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How do non-carbon priorities affect zero-carbon electricity systems? A case study of freshwater consumption and cost for Senate Bill 100 compliance in California

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HIGHLIGHTS

- Modeled costs for four zero-carbon electricity narrative scenarios for California.
- Analyzed the life cycle freshwater consumption of zero-carbon electricity mixes.
- Lowest cost mix has highest water consumption, 9 times that of lowest water mix.
- Lowest water consumptive mix has highest cost, 30% greater than lowest cost mix.
- Non-carbon criteria should be considered in zero-carbon electricity planning.

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ABSTRACT

Characterizing the advantages and disadvantages of different electricity resource mixes in meeting electricity decarbonization goals is an active area of research. Many system-level assessments, however, evaluate different mixes on the basis of minimizing electricity costs without accounting for regional environmental externalities. California represents a highly populated region with both aggressive electricity decarbonization policies and water scarcity issues that are projected to worsen under climate change, representing an interesting case study for assessing the tradeoffs between the costs of electricity decarbonization and water resource consumption. This study therefore combines electric grid dispatch modeling and regional life cycle freshwater consumption data to compare in-state freshwater consumption and levelized cost of electricity for four electricity mix scenarios designed to achieve zero-carbon electricity in California by 2045, compliant with current law (California Senate Bill 100). In modeled scenarios, we find that the lowest costs occurred for mixes with lower energy storage capacity needs enabled by high capacity factor and dispatchable renewables. However these mixes also resulted in high freshwater consumption due largely to heavy reliance on geothermal resources. By contrast, the mix with the lowest freshwater consumption relied exclusively on wind, solar, and hydropower and reduced water consumption by an order of magnitude compared to that of the lowest cost mix. Due to lower capacity factors and greater difficulty in matching supply to demand (increasing energy storage needs), this mix increased the levelized cost of electricity by 30%. Overall, our results show that prioritizing low electricity costs as well as other climate-relevant criteria, such as freshwater consumption, in meeting zero-carbon electricity goals will result in a very different electricity mix than simply considering costs alone.

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1. Introduction

1.1. Context and literature review

Burning fossil fuels for energy is the primary source of anthropogenic greenhouse gas (GHG) emissions, which cause climate change [1]. Concerns about climate change have motivated policies to reduce GHG emissions, particularly in the electric power sector [2]. Zero-carbon electricity is currently recognized by energy system planning studies as a cornerstone of broader, economy-wide GHG emissions reduction goals through electrification of multiple energy-related end-uses such as transportation and heating. This is reflected in regional studies for California by Mahone et al. [3] and Williams et al [4] as part of a broader economy-wide decarbonization goal, for the U.S. as a whole in a study by Steinberg et al. [5], and internationally in studies such as those for Portugal [6], for electricity systems in France [7], and for Europe as a whole [8]. One notable example of a zero-carbon electricity policy is California Senate Bill 100 (SB100) [9], which requires a 60% renewable and 100% zero-carbon electricity system by 2045. Other US state governments have set similar policies. For example, Nevada's 2019 Senate Bill 358 mandates a 50% renewable electricity system by 2030 and a 100% zero-carbon electricity system by 2050. In similar supply side, electricity-focused actions, 29 states have passed Renewable Portfolio Standards (RPS) as of June 2019 [2], which designate state targets for renewable electricity. Examples outside the US include a 2018 goal by the European Union for economy-wide GHG neutrality by 2050 [10]. Municipalities of various sizes also have strong policy momentum, or, at a minimum, recognition of the advantages of transitioning towards a zero-carbon electricity infrastructure [11].

RPS targets and policies mandating GHG reductions are widespread, but most do not dictate a specific path to compliance. Given the societal relevance of the electricity system's costs and other impacts, including freshwater demand, many studies have prospectively analyzed hypothetical fuel portfolios that could meet high renewable penetration and/or zero-or-low carbon energy goals. Much of this literature compares approaches on the basis of costs, particularly levelized cost of electricity [12,13] or cost of different levels of decarbonization [14], or the scale of required infrastructure [4]. A review of 45 cost-based studies for reaching high renewable penetrations is provided by Deason [15]. Many studies find that high renewable penetration grid mixes will lead to higher system-wide installed capacities (due to lower dispatchability and lower capacity factors than conventional mixes) and higher capital costs than a comparably sized future business-as-usual electricity system. However, they note the potential for lower costs over the system lifetime. Models of zero-or-low carbon electricity in California specifically, including work associated with the Energy and Environmental Economics (E3) PATHWAYS project [16], have investigated a suite of scenarios including both renewable and nonrenewable zero-or-low carbon resources like nuclear and fossil plants equipped with carbon capture and storage [4].

Renewable electricity targets can provide not only GHG emissions reductions but also synergistic benefits for reducing regional environmental impacts such as potential reductions in consumptive water usage for cooling thermal power plants [17,18], which is particularly important in arid regions such as California. Other synergistic benefits include improved local air quality [19,20] and increased reliance on local energy resources [21,22]. Although these potential benefits are acknowledged and sometimes quantified [23,24], prospective non-carbon performance targets are rarely included in renewable electricity targets, particularly as they relate to water usage. Similarly, aside from costs, restrictions aimed explicitly at preventing negative externalities like increased water stress [25] or increased land use [26] are rare.

Given that climate change will further challenge California's ability to meet future freshwater demand, and given that the State has a legally binding timeline to remake its electricity system, consumptive freshwater demand of possible future electricity systems is a critical externality that a sustainable electricity system should consider. Although electricity systems typically do not dominate anthropogenic freshwater consumption [27,28], electricity-related water demand is nondiscretionary and further hardens the State's water demand [29]. As California electrifies historically non-electric energy demands (e.g., natural gas space and water heating) [30–32], ensuring that the growing electricity system's needs are met becomes even more relevant. During California's recent 6-year drought (2011–2017) [33], hydropower production declines led to increased CO_2 emissions due to the need for increased natural gas generation [34]. Communities such as East Porterville lost access to piped potable water [35] and increased farmland area was fallowed [36]. Such outcomes have severe consequences, and as California moves to develop a zero-carbon electricity system, it is particularly important that the electricity mix implemented by the state does not lock in the need for costly tradeoffs related to exacerbated freshwater stress. Given that the consumptive freshwater intensity of zero-carbon electricity generation sources in California varies by a factor of over 1000 depending on fuel [28], understanding both the cost and freshwater consumption implications of potential pathways to SB100 compliance is highly relevant.

