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RESEARCH ARTICLE

Comparing the Role of Long Duration Energy Storage Technologies for Zero-Carbon Electricity Systems

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ABSTRACT The successful integration of renewable energy resources into the power grid hinges on the development of energy storage technologies that are both cost-effective and reliable. These storage technologies, capable of storing energy for durations longer than 10 hours, play a crucial role in mitigating the variability inherent in wind and solar-dominant power systems. To shed light on this matter, a transparent, least-cost macro energy model with user-defined constraints has been utilized for a case study of California. The model addresses all included technologies, solving for both hourly dispatch and installed capacities. Real-world historical demand and hourly weather data have been utilized to do this analysis. A novel approach has been introduced to assess the significance of long-duration energy storage technologies (LDS) in terms of their energy and power capacity. This method explores the contributions of pumped hydropower storage (PHS), compressed air energy storage (CAES), and power-to-gas-to-power (PGP) storage toward minimizing the overall balance of system cost. Historical electricity demand, hourly weather data, and current technology costs are used to investigate high-level implications for California's power system options. Increasing the storage capacity of each technology from 1 to 10 hours results in 29.6%, 14.4%, and 7.5% cost reduction for PHS, CAES, and PGP cases respectively. However, in studied simulations, maximum availability (maximum) of pumped hydropower storage reduces the balance of system costs by 72.3% followed by CAES (60.6%) and PGP (48.6%) and suggests that pumped hydropower storage in combination with CAES/PGP could play an important role in California's electricity system, provided that suitable sites can be identified and constructed at reasonable costs.

INDEX TERMS 100% renewable electricity, long-duration energy storage, macro-energy modeling, solar power, wind power.

I. INTRODUCTION

Climate change presents significant dangers to natural systems and human beings worldwide. It is caused by increased concentrations of greenhouse gases in the atmosphere, principally Carbon emissions emitted by human activities [1], [2]. Global decarbonization, or carbon emission reduction, is crucial for mitigating the effects of climate change [3]. Moreover, decarbonization is necessary to ensure a sustainable

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future for current and future generations, and it can also lead to other advantages, such as improved public health and air quality, and new economic opportunities in the clean energy sector [4], [5].

Renewable Energy Sources (RES) like hydropower, wind, and solar are ideal for decarbonizing the electric sector and reducing its carbon footprint [6], [7]. In addition, energy storage technology can support the integration of RES into the primary grid by storing surplus power generated during low-demand periods and releasing it during times of higher demand [8]. Energy storage is a powerful technology in the transition towards decarbonization of the energy system because it allows RES to be integrated into the grid and improves its stability and reliability through demand and supply balancing [8], [9]. This technology is divided into two categories based on its ability to store power and the duration over which it can store energy: short and long-duration energy storage (LDES). Compared to short-duration energy storage, the LDES technologies are well suited for applications that require a sustained release of energy (Sustained release of energy refers to providing a reliable and consistent power supply for continuous operation or to meet long-term energy demands. This sustained release can be achieved through various means, such as efficient energy storage systems or power generation methods that maintain a consistent output for an extended duration.) grid stability (Grid stability refers to the ability of an electrical power grid to maintain a balanced and reliable supply of electricity to consumers. It involves maintaining a stable frequency, voltage levels, and power factor within acceptable limits.), and long-term cost-effectiveness (Long-term cost-effectiveness refers to the economic viability and efficiency of the grid infrastructure and operations over an extended period. It involves assessing the balance between the initial investment, ongoing operational expenses, and the benefits derived from the grid infrastructure over its lifespan.) [10]. These long-duration technologies can store energy for periods ranging from several hours to several days and have several benefits. It allows utilities to better manage their generation and consumption, reducing the need for fossil-fuel-based power stations, which can be used during peak demand periods in highly renewable power systems [11]. It can lead to a reduction in carbon emissions, an improvement in energy security, and a decrease in consumer energy costs [9].

However, the development and implementation of LDES technologies, apart from pumped hydro, are still in their early phases, and several issues need to be addressed, such as cost, scalability, and regulatory barriers. Nevertheless, the continued growth of RES and the urgent need to address climate change are driving efforts to overcome these issues and accelerate the decarbonization of the electric sector using LDES technologies [12], [13]. Some LDES technologies, including pumped hydro storage (PHS), compressed air energy storage (CAES), and power-to-gas-to-power (PGP), have more flexibility compared to demand response or other flexibility providers because they allow for independent sizing of their power and energy capacities, each one with unique benefits and limitations [14]. Additionally, LDES can respond rapidly to grid conditions, providing instantaneous power injections or absorptions as needed. This fast response capability contributes to grid stability and reliability. PHS stores energy by pumping water from a lower to a higher reservoir when energy is plentiful and then releases it via turbines to produce electricity when required.

Pumped storage hydropower stands as the dominant storage technology on a global scale, with a staggering share of more than 94 percent of the installed energy storage capacity worldwide [15]. This puts it far ahead of other battery types, including lithium-ion and various alternatives. According to the International Hydropower Association (IHA), pumped hydro projects worldwide can store approximately 9,000 gigawatt hours (GWh) of electricity. Recent research indicates that there is considerable potential for expanding the global pumped hydro capacity, including from over 600,000 off-river sites that have been identified [15]. Pumped hydropower storage provides rapid dispatch, typically within minutes or seconds [14], and can offer a wide range of power capacities, ranging from several megawatts (MW) to several gigawatts (GW) [16]. Moreover, these systems have a long operational lifespan, spanning from 50 to 100 years [17], [18]. Although pumped hydro storage offers valuable energy storage capabilities, its implementation can be subject to various limitations including geographic constraints, environmental impacts, capital costs, and technical challenges [19], [20].

The CAES technology compresses air and stores it in underground reservoirs before releasing it to drive turbines when energy is required. CAES has been implemented at the grid level for over 40 years [21]. CAES stands out for its lifetime, allowing for long-lasting performance. CAES also offers extended energy storage durations, enabling the storage of electricity for prolonged periods. Additionally, it boasts minimal self-discharge, ensuring minimal energy loss over time [22]. Furthermore, CAES is highly scalable, offering flexibility in terms of capacities and power output. A summary of such features has been presented in Table 1. Although, compared to PHS, it has a lower energy capacity, in some cases, CAES might be more adaptable due to its flexibility in location and scalability [23].

While CAES systems are generally considered low-emission energy storage solutions, it's essential to acknowledge that some implementations may include gas turbines that consume natural gas for compression. In the context of decarbonization, it's crucial to assess and mitigate the emissions associated with these gas turbines.

Strategies to address emissions from gas turbine usage may involve carbon capture and storage technologies or transition to alternative fuels such as green hydrogen. By considering the emissions implications holistically and exploring mitigation measures, our study aims to provide insights

TABLE 1. Characteristics of selected energy storage technologies [24], [25], [26], [27], [28], [29], [30], [31], [32], [33], [34], [35], [36], [37].

Parameters	Pumped Hydropower Storage (PHS)	Compressed Air Energy Storage (CAES)	Power to-gas-to Power (PGP) Storage
Energy Storage capacity	MWh to 10 GWh	10-400 MWh	100 GWh
Power Storage Capacity	200 to 1000 MW	500MW	100 to 1000 MW
Lifespan (years)	50-100 years	20 – 40 years	5 – 30 years
Round trip Efficiency	70% – 85 %	40% – 70 %	25% – 45%
Discharge duration	Several hours to several weeks	Several hours to a few days	Days to months
Energy Density	10 to 20 megajoules per cubic meter (MJ/m³) or 2.8 to 5.6 kilowatt-hours per cubic meter (kWh/m³).	1 to 5 megajoules per cubic meter (MJ/m³) or 0.3 to 1.4 kilowatt-hours per cubic meter (kWh/m³).	20 megajoules per kilogram (MJ/kg) or 33.3 kilowatt-hours per kilogram (kWh/kg)
Site Requirements	Specific geographic features	Underground caverns or large above-ground storage vessels	More flexible in site placement, not limited by geographical requirements.
Maturity and Commercial Availability	Well-established	Relatively mature	Early-phase
Global Capacity	Over 200 GW	Around 2 GW (gigawatts) to 4 GW	few MW to few GW

into achieving decarbonization goals while leveraging CAES technology for energy storage.

PGP converts surplus renewable electricity into hydrogen (or any other suitable fuel type), which can then be stored and later used to generate electricity. Hydrogen can be stored in high-pressure tanks, cryogenic tanks (in liquid form) and in the form of certain metal alloys or compounds known as metal hydrides. PGP can offer long-duration storage, ranging from hours to days or even longer, depending on the specific design and capacity of the storage facility [24]. While PGP storage can provide numerous advantages, it has some limitations. The limitation of PGP includes efficiency losses during the conversion processes, which can result in energy wastage. PGP can also be capital-intensive, requiring significant investments in infrastructure, and may face challenges related to the development of hydrogen supply chains and the overall cost-effectiveness compared to other energy storage technologies.

