Docket No.: A.24-03-018
Date: July 29, 2024
Commissioner: Douglas ALJ: Atamturk
Witness: Mark Cooper

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees (U 39 E)	Application 24-03-018 (Filed March 29, 2024)

OPENING TESTIMONY OF MARK COOPER ON BEHALF OF SAN LUIS OBISPO MOTHERS FOR PEACE

Dated: July 29, 2024

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VERIFICATION

The statements in the foregoing document are true and correct to the best of my knowledge. The facts presented in the forgoing document are true and correct to the best of my knowledge, and the opinions expressed therein are based on my best professional judgment. I declare under penalty of perjury under the laws of the state of California that the foregoing is true and correct.

Executed on July 29, 2024, in Silver Spring, MD.

Mark Cooper

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I. STATEMENT OF QUALIFICATIONS

Q. Please summarize your qualifications.

A. My name is Dr. Mark Cooper. As stated in my initial testimony in the resource proceeding, I participated in the 2015 proceeding that dealt with the application for a license extension for Diablo Canyon. Since I testified in opposition to the license extension, I have continually updated the analysis a dozen times. These include books and chapters, testimony before various state and 10 federal agencies, and research reports.[1] This experience is located within over forty years as an expert witness and researcher.[2] I have testified almost 500 times before state and federal regulators on energy, communications and technology issues in virtually every state in the United States. I have also testified in several Canadian provinces. In my testimony in the Rulemaking proceeding (R.23-01-007) I updated the earlier analysis I conducted of the Diablo Canyon reactors, adding a number of additional points that seem particularly relevant under the current circumstances, although they are all related to the earlier issues I addressed.[3] I incorporate by reference the entirety of my Opening and Reply Testimony on R.23-01-007 as if fully set forth herein. In this testimony I further the update, based on new data, including but not limited to the California Energy Commission S.B. 846 Cost Comparison.[4]

II. PURPOSE, SUMMARY AND RECOMMENDATIONS

Q. What is the purpose of your testimony?

I will be providing testimony on issue 1 as identified in the Assigned Commissioner's Scoping Memo and Ruling, including but not limited to the issue of costs-effectiveness.

Q. What is your evaluation of PGE's estimate of the cost of Diablo Canyon Power Plant (DC)?

A. The costs are probably too low, but still excessive and certainly are not a justification for imposing them on ratepayers. They are imprudent because neither PG&E nor the California Energy Commission has shown they are the least cost-effective way to meet the needs of California.

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[1] As shown in Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007, Attachment MNC-1.1.

[2] My resume is included in Initial testimony.

[3] See Exh. SLOMFP_04 – Corrected Opening Testimony of Mark Cooper, on Phase 1, Track 2 Issues [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] in R.23-01-007.

[4] See Attachment A - May 2024, CEC Cost Comparison].

Q. Why do you say probably too low?

A. My prior testimony used $70/mwh, on average, with a high side, based on annual escalation of $90/mwh.[5] Others in the Rulemaking proceeding put the total cost at almost $100/mwh. My range is between 3% and 32% higher.[6] But, my estimate was pure operating costs and did not include the cost of deferred maintenance and the costs needed to bring the reactors up to standard, so their operations could be extended beyond the original federal license expiration dates of 2024/2025. Those costs are real and should be examined by the CPUC. PG&E has said it will use the federal subsidy to buy down most of the state loan, leaving "only" $300 million to be collected from ratepayers. Adding just the $1.1 billion to the total puts the real cost at almost $130/mwh.

Q. Why do you say the costs are excessive?

A. There are three reasons. First, there are alternatives that are lower in cost. Second, and more importantly, the alternatives can be purchased in much smaller increments. Third, because the alternatives can be located where they are needed, they help to transform the system toward a more decentralized, distributed network that is less vulnerable to the big events that have plagued the 20th century system. These benefits flow from the fact that the California Independ System Operator (CAISO) has done and continues to do its job of meeting the needs for reliable electricity. Efficiency and demand response must be recognized as key elements of a 21st century system.

Q. Why do you say certainly not a basis for imposing them on ratepayers?

A. In making a decision about which resources to acquire the PUC must ask whether there are lower cost alternatives that could do the job.[7] In fact, as I showed in my initial testimony and confirmed in the update of costs, the main alternatives – efficiency, wind and solar– are lower. With capital cost on an apples-to-apples basis, wind and solar with storage are lower in cost. Combined cycle gas with carbon capture and geothermal might also be less costly, although there is a timing issue with these.

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[5] See Exh. SLOMFP_04 – Corrected Opening Testimony of Mark Cooper, on Phase 1, Track 2 Issues [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] in R.23-01-007, pp. 29-30.

[6] Exh. SLOMFP_08 Reply Testimony of Mark Cooper on Phase 1, Track 2 issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6524/515355348.pdf], pp. 5-16.

[7] See Opening Testimony of Peter Bradford, pp. 6-8.

Q. Do you have other concerns about the cost data provided by PG&E?

A. Even without the $1.1 billion "gift" from federal taxpayers, there is still the issue of the $300 million in state loans. This could raise the burden on ratepayers substantially. Moreover, PG&E assumes that 2/3 of the cost will be covered by purchases from CAISO[8], but it is unclear that CAISO needs that much power from DC, especially with so many lower cost alternatives available. Indeed, CAISO specializes in efficiency and demand response, which are very low cost was to meet the need for reliability.

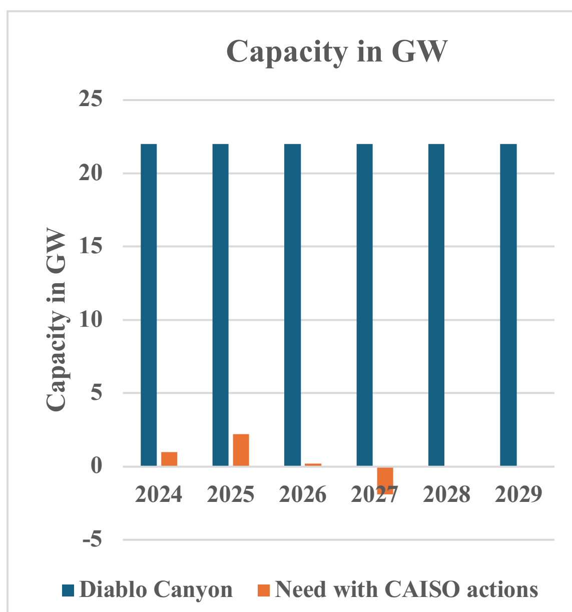
Q. Please summarize the comparative view of extending Diablo Canyon versus developing alternatives.

A. The following table summarizes a comparative view of the cost of extension compared to the cost of the resources of alternatives based on the average cost presented by in the most recent lifecycle cost by Lazard. The central point is that the three core renewables are much lower in cost. Depending on what one assumes about the level of costs, and cost escalation, wind and solar with storage could be less costly. How one treats the subsidies makes DC more costly than wind-offshore and Community/Ind. PV. More importantly, if one recognizes CAISO actions to ensure reliable power, DC is vastly excessive because it delivers far more power than is needed. Moreover, CAISO has done such a good job that there is no need for DC at all.

COST OF ALTERNATIVES

Technology/Scenario	Cost/$/mw Annual
Efficiency	35
Wind-onshore	49.5
Utility PV	60
Diablo Canyon @70	70
Solar+ Storage	74
Wind-on + Storage	78
Geothermal	81.5
CC Gas w/CCs	83
Diablo Canyon +$.3 billion	86
Diablo Canyon @90	90
Wind-offshore	106
Community/Ind. PV	115
DC + $1.1b Federal	124
DC + $1.4b State	146

	5-year Avg.	Total ($b)
Cooper with 7% escalation)	91	8. 2
A4NR with "slush" fund	130	11.7
Risk Aware Costs		



[8] See generally PG&E Prepared Testimony, p. 8-2.

Nuclear	
Diablo Canyon	81
New Build	190
Alternatives (assume equal shares)	
Base Eff, + wind-on + Util. PV	63
Add Wind + Storage	68
add Solar + Storage	73
add Geo	76
add CCGas w/CCS	76

Source: Costs are from Lazard v 17.0; Alliance for Nuclear Responsibility's Protest, 2024, *Application of Pacific Gas and Electric Company to Recover in Customer Rates the Costs to Support Extended Operation of Diablo Canyon Power Plant from Application A.24-03-018 September 1, 2023 through December 31, 2025 and for Approval of Planned Expenditure of 2025 Volumetric Performance Fees,* Before The Public Utilities Commission of the State of California, (U 39 E) March 29.

As occurred with the Reply briefs, the other intervenors have higher figures.[9] My highest figure is $146/mwh, assuming the $1.4 billion loan has been glossed over. While the rate is higher than others, (e.g. $130/mwh, according to A4NR), their figure includes all five years, leading to a total of $11.7b, which they assert includes a "slush" fund. A4NR claims that those costs should (at best) be the subject of a separate proceeding.

If we assume the hard costs for 2025 are $1.22b, with escalation that would grow to, on average, $1.4b per year, or a total of $8.2 in operating costs (including the $1.4 billion one time charges). That puts the average cost of DC at $91/mwh. The "slush" find would be a total of $3.6 billion.

Even without adding the "slush" fund, I observe that at $91/mwh, the extension of operation of DC is far too costly to be considered prudent or cost-effective. If we do risk aware costs based on Lazard, we find that every cost estimate of alternatives, assuming equal parts for each of the five alternatives, is lower than the estimated cost of DC. The amount of ratepayer funds wasted in extending DC runs into the billions of dollars. This assumes a mix of seven technologies (efficiency, wind-on, solar, solar plus storage, wind plus storage, geothermal and CCGas w/ CCS). The acquisition of these resources would build up to the full replacement of Diablo Canyon. Therefore, if the acquisition of alternative resources is "right sized," the cost

[9] Exh. TURN_01 – Opening Testimony of William Monsen on behalf of TURN [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6409/512708454.pdf] in R.23-01-007; Exh. A4NR_01 – Opening Testimony of John Geesman on behalf of A4NR [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6406/512707756.pdf] in R.23-01-007.

would be 95% less costly than Diablo Canyon. Thus, the assumption that extending DC is reasonable, prudent and cost-effective is wrong and could be very wrong. DC is not only too costly, but also unnecessary.[10]

Q. What is your view of the huge resource and greenhouse gas benefits of Diablo Canyon that PG&E claims? [11]

A. These two dubious benefit claims are very large ($3 billion) and very misleading. I doubt that these claims can be monetized in the market for two reasons.

1. Given the immense excess capacity that DC represents, I doubt the $1 billion resource adequacy benefit PG&E claims, since the reactor is not needed. Who will they sell it to at the market clearing price?
2. The societal, greenhouse gas benefits are "fictitious" since that benefit is not actually collected from anyone. Since DC is not needed, it will not be able to dispose of its power, or it will be crowding out equivalent quantities of renewables. One could calculate how long it would take renewables to replace the entirety of DC, which would equal a slow buildup of benefits, only if PG&E were able to "sell" its power at the market clearing price, which it has admitted it will not be able to do. That is why they decided not to extend the license in the first place. Moreover, if PG&E is going to consider societal benefits, it must also be required to consider societal and environmental risks and costs of extended operations.[12]

Q. What is your response to the claims of macroeconomic, employment and local economy impact?

A. I have dealt with these at length in my initial testimony showing that the alternatives produce many more jobs, economic activity and is a more efficient use of local resources.[13] This is the clearest example of PG&E failing to consider the alternative, which the CPUC must. When the comparison is made and a longer-term perspective is taken, Diablo Canyon is a poor choice.

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[10] See Opening Testimony of Rao Konidena, p. 15.
[11] PG&E Prepared Testimony, p.2-8.
[12] See Exh. SLOMFP_03 Opening Testimony of Peter Bradford on Phase 1, Track 2 Issues in Rulemaking R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6411/512708456.pdf].
[13] See Exh. SLOMFP_04 – Corrected Opening Testimony of Mark Cooper, on Phase 1, Track 2 Issues [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] in R.23-01-007, attachments 4.5-thru 4.8 and accompanying text.

III. THE COST OF RESOURCES

Q. What is your approach to the Cost Recovery Proceeding?

A. In my testimony and reply testimony in the proceeding involving the decision of whether the California Public Utility Commission should extend the life of, I raised many of the issues that related to the costs that would be incurred by extending the life of DC and raising the specter of a long-term commitment to nuclear power.[14] The Commission chose not to examine those issues at that time, holding them for a separate (the above captioned) proceeding.[15] Since all those issues must be addressed in this proceeding, my initial and reply testimony from that proceeding remains directly relevant. In bringing that analysis forward, I will not repeat my full analysis, since I have made it part of the record by incorporation by reference herein.

Moreover, the cost recovery proceeding is forward-looking and the decision on prudence and cost-effectiveness must reflect facts on the ground today, or relevant projections of conditions going forward. Since a year has passed since the initial testimony, I believe that it is important, as a matter of determining the prudence and cost-effectiveness of these costs, to update the key characteristics of the conditions that led to the decision to extend the license. I believe that the Commission cannot base a prudence or cost-effectiveness determination that allows cost recovery based on data and analyses that were incomplete at the time and have undergone significant change in the past year. Throughout this analysis, I will provide footnotes to the factors I am updating from my earlier testimony.

Q. How does your analysis Proceed?

A. To distinguish the new discussion from the earlier testimony I label the attachments as Cost Recovery (e.g. MNC-CR-). I update the previous analysis, however, I have reached the same conclusions as I did earlier. I then address the misleading analysis that the CEC presented to the PUC by presenting a static, backward looking answer to the question of allowing PG&E to recover costs for DC from ratepayers, when the PUC must recognize the current, dynamic situation and present a forward-looking comparison.

Q. Which costs should the Commission consider in its analysis the instant proceeding?

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[14] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] and Exh. SLOMFP_08 Reply Testimony of Mark Cooper on Phase 1, Track 2 issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6524/515355348.pdf]

[15] D.23-012-036.

A. In my initial testimony I argued that the cost of resources must take center stage in any decision about extending the life of Diablo Canyon (DC). The Commission deferred that decision to this proceeding, but now the costs of nuclear compared to other available resources take center stage. Moreover, as I argued it is not just the mid-term costs (up to five years) that matter, but the long run costs, because the mid-term decision can deeply affect the long-term decision, delaying or distorting the effort to implement a 21st century electricity system in California.

Evaluating the potential contribution of resources to meeting the need for electricity must take the cost of each resource into account. The first step is to examine long-term costs. Over a 25-year period (roughly to 2050 from the present) most of the existing resources will have to be replaced at least once. This means that the cost of new builds must be taken into account. Of course, over a 50-year period, just about all resources will have to be preplaced.[16]

Since costs are central to the decision to extend DC operations, I focus my attention on updating the cost estimates.

Q. How have you updated your costs analysis?

A. In my earlier testimony I showed that nuclear power, in general, and DC, in particular, are an extremely poor and imprudent expenditure of ratepayer moneys.[17] They are more expensive than the alternatives available in California. Therefore, the Commission should not allow cost recovery for the extension of DC operation. I showed that the extension of DC operations is likely to distort the development of alternative, delay the transition to a 21st century system, and expand the role of nuclear in California's electricity future. There was little need for the extension of operation of the reactors.[18]

Developments since the Commission's December 2023 decision reinforce that conclusion. The growth of a number of alternatives at relatively low cost strongly argues against

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[16] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] p.8. and Exh. SLOMFP_08 Reply Testimony of Mark Cooper on Phase 1, Track 2 issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6524/515355348.pdf]

[17] *Ibid* MNC-1.

[18] *Ibid.*

the extension. In short, the extension of operation of DC is unnecessary and imprudently expensive and is not cost-effective.

To expand on that analysis, I apply the same principles but apply them to different data sets, all of which post-date my earlier testimony. In a sense they are "simpler" data sets, which makes the cost evidence more compelling. In short, the cost analysis strengthens the case against extending the operation of DCPP.

Q. Describe your approach to the new cost data.

A. My earlier analysis concluded that the risk-aware estimate of costs was the most appropriate,[19] since it included more information for the underlying studies. It utilizes the mean of all estimates and their standard deviations, thereby taking uncertainty into account. As shown in Attachment MNC-CR-1, I compare the 2023 estimates from Lazard to the 2024 estimates.

The exhibit displays a very high correlation between the two risk-aware costs (r = .86). The only technology that shows a significant change is PV with storage. Without that technology, the correlation is almost perfect (r = .98). The increase in the PV with storage (Hybrid) technology is influenced by the high projection (more than 100 percent) with the low projection (less than 25 percent). Since it is at the high end, it is avoidable. Utilities might avoid the expensive applications. As discussed below, there is other evidence that uniquely expensive applications are not the problem, and it may not be in California. Be that as it may, we find the key alternatives are much less costly than nuclear large or small.

Attachment MNC-CR-2 compares the risk-aware cost estimates based on 2022 data to the latest update of NREL's projection of costs. The new estimate of costs is consistent with the earlier analysis. The five least cost approaches are wind-onshore, utility PV, efficiency, geothermal, and PV with storage. The middle range cost approaches incudes wind with storage, CC gas w/CCs, and long duration storage. Commercial and industrial PV and aging reactors come next. New nuclear (small and large) and biomass are much more costly. Building the 21st century system is the task at hand.

The next attachment (MNC-CR-3) deals with the Levelized avoided cost of energy, (LACE) which was presented in The Energy Information Administration (EIA)'s discussion of

[19] *Ibid*, MNC-6.3 and related text.

these issues.[20] Because this is a novel approach and a complex topic, we bring forward some of the discussion. It takes a different approach, but with some of the same elements at work. LACE is part of a triumvirate of costs calculated by EIA.

> The levelized cost of energy (LCOE) and levelized cost of storage (LCOS) represents the average revenue per unit of electricity generated or discharged that would be required to cost the costs of building and operating a generating plant… during an assumed financial life and duty cycle… Along with LCOE and LCOS, we compare economic competitiveness between generation technologies by considering the value of the plant in serving the electricity grid… We sum this into an annualized value… to develop the levelized avoided cost of electricity. 1 (LACE)… LACE accounts for the difference in the grid services that each technology provides, and it recognizes that intermittent resources, such as wind or solar, have substantially different duty cycles than the baseload, intermediate, and peaking duty cycles of conventional generators… When the LACE of a particular technology exceeds it LCOE or LCOS, that technology would generally be attractive to build.[21]

As Attachment MNC-CR-3 shows, there is a high correlation (r = .87) between the two analyses. The basic resources are the same, but standalone batteries enter the mix early. Combined cycle enters somewhat later. All of these technologies have a lower risk-aware cost than nuclear and specifically are lower risk-aware costs than PG&E's forecasted costs for DCPP.

Q. How do renewable energy sources fare in your update?

A. As I noted in earlier testimony LBNL took a different approach to evaluation renewables, calculating the specific "system" value of renewables in California.[22] They showed that PV was

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[20] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] p.8. and Exh. SLOMFP_08 Reply Testimony of Mark Cooper on Phase 1, Track 2 issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6524/515355348.pdf] and MNC-2.16 and associated text.

[21] Energy Information Administration, 2022, Levelized Cost of New Generation Resources in the Energy Outlook, 2022, pp. 4.1.

[22] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6447/513343356.pdf] p.8. and Exh. SLOMFP_08 Reply Testimony of Mark Cooper on Phase 1, Track 2 issues in R.23-01-007 [https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6524/515355348.pdf] attachment thereto - MNC-2.18 and related text.

the last renewable to go positive by 2018, with increasing value thereafter. As MNC-CR-4 shows, wind and solar are now positive. Moreover, despite the Lazard increase in the high-end of hybrid systems batteries have dramatically altered the landscape in California. There was a shift in installations from 10% hybrid to at least 60% hybrid.[23] Solar installations on an annual, if this rate is maintained, would bring more than five times the capacity of solar, the majority of which was hybrid into the California supply. Moreover, the increase in cost noted was below the low end of the increase in cost noted by Lazard.[24]

This figure does not include electric vehicles (EVs), which even PGE admitted had the capacity to replace DCPP five times.[25] This requires a tariff structure that makes these available for power to the grid. By the end of the decade, with ten times as much capacity as DCPP available in untapped battery capacity, there is no shortfall, and no need to incur the cost of DCPP extended operation. This dramatic increase in battery installations has been driven by a sharp decline in the cost of the underlying technology, as shown in Attachment MNC-CR-5. Even without any further decrease in prices, the cost of batteries has fallen to a range that makes them highly competitive as a firm, or quasi-firm source of power.[26]

While I emphasize the solar hybrid and EV applications of batteries, there is a broad range of applications that batteries can provide. These were identified in my prior testimony.[27] MNC-CR-6 provides a more recent account of the many functions batteries can provide in the power system. In a sense, the current applications are a very large tip of a huge iceberg. As the International Energy Agency points out, the decision to use batteries in these other applications involves a complex "business case" analysis[28] (which is the approach taken by Lazard).[29]

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[23] Martucci, Brian, 2024, "Residential solar + storage surged in California after NEM 3,0, LBNL, *Utility Dive,* May 20, citing Barbose, Galen, 2024, "One Year In: Tracking the Impacts of NEM 3.0 on California's Residential Solar Market," *Lawrence Berkeley National Laboratory,* May.

[24] Just 17%. Martucci, Brian, 2024, "Residential solar + storage surged in California after NEM 3,0, LBNL, *Utility Dive,* May 20, p. 1.

[25] Lopez, Nadia. 2003, "PG&E's CEO Wants Electric Vehicles to Save California's Power Grid", *Bloomberg News, Financial Times,* Aug 8, "Poppe said there are enough electric vehicles on the road to return roughly 9,000 megawatts of power to the grid — nearly the equivalent of five Diablo Canyon Nuclear Power Plants."