Modeling future electricity systems requires that fuel mix be specified, and several studies have focused on technology-specific water demand factors that can enable the development of fuel mix scenarios. Macknick [37] and Peer and Sanders [38] published US water consumption and withdrawal factors at the point of generation for various technologies. This body of work was extended by Grubert and Sanders [27] to characterize full life cycle water consumption and withdrawal factors for US fuels. Most recently, Peer et al. [28] regionalized national electricity-related water consumption data from Grubert and Sanders [27] to provide fuel-specific water consumption and consumptive intensity for the Environmental Protection Agency's Emissions & Generation Resource Integrated Database (eGRID) regions [39,40]. Peer et al.'s [28] factors for the U.S. portion of the California-Mexico Power Area (CAMX), which have boundaries roughly equivalent to California's, are the source of in-state freshwater consumption intensity assumptions utilized in this study.

The combination of regional water stresses and integrated water and energy infrastructure have motivated numerous studies of the water usage of electricity systems [41]. Often, such studies have found that policies that foster the development of low-water resources like wind and solar reduce freshwater demand for electricity. For example, Bartos et al. [42] find that a 15% RPS in Arizona could reduce nonagricultural water demand (withdrawals) by up to 15% by 2025. In a US-wide study, Macknick et al. [43] find that an 80% renewable scenario with energy efficiency yielded the largest reduction in freshwater consumption (85.2% below year 2010 levels). By contrast, zero-or-low carbon systems relying on centralized thermal electricity generation are often found to increase freshwater demand for electricity. Byers et al. [44] find that under scenarios outlined in the 2011 UK Government Carbon Plan [45], which aims for an 80% reduction in overall nationwide GHG emissions below year 1990 levels by 2050, future electricity systems including CCS increase freshwater consumption by up to 107% of year 2030 values. Pathways with high nuclear capacity increase freshwater consumption by up to 399% of year 2030 values. This finding that zero-or-low carbon systems relying on thermal power plants increase freshwater demand is not confined to nonrenewable resources. Baker et al. [46] find that depending on cooling technology, solar thermal and geothermal plant deployment can increase water consumption by up to 40% relative to the year 2050 reference case.

1.2. Research gap, research questions and contribution of the current study

This study simultaneously investigates the levelized costs and in-state freshwater consumption implications of various future fuel mixes compliant with California's legally binding 100% zero-carbon

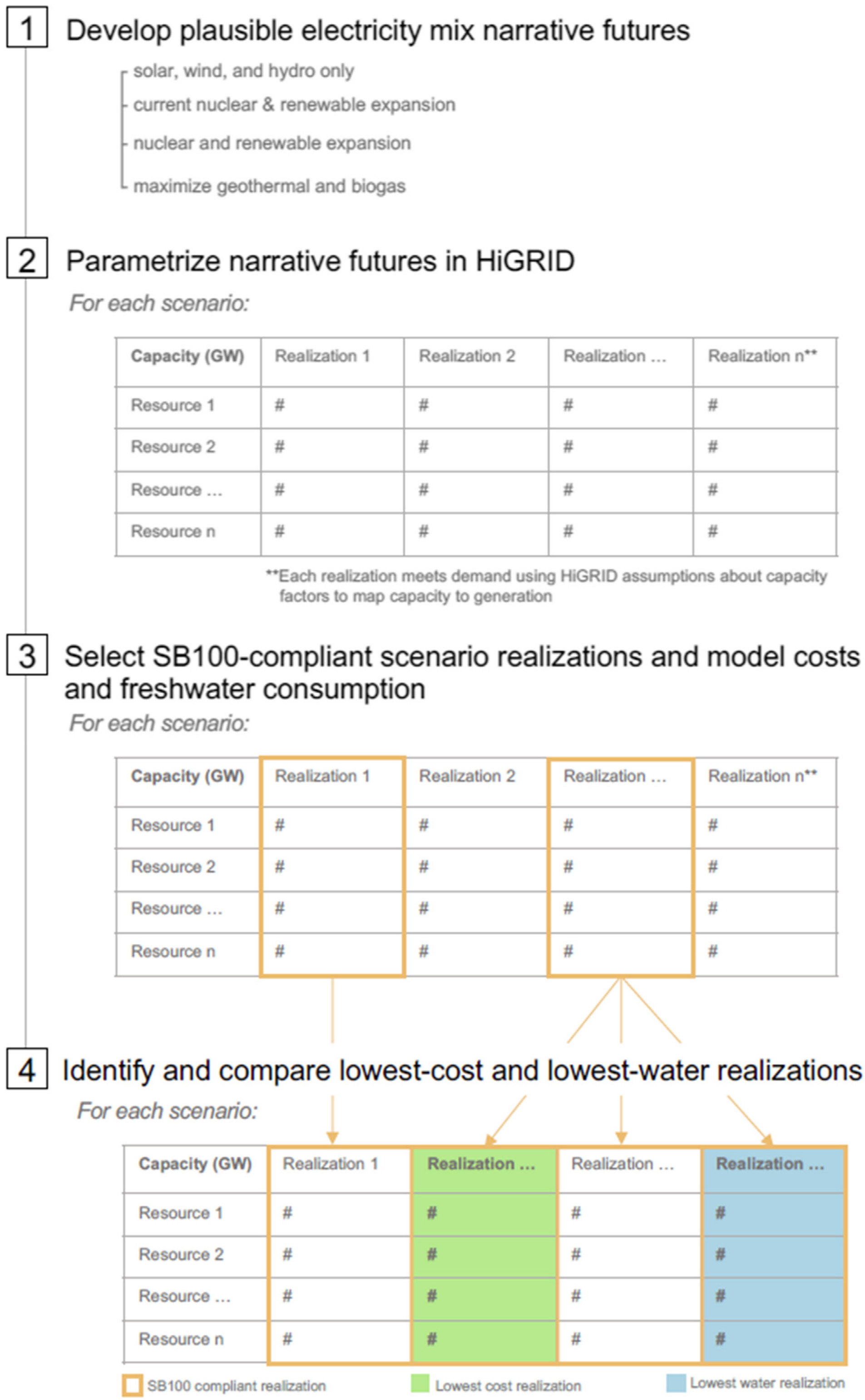

Fig. 1. Schematic overview of the study's analytical approach. Note: common parameters for these scenarios such as electric loads are based on the E3 PATHWAYS [3] study. However, the scenarios are constructed by modifying the resource mix as needed to match a given theme.

electricity mandate (SB100). The goal is to enable a direct evaluation and communication of tradeoffs between the system-wide levelized cost of electricity and freshwater consumption for a given electricity pathway. We focus on California because it is a prominent example of a region with ambitious power sector decarbonization goals that also faces electricity-relevant challenges associated with a critical externality: water scarcity exacerbated by climate change. Although we focus specifically on SB100, our work provides a model for integrating the evaluation of cost and region-specific critical externalities associated with other electricity systems. This work highlights the points that (1) choice of compliance strategy drives cost and other operational ramifications of future energy systems and (2) considering key externalities (e.g., water consumption in a water-scarce context), in addition to GHG emissions, can qualitatively alter system design versus designs that consider GHG emissions alone.