These three long duration technologies can be applied across a range of scales (Table 1). Pumped hydro storage is the most mature and widely deployed energy storage technology among the three followed by CAES, which is relatively mature and commercially available. PGP is still in its early phases of development and implementation. CAES and Pumped Hydro Storage have high round trip efficiencies but, they have limitations related to specific geographic and geological requirements, restricting their site placement options [23], [24]. PGP storage using hydrogen and/or its derivatives can store energy over longer period and in future, PGP can stand out as a promising candidate for storing large quantities of energy while enabling flexible resource relocation with reduced CO2 emissions [25].

The suitability of each technology depends on specific project requirements, geographical considerations, available resources, and cost-effectiveness [26], [27], [28], [29]. The choice between these technologies often involves a trade-off between factors such as energy storage capacity, duration, site requirements, flexibility, and efficiency.

Several research papers propose long-duration energy storage technologies for deep decarbonization. The paper [38] proposes a 100% renewable energy system for East Asia that relies on a mix of renewable energy sources and energy storage technologies, including PHS. The authors demonstrate that PHS can provide long-duration energy storage and support the integration of renewable energy into the grid. While the work [39] addresses the role of PHS to decarbonization of the electricity sector using Spain's power system as a case study, it can improve the utilization of low-carbon generation sources (Wind, Solar PV, and nuclear), while decreasing the dispatch of natural gas-fired generation and greenhouse gas emissions. The decarbonization goals of the People's Republic of China are based on the extensive use of PHS to balance grid issues as presented in [40]. PHS is the most used electricity storage technology, and China already has the most PHS capacity installed globally. The goal of this study is to better manage the challenge of balancing RES production by examining the potential for technological advancement of the current and future PHS fleet in China. An optimal planning structure for bulk-scale CAES in combination with the use of wind and solar energy to replace fossil fuels in a power generation system is presented in [41]. The authors argue that this system can support deep decarbonization by providing reliable and cost-effective storage for renewable energy. An energy balance to analyze the efficiency of a complete cycle of charging and discharging for CAES configurations is used in [42], and sensitivity analysis is used to examine the key factors that influence the effectiveness of the CAES configurations.

According to a study [43] that focuses on the integration of CAES into the German power system, CAES can be a flexible, cost-effective option when there is enough wind generation. However, this study specifically examines the integration of wind power and suggests that the economic viability of CAES is limited when considering a discharge time of 2 hours. The study [44] looks at how carbon pricing and PGP energy storage can be used to transition energy systems toward deep decarbonization. These findings stand up to PGP costs that are higher than expected. Authors concluded that, the utilization of Power-to-Gas is not only a technological imperative but also economically justifiable, as it can lead to reduced overall system costs while simultaneously achieving the goal of net-zero emissions. In [45], the authors suggest a PGP using hydrogen fuel for the complete decarbonization of the electric sector and demonstrated how the benefits of PGP are more sensitive to the cost of conversion than to conversion efficiency. With the restricted dispatch of natural gas (10-25%), PGP with underground storage can play a substantial role in the system cost reduction. To store the excess energy from RES a PGP technology has been proposed in [46], which is a method that offers promise in long-term storage. In [47], the authors evaluate the potential of a PGP as an inter-seasonal energy storage technology. This work highlights the importance of balancing seasonal variation in energy systems with high-RES penetration. The analysis of three large-scale energy storage technologies namely PHS, CAES, and PGP, and how they might be used as well as how much it would cost to store energy is presented in [29], and the analysis of these technologies PHS, CAES, and PGP regarding their potential and the cost of storing energy has been presented in [48]. The use of CAES with various wind and solar energy penetration in power systems has been investigated in [49] considering the deep decarbonization of power system. The paper concludes that, in case of 2 times increase in the wind and solar potential the required CAES capacity would be 19.2% less (3.10TWh) and the corresponding cost would decrease up to 29.7%.

While the literature has made substantial progress in highlighting the significance of long duration energy storage in deep decarbonization scenarios, there is a gap in understanding the specific role of storage energy and power capacities in achieving cost reduction and decarbonization objectives.

This paper specifically investigates the influence of varying storage power capacity (kW) and storage energy capacity (kWh) on the cost reduction of a highly renewable power system. The aim of this paper is to explore the value of different long-duration storage technologies (including pumped hydropower storage (PHS), compressed air energy storage (CAES), and power-to-gas-to-power (PGP) storage), to identify the least-cost solution considering the deep decarbonization of a power system and how the variability of wind and solar-based power systems can be mitigated through bulk energy storage. California was selected as the case study for this research. A novel least-cost approach has been proposed to assess the value of long-duration storage technologies by assessing their value across a range of power and energy storage capacities, spanning from minimum to maximum values. The analysis specifically focuses on examining the balance of system cost, power dispatch, and power capacities within deeply decarbonized scenarios.

This analysis aims to provide valuable insights for policymakers regarding the necessary energy storage requirements to achieve California's zero-emissions electricity goal.

II. MATERIAL AND METHODS

Figure 1 depicts the modeling methodology used in this work. The analysis is accomplished by utilizing a least-cost optimization model known as the Macro-Energy Model (MEM). The directional flows of various techniques employed in MEM are shown in Fig. 1. Mechanisms that respond to demand and enable the system to deliver less than its historical usage appear as high-priced (costing \$10/kWh) load shedding, also known as unmet demand. The macro energy model is used to optimize the generation and distribution of electricity in a power grid based on the least costs associated with different sources of generation.

The optimization model simultaneously optimizes the deployment of power generation and storage assets, as well as the dispatch order of these deployed assets, with the objective of minimizing the overall system cost. The model considers fundamental physical constraints to ensure the integrity of the system. These constraints include maintaining an energy balance between electricity generated and consumed at any given hour, as well as ensuring energy balance for energy storage at each hour. Additionally, the model considers constraints that establish a connection between the dispatched generation and the potential generation determined by the capacity of each considered generation technology. By incorporating these constraints and optimizing the deployment and dispatch of assets, the model provides valuable insights into the most cost-effective and efficient utilization of power generation and storage resources.

The decision variables include hourly dispatched electricity from wind and solar generation assets at hour t; deployed capacity of wind and solar assets; discharged energy (from the grid to energy storage) and charged energy (from energy storage to the grid), discharge, charge; deployed capacity of Li-ion energy storage; and finally, electricity load not met by either variable renewable electricity or discharged electricity from energy storage and unmet demand. Energy stored in energy storage is a state variable and is determined by optimization as well. All these variables take non-negative values but are otherwise unconstrained in obtaining the least-cost solution for the specified types of generation and storage assets to be deployed.

Each technology in the model is characterized by a variable cost and a fixed cost. Existing technology costs as collected by the US-EIA are used in our analysis [50]. Cost minimization is the main objective function and installed capacity, and hourly dispatch of all available technologies are the decision variables. The MEM output achieves energy balance by considering the combined sum of electricity sources, sinks, curtailment, and the lost load. The detailed costs for all technology solutions can be found in the supplementary material, specifically in Table 3-4.

For the electricity demand inputs used in the model, hourly data is obtained from balancing authorities in the United States and accessed through the U.S. Energy Information Administration (US-EIA) data portal [51]. Additionally, hydropower generation data is collected from the US-EIA, focusing on the selected region and hourly generation by source. Hourly wind and solar data are acquired from the European Centre for Medium-Range Weather Forecast (ECMWF) Version 5 [52], [53]. To enhance our analysis, the wind speed and solar irradiation data retrieved from the ERA5 dataset are adjusted using the methodologies presented in reference [54].

In this study, the central question focuses on how much value can be provided from additional long-duration energy storage technologies (PGP, CAES and pumped hydropower storage) for a deeply decarbonized power system in California. Parameters for this study are the energy capacity represented by the maximum amount of electrical energy that can be stored and subsequently discharged and the power capacity represented by the maximum rate at which electricity can be generated. Power and energy capacities have been varied to the values where the power and energy capacities no longer provided a constraint, and yield results became equivalent to maximum capacities. A maximum power capacity exceeding unconstrained needs, more than three times the mean demand, is specified initially to exceed all peak electricity demand in California. Energy storage capacity is presented as hours of mean demand. A maximum storage energy capacity that exceeds unconstrained needs is specified at 10,000 hours of mean demand, more than enough to power one year's electricity needs.

We have chosen around 1 year of energy storage capacity. Although, in literature it has been specified that an optimally utilized storage of about daily average demand would be sufficient to reach grid penetration of about 90% of the total demands from VRE [55].

But, based on the time series analysis [56], authors reveal that the maximum energy deficit can extend over a longer period of nine weeks, as consecutive scarcity periods can occur. Considering factors such as storage losses and charging limitations, the duration that defines the storage requirements can even stretch up to 12 weeks. By incorporating additional sources of flexibility, such as bioenergy, the timeframe that determines the necessary storage capacity extends beyond one year [56]. This highlights the importance of considering a diverse range of options to meet long-term storage requirements and ensure a reliable and sustainable energy system.

