditions
3.2.8 Other Information (may be provided in written proposal or as appendices)

All proposals should include complete responses to the parts set forth above in addition to the information provided in the relevant RFP attachments. Supporting documentation for these sections may be included separately as appendices by providing clear references to the sections concerned. Section titles should match those listed above. Attachment H (Bidder Proposal Compliance Checklist) is intended to aid Bidder in their compliance and is to be completed by inserting an "X" in column B for each completed item and returned with proposal.

If submitting a document as a separate file, the document name/reference must be stated in the written proposal (see file naming convention under Section 3.3). As an alternative, the document may be included as an attachment at the end of the written proposal, and should also be referenced within the body of the written proposal.

Supporting documentation in the form of an official document (e.g. permits, studies, applications, etc.) may be submitted as a comprehensive listing, in spreadsheet format, summarizing the pertinent aspects of the required documents. Please specify whether or not approvals have been obtained or applied for.

3.1 Part One of Proposal

3.1.1 Cover Letter

The cover letter must include all signatures necessary to approve and submit Bidder's proposal by one or more representatives[13] having the authority to contractually commit Bidder to Bidder's offer(s) provided in the proposal. Additionally, the cover letter must be addressed to NV Energy and include the following declaration:

[13] If the proposal is being bid under a partnership, the partnership must be fully established, including a legally binding agreement (not a letter of intent), prior to submission of a proposal under this RFP. Each partner shall be bound to comply with the terms of this RFP and the proposal. The signature of each partner must be included on the cover letter, along with their contact information (i.e. company name, phone number, email address, etc.). The proposal must include evidence documenting the legal and binding partnership with an effective period that extends well beyond the expected contract execution date stated in Table 1 (RFP Schedule), otherwise the proposal will not be accepted.

"[Insert legal name of Bidder] (the "Bidder") acknowledges receipt of NV Energy's 2023 Open Resource Request for Proposals on or about January 17, 2023. Bidder makes the following representations to NV Energy:

1. All of the statements and representations made in this proposal are true to the best of Bidder's knowledge and belief;
2. Bidder possesses a legally binding agreement(s) or option(s) to possess all necessary land rights for sufficient site control to undertake development of the project as set forth in the proposal, including ingress and egress to and from the site;
3. Bidder possesses or will possess all necessary water rights for construction and ongoing maintenance of the project through the term of the agreement, or life of the project if proposal is for a BTA or APA;
4. Bidder has obtained, or can demonstrate how it will obtain, all necessary authorizations and approvals that will enable Bidder to commit to the terms provided in this proposal;
5. This proposal pertains to a renewable energy system, including environmental and renewable energy attributes, from a renewable energy system. The renewable energy system will meet the requirements of NRS §704.7315, §704.7811 and §704.7815; and NAC §704.8831 to 704.8893; and the generating facility is or will be qualified as a renewable energy system in accordance with NRS §704.7801 to 7828; and the associated regulations promulgated by the PUCN;
6. Bidder has read the requirements, obligations and disclaimers of this RFP and understands Bidder's obligations and NV Energy's rights.
7 Bidder and its legal counsel have reviewed the pro forma agreement(s), and Bidder's provided mark-up(s) of the applicable pro forma agreement(s) reflect all of the now known issues that Bidder may have, or revisions that Bidder intends to request, with respect to the applicable pro forma agreement(s);
8. Bid pricing is based on the terms of the pro forma prior to the mark-ups; and

9. This proposal is a firm and binding offer, for a period of at least 220 days from [insert date of letter/bid submittal].”

3.1.2 Bidder Information

In this Section Bidder should provide the following information:

- Organization Structure: Profile of Bidder’s organization and its ownership structure (including direct ownership and ultimate parent company, which can be in the form of a diagram);
- Equivalent Development: Description (including total nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and ESS systems, if applicable, <u>of the same technology</u> and equivalent or larger capacity proposed in the proposal which were successfully and <u>fully developed</u> (from start to finish), including land/property acquisition, permitting, construction, and placement into commercial operation <u>by Bidder</u>; *not to include projects acquired after start of development*;
- Equivalent Ownership/Operation: Description (including nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and ESS systems, if applicable, <u>of the same technology</u> and equivalent or larger capacity proposed in the proposal which are currently in service and owned or operated <u>by Bidder</u> (and not otherwise set forth in response to the above request);
- Similar Development: Description (including total nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water lines, gas lines, and telecommunication systems, as applicable) and ESS systems, if applicable, <u>of any technology</u> and equivalent or larger capacity, that have been successfully and <u>fully developed</u> (from start to finish), including land/property acquisition, permitting, construction, and placement into commercial operation <u>by Bidder</u>; *not to include projects acquired after start of development*;
- Shared Ownership or Operation: Description (including nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and

distribution lines, water/gas lines, and telecommunication systems, as applicable) and ESS systems, if applicable, of any technology and equivalent or larger capacity, that are owned or operated by Bidder and currently in service (and not otherwise set forth in response to the above request);

- Other Projects: Description (including nameplate, gross and net capacities) of generating facilities (including associated substation, transmission and distribution lines, water/gas lines, and telecommunication systems, as applicable) and ESS systems, if applicable, of any other similar projects not otherwise set forth in response to the above requests;
- Nevada Development Experience: Bidder's pertinent experience developing (i.e. siting, routing, acquiring land rights, permitting, transmission, telecommunications, and other associated project components) similar or comparable types of projects, within the state of Nevada;
- Federal and Tribal Lands Experience: Bidder's pertinent experience in developing (i.e. siting, routing, acquiring land rights, permitting, transmission, telecommunications and other associated project components) similar or comparable types of projects, on federal or tribal lands (i.e. Bureau of Land Management or Bureau of Indian Affairs, respectively) within Nevada and/or other states within the United States;
- Licensing: Bidder's Nevada contractor's license information; and
- Litigation: Any current litigation that Bidder, or any of its subsidiaries (including any off-balance sheet entities in which Bidder has an interest) is involved in regarding an energy generating facility or an energy supply contract.

Note: Bidder contact and corporate information is to be provided in Attachment G under the "Corporate Information" tab.

As evidence of financial capability to carry out its obligations explicitly articulated or implied in the proposal, the following information must also be included in this Section[14] of the proposal for Bidder's company, any parent company and any partners[15] involved with the generating facility or ESS system, and all appurtenant facilities, proposed in the proposal:

[14] See related Section 3.2.6.8, Financing Plan, under Project Execution Plan
[15] See footnote under Section 3.1.1.

- Current bond ratings, if any;
- Current rating agency ratings or reviews, if any;
- Audited financial statements and footnotes, including cash flow statements, from the last three (3) years. If Bidder does not have audited financials, Bidder must provide equivalent financials or the audited financials of the nearest level parent company;
- If financing has not been secured for the proposed project, provide information demonstrating that project financing can be secured, including references to lenders from other project financings who have a potential interest in the proposed project;
- If a guarantee of support is to be provided by an affiliate of the Bidder that affiliate must provide the above financial information and a guarantee that is enforceable in the United States;
- Provide information on the number of projects that Bidder has received financing on within the last three years for: 1) similar technology; and 2) similar or larger capacity;
- Describe any bankruptcy proceedings that Bidder, its direct affiliates or the proposed project is involved in, including current status and expected outcome; and
- Other financial information that would be pertinent to NV Energy's evaluation of Bidder's financial capability.

NV Energy's Credit Department will analyze the required financial criteria to determine, in its sole discretion, Bidder's financial capability to successfully implement its proposal, and may require the provision of credit support in connection with the definitive agreements.

3.2 Part Two of Proposal

3.2.1 Proposal Executive Summary

The Executive Summary should highlight the content of the proposal and features of the offer broken down by resource and site. Each resource and site description must include the commercial operation date, the amount of energy being offered, the type of energy being offered (e.g., wind, solar, geothermal, etc.), a general description of the pricing proposal, the status of interconnection, a summary description of the transmission and telecommunication interconnection with location and route for the project to connect to the NV Energy transmission system, a summary description of project water supply agreement(s) and plans for water delivery/use, a summary description of land and environmental permitting including any major land constraints and/or natural resource concerns, description of current land rights, proposed land rights to be acquired and any other pertinent land right information whether federal, state, local or private and whether the overall project facilities (e.g. generation, transmission/distribution, access roads, water/gas pipelines, telecommunication systems, etc.) are currently operational, in construction, or in development. In addition, this Section should identify any material government incentives that are being sought in connection with the proposal.

3.2.2 Technical Information

Bidders must provide technical information regarding the proposal as described below. Attachment G, provided as a separate Microsoft Excel file, must be completed in its entirety and in accordance with the corresponding instructions in order for proposal to be considered in conformance. A separate Attachment G must be submitted for each bid/pricing option. Attachment G is *used for modeling and scoring*. Do not modify the file other than to provide responses in the yellow input cells. Complete the file in full and avoid inserting comments where a value is expected, particularly numeric values. Please note that alternative offers within the written proposal, without a corresponding Attachment G, will not be considered for initial shortlisting. Any discrepancies between Attachment G and proposal documents, Attachment G will rule. If the project is bid using photovoltaic ("PV") technology, the plant capacity and pricing should reflect the facility's AC MW rating.

Responses under the Non-Price Input worksheet of Attachment G are to be concise with details provided in Part Two of the proposal. Do not simply refer to the proposal document, provide a summary response to each question. Column E of the worksheet should include proposal page/section references where the detailed information is located, as applicable. It is to provide references to the detailed information/clarifications provided under Part Two of the proposal, and is not acceptable, on its own, as a response to a question. Responses under the Non-Price Input worksheet will be scored.

Use caution if copying Attachment G for multiple bids (not recommended), that Product, Type, Bid #, project name, capacity, MW, price, etc. are correct for each individual bid under the

Price Input, 8760 Prod. Profile, Price Input-ESS, Financial Inputs, and Economic Benefits worksheets. Ensure that there are no data links to other files before uploading to BHE JAGGAER.

Attachment G, as provided within this protocol document, contains an outline of the Microsoft Excel file that is to be completed for each bid and pricing option.