[26] International Energy Agency, 2024, *Batteries and Secure Energy Transition,* April; Martucci, Brian, 2024, "Residential solar + storage surged in California after NEM 3,0, LBNL, *Utility Dive,* May 20.

[27] See Exh. SLOMFP_04 Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007, Attachment MNC-5.14 and related text.

[28] International Energy Agency, 2024, *Batteries and Secure Energy Transition,* April.

[29] Lazard, v.17 for the most recent analysis of business cases.

> Whether it is economical to deploy batteries depends on the individual circumstances of the particular case. The answer can vary from region to region, depending on the characteristics of the electricity system and the regulatory environment. Value stacking by providing multiple services at the same time can boost the economics of battery storage, but also the complexity of the business case.[30]

With the basic applications of batteries (primarily on the lower left of MNC-CR-6), charging ahead, the importance of batteries has already been made clear and the prospects of additional functions can only expand those impacts. Moreover, and perhaps more importantly, the quote points out that the regulatory environment will be an important factor in determining the expansion of functionalities. This reinforces my concern that extending nuclear operations will "crowd out" the key resource of the 21st century system,[31] actively (with the opposition of nuclear advocates) and passively (by rendering them less "needed").

Q. How have the cost and construction period of Small Modular Reactors fared since your testimony?

A. Although only a year has passed, it was a very bad one for the prospect for small modular reactors (SMRs). While the SMR focused companies continue to put on a brave face, the past several years has been extremely negative for the technology. As shown in MNC-CR-7, costs have risen dramatically and (as shown in MNC-CR-8) the construction period has lengthened. While this is "speculative" for the U.S., since no SMRs have been built (or will be for another decade), it is also true for foreign SMRs which are online or under construction. Cost estimates have at least doubled and perhaps quadrupled. Construction periods have at least tripled and perhaps quadrupled. The optimism reflected in the industry hype is unjustified. The PUC must base its decision on realistic assumptions.

Q. How have the cost and construction periods for large nuclear reactors faired?

A. Large reactors have remained high and late. Attachment MNC-CR-7 shows the cost of the Vogtle plant, which is the last of the "nuclear renaissance" reactors to be built. The costs doubled, as did the construction period. The failure of Vogtle and the huge increase in customer bills that is necessary to support its costs have caused U.S. utilities to take a step back from large

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[30] International Energy Agency,2024, *Batteries and Secure Energy Transition,* April 2024, p. 37.
[31] Initial Testimony, Attachments MNC-3.7 and 3.8 and related text.

nuclear facilities. Since the prospects for SMRs are no better, it is safe to say that the deployment of any new nuclear capacity is more than a decade away. Simply put, there is no future in nuclear power if cost-effectiveness and prudency are the concerns. It is much more costly and by the time construction is completed, it will be too late to address the urgency of reducing carbon output.

Q. Has PG&E calculated the costs of alternatives?

A. Actually, no one has calculated the cost of alternatives in this proceeding.

PG&E does not consider the alternatives to Diablo Canyon. It only presents its estimate of the cost of upgrading and operating DC. It is understandable that PG&E is not interested in presenting the costs of the alternatives to the reactors it wants to operate.

The only entity that mentions the alternatives is the California Energy Commission, (CEC) but its discussion stops short of actually calculating the costs. It claims that it need not calculate those cost because none of those alternatives meet the criteria of the legislation (HR 856).

IV. RESOURCE AVAILABILITY

Q. What is your view of the possibility to build the 21st century system?

A. It remains quite positive and has been strengthened by recent events. In my initial testimony, I focused on the availability of resources and the crowding out phenomenon by looking primarily at U.S. states.[32] Here I update that analysis with global comparisons.

First in Attachment MNC – CR – 9, I provide a measure of the insolation of nations compared to the reliance on non-hydro-renewables. We find the U.S. is in the middle of the pack, close to China. There is obviously a substantial improvement compared to other advanced industrial nations, the Netherland and Australia in particular, but also Germany.

Second, we observe the crowding out phenomenon. The higher dependence on nuclear, the lower the use of other resources. Here, there is an interesting pattern involving the former members of the Soviet Union (the SSR nations). Several of them are outliners and all of them are on the high side. This was the policy of Russia. Chernobyl and the war in Ukraine remind us of the dangers associated with this dependence on nuclear.

Third, in my initial testimony, I identified a lengthy bibliography of peer-reviewed papers and research reports that support the conclusion that the tools are available to run a 21st century system that delivers reliable, low cost, low carbon clean electricity. Here I add about 50 citations, some old that I had missed, but the vast majority are more recent. The case for the availability of tools is stronger today.

Q. Why are you concerned about the CEC analysis?

A. The analysis of availability has been given a central location in this proceeding by the California Energy Commission (CEC), but the CEC puts all the errors of the earlier, Rulemaking proceeding at the center of the cost recovery proceeding, I criticize the unrealistic assumptions applied, as I did in my earlier testimony.

The CEC's analysis of cost is essentially a static backward-looking analysis at a dynamic moment where forward-looking trends are powerful. Additionally, it has the following flaws:

1. Like-for-like analysis is inane in a time of transition. It is a classic example of baseload bias that results in a bad case of myopia.[33]

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[32] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007, Attachments MNC-3.7 and MNC -4.2 and associated text.

[33] *Id.*, pp. 73-76.

2. The practice of like-for-like is also biased against the alternatives. While the alternatives are excluded because they do not meet the explicit letter of the law, many of the factors that could raise the cost of DC are not included. I referred to this as the unacceptable "willing suspension of disbelief."[34]
3. The shortfall that the CEC talks about is extremely limited and could well be smaller than a number of alternatives which have been excluded by assumption. Relaxing one or two of the assumptions (against alternatives or for DCPP) could change the conclusion.[35]
4. Diablo Canyon is assumed to be spending about 1billion dollars of Taxpayer moneys (much of which is recovered as a subsidy from federal taxpayers), which distorts the picture of the cost of DC substantially. In fact, California accounts for about 13% of federal revenues, so part of that burden falls on the taxpayers in the state.
5. While the cost of DC in the first year of extension (2025) is just under $80/mwh, when the taxpayer funded subsidy is included, it is close to $130/Mwh.
6. The CEC admits that it has a very different charge than it pursued. By truncating the analyses, it ignores at least half a decade of development. This requirement specifies that the California Energy Commission (CEC) must determine whether extended operations of the Diablo Canyon Power Plant, compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code. Yet the CEC report repeatedly states that developments of alternatives could result in rendering Diablo Canyon unnecessary by "2030 or before." As the CEC report puts it:

   "However, continued investments by LSEs in clean resources to meet IRP procurement orders, which includes resources to replace DCPP, can position the state to replace the energy and capacity provided by DCPP by or before 2030. This report does not come to any conclusion how long it would be cost effective and prudent to extend DCPP operations. Complementary investments in demand-side resources and

[34] *Id.*, passim, defined at p. 2.
[35] *Id.*, MNC-6.2 and associated text.

long-duration energy storage would bolster the state's position to maintain reliability with DCPP by or before 2030 while promoting resource diversity."[36]

Q. How has the grid performed in the opinion of CAISO

A. I begin by showing that the past two years are consistent with my previous testimony (see Attachment MNC – CR – 9). Two years later, in spite an extremely hot early summer, CALISO had "a fairly comfortable cushion of around 12,000 megawatts" (almost one quarter of the system).[37] It had met the challenge without any "flex alerts" because in just a year and a half, "the state has added nearly 11,600 megawatts of new grid resources since 2022. Of that amount, energy storage from batteries accounts for 5,800 megawatts."[38] This tremendous growth of renewables and storage is consistent with the long-term trend).

As Attachment MNC-CR-10 shows, after a hiccup in 2020 (which may have influenced the misunderstanding of the condition of the grid by legislators and the CEC), the growth of the Clean Energy Grid in California is adding capacity that will more than replace the equivalent of the power as produced by DCPP by 2030.

Attachment MNC – CR - 11 presents the CPUC's Preferred System Portfolio total installed capacity mix by fuel type. We focus on the relative contributions of the five largest renewable resources compared to DCPP in the period between 2025 and 2030. By 2026 the additions to capacity are twice as large as DC. By 2030, they are almost 10 times as many new resources as DC.

The PUC may have been a bit optimistic in its PSP, but not by enough to justify the multibillion dollar expenditures on DC, as shown in Attachment MNC – CR – 11, which reproduces attachment MNC – 6.2).[39] The shortfall in 2024 and 2025 can be largely filled with supply-side resources and demand response that CAISO has shown are available. By 2026 there is no shortfall, and the chances of any shortfall are diminishing. This conclusion is certainly consistent with the CEC observation that resources will be adequate by 2030 or even sooner.

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[36] California Energy Commission, 2024, Staff Report Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison: Comparison to Alternative Portfolio of Resources Consistent with Greenhouse Gas Reduction Goals, May, p. 3

[37] Nikolewski, Rob, 2024, "California's power grid stood up to a recent heat wave, but summer is far from over," *The San Diego Union-Tribune,* July 22.

[38] Nikolewski, Rob, 2024, "California's power grid stood up to a recent heat wave, but summer is far from over," *The San Diego Union-Tribune,* July 22.

[39] This is the first attachment have brought forward directly from my Initial testimony, only because the CEC has brought forward all the arguments from the earlier proceeding.

In my initial testimony I assumed that the federal and state subsidies were cumulative.[40] However, PG&E gas declared that it would use the federal "gift" to retire a part of the state loan. However, that just serves to make an important point. The subsidies are part of the total cost of bringing DC back online. The use of the subsidies just determines who is on the hook for the cost of the subsidy, not how much it will cost. State ratepayers are also asked to pick up the other costs of DC, particularly the operating costs (see Attachment MNC -CR- 11).

Another way to approach this analysis is to ask how much alternatives the total cost of DCPP could buy. Moreover, since there is no need for DC after 2026, we would not have to "buy" all of DC. Unlike renewable supply, which comes in the form of projects thar are 100 to 175 MW, Diablo Canyon is an "all or nothing" proposition (all 22,000 MW). As shown in Attachment MNC – CR- 12, buying two tranches of wind or solar would fill any resource shortfall at a fraction (7%) of the cost. If these resources added the same amount to the mix, even though there is no gap, they would cost only 35% of DC while adding a total of 6 time as much capacity. Going back to Attachment MNC-1of my earlier testimony, this is the bulk of the difference between nuclear and wind and solar, with storage. The most recent number from Lazard puts the capital cost of wind and solar with batteries at only 41% of nuclear, but the difference in operation and maintenance costs is much larger, with wind and solar being only 30% of nuclear costs.

In my initial testimony I argued that aging reactors cost at least $70/Mwh and perhaps as much as $90.[41] Others in resource proceeding projected higher prices and I showed how this was possible.[42] Even at $70/Mwh, there are numerous alternatives (efficiency, wind, hybrid system with wind or solar) that have a substantially lower cost and are quick to market.The demand-side measures taken by CAISO and the other utilities have had a significant impact and cannot be ignored.vThe dramatic change in circumstances has dramatically lowered the threat of a shortfall.

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[40] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007, Attachment MNC – 6.5 and associated text.
[41] Exh. SLOMFP_04 Corrected Opening Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007, Attachment 3.6 and associated text.
[42] Exh. SLOMFP_08 Reply Testimony of Mark Cooper on Phase 1, Track 2 Issues in R.23-01-007, Attachment MNC-R-1 and associated text.

Q. Does this conclude your testimony?

A. Yes.

ATTACHMENT A

DOCKETED

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STAFF REPORT

Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison

Comparison to Alternative Portfolio of Resources Consistent with Greenhouse Gas Reduction Goals

May 2024 | CEC-200-2023-013-SF

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ABSTRACT

The *Senate Bill 846 Diablo Canyon Power Plant Extension Cost Comparison – Comparison to Alternative Portfolio of Resources Consistent with Greenhouse Gas Reduction Goals* addresses a requirement in Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846). This requirement specifies that the California Energy Commission (CEC) must determine whether extended operations of the Diablo Canyon Power Plant, compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code.

Keywords: Reliability, Diablo Canyon Power Plant, demand side resources, supply side resources, extreme events, climate change, reliability assessments

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Diablo Canyon Power Plant and SB 846 Overview

Diablo Canyon Power Plant (DCPP) consists of two nuclear reactors (Units 1 and 2) that produce a total of about 18,000 gigawatt-hours (GWh) of electricity annually, or 2.2 gigawatts (GW) of net peak capacity. PG&E is the holder of Facility Operating License Nos. DPR-80 (Unit 1) and DPR-82 (Unit 2). Each license authorizes the operation of DCPP units 1 and 2, set to expire by the end of 2024 and 2025, respectively. While planning for the replacement for DCPP has been ongoing since 2016, CPUC ordered load-serving entities (LSEs) in 2021 to procure at least 2,500 MW of zero-emitting resources to replace DCPP by June 1, 2025.

As described in the (DCPP Power Plant Extension Report) issued by the CEC in March 2023, there have been delays with resources coming online. Recent supply chain constraints in the market for solar, wind and energy storage resources and development delays (for example, interconnection and permitting), as well as increasingly frequent and more intense climate-driven extreme weather events, have resulted in risks to new resources coming online as planned and overall system reliability upon the retirement of DCPP. These challenges result in an upper limit to what resources can be brought on-line in a given time frame. Thus, maintaining grid reliability during the increasingly frequent extreme weather events may require the delay and careful planning of the retirement of DCPP or a significant increase in demand-side resources that are not subject to the same supply chain and interconnection challenges.

Senate Bill 846 (Dodd, Chapter 239, Statutes of 2022) (SB 846) notes that seeking to extend DCPP operations is the policy of the Legislature because it is prudent, cost effective, and in the best interest of California electricity customers. As such, SB 846 creates an option to extend DCPP operations by five years with a $1.4 billion loan provided by the state. In parallel to this extension, SB 846 calls for the California Energy Commission (CEC) to "present a cost comparison of whether extended operations at the Diablo Canyon powerplant compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, inclusive, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code. As part of this comparison, the CEC shall evaluate the alternative resource costs, and shall make all evaluations available to the public within the proceeding docket" by September 30, 2023. However, as described in this report, there are no supply resources incremental to those already begin procured that can be brought on-line before the planned 2024 and 2025 retirements of the DCPP units to meet the like-for-like energy generation of 18,000 GWh per year. This report describes the analysis conducted on the technical potential and costs of alternative resources against extending DCPP.

Given that the operational licenses of DCPP Units 1 and 2 are set to expire by the end of 2024 and 2025, respectively, and the state is facing near-term potential for grid reliability issues from climate change impacts, this report evaluates resources that can support grid reliability at the planned retirement dates However, it should be noted that on December 15, 2023, the CPUC issued Decision 23-12-036 conditionally approving the extended operations at Diablo

Canyon powerplant pursuant to SB 846 until October 31, 2029 for Unit 1 and October 31, 2030 for Unit 2.[1]

On December 19, 2023, the U.S. Nuclear Regulatory Commission (NRC) staff determined the license renewal application submitted by Pacific Gas & Electric on November 7, 2023, contained sufficient information to formally docket the application and begin the detailed safety and environmental reviews. With the docketing of the application, the reactors' operating licenses will remain in effect under an exemption to NRC regulations until the review is complete. A copy of the Diablo Canyon license renewal application is available online and publicly at the San Luis Obispo Library at 995 Palm Street, San Luis Obispo.[2] NRC license renewals typically take 18 – 22-months after submittal.

Resource Eligibility Criteria

Resource eligibility criteria were developed to identify resources to replace DCPP generating capacity and energy production in alignment with legislative requirements and DCPP characteristics. Supply and demand resources that satisfy the following criteria were further evaluated to potentially replace DCPP:

- **Zero-carbon:** Resources that produce no carbon emissions, similar to DCPP operations and consistent with the greenhouse gas (GHG) emission reduction goals.
- **Does not compete with Integrated Resource Plan (IRP) procurements:** Resource types incremental to, and not identified in, planned procurements to prevent increased costs in the market for resources already being procured by load-serving entities.
- **Grid value:** Resources that can provide the grid with consistent energy production throughout the day and reliable power during net-peak periods.

Diablo Canyon Costs

At the direction of the California Public Utilities Commission (CPUC), Pacific Gas and Electric (PG&E) submitted testimony presenting historical and forecast costs associated with potential improvements, day-to-day operations, and extended operations to be $736 million in 2023, $969 million in 2024, and $1.4 billion in 2025. These are preliminary cost estimates and may grow with additional planning and implementation. The costs presented by PG&E have been contested as being inaccurate by comments submitted in response to the draft of this report. This report does not reach any findings with respect to how long it may be cost-effective or prudent to operate DCPP.

SB 846 includes a provision that allows PG&E to access a $1.4 billion loan from the state's general fund to help extend DCPP operations, which include one-time expenditures such as capital, operating, relicensing, transition, and fuel costs. Through the SB 846 loan, PG&E could seek to recover $42 million in 2022, $381 million in 2023, $408 million in 2024, $210 million in 2025, and $58 million in 2026 for costs associated with extending the operation of DCPP,

1 https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M521/K496/521496276.PDF

2 The potential costs associated with PG&E's license renewal application and Diablo Canyon Independent Safety Committee recommendations regarding seismic safety and deferred maintenance are not included in this report.

which is a portion of the annual total forecasted costs above. PG&E will need to obtain these funds from the Department of Water Resources in advance of actual expenditures.
This report evaluates alternative resources against anticipated incurred costs of a DCPP extension. Therefore, it is noted that PG&E would need to request funds before costs are incurred in order to secure necessary materials and services.

Furthermore, PG&E applied for funding from the U.S. Department of Energy's Civil Nuclear Credit Program. DCPP received conditional federal funding under the DOE's new nuclear credit program. In November 2022, the DOE approved conditional funding of up to $1.1 billion to prevent the closure of DCPP. For the analysis in this report, CEC has compared alternatives to the $1.4 billion state loan.

When evaluating potential extended retirement dates, a robust additional analysis of the cost-effectiveness and prudence of DCPP extended operations should be performed based on updated DCPP cost recovery requests.

Alternative Resource Scenarios

Resources were evaluated for their ability to replace DCPP's full energy production in a **like-for-like** manner (18,000 gigawatt-hours [GWh]/year) or DCPP's **net peak** capacity (2.2 GW). Three scenarios were developed:

- The **supply scenario** evaluates supply resources that can provide consistent energy throughout the day to directly replace DCPP energy generation in a **like-for-like** manner.
- The **demand scenario** evaluates a combination of demand and distributed resources that can replace DCPP **net peak** capacity when operated together within a virtual power plant (VPP) construct.
- The **demand + supply scenario** evaluates demand and supply resources, particularly long-duration energy storage, that can replace the **net peak** capacity for DCPP.

Only resources that align with all resource eligibility criteria were evaluated for technological potential, cost, and project lead time in these scenarios.

Conclusions

The analysis shows that there are no supply resources that can be brought on-line before the planned 2025 retirement of DCPP to meet the like-for-like energy generation of 18,000 GWh per year. This situation is due to technology characteristics and the time required to develop and interconnect the projects but also due to the technology maturity of some resources. While there are about 500 MW of demand-side resources that could be deployed by 2025, there is no mix of resources that can adequately replace the 2.2 GW of net peak capacity of DCPP by 2025.

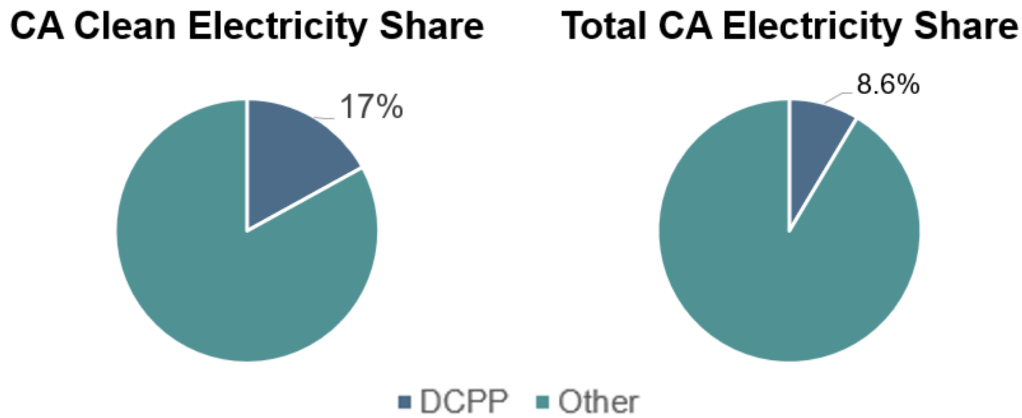
However, continued investments by LSEs in clean resources to meet IRP procurement orders, which includes resources to replace DCPP, can position the state to replace the energy and capacity provided by DCPP by or before 2030. This report does not come to any conclusion how long it would be cost effective and prudent to extend DCPP operations. Complementary investments in demand-side resources and long-duration energy storage would bolster the state's position to maintain reliability with DCPP by or before 2030 while promoting resource diversity.