Similarly, minimum capacities were set to values that produce results indistinguishable from zero capacity. Minimum and maximum limits of PGP, CAES, and pumped hydropower storage power capacity and energy capacity are used to examine a broad range of scenarios. A base case technology mix with generation from solar, wind, and Li-ion has been considered without any long-duration storage.

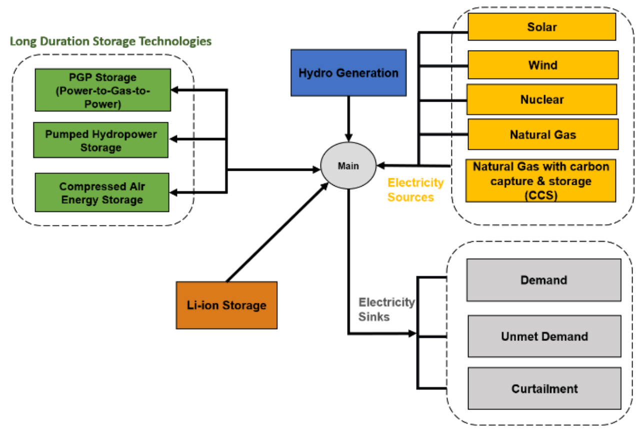

FIGURE 1. Energy flow diagram showing how technologies are connected in the Macro-Energy Model (MEM).

III. RESULTS

In this section, a base case for California with technologies (wind, solar and lithium-ion batteries) excluding any long-duration energy storage has been considered (Fig. 1). In this base case, wind, solar and hydropower generation (with no energy-storing ability) is set equal to the year 2020 actual generation at hourly time resolution. A comparison of the base case against a case with storage (where the observed hydropower generation may be delayed without limitation for later dispatch), a case with maximum amount of power-to-gas-to-power storage and another case with maximum amount of compressed air energy storage (Fig. 2) has been considered.

The 'balance of system costs' is defined as the total cost of the optimized electricity system in balancing the given effective-free PGP, CAES and pumped storage technology, compared to the case with no long duration storage. The 'balance of system costs' shows the cost of adding all other technologies needed to satisfy hourly electricity demand. Annual mean demand is normalized to 1 kWh in this analysis. It has been found that maximum amount of long-duration energy storage (pumped, PGP and CAES) can fully compensate for the variability of wind and power dominant power systems of California with the least cost option of pumped hydropower storage that can reduce the system cost substantially and can fully compensate the renewable intermittency. Pumped hydropower storage can provide greater value by shifting curtailed energy from all technologies to low renewable production periods, and by reducing the need for other storage technologies. Some additional dispatchable power can also compensate for this variability of renewables. The second least-cost option is the maximum availability of PGP followed by CAES.

Fig. 2 presents the simulated annual dispatch curves of the least-cost electricity systems assuming current costs. Positive

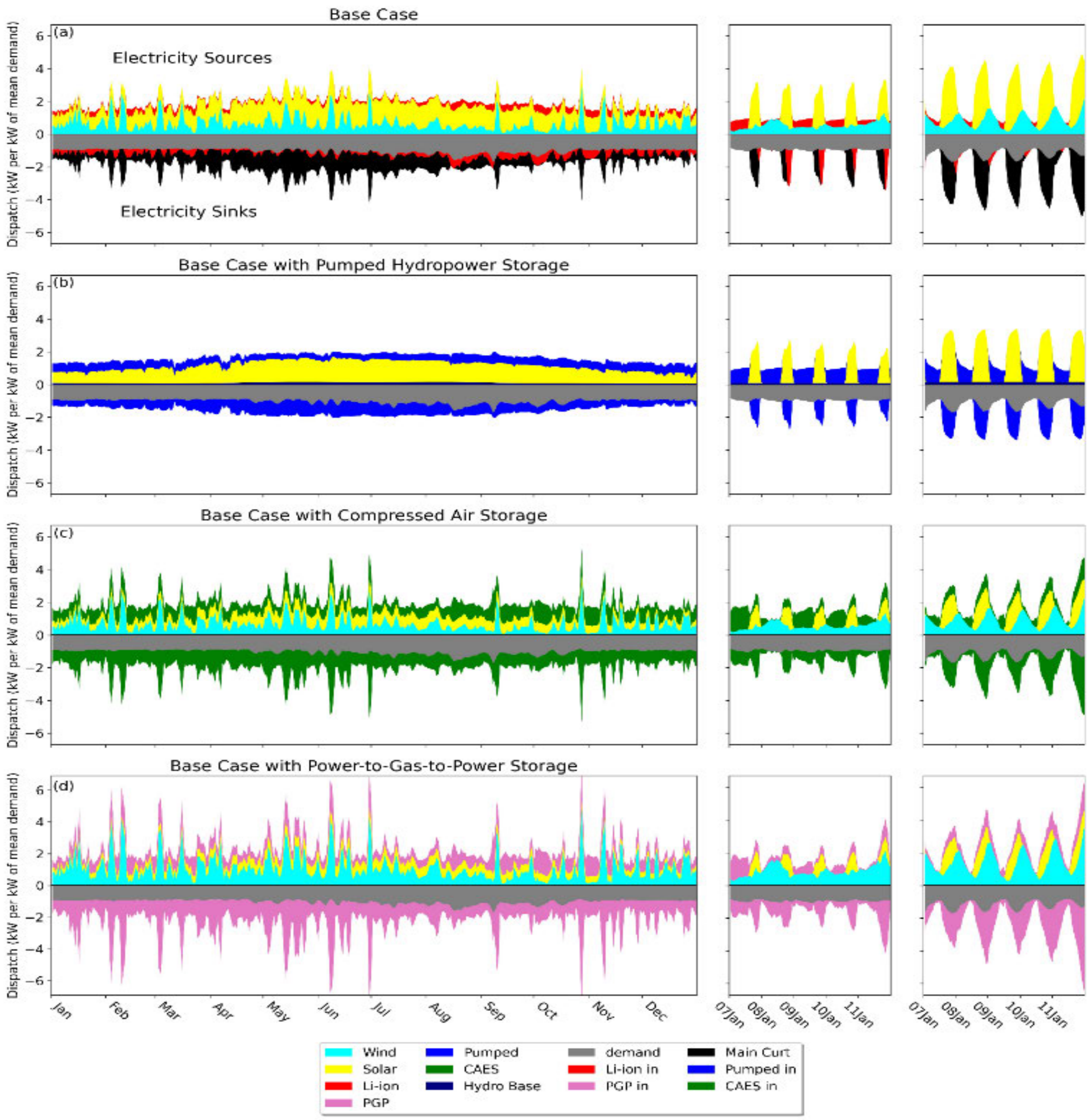

FIGURE 2. Dispatch curves showing the pumped hydropower storage, PGP, and CAES roles for cases with maximum available capacities. Panels show dispatch curves for the following cases: Fig.2(a) base case (wind, solar and li-ion battery); Fig.2(b) base case technologies plus pumped hydropower storage; Fig.2(c) base case technologies plus maximum power-to-gas-to-power storage; and Fig.2(d) base case technologies plus maximum compressed air storage. The right two panels in each row show hourly electricity dispatches for five continuous days of the simulation year covering periods from 07 January to 11 January (winter) and from 07 August to 11 August (summer).

values represent the contribution of electricity sources to the grid, while negative values indicate the outflow of energy from the grid. Panels A-D display the yearly distribution of electricity in 2020, with a daily time interval. The two boxes on the right exhibit the hourly electricity distribution over five consecutive days during both winter and summer. The cost of each technology is depicted in Figure 3, positioned at the far right of each panel.

Fig. 2(a) shows power dispatch of the base case with generation technologies (wind and solar) and storage technologies (Li-ion battery). Electricity sinks include end-use demand, charging of all storage technologies, and main node curtailment. No PGP, CAES or pumped hydropower storage is available in the base case. The main energy mix here is wind, solar and Li-ion battery with huge main node curtailment. The hourly dispatch panels show that Li-ion fills the short-term gaps in resources that usually last for less than one day, whereas no long duration storage is available to fill the multi-day gaps. In base case, in the absence of long duration energy storage, solar power is the most dominant technology.