In addition, Bidder must provide the following information describing the generating facility and ESS system, if applicable, as well as all appurtenant facilities (as further described in Sections 3.2.2.1 through 3.2.2.5):

- Facility and Equipment Description
- Site and Route Characteristics
- Land Permitting/Acquisition and Demonstrated Site Control
- Environmental Permitting and Compliance Authorization
- Construction and Operating Permits
- Benefits of the proposed project and ESS Systems, if applicable, to Nevada

3.2.2.1 Facility and Equipment Description

Bidder must include a description of the generating facility and ESS systems, if applicable, as well as all appurtenant facilities forming the basis of the proposal to NV Energy. All facilities should be included in the description (e.g. gen-tie line(s), roads, affected NV Energy substation(s), water lines and source, gas lines, etc.), including identifying and describing any and all facilities and/or equipment shared with a third party or under a separate agreement. This Section, along with Attachment G, should also include information related to the type of plant, configuration, general layout diagrams, preliminary site plan showing site boundaries and plant layout, single-line diagram including metering scheme (see Attachment O for examples), resource type (e.g. wind, solar, geothermal, etc.), nameplate capacity rating (MW AC), net plant capacity (MW AC), annual net output (MWh), net output for each hour of the year (MWh), projected capacity factor, proposed in-service date, and the current or contemplated major equipment providers. See Section 3.2.5 regarding major equipment providers and the approved vendors list (Attachment K). In addition, provide information, including technical specifications, for the major equipment that will be used in this project. To demonstrate commercial use at a similarly sized, and environmentally comparable site, explain how many similar projects the equipment has been used in, or identify if it is a first-of-its-kind scale. Demonstrate or explain quality of materials that will be used in relation to competitor materials, if applicable. If available, provide a third party, independent engineer's report that verifies the performance of the proposed equipment.

If the proposal is based on an existing generating facility, Bidder must provide historical data (a) for the last three (3) years, or (b) if the age of the generating facility is less than three (3) years, from when the generating facility was built. Existing generating facility information must also include the historical production schedule, net output rating (MW AC), capacity factor, equivalent availability, forced outage rate, scheduled outage rate, deratings, and the forecasted five (5) year scheduled maintenance cycle and production schedule. Any known flexibility as to the timing of the maintenance schedule must also be described. If the plant has any Trench bushings installed on generator step-up ("GSU") transformers, explain how many, what voltage, what vintage and where they were manufactured. Bidder must also provide a general (non-confidential) description of any existing or proposed energy and capacity arrangements involving the generating facility and how they relate to this proposal.

If the proposal for sale of energy is from a new facility that is yet to be built, Bidder must describe any feasibility studies performed for the proposed facility as well as all appurtenant facilities. Bidder must also describe the level of engineering completed for the facility as well as all appurtenant facilities and the plan for equipment procurement and construction. Bidder should also identify any contractors that have been engaged to provide any of these services. Bidder should also describe any innovative technical features of the facility as well as all appurtenant facilities, incorporating new energy technologies. Trench bushings are not permitted on GSU transformers. If innovative technical features are included, Bidder must describe any previous experience with implementation of such technical features and the level of risk involved in this application. A production profile for the generating facility must be provided showing the energy deliveries in average energy production by month and time of day. The data and evaluations provided must support the proposed level of generation and the projected capacity factor.

For ESS system bids, Bidder must provide a description of the plant communications and control plan. The plan shall include a description and diagrams (as applicable) that demonstrate how Bidder will provide:

- ESS systems data, including state of charge, power charge/discharge status, and asset health indicators (temperature, HVAC alerts, emergency status, etc.)
- ESS system control, including limitation of charging only from renewable energy production, charge/discharge scheduling, and station service load

All information provided in this Section must be consistent with the information provided in Attachment G, which includes information required for the evaluation of the proposal as further described in Section 5.0 of this RFP.

3.2.2.2 Site and Route Characteristics

As applicable, Bidder must:

(a) Provide a legal description, including, County, Section, Township & Ranges and metes and bounds legal description with exhibit, of the facility as well as all appurtenant facilities and, both a street map and the appropriate section of a USGS (or equivalent) map showing the location and boundary/route of the facility and ESS systems, if applicable, as well as all appurtenant facilities. The maps should show all land parcels, with parcels owned, leased or optioned by Bidder clearly marked.

(b) Provide an aerial photo and Google Earth® file of the project site showing project boundary(s), linear facility route(s), and a layout of the proposed facilities.

(c) Provide the County Assessor's parcel number, site address, and site coordinates for all project facilities.

(d) Provide an ALTA/ACSM survey of the project site if such survey has been conducted. This survey will be required if the proposal is selected under the final shortlisting, and in accordance with the applicable pro forma agreement.

3.2.2.3 Land Permitting/Acquisition, Demonstrated Site Control, Water Rights

As applicable, Bidder must:

(a) Provide a list of all land parcels for the project, including current ownership.

(b) Provide a description of the legally binding lease or ownership arrangement[16] for each parcel, along with all copies, including amendments, of fully executed leases, deeds, options, purchase agreements, preliminary title reports, easements, other land rights and other documentation for private, local municipalities and state owned lands, as well as any other non-federal owned lands (e.g. Union Pacific Railroad), that are in place or contemplated for the site and all linear appurtenances (e.g., gen-tie lines, microwave facilities, access roads, substation expansions, etc.), the number of acres at the site and of all linear appurtenances, site access roads and, as applicable, water supply agreement or the plan for securing sufficient water, the waste disposal plan, fuel supply (as applicable), associated water/fuel transmission plans, or other infrastructure additions required outside of the site boundaries for the proposed project to be implemented.

(c) Specify the quantity of water required for construction and operation of the facility for the full life of the project. Provide status of necessary documents or permits required for securing sufficient water rights or other water supply, including date delivery will commence, name of water purveyor, acre-feet annually, pump rate, limitations, location of source and proximity to project, any supplemental sources, and permitting or licensing status. As applicable, explain if water right application is in permitted or certificated status, including the priority date for each water right. Provide copies of any permits, and agreements or letters of intent with a third-party to secure sufficient water supply. Specify any water rights that are in dispute or facing potential reduction.

(d) Provide all documentation of exclusive or non-exclusive site control[17] or a description of the current status of efforts to secure such site control for all Federal Agency managed land regardless of how the land is actually held (e.g. in Trust for the Bureau of Indian Affairs, withdrawn for branch of military, Bureau of Land Management). For all federal lands, provide SF299 application packages, or agency specific application, including but not limited to, all exhibits, attachments and the Plan of Development. Provide all federal right of way offers/grants and/or option agreements, Limited or Full Notices to Proceed, or agency specific land

[16] A non-binding letter of intent to reach an agreement or an agreement that is not fully executed is unacceptable. A legally binding option agreement is acceptable.

[17] A Tribal letter of intent to reach an agreement not addressed to Bidder or not accompanied by an executed Term Sheet or an agreement that is not fully executed is unacceptable. A legally binding option agreement is acceptable, provided that it includes all the terms of the lease agreement.

right, etc. if already issued by the respective agencies. Provide a detailed explanation that verifies all land acquisition efforts such as, but not limited to, fees paid, option agreements, executed Tribal consent, executed Tribal Term Sheet, Bureau of Indian Affairs (BIA) consent, Military Branch approval, expected dates for approvals, executed site option(s) with ongoing option payments, unilateral right to strike on site option(s) at agreed upon price(s) over the term of the option agreement(s), any future site procurement costs, etc.).

(e) If 100% site control has already been attained, provide a detailed explanation that identifies all environmental mitigation requirements that will be required to be implemented along with estimated costs and scheduling.

(f) List and provide a description of all Land Use Permits, including but not limited to Special Use Permit from local governmental agency, and provide copies if available.

(g) Provide a detailed list of all applicable state, local and federal land permits and authorizations anticipated for securing land rights for the facility as well as all appurtenant facilities that authorize the construction and operation of all facilities. Provide a detailed critical path schedule containing clear and concise task descriptions and anticipated timelines for securing those permits and approvals.

(h) Identify important milestones and decision points in the schedule along with an explanation of how land permitting activities will be coordinated within the overall construction and development schedule.

(i) Identify and fully describe the arrangements of any and all facilities and/or equipment shared with a third party or under a separate agreement, even if the separate agreement is with NV Energy. Include any impacts to NV Energy due to such shared facilities/equipment and plans to alleviate potential negative impacts.

3.2.2.4 Environmental Permitting, Compliance and Authorization

Bidder must also:

(a) List and provide a description of all local, state and federal environmental requirements, authorizations, permits, etc., anticipated to be required in order to support the acquisition of land rights, as well as to construct and operate the generating facility and ESS systems, if applicable, as well as all appurtenant facilities in accordance with all applicable environmental laws and regulations. Provide a detailed critical path schedule containing clear and concise task descriptions and anticipated timelines for securing those permits and approvals along with all associated environmental compliance tasks and activities required by any regulatory agency(s).[18]

(b) Describe all coordination efforts/actions already taken, or anticipated to be taken, with local, state, and federal agencies with respect to environmental permitting and regulatory compliance with a description of current status of each effort/action.

(c) Provide any evidence that an environmental assessment, an environmental impact statement or an environmental impact report is being completed or has been completed with regard to the renewable energy system, or any evidence that a contract has been executed with an environmental contractor who will prepare such an assessment, statement or report within the 3-year period immediately preceding the date on which the renewable energy system is projected to begin commercial operation.

(d) Provide copies of all environmental permit applications with associated attachments, any environmental analysis and review documents pursuant to the National Environmental Policy Act, Endangered Species Act, National Historic Preservation Act, Clean Water Act, Clean Air Act, etc., documents of any environmental surveys conducted, land/environmental constraint studies, environmental site assessments, hazardous material, waste material reports or other information associated with the land(s) acquisition and land use to support the proposed generating facility and ESS systems, if applicable, as well as all appurtenant facilities.

(e) Describe any existing environmental issues of concern associated with the generating facility and ESS systems, if applicable, as well as all appurtenant facilities, such as site contamination, presence of waste disposal area, state or federally protected plant and wildlife species or habitats and species of concern present or potentially present, National Conservation Lands, wetlands, and any other known or potential environmental issues, with an explanation of how Bidder will address any such issues so as to maintain the ability to meet the anticipated commercial operation date and other long-term obligations of the agreement.

[18] See related <u>Section 3.2.6.9</u>, Environmental Plan, under Project Execution Plan

(f) Include any current Phase I or Phase II environmental site assessment reports/action conducted by or available to Bidder.