In addition to our timely assessment of an active policy and implementation process, this work contributes an analysis using the Holistic Grid Resource Integration and Deployment (HiGRID) model [47] that leverages both recent cost data inputs (capital, fixed operations & maintenance, and variable operation & maintenance parameters from the National Renewable Energy Laboratory Annual Technology Baseline 2019) [48] and recent, spatially resolved life cycle freshwater consumption data [28], which are unusual in the literature. Our focus on SB100 contributes to the literature on zero-carbon electricity systems, building on a more extensive body of work on high renewable penetration electricity systems.

The research questions explored in this study are as follows:

- What are the in-state life cycle freshwater consumption implications of California's SB100 policy requirement of full electricity system decarbonization by 2045?
- How do electricity generation technology mixes, levelized cost of electricity, and freshwater consumption for electricity generation vary across SB100 compliant fuel mixes?
- Does prioritizing the reduction of freshwater consumption in meeting SB100 requirements impose significant increases in the levelized cost of electricity?

The methodological approach and construction of scenarios for addressing these questions are provided in Section 2, with additional detail on the workings of the modeling tools and parameters used to construct and simulate the scenarios for analysis presented in the Supplemental Information (SI). Specifically, SI Section A describes the electric grid modeling tool used for the study, SI Section B describes the construction of the scenarios for analysis, and SI Sections C and D describe water intensity and cost data inputs used in each of the scenarios.

This study provides original insight for the literature by (1) examining the specific implications for a critical resource—-freshwater—for electricity mixes that could comply with California's SB100 requirements and (2) exploring how the composition and prioritization of zero-carbon electricity mixes based on cost compare with that based on freshwater consumption. Specifically, this study provides insight for the planning of fully decarbonized electricity systems while minimizing regional environmental externalities, in contrast to much of the literature that focuses primarily on electricity cost. Additionally, this study is original in that it leverages recent and spatially-resolved life cycle freshwater consumption data to provide more accurate assessments of this environmental externality. Finally, this study is the first of its kind to directly address planning to meet California's Senate Bill 100 goal of developing a 100% zero-carbon electricity system by 2045 at the time of this writing. Assessing the impact of future electricity mixes on consumptive freshwater demand is important for informing policy and planning technology investment in the face of climate change, particularly given the variable water requirements of zero-carbon resources.

2. Methods

This study evaluates potential California-based freshwater consumption and levelized costs for electricity provisioning compliant with SB100 by modeling discrete electricity mixes identified using a four-step process (Fig. 1).

We start by developing four narrative future scenarios for complying with SB100, summarized in Table 1: Solar, Hydropower, and Wind Only (Scenario 1); Current Nuclear and Renewable Expansion (Scenario 2); Nuclear and Renewable Expansion (Scenario 3); Maximize Geothermal and Biogas (Scenario 4). Each of these scenarios is assigned static capacity levels for nuclear, hydro, geothermal, and biogas, with details and rationale presented in Section B of the SI. For this study, no solar thermal was considered, and "solar" will henceforth be used to mean solar PV only. LCOE and freshwater consumption results are presented for the SB100 compliance year, 2045. For this study, zero-carbon resources are defined as those counted as eligible resources for complying with the SB100 law as defined by the state of California. It is important to note that these scenarios are constructed to represent different approaches to designing the resource mix to meet the goals specified by SB100. While some of the parameters for these scenarios are based on the E3 PATHWAYS study [3], some were modified from that study in order to construct these scenarios. These details are described in depth in the SI.

Step 2 (Fig. 1) is to parametrize the narrative future scenarios with explicit installed capacities for the resources under consideration, which are inputs to the HiGRID electric grid dispatch model used in this study (see Section A of the SI for more details on HiGRID and specifically Table S1 for details on how HiGRID converts installed capacity to hourly generation by resource). As Table 1 shows, parametrization for each scenario proceeds by assuming variable levels of expanded rooftop PV, utility-scale PV, onshore wind, and battery electricity storage capacity (in the form of vanadium redox flow batteries, selected due to their relative scalability and maturity [50]). These varying resource capacities are added to the scenario-based capacities for hydropower, nuclear, geothermal, and biogas. Given that modeled demand can be met with multiple configurations of added solar, wind, and storage, we model multiple discrete realizations in the form of quantified resource-specific capacities (Tables S2-S5) for each narrative future scenario. See SI Section B for more detail on the development of these realizations.

HiGRID requires that demand is satisfied, deploying natural gas-fired power plants as necessary if the input resources do not successfully meet demand. In this work, to isolate the effect of electricity resource mix on costs and freshwater consumption, all realizations are required to meet common load assumptions based on the E3 PATHWAYS study for 2045 [3]. See Table S6 in Section B of the SI for more detail. One result of this approach is that not all of the realizations shown in Tables S2-S5 of the SI are compliant with the GHG restrictions imposed by SB100. Thus, Step 3 (Fig. 1) is to identify the SB100-compliant realizations for each scenario. For our main results, we consider a configuration as zero-carbon if it meets 99.5% of the annual electric load with zero-carbon resources, with the remainder assumed to be satisfied by in-state legacy natural gas-fired power plants. Fig. S8 in Section F of the SI shows results assuming compliance at 99.9% zero-carbon and Fig. S9 in Section F of the SI shows results assuming compliance at 99.0% zero-carbon. Once compliant realizations are identified, in-state life cycle freshwater consumption and levelized cost of electricity (LCOE) are modeled. Freshwater consumption data reflect Peer et al.'s regional life cycle values (for CAMX region) [28], expanded from Grubert and Sanders' 2014 life cycle water use for the US energy sector [27] (see SI Section C for details). Cost data include capital, fixed operation and maintenance, and variable operation and maintenance cost estimates based on cost input data from the NREL Annual Technology Baseline dataset [48] and temporally-resolved operational data for grid resources from each HiGRID realization. These data are used to calculate the LCOE as the metric for electricity costs. LCOE is used by other assessments for the costs of future electricity system designs [12–14]; however, changing grid characteristics might motivate a different metric in the future [51].