Fig. 2(b) presents the dispatch curve with the maximum amount (both maximum power and energy capacity) of pumped hydropower storage with all available technologies. The pumped hydropower adds flexibility and allows more solar in the system. With maximum pumped hydropower storage, all the solar that would have been curtailed goes into

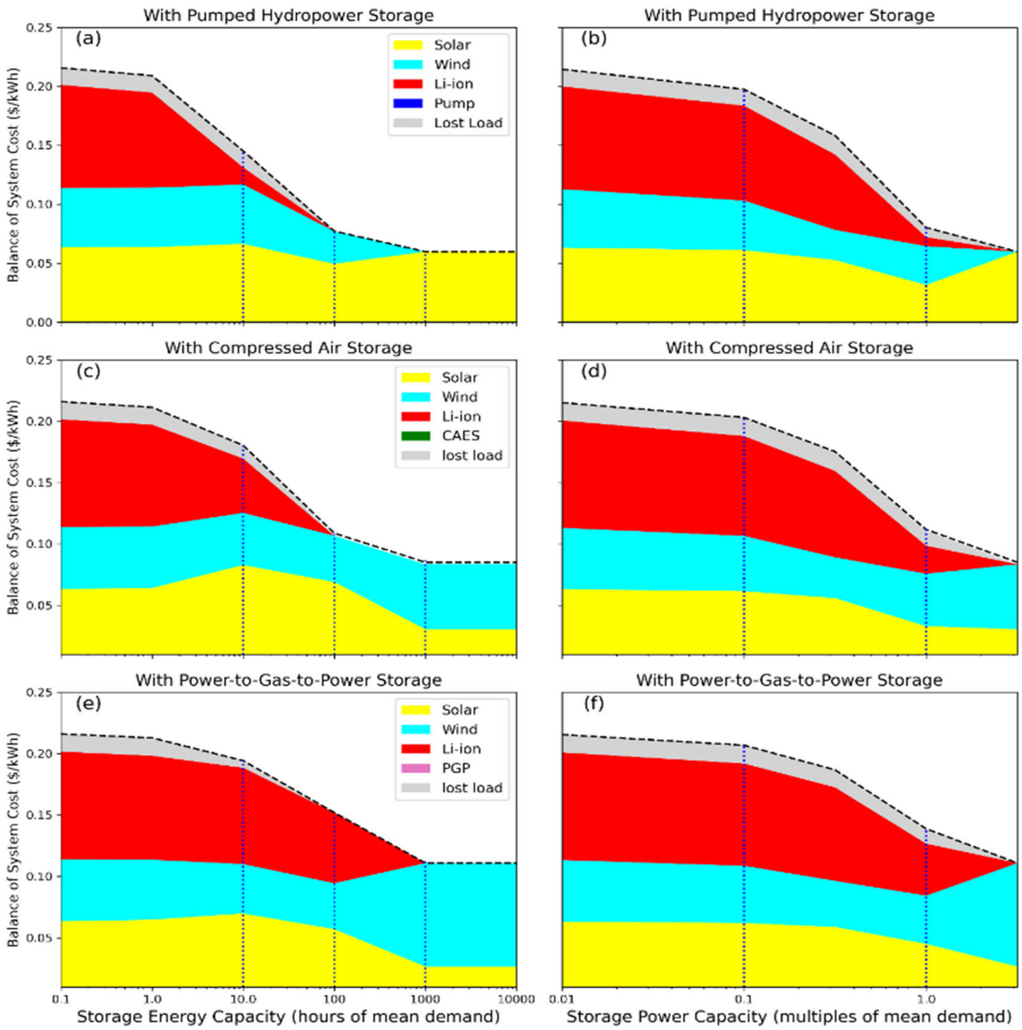

FIGURE 3. Stacked costs with power and energy capacities for base case technologies plus long-duration storage technologies. The left column shows results at maximum power capacity, varying energy capacity for (a) pumped hydropower storage, (c) compressed air energy storage, and (e). power-to-gas-to-power storage. The right column shows results at maximum energy capacity, varying power capacity for (b) pumped hydropower storage, (d) compressed air energy storage, and (f) power-to-gas-to-power storage. The left edge of each panel corresponds to the dispatch in Fig. 2(a). The right edges of panels (a) and (b) correspond to the dispatches shown in Fig. 2(b); the right edges of panels (c) and (d) correspond to the dispatches shown in Fig. 2(c); the right edges of panels (e) and (f) correspond to the dispatches shown in Fig. 2(d).

the system, with the result that there is cheaper dispatchable power to meet the demand. Therefore, there is no role for other storage technologies in the least-cost optimization for this case. In Fig. 2(c), compressed air storage is available with maximum capacity. The system chooses CAES with wind and solar to meet the load demand at the least cost, however more solar has been dispatched in this case as compared to the case with PGP Fig. 2(d). Fig. 2(d) presents the dispatch curve with the maximum amount (both maximum power and energy capacity) of power-to-gas-to-power storage with all available technologies. In this case, PGP supports more wind power as compared to solar, high wind dispatch can be seen in panel 2(c).

Overall, the impact of long-duration energy storage is important to meet the load demand with zero emissions, and to firm up the intermittency of wind and solar. The analysis shows that adding only a short-duration energy storage technology (Li-ion) does not firm up the intermittency of renewables for deep decarbonization of the power system of California. While adding long-duration energy storage technologies can fully compensate for the variability of wind and solar power generation.

In this work, the value of energy capacity (in hours of mean demand) sweeps at 0.1 hour, and power capacity sweeps at 0.01 as a multiple of mean demand, so that both power and energy capacities go low enough that they do not make a visible difference compared to the base case. Power capacity ranges from 0.01 to ∼3 times the mean demand. The idea is that 3 times the mean demand is greater than the maximum demand at every hour, so we are not

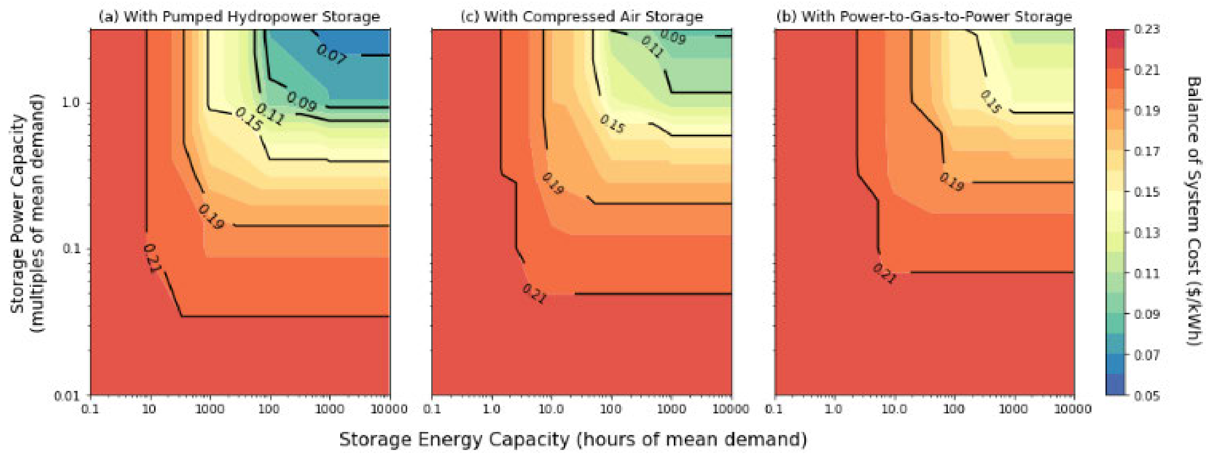

FIGURE 4. **Balance of system costs as a function of storage power and energy capacity. (a) Contour plot varying cost of pumped hydropower storage (b) with CAES storage and (c) with PGP storage. All costs are shown as a value of the system cost. The left edges of panels (a), (b) and (c) correspond to the balance of system costs shown in Fig 3, panels (a), (c) and (e) respectively. The top edges of panels (a), (b), and (c) correspond to the balance of system costs shown in Fig. 3. (b), (d) and (f) respectively.**

power limited in meeting the demand at any time of the year.

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Fig. 3 shows different technologies' contributions to the overall balance of system costs under different long-duration storage technologies with different storage power and storage energy capacities, derived from the cost-minimization framework using the year-2020 of electricity data. (Corresponding dispatch amounts are shown in supplementary material Fig. 7) Stack plots (a), (c) and (e) present the balance of system costs with fixed storage energy capacity (maximum). The x-axis shows different power capacity values as they vary from minimum to maximum in multiples of mean demand. Similarly, Fig. 3 (b), (d) and (f) present a balance of system costs with fixed storage power capacity(maximum) and the x-axis showing different storage energy capacity values varying from minimum to maximum in hours of mean demand.

Fig. 3(a) and (b) illustrate that base case technologies with maximum pumped hydropower storage reduce the system cost from 0.216$/kWh down to 0.060$/kWh (72.3% cost reduction). Adding pumped hydropower storage energy capacity at the 100th hour eliminates the Li-ion battery storage (a). Beyond the 1000th hour, adding further energy capacity is not beneficial at all and no cost reduction is seen after this point. Similarly, in panel (b), when storage power capacity becomes equal to mean demand, there is no Li-ion battery in the system. Beyond this point no further reduction in cost is seen. At maximum pumped hydropower storage and energy capacity, the main energy mix is pumped hydropower storage with solar. No batteries are needed in the case of maximum pumped hydropower storage to meet the load demand. It is interesting to note that no wind has been dispatched in this case.

In the cases of PGP storage, Fig. 3 (c), (d) adding PGP storage capacity also shows this benefit, and system cost reduces from 0.216$/kWh to 0.11$/kWh (48.6% cost reduction). In the cases of CAES storage, Fig. 3 (c), (d) adding CAES storage capacity reduces the balance of the system cost from 0.216$/kWh to 0.085$/kWh (60.6% cost reduction). The importance of adding energy storage capacity in between the 100th and 1000th hour is also prominent here. In the case of CAES and pumped hydropower storage, there is no Li-ion in the system at 100-100th hour, but due to the low efficiency of PGP, still Li-ion has been built in this case. One important benefit of adding long-duration storage with wind/solar dominant power system is that at higher values of power and energy storage power capacities, there is no need for storage batteries to meet the system demand in a deeply decarbonized system.