(g) Describe whether or not the project would potentially require any air permits, and if so, provide any air quality modeling results, and estimated air emission rates identified or expected to be included in an air permit process.

(h) Describe the land uses adjacent to and in proximity of the generating facility and ESS systems, if applicable, as well as all appurtenant facilities. Describe current or planned efforts to build local community support.

(i) Provide copies of environmental permits already successfully secured, including their associated applications and supporting documents, studies and reports.

(j) Identify important milestones, all key environmental tasks and activities, and decision points in the schedule along with an explanation of how environmental permitting and regulatory compliance activities will be coordinated within the overall development schedule, including construction and operation and maintenance.

3.2.2.5 Construction and Operating Permits

Bidder shall provide a list of permits required for construction, operation and occupancy of the proposed project. Bidder is responsible for obtaining all permits. Additionally, Bidder shall:

(a) Describe all local, state and federal construction requirements, authorizations, permits, (e.g. grading, stormwater, fencing, building, dust control, occupancy, etc.) anticipated in order to construct and operate the entire project in accordance with all applicable laws and regulations.

(b) Describe all coordination efforts and actions already taken, or anticipated to be taken, with local, state, and federal agencies with respect to acquiring the necessary construction and operations related permits.

(c) Describe any existing on-site construction issues of concern that may impact the ability to meet the anticipated commercial operation date. Include risk mitigation efforts planned to maintain the commercial operation date.

(d) Provide copies of any construction and operating permits already secured, including their associated applications and supporting documents, studies and reports.

(e) Provide a detailed critical path schedule containing clear and concise task descriptions and anticipated timelines for securing all applicable state, local and federal construction and operating permits.

(f) For wind projects, include airspace and radar clearance, Federal Aviation Administration ("FAA") and Federal Communication Commission ("FCC") permit status if applicable.

3.2.2.6 Benefits of the Proposed Project to Nevada

Bidder must describe any other special expected environmental, social, or economic benefits of the proposed project, including value attributes (e.g. availability, dispatchability, scheduling, fuel diversity, hedging, ancillary services, etc.). Bidder must describe how the project will provide the creation of new jobs in the state of Nevada. In addition, Bidder must also complete the applicable economic benefits spreadsheet in Attachment G. Instructions are provided in the "Economic Benefit Input" tab. All inputs should only include *direct* costs and job data in Nevada.

3.2.3 Interconnection

Bidders are expected to have an LGIA or a completed Facilities Study submitted with their proposal. Bidder must provide the status of such interconnection documents. Bidder shall demonstrate that the resource can effectively be integrated through the transmission path or as a network resource to NV Energy, and explain any known transmission constraints. Bidder shall specify whether any ancillary services have been confirmed. Bidder must provide copies of the completed Facilities Study or the LGIA in final or draft form. Bidder will also identify the anticipated interconnection point and in-service date for the proposed facility. The in-service date must be as specified by the transmission provider and well in advance of the required commercial operation date in order to allow for testing. For proposals where an LGIA has been executed, Bidder will provide documentation supporting any completed milestones.

All proposals that will require a new electrical interconnection or an upgrade to an existing electrical interconnection must include all costs to interconnect to the transmission provider's system, as specified in the LGIA or Facilities Study and for the required transmission capacity for the project. In addition, bidder shall provide a diagram of the interconnection facilities provided in the LGIA or the most recent Facilities Study on the project, as completed by the transmission provider. The interconnection costs for network upgrades will be included in the LCOE calculation. Bidders will describe interconnection costs in their proposals by disclosing that portion of costs associated with network upgrades and that portion that is facility-specific. Bidders are reminded that the cost responsibility for all transmission facilities will be pursuant to the provisions of the OATT. The Interconnection Customer is responsible for all of the Transmission Provider's Interconnection Facilities ("TPIF") costs. The Transmission Provider is responsible for the costs associated with Network Upgrades ("NU") pursuant to the OATT; however, such costs will be securitized by the Interconnection Customer as provided under the provisions of the OATT. Interconnection Customer's Interconnection Facilities ("ICIF") are the sole responsibility of the Interconnection Customer.

If the existing renewable energy project LGIA does not already include the proposed ESS system, the LGIA will need to be amended and restated to incorporate the ESS systems. The Interconnection Customer specified in the LGIA will need to submit an evaluation for a material modification along with updated plant specifications and generator model data to the Transmission Provider in accordance with the applicable Open Access Transmission Tariff requirements.

Bidder must provide a copy of its executed Voluntary Consent in the form provided in Attachment B of this RFP. The original must be submitted directly to the transmission provider, separate from the RFP proposal, on or before submission of the proposal.

3.2.4 Resource Supply

Bidder must provide sufficient information with respect to resource supply to provide assurance to NV Energy that the facility will be able to meet its projected production estimates for the full term of the PPA or, in the case of an APA or BTA, the expected useful life of the generating facility and provide the means and specifications to meet the dispatchability requirements. Provide any third-party resource assessment reports supporting the expected capacity factor. In addition, identify proposed manufacturers and model numbers for major equipment. In particular, the following information is requested for the different technologies:

Geothermal

- Provide a summary of all collected geothermal data for the proposed generating facility site.
- Characterize the geothermal resource quality, quantity and projected production levels.
- Provide a graph or table that illustrates the annual and monthly projection of geothermal resources.
- Describe any other existing geothermal facilities in the resource area and characterize their production and their anticipated impact, if any, on the generating facility.
- Provide a minimum of one production well and one injection well flow results to support the viability and capacity of geothermal resource. For results in excess of three (3) years, summarize the results for all years and provide the detail for the past three (3) years of production well flow tests.

Solar

- Describe the sources of insolation data, either onsite, satellite, or a nearby station. If using a nearby station, state the exact distance from that station.
- Provide source and number of years of solar data used to support the capacity factor.
- Provide a third-party PVSyst report or similar assessment report based on credible solar radiation meteorological data.
- Specific resource and technology, including a requirement that all bids include panels manufactured by a Tier 1 solar panel manufacturer, and inverters from a vendor on the Approved Vendors List (Attachment K).

Wind

- Provide a summary of all collected wind data for the generating facility site.
- Indicate where the data was collected and its proximity to the generating facility site.
- Provide one (1) year of applicable wind resource data utilizing at least two anemometers for any wind project to support capacity factors and a third-party wind resource assessment report based on meteorological tower data.
- Compare the long-term wind speeds in the area to the collected resource data at the generating facility site.
- Confirmation of wind turbine availability and size.

Biomass

- Describe the biomass fuel makeup and its source.
- Provide third-party resource assessment reports of available biomass fuel for the generating facility and its proximity to the generating facility. Such resource

assessments should include a discussion of long-term fuel price risk and availability risk issues.

- Identify competing resource end-uses.
- Provide a plan for obtaining the biomass fuel, including a transportation plan.
- Identify any contracts or option agreements to acquire and transport the biomass fuel.
- Provide an agreement or option agreement with a biomass fuel source for a period of ten (10) years or greater.

Biogas

- Provide third-party resource assessment reports of available biogas fuel for the generating facility and its proximity to the generating facility. Such assessment reports should include at a minimum: history of landfill, total volume permitted, volume filled, estimated closure date, organic fraction of the municipal solid waste, moisture levels, temperatures and pH of the waste, future waste receipt, increase or decrease and average rainfall in the area.

ESS

- ESS systems degradation, round trip efficiency, controls, location, life, cycles, load duration, descriptions of all facilities and equipment shared with the associated renewable generation facility, and the other applicable information listed in Attachment G. Include a discussion of ESS chemistry and how degradation will be managed (e.g. overbuild, augmentation, etc.).

3.2.5 Assurance of Generating Equipment Supply

To demonstrate ability to deliver on time, Bidder must list and demonstrate that it has access to, or has completed sourcing of, the necessary major equipment, consistent with the Approved Vendors List provided in Attachment K of this RFP, to complete the design, engineering and construction of the facility contemplated in the proposal to meet the stated commercial operation date.[19] Provide details of all equipment including supplier detail, make and model and any form of supply, warranty and performance commitment from suppliers. If Bidder has a preferred equipment provider that is not included in Attachment K, please identify the vendor and their experience within the United States for projects of similar technology and size, detail Bidder's reasoning for the preference, and specify any direct experience Bidder has had with the vendor. If

[19] See related Section 3.2.6.4 , Quality Control Program, under Project Execution Plan

a contract is in place for any equipment, please identify the contracted party. Provide a mark-up of Attachment K if recommending new vendors. Attachment K will become part of the applicable pro forma agreement.

3.2.6 Project Execution Plan

Bidder will provide a summary-level, site-specific project execution plan. The project execution plan will be referenced and become part of the pro forma agreement. Key elements of the execution plan are:

3.2.6.1 Project Schedule

Bidder must provide a detailed project schedule that includes the anticipated period to permit and complete the project in order to achieve commercial operation, referenced in months, following receipt of all regulatory approvals, including PUCN approvals (i.e., IRP and UEPA). This time period must allow for environmental and land right acquisition and permitting, environmental studies, mitigation and treatment, transmission construction, financing, site development, construction permitting, construction, testing, and any other development and construction requirements. Bidder must provide a milestone schedule for the proposed project, inclusive of the major development milestones listed below (as applicable):

- Major Equipment Ordered;
- Project Interconnection to Transmission System;
- All Permits Obtained for land, environmental and construction;
- All land rights acquired;
- Construction Financing Obtained;
- Construction Start;
- Environmental Compliance/Mitigation;
- Operation Date (first energy to grid); and
- Commercial Operation Date.

These milestones should be noted in number of months following receipt of all regulatory approvals, including PUCN approvals (i.e., IRP and UEPA).

Bidder also shall describe any measures to be taken to ensure the proposed schedule will be met.

Note that Bidder will be required to post security following execution of a definitive agreement and prior to the submittal of the definitive agreement for PUCN approval (i.e., IRP).

3.2.6.2 Safety Program

The development and implementation of a good safety program at the site is of paramount importance to NV Energy. Safety is a core principle of NV Energy and is a priority in every aspect of our business. The same level of safety diligence is expected from contracted parties. Bidder's safety program must comply with or exceed NV Energy's safety requirements, as outlined in Attachment J to this RFP. Any exceptions or comments must be noted in Bidder's proposal. As part of its proposal, Bidder must submit its OSHA 300 and OSHA 300A logs for the previous three (3) calendar years. In addition, a written safety improvement plan is required for any fatalities that have occurred in the past three (3) years. Plan should include a description of what occurred and how the incident will be mitigated in the future.