CHAPTER 1: Introduction

Diablo Canyon Power Plant and SB 846 Policy Background

The Diablo Canyon Power Plant (DCPP) is a nuclear power plant near San Luis Obispo that is owned and operated by Pacific Gas and Electric Company (PG&E). The DCPP consists of two nuclear reactors (Units 1 and 2) that began operation in May 1985 and March 1986, respectively. DCPP produces about 18,000 gigawatt-hours (GWh) of electricity annually, which is about 9 percent of California's current in-state generation and 17 percent of California's zero-carbon electricity, as seen in Figure 1: DCPP Electricity Shares in California. DCPP reactor units are licensed by the United States Nuclear Regulatory Commission (NRC) to operate until November 2, 2024 (Unit 1), and August 26, 2025 (Unit 2).[3]

Figure 1: DCPP Electricity Shares in California



Source: Senate Bill 846, figure developed by Guidehouse for this report

In November 2009, PG&E submitted a license renewal application for Units 1 and 2 of DCPP to extend the units for another 20 years past the end of the current expiration dates: Unit 1 in November 2024 and Unit 2 in August 2025. On March 7, 2018, PG&E requested to withdraw the license renewal application based on projected energy demands and other economic factors in California. The California Public Utilities Commission (CPUC) approved PG&E's resource planning decision to withdraw the license renewal application review in a decision dated January 11, 2018. Subsequent to withdrawing its license renewal application, PG&E has stated that it has begun decommissioning planning.

3 Erne, David and Mark Kootstra. 2023. *Diablo Canyon Power Plant Extension – CEC Analysis of Need to Support Reliability.* California Energy Commission. Publication Number: CEC-200-2023-004. Available at https://www.energy.ca.gov/publications/2023/diablo-canyon-power-plant-extension-cec-analysis-need-support-reliability.

In the CPUC's Decision Requiring Procurement to Address Mid-Term Reliability,[4] the CPUC ordered load-serving entities to procure 2,500 MW of zero-emitting generation, generation paired with storage, or demand response resources by June 1, 2025, to replace DCPP.

On September 2, 2022, the State of California enacted Senate Bill 846 (SB 846, Dodd, Chapter 239, Statutes of 2022). This law invalidated the 2018 CPUC decision to approve termination of PG&E's license renewal application and retirement of DCPP Units 1 and 2 and directed the CPUC to establish new retirement dates conditioned on further action by the Nuclear Regulatory Commission.[5] SB 846 includes the following:

- Preserves the option of continued operations of DCPP "for an additional five years may be necessary to improve statewide energy system reliability and to reduce the emissions of greenhouse gases while additional renewable energy and zero-carbon resources come online, until those new renewable 1 and zero-carbon resources are adequate to meet demand."
- "Accordingly, it is the policy of the Legislature that seeking to extend the Diablo Canyon power plant's operations for a renewed license term is prudent, cost-effective, and in the best interest of California's electricity customers."
- States the intent of the Legislature to make available a $1.4 billion loan from the general fund to the Department of Water Resources to continue operations of DCPP Unit 1 until no later than November 1, 2029, and Unit 2 until no later than November 1, 2030.
- Requires that the CPUC not include and "disallow a load-serving entity from including in their adopted integrated resource plan the energy, capacity, or any attribute from (DCPP) Unit 1 beyond November 1, 2024, or Unit 2 beyond August 26, 2025."
- Requires the CPUC to set new retirement dates for the Diablo Canyon power plant, conditioned upon the United States Nuclear Regulatory Commission extending the operating licenses of the power plant by December 31, 2023.
- Requires the CEC to determine whether the state's electricity forecasts for 2024–2030 "show potential for reliability deficiencies if Diablo Canyon Power Plant operations are not extended beyond 2025, and whether extending operations to at least 2030 is prudent to ensure reliability and consistency with the state's emission reduction goals."
- Requires the CEC to "present a cost comparison of whether extended operations at the Diablo Canyon powerplant compared to a portfolio of other feasible resources available for calendar years 2024 to 2035, inclusive, is consistent with the greenhouse gases emissions reduction goals of Section 454.53 of the Public Utilities Code. As part of this comparison, the CEC shall evaluate the alternative resource costs, and shall make all evaluations available to the public within the proceeding docket" by September 30, 2023.

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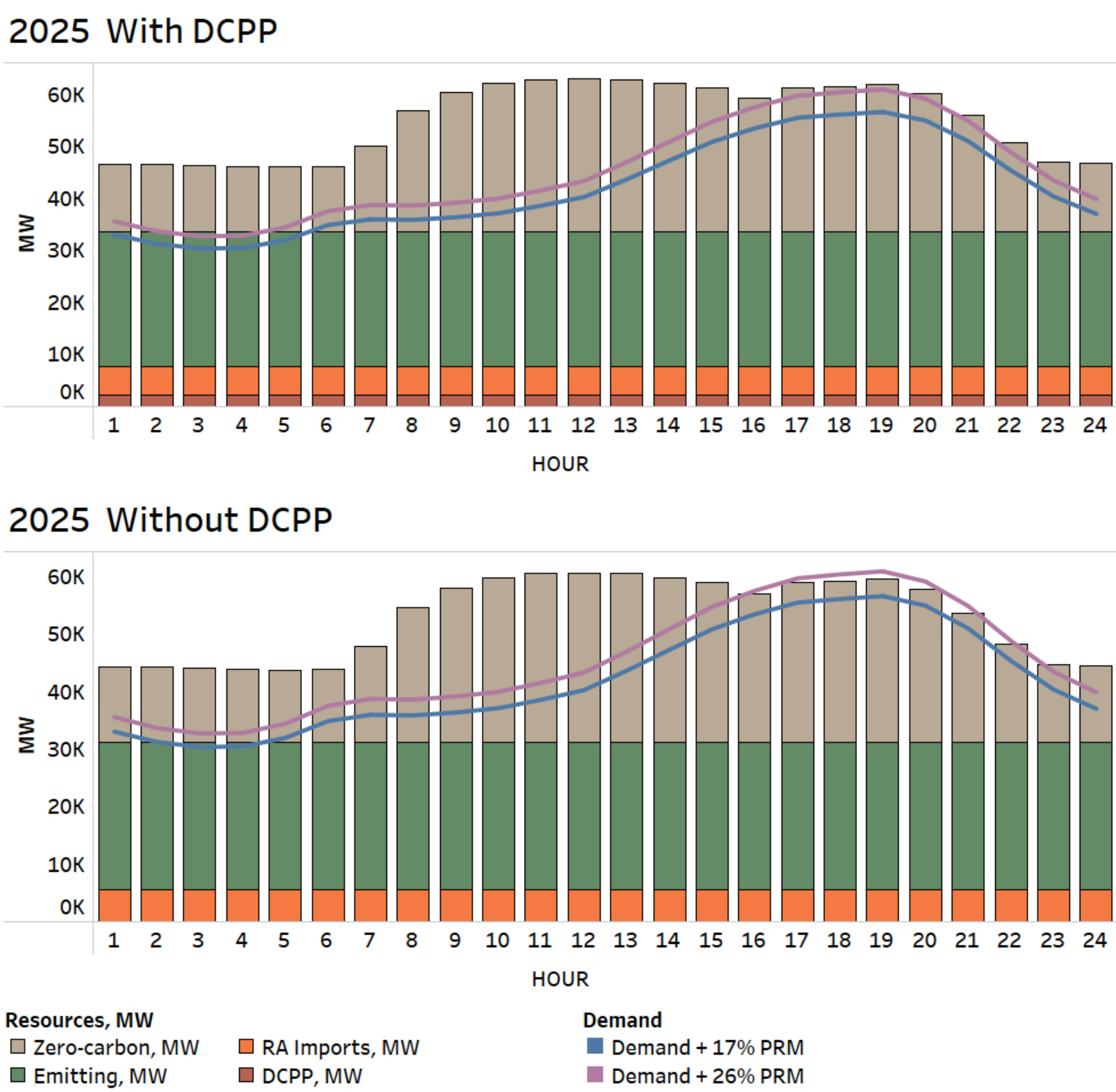
4 Decision Requiring Clean Energy Procurement for Mid-Term Reliability, California Public Utilities Commission, D21-06-035, June 24, 2021

5 Nuclear Regulatory Commission, Docket Nos. 50-275 and 50-323, Pacific Gas and Electric Company, Diablo Canyon Power Plant, Units 1 and 2 Exemption.

The key driver for SB 846 was to support grid reliability. The California grid is facing challenges, such as climate change (for example, extreme heat, extreme drought, and wildfire) supply chain issues impacting resource build-out, and interconnection timelines. The supply chain and interconnection challenges result in an upper limit to what can be brought on-line in a given time frame regardless of how much additional procurement is ordered. Thus, DCPP was identified as an incremental resource to what is already projected to come on-line, and that provides reliable electricity output for California's grid while being a clean-energy resource.

Figure 2: 2025 Projected Capacity With and Without DCPP Figure 2 shows the impact of DCPP on projected 2025 capacity within the California Independent System Operator (California ISO) system when compared to the CEC's demand forecast. By applying 24-hour resource profiles to projected capacity for all California ISO supply resources, Figure 2: 2025 Projected Capacity With and Without DCPP demonstrates DCPP's effect on the net-peak period during the max-peak day in September 2025, where there is greater chance of supply shortfall under extreme conditions (Demand + 26 Percent PRM).

Figure 2: 2025 Projected Capacity With and Without DCPP



Note: Figures were created using data from [Joint Agency Reliability Planning Assessment: SB 846 Quarterly Report and AB 205 Report].

Source: CEC staff with CPUC and California ISO data

SB 846 Approach and Considerations

This report evaluates the feasibility, cost, and potential of alternative resources, with similar characteristics as DCPP. The two characteristics considered are 18,000 GWh/year energy production (9,000 GWh/year from Unit 1, 9,000 GWh/year from Unit 2) and the 2.2 GW of DCPP generation capacity that supports reliability at net peak, the time of day in which total demand minus wind and solar generation is the highest. This net peak occurs in the evening hours, typically between 4 p.m. and 9 p.m., and is the time in which California is vulnerable to experiencing its most stressed grid conditions.

To align with the intent of SB 846 and evaluate the feasibility of resources to come on-line and replace DCPP before the current retirement dates, the CEC has focused its analysis on 2024 and 2025. These are the two years where the two reactors for DCPP may be decommissioned to compare to a set of resources that could potentially replace DCPP before it retires. CEC identified a broad set of resources ranging from demand side to supply side. Examples of these types of resources can be found in Tables 1-4. The CEC then filtered the list based on the ability of these resources to satisfy three resource eligibility criteria that align with DCPP characteristics. Resources that satisfy all criteria, which are described in Chapter 2, are eligible for analysis. These resources are grouped into supply resources and demand resources to ease evaluation of resources. All resources are evaluated based on the associated technical energy production potential, costs, and project lead time. Under SB 846, these resources are evaluated primarily to directly replace the 18,000 GWh of energy production from DCPP (like-for-like analysis) and secondarily replace the full capacity of DCPP during net-peak hours (net-peak analysis). For a like-for-like analysis, resources must provide consistent energy production to fully replace DCPP. Conversely, the net-peak analysis objective is less stringent, so more resources are eligible for consideration. Based on these two analysis objectives, resources are grouped into different scenarios catered to each objective.

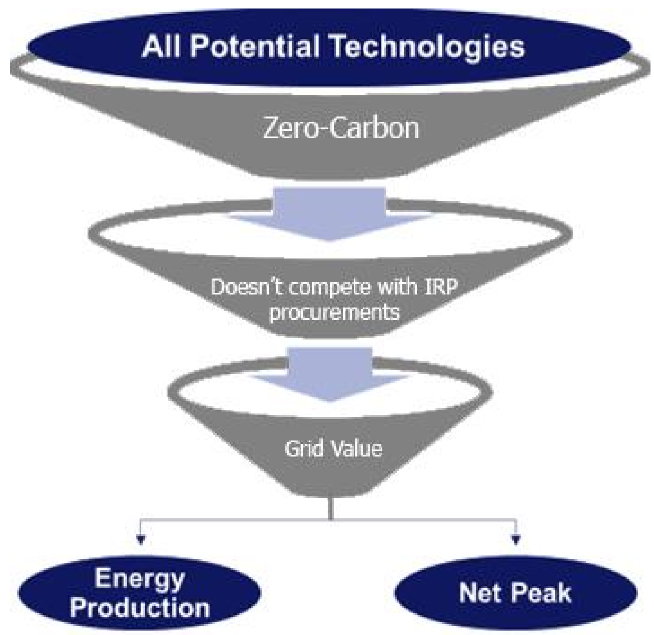
CHAPTER 2:
Alternative Resource Characterization

Resource Eligibility Criteria

In alignment with legislative requirements and DCPP characteristics, the CEC has developed three resource eligibility criteria (eligibility criteria, or criteria) to identify resources to replace the generating capacity and energy production of the DCPP. Resources that satisfy all three criteria are further evaluated as part of an alternative portfolio to replace DCPP. Figure 3 demonstrates the resource filtering process based on the following criteria:

- **Zero-carbon**: Refers to resources that produce no carbon emissions. As stated in SB 846, DCPP supplies zero-carbon electricity, and an extension may be necessary until "new renewable energy and zero-carbon resources are adequate to meet demand."[6] Therefore, this criterion focuses on zero-carbon resources that can replace DCPP's capacity. Replacement with a fossil-fueled resource would result in increased GHG emissions. Therefore, flexible-fuel resources[7] are excluded from evaluation.
- **Integrated resource plan (IRP) procurements**: SB 846 notes the importance of having "sufficient, predictable resource procurement and development to avoid unplanned energy supply shortfalls by taking into account impacts due to climate change and other factors that can result in those shortfalls." Supply chain and interconnection delays have impacted the ability of new projects to come on-line as planned. As such, the extension of DCPP provides support for grid reliability until the new resources can come on-line to meet demand. SB 846 requires that the CPUC direct load-serving entities to not procure capacity and energy from the DCPP and report it in the integrated resource plan portfolios (IRPs).[8] This requirement ensures that LSEs will continue to procure clean energy resources as if DCPP were not

Figure 3: Resource Filtering on Eligibility Criteria



Source: Guidehouse analysis for this report

6 California Legislative Information. 2022. [Senate Bill No. 846](https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB846), Section 5 25548 (b), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202120220SB846.

7 *Flexible-fuel resources* are technologies that have the flexibility of operating on different fuel types and potentially different fuel blends, including fossil fuels. These technologies are used as transitional technologies from fossil fuels to zero-carbon fuels.

8 California Legislative Information. 2022. Senate Bill No. 1174, California Public Utilities Code Section 454.52(f)(1) at https://legiscan.com/CA/text/SB1174/id/2605746.

on-line — allowing for a swifter replacement of the energy and capacity of DCPP with newly built clean power projects. Resources being pursued for procurement by LSEs are solar, wind, and energy storage. While these resources are coming on faster than ever in California, they are still not coming on quickly enough to meet demand due to interconnection delays, supply chain issues, and sheer competition for limited clean energy resources, resulting in a tight market for available solar, wind, and energy storage. Ordering more of these resources does not mean that they can come on-line quickly enough to provide the necessary grid support.

With recent supply chain disruptions and increased demand for materials for clean energy projects, the price of solar modules increased by 25 percent and wind turbines by 20 percent.[9] Ordering more clean energy supply in a tight market would likely have the unintended consequence of driving up prices further and creating further delays for current projects.

Therefore, this analysis excludes these conventional clean resources from consideration for further investment from the state, as state investments in conventional solar, wind, and battery storage would only exacerbate the tight market conditions[10] and interconnection bottlenecks in getting these clean resources on-line.

While resources that compete for IRP procurements are screened out, there may be opportunities for the state to further invest in resources that could meet energy demand but are not readily available or cost-effective today and are therefore not being procured by LSEs.

- **Grid value**: Focuses on resources that can provide the grid with similar reliability and electricity output as DCPP. The biggest values DCPP provides to the grid are consistent energy production throughout the day and reliable power during net-peak periods.
  - **Energy production (like-for-like)**: Since DCPP generates 18,000 GWh/year, a **like-for-like** replacement looks for resources that can replicate or exceed this energy production with zero emissions. This type of resource provides GHG-free energy to the grid at any time.
  - **Net Peak**: From a grid reliability perspective, DCPP provides 2.2 GW of capacity during net-peak periods (4 p.m. to 9 p.m.). To properly replace the net-peak capacity of DCPP, alternative resources are needed that can reliably satisfy the net-peak demand of the grid.

Resource Analysis

CEC staff evaluated alternative resources that met the above criteria for the ability to come on-line in 2024 and 2025 in line with the planned retirement of each DCPP generating unit to measure how those resources can contribute toward the California electricity grid by the time of DCPP's retirement. Staff evaluated alternative resources based on the following three characteristics:

9 IEA - Clean energy supply chains vulnerabilities, via https://www.iea.org/reports/energy-technology-perspectives-2023/clean-energy-supply-chains-vulnerabilities

10Summer Reliability Workshop presentation, https://efiling.energy.ca.gov/GetDocument.aspx?tn=250179, slide 9.

- **Technological potential**: How much energy production (GWh) or capacity (GW) of this resource can be integrated annually?
- **Project lead time**: How long does this resource take to implement?
- **Cost estimate**: How much does this resource cost to acquire, integrate, and operate?

The CEC considered other resource-specific attributes such as supply chain limitations, permitting processes, and implementation requirements. CEC staff bundled these alternative resource characteristics into portfolios and compared them to DCPP cost and capacity characteristics.

Resource Categorization and Definitions

CEC staff separated the alternative resources under analysis into two resource classes — supply resources and demand resources. This section describes how the alternative resources for DCPP were considered and filtered based on the resource eligibility criteria.

Supply Resources

The supply resource class refers to resources that can generate electrical energy and provide capacity or energy to the electrical grid. Table 1 provides a complete list of the supply resources considered for this effort before filtering using the resource eligibility criteria.

Table 1: Complete Supply Resource List

Category	Supply Resources
Gaseous Fuel Generation	Combustion turbines/reciprocating engines (100% Clean Hydrogen)
Gaseous Fuel Generation	Fuel cells (100% clean hydrogen)
Gaseous Fuel Generation	Noncombustion and non-fuel-cell gas-fueled generator, such as linear generators (100% Clean Hydrogen)
Gaseous Fuel Generation	Fossil and nonclean hydrogen (reciprocating engines/combustion turbines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)
Gaseous Fuel Generation	Blended gas generation (reciprocating engines/combustion turbines, noncombustion, and non-fuel-cell gas-fueled generators)
Gaseous Fuel Generation	Renewable natural gas (RNG) combustion and fuel cells
Renewables	Solar (≥1 MW)
Renewables	Wind (onshore, floating offshore)
Renewables	Geothermal
Renewables	Small hydro (< 30 MW[11])
Long-Duration Energy Storage	Pumped storage hydro
Long-Duration Energy Storage	Electrochemical (e.g., flow, iron-air, zinc, sodium, excluding lithium-ion)
Long-Duration Energy Storage	Mechanical* (e.g., gravity-based, geo-mechanical, excluding PSH)
Long-Duration Energy Storage (LDES)	Thermal* (solid medium, liquid medium)
Other Energy Storage	Compressed air energy storage* (CAES)
Other Energy Storage	Energy storage (short duration, < 8 hours)

***These LDES options do not directly store electricity/electrons and require additional processing to provide electricity output.**

Source: Guidehouse analysis for this report

With this complete list of supply resources, CEC staff then applied the eligibility criteria to evaluate which technologies fit into the scope of SB 846 and are appropriate alternative resources to DCPP. Many conventional supply resources, such as gas-fired plants, were screened out because of incompatibility with the eligibility criteria. After filtering for zero-carbon supply resources, the biggest limiting factor was screening out resources that competed with procurement by electricity providers within the California ISO.

Renewable energy resources such as geothermal, hydropower, solar, and on/offshore wind are proven resources that may be important for California's energy future, but they were removed from this analysis as are the resources likely to be procured by CPUC jurisdictional LSEs for

11 The CEC defines small hydro as any facility less than 30 MW, https://www.energy.ca.gov/data-reports/california-power-generation-and-power-sources/hydroelectric-power.

their compliance with IRP procurement requirements and POUs within California ISO to meet the state's carbon reduction goals and reliability need.

The rationale behind excluding geothermal, hydropower, solar, and on/offshore wind resources was the existence of considerable competition for their procurement. The current rigorous competition for clean energy projects necessitated a comprehensive screening process. Notably, this screening resulted in the exclusion of all technologies dependent on clean hydrogen, given that hydrogen production relies on the same pool of clean energy resources that have already been allocated for other purposes such as charging battery storage systems to support reliability during the net peak.

Flexible or blended gaseous fuel generation resources are not zero-carbon resources as they use fossil fuels to varying extents. Table 2 provides a list of the filtered supply resources and gives specific causes for the exclusion resources.

Table 2: Filtered Supply Resource List

Supply Resource	Included or Excluded?	Causes for Exclusion
Electrochemical (e.g., flow, iron-air, zinc, sodium, excluding lithium-ion)	Included	Not applicable.
Mechanical (e.g., gravity-based, geomechanical, excluding PSH)	Included	Not applicable.
Thermal (solid medium, liquid medium)	Included	Not applicable.
Solar (utility-scale > 5 MW, other 1 – 5 MW)	Excluded	Competes with IRP procurement orders
Wind (onshore, floating offshore)	Excluded	Competes with IRP procurement orders
Geothermal	Excluded	Competes with IRP procurement orders and GHG releases during operation
Small Hydro (< 30 MW)	Excluded	Competes with IRP procurement orders
Pumped Storage Hydro (PSH)	Excluded	Competes with IRP procurement orders
Compressed Air Energy Storage (CAES)	Excluded	Competes with IRP procurement orders
Energy Storage (short duration, < 8 hours)	Excluded	Competes with IRP procurement orders
Combustion Turbines/Reciprocating Engines – 100% clean hydrogen/ Renewable Gas (RNG)	Excluded	Hydrogen: Relies on clean energy resources for electrolysis. RNG/Biogas: Competes with IRP procurement orders

Supply Resource	Included or Excluded?	Causes for Exclusion
Fuel Cells	Excluded	100% clean hydrogen source not available at this time.
Noncombustion and Non-Fuel-Cell Gas-Fueled Generator	Excluded	100% clean hydrogen source not available at this time.
Fossil and non-clean hydrogen (reciprocating engines/combustion turbines, fuel cells, noncombustion and non-fuel cell gas-fueled generators)	Excluded	Not a zero-carbon resource
Blended Gas Generation (reciprocating engines/combustion turbines, noncombustion and non-fuel cell gas-fueled generators)	Excluded	Not a zero-carbon resource

Source: Guidehouse analysis for this report

Supply resources included in this analysis may compete with IRP procurement order requirements in the future as they become more technologically and commercially mature and costs drop to make them more competitive. As they are not competitive, they are included in this analysis. While LDES resources are called out by the CPUC's procurement orders, most of the near-term (1-2 years time horizon) are predominantly lithium-ion battery storage systems, which are intentionally excluded from this analysis to avoid competition with LSEs' ongoing procurement requirements.