Fig. 4 shows the balance of system costs when giving different amounts of pumped, PGP and CAES storage capacities. These contours in Fig. 4 indicate that the maximum reductions in system cost in the case of pumped hydropower storage, the system cost reduces from 0.216$ per kWh to 0.060$ per kWh. In the case of CAES storage, the system cost reduces from 0.216$ per kWh to 0.085$ per kWh and in the case of PGP storage, the system cost reduces from 0.216$ per kWh to 0.111$ per kWh. Hence, the value of adding pumped hydropower storage is greater than the value of adding PGP or CAES storage. At high power capacities, the contour lines shown in Fig. 4 are approximately evenly spaced in the horizontal direction as energy storage capacity increases on the logarithmic scale. This implies that the marginal value of energy storage capacity decreases quasi-exponentially with additional energy storage capacity.

TABLE 2. Percent cost reductions in the balance of system cost for different amounts of long-duration storage technologies. Base case cost is *0.216 $/KWH*.

Balance of System Cost Reduction	Power Capacity (1% of mean demand)			Power Capacity (10% of mean demand)			Power capacity (100% of mean demand)			Power Capacity (Maximum)		
Energy Capacity	Pumped	CAES	PGP	Pumped	CAES	PGP	Pumped	CAES	PGP	Pumped	CAES	PGP
1 hour of mean demand	0.4%	0.2%	0.2%	3.2%	2.1%	1.4%	3.2%	2.1%	1.4%	3.2%	2.1%	1.4%
10 hours of mean demand	0.7%	0.4%	0.2%	8.6%	6.0%	4.2%	32.8%	16.5%	10.0 %	32.8%	16.5%	10.0 %
100 hours of mean demand	0.7%	0.4%	0.2%	8.6%	6.0%	4.2%	56.8%	39.4%	28.2 %	64.3%	49.6%	29.6 %
1000 hours of mean demand	0.7%	0.4%	0.2%	8.6%	6.0%	4.2%	62.8%	48.2%	35.7 %	72.3%	60.6%	48.6 %
Maximum	0.7%	0.4%	0.2%	8.6%	6.0%	4.2%	62.8%	48.2%	35.7 %	72.3%	60.6%	48.6 %

For pumped hydropower storage, in the case of maximum power capacity (Table 2), the balance of system cost reduction of going from 1 to 10 hours of energy storage is *29.6%,* which is a little smaller than that of going from 10 to 100 hours of energy storage (*31.5%* cost reduction); this in turn, is much larger than the *8%* cost reduction achieved by going from *100* to *1000* hours of energy storage. With pumped hydropower storage capacity, the benefits of increased power capacity tend to saturate at lower power capacity levels. In the case of maximum energy capacity, a power capacity of *10%* of mean demand supplies about *21%* of the value that would be provided by a system with maximum power capacity; a power capacity of *100%* of mean demand supplies 68% of the value of a system with maximum power capacity.

For CAES storage, in the case of maximum power capacity (Table 2), the balance of system cost reduction of going from 1 to 10 hours of energy storage is 14.4%, which is a little smaller than that of going from 10 to 100 hours of energy storage (33.1% cost reduction); this in turn is much larger than the 11% cost reduction achieved by going from 100 to 1000 hours of energy storage. In the case of maximum energy capacity, a power capacity of 10% of mean demand supplies about 19% of the value that would be provided by a system with maximum power capacity; a power capacity of 100% of mean demand supplies 58% of the value of a system with maximum power capacity.

For PGP storage, in the case of maximum power capacity (Table 2), the balance of system cost reduction of going from 1 to 10 hours of energy storage is *8.6%*, which is a little smaller than that of going from *10* to *100* hours of energy storage (*19.6%* cost reduction); this in turn, is like *19%* cost reduction achieved by going from *100* to *1000* hours of energy storage. With PGP, going from *10* hours to *1000* hours of mean demand shows a linear trend in cost reduction. In the case of maximum energy capacity, a power capacity of *10%* of mean demand supplies about *18%* of the value that would be provided by a system with maximum power capacity; a power capacity of *100%* of mean demand supplies *46%* of the value of a system with maximum power capacity.

Results for scenarios with different long-duration storage technologies (Table 2) are almost identical, however, the benefits of additional pumped hydropower are greater as compared to CAES and PGP.

This is because solar and wind are cheaper, and flexibility has been provided by the long-duration energy storage. In our cases with plentiful power capacity, electricity generation is exclusively with wind and solar power, and there is enough electricity that would otherwise be curtailed. Of course, we are presenting a stylized analysis and in the real world, social, environmental, economic, and political limitations may play important roles.

Fig. 5 presents the contour plots of power dispatch for all three case studies. In the case of pumped hydropower storage, at lower values of pumped hydropower storage, there is more solar and wind dispatch. But, if we don't have a good wind resource, adding pumped hydropower storage energy capacity provides more benefits to solar, as shown. Overall, solar power tends to exhibit a higher capacity factor, or power dispatch, compared to wind power in California [57], [58], [59].

In the case of compressed air storage, the main power dispatch is CAES with wind and solar. The value of wind dispatch decreases with increased CAES capacity but does not eliminate as in the case of pumped hydropower storage. Even at lower values of CAES storage power and energy capacity, Li-ion is not playing a significant role in meeting

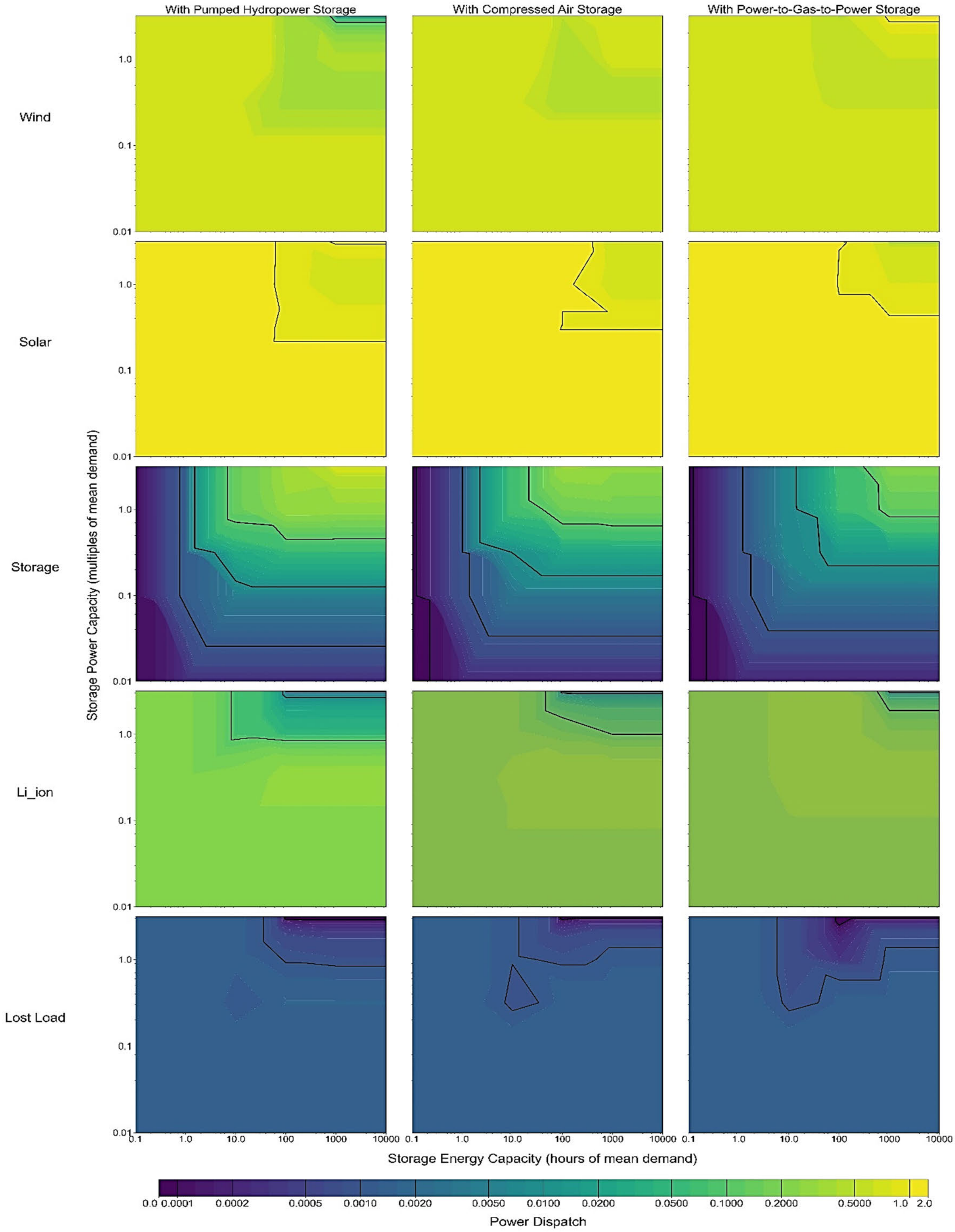

FIGURE 5. Power dispatch of pumped hydropower, CAES, and PGP with power and energy storage capacities varying from minimum to maximum.

demand. In the case of PGP, more wind and Li-ion is available as compared to CAES and pumped hydropower storage. (Corresponding power capacity contours are shown in supplementary material Fig. 7).