3.2.6.3 Project Controls and Reporting Plan

Bidder will submit their Project Controls and Reporting Plan, including a summary (Level II) construction schedule displaying major activities, durations and proposed sequencing which demonstrates Bidder's proposal to achieve substantial completion prior to the operation date as listed in its proposed Project Schedule as provided under Section 3.2.6.1.

3.2.6.4 Quality Control Program

Bidder will provide an outline of its Quality Control Program in line with its proposal, including, in accordance with the Approved Vendors List (Attachment K), the plan for procurement of equipment.

3.2.6.5 Subcontractor Strategy

Bidder will provide detailed information as to a proposed execution plan for its proposed project, including the name and experience of anticipated major subcontractors. It is the expectation that Bidder (or an affiliate thereof) would remain primarily responsible for the obligations of Bidder regardless of whether the obligations are performed by Bidder or a subcontractor.

3.2.6.6 Work Site Agreement Plan

A pro forma work site agreement ("WSA") is attached as Attachment N to this RFP. This form may be modified based on the applicable unions and their associated master agreements. The form of WSA, as modified, or an executed WSA, is to be inserted in the applicable exhibit of the agreement being proposed. Bidders who take exception to the terms of the WSA agreement must provide a mark-up of the agreement, including Bidder's proposed language. In addition, a statement of acceptance of the agreement as written, or explanation of each exception must be provided within the proposal. Please note that the WSA agreement is between Bidder and the union(s), not Bidder's contractor.

Bidders that advance to the initial shortlist shall commence discussions with the unions immediately following notice of shortlisting. Bidders that advance to the final shortlist are required to provide weekly updates on the status of their WSA negotiations with the union(s). Bidders must provide an executed WSA, with Nevada union(s), prior to or at the time of execution of the RFP agreement. Bidder must be a signatory on the WSA. If Bidder elects to contract with an EPC, the EPC will be required to comply with the terms of the WSA.

3.2.6.7 Staffing Plan

Bidder shall provide a good faith estimate of the following (*values for Nevada only*):

- Number of *direct* jobs during construction (full-time equivalent) average and at peak construction and average salary of construction staff.
- Number of *direct* jobs during operation and maintenance (full-time equivalent).
- Average annual Salary of such jobs during operation and maintenance.
- Total *direct* payroll expenditure over the term of the agreement (e.g. 25 years).

The above estimates should match the values provided in Attachment G under the Economic Benefits Input worksheet, as applicable (i.e. Solar PV, Wind, Geothermal, etc.). If a contract is executed, these values will be stated in the regulatory filing for PUCN approval.

3.2.6.8 Financing Plan

Bidder should provide a detailed description of the financing plan for the proposed project (government, private, self-funded, balance sheet, power purchase agreement, etc.) and general description of status. If financing has been secured for the proposed project, provide commitment letter from financier.

3.2.6.9 Environmental Plan

Provide a detailed description of how Bidder will develop, permit, construct, operate and maintain the generating facility and ESS systems, if applicable, as well as all appurtenant facilities that includes the known and anticipated environmental permits, environmental activities associated with any land and permitting efforts, and known and anticipated mitigation measures required for pre-construction activities, construction activities and post-construction activities.

3.2.6.10 Facility Operation and Maintenance Plan

Bidder must provide a description of the expected operation and maintenance ("O&M") plan for the facility as well as all appurtenant facilities. This information should include the following:

- Whether Bidder or affiliate will operate and manage the facility as well as all appurtenant facilities or will contract for O&M services. If Bidder will contract for O&M services, explain the current status of selecting an O&M contractor.
- Completed integrated solar and storage O&M term sheets and pricing for facility as well as all appurtenant facilities.
- A brief description of the basic philosophy for performing O&M including a discussion of contracting for outside services.
- Planned maintenance outage schedules.
- Plan for replacement of major equipment during the term of the contract.
- Plan for any land rights issues or environmental concerns including any post-construction environmental compliance monitoring, studies and reports as well as ongoing environmental compliance requirements during operations and maintenance.

3.2.7 Contract Terms and Conditions

Bidder's proposals will be scored based on the number and extent of risk shifting which results from Bidder proposed revisions to the applicable pro forma agreement(s) and related exhibits included as attachments to this RFP. Bidders who take exception to the terms of the pro forma agreements must provide a comprehensive mark-up of the applicable agreements, including Bidder's proposed language modifications (*not just comments*). Mark-ups should be provided in Microsoft Word format. In addition, a statement of acceptance of the agreement as written, or explanation of each exception must be provided within the proposal. **Proposals submitted without a comprehensive mark-up or in the alternative acceptance of the pro forma, may be disqualified.** Allowances will be made for mark-ups to ESS systems provisions. Attachment K and Attachment N of this RFP bid protocol document are to be inserted in the applicable exhibits of the agreement. **Bidder is required to have an officer of its company certify that the applicable pro forma agreements have been thoroughly vetted, including review by Bidder's legal counsel, and that the pro forma agreements either are accepted or the mark-ups provided by Bidder are substantially complete. See item 7 of cover letter under Section 3.1.1 of this RFP bid protocol document.**

3.2.8 Other Information

Bidder should provide any additional information that will assist NV Energy in its evaluation of the proposal. The proposal should indicate whether or not other information has been provided, and specify or list (if appendage) the other information.

3.3 Bid Numbering and File Naming Convention

Bid numbers will be self-assigned by Bidder in accordance with the directives below. There is no limit to the number of proposals and alternative pricing options that may be submitted, subject to the Bid Fee requirements stated in Section 2.6.

Bid numbers must be expressed as a whole number followed by one decimal place, beginning with the number 1.0. Each subsequent proposal will have a separate sequential bid number (i.e. 2.0, 3.0, etc.). The decimal place will be used to indicate alternative pricing options,[20] necessary for Attachment G. The initial proposal/pricing option will be identified as 1.0 and the first alternative pricing option, for the same proposal, would be 1.1.[21] Bidder's next proposal, if

[20] See Section 2.6 regarding qualified pricing options, and requirement for separate Attachment G for each option.
[21] For PPA bids, add the term length at the end of the file name (e.g. '_15') if an alternative term length is proposed. For bids with co-located ESS, add the ESS relative size at the end of the file name (i.e. 100-Pct, 50-Pct).

any, would be 2.0 with 2.1 as the first alternative pricing option, and any additional pricing options would be 2.2 and 2.3, as applicable.

File names should be kept short by using abbreviations wherever possible. All required documents must use the following naming convention:

- [Abbreviated Bidder name]_[Bid number]_[Abbreviated_File_Descriptor]

For appendices, include appendix number and RFP section reference in the abbreviated file descriptor (i.e. XYZ_1.0_Part_2_Appx_1_3.2.2.1_SLD). See Attachment P (Proposal Zip File Structure) for further file naming examples.

All files related to a single bid must be compressed together and uploaded into BHE JAGGAER as a single .zip file named [Bidder name abbreviated]_[Bid number].zip (example: "NVE_1.0.zip"). Folders and subfolders for specific document types should be included in the .zip file following the directory structure/organization and folder naming convention provided in Attachment P (Proposal Zip File Structure). Documents provided in this RFP that have been modified by Bidder and any additional files provided by Bidder must apply the naming convention specified above before being compressed into the .zip file. *Please note, the .zip file associated with a bid may be quite large and take some time to upload, so please plan adequate time to upload each bid's .zip file into BHE JAGGAER hours in advance of the bid submission deadline.*

4.0 STANDARDS OF CONDUCT

Each Bidder responding to this RFP must conduct its communications, operations and other actions in compliance with FERC's Standards of Conduct for Transmission Providers. Any necessary interconnection to, or transmission service on, NV Energy's transmission system contemplated in a Bidder's proposal will not be considered an arrangement with NV Energy's merchant function, which is sponsoring this RFP. Such arrangements for interconnection and transmission service will be with NV Energy's functionally separate transmission function, and therefore, absolutely no communication by a Bidder to NV Energy's transmission function can be made through the submission of a proposal in this RFP. **Any Bidder seeking to communicate with NV Energy's transmission function personnel through this RFP process will have its proposal(s) summarily rejected if the attempt is not immediately withdrawn when discovered.** Bidders are required to execute the Voluntary Consent Form in Attachment B to this

RFP that enables NV Energy's merchant function to discuss Bidder's interconnection and transmission service application(s) with the transmission interconnection or transmission service provider, including, if applicable, NV Energy's transmission function.

Bidder will cooperate with and provide information to any person or entity retained by NV Energy for purposes of evaluating Bidder's proposal.

Bidder shall not attempt to influence NV Energy in the evaluation of the proposals outside the solicitation process.

Bidder shall not participate in collusive bidding or any other anticompetitive behavior or conduct.

5.0 EVALUATION PROCEDURES AND CRITERIA

Each proposal will be initially evaluated by NV Energy to determine the proposal's conformance to the directives of this RFP bid protocol document and Bidder credit risk. **Proposals may be eliminated for non-conformance or due to credit risk.**

For each proposal in this RFP that passes the initial evaluation, NV Energy may conduct a two-stage process as part of its proposal evaluation and selection process, for each resource type, leading up to selection of the preferred proposal(s) for contract execution. In the first stage, NV Energy will conduct price, economic benefit (including job impacts) and non-price analyses, as well as a price screening methodology designed to identify the lowest cost proposals for each product. NV Energy will select a shortlist based on those proposals for each product which best meet NV Energy's needs, have the highest overall score based on an evaluation of price, economic benefit and non-price factors. In the second stage, bidders of the shortlisted proposals will have the opportunity to refresh their prices; provided, however, that Bidders will not be permitted to increase the prices initially submitted with their proposal. The final proposals may then be modeled and evaluated based on the impact of the proposals on NV Energy's overall system costs. A more detailed description of each stage of the process is provided below.

NV Energy will conduct the two-stage evaluation and selection process independently for each of the proposals, by resource type. NV Energy will select and propose to the PUCN, for review and final approval, the proposal(s) that provide the best value to NV Energy's customers, considering all the factors described in this Section 5.