Finally, in Step 4 (Fig. 1) we identify the modeled realizations with the lowest cost and lowest freshwater consumption within each scenario. These are then compared across scenarios to evaluate the drivers of cost and in-state freshwater consumption across representative possible SB100 compliance routes.

3. Results

3.1. Behavior of the levelized cost of electricity (LCOE)

Across narrative futures, the lowest cost SB100-compliant

Table 1
Summary of the narrative scenarios investigated in this study.

	Summary Points
Scenario 1 Solar, Hydropower, and Wind Only	• All generation resources other than solar, hydropower, and onshore wind resources are retired before 2045. • 2018 hydropower capacity is maintained. Note that 2018 exhibited hydropower generation that was slightly below the average hydropower generation in California from 1983 to 2017 [49]. • Rooftop PV, utility-scale PV, onshore wind, and energy storage capacity are expanded as needed to meet SB100.
Scenario 2 Current Nuclear and Renewable Expansion	• 2018 capacities of hydropower and nuclear resources (Diablo Canyon Nuclear Power Plant only) are maintained. • Geothermal resource capacity is expanded by 63% from 2018 levels. • Rooftop PV, utility-scale PV, onshore wind, and energy storage capacity are expanded as needed to meet SB100.
Scenario 3 Nuclear and Renewable Expansion	• 2018 hydropower capacity is maintained. • Geothermal resource capacity is expanded by 63% from 2018 levels. • Nuclear capacity is expanded to 5 times that of 2018 nuclear capacity by 2045. • Rooftop PV, utility-scale PV, onshore wind, and energy storage capacity are expanded as needed to meet SB100.
Scenario 4 Maximize Geothermal and Biogas	• 2018 hydropower capacity is maintained. • Nuclear capacity serving California is retired before 2045. • Geothermal resource capacity is expanded to use the full technical potential of conventional geothermal in California, roughly 374% of 2018 levels. • Biogas resource potential in California from wastewater treatment, landfills, animal manure, and industrial/commercial organic waste is fully utilized in combined-cycle gas turbine power plants. • Rooftop PV, utility-scale PV, onshore wind, and energy storage capacity are expanded as needed to meet SB100.

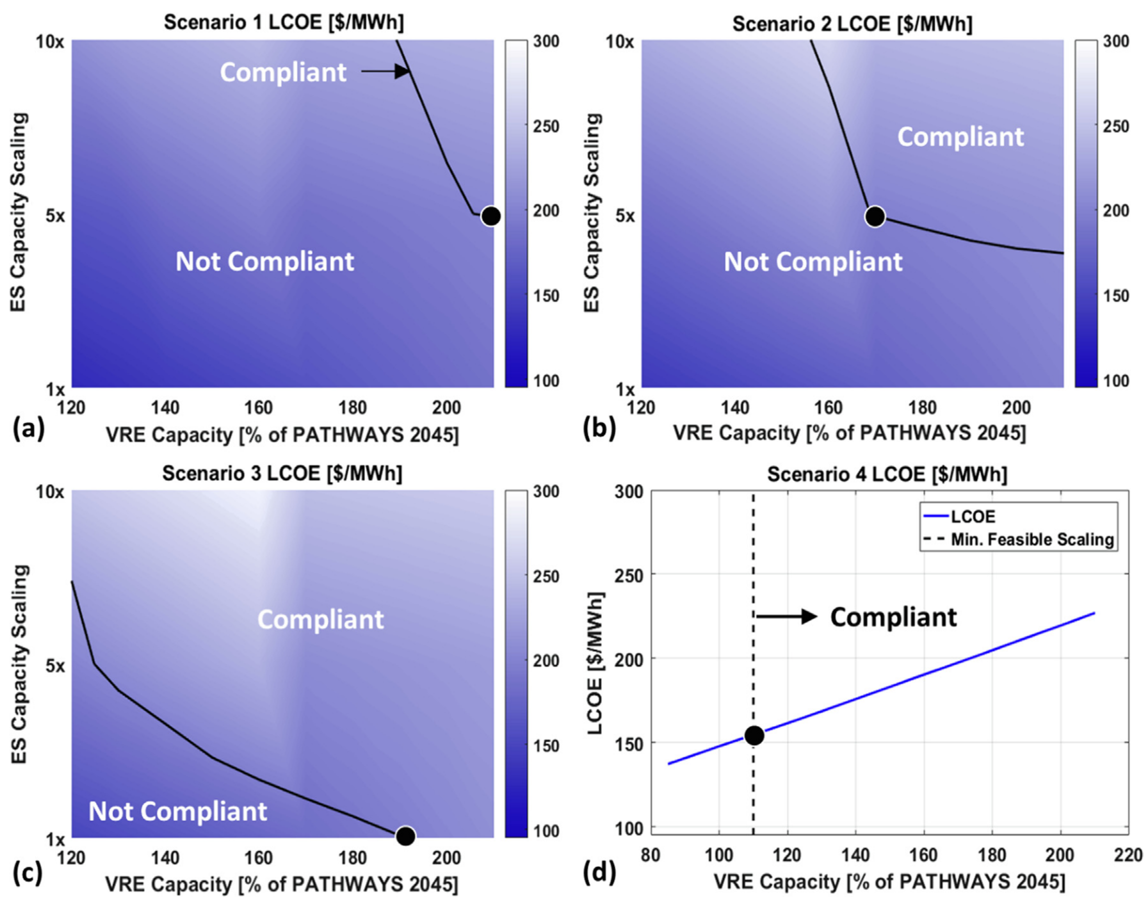

Fig. 2. Levelized Cost of Electricity (LCOE) values for different realizations of each narrative scenario using a 99.5% zero-carbon threshold: (a) Scenario 1 – Solar/Hydro/Wind Only, (b) Scenario 2 – Current Nuclear and Renewable Expansion, (c) Scenario 3 – Nuclear and Renewable Expansion, and (d) Scenario 4 – Maximize Geothermal and Biogas. The black dot notes the realization with the lowest LCOE value in each scenario. Variable renewable energy capacity is presented as a percentage of levels in the E3 PATHWAYS 2045 study and energy storage capacity is presented as a multiple of levels in the E3 PATHWAYS 2045 study.