The specific technologies used to provide reliable electricity service in least-cost optimizations will vary depending on cost assumptions and geographic conditions. The assumptions made here include relatively high storage costs, and consider California's renewable energy resources, which tend towards relatively good solar power and relatively poor winds. At intermediate levels (10 to 100 hours) of pumped hydropower energy storage capacity, solar power

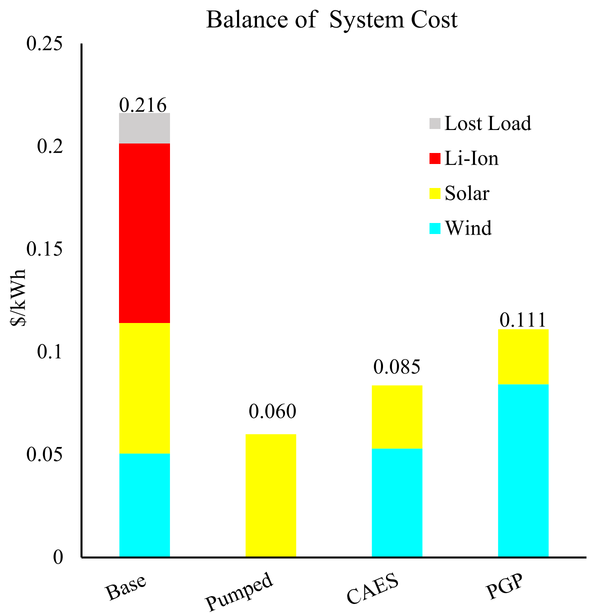

FIGURE 6. Balance of the system cost for cases with base technologies, and base case technologies plus pumped hydropower storage, CAES, and PGP cases correspond to cases show in Figure 2. Note that in the balance of system cost, the cost of long-duration storage technologies is not included in these costs.

dominates energy supply: under these conditions the pumped hydropower reservoir is sufficient to compensate for daily solar cycles, but not sufficient to compensate for multi-day wind droughts. This behavior can be seen in Fig. 3 and 5.

Fig. 6 shows the balance of system cost of different technology combinations for the maximum amount of pumped hydropower, PGP and CAES storage case study. In the base case, without any long-duration storage the balance of system cost is *0.216$/kWh*. With pumped hydropower storage, the cost is *0.06$/kWh*, with CAES the balance of system cost is *0.085$/kWh* and with PGP the balance of system cost is *0.111$/kWh*. In the case of maximum pumped hydropower storage, solar is the most dominant technology with pumped hydropower and no wind has been built in the system in this case. At maximum power and energy capacity, pumped hydropower has supported more solar dispatch, however, CAES and PGP have supported more wind as compared to solar.

IV. DISCUSSION

Deep decarbonization of the electricity system can be provided by renewable sources of power generation such as wind, solar and hydropower. Flexibility from long-duration storage complements the high temporal variability of wind and solar and helps to meet the peak load demand.

Today in California, much of hydropower dispatch is timed for purposes other than electricity generation, such as the need to provide irrigation water or achieve environmental goals [60]. Without approaches to add flexibility to hydropower, achieving additional benefits from hydropower may be limited. If pumped hydropower could be made more flexible, doing so would provide substantial value for renewable energy integration and deep decarbonization of the electricity sector.

In real life, power capacity limits the ability of hydropower to fully compensate for a no-sun/no-wind scenario. However, pumped hydropower can help to fill in during even long periods with insufficient sun or wind. We analyze variations of the pumped hydropower energy and power capacity in a macro energy model and consider zero emission constraints. We have compared the results of pumped hydropower storage technology with CAES and PGP power and energy storage capacities.

Results of our case studies show that in a deeply decarbonized power system, pumped hydropower storage and CAES to substantially reduce systems costs, power capacity needs to be almost equal to mean electricity demand. But, in the case of PGP to substantially reduce the systems' costs, power capacity needs to be almost more than *1.3* times of mean electricity demand. But, in case This is because in this system, PGP's main benefit is to reduce capacity needs during times of peak net demand and low efficiency of PGP (as compared to pumped hydropower and CAES) can take longer to add substantial benefit to the system.

We consider a maximum amount of pumped hydropower storage capacity, CAES and PGP and found that all these long-duration energy storage technologies could help to meet peak electricity demand with less generating capacity. However, the benefits of expanding pumped hydropower storage capacity are much greater as compared to CAES and PGP. Maximum pumped hydropower storage capacity can reduce the balance of system costs by *72.3%*, and maximum CAES capacity can reduce the balance of system cost by *60.6%* and maximum PGP capacity can reduce the balance of system cost by *48.7%*.

In our stylized model, in the presence of all available technologies to balance the intermittency of renewables, the optimal energy mix would be long-duration energy storage, wind and solar. In the case of maximum available pumped hydropower storage, the optimal mix is mainly pumped storage with solar. In the case of maximum available CAES and PGP, the optimal mix is CAES/PGP with wind and solar. In all the cases, the amount of Li-ion storage batteries decreases significantly with the increase in power and energy storage capacities of long-duration storage technology., Without any long-duration storage of any kind, the least-cost generation mix is primarily Li-ion wind, solar and huge main node curtailment and significant lost load can be observed in this case.

Our results strengthen the case made in prior work, which shows the potential of long-duration storage technology as an energy storage resource [59], [61], [62], [63], and show that pumped hydropower compares favorably against other storage technologies, balancing options and lowers the cost of decarbonization. Additionally, it has been observed [29] that PGP storage is not competitive in terms of cost. Comparatively, the levelized electricity costs associated with PGP storage can be 2 to 6 times higher than those of pumped hydro and compressed air storage, depending on the specific storage path chosen. This highlights the significant cost advantage of pumped hydro and compressed air storage over PGP storage.

While our study highlights the potential benefits of maximum availability of long-duration energy storage technologies to fully compensate for the variability in wind and solar generation and our results focus on the benefit of pumped hydropower storage technology over CAES and PGP to reduce the balance of system cost. While pumped hydropower could conceivably fulfill this role, it might require very large facilities – sufficient to store enough power to fully power California for 10 or more hours and sized to deliver that power at rates comparable to California's mean electricity demand. Thus, pumped hydropower could play important roles in helping to reliably satisfy electricity demand in a system dominated by solar and wind generation, other technologies that can dispatch electricity on demand will also be needed.

V. CONCLUSION

Long-duration storage can potentially add substantial value to electricity systems that are highly dependent on wind and solar generation. Results indicate that the maximum available amount of long duration storage technologies can substantially reduce the balance of system cost and can firm up the variability of wind and solar power generation for California. It has been concluded that the benefit of considering storage duration from 10. to 100. hours of storage lead to greater cost savings with reductions of 31.5%, 33.1% and 19.6% for PHS, CAES and PGP respectively. In the case of maximum available storage capacity these benefits can lead to greater benefits and can reduce the balance of system cost 72.3% for pumped hydro, followed by CAES (60.6%) and PGP (48.6%).

This study focuses on California but highlights a more general point. Expansion of pumped hydropower storage may provide great benefits to the balance of the electricity system. However, these benefits are limited by geophysical factors such as the amount of water flowing down rivers, and by social, political and economic factors. Therefore, it is likely that a broader range of dispatchable technologies will be needed in electricity systems that are highly reliant on wind and solar electricity generation. Furthermore, it is crucial to assess a range of physical and operational policy scenarios to effectively define future operational rules that incorporate technological advancements and their associated costs.

In the future, the examination of long-duration storage technologies' dispatch can be expanded by incorporating California's energy imports/exports and diverse generation technologies. Additionally, exploring the role of long-duration technologies in addressing seasonal demand variations during winter and summer can provide valuable insights. Analyzing the impact of different seasons on the dispatch of long-duration technologies will enhance our understanding of their performance in varying conditions. Moreover, the inclusion of additional clean fuel generation technologies in dispatch considerations can contribute to identifying low-emission energy solutions.

VI. DATA AND CODE AVAILABILITY

The Macro-Energy Model (MEM) utilizes historical weather data with hourly time resolution for wind and solar input data across the contiguous U.S. The model integrates demand data from the U.S. Energy Information Administration (EIA) with hourly time resolution spanning from 2000 to 2020. The model code, along with the hourly input data and data visualization code, are accessible on GitHub at https://github.com/carnegie/MEM_public. Input data used in this analysis is available at https://github.com/ClabEnergy Project/MEM/tree/master/Input_Data.