5.1 First Stage: Development of Initial Shortlists

The price, economic benefit and non-price forms in Attachment G will be used as a model to determine individual initial shortlists of proposals, separated by type of resource (i.e., wind, solar, geothermal, hydroelectric, biomass, biogas and ESS systems). These resource-specific shortlists will be deemed the initial shortlists for further evaluation.[22]

In considering a proposal, NV Energy will, in addition to considering the cost to customers, evaluate the following:

(a) The greatest economic benefit to the State of Nevada;

(b) The greatest opportunity for the creation of new jobs in the State of Nevada; and

(c) The best value to customers of the electric utility.

Price factors will be analyzed to determine the LCOE or Levelized Cost of Storage ("LCOS"), as applicable, per MWh value of each proposal, and then ranked using the comparison metric described in Section 5.1.1 below. Price factors will recognize the value of the power associated with the delivery profile submitted in the proposal.

Non-price factors considered by the Company fall into four general categories:

1) Bidder's project development and operational experience;
2) Technology and value attributes;
3) Conformity to the terms of the applicable pro forma agreements; and
4) Development milestones.

NV Energy intends to evaluate each proposal in a consistent manner by separately evaluating the non-price characteristics, economic benefit characteristics and the price characteristics of the proposal utilizing a proposal scorecard.

The proposal scorecard will include three factors, all of which may be viewed in Attachment G:

1) Price factor;
2) Non-price factor with four primary categories; and

[22] See Section 3.2.2 for additional information on Attachment G.

3) Economic benefit factor with three categories.

Each component will be evaluated separately and recombined to determine the bundled price, economic benefit and non-price score. The price factor will be weighted up to 60%, the economic benefit factor will be weighted up to 10%, and the non-price factor will be weighted up to 30%. No proposal will receive a total weighting in excess of 100%. The price, economic benefit and non-price evaluations will be added together and used to determine the initial shortlist for each resource type. The initial shortlists in this RFP will be made up of the highest scoring proposals for each resource type.

5.1.1 Price Factor Evaluation (up to 60%)

A pricing model will be used to derive the LCOE per MWh value of each proposal (Products A and B, from Table 1) based on the price factors ("Proposal LCOE"). For associated ESS systems, the pricing model will derive the LCOS per MWh value of each proposal based on the price factors ("Proposal LCOS"). The Proposal LCOE and Proposal LCOS may also be referred to as the proposal levelized cost value ("Proposal LCV").

For each of the products, NV Energy will utilize a comparison metric to evaluate and determine the Proposal LCV ranking for the resource-specific initial shortlists.

The comparison metric will be the Proposal LCV per MWh. The Proposal LCV will be determined by calculating the present value of the annual cost over the term, converting the present value to an equivalent annual annuity and then dividing that annual annuity by the levelized annual energy provided. The discount rate will be the weighted average cost of capital as approved by the PUCN in NV Energy's most recent General Rate Case, as applicable. Project LCOE and LCOS will not be compared to one another. ESS systems and renewable energy systems will be evaluated separately.

5.1.2 Non-Price Factor (up to 30%)

The primary purpose of the non-price analysis is to help gauge the factors related to the proposal which are outside of price. The non-price factor will be weighted up to 30% in the determination of which proposals in this RFP will be chosen for each resource-specific initial shortlist. The scorecard will be used to score the non-price criteria under four categories: (1)

Bidder's (or its development team's) project development experience; (2) technology and value attributes; (3) conformity to the terms of the pro forma agreement(s) and related exhibits; and (4) development milestones. The criteria for each of these four categories are set forth below.

Category 1 – Bidding Company/Development Team's Project Development Experience

- Project Development Experience
- Nevada, Federal or Tribal Lands Development Experience
- Ownership/O&M Experience
- Safety – Occupational Safety and Health Administration recordable incident rate
- Financial Capability

Category 2 – Technology and Value Attributes

- Technical Feasibility
- Resource Quality
- Equipment Supply Control
- Utilization of Resource
- Flexibility
- Environmental Benefits
- Fuel Diversity/Hedging
- Other Ancillary Services

Category 3 – Conformity to Pro forma Agreement(s) and Related Exhibits

- Magnitude of proposed revisions to pro forma agreement(s)

Category 4 – Development Milestones

- Land and Environmental Authorization Status/Feasibility
- Water Rights
- Project Financing Status
- Interconnection Progress
- Transmission Requirements (Network Upgrades)
- Reasonableness of COD as Demonstrated by Critical Path Schedule

5.1.3 Economic Benefits Factor (up to 10%)

The economic benefits to the state of Nevada will take into consideration the following matters, based on information submitted by Bidders, and NV Energy's evaluation:

- Location of jobs created
  - Within the soliciting NV Energy service territory
  - Within the non-soliciting NV Energy service territory
  - Within the state of Nevada
- Number of *direct* jobs created in Nevada
  - Jobs created during construction
  - Jobs created during operation
- Economic *direct* benefits to Nevada
  - The direct value of expenditures made in Nevada attributed to the Project
  - Other *direct* economic benefits to Nevada

Please note, if project is selected, the values provided for jobs and economic benefits will be included in the regulatory filing for approval of the agreement, which is available to the public.

5.2 Second Stage: Best and Final Pricing

Proposals selected for the shortlist in each product will have an opportunity to refresh (in the form of Attachment G) their price to take into account further development of the project or updated pricing for equipment or other costs from the time the initial proposal was submitted to the time of "best and final" offer. Bidders are encouraged to lower their pricing or look for opportunities to enhance their production profiles (based, for example, on changes to equipment) and other means to increase the value of their proposals to NV Energy.[23]

Bidders that advance to the initial shortlist are also required to submit, along with their best and final pricing:

- Completed Attachment I – NAC 704 Requirements;
- Proposed reactive capability curves and single line diagrams of the facility; and

[23] A price increase at this stage will necessitate revisiting proposal rankings which may result in the proposal being removed from the initial shortlist.

- A notice that Bidder has commenced discussions with the union(s) in accordance with Section 3.2.6.6 of this protocol.

5.2.1 The Final Shortlist

For each of the products, some or all of the proposals on the initial shortlists may then be evaluated using a production cost model to aid in determining the final shortlist based on the best and final pricing. ESS systems will be evaluated separately.

In its analysis for this RFP, the Company may run some or all of the final shortlisted proposals and portfolios through its production cost model to determine the Present Worth Revenue Requirement ("PWRR") of each alternative portfolio of resources.

NV Energy may choose to engage the final shortlist Bidders in further discussions or negotiations. Any such discussions or negotiations may be terminated by NV Energy at any time, for any reason.

5.3 Final Selection of Proposal(s)

The two stages described above constitute the formal evaluation process which will be utilized to select the proposals that will be submitted to the PUCN for approval. In addition to this two-stage analysis, in selecting the final proposals, NV Energy will consider the non-price factors qualitatively. Furthermore, NV Energy will also include in its evaluation any factor that may impact the total cost of a resource, including, but not limited to, all of the factors used in the initial shortlist cost analysis plus consideration of accounting treatment and potential effects due to rating agency treatment, if applicable.

6.0 AWARDING OF CONTRACTS

This RFP is merely an invitation to make proposals to the Company. No proposal in and of itself constitutes a binding contract. The Company may, in its sole discretion, perform any one or more of the following:

- Determine which proposals are eligible for consideration as proposals in response to this RFP.
- Issue additional subsequent solicitations for information and conduct investigations with respect to the qualifications of each Bidder.

- Supplement, amend, or otherwise modify this RFP, or cancel this RFP with or without the substitution of another RFP.
- Negotiate and request Bidders to amend any proposals.
- Select and enter into agreements with the Bidder(s) who, in the Company's sole judgment, is most responsive to this RFP and whose proposals best satisfy the interests of the Company, its customers, and state legal and regulatory requirements, and not necessarily on the basis of any single factor alone.
- Issue additional subsequent solicitations for proposals.
- Reject any or all proposals in whole or in part.
- Vary any timetable.
- Conduct any briefing session or further RFP process on any terms and conditions.
- Withdraw any invitation to submit a response.
- Select and enter into agreements with Bidder(s) for additional MW of renewable energy resources should additional demand be identified.

7.0 POST-BID NEGOTIATIONS

NV Energy may further negotiate both price and contract terms and conditions during post-bid negotiations. Post-bid negotiation will be based on NV Energy's cost and value assessment. NV Energy will continually update its economic and risk evaluations until both parties execute a definitive agreement acceptable to NV Energy. Transactions may be subject to the approval of the PUCN on terms and conditions that are satisfactory to NV Energy in its sole and absolute discretion.

ATTACHMENT A – CONFIDENTIALITY AGREEMENT

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT B – VOLUNTARY CONSENT FORM

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT C.1 – PRO FORMA RENEWABLE POWER PURCHASE AGREEMENT AND EXHIBITS

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT C.2 – PRO FORMA CONVENTIONAL POWER PURCHASE AGREEMENT AND EXHIBITS

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT C.3 – WSPP MASTER TOLLING CONFIRM

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT C.4 – WSPP LONG TERM CONFIRM

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT D.1 – PRO FORMA RENEWABLE ASSET PURCHASE AGREEMENT AND EXHIBITS

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT D.2 – PRO FORMA CONVENTIONAL ASSET PURCHASE AGREEMENT AND EXHIBITS

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT E.1 – PRO FORMA BUILD TRANSFER AGREEMENT AND EXHIBITS

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT E.2 – PRO FORMA CONSTRUCTION COMPLETION MANAGEMENT AGREEMENT TERM SHEET

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT F.1 – PRO FORMA O&M TERM SHEET

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT F.2 – PRO FORMA SOLAR O&M TERM SHEET

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT F.3 – PRO FORMA SOLAR & STORAGE O&M TERM SHEET

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT F.4 – PRO FORMA STORAGE O&M TERM SHEET

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT F.5 – PRO FORMA WIND SERVICE AND MAINTENANCE AGREEMENT TERM SHEET

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT G – PROPOSAL INPUT FORMS

(Price, Non-Price and Economic Benefit Input Forms)

This attachment is available in electronic format in BHE JAGGAER. The contents of the workbook are as follows:

1) TOC (*Table of Contents*)
2) Scoring Structure
3) Evaluation Components
4) Corporate Information *
5) Price Input *
6) 8760 Prod. Profile *
7) Price Input –ESS *
8) Financial Inputs *
9) Non-Price Scoring
10) Non-Price Input *
11) Economic Benefit Scoring
12) Econ Benefit Input *
    a. SolarPV *
    b. Energy Storage *
    c. Wind *
    d. Geothermal *
    e. Biopower *
    f. Hydro *
    g. Fossil *
13) Technology Specific Data
    a. Solar Data *
    b. Energy Storage Data *
    c. Wind Data *
    d. Geo Data *
    e. Biopower Data *
    f. Hydro Data *
    g. Fossil Data *

*** Worksheet required to be completed by Bidder, as applicable to proposed technology**

ATTACHMENT H – BIDDER PROPOSAL COMPLIANCE CHECKLIST

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT I – NEVADA ADMINISTRATIVE CODE 704 REQUIREMENTS

This attachment is available in electronic format in BHE JAGGAER.