Demand Resources

The demand resource class refers to resources that are installed and operated on the customer side to generate energy or manage load. Demand resources can be diverse in terms of technologies and end uses, as well as in terms of market design or program constructs. Demand resources encompass distributed energy resources (DERs), such as rooftop solar and storage and smart thermostats to provide demand response (DR). On a per customer basis, demand resources have relatively small contributions and may be subject to fluctuations in performance based on customer preferences or behavioral choices. However, aggregation, or collection, of demand resources, whether by LSEs or third-party DR providers (sometimes referred to as "aggregators"), can provide meaningful impacts. In addition, centralized control of several resources provides greater assurance of those resources being available when needed.

Given these considerations, demand resources are evaluated as aggregated resources through a virtual power plant (VPP) construct. For this analysis, VPPs are defined[12] as centrally

12 The VPP definition used in this SB 846 analysis was shaped by the Department of Energy and Brattle Group's VPP definitions.

controlled DERs from multiple customers to provide cost savings to customers and demand reductions that can benefit grid reliability. The VPP construct assumes DERs and other demand resources are controlled through aggregators and are visible to the grid operator. VPPs are composed of zero-carbon DERs and dispatchable DR and would be best suited to address the 2.2 GW capacity of DCPP during net-peak periods. As VPPs grow large enough and the market matures, they may ultimately be able provide energy support for the grid; however, there is a stronger case for capacity support. Table 3 lists the demand resources that were considered in the analysis.

Table 3: Complete Demand Resource List

Category	Demand Resources
Demand Response	Dispatchable DR measures[13]
Electric Vehicles	Electric vehicle control infrastructure (smart chargers, bidirectional chargers)
Distributed Generation	Solar + battery storage
Distributed Generation	Clean Hydrogen-powered distributed generation (reciprocating engines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)
Distributed Generation	Fossil, renewable gas generation, and non-clean hydrogen (reciprocating engines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)
Distributed Generation	Blended gas generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)
Distributed Generation	Diesel or biodiesel generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)

Source: Guidehouse analysis for this report

In alignment with the eligibility criteria, any aggregated demand resources to replace DCPP should be zero-carbon and provide generation or load reduction at net peak. Because certain demand resources depend on customer participation, such as DR and EV control, these resources better address capacity needs during peak and net-peak periods. From the full list of demand resources in Table 3: Complete Demand Resource List, the below distributed generation resources, in Table 4, were removed from consideration based on the reliance on fossil fuels and/or emissions of greenhouse gases or competition with IRP procurement orders. Table 4 shows the resulting list of eligible demand resources after this exclusion.

13 "Dispatchable DR measures" refer to various technologies that enable shedding or shifting of customer end use load when called upon, such as smart thermostats, smart water heating controls, industrial process load control, and agricultural pumping control.

Table 4: Filtered Demand Resource List

Category	Demand Resource	Included or Excluded	Causes for Exclusion
Demand Response	Dispatchable DR measures	Included	Not applicable
Electric Vehicles	Electric vehicle control infrastructure (smart chargers, bidirectional chargers)	Included	Not applicable
Distributed Generation	Solar + battery storage	Included	Not applicable
Distributed Generation	Clean hydrogen-powered distributed generation (fuel cells, reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	100% clean hydrogen source not available at this time.
Not applicable	Fossil, nonclean hydrogen, or renewable gas generation (reciprocating engines, fuel cells, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	Not a zero-carbon carbon resource RNG/Biogas: Competes with IRP procurement orders
Not applicable	Blended gas generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	Not a zero-carbon carbon resource
Not applicable	Diesel or biodiesel generation (reciprocating engines, noncombustion and non-fuel-cell gas-fueled generators)	Excluded	Not a zero-carbon carbon resource

Source: Guidehouse analysis for this report

The list of remaining demand resources in Table 4 includes dispatchable DR measures, electric vehicle control infrastructure, solar, and battery storage. These resources satisfy the resource eligibility criteria and were considered in the potential and cost analysis of a VPP-type construct to replace the 2.2 GW net-peak contributions of DCPP.

CHAPTER 3: Diablo Canyon Costs

New sources of state and federal funding have become available to keep DCPP operational via SB 846 and the U.S. Department of Energy's (DOE's) Civil Nuclear Credit Program. SB 846 includes a provision that allows PG&E to access a $1.4 billion loan from the state's general fund to help extend DCPP operations. Furthermore, PG&E applied for funding in the initial phase of the DOE's $6 billion Civil Nuclear Credit Program, meant to keep struggling nuclear power reactors open. DCPP was the first nuclear plant to receive conditional federal funding under the DOE's new nuclear credit program. In November 2022, the DOE approved conditional funding of up to $1.1 billion to prevent the closure of DCPP.[14] DOE continues to track the status of DCPP given the funding it has provided. Given state funding support and ongoing evaluation of the potential extension, SB 846 also requires PG&E to track all costs associated with continued and extended operations of DCPP.

PG&E Forecast Costs for DCPP

On April 6, 2023, the CPUC directed PG&E to submit testimony presenting "historical and forecast cost data (through 2030) for Diablo Canyon, focusing on costs associated with likely or potential improvements that might reasonably be required as part of the relicensing process."[15] The data found in PG&E's testimony,[16] presented in this chapter, are used as a baseline to compare DCPP extension costs and the cost of a mix of alternate resources in Chapter 4. These estimates were preliminary, and more detailed analysis of costs may be higher. PG&E will need to obtain these funds from the Department of Water Resources in advance of actual expenditures. This report evaluates alternative resources against anticipated incurred costs of a DCPP extension. Therefore, it is noted that PG&E would need to request funds before costs are incurred in order to secure necessary materials and services The Utility Reform Network[17] (TURN) conducted an independent analysis of DCPP extension costs, provided testimony in CPUC's proceeding, and provided a summary in CEC's reliability docket. TURN's testimony states that PG&E has underestimated the costs of extending DCPP operations.[18] Extension cost allocations, operational costs, and cost recovery will be addressed under established CPUC cost-recovery mechanisms and processes.[19] For this report, CEC used

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14 Civil Nuclear Credit Award Cycle 1 | Department of Energy.

15 California Public Utilities Commission. April 6, 2023. *Assigned Commissioner's Scoping Memo and Ruling*, Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations (R.23-01-007), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M505/K462/505462882.pdf.

16 Pacific Gas and Electric Company. May 22, 2023. *Opening Testimony, Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations* (R.23-01-007), https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6222/511023089.pdf.

17 TURN is a consumer advocacy organization and their website is https://www.turn.org/

18 The Utility Reform Network Comments – (SB 846 Diablo Canyon Power Plant Cost Analysis) – TURN testimony to CPUC on Diablo Canyon Costs available via https://efiling.energy.ca.gov/GetDocument.aspx?tn=251135

19 California Public Utilities Commission, 2023, Rulemaking 23-01-007, via https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M520/K614/520614035.PDF.

existing public information and subsequently updated the DCPP cost estimates based on PG&E's rebuttal testimony submitted July 28, 2023, for Rulemaking 23-01-007.[20] These cost estimates include costs for performance-based disbursements (total $136 million for 2024 and 2025) that will be reimbursed by the SB 846 loan program and additional extended operational fees and employee retention program expenses, which are estimated to be, on average, $295 million per year from 2024 to 2030. It does not include operational costs beyond 2025.

PG&E presented cost values for DCPP in the Electric Utility Cost Group (EUCG) accounting format, which is distinct to the general rate case (GRC)[21] accounting format, which uses the two major work categories (MWCs)[22] of expense and capital that the CPUC is most accustomed to using. PG&E claimed that EUCG cost definitions are designed to capture relevant holistic costs related to operating a nuclear generation plant. Moreover, PG&E claimed that EUCG categories tend to comingle with MWCs and thus allow for better industry benchmarking. Beyond EUCG, PG&E tracked capital, fuel, and refueling outage costs separately. Table 5 provides the complete list of the cost components PG&E used in its testimony, including EUCG components and others tracked separately, the descriptions, and ways that they map to MWCs typically used in GRCs, according to PG&E.

Table 5: Description of PG&E's Cost Components for DCPP and GRC MWC Mapping

Costs	Category	Details	GRC MWC Mapping
Nuclear Operating Costs (NOC), EUCG Cost Components	Engineering	Costs associated with study, design, and implementation of engineering	Maintain Plant Configuration
Nuclear Operating Costs (NOC), EUCG Cost Components	Loss Prevention	Costs include security, quality assurance/control, corrective action program & operating experience, safety and health, licensing, emergency preparedness, and dedicated dire responders	Loss Prevention, Manage Production, Nuclear Generation Fees

20 Pacific Gas and Electric Company, 2023, REBUTTAL TESTIMONY, via, https://docs.cpuc.ca.gov/PublishedDocs/SupDoc/R2301007/6511/515314717.pdf.

21 CPUC general rate cases (GRCs) are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. GRCs are parsed into two phases: Phase I of a GRC determines the total amount the utility is authorized to collect, while Phase II determines the share of the cost each customer class is responsible and the rate schedules for each class. CPUC web page https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/general-rate-case.

22 PG&E's GRC testimony is typically organized by its Lines of Business, in which expense and capital costs are presented separately. Expense and capital forecasts are then further broken down into Major Work Categories to represent different types of work for the LOB. Within each Major Work Category, individual projects are described for consideration by the Commission. Pacific Gas and Electric GRC Proceedings web page https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-rates/general-rate-case/pacific-gas-and-electric-grc-proceedings.

Costs	Category	Details	GRC MWC Mapping
Nuclear Operating Costs (NOC), EUCG Cost Components	Materials and Services	Costs include materials management & warehousing, contracts & purchasing, procurement engineering, and unneeded material disposal	Manage DCPP Assets
Nuclear Operating Costs (NOC), EUCG Cost Components	Fuel Management	Administrative and technical activities associated with the fuel-cycle process (contract, core designs, safety, monitoring performance, analyzing fuel market)	Maintain Plant Configuration
Nuclear Operating Costs (NOC), EUCG Cost Components	Operations	Activities associated with preparing and placing systems and components in and out of service to support normal and off-normal system operations and actions required to maintain the plant in sage operating conditions	Manage Production, Manage Environmental Operation
Nuclear Operating Costs (NOC), EUCG Cost Components	Support Services	Activities associated with information technology, business services, records management & procedures, human resources, housekeeping & facilities management, communications & community relations, nuclear offices, executives, management assistance and industry associations, employee incentive payments, insurance, payroll taxes, and pension & benefits	Manage DCPP Business, Manage DCPP Assets, Operational Management, Operational Support
Nuclear Operating Costs (NOC), EUCG Cost Components	Training – Develop and Conduct	Activities associated with development and conduction of training programs, including instructor preparation and instruction delivery time, production of class materials and assessment of the training	Nuclear Generation Fees, Operational Support
Nuclear Operating Costs (NOC), EUCG Cost Components	Work Management	Activities associated with planning & scheduling/outage management and maintenance.	Manage DCPP Assets, Operational Management, Operational Support
Other	Capital	Capital projects, including enhancements, infrastructure, information technology, capital spares, sustaining	DCPP Capital
Other	Outage	Refueling outage costs include the costs for labor, materials, equipment, and outside services	All MWC

Costs	Category	Details	GRC MWC Mapping
Other	Fuel	Provide and transport fuel (activities associated with provision and transportation of fuel including procurement, enrichment, conversion, and fabrication). Provide handling, storage, and disposal of fuel (activities associated with receiving and storing new fuel)	Energy Resource Recovery Account

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations.

PG&E redacted cost data related to the following components: support services, total nuclear operating costs (NOCs), and fuel. Support services and total NOCs were excluded to protect market-sensitive fuel costs and prevent historical fuel costs from being derived from publicly available information. Fuel costs were excluded to avoid putting PG&E at a competitive disadvantage to other market participants, which could negatively impact PG&E customers. Table 6 and Table 7 provides a detailed cost breakdown of forecasted DCPP costs provided by PG&E.

Table 6: Detailed DCPP Forecasted Cost Components 2023–2025

Cost Component	2023 ($M)	2024 ($M)	2025 ($M)
Engineering	$44.4	$44.8	$39.0
Loss Prevention	$77.6	$78.2	$68.2
Materials and Services	$7.9	$7.9	$6.9
Fuel Management	$0.8	$0.8	$0.7
Operations	$76.3	$76.8	$67.0
Support Services	**REDACTED**	**REDACTED**	**REDACTED**
Training – Develop and Conduct	$9.4	$9.4	$8.2
Work Management	$108.1	$108.9	$192.0
Total Nuclear Operating Costs	**REDACTED**	**REDACTED**	**REDACTED**
Capital	$150.2	$150.0	$150.1
Outage	$46.8	$46.8	$97.0
Fuel	**REDACTED**	**REDACTED**	**REDACTED**
Other DCPP Costs	N/A	$222.6	$505.3
Additional Costs	N/A	$2.4	$5.4
Total Redacted Costs	**$214.2**	**$220.6**	**$264.0**
Total[23]	**$735.7**	**$969.2**	**$1403.8**

[23] As compared to the draft Diablo Canyon Power Plant Operations Assessment report published August 1, 2023, the final report is updated with cost data from the July 28, 2023, Rebuttal Testimony. This included changes to the "Other DCPP Costs" and "Additional Costs" categories. "Other DCPP Costs" are defined as costs and/or funding for DCPP have been established in statute for the extended operations of DCPP. "Additional Costs" are defined as cost allocations based on the 2023 General Rate Case (GRC) for DCPP for the retirement years of 2024

Note on redacted costs: Release of market sensitive information could put PG&E at a competitive disadvantage with regard to other market participants and could detrimentally impact all customers. Therefore, some cost details are not provided in their forecast.

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations (updated with July 28, 2023, rebuttal testimony)

Table 7: Detailed DCPP Forecasted Cost Components 2026–2030

Cost Component	2026 ($M)	2027 ($M)	2028 ($M)	2029 ($M)	2030 ($M)
Engineering	$39.80	$41.20	$42.60	$44.10	$19.00
Loss Prevention	$69.50	$71.90	$74.40	$77.00	$33.20
Materials and Services	$7.10	$7.30	$7.60	$7.80	$3.40
Fuel Management	$0.70	$0.80	$0.80	$0.80	$0.40
Operations	$68.30	$70.70	$73.20	$75.70	$32.60
Support Services	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Training — Develop and Conduct	$8.40	$8.70	$9.00	$9.30	$4.00
Work Management	$142.60	$147.60	$206.50	$158.10	$68.20
Total Nuclear Operating Costs	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Capital	$154.30	$119.80	$124.00	$96.20	$20.80
Outage	$50.20	$51.90	$107.50	$55.60	$24.00
Fuel	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**	**REDACTED**
Other DCPP Costs	$515.50	$460.40	$462.20	$454.60	$176.20
Additional Costs	$5.60	$5.80	$5.80	$5.8	$2.90
Total Redacted Costs	***$224.20***	***$232.10***	***$240.20***	***$248.90***	***$217.00***
Total[24]	**$1286.20**	**$1218.20**	**$1353.80**	**$1233.90**	**$601.70**

Note on REDEACTED costs: Release of market sensitive information could put PG&E at a competitive disadvantage with regard to other market participants and could detrimentally impact all customers. Therefore, some cost details are not provided in their forecast.

Source: PG&E's Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations (updated with July 28, 2023, rebuttal testimony)

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and 2025. "Other DCPP Costs" include performance-based disbursements, retention, volumetric fee, fixed fees, and liquidated damages while "Additional Costs include property and other taxes.

[24] As compared to the draft Diablo Canyon Power Plant Operations Assessment report published August 1, 2023, the final report is updated with cost data from the July 28, 2023, Rebuttal Testimony. This included changes to the "Other DCPP Costs" and "Additional Costs" categories. "Other DCPP Costs" are defined as costs and/or funding for DCPP have been established in statute for the extended operations of DCPP. "Additional Costs" are defined as cost allocations based on the 2023 General Rate Case (GRC) for DCPP for the retirement years of 2024 and 2025. "Other DCPP Costs" include performance-based disbursements, retention, volumetric fee, fixed fees, and liquidated damages while "Additional Costs" include property and other taxes.

DCPP Costs Used for Analysis

The NOC costs (including all costs except capital, outage, and fuel) represent an operational baseline or nonoutage routine annual cost profile. While fuel and outage costs were not included in the NOC category, the CEC assumed for the SB 846 analysis that all costs except capital costs are operating and fuel costs. Table 8 shows the capital expenditures (CAPEX) and operating expenditures (OPEX) and fuel values used in this SB 846 analysis to compare against scenarios of alternative resources.

Table 8: DCPP CAPEX and OPEX Values for SB 846 Analysis, in Millions of Dollars

Cost Component	2023	2024	2025
Capital Expenditures (CAPEX)	$150.2	$150.0	$150.1
Operating Expenditures (OPEX) and Fuel	$585.6	$594.4	$743.0

Source: PG&E’s Opening Testimony (May 22, 2023), CPUC Rulemaking to Implement SB 846 Concerning Potential Extension of DCPP Operations

CHAPTER 4: Comparison of Alternative Resources to DCPP

Scenario Development Approach

Like-for-Like Analysis vs. Net Peak Analysis

The alternative resource comparison evaluates the extent to which alternative resources can replace the generating capacity of DCPP from an energy-production perspective and a net-peak-capacity perspective. First, under the energy-production perspective, or **like-for-like analysis**, only resources that can successfully participate in replacing the full energy production of DCPP are considered. These resources, in total, must be capable of replacing the full energy production of DCPP. Resources in the like-for-like analysis succeed in replacing DCPP only when they cumulatively generate 18,000 GWh/year, which is equivalent to the annual energy production of DCPP. The resources considered for the like-for-like analysis are carefully selected based on whether they can consistently produce energy in a manner like DCPP while satisfying all the resource eligibility criteria.

On the other hand, the **net-peak analysis** evaluates the ability for alternative resources to cover DCPP contributions to grid reliability, that is, the capacity contributions of the plant during net-peak periods. Under the net-peak analysis, resources must be able to provide consistent, reliable capacity during net-peak periods. Resources under the net-peak analysis succeed in replacing the net-peak generating capacity of DCPP when they can provide 2.2 GW, which is the full capacity of DCPP, during net-peak periods. With the like-for-like and net-peak analysis objectives in mind, CEC developed and analyzed a set of scenarios, each composed of different mixes of resources based on the associated ability to meet each objective.

Scenario Development

Based on the characterization of supply resources and demand resources and the like-for-like and net-peak analysis objectives, CEC developed three scenarios of alternative resources to replace DCPP. The first is the Supply Scenario, which consists of supply resources that can provide consistent energy throughout the day to directly replace DCPP generation and satisfy the requirements of a like-for-like replacement. The second and third scenarios, the Demand Scenario and the Demand-and-Supply Scenario, focus on satisfying the requirements of a net-peak replacement of DCPP. The Demand Scenario consists of only demand resources and evaluates the capabilities of these resources to replace DCPP during net-peak periods. The Demand-and-Supply Scenario consists of all demand resources and supply resources, including those that could not participate in the like-for-like analysis (that is, LDES), and evaluates which mix of resources can best replace the net-peak generating capacity of DCPP.

To complete the alternative resource comparison with DCPP, the analysis answered the following questions for each of the three scenarios:

1. Can the resources be implemented to replace the energy production or capacity (like-for-like or net peak) of DCPP before retirement? This question evaluates the ability to replace half the energy production or capacity by 2024 when the first unit is scheduled to retire, and the second half of energy production or capacity by 2025 when the second unit is schedule to retire. To answer this question, CEC quantified the annual

technological potential (in GWh or GW) of resources in each scenario, considering the project lead time required to develop and implement these resources.

2. What is the cost to implement these resource options? How does this cost compare to the cost of keeping DCPP operational? To answer these questions, CEC quantified the **costs** associated with developing the resources in each scenario.[25]

Like-for-Like Analysis – Supply Scenario

Supply Scenario Overview

The Supply Scenario seeks to address a like-for-like replacement for DCPP zero-carbon energy production (GWh) by evaluating resources capable of providing consistent zero-carbon energy over extended periods. To be considered a true like-for-like replacement, the Supply Scenario must cumulatively generate 18,000 GWh/year, equivalent to the annual energy production of DCPP. Many common supply resources were screened out because of incompatibility with the eligibility criteria. Many supply resources are commonly included in state planning and, therefore, in competition with what the CPUC ordered in the three procurement orders of IRP (that is, geothermal, small hydropower, compressed air energy storage) and are thus screened out. Clean, renewable hydrogen technologies are also screened out because of the need for additional resources such as solar and wind to generate the clean hydrogen. SB 846 is also seeking zero-carbon replacements to DCPP, so fossil gas generation, blended gas generation, and non-clean hydrogen technologies were excluded because they produce carbon emissions.