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APPENDIX

See Tables 3 and 4, and Figures 7–11.

A. PROBLEM FORMULATION

Symbol	Description.
g	Generation Technology (wind, solar, natural gas).
s	Energy storage (Redox flow battery, power-to-gas-to power, Li-ion, compressed air, gravitational,pumped).
from s	Discharge from energy storage.
to s	Charge to battery storage.
t	Time step (in hours) starting from 1 to T.
C	Kwh for storage.
D_t	Dispatch at time t.
C_{fixed}	Fixed cost ($/kWh).
C_{var}	Variable cost ($/kWh).
$C_{fixedO\&M}$	Fixed operation and maintenance ($/kWh).
f	Capacity Factor.
i	Discount rate.
n	Years (project life).
Δt	Time step (1 hour).
C	Energy Capacity (kWh).
D_t	Dispatch at time step t (kW).
M_t	Demand at time step t (kW).
S_t	Energy remaining in storage at time t (kWh).
γ	capital recovery factor (1/year).
δ	Storage decay rate (1/hour).
η	Round-trip efficiency.
τ	Storage charging duration(hours).

1) OBJECTIVE FUNCTION

The total system cost (1.1) is minimized by varying the decision variables for generation and storage assets, subject

TABLE 3. Cost and performance assumptions used for generation technologies in this analysis. Both the total overnight capital cost, fixed O&M cost, variable O&M cost, and fuel cost for all generation technologies are based on the energy information administration (EIA) 2020 annual energy outlook. All dollar values are represented in the year-2020 dollar.

Costs for new nuclear sectors are in 2017 $, and other costs are in 2019 $	Solar	Wind	Natural Gas	Natural Gas-Carbon Capture Storage
Total overnight cost ($/kW for generator or $/kWh for storage)	1391	1436	1054	2670
Fixed O&M ($/kW-yr)	23	43	27	65
Assumed Lifetime	30	30	30	30
Capital recovery factor (% /year)	8.06%	8.06%	8.06%	8.06%
ACC	135.09	158.72	111.93	280.16
FHC	0.015	0.02	0.013	0.032
Variable O&M ($/MWh)			2.00	6.00
Heat Rate (Btu/kWh)			6360.00	5180.00
Efficiency			0.54	0.66
Fuel Cost ($/MWh)			8.00	8.00
Variable Cost ($/MWh)			10.00	14.00

TABLE 4. Cost and performance assumptions used for storage technologies in this analysis. Both the total overnight capital cost, fixed O&M cost, variable O&M cost, and fuel cost for all generation technologies are based on the energy information administration (EIA) 2020 annual energy outlook. All dollar values are represented in the year-2020 dollar.

Total overnight cost ($/kWh for energy components and $/kW for power components)	Adiabatic Compressed Air Energy Storage		
	Power In	Energy	Power Out
Fixed O&M (% of capital cost or $/kWh/yr $/kW/yr)	517.14	51.10	774.18
Fixed property tax, insurance, licensing, permitting (% of capital cost)	13.81	1.50%	13.810
Assumed Lifetime (yr)	1.50%	-	1.50%
Capital recovery factor (%/yr)	30	30	30
Fixed Annual Costs ($/kWh/yr, $/kW/yr)	8.06%	8.06%	8.06%
Fixed Hourly Costs ($/kWh/h, $/kW/h)	56.11	4.1799	77.1350
Total Fixed Hourly Costs for Li-ion ($/kWh)	0.0064	0.0005	0.0088
Variable Cost ($/kWh)	0.00E+00	-	3.30E-03
Decay rate (% per hour)	0.00E+00	-	3.30E-06
Round-Trip Efficiency (%)	65%		

to fundamental physical constraints in (1.2)-(1.12).

$$\min(sys\,cost) = \sum_g c^g_{fixed} C^g + \sum_g \frac{\sum_t c^g_{var} D^g_t}{T} + \sum_s c^s_{var} D^s_t + \sum_g \frac{\sum_t c^{to\,s}_{var} D^s_t}{T} + \frac{\sum_t c^{from\,s}_{var} D^s_t}{T} \tag{1.1}$$

where

$$\sum_g c^g_{fixed} C^g = \sum_s c^w_{fixed} C^W + \sum_s c^s_{fixed} C^s + \sum_s c^n_{fixed} C^n$$

$$\sum_g \frac{\sum_t c^g_{var} D^g_t}{T} = \sum_w \frac{\sum_t c^w_{var} D^w_t}{T} + \sum_s \frac{\sum_t c^s_{var} D^s_t}{T} + \sum_s \frac{\sum_t c^n_{var} D^n_t}{T}$$

Fixed hourly cost of generation and storage technologies (wind, solar, nuclear and compressed air energy storage) has been calculted by using the following expression.

$$C^{g,s}_{fixed} = \frac{\gamma^{g,s}_{fixed} + C^{g,s}_{fixedO\&M}}{h} \tag{1.2}$$

where γ is capital recovery actor. It has been calculated by using the Eq.

$$\gamma(Capital\,recovery\,factor) = \frac{R(1+R)^N}{(1+R)^N - 1} \tag{1.3}$$

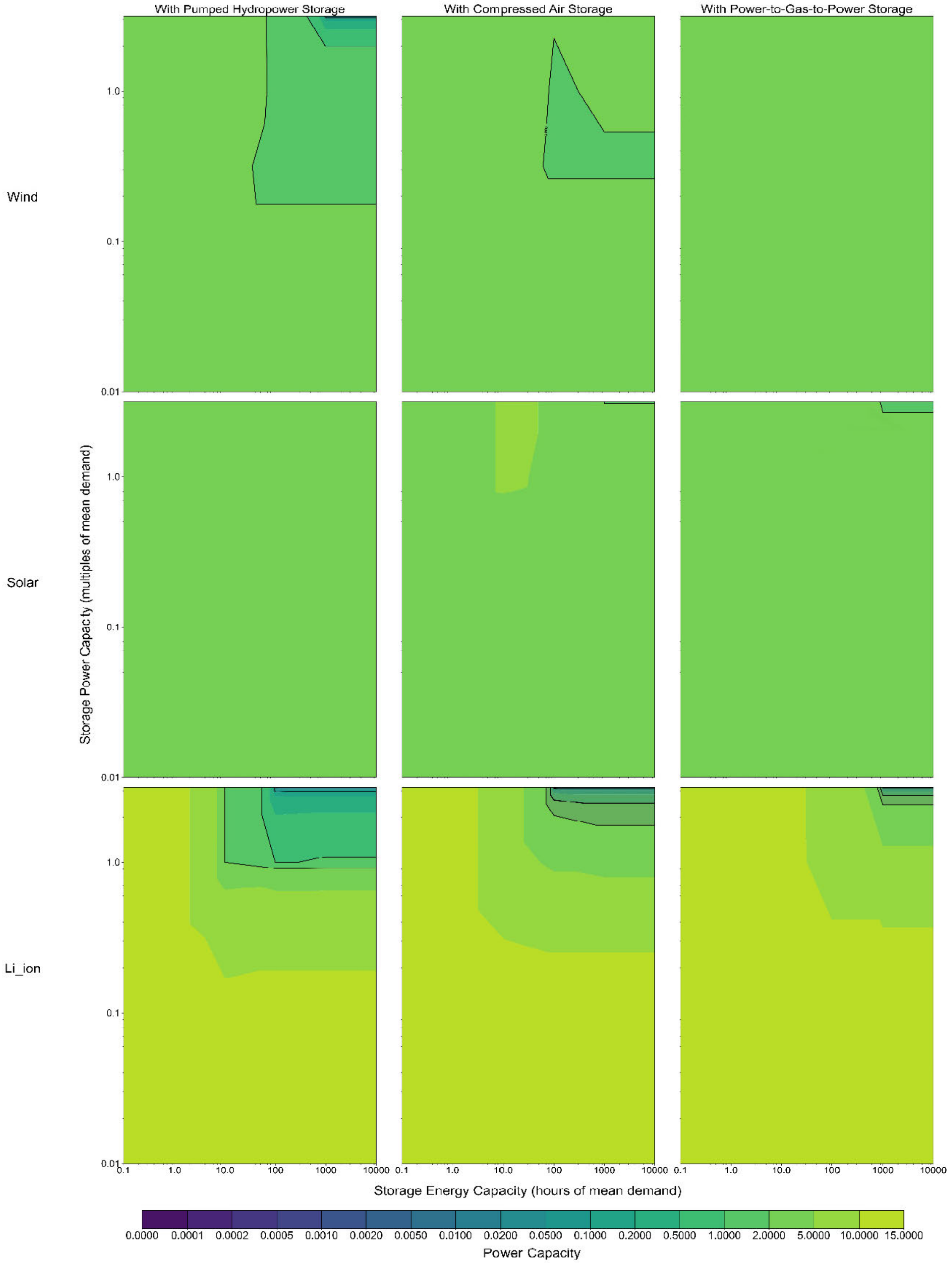

FIGURE 7. **Power capacity of pumped hydropower, CAES, and PGP with power and energy storage capacities varying from minimum to maximum.**

where R is the appropriate discount rate and N is the economic lifetime.