realizations are, perhaps unsurprisingly, those that avoid deployment of the highest cost resources (Fig. 2). For Scenarios 1 (Solar, Hydropower, and Wind Only) and 2 (Current Nuclear and Renewable Expansion), prioritizing variable renewables over battery storage is correlated with lower LCOE. This is largely because the incremental benefit of storage for excess renewable generation decreases as more energy storage capacity is installed in the system [52]. Scenario 2 displays lower costs in general because the presence of a nuclear plant means less variable renewable capacity is needed. For Scenario 3 (Nuclear and Renewable Expansion), minimizing either energy storage or renewable capacity yields similar costs to Scenario 2. The presence of additional nuclear generation means that the incremental benefit of installing more energy storage diminishes faster than for the other scenarios. Scenario 4 (Maximize Geothermal and Biogas) similarly shows lower costs for scenarios that minimize more expensive variable renewable capacity in favor of cheaper biogas.

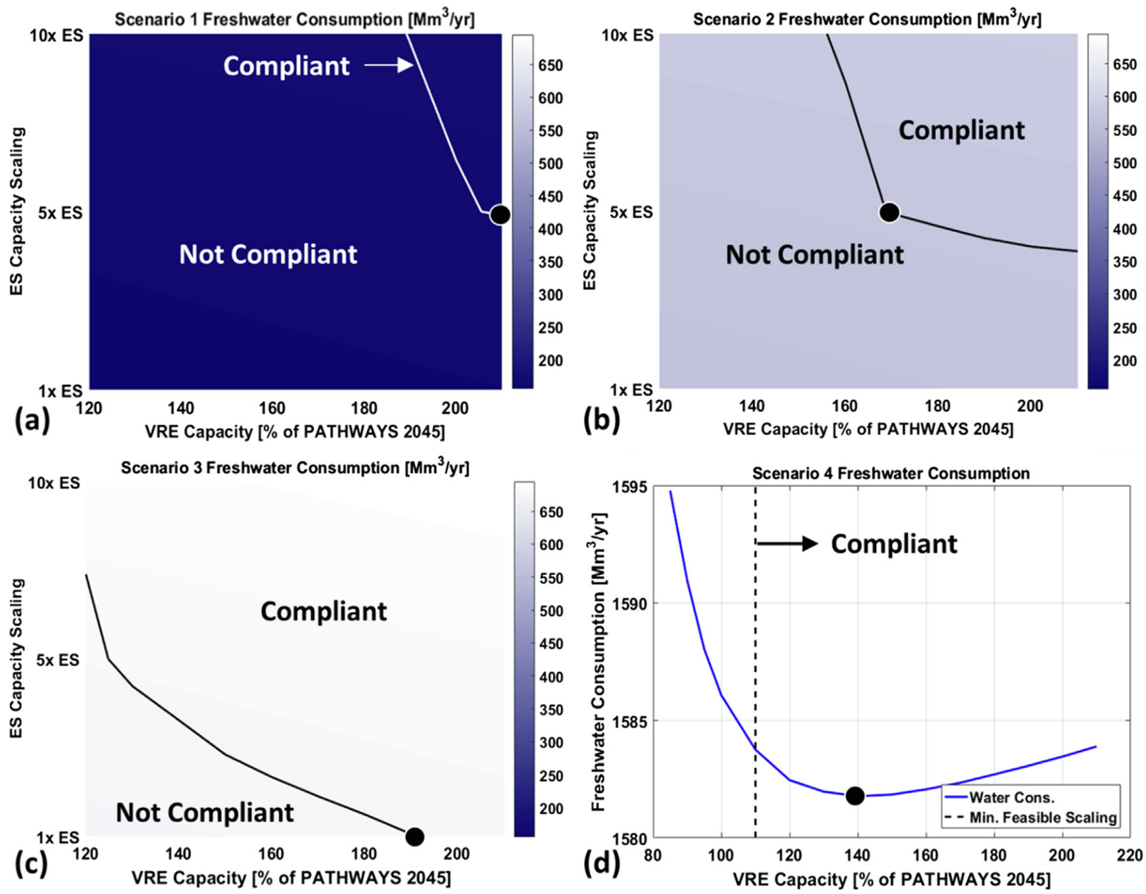

Fig. 3. Freshwater Consumption values for different realizations of each narrative scenario: (a) Scenario 1 – Solar/Hydro/Wind Only, (b) Scenario 2 – Current Nuclear and Renewable Expansion, (c) Scenario 3 – Nuclear and Renewable Expansion, and (d) Scenario 4 – Maximize Geothermal and Biogas. The black dot notes the realization with the lowest freshwater consumption value in each scenario. Variable renewable energy capacity is presented as a percentage of levels in the E3 PATHWAYS 2045 study and energy storage capacity is presented as a multiple of levels in the E3 PATHWAYS 2045 study.

Full cost assumptions can be found in SI Section D. Note that the HiGRID Cost Module captures the financial impact of renewable curtailment on the technology-specific LCOE of wind and solar resources (SI Section A). Across the four scenarios, curtailment ranges from 20% to 50%. All modeled realizations for this study adopt the PATHWAYS assumption of at least 24.5 GW of installed battery storage ("1x ES Capacity Scaling" in Figs. 2 and 3), for which costs remain significant. Modeled LCOE values presented here are designed to provide intuition about differences across potential electricity mixes, based on internally consistent assumptions. They are not designed to be compared with present-day or business-as-usual trajectory electricity system costs.