Bidders that advance to the initial shortlist are required to submit Attachment I along with their best and final pricing.

ATTACHMENT J – BIDDER'S SAFETY PLAN

(Outline of NV Energy's Safety Plan, as Example)

This attachment is available in electronic format in BHE JAGGAER.

ATTACHMENT K – APPROVED VENDORS LIST[24]

This attachment is available in electronic format in BHE JAGGAER.

<u>The Approved Vendors List shall be included as an exhibit to any agreement executed by the parties.</u>

[24] This list is not intended to be an endorsement of the vendors listed or to be all-inclusive. It simply acknowledges the vendors that NV Energy has approved of as of the date of this document, and is subject to change.

ATTACHMENT L – RESERVED

ATTACHMENT M – RESERVED

ATTACHMENT N – FORM OF WORK SITE AGREEMENT

This attachment is available in electronic format in BHE JAGGAER.

The form of WSA, as modified, or an executed WSA, is to be inserted in the applicable exhibit of the agreement being proposed, unless the proposal is for an existing generating facility (i.e. Product 1, Product 2, or Product 3), as set forth in Table 1.

ATTACHMENT O – METERING SCHEME EXAMPLES

Energy Storage: NV Energy requires that all energy storage facilities have a dedicated bi-directional meter. For generation and storage facilities, the storage meter will be installed on the low-side common AC bus-side of the inverter(s). This meter will be used to track the energy used to charge the energy storage system as well as energy discharged from the energy storage system. Facilities utilizing energy storage system on a dedicated lead line will install a single high-side meter.

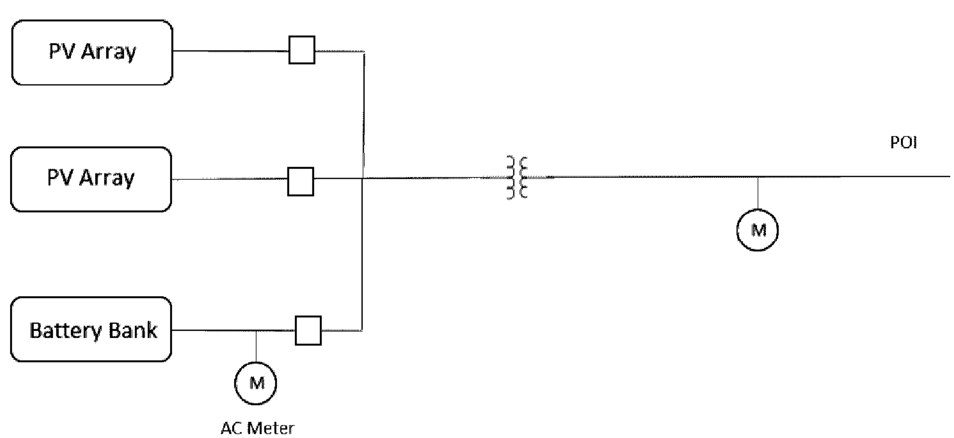
In addition to the required bi-directional energy storage system meter, NV Energy requires all generation facilities to have a high-side aggregate meter. This meter must be located on the high-side of the generator step-up transformer and will measure the total output of the interconnected facility.

With the addition of multiple complex generation facilities, NV Energy proposes the use of the following metering schemes for generation/storage facilities.

Scheme 1:

The configuration in Figure 1 shows a generation facility with two PV feeders and a battery storage feeder. The battery storage feeder is required to have an AC, low-side meter compensated to the point of interconnection (POI). The two PV feeders are under the same PPA and selling to the same company. A high-side meter accounts for the output of all three facilities. Since the PV feeders are under the same PPA, no additional meters are required.

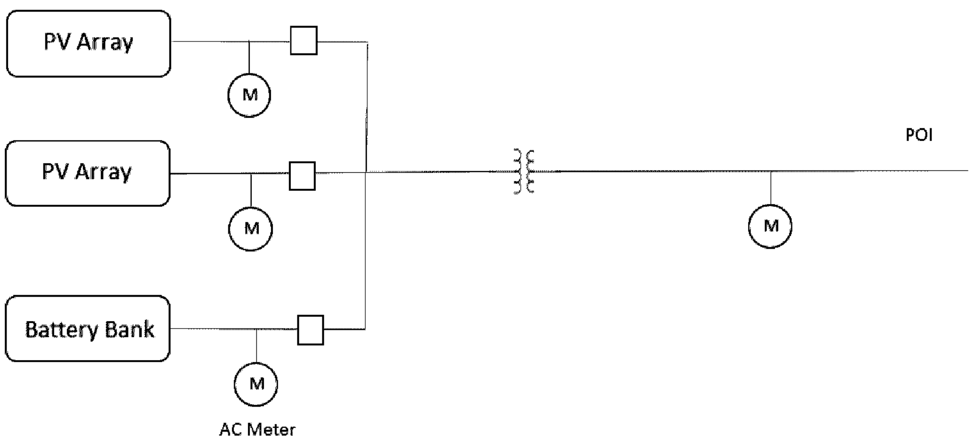
Figure 1: Solar and Storage with Single GSU and Common PPA



Scheme 2:

The configuration in Figure 2 is similar to Figure 1, except the solar feeders have different PPA's. In addition to the AC coupled battery storage meter, each solar feeder is required to have an individual meter. This allows each PPA to be metered while adhering to CAISO EIM requirements. NV Energy is currently working on an advanced metering system to dynamically allocate losses between all generation feeders. This will allow the low-side meters to accurately allocate line and transformer losses based on PV/storage production.

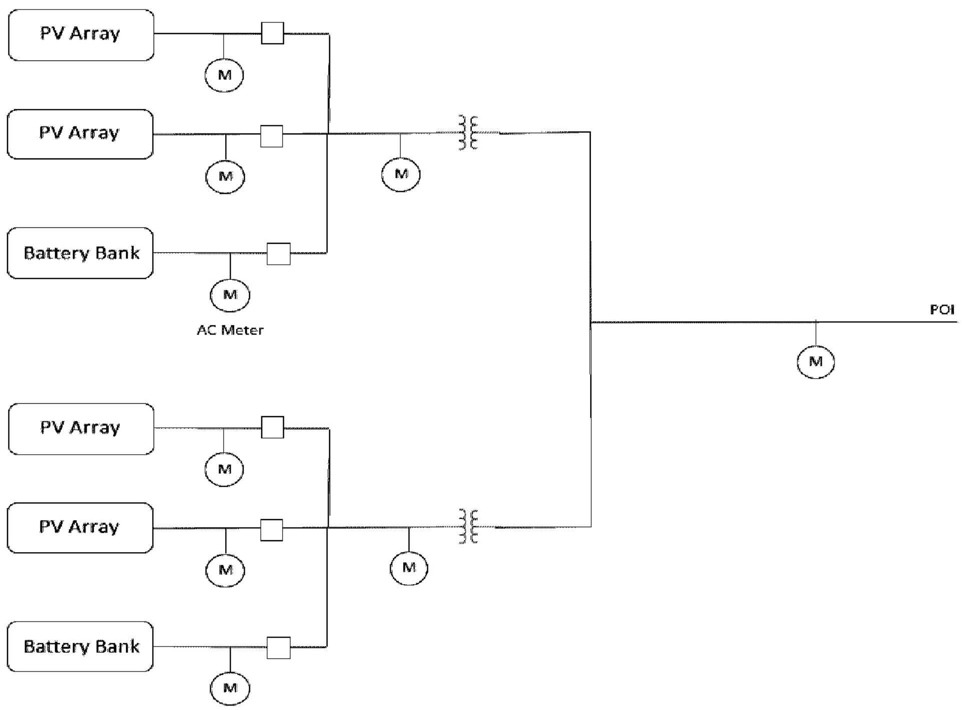
Figure 2: Solar and Storage with Single GSU and Multiple PPA's



Scheme 3:

The configuration proposed in Figure 3 is for multiple GSU's and PPA's. This configuration is similar to Figure 2, except the addition of another GSU requires the inclusion of a common low-side meter. Each storage facility will continue to be required to have an AC meter. Each solar facility will be required to have a low-side meter measuring the gross output of the feeder. An additional common low-side meter is required to accurately allocate transformer and line losses using dynamic loss compensation.

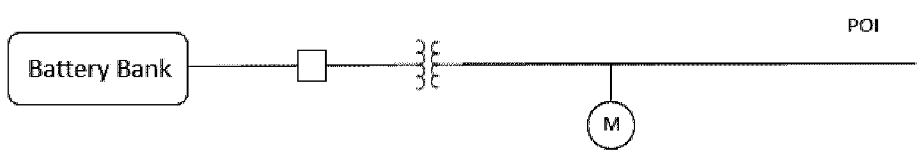
Figure 3: Solar and Storage with Multiple GSU's and PPA's



Scheme 4: ***NOT APPLICABLE UNDER THIS RFP***

The configuration proposed in Figure 4 is for a single storage facility on a dedicated lead line. This configuration requires a high-side meter compensated to the POI. If multiple feeders of battery storage are added, each with separate PPA's, Scheme 2 will be required.

Figure 4: Single Battery Storage on a Dedicated Lead Line



ATTACHMENT P – PROPOSAL ZIP FILE STRUCTURE

This attachment is available in electronic format in BHE JAGGAER.

Staff 115

Please note there are two tabs in this worksheet.