Supply Scenario Method and Evaluation

The supply resources included for analysis consist of long-duration energy storage technologies (LDES). LDES supply resources are utility-scale storage options that can provide more than four hours of continuous energy. However, LDES resources are unable to substitute for the ability of DCPP to provide energy as they are not generation resources . Rather than a like-for-like DCPP replacement, LDES paired with existing clean energy generation can help replace the 2.2 GW capacity of DCPP during net peak.

Large supply-side projects are vulnerable to external lead-time factors such as supply chain, permitting, and interconnection processes. Based on California ISO's Resource Interconnection Management System (RIMS) data, interconnection has taken an average of six years[26] for projects that have come on-line since 2010. Interconnection processes, which include study, procurement by load-serving entities, construction of the facility, and in some cases transmission upgrades, add to the overall lead times for projects. Overall, these long lead times remain a key consideration when planning for these technologies.

The California ISO Track 2 Straw Proposal[27] for the 2023 Interconnection Process Enhancements (IPE) initiative seeks to address the unprecedented influx of interconnection requests due to the rapid growth of clean energy development in California. While the IPE has

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25 CEC notes that operational costs for most renewable resources are lower than the historic operational costs for DCPP.

26 This is the elapsed time between interconnection application submittal and the date the system was on-line.

27 California ISO, 2023, 2023 [Interconnection Process Enhancements](https://www.caiso.com/InitiativeDocuments/Straw-Proposal-Interconnecton-Process-Enhancements-2023-Sep212023.pdf), via https://www.caiso.com/InitiativeDocuments/Straw-Proposal-Interconnecton-Process-Enhancements-2023-Sep212023.pdf

potential to improve interconnection times, the approval and implementation could take most of 2024 which means it will not be available to help bring projects on-line by 2025.

Supply Scenario Takeaways

Gaseous fuel generation resources in the Supply Scenario are unable to provide any energy production by the end of 2025. California's clean hydrogen production, distribution, and storage shortfalls highly constrain Supply Scenario resources and prevent them from fulfilling DCPP energy production. As defined in the eligibility criteria, the Supply Scenario must generate 9,000 GWh/year in 2024 and an additional 9,000 GWh/year by 2025 to act as a like-for-like replacement to DCPP. Considering there is not a Supply Scenario that is projected to be operational as a portfolio in the next two years, the like-for-like analysis conveys that there are no direct replacements for DCPP before 2025, or until a steady flow of hydrogen becomes available.

Net Peak Analysis – Demand Scenario

Demand Scenario Overview

The Demand Scenario analyzes how a combination of demand resources could replace the 2.2 GW capacity of DCPP during net-peak periods. In considering a scenario composed of demand resources, CEC staff notes that centralized control of multiple resources provides greater assurance of those resources being available when needed. California has existing experience with controlling end uses and associated enabling technologies through VPP constructs in utility and third-party administered DR programs such as the Demand Response Auction Mechanism (DRAM), Capacity Bidding Program (CBP), Emergency Load Reduction Program (ELRP), and the Demand Side Grid Support (DSGS) program. In addition to these programs, utilities have been offering time-varying rates to modify customer behavior and shape loads to address grid needs (for example, time-of-use rates, critical peak pricing, real-time pricing).

Significant efforts are also underway to unlock greater potential from demand-side resources through widespread adoption of advanced rates, paired with enabling technologies, under CPUC's CalFUSE framework.[28] However, VPP constructs would need to scale significantly and quickly above existing levels to replace the 2.2 GW of capacity of the DCPP before the current retirement dates. For reference, the size of existing demand-side resources (available through DR programs and rates) is 3.1 GW–3.6 GW in 2022.[29] A breakdown of these existing resources is in Table 9.[30] These programs and rates were launched at different points in time and have achieved this level of capacity over time. For example, economic DR programs includes about 200 MW from DRAM, which launched in 2016, and about 40 MW from CBP, which launched in 2007. Emergency programs such as ELRP were launched in 2021.

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28 CalFUSE refers to the CPUC Staff Proposal for a California Flexible Unified Signal for Energy. See also CPUC proceeding R.22-07-005, Demand Flexibility Rates.

29 Neumann, Ingrid and Erik Lyon. May 2023. *Senate Bill 846 Load-Shift Goal Report*. California Energy Commission. Publication Number: CEC-200-2023-008. Available for download at https://efiling.energy.ca.gov/GetDocument.aspx?tn=250357&DocumentContentId=85095.

30 Ibid.

Table 9: Existing Demand-Side Resources

Demand Resource	Capacity (MW)
Load-modifying rates and programs	~650–1,000
Economic programs, integrated in California ISO market	670–825
Reliability programs, integrated in California ISO market	740
POU DR programs	210
Emergency programs	~1,200
TOTAL	**3,100–3,600**

Refer to CEC Load-Shift Goal Report for specific breakdown of each DR resource type.

Source: CEC Senate Bill 846 Load-Shift Goal Report

There are structural and policy barriers that need to be resolved before the full potential from demand-side VPP resources can be realized.[31] Also, mechanisms to value exports from behind-the-meter (BTM) DERs at a customer site do not exist, which restricts realization of the potential from these resources. In addition, there are performance challenges with DR programs, which can be attributed partly to customer fatigue and attrition resulting from extended multiday or multiweek periods of DR dispatch during high-demand periods in summer. Customer participation levels in DR programs are relatively low as the value proposition for customers is not clearly established. Based on the average realized DR performance of 67 percent in the California ISO market in recent years, a portfolio of demand resources should aim to reach 3.3 GW of procured capacity to replace the 2.2 GW capacity of DCPP.[32] Still, DR and other demand or distributed resources have contributed to alleviating grid emergencies in recent years. So, the Demand Scenario explores using such resources to replace the net-peak contributions of DCPP beyond what is expected to be procured in existing DR programs.

Demand Scenario Method and Evaluation

Characterizing the potential and cost from demand resources that could contribute to the analysis of the Demand Scenario required a more granular specification of the included resources listed in Table 4. Dispatchable DR measures is broad and encompasses a wide range of controllable end uses and potential DR technologies. Consequently, CEC staff further divided the DR measures category into the following end-use subcategories:

- Heating, ventilation, and air conditioning (HVAC) control
- Industrial process load control
- Agricultural load control

31 The CEC Load-Shift Goal Report discusses many of the barriers and challenges facing demand resources in California and includes a series of policy recommendations to increase load shifting and demand flexibility.

32 See California ISO *Demand Response Issues and Performance Report 2022* (overall average supply plan DR performance for high-demand summer days).

- Other end-use control

Table 10 lists the resources considered in the Demand Scenario, including this subcategorization of DR measures.

Estimates of the incremental net-peak achievable potential (MW) that each resource in Table 10 could contribute to a VPP construct by the end of 2025 were derived from the CEC's modeling and analysis for the Statewide Load-Shift Goal adopted in May 2023.[33] These estimates are based primarily on CEC forecast data and inputs from the Lawrence Berkeley National Laboratory (LBNL) California Demand Response Potential Study.[34]

The CEC Load-Shift Goal Report provides a comprehensive overview of the method, inputs, and assumptions used for the potential modeling. The Load-Shift Goal model forecasted hourly gross and net-peak load estimates and characterized the achievable potential from technical options to control end-use load. The hourly gross and net-peak load calculations used annual electricity consumption and renewable generation forecasts from the 2021 and 2022 IEPR forecasts (including load modifiers for energy efficiency, fuel substitution, and transportation electrification), along with hourly load shapes from the LBNL-Load model (which is based on California IOU AMI data). The characterization of achievable potential from demand-side resources included defining inputs such as projected saturation, cost-optimized participation fractions, and unit impacts, which were sourced from the LBNL California Demand Response Potential Study assumptions. The primary output from the Load-Shift Goal modeling was an estimate for 7,000 MW of cumulative achievable net-peak load reduction that could be attained from DR and other load-shifting mechanisms by 2030, which represents 3,400 MW to 3,900 MW of incremental growth above existing 2022 DR MWs in the state.

CEC staff used the results from the Load-Shift Goal modeling and performed additional analysis to arrive at the 2025 incremental estimated net peak achievable potential values shown for the DR, electric vehicle, and solar + battery storage resources in Table 10. The first adjustment to the load shift model was to break down the estimates for existing 2022 MWs to the technology and end-use levels, which was done by applying assumptions about the end uses targeted by existing California DR programs and rates. This application then allowed staff to estimate the incremental growth potential from 2022 to 2030 for each VPP component resource. Finally, incremental potential estimates for 2025 were derived by estimating growth ramps for each resource from existing 2022 levels to 2030 potential levels from the Load-Shift Goal estimate. For this exercise of determining how quickly the estimated potential for each VPP component can be realized, staff used the qualitative determination of current resource maturity shown in Table 10 (as either mature or emerging), which reflects existing technological maturity and saturation as well as the current ability to participate in VPP constructs. Based on these results, CEC determines that a portfolio of demand resources could feasibly be expected to contribute a maximum of about 725 MW of procured incremental net-

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33 The CEC Load-Shift Goal Report addresses the requirement in SB 846 for the CEC to develop a statewide goal for load shifting to reduce net peak electrical demand. The CEC-adopted Load-Shift Goal is 7,000 MW of total load shift capacity (or 3,400 to 3,900 MW incremental growth relative above 2022) by 2030.

34 Gerke, Brian, Giulia Gallo, Sarah Josephine Smith, Jingjing Liu, Shuba V Raghavan, Peter Schwartz, Mary Ann Piette, Rongxin Yin, Sofia Stensson. 2020. *The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource through 2030*. Lawrence Berkeley National Laboratory.

peak capacity (or about 500 MW of realized potential)[35] by the end of 2025, which is insufficient to replace the reliability contributions of DCPP.

Table 10: VPP Resource Estimated Incremental Potential, 2025

VPP Resources	Resource Maturity	2025 Incremental Net Peak Achievable Potential (MW)
DR: Heating, Ventilation, and Air Conditioning (HVAC) Control	Mature	250
DR: Process Control	Mature	100
DR: Agricultural Control	Mature	100
DR: Other End-Use Control	Emerging	25
Electric Vehicles	Emerging	50
Solar + Battery Storage	Emerging	200
Hydrogen-powered Distributed Generation	Emerging	0
TOTAL (Achievable)	Not Applicable	**725**
TOTAL (Realized)	Not Applicable	**485**

Source: Guidehouse analysis for this report

Staff performed the cost assessment for the Demand Scenario using cost factors representing average per-kW upfront and ongoing incentive costs required to enroll and aggregate various demand resources into a VPP or DR program. Cost factors were sourced from the LBNL *2025 California Response Potential Study* and from a recent report published by the Brattle Group titled *Real Reliability: The Value of Virtual Power*.[36] For demand resources contributing, ongoing incentives (for example, annual or seasonal participation payments) are required to build a VPP or DR resource in addition to any upfront equipment, installation, or recruitment costs.

Table 11 shows a summary estimate for the cost required to achieve about 725 MW of procured incremental net-peak capacity (about 500 MW of realized potential) from an example composition of demand resources in a VPP, which is aligned with the estimated incremental achievable potential by the end of 2025. The estimate is an upfront capital cost between $230 million and $330 million plus recurring annual incentive costs of about $50 million–$65 million per year.

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35 Considering the average realized DR performance of 67 percent in the California ISO market in recent years (from California ISO Demand response issues and performance report 2022), 725 MW of procured capacity could be expected to yield roughly 500 MW of realized impact.

36 Brattle Group. 2023. *Real Reliability: The Value of Virtual Power*, https://www.brattle.com/real-reliability/.

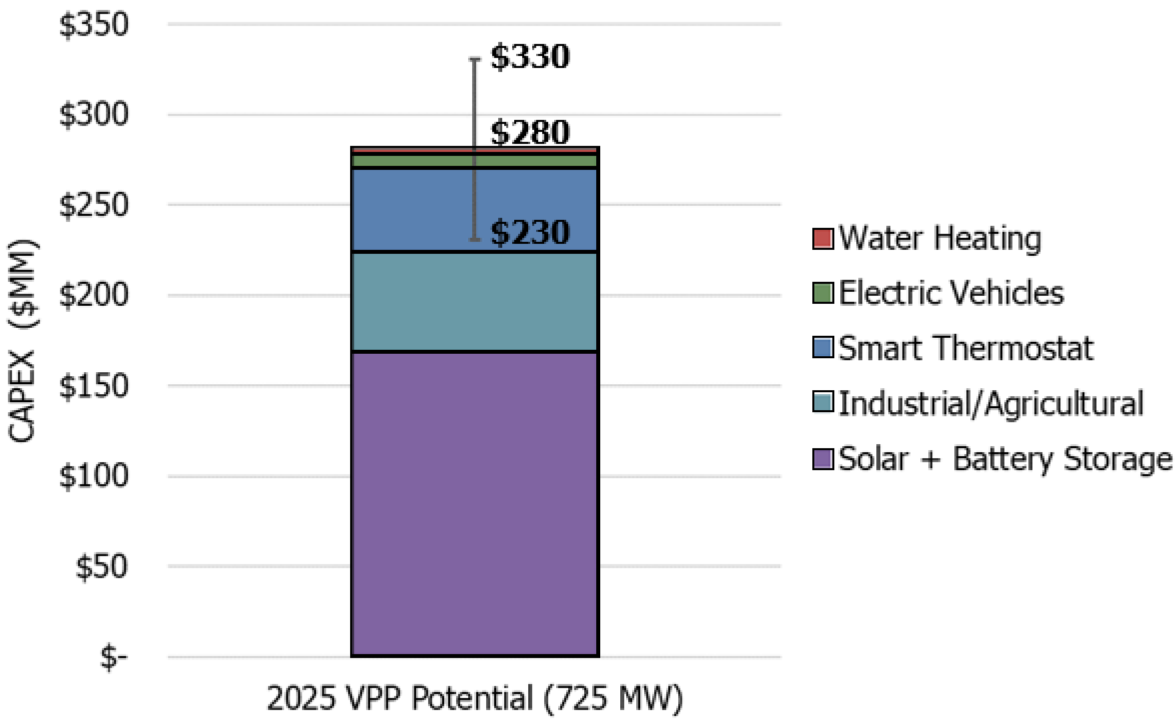
Table 11: VPP Potential and CAPEX Costs for 2025

Representative VPP Resource	Capacity (MW)	CAPEX Only ($M)
Smart Thermostat	250	30–60
Water Heating	25	1–2
Electric Vehicles	50	3.5–12
Solar + Battery Storage	200	145–195
Industrial/Agricultural	200	50–60
TOTAL	**725**	**230–330**

Source: Guidehouse analysis for this report

To obtain an aggregate estimate for the cost of demand resources in a VPP, an assumption must be made about the relative contributions of various end-use or control technologies within a representative VPP. In Table 11, the allocated capacity of each representative VPP resource is based on the relative size of overall load-shift potential as calculated for the development of the Statewide Load-Shift Goal. Figure 4 illustrates ways that the estimated total capital expenditures (CAPEX) are broken down among the constituent end uses.

Figure 4: Representative 725 MW VPP CAPEX for 2025



Source: Guidehouse analysis for this report

Demand Scenario Takeaways

Overall, the Demand Scenario analysis indicates that there is about 725 MW of procured incremental net-peak capacity that could be achieved from demand resources by the end of 2025. The estimated 725 MW of procured capacity could be expected to yield nearly 500 MW of realized potential, considering historical DR performance in the California ISO market. On an ongoing per MW basis, the demand resources do appear to be less expensive than DCPP. However, the size of the resource is insufficient to replace the 2.2 GW of capacity from DCPP by 2025. Achieving the estimated 725 MW procured capacity by the end of 2025 would require an upfront capital investment between $230 million and $330 million.

Net-Peak Analysis – Demand + Supply Scenario

Demand + Supply Scenario Overview

The Demand and Supply Scenario focuses on ways that demand and supply resources can be leveraged to replace the net-peak capacity of 2.2 GW for the DCPP. This scenario looks to evaluate an optimal combination of resources that can achieve the DCPP net-peak capacity at the lowest cost and fastest time frame. As seen in the Demand Scenario, demand resources can contribute only about 500 MW of realized capacity during net-peak periods by the end of 2025. Meanwhile, the Supply Scenario evaluates only resources that can address the like-for-like analysis, not the net-peak analysis that this scenario looks to address. LDES was excluded from the Supply Scenario for the inability to act as a reliable resource for all hours of the day, thus being unable to replace DCPP in the like-for-like analysis. Moreover, LDES is not a generation resource and is carbon-free only if the generation charging LDES is carbon-free. However, LDES can be an important capacity-contributing resource under the net-peak analysis based on the ability to provide consistent power across a full net-peak period.

Therefore, the Demand and Supply Scenario analysis includes LDES as supply resources, as seen in Table 12.

Table 12: Long-Duration Energy Storage (LDES) Resources Considered

LDES Resources
Electrochemical (e.g., flow, iron-air, zinc, sodium, excluding lithium-ion)
Mechanical (e.g., gravity-based, geomechanical, excluding PSH)
Thermal (solid medium, liquid medium)

Source: Guidehouse analysis for this report

Demand and Supply Scenario Method and Evaluation

The analysis for demand resources was completed in the Demand Scenario, so this section focuses on the LDES resources that have not been evaluated, noting that lithium-ion was excluded from this analysis to avoid competition with IRP procurement orders and expected POU procurement. To fully understand the technological potential of LDES technologies in California, it is necessary to understand what is being planned in the state.

- The CEC has a Long-Duration Energy Storage Program that is providing $140 million to support LDES development in the state.[37]
- The CPUC has ordered the procurement of 1,000 MW of new LDES by 2028.[38]

The resources in Table 12 vary in terms of commercial maturity and availability but are largely still nascent in the market for durations long enough to satisfy net-peak periods readily and reliably, above eight hours within the period before 2025.[39] Furthermore, the technical project lead time to install these technologies at the scale required for this analysis ranges from one to three years with supply chain constraints playing a critical role in this timeline. This technical project lead time does not reflect external lead times factors, such as time required for interconnection. As evidenced in the Supply Scenario, interconnection has taken an average of six years for projects that have come on-line since 2010. Thus, LDES resource lead times may be affected by a combination of the ability to scale these resources in the next two years, project lead times, and interconnection timelines. Therefore, achieving incremental capacity beyond what is already planned in the state may require more efforts and funding opportunities.

Demand and Supply Scenario Takeaways

The addition of LDES resources for consideration in this scenario, in principle, provides potential to reach the net-peak capacity of DCPP that cannot be met by resources considered

37 Minutes of the June 16, 2023, CEC Business Meeting, pg. 4. Information item 4: Current Activities of the Long-Duration Energy Storage (LDES) Program

38 CPUC's IRP proceeding [R.] 20-05-003. Decision Ordering Supplemental Mid-Term Reliability Procurement (2026-2027) and Transmitting Electric Resource Portfolios to the California Independent System Operator for the 2023-2024 Transmission Planning Process

39 Based on technology maturity and availability information gathered from interviews with LDES technology developers conducted by Guidehouse Insights, Guidehouse's internal research branch. The duration of 8 hours was deemed as an appropriate target to classify energy storage as long duration in coordination with CEC.

in the Demand Scenario or the Supply Scenario. Nevertheless, given the difficulty to achieve incrementality, extended project lead times, and the current constraints on scale, it is unlikely that LDES will provide any additional capacity in this Demand + Supply Scenario by the end of 2025.

Alternative Resource Replacement of DCPP Takeaways

This report evaluates the potential for alternative resources to replace the energy production and power capacity of DCPP before the end of 2025, when DCPP is up for extension or decommissioning. Alternative resources were evaluated based first on the associated competition with IRP procurement and carbon intensity, and secondly on technical energy production potential, costs, and project lead time. First, staff evaluated alternative resources under the like-for-like analysis to replace the energy production of the DCPP. A full like-for-like replacement of DCPP requires a set of resources capable of providing 18,000 GWh/year of consistent, zero-carbon energy in total. The like-for-like analysis was highly selective because resources must satisfy the resource eligibility criteria and provide consistent energy, like DCPP, throughout the day.

On the other hand, the net-peak analysis was performed to evaluate the ability of alternative resources to cover the contributions of DCPP to grid reliability, that is, the capacity during net-peak periods. For alternative resources to succeed in a full replacement of the net-peak capacity of DCPP, they must provide 2.2 GW of consistent, reliable capacity during net-peak periods. Under the like-for-like analysis and net peak analysis, alternative resources were evaluated based on the ability to replace DCPP. The following are key takeaways of this analysis:

- There are no supply-side or demand-side resources incremental to current procurements that can be built before the planned retirement of DCPP in 2025 because they fail one or more criteria: they are not zero-carbon resources, they compete with existing ordered procurement, they are not technologically mature, or they would be severely limited by the ability to interconnect in a timely manner.
- Demand resources exist in the market but face structural and policy barriers preventing them from scaling up quickly and realizing the full potential.
- By the end of 2025, the Demand Scenario is expected to procure only about 725 MW of incremental net peak capacity (roughly 500 MW of realized potential) out of the 2.2 GW of net-peak capacity provided by DCPP.
- LDES systems with sufficient reliable duration to cover net peak are still being developed and implementing LDES capacity beyond what is already planned in California would require significant effort to make operational in the short term. Thus, LDES options are not available as a replacement to the net-peak capacity of DCPP by the end of 2025.