3.2. Behavior of the electricity system freshwater consumption

The freshwater consumption for the realizations in each of the four scenarios is presented in Fig. 3:

The variability in freshwater consumption among the different scenarios is much greater than that among realizations within each scenario. Scenarios 1, 2, 3, and 4 span SB100-compliant freshwater consumption ranges of 170 to 200 Mm^3/yr, 570 to 590 Mm^3/yr, 680 to 690 Mm^3/yr, and 1580 to 1600 Mm^3/yr, respectively. The major contributors to freshwater consumption in all scenarios are the geothermal, hydropower, and nuclear resources. Scenario 4 exhibits the highest freshwater consumption due to its strong reliance on geothermal resources, while Scenario 1 exhibits the lowest freshwater consumption since it is mostly comprised of wind and solar resources. Scenario 2 and 3 fall between the other two scenarios, with Scenario 3 exhibiting higher freshwater consumption levels than Scenario 2 due to the larger capacity of nuclear resources.

Variability among realizations within each scenario, while small compared to that across scenarios, is present and depends on the installed energy storage and renewable capacity. Increases in either energy storage or variable renewable capacity result in slightly increased freshwater consumption. Note that the assumption of flow batteries for energy storage in this study drives the result that more energy storage leads to more freshwater consumption. Flow batteries are shipped from the manufacturer without their electrolyte in liquid form. When these units arrive at the site of installation, local water supplies are mixed with solid, powdered electrolyte material to produce the liquid electrolyte used during the operation of the battery [53,54].

For Scenarios 1, 2, and 3, the realizations with the lowest freshwater consumption also have the lowest LCOEs. This occurs since overbuilding variable renewable resources (i.e., wind and solar) and installing energy storage only to the extent necessary to meet SB100 compliance yielded the lowest LCOE values. In parallel, from a freshwater consumption perspective, increasing variable renewable capacity consumed less freshwater than increasing energy storage capacity. This is due to the low freshwater intensity of wind and solar resources and the comparatively larger water needs for filling the electrolyte of the battery energy storage systems. Therefore, the realizations that prioritized overbuilding variable renewable capacity with a minimal capacity of energy storage yielded both the lowest LCOE and lowest freshwater consumption values. It is important to note that this relationship is not a general finding, but rather a function of this particular study. If the study were performed with energy storage types that had lower freshwater consumption intensities such as flywheels, for example, it

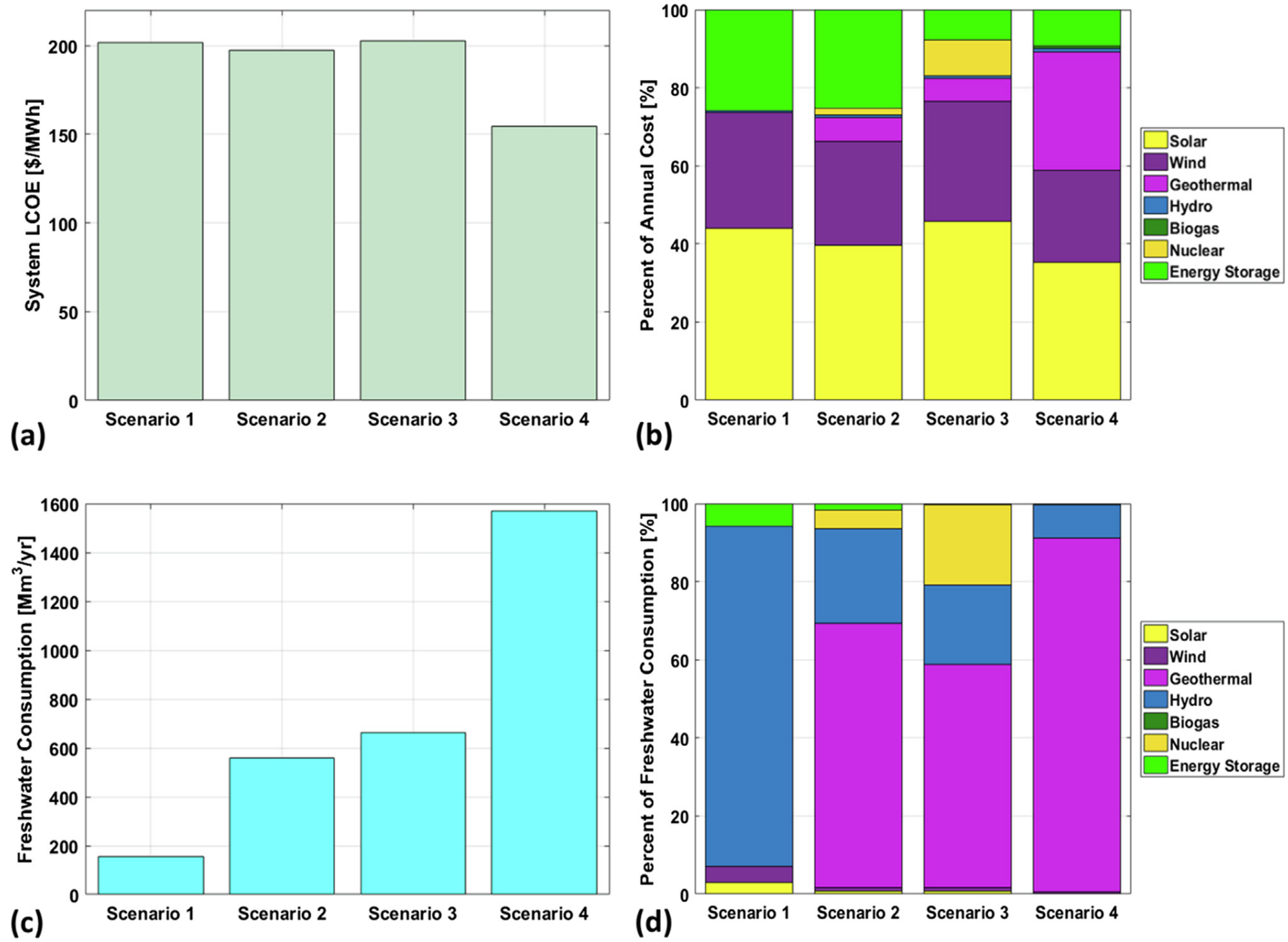

Fig. 4. (a) Systemwide Levelized Cost of Electricity [2017 $/MWh] for the lowest cost realizations in each of the narrative scenarios: Scenario 1 – Solar, Hydropower, and Wind Only, Scenario 2 – Current Nuclear and Renewable Expansion, Scenario 3 – Nuclear and Renewable Expansion, and Scenario 4 – Maximize Geothermal and Biogas. (b) Normalized distribution of annual costs by electric grid resource type for the realizations presented in (a). (c) Annual Freshwater Consumption [Mm^3/yr] for the lowest freshwater consumption realizations in each of the narrative scenarios. (d) Normalized distribution of annual freshwater consumption by resource type for the realizations presented in (c).

would not necessarily hold that the realizations with the lowest freshwater consumption would also have the lowest LCOEs. The lowest freshwater consumption realization in Scenario 4 occurs with a 140% variable renewable capacity relative to that in the E3 PATHWAYS study for 2045.