Capacity constraints:

$$C^{g,s} \geq 0\ ,\ \ \forall g,\ s \tag{1.4}$$

Dispatch constraints:

$$0 \leq D_t^g \leq C^g f_t^g \quad \forall g,\ t \tag{1.5}$$

$$0 \leq D_t^{from\ s} \leq \frac{C^s}{\tau^s} \quad \forall g,\ t \tag{1.6}$$

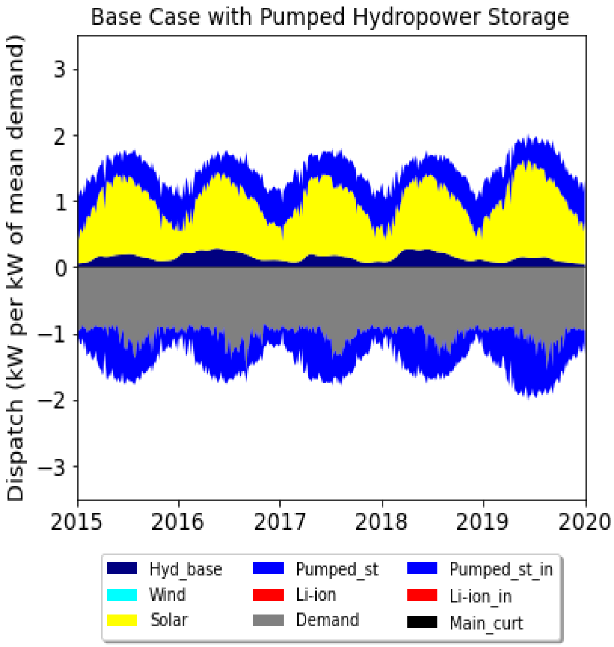

FIGURE 8. 5-year power dispatch of base case with maximum available pumped hydropower storage

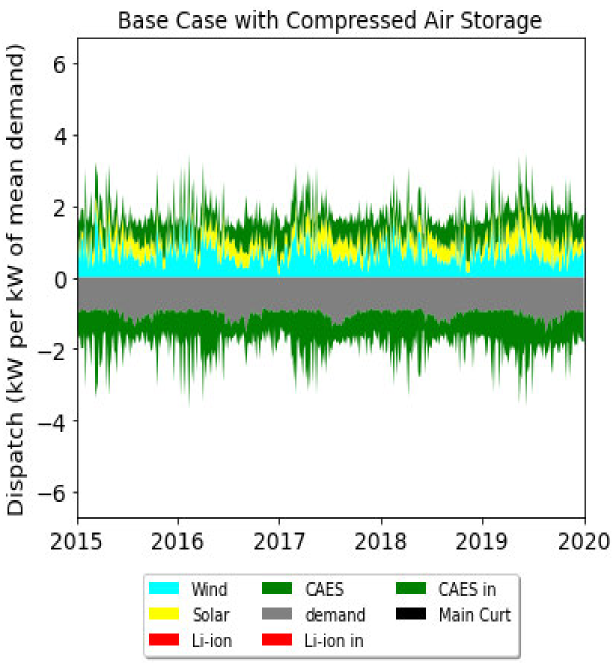

FIGURE 9. 5-year power dispatch of base case with maximum available CAES storage

$$0 \le D_t^{to\ s} \le \frac{C^s}{\tau^s} \quad \forall s,\ t \tag{1.7}$$

$$0 \le S_t^s \le C^s \quad \forall s,\ t \tag{1.8}$$

$$0 \le D_t^{from\ s} \le C^s(1-\delta^s) \quad \forall s,\ t \tag{1.9}$$

Storage energy balance constraint:

$$S_1^s = S^T \Delta t(1-\delta^s) + \eta^s D_T^{to\ s}\Delta t - D_T^{from\ s}\Delta t \ \ \forall s \tag{1.10}$$

$$S_{t+1}^s = S^T \Delta t(1-\delta^s) + \eta^s D_T^{to\ s}\Delta t - D_T^{from\ s}\Delta t$$

$$\forall s, t \in 1 \ldots (T-1) \tag{1.11}$$

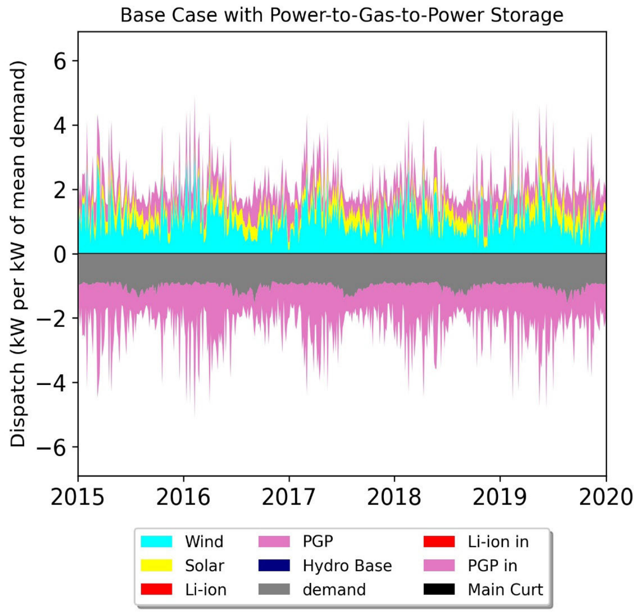

FIGURE 10. 5-year power dispatch of base case with maximum available PGP storage.

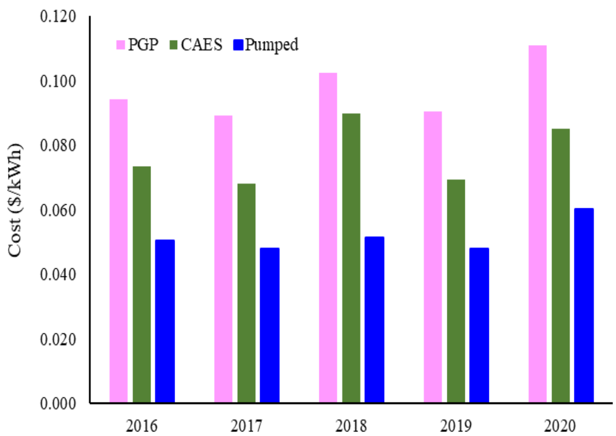

FIGURE 11. Balance of the system cost for cases with base technologies, and base case technologies plus pumped hydropower storage, CAES and PGP cases for the period of 5 years.

System energy balance constraint:

$$\sum\nolimits_g D_t^g \Delta t + D_T^{from\ s}\Delta t = M_t + D_t^{to\ s}\Delta t \quad \forall g, t \tag{1.12}$$

Equation (1.4) represents the capacity constraint for generation and storage technologies. Equation (1.5) constrain renewable energy generation based on historical capacity factors, which are dependent upon the assumed technology and the input weather data. Equations (1.6)-(1.9) characterize the discharged energy, charged energy, and stored energy in compressed air energy storage. In this analysis a steady-state operation of CAES has been assumed. δ is the loss rate for energy stored in CAES, τ is storage charging duration (hours) and η is the round-trip efficiency of CAES. CAES energy balance constraints have been presented in (1.10)-(1.11) and overall system energy balance has been presented in (1.12).

B. LIMITATIONS OF THE MACRO-ENERGY MODEL

In the idealized linear optimization model utilized in this study, the response of an idealized electricity system to the integration of wind and solar power generation is examined. Zero-emission constraint scenarios are explored, where the dispatch of generation from fossil fuel sources is limited. The analysis focuses on the dynamic interrelationships among different technologies and investigates the benefits of incorporating additional wind, solar, and combined wind and solar power generation into the system. The macro-energy model assumes lossless, zero-cost transmission from generation to load and perfect forecasting of wind and solar resources. However, future studies could introduce stochastic forecasting of wind and solar for more realistic scenarios.

While this study provides valuable results as a limited case study, showcasing the role and value of 1 wind, solar, and combined generation for California's electricity system, it should be noted that the macro-energy model does not impose pre-defined capacities on available technologies unless specified at the outset of the optimization process. The model assumes constant costs for all available technologies throughout the simulations, which differs from real-time scenarios where costs can vary. Future analyses could incorporate scenarios with dynamically changing costs to enhance realism.

The study employs hourly time steps; however, it acknowledges that events in a real electric power system can occur at much smaller timescales, such as seconds or milliseconds. Despite these limitations, some of the conclusions drawn from this study, such as the need for long-duration storage capacity in variable electricity systems with wind and solar power generation, followed by a significant reduction in overall system costs, align with previous research. Given the constraints on the development of bulk storage capacity in real-time environments, the study suggests that California may need to explore other dispatchable sources to ensure the reliability of renewable energy resources (such as wind and solar) in achieving deep decarbonization.

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