Table 13: DCPP Resource Replacement Summary

	Like-for-Like Analysis	Net Peak Analysis
Supply Resources	No supply resources can be built by 2025 to cover DCPP's energy production	No supply resources can be built by 2025 to cover capacity of DCPP at net peak
Demand Resources	Demand resources cannot currently provide DCPP energy production by 2025	Only 725 MWs of demand resources could be on-line by 2025
Supply + Demand	No supply + demand resources can be built by 2025 to cover DCPP's energy production by 2025	No additional demand resources can be built by 2025 to cover capacity of DCPP at net peak

Source: Guidehouse analysis for this report

Overall, this analysis shows that by the end of 2025, the 725 MW of incremental resources that can be procured will still lead to a shortfall in both peak power supply and energy generation without increasing GHG emissions. It is possible to do so provided a longer timeline.

APPENDIX A: Acronyms and Abbreviations

ACES	Advanced clean energy storage
BTM	Behind-the-meter
CA	California
CAES	Compressed air energy storage
California ISO	California Independent System Operator
CAPEX	Capital expenditure
CBP	Capacity Bidding Program
CEC	California Energy Commission
CPUC	California Public Utilities Commission
DCPP	Diablo Canyon Power Plant
DER	Distributed energy resource
DOE	Department of Energy
DR	Demand response
DRAM	Demand Response Auction Mechanism
EIA	Energy Information Administration
ELRP	Emergency Load Reduction Program
EUCG	Electric Utility Cost Group
GHG	Greenhouse gas
GRC	General rate case
GW	Gigawatt
GWh	Gigawatt-hour
HVAC	Heating, ventilation, and air conditioning
IRP	Integrated resource plan
LBNL	Lawrence Berkeley National Laboratory
LDES	Long-duration energy storage
LSE	Load-serving entity
MW	Megawatt
MWC	Major work category
NOC	Nuclear operating costs

NRC	Nuclear Regulatory Commission
PG&E	Pacific Gas and Electric
POU	Publicly owned utility
PSH	Pumped storage hydro
RIMS	Resource Interconnection Management System
RPS	Renewables Portfolio Standard
SB	Senate Bill
VPP	Virtual power plant

APPENDIX B: Glossary

Blended gas

Blending of alternative gaseous fuels, such as hydrogen and renewable gas, with fossil gas to operate a system with lower carbon footprint than just operating on fossil gas. Most technologies require modifications or upgrades to properly function with high blends of alternative fuels, where lower blends could potentially be integrated into the system without major modifications.

Combustion turbine

A combustion or gas turbine is a combustion engine installed in a power plant that can convert gaseous fuels to mechanical energy, which in turn drives a generator that produces electrical energy. This conversion is achieved through the localized combustion of the fuel in a combustion system resulting in high-temperature, high pressure-gas stream that spins the blades that make up the turbine that then spins the generator to produce electricity.

Compressed air energy storage (CAES)

Compressed air energy storage is a type of storage that involves compressing air using an electricity-powered compressor into an underground cavern or other storage area. This compressed air is then expanded through a turbine to generate electricity. Usually, fuel is burned before the expansion to increase the quantity of electricity produced and improve the overall efficiency. Similarly, heat losses from compression are sometimes recaptured and supplied to the air before expansion.[40]

Capacity Bidding Program (CBP)

Capacity Bidding Program (CBP) is an aggregator-managed program, a third-party entity acting on behalf of a customer to manage and administer a demand response program, that operates with a day-ahead option and runs May 1 through October 31 but is promoted year-round. There are numerous aggregators participating in CBP.

CAPEX

CAPEX is the contraction of the term capital expenditure, and refers to the expenditures made to acquire, upgrade, and maintain physical assets such as property, plants, buildings, technology, or equipment.[41]

Demand Response Auction Mechanism

The Demand Response Auction Mechanism (DRAM) was created in 2014 under the guidance of the California Public Utility Commission (CPUC) to harmonize utility-based reliability demand response with California ISO, the state's grid operator. The program seeks to allow California

40 Compressed Air Energy Storage - EPRI Storage Wiki.

41 Capital Expenditure (CAPEX) Definition, Formula, and Examples (investopedia.com).

ISO to add reliable demand response resources to areas of California where electric reliability may be at risk.

Distributed energy resources (DER)

Small-scale power generation technologies (typically in the range of 3 to 10,000 kilowatts) located close to where electricity is used (for example, a home or business) to provide an alternative to or an enhancement of the traditional electric power system.

Demand response (DR)

Demand response refers to providing wholesale and retail electricity customers with the ability to choose to respond to time-based prices and other incentives by reducing or shifting electricity use ("shift DR"). Particularly this occurs during peak-demand periods, so that changes in customer demand become a viable option for addressing pricing, system operations and reliability, infrastructure planning, operation and deferral, and other issues. It has been used traditionally to shed load in extreme events ("shed DR"). It also has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, especially when several distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile. For more information, see the CPUC Demand Response Web page.

Electric Utility Cost Group (EUCG)

Electric Utility Cost Group (EUCG) is a nonprofit trade organization that provides a professional working forum for the electric utility industry to share information to help individual companies improve their operating, maintenance, and construction performance. Performance, cost, and process information using standardized formats is shared via workshops and data reports. EUCG web page, https://www.eucg.org/about/learn.cfm.

Electric vehicle control infrastructure

Electric vehicle (EV) control infrastructure are components and technologies in EV charging networks. In the context of this analysis and advanced EV charging, these refer primarily to smart chargers and bidirectional chargers. Smart chargers are EV chargers that respond automatically to price signals and can optimize EV charging loads. Bidirectional chargers are chargers that allow energy to flow two ways into the vehicle and out of the vehicle. Common uses for these types of chargers are commonly referred to as vehicle-to-everything (V2X) and include applications such as vehicle-to-grid (V2G) and vehicle-to-building (V2B). In the context of this analysis and demand response (DR), bidirectional chargers are typically connected to the electrical grid (V2G) to provide support with load reduction and shifting.

Emergency Load-Reduction Program (ELRP)

The ELRP is a five-year pilot program administered by PG&E designed to pay electricity consumers for reducing energy consumption or increasing electricity supply during periods of electrical grid emergencies. The ELRP pilot seeks to offer a new tool for the electric grid operators and utilities for reducing energy consumption during a grid emergency to reduce the risk of electricity outages when the available energy supply is insufficient to satisfy the anticipated electricity demand.

Fuel cells

A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

Heating, ventilation, and air conditioning (HVAC)

HVAC refers to equipment and systems that regulate and move heated and cooled air throughout residential and commercial buildings. While there are a wide variety of HVAC systems, in principle, they all take air and use a mechanical ventilation system to heat or cool it to a desired temperature.

Integrated Resource Planning (IRP)

The CPUC's Integrated Resource Planning (IRP) process is an "umbrella" planning proceeding to consider all of its electric procurement policies and programs and ensure California has a safe, reliable, and cost-effective electricity supply. The proceeding is also the Commission's primary venue for implementation of the Senate Bill 350 requirements related to IRP (Public Utilities Code Sections 454.51 and 454.52). The process ensures that load serving entities meet targets that allow the electricity sector to contribute to California's economy-wide greenhouse gas emissions reductions goals. For more information see the CPUC Integrated Resource Plan and Long-Term Procurement Plan (IRP-LTPP) Web page.

Long-duration energy storage (LDES)

There is no single definition for LDES in the energy community. For this analysis, long-duration energy storage (LDES) is an energy storage system that is able to provide at least 8 hours of stored energy. There are systems that look to go well beyond 8 hours to provide 100 hours or even seasonal storage capabilities. There are several types of LDES technologies that are currently being explored, including:

- **Electrochemical:** These are the most known storage technologies in the market. These are systems capable of using electrical energy to promote chemical reactions, thus storing electricity as chemical energy, and inversely can convert the stored chemical energy into electric energy, discharging. Common electrochemical technologies include lithium-ion, flow, iron air, zinc, and sodium.
- **Mechanical:** Technologies that are capable of storing energy by applying force to an appropriate medium, such as water and air, to deliver acceleration, compression, or displacement against gravity. This is the storage of kinetic energy or potential energy. This process can be reversed to recover the stored energy. Common systems include pumped storage hydro storage, compressed air energy storage, and flywheels.
- **Thermal:** Technologies that are capable of storing energy by heating a medium. A medium gains energy when its temperature is increased and loses it when it is decreased. Common mediums and materials used for these energy storage systems include solid (for example, sand) and liquid (for example, molten salts).

Load-serving entity (LSE)

A load-serving entity is defined by the California Independent System Operator as an entity that has been "granted authority by state or local law, regulation or franchise to serve [their] own load directly through wholesale energy purchases." For more information, see the California Independent System Operator's Web page.

Publicly owned utility (POU)

Nonprofit utility providers owned by a community and operated by municipalities, counties, states, public power districts, or other public organizations. Within POUs, residents have a say in decisions and policies about rates, services, generating fuels and the environment.

Pumped storage hydropower (PSH)

Pumped storage hydropower (PSH) is a type of hydroelectric energy storage. It is a configuration of two water reservoirs at different elevations that can generate power as water moves down from one to the other (discharge), passing through a turbine. The system also requires power as it pumps water back into the upper reservoir (recharge). PSH acts similarly to a giant battery because it can store power and then release it when needed.[42]

Reciprocating engine

A reciprocating engine is an engine that uses reciprocating pistons to convert high temperature and high pressure into a rotating motion. Reciprocating engines are typically internal combustion engines and can be used for power generation, transportation, and other uses.[43]

Renewable gas

Renewable gas is essentially biogas or biomethane that has been cleaned and conditioned and can be a direct replacement of natural gas. It can be used to generate electricity, heat, and combined electricity and heating for power plants. Biogas can be produced through a biochemical process such as anaerobic digestion, through thermochemical means such as gasification, or from landfills.[44]

Smart thermostat

Wi-Fi thermostat that can be used with home automation and are responsible for controlling a home's heating, ventilation, and air conditioning.

Virtual power plant (VPP)

In the context of this analysis, VPPs are controlled aggregations of zero-carbon distributed energy resources (DERs) and dispatchable demand response (DR) measures optimized to provide clean energy, reliability, and grid services. The following provide two more general definitions of VPPs:

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42 https://www.energy.gov/eere/water/pumped-storage-hydropower

43 https://www.energy.gov/eere/amo/articles/reciprocating-engines-doe-chp-technology-fact-sheet-series-fact-sheet-2016

44 https://afdc.energy.gov/fuels/natural_gas_renewable.html

- **Department of Energy:** Virtual power plants, generally considered a connected aggregation of distributed energy resource (DER) technologies, offer deeper integration of renewables and demand flexibility, which in turn offers more Americans cleaner and more affordable power.[45]
- **Brattle Group:** A VPP is a portfolio of actively controlled distributed energy resources (DERs). Operation of the DERs is optimized to provide benefits to the power system, consumers, and the environment.[46]

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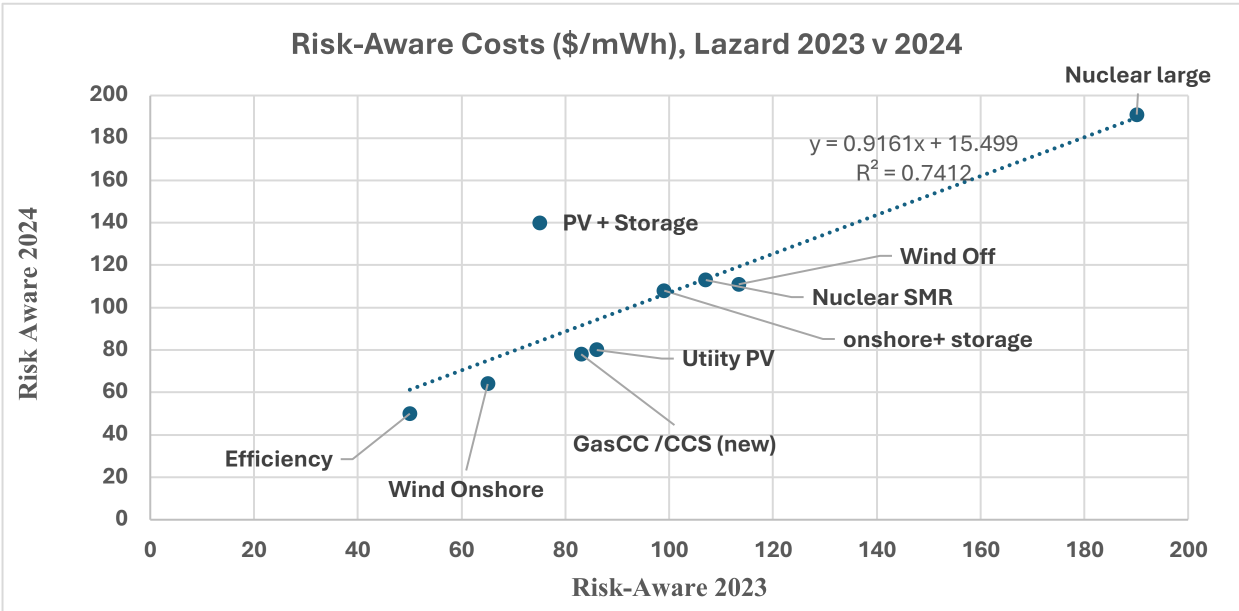
45 https://www.energy.gov/lpo/virtual-power-plants

46 https://www.brattle.com/wp-content/uploads/2023/04/Real-Reliability-The-Value-of-Virtual-Power_5.3.2023.pdf

ATTACHMENT MNC-CR-1 – MNC-CR-16

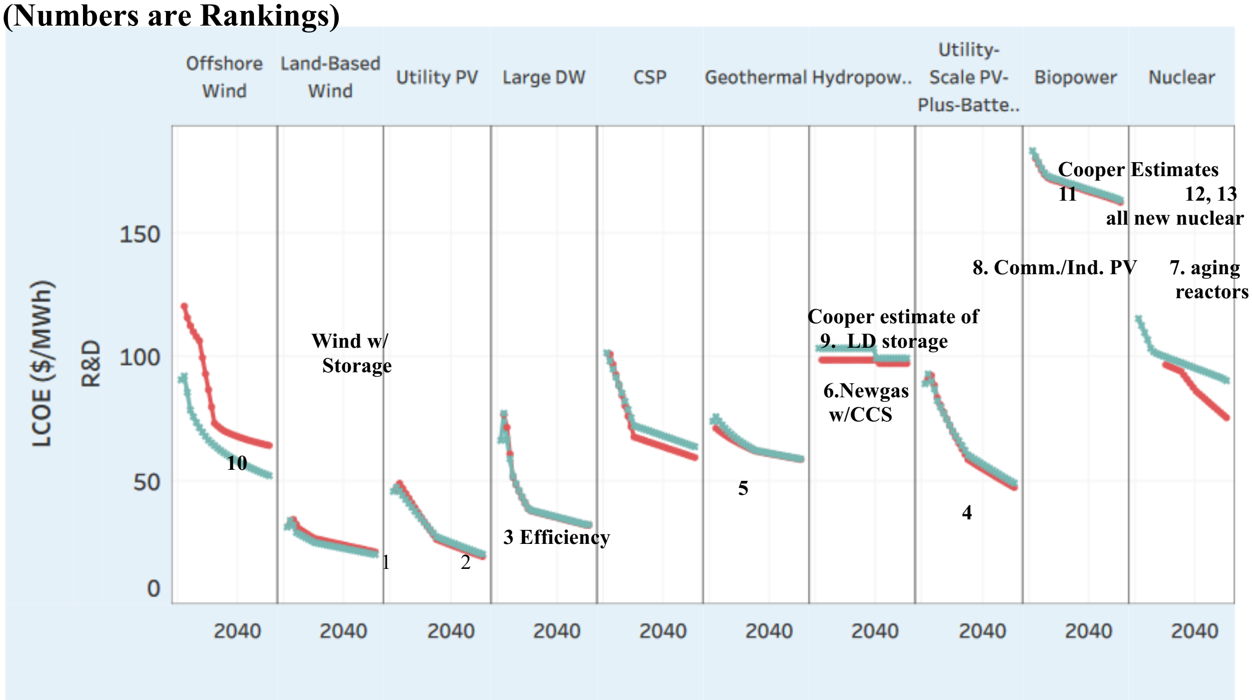
ATTACHMENTS

RISK-AWARE COSTS BASED ON LAZARD **MNC-CR-1**



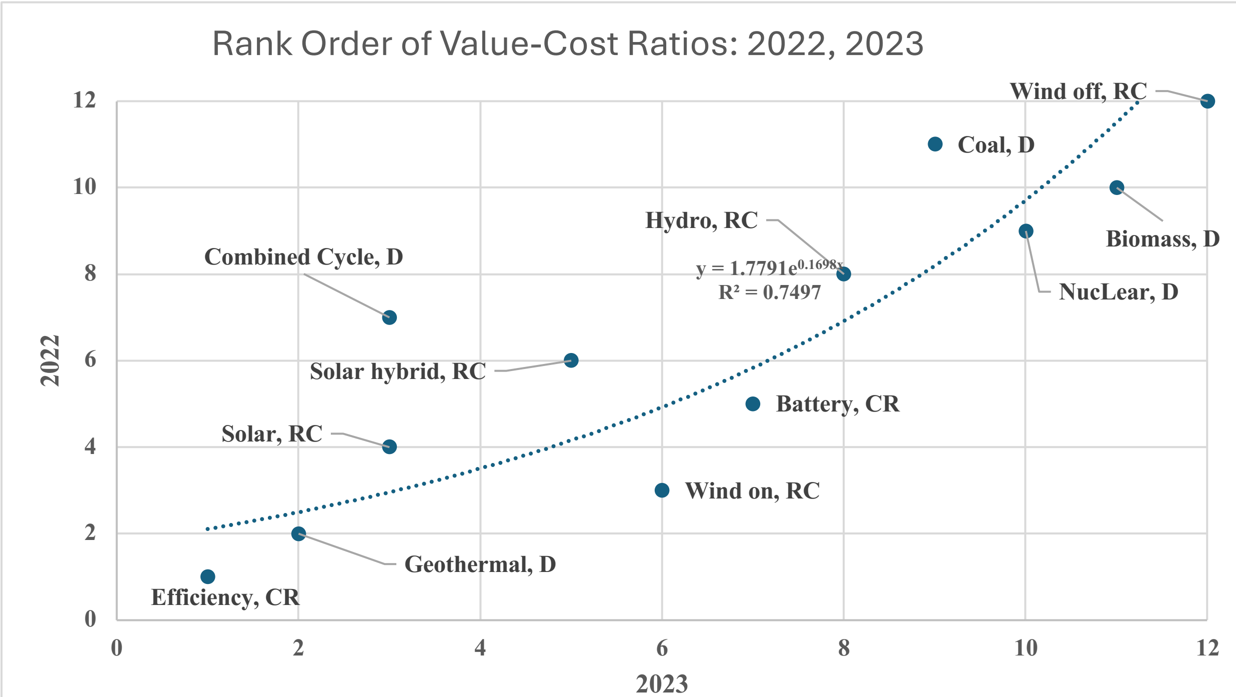
Source: Lazard, Levelized Cost of Energy, v. 16 and v.17

NREL 2024 PROJECTED COSTS V. 2023 RISK ADJUSTED COSTS **MNC-CR-2**
(Numbers are Rankings)



Source: National Renewable Energy Laboratory, 2024, *Annual Technology Baseline,* Cooper, Building A Low Carbon, Low Cost 21st Century Electricity System.

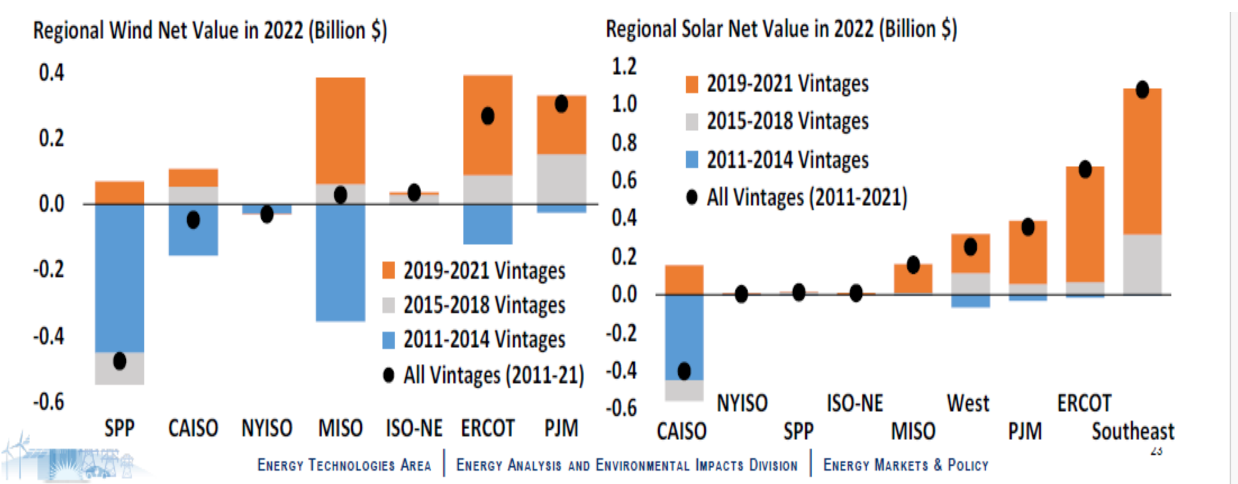
LEVELIZED AVOIDED COSTS, PER EIA **MNC-CR-3**



Legend: D = Dispatchable. RC = Resource Constrained, CR = Capacity Resource

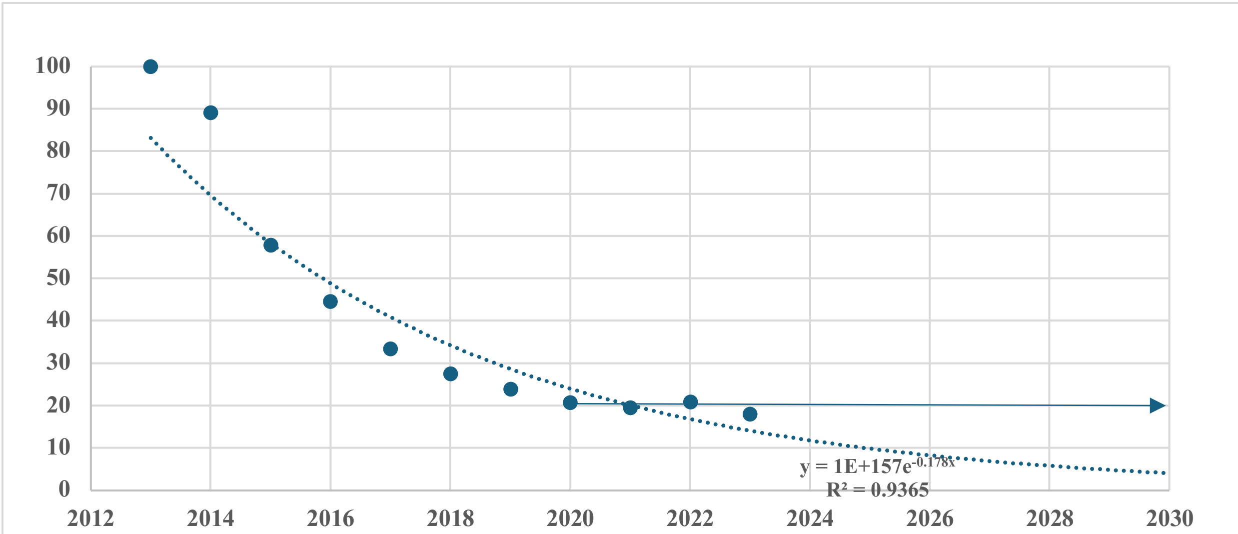
Source: Energy Information Administration, 2022, 2023, *Levelized Costs of New Generation Resources in the Annual Energy Outlook,* various years as noted; 2022 is for resources entering service in 2027, 2023 is for resources entering service in 2028.