Project Differences		
Attribute	Boulder Solar III PPA (2020)	Boulder Solar III PPA (2024)
Project Name	Boulder Solar III	Boulder Solar III
Counterparty name	Boulder Solar III, LLC	Boulder Solar III, LLC
Parent Company	174 Power Global	174 Power Global
Operator	174 Power Global	174 Power Global
Location	El Dorado Valley, NV	El Dorado Valley, NV
Delivery Point	230 kV NSO substation	230 kV NSO substation
COD (planned)	12/31/2023	6/1/2027
Development time to COD following PUCN approval	36 months	29 months
Contract term PV (years)	12	25
Contract term BESS (years)[1]	12	25
Capacity PV (MW)	127.9	127.9
Capacity BESS (MWh)	232	511.6
Total Capacity (MVA)	138.6	184.8
Controlled Ramp Rate (MW/min)	50	128
Minimum Operating Capacity (MW)	1.0	0.1 MW
Pricing PV ($/MWh)	$ 22.45	$ 34.60
Pricing BESS ($/MW-month)	$ 6,800	$ 15,460
Network Upgrade costs ($)	$ -	$ -
Annual Supply Amount (MWh)[2]	390,473	412,809
Annual PC Amount[3] (MWh)	390,473	412,809
Annual Charging-Only Energy	N/A	58,652
BESS Round Trip Efficiency (%)[4]	88	85
Panel manufacturer (planned)	Undetermined	Hanwha Q Cells
BESS manufacturer (planned)	Undetermined	Tesla or equivalent
Securities		
Development Security (upon execution)	$ 4,339,831	$ 6,395,000
Development Security (upon PUCN approval)	$ 12,156,389	$ 17,906,000
Operating Security	$ 10,359,600	$ 21,713,500
Daily Delay Damages		
Day 1-60 (per MW per day)	$ 264.10	$ 264.10
Day 61-120 (per MW per day)	$ 528.20	$ 840.17
Day 121 - 180 per MW per day	$ 792.30	$ 1,229.06
Nameplate Damages		
Deficit Damages Rate ($/MW)	$ 200,000	$ 400,000
Deficit Damages Maximum	$ 3,018,600	$ 5,116,000

[1]The BESS term of the 2024 BSIII contract stipulates no monthly payment (i.e. $/MW-month) for years 21-25.

[2]The expected annual supply amount of the 2024 BSIII project anticipates the sum of the annual supply amount and the annual charge-only energy

[3]The expected annual PC amount of the 2024 BSIII project anticipates the sum of the annual supply amount and the annual charge-only energy

[4]The RTE of the 2020 BSIII is presented as an average; the RTE of the 2024 BSIII is presented as a gaurantee

Material PPA terms		
Attribute	**Boulder Solar III PPA (2020)**	**Boulder Solar III PPA (2024)**
Concepts		
Charging-Only Energy	N/A	"Charging-Only Energy" means, for any Delivery Hour, Energy that the Generating Facility is capable of generating in such Delivery Hour that is in excess of the Delivery Point Maximum Amount.
Excess Energy	N/A	1.74 adds Annual Charging-Only energy concept to stub period and contract year
Excess Energy Rate (section 4.1.2.3)	For amounts ≤ 5% of the annual supply amount, paid at 74% of the product rate; for amounts >5% of the annual supply amount, the Test Product Rate	All Product (except Storage Product) associated with Excess Energy from and after the Commercial Operation Dates shall be paid for at the Test Product Rate for each MWh of Excess Energy.
PUCN Approval Deadline	means December 31, 2020	means 270 days after regulatory filing is made by NVE
Round Trip Efficiency Test	N/A	3.4.9 added requirement to maintain 85% RTE and performance demonstration via test (Exhibit 29)
Purchase Options		
6 months following	facility's 8th anniversary at greater of Fair Market Value or $180,000,000	facility's 8th, 14th, and 20th anniversary at Fair Market Value
End of Term	greater of Fair Market Value or $175,000,000	at Fair Market Value
Force Majeure		
Definition changes	N/A	see section 20.2
Exclusions	N/A	20.3.1.12 Inability to obtain any supply of goods or services,
	N/A	20.3.1.13 Delays in clearing customs or similar regulatory clearance,
	N/A	20.3.1.14 The imposition of any tariffs (including anti-dumping or countervailing duties) that may apply to any products or equipment or other fines, penalties or other actions as a result of violation of Laws regarding unfair trade practices
	N/A	20.3.1.15 The occurrence after the Effective Date of an enactment, promulgation, modification or repeal of one or more Laws, including regulations or national defense requirements that affects the cost or ability of either Party to perform under this Agreement
Milestone Schedule		
Additional Critical Project Milestones	N/A	E. Supplier shall execute all Construction Contracts and Major Equipment Contracts for the Facility. (3 months after PUCN approval)
	N/A	F. Supplier holds fee title, a leasehold interest, an easement, a right of way grant, or other interest in real property to install the Facility's photovoltaic modules and battery packs at the Project Site or an option to acquire such real property interests. (on or before PUCN approval)

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-06-2024
REQUEST NO:	IEA 001	**KEYWORD:**	vol 4 p92-93 p95-100 williams direct; model resource combinations
REQUESTER:	Harris	**RESPONDER:**	Williams, Kimberly

REQUEST:

In her testimony, Kimberly Williams discusses resources that progressed to the economic modeling stage (Volume 4, pages 92-93), and the combination cases studied by NV Energy (Volume 4, pages 95-100)

a. Did NV Energy model resource combinations not listed in the combination cases in Volume 4?

b. If the answer to part (a) is yes, please list all resource combinations analyzed, including details on each combination.

c. In the list of resources that progressed to the economic modeling stage, Kimberly Williams includes Geo-1, Solar-1, Battery-1, Solar-2, and Wind-1. Please explain the source of these projects, e.g., are these resources placeholder resources or projects in development?

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One (Zipped)

RESPONSE:

a. Yes, the Companies modeled resource combination cases not listed in Volume 4.

b. Please see attached file.

c. The projects listed in Table REN-8 that were included in the economic model originated from either the 2023 OR RFP or bilateral discussions. However, as stated in the Renewables narrative, the Companies' evaluation, including, but not limited to, due diligence and commercial negotiations, could not be completed in time to bring any of these projects forward in this filing but these projects remain candidates for future filings.

	In-Service Year	2028	2029	2030	2027	2026	2027	2027	2027	2027	2027	2026	2028	2027-2033	2026	2028	2028	2027-2029
	Location	North	South	South	South	South	North	North	North	North	North	South	South	North	South	South	North	North
	Company	SPPC	NPC	NPC	NPC	NPC	NPC	NPC 40% SPPC 60%	NPC 60% SPPC 40%	NPC 50% SPPC 50%	NPC 45% SPPC 55%	NPC	NPC	SPPC	NPC	NPC	SPPC	SPPC
	Type	Company Owned	Company Owned	Company Owned	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	PPA	Company Owned	PPA	PPA
	Size	411 MW	440 MW	445 MW	128 MW	200 MW	700 MW	700 MW	700 MW	700 MW	700 MW	57 MW	200 MW	152 MW	80 MW	300 MW	110 MW	65 MW
Reference Number	**Resource**	Valmy CTs	Higgins CTs	Harry Allen CTs	Boulder Solar III Paired PV/BESS	Dry Lake East Paired PV/BESS	Libra Paired PV/BESS	Libra Paired PV/BESS	Libra Paired PV/BESS	Libra Paired PV/BESS	Libra Paired PV/BESS	Solar-1	Solar-2	Geo-1 (Portfolio)	Battery-1	Amargosa PV	Wind	Geo (Portfolio)
1	*Included in filing as VBDL1*	X			X	X	X											
2	*Included in filing as IBDL3*		X		X	X				X								
3	*Included in filing as ABDL3*			X	X	X				X								
4	*Included in filing as BDL2*				X	X			X									
5		X			X	X	X									X	X	X
6		X			X	X	X									X		
7		X			X	X						X	X	X	X	X	X	X
8		X			X		X									X	X	X
9		X				X	X									X	X	X
10		X				X	X									X	X	
11		X			X	X	X										X	X
12		X			X	X	X										X	
13		X			X	X	X											X
14		X			X		X										X	
15		X				X	X										X	
16			X		X	X		X								X	X	X
17			X		X	X		X								X		
18			X			X				X							X	
19			X		X	X				X							X	X
20			X		X	X				X							X	
21			X		X	X				X								X
22			X		X	X					X						X	X
23			X		X	X					X						X	
24			X		X	X					X							X
25			X		X					X							X	
26				X	X	X				X							X	X
27				X	X	X					X						X	X
28					X	X		X						X	X	X	X	X
29					X	X		X								X	X	X
30					X	X			X								X	X

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-06-2024
REQUEST NO:	IEA 0018	**KEYWORD:**	sierra solar development status timeline
REQUESTER:	Harris	**RESPONDER:**	Spitzer, Sean

REQUEST:

Is NV Energy proceeding with the development of Sierra Solar? If so, provide details of the development status and timeline.

RESPONSE CONFIDENTIAL (yes or no): No.

TOTAL NUMBER OF ATTACHMENTS: None.

RESPONSE:

NV Energy is moving forward with the development and construction of Sierra Solar while it continues to evaluate options. EPC contracts for the solar facility and O&M building, as well as the BESS, have been executed. The project is on schedule to meet its planned CODs for the BESS and PV, respectively.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	07-01-2024
REQUEST NO:	Staff 99	**KEYWORD:**	open capacity position target vol 8 p217; 750MW guideline
REQUESTER:	Venkat	**RESPONDER:**	Runyan, Joe (NV Energy)

REQUEST:

Reference: Open Capacity Position Target

Question: Volume 8, Page 217 of 393 states that the Companies set an open capacity position target of no more than 750 MW in 2028 and every year thereafter. Please answer the following questions:

A. Please explain why the Company chose a guideline of 750 MW.

B. Did the Company consider any different guidelines for an open position? If so, what other guidelines were considered and why was 750 MW chosen?

C. In Docket No. 21-06001, the Companies chose a guideline of 2,000 MW for the open position. Please explain in detail the reason for the change from 2,000 MW in the last IRP to 750 MW in the instant filing.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: None

RESPONSE:

A. The Companies chose to set an open position capacity target of no more than 750 MW starting in 2028 as stated in the narrative on page 217 of 393 and elsewhere in Volume 8 due to ongoing concern about the uncertain availability and deliverability of market capacity and energy as well as the requirement to be resource sufficient in WRAP with the initial binding season in winter 2027-2028, which is also an expected requirement of a future regional market or RTO.