3.3. Comparison of lowest LCOE and lowest freshwater consumption realizations

The LCOE values for the lowest cost realization in each narrative scenario are presented in Fig. 4a, with the corresponding normalized distribution of annual costs by resource type in Fig. 4b. For comparison, Fig. 4c presents the freshwater consumption values for the lowest freshwater consumption realization in each narrative scenario, with the corresponding normalized distribution of freshwater consumption by resource type provided in Fig. 4d.

Comparing the ordering of the scenarios on the basis of costs in Fig. 4a versus that on the basis of freshwater consumption in Fig. 4c, we observe that Scenario 4 (Maximize Geothermal and Biogas) yields the lowest LCOE value of $154/MWh but also the highest freshwater consumption of 1590 Mm^3/yr. This scenario relies on high capacity factor, relatively low-cost zero-carbon geothermal resources and the use of flexible biogas generation. Including a high capacity factor resource like geothermal reduces the maximum extent of misalignment between variable renewable resource provisioning and load, thereby reducing the influence of difficult-to-match demand conditions on variable renewable capacity needs. Including biogas resources allow the system to directly meet peaks in the net load demand with flexible gas turbine resources, reducing the need for energy storage. While the capacity factor of the modeled power plants utilizing biogas resources is relatively low, its influence on the overall system LCOE is small (see Fig. 4b) since it contributes about 2% of annual electricity generation. This suggests that avoiding additional energy storage capacity to meet net load peaks provides significant value to the electricity system. The strong reliance on geothermal resources, however, also results in very high freshwater consumption based on the life cycle freshwater consumption data applied in this study, shown by the large contribution of geothermal to freshwater consumption for Scenario 4 in Fig. 4d. The 16.7 GW of geothermal capacity in this scenario alone consumes more freshwater than the entire system simulated in the other three scenarios.

From Fig. 4a, we observe that Scenario 1 (Solar, Hydropower, and Wind Only) and Scenario 3 (Nuclear and Renewable Expansion) yield the highest LCOE values of $202/MWh (year 2017 dollars). Scenario 1 incurs high costs since it requires higher capacities of installed variable renewable resource capacity to meet the zero-carbon mandate. The lowest cost realization in Scenario 1 requires the largest buildout of variable renewable capacity among the four scenarios (210% of that projected in the E3 PATHWAYS 2045 study) as well as requiring increased energy storage capacity. Curtailment of wind and solar

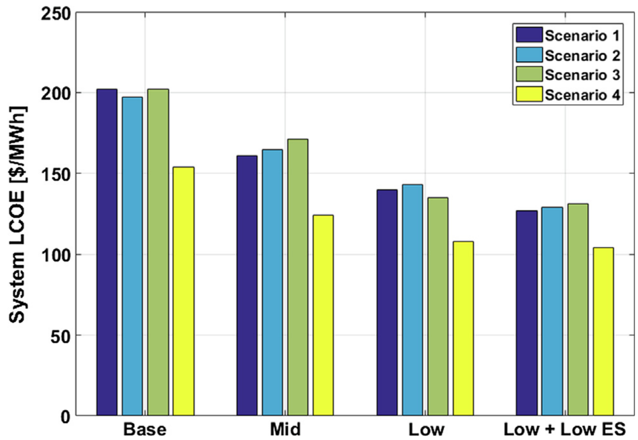

Fig. 5. Sensitivity of the lowest LCOE values in each scenario to projected future costs of energy resources using a 99.5% zero-carbon threshold. "Base" = Cost data inputs from the NREL ATB dataset for the base year of 2017. "Mid" = Cost data inputs from the NREL ATB Mid-case for the year 2045. "Low" = Cost data inputs from the NREL ATB Low-case for the year 2045. "Low + Low ES" = Same as the "Low" case, but additionally includes the projected cost reductions in energy storage system capital costs.

generation in Scenario 1 is equivalent to 50% of annual electric load, which also increases the LCOE from variable renewable resources. However, with the current study cost inputs, it is cheaper to accept curtailments than further increase the energy storage capacity. While tied for the highest LCOE values with Scenario 3, Scenario 1 exhibits the lowest freshwater consumption among the different scenarios (see Fig. 4c). In Scenario 1, hydropower is the primary contributing factor to scenario freshwater consumption due to reservoir evaporation, but the capacity of this resource is maintained at present-day (year 2018) levels. Wind and solar resources, which comprise the majority of the installed capacity in Scenario 1, have very low freshwater consumption intensities.

High costs in Scenario 3 are a direct result of the high capital costs of expanding existing nuclear capacity using conventional technologies, per the cost data inputs used in this study. While the expanded nuclear fleet in this scenario contributes about 21% of total freshwater consumption, the majority of freshwater consumption is still driven by geothermal resources (Fig. 4b), which accounts for 57% of the scenario's total freshwater consumption. However, Scenario 3 still exhibits less than half of the freshwater consumption of Scenario 4 (Fig. 4c).

Scenario 2 (Current Nuclear and Renewable Expansion) exhibits slightly lower costs than Scenarios 1 and 3 (Fig. 4a) and freshwater consumption levels between those scenarios (Fig. 4c). Maintaining present-day nuclear capacity levels allows costs to be lower than the expanded nuclear scenario since these facilities are fully amortized. The inclusion of geothermal resources in this scenario does increase its freshwater consumption relative to Scenario 1 and with present-day nuclear capacity, the freshwater consumption associated with nuclear remains relatively small (Fig. 4d).

4. Sensitivity analyses

4.1. Sensitivity to cost input data

Cost results from this study depend strongly on the inputs – here, 2017 values from the National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB) 2019 cost dataset [48]. This work uses a 2017 base year rather than future projections primarily because future projections are not available for all relevant technologies, such as nuclear and flow battery energy storage. Expectations for future costs depend heavily on technology development rates and future markets for required materials and associated cost changes could lead to qualitatively different results from those presented here.