NET VALUE OF MAIN RENEWABLES **MNC-CR- 4**



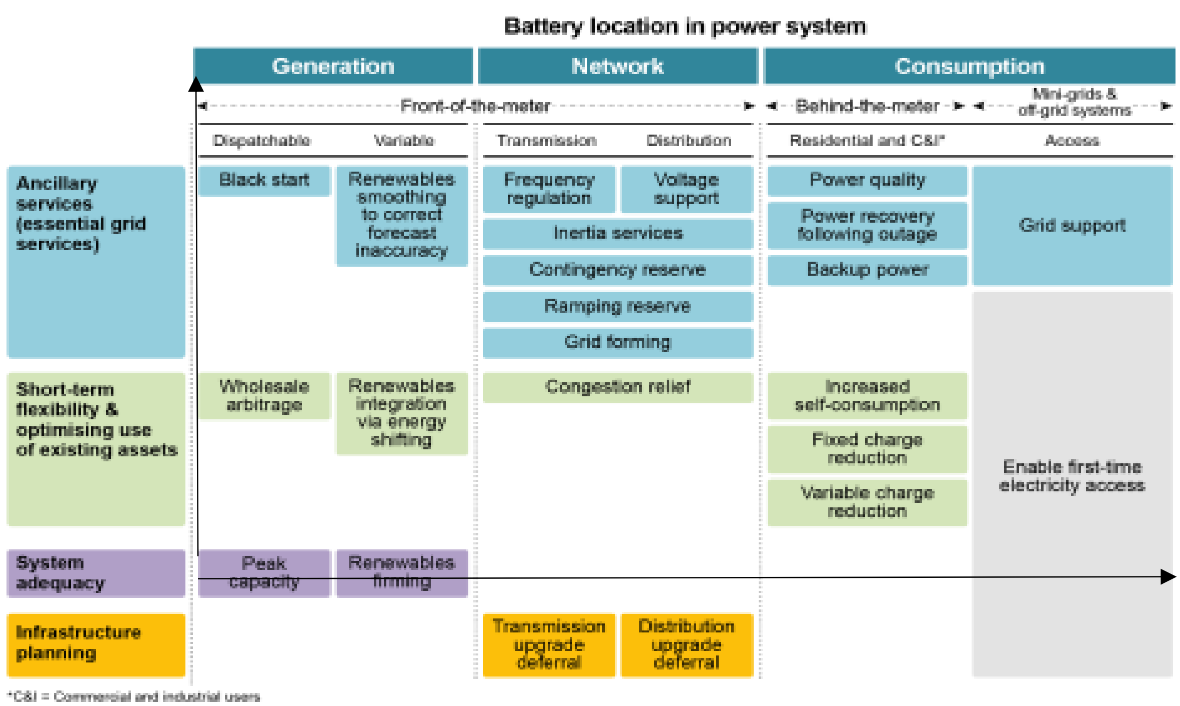
Source: Ryan Wiser, et al., 2024, "Grid Value and Cost of UtilityScale Wind and Solar: Potential Implications for Consumer Electricity Bills," *Lawrence Berkeley National Laboratory* June 2024, p. 23.

LITHIUM-ION BATTERY CELL AND PACK PRICES (2013=100%) MNC-CR- 5



Source: International Energy Agency, *Batteries and Secure Energy Transition,* April 2024, p. 22.

BATTERY STORAGE IN POWER SYSTEMS MNC-CR- 6

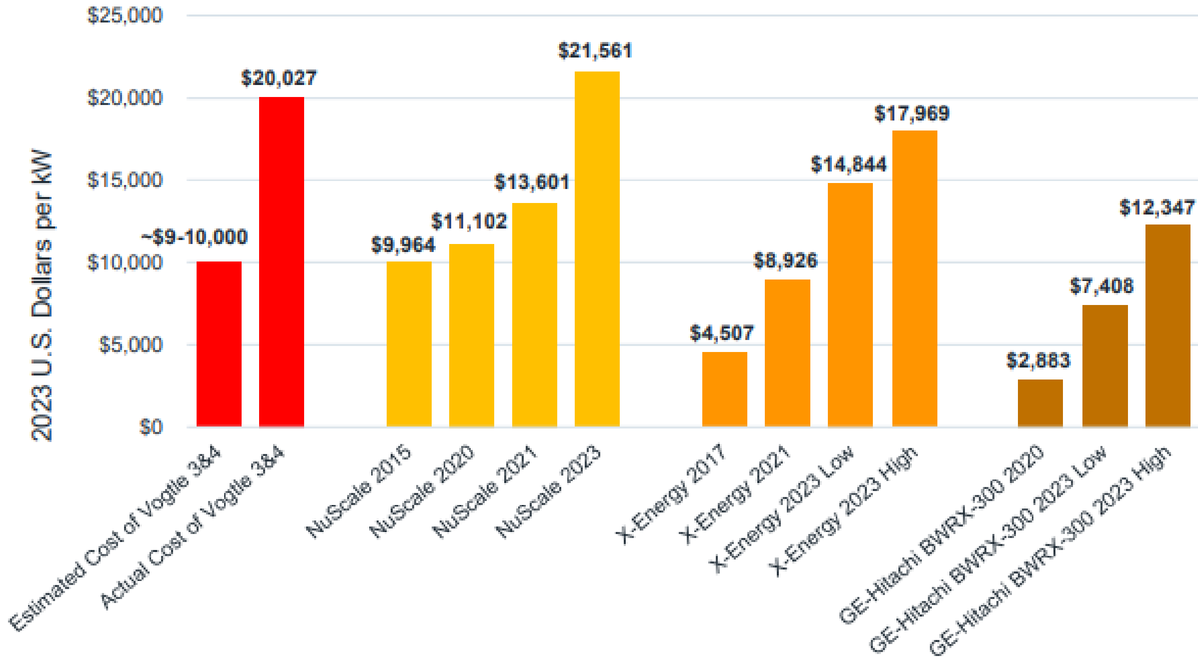


Battery storage can provide a broad range of services to a power system

Note: Battery storage applications are represented along the dimensions: horizontal axis shows the location within a power system; vertical axis shows the type of services.

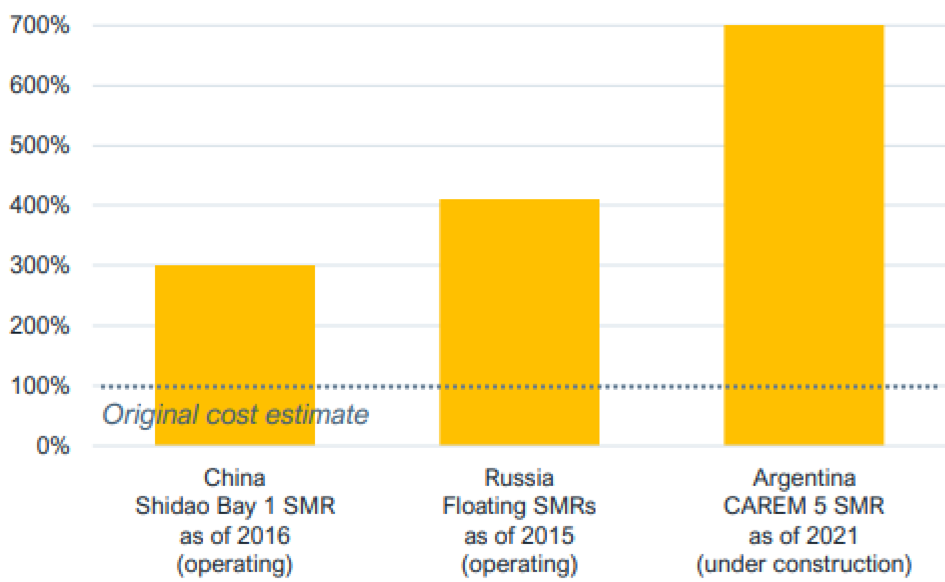
Source: International Energy Agency, *Batteries and Secure Energy Transition,* April 2024, p. 36.

THE WORSENING PROSPECTS FOR SMR COSTS **MNC-CR- 7**



Source: IEEFA calculations based on public data for each of the projects converted to 2023-year U.S. dollars. For example, see the GE Hitachi website, Four reactors could cost Saskatchewan $12 to $20 billion,, X-Energy and ARES Acquisition Corporation Announce Strategic Update, Georgia Power Company's monthly and Quarterly Reports to the Georgia Public Service Commission on construction of the Vogtle Nuclear Project and IEEFA reports on NuScale.

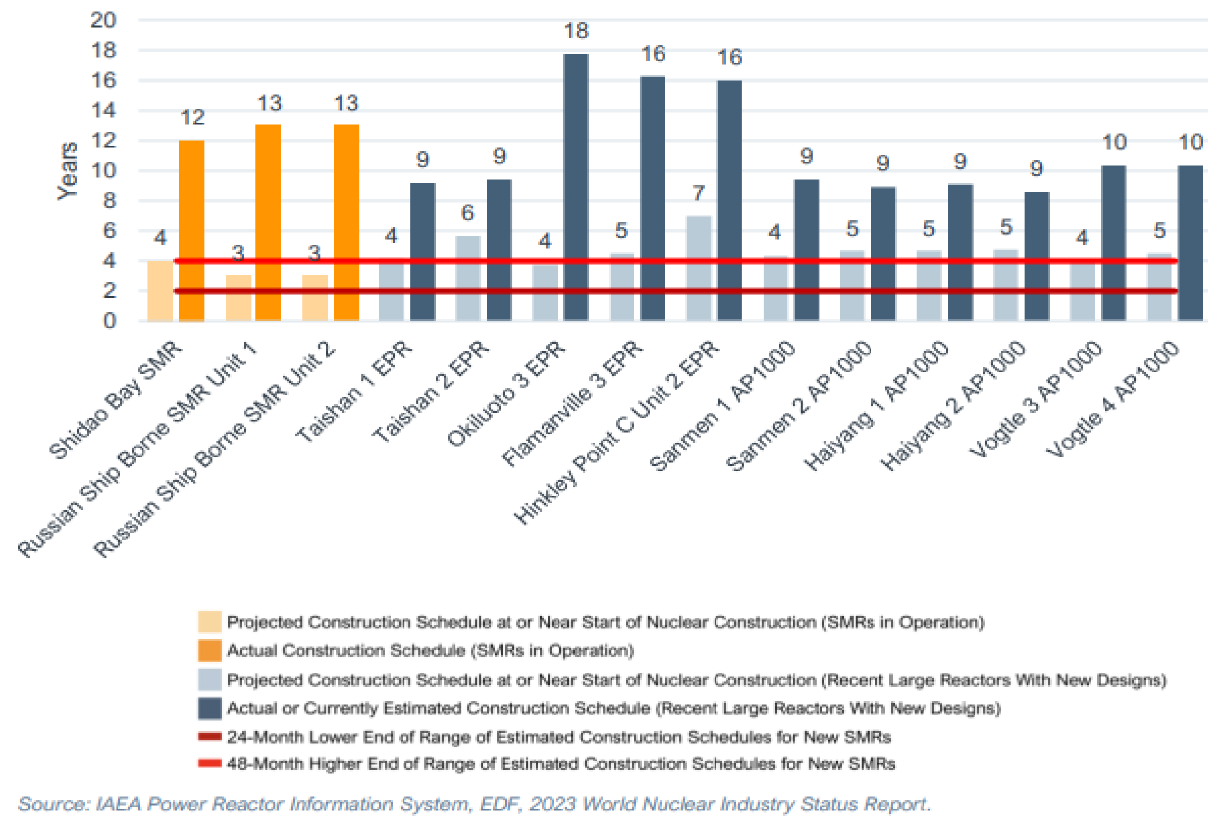
Figure 1: Cost Escalation Experienced by SMRs in Operation or Under Construction



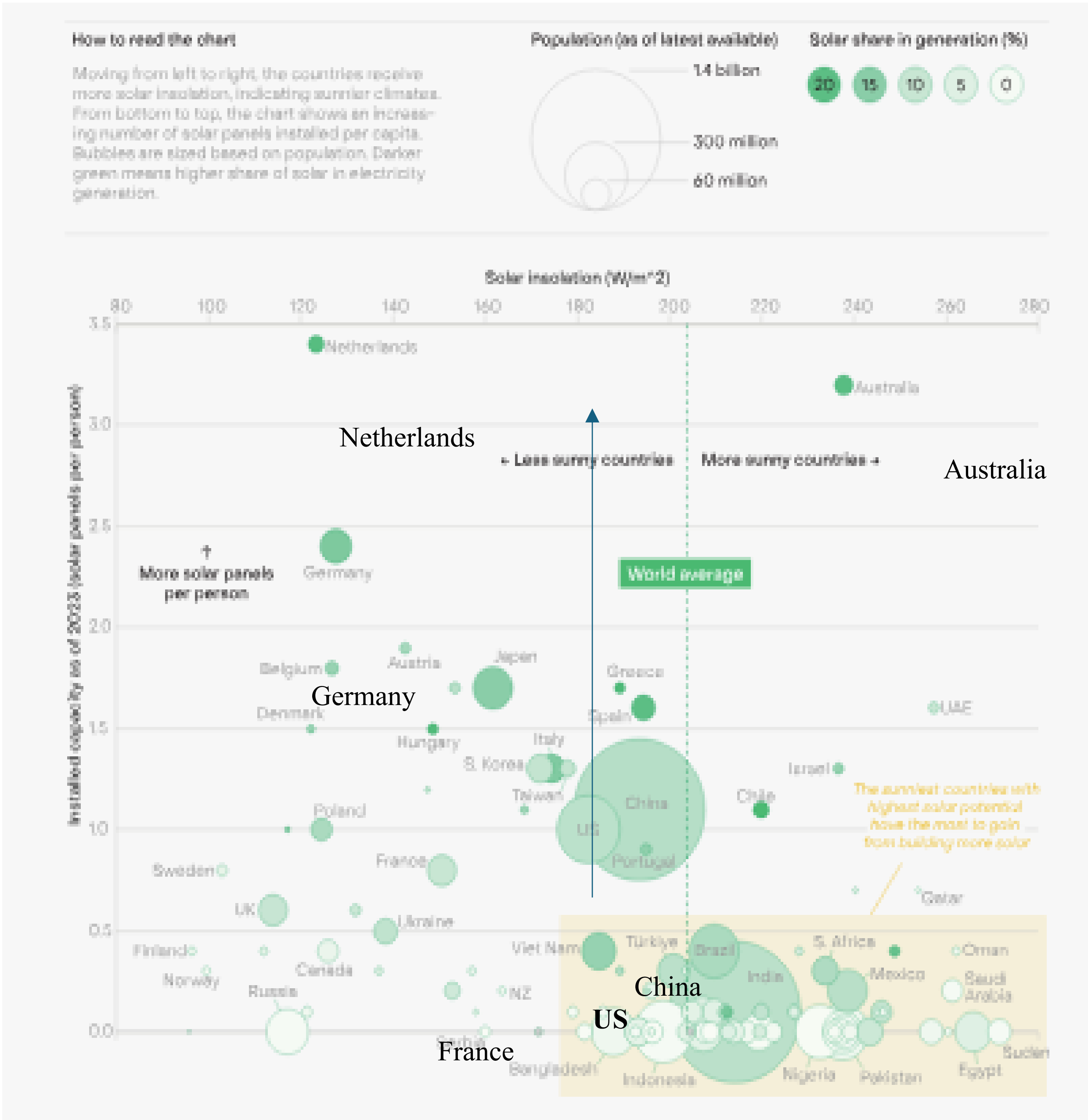
Source: IEEFA calculations from data in the 2023 World Nuclear Industry Status Report and Bellona Environmental Foundation.

Source: Schlissel, David and Dennis Wamsted, 2024, *Small modular reactors are still too expensive, too slow, and too risky,* The Institute for Energy Economics and Financial Analysis (IEEFA), May, p. 6 ,8.

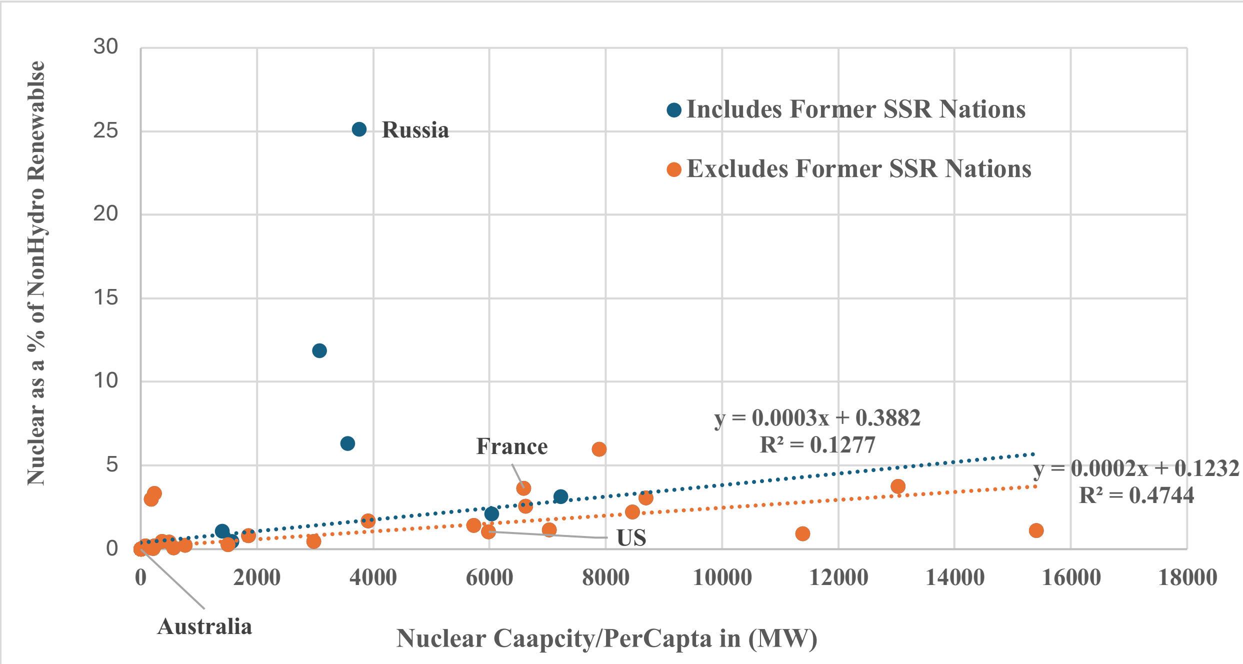
WORSENING PROSPECTS FOR SMR CONSTRUCTION PERIODS HYPE v. REALITY: MNC-CR- 8



Source: Schlissel, David and Dennis Wamsted, 2024, *Small modular reactors are still too expensive, too slow, and too risky,* The Institute for Energy Economics and Financial Analysis (IEEFA), May, p.14.

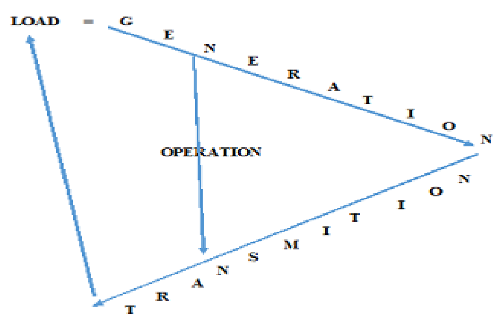


Source: Rangelova, Kostantsa, 2024, *2023's record solar surge explained in six charts,* Ember, Chart 6.