Western Markets are in considerable flux since the last IRP which has led to more uncertainty in market availability and deliverability. The testimony of Ryan Atkins, in his Q&A 11 in this filing, discusses the risk of having a large open position and points to the testimony of Nicolai Schlag. In testimony in the Fifth Amendment to the 2021 IRP (Docket No. 23-08015), Mr. Schlag discussed risks associated with maintaining a large open position as well as evidence to support the notion that the supply of capacity in western wholesale markets is growing increasingly constrained. He also discussed the extent to which other utilities in the west count on short-term market purchases to meet their needs in their resource plans and signaled intent by utilities that currently hold large open positions to reduce those positions over time. In his Q&A 17-19 in the instant docket, Mr. Schlag explains the evidence that led to his conclusion that the Companies' plans to reduce the open position were reasonable in the Fifth Amendment and states additional evidence to support this position as well as support of the Companies continued efforts to reduce its open position in this filing.

While in the 2021 IRP, a larger open position of 2,000 MW was deemed reasonable, the current market landscape and experience in recent years suggest that availability and deliverability of external market capacity and energy will be more limited and uncertain. The open positions in alternative plans in the Companies' more recent filings have been lower than the 2,000 MW target in the 2021 IRP. Open positions of the alternative plans in the Fourth and Fifth Amendments to the 2021 IRP were reduced to near or below 600 MW in the first 20 years of the plans. The open position target in this filing is consistent with recent filings.

In addition to concerns about uncertain market availability and deliverability, there is risk in relying on market purchases to meet resource sufficiency requirements in WRAP as stated on page 351 of 393 in the narrative:

> "Any participant that fails the forward showing will be subject to penalties that utilize a cost of new entry charge, which is equal to the amount that it would cost to build new generation. It is important to note that market purchases may apply towards the forward showing, however, any contracts will need to satisfy strict requirements and limited market supply is available that meets the guidelines. Contracts must be in place ahead of the seven-month deadline to submit the forward showing for the binding season in order to count towards qualifying capacity for the forward showing. The contract must also include an identified source committed to the supply, provide assurance the capacity is not used for another entity's resource adequacy requirements, provide assurance the seller will not fail to deliver, and also commit that the energy will be delivered on firm transmission. Therefore, it may not always be possible for an entity to close forward showing shortfalls with contractual supply."

The Companies sent out a Request for Information ("RFI") in mid-November 2023 seeking to purchase source specific energy, consistent with WRAP requirements for qualifying capacity, for June-September 2026-2028. Response was received from three counterparties as shown below.

- Counterparty A – 85 MW firm and source specific, was ready to be executed but not cost

competitive compared to forward pricing we were seeing
- Counterparty B – No firm price or quantity given, additional negotiation needed, indicated an openness to begin negotiations for up to 300 MW
- Counterparty C – No actual energy offered, more of a ‘conversation starter’ with no price or quantity given, just stating they would be interested if they could find source specific energy to sell to us

Informed by the concerns and evidence presented as well as the results of the RFI, the Companies chose to set an open position capacity target of no more than 750 MW starting in 2028.

B. Determining an open position target is not an exact science. For that reason, the Companies worked to determine a balanced approach that reduced the risk of relying too heavily on market purchases while not being overly conservative. The topic was discussed with subject matter experts within the Companies and the 750 MW target was agreed upon.

C. See response to item A.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	22-11032	**REQUEST DATE:**	02-27-2023
REQUEST NO:	IEA 3-02	**KEYWORD:**	electric resource acquisition RFP; 2023, PROMOD PLEXOS
REQUESTER:	Tanner, Lina	**RESPONDER:**	Pritchard, Shane

REQUEST:

Reference:

Question:

1. Identify and produce the Company's most recent electric resource acquisition request for proposals ("RFP") prior to the pending 2023 Open Resource Requests for Proposals, referenced at this website: https://www.nvenergy.com/about-nvenergy/doing-business-with-us/energy-supply-rfps ("2023 RFP").

2. Identify the nameplate capacity of bids received in the last electric resource acquisition RFP completed by the Company, categorized by generation technology type.

3. Identity all resources acquired in the last electric resource acquisition RFP by technology and contract type.

4. Please describe the bid evaluation and selection process to be used for the 2023 RFP.

5. Under what Commission decision or process, if any, was the 2023 RFP approved?

6. Please confirm that the Company is considering facilities owned by the Company as well as those owned by independent power producers for all technologies under the 2023 RFP. If not, please explain your answer in detail.

7. Please provide a copy of any questions submitted by bidders and all thereto ed by the Company for the 2023 RFP to assist with clarification of the 2023 RFP.

8. Are either PROMOD or PLEXOS used in the bid evaluation process for the Company's RFPs, including its most recent RFP or the 2023 RFP? If so, please describe. If not, please explain why not.

RESPONSE CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: Four (Zipped)

RESPONSE:

1. The most recent RFP prior to the pending 2023 Open Resource RFP was the "2022 Freedom Park Solar and Moana Solar Request for Proposals," however that RFP was only to solicit construction of the 2 named community-scale PV projects. The most recent RFP similar to the 2023 RFP was the 2022 Spring Renewable RFP. Please see attached document "Interwest 3-02 (1) 2022 Spring RE RFP Protocol".

2. Please see attached document "Interwest 3-02 (2) Bids Received 2022 Spring RE RFP"

3. The Company did not acquire any resources from the 2022 Spring RE RFP

4. The bid evaluation process is described in Section 5 of the 2023 Open Resource RFP. Please see attached document "Interwest 3-02 (4) 2023 OR RFP Protocol"

5. Approval to issue an RFP is not required by the Commission

6. As shown in the 22 Spring RE RFP Protocol attached, the Company solicits various contract types, some resulting in Company-owned projects, and some PPAs.

7. Please see attached document "Interwest 3-02 (7) QandA-2023.03.01" 8. PROMOD was used for the 2022 Spring RE RFP. PLEXOS is expected to be used for the 2023 OR RFP.

NV Energy

RESPONSE TO INFORMATION REQUEST

DOCKET NO:	24-05041	**REQUEST DATE:**	08-06-2024
REQUEST NO:	IEA 007	**KEYWORD:**	2023 open resource RFP bids projects shortlist contract types
REQUESTER:	Harris	**RESPONDER:**	Spitzer, Sean (NV Energy)

REQUEST:

The summary of the IRP describes the number of bids and selected projects.

a. How many bids were received via the 2023 Open Resource RFP?

b. Of those, how many projects made the RFP shortlist?

c. How many were chosen from the shortlist?

d. List the generation technology types and MW amounts in aggregate for bids at each stage.

e. Enumerate the number of differing contract types (BTA, PPA, Company-build) evaluated by the Company for each stage.

RESPONSE CONFIDENTIAL (yes or no): No

ATTACHMENT CONFIDENTIAL (yes or no): No

TOTAL NUMBER OF ATTACHMENTS: One (Zipped)

RESPONSE:

a) 84 bids
b) 28 bids
c) 3 bids
d) Please see the attached “24-05041 - IEA 007-Attach 01.xlsx”.
e) Please refer to the attached “24-05041 - IEA 007-Attach 01.xlsx” provided in d.

IEA 007

RFP	Geo	Wind - PPA	Solar + Storage - PPA	Solar-PPA	Storage-PPA	Solar + Storage 0.5:1 - BTA	Solar + Storage 1:1 - BTA	Solar - BTA	Storage - BTA	Conventional	WSPP	Total
MW	152	2,340	5,671	240	550	1,180	5,390	190	3,975	170	340	20,198
Bids	1	6	23	1	5	5	14	1	22	2	4	84

Shortlist	Geo	Wind - PPA	Solar + Storage - PPA	Solar-PPA	Storage-PPA	Solar + Storage 0.5:1 - BTA	Solar + Storage 1:1 - BTA	Solar - BTA	Storage - BTA	Conventional	WSPP	Total
MW	152	1,560	1,308	none shortlisted	none shortlisted	795	2,600	none shortlisted	1,325	85	170	7,995
Bids	1	4	5	0	0	3	6		6	1	2	28

Selected	Geo	Wind - PPA	Solar + Storage - PPA	Solar-PPA	Storage-PPA	Solar + Storage 0.5:1 - BTA	Solar + Storage 1:1 - BTA	Solar - BTA	Storage - BTA	Conventional	WSPP	Total
MW	-	-	1,028	-	-	-	-	-	-	-	-	1,028
Bids	0	0	3	0	0	0	0	0	0	0	0	3

Footnotes: 84 bids were received, however, some bidders provided multiple bid options for the same project. There were 31 distinct project sites.
Energy Storage values not included in MW values above, unless the category is for storage only (i.e., Storage-PPA, Storage-BTA).

Gmail

Sam Johnston <sam@interwest.org>

Update on Launch of NV Energy RFP

Mitchell, Rainie (NV Energy) <Rainie.Mitchell@nvenergy.com>
To: Sam Johnston <sam@interwest.org>

Wed, Aug 14, 2024 at 3:40 PM

Hello Sam,

I just wanted to give you an update on the launch of NV Energy's 2024 RFP that was expected to be issued this month. It has been postponed but is expected to be issued this fall. Feel free to notify your contacts.

Regards,

Rainie Mitchell

NV Energy

RAINIE MITCHELL | Renewables and Origination

7155 Lindell Road, MS B13RE

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702.290.8105 m

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AFFIRMATION

I, Mark Detsky, do hereby swear under penalty of perjury the following:

That I am the person identified in the foregoing Direct Testimony and that such testimony was prepared by me or under my direct supervision; that the answers and information set forth therein are true to the best of my knowledge and belief as of the date of this Affirmation; that I have reviewed and approved any modifications after the date of this Affirmation; and that if asked the questions set forth therein, my answers thereto would, under oath, be the same.

Dated this 18th day of October, 2024.

Signed by:

Mark Detsky

5055046288C0471...

MARK DETSKY

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that I have this day served the foregoing **Prepared Direct Testimony** upon each of the parties on the attached service list in this proceeding via electronic mail.

DATED this 18th day of October.

/s/ Nannette M. Moller
Nannette M. Moller
Paralegal

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