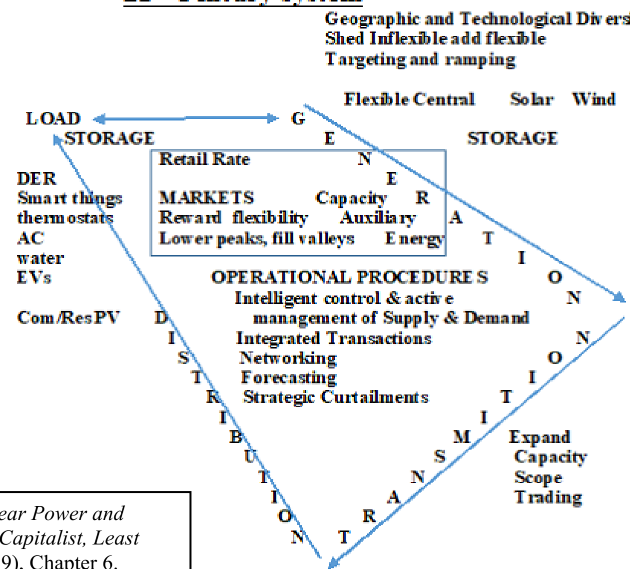


Source: Based on *Annual Electricity Data,* Ember

20th Century System



21st Century system



Source: (12) Mark Cooper, *The Green New Deal, Nuclear Power and Other Potholes to avoid on the Road to a Progressive, Capitalist, Least Cost, Low Carbon, Clean, Electricity Sector*, April 2019), Chapter 6.

SPECIFIC MEASURES AND TOOLS FOR MANAGING THE 21ST CENTURY ELECTRICITY SYSTEM

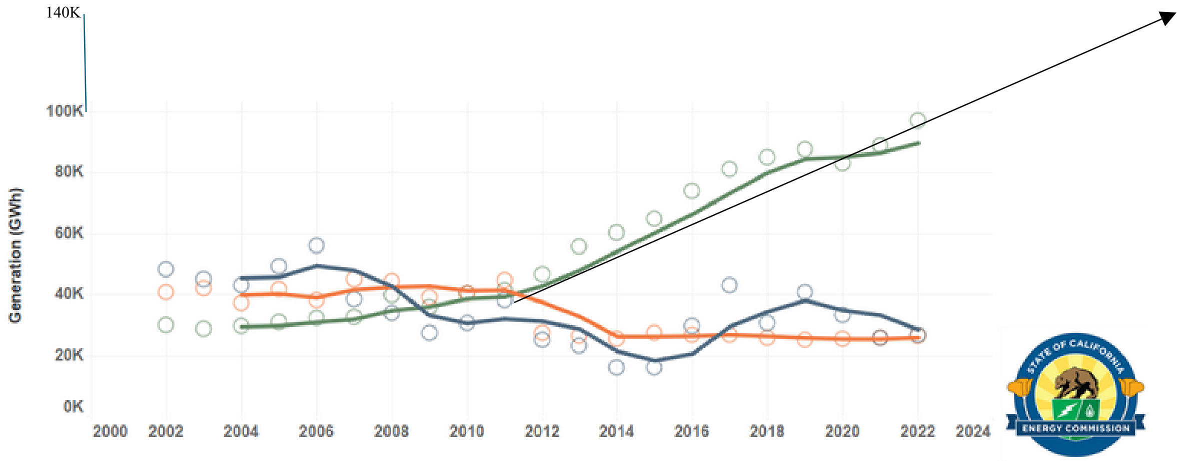
1	Penetration: States
2	Nations
	a. recent 2023
	b. recent 2024
3	Cost: General Components
	a. recent 2023
	b. recent 2024
4	System cost/value
	a, recent 2024
	b, recent 2024
5	Challenges: With solutions
	a. recent2023 (deep decarb.)
	b. recent 2024
6	Pure Negatives
	a. recent 2023
	b. recent 2024
7	Generation (100% Decarb.)
	a. recent 2023 (wind & Solar)
	b. recent 2024
8	Geographic diversity
9	Technological diversity
	a. recent 2023
	b. recent 2024
10	Peak targeted solar
11	Quick start/rapid ramp
12	Shed inflexible baseload
13	Shift to flexible central

14	Flexible central
15	Firm renewables
	a. recent 2023 Geothermal
	b .recent 2024
16	Value ancillary services;
17	Avoid lumpy investment
18	Load
	a. recent 2023
	b. recent 2024
19	Supply-side
20	Target peaks
21	More in slack, less in scarcity
22	Demand-side
	a. recent 2023
	b. recent 2024
23	Aggressive demand response
24	Smart controllers manage use
25	Transmission
	a. recent 2023
	b. recent 2024
26	Expand balance areas
27	Storage
	a. recent 2023 (Hybrid, LDS)
	b. recent 2024
28	Dispatchable, traditional

29	Distributed (VPP)
30	Electric vehicles
	a. recent 2023
	b. recent 2024
31	Operational Procedures
32	Flexibility integration
33	a. recent firming load
	b. recent 2024
34	Strategic Curtailment
35	Improve forecasting
36	Market Design
	a. recent
37	Positive and negative prices
	a. recent
	b. recent 2024
38	Target fixed cost recovery
39	TOU (cut peaks, fill valleys)
40	Smart Grid
	a. recent 2023
	b. recent 2024
41	CHP

Sources: Citations are presented in Appendix 1.

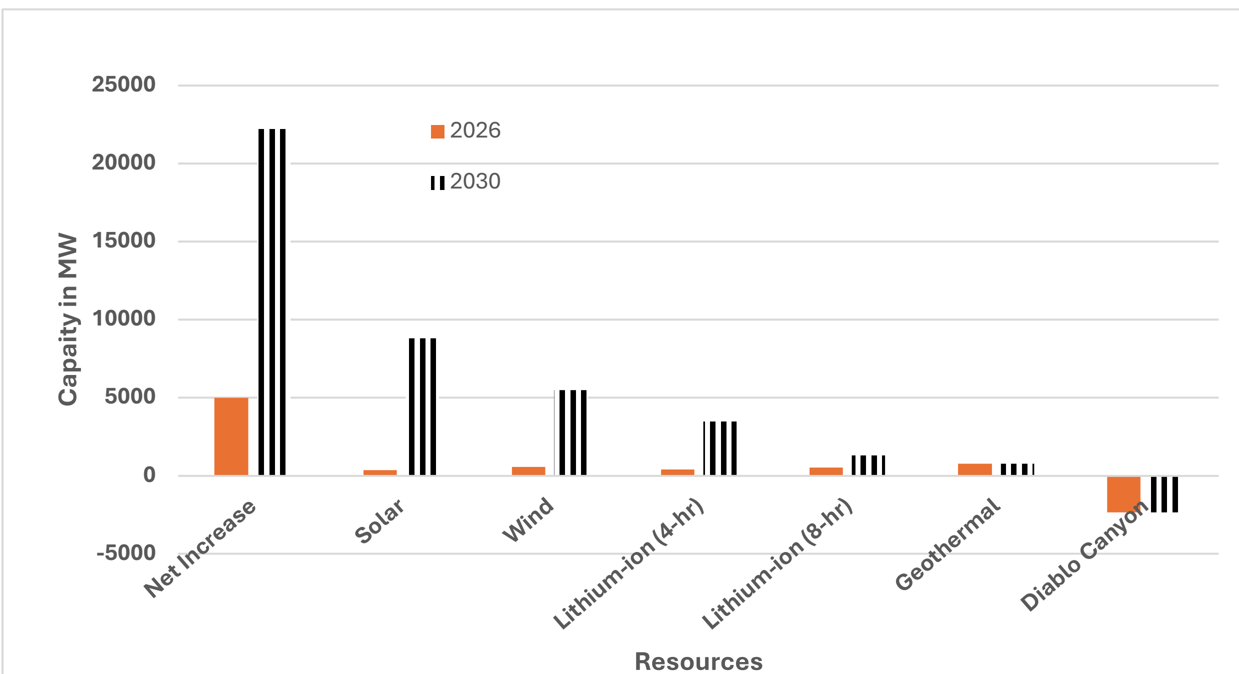
ESTIMATED ANNUAL CLEAN ENERGY PROGRESS **MNC-CR-12**



2030

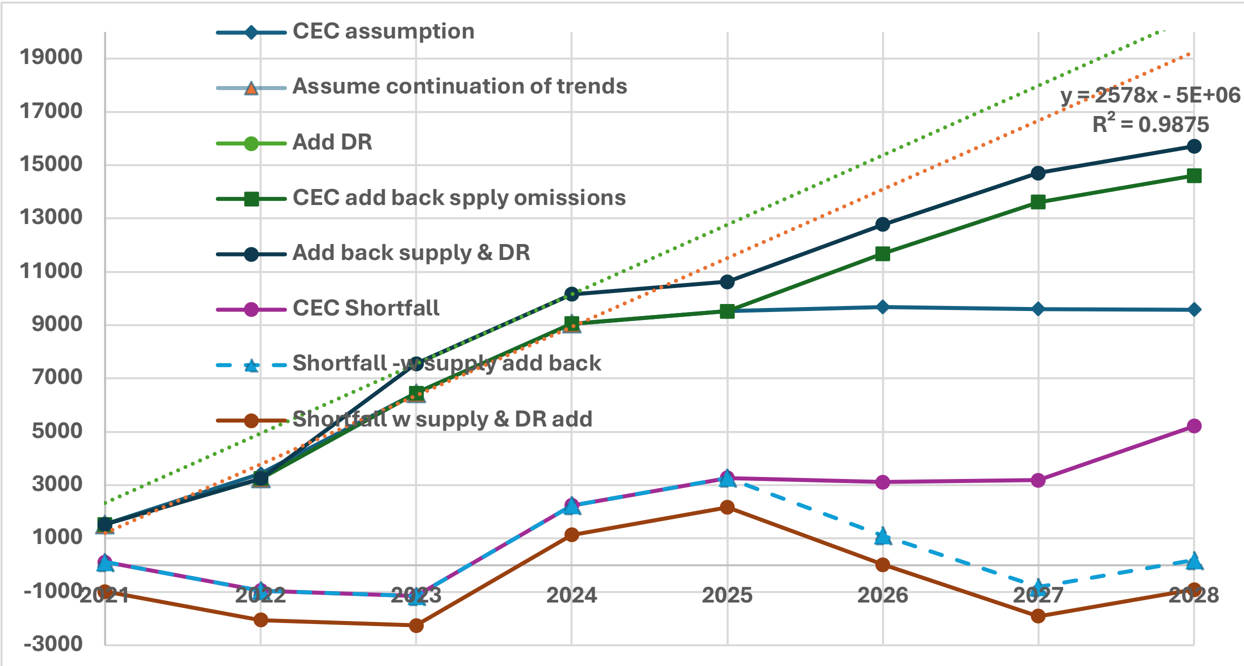
Energy Grid of the Future are Paying Off, May 9. Source: California Energy Commission, 2024, *New Data Shows Investments to Build California's Clean*

CHANGES IN INSTALLED CAPACITY, 2024-2030, IN THE CPUC PSP **MNC-CR-13**



Source: California ISO, 2024, *2023 Summer Loads and Resources Assessment,* May,8, Table 2.6

CEC's Mischaracterization of the PG&E Net Load Condition **MNC- CR - 14**



Source: Public Utilities Commission of the State of California, Implementing Senate Bill 846 Concerning Potential Extension of Diablo Canyon Power Plant Operations, Rulemaking 23-01-00, Attachment E: Diablo Canyon Power Plant Extension, Final Draft CEC Analysis of Need to Support Reliability, modified as described in text.

Spreading the Burden does not Lower the Real Cost (Cost in Billions) MNC- CR – 15

	Subsidy + Capital Costs	Other costs 2026-2029	Total
Federal Taxpayers	1.1	0	1.1
State Taxpayers	.3	0	.3
State Ratepayers	.8	3.4	4.2

Source: Author calculation.

ALTERNATIVES ARE LESS COSTLY & AVAILABLE IN SMALLER INCREMENTS MNC- CR- 16

(Cost in $)

		Costs Per KW				Costs per KW	
		Low	High	Avg.	Avg. Capital plus 2 x O&M 2 x O&M	Capital + per kw	KW > MW Load factor
Wind+ Storage	Capital	1375	2250	1812.5	1125	1237	1237000
100 MW	Fixed O&M	32	80	56	112		
Solar + Storage	Capital	1075	1600	1337.5	800	865	865000
100 MW	Fixed O&M	20	45	32.5	65		
					Total filling the shortfall % of DC costs		
	Filling the gap				7%		
	Building at a sustained rate of 1000MW/year				35%		

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APPENDIX 1
TOOLS CITATIONS

This appendix updates the citation for specific tools to manage the 21st century system according to the categorization scheme introduced earlier and reproduced below. All of the most recent additions, noted by the letter b. begin with citation 400.

SPECIFIC MEASURES AND TOOLS FOR MANAGING THE 21ST CENTURY ELECTRICITY SYSTEM

1	Penetration: States
2	Nations
	a. recent 2023
	b. recent 2024
3	Cost: General Components
	a. recent 2023
	b. recent 2024
4	System cost/value
	a, recent 2024
	b, recent 2024
5	Challenges: With solutions
	a. recent2023 (deep decarb.)
	b. recent 2024
6	Pure Negatives
	a. recent 2023
	b. recent 2024
7	Generation (100% Decarb.)
	a. recent 2023 (wind & Solar)
	b. recent 2024
8	Geographic diversity
9	Technological diversity
	a. recent 2023
	b. recent 2024
10	Peak targeted solar
11	Quick start/rapid ramp
12	Shed inflexible baseload
13	Shift to flexible central
14	Flexible central
15	Firm renewables
	a. recent 2023 Geothermal
	b .recent 2024
16	Value ancillary services;
17	Avoid lumpy investment
18	Load
	a. recent 2023
	b. recent 2024
19	Supply-side
20	Target peaks
21	More in slack, less in scarcity
22	Demand-side
	a. recent 2023
	b. recent 2024
23	Aggressive demand response
24	Smart controllers manage use
25	Transmission
	a. recent 2023
	b. recent 2024
26	Expand balance areas
27	Storage
	a. recent 2023 (Hybrid, LDS)
	b. recent 2024
28	Dispatchable, traditional
29	Distributed (VPP)
30	Electric vehicles
	a. recent 2023
	b. recent 2024
31	Operational Procedures
32	Flexibility integration
33	a. recent firming load
	b. recent 2024
34	Strategic Curtailment
35	Improve forecasting
36	Market Design
	a. recent
37	Positive and negative prices
	a. recent
	b. recent 2024
38	Target fixed cost recovery
39	TOU (cut peaks, fill valleys)
40	Smart Grid
	a. recent 2023
	b. recent 2024
41	CHP

Citations by Tool Number

Measures/tools	Citations by #
1. Penetration: States	1, 2, 23, 47, 51, 52
2 Nations	1, 32, 36, 53, 54, 55, 56, 57, 58, 59 60, 66, 154
a. Recent 2023	69, 278, 289, 341, 352, 374, 377,380, 381
b. Recent 2024	400
3 Cost: General Components	1, 5, 9, 10, 16, 18, 29, 36, 46, 47,63, 69, 71, 75, 76, 77, 98, 116, 130, 137, 147, 150, 183, 184, 246
a. Recent 2023	261, 262, 263, 368,369
b. Recent 2024	424, 406, 407, 427
4 System cost/value	5, 75, 155, 184, 217, 243,244, 260
a. Recent 2023	2, 7, 325-327, 386
b. Recent 2024	408, 412, 415, 420
5 Challenges: With solutions	5, 8, 9,, 10, 12, 93, 94, 215, 232
a. Recent, 2023 Deep Decarb	276, 376, 269, 274, 280-283, 286, 289, 300, 301, 322, 336, 337, 339, 342-345, 347-351, 353-355, 357,358-368, 371-373 378, 379, 382, 383, 385, 389, 393, 399,
b. Equity	128, 141, 151, 161, 182, 187, 189, 236
6. Pure negatives	83, 87, 95, 96, 214, 230
a. Recent	357, 388, 391, 400
7 Generation (100% Decarb.)	257, 258, 259, 278, 279
a. Resent (Wind and Solar)	261-263, 269, 293, 294, 299, 306-308, 312, 314, 317-319, 324, 325, 330, 332, 333, 341, 346, 396, 397
b. Recent (2024)	411, 433, 450
8 Geographic diversity	5, 7, 8, 12, 36, 151, 152, 153, 237
9. Technological diversity	7, 8, 10, 15, 36, 38, 44, 102, 151, 237, 240, 246, 247
a. Recent 2023	289, 302, 304, 341, 377
b. Recent 2024	412. 416
10. Peak targeted solar	7, , 155, 156, 246, 247

11. Quick start/rapid ramp	1, 7, 10, 23, 151, 246
b. Recent 2024	451
12, Shed inflexible baseload	7, 27, 151, 230, 232, 247
13. Shift to flexible	5, 7, 160, 161, 162, 163, 164, 165, 166, 167, 232
14, Flexible central1,	2, 26, 60, 84, 85, 183
15. Firm renewables	1, 2, 10, 19, 22, 24, 26, 88
a, Recent 2023 Geothermal	264, 266, 284, 285, 290, 291, 298, 365, 377
b. Recent 2024	419, 422, 456
16. Value ancillary services;	1, 2, 5, 8,12, 48, 52, 59, 60, 138, 139, 140, 182, 183, 185
17 Avoid lumpy investment	7, 155
18 **Load**	1, 3, 26, 70, 105, 106, 107, 108, 109, 110, 111, 112, 113
a. Recent 2023	368-370
b. Recent 2024	405, 412, 421, 423,424,425, 427, 457
19 Supply-side	7, 169,
20 Target peaks	7, 27, 151, 240
21 More in slack, less in scarcity	1, 7, 105, 160
22 Demand-side	7, 12, 13, 27, 36, 172, 173, 174, 175, 176, 177, 178, 179, 85
a. Recent 2023	368, 369
b. Recent 2024	400, 431, 432, 446
23 Aggressive demand response	7, 27, 151, 175, 177, 178, 179, 181
24 Smart controllers manage use	7, 8, 27, 186, 187
25 Transmission	1, 2, 3, 5, 7, 22, 24, 25, 26, 28, 31, 34, 40, 41, 57, 65, 67, 68, 103, 126, 127, 128, 129, 181, 183, 185, 188, 189, 190, 191, 192
a. Recent 2023	87, 311, 35
b. Recent 2024	
26 Expand balance areas	5, 7, 27, 151, 160, 181
27 Storage	1, 5, 7, 8, 12, 19, 20,21,22,23, 41, 43, 49, 100, 101, 102, 151, 157, 185, 194, 196, 197, 198, 199, 200, 201, 202, 203, 204, 205, 206, 207, 208, 209, 210, 230
a. Recent2023 (hybrid, LDS)	261, 270, 271, 302, 309, 310, 314, 316, 333, 342, 384
b. Recent 2024	401, 402, 403, 417, 433, 435, 446
28 Dispatchable, traditional	1, 36, 111, 183, 232
29 Distributed (VPPt)	1, 2, 11, 13, 27, 36, 39, 45, 56, 115, 116, 117, 118, 119, 194, 233, 254
including VPP, Mico grids, etc.	368, 369
30 Electric455 vehicles	1, 11, 13, 35, 104, 113, 114, 233
a. Recent	340, 348, 375
b, Recent 2024	43, 450
31 Operational Procedures	1, 7, 12, 25, 26, 136, 212, 213,231, 250, 252
b. Recent	449, 455
32 Flexibility/integration	1, 5, 8, 9, 10, 13, 17, 18, 24, 26, 30, 31, 32, 34, 36, 72, 73, 78, 82, 97, 99, 127, 147, 173, 171, 180, 183, 85, 194, 230, 231, 245, 253
a. Recent 2023 (Firming load)	261, 269, 320
33 Integrated Transactions	8, 9, 18, 241, 242
a. Recent	320, 368, 387
b. Recent 2024	413, 418, 425, 429, 440, 441, 453. 456
34 Strategic Curtailment	1, 8, 23, 61, 120, 121, 122, 123, 124, 125, 248, 249
35 Improve forecasting	1, 7, 12, 36, 37, 54, 143, 144, 145, 151, 215, 216, 217, 218, 219
36 Market Design	1, 2, 8, 12, 13, 18, 23, 26, 32, 33, 40, 41, 56, 57, 58, 59, 60, 62, 94, 146, 147, 148, 181, 183, 184, 248, 250, 252
a. Recent 2023	278, 276, 315, 373, 322, 376-378, 394
b. Recent 2024	444, 445
37 Positive and Negative prices	1, 5, 8, 10, 17, 57, 148, 181, 235, 238, 253, 269
38 Target fixed cost recovery;	9, 14, 181, 183, 184
a. Recent	373
39 TOU (cut peaks, fill valleys)	7, 8, 9, 27, 64, 105, 106, 107, 108, 109, 110, 111, 112, 93, 193, 220, 221, 222, 223, 234, 235, 239
40 Smart Grid	1, 3, 7, 8, 11, 12, 22, 42, 79, 80, 81 ,82, 119, 131, 132, 133, 134, 135, 224, 225, 226, 227, 228, 229
a. Recent	272, 328, 329, 371, 399
41. CHP	2, 26, 50, 54, 89, 90

Alphabetical with Tools Citations by number

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333 Ahlstrom, M. (2019). Renewable electricity, storage and electrification: amazing progress, transformations and challenges. Presented at NASEM workshop Deployment of Deep Decarbonization Technologies.

Alexandra Klass, et al., **Citations by number**

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35 Improve forecasting 1, 7, 12, 36, 37, 54, 143, 144, 145, 151, 215, 216, 217, 218, 219
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250, 252
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