Between 2017 and 2050, the NREL ATB dataset projects overnight capital cost decreases of 35–66% for solar PV; 31–45% for onshore wind; and 13–21% for hydrothermal geothermal systems. While the vanadium flow batteries considered in this study are not included in NREL ATB projections, 4-hour lithium-ion battery overnight capital costs are projected to decrease by 56–74% between 2017 and 2050. Given that our analysis includes a substantial deployment of energy resources that are anticipated to have lower costs in the future, we recalculate our results for each of the four narrative scenarios using different sets of cost input data gathered from the NREL ATB Mid- and Low-cases for the year 2045. Additionally, we add a sensitivity case where we assume that the capital cost reduction for vanadium redox flow batteries would match that for lithium-ion batteries as predicted by the NREL ATB dataset. The NREL ATB dataset does not include a future cost projection for nuclear power. To address the potential cost reductions in nuclear power, used in Scenarios 2 and 3, we incorporate cost data from the Energy Innovation Reform Project (EIRP) [55] for advanced nuclear technologies. We implement the median values for advanced nuclear costs alongside the NREL ATB Mid-case and the low-end values for advanced nuclear costs alongside the NREL ATB Low-case. Compared to the nuclear costs used on the main results, the median value and low-end value for nuclear costs represent decreases in capital costs of 39 and 66%, respectively.

The LCOE results for each scenario using the different cost input datasets are presented in Fig. 5. The LCOE values for the spectrum of realizations examined for each scenario are presented in Figs. S4-S6 in Section E of the SI.

Solar and wind resources are significant contributors to system LCOE in all narrative scenarios (Fig. 4b). Therefore, implementing the projected future cost inputs for wind and solar decreases LCOE values for all scenarios. Scenario 4, which maximizes its reliance on both high capacity factor (geothermal) and fully dispatchable (biogas in combined cycle gas-turbines) zero-carbon generation, still yields the lowest LCOE values of all scenarios. The fundamental factors of 1) using high-capacity factor zero-carbon generation to reduce the extent of required variable renewable generation to meet a zero-carbon threshold and 2) incorporating a dispatchable resource that is able to meet peaks in the net load demand directly both act to reduce the capacity requirements for energy storage and its associated costs. Combined, these act to provide the lowest-cost approach to meeting the zero-carbon target in this study. Further, these results also highlight that significant cost reductions in wind and solar resources and/or energy storage would need to occur for a variable renewable-dominant scenario (Scenario 1) to exhibit LCOE values equal to or lower than a scenario with dispatchable and high capacity factor zero-carbon resources. For example, Scenario 1 requires the Low-case cost reductions for its LCOE value to drop below that of Scenario 4 in the base case. Note, however, that this result is sensitive to load flexibility and while this study included flexible loads in the form of grid-responsive electric vehicle charging and flexible hydrogen electrolysis, deploying additional flexible loads may affect the value of dispatchable generation.

Scenarios 2 and 3 both incorporate nuclear power to different extents, making use of a high capacity factor zero-carbon resource. In the Mid- and Low-cases for future cost projections, the capital cost of nuclear drops below that for geothermal (Tables S8 and S9 of the SI). However, both Scenarios 2 and 3 exhibit higher LCOE values than Scenario 4 under future cost projections. Scenario 2 does not incorporate sufficient nuclear capacity to significantly reduce the required capacity of energy storage to meet the zero-carbon goal (illustrated by the location of the lowest-cost realization in Figs. S4-S6 of the SI). Scenario 3 does incorporate sufficient nuclear capacity to reduce the required capacity of energy storage to meet the zero-carbon goal, but nuclear has low dispatchability. As operated in the US, nuclear generation does not ramp up to meet net load peaks and ramp down to accommodate renewable generation, which leads to significant wind and solar curtailment—and associated higher costs—in SB100-compliant realizations in Scenario 3. These results show that only incorporating the first characteristic of Scenario 4 – the use of high-capacity factor zero-carbon generation – is not sufficient to provide the full cost savings associated with reducing energy storage needs to meet a zero-carbon threshold. The ability to match supply with demand, whether through storage, dispatchability, or demand-side strategies, is highly relevant for LCOE. Note that, while not modeled here (since this study focuses on comparing low-cost vs. low-water approaches to decarbonization), pairing nuclear rather than geothermal expansion with biogas resources would likely provide similar cost characteristics to Scenario 4, and potentially even lower costs under the future cost projections.

In the Low + Low ES case, which incorporates significant cost reductions for batteries alongside those for the electricity generating resources, both of the scenarios including nuclear capacity yield higher LCOE values than those excluding it, with Scenario 3 yielding the highest. This further shows that a primary benefit of using high capacity factor zero-carbon resources with higher capital costs is to reduce the capacity of energy storage (and its associated costs) required to meet a zero-carbon target. When energy storage costs are also reduced, the value of this benefit diminishes.

4.2. Sensitivity to the zero-carbon threshold

In addition to cost data inputs, we assess the sensitivity of the results to changes in the selection of the zero-carbon threshold by repeating the analysis for 99.0% and 99.9% zero-carbon thresholds. These results are described in detail in Section F of the SI. In summary, we find two main points. First, in general, LCOE values increase with more stringent zero-carbon thresholds and decrease with less stringent zero-carbon thresholds. Second, the LCOE of the lowest-cost realization increases dramatically for Scenario 1 as the zero-carbon threshold is increased due to the increased needs for energy storage and overbuilt wind and solar capacity. Scenario 4, which incorporates flexible biogas as a peak-serving resource, is able to maintain similar LCOE values across the range of zero-carbon thresholds. In general, our results highlight the sensitivity of LCOE to the cost of matching supply with demand and the financial value of incorporating flexibility when building a zero-carbon electricity system. Matching supply with demand via approaches that require overgeneration (resource curtailment and energy storage) tend to have higher costs while matching supply with demand more precisely (with highly dispatchable resources like demand-side management, biogas or, under less stringent carbon thresholds, natural gas) tends to result in lower modeled costs.

5. Discussion

5.1. Implications for California's efforts to meet SB100

For California, our results show that the lowest LCOEs are obtained when maximizing the use of high capacity factor and dispatchable zero-carbon resources to the extent possible (e.g., within reasonable differences between the capital costs of these resources compared to cheaper but variable renewable resources). In California, geothermal potential fulfills the role of a high capacity factor zero-carbon resource and biogas fulfills the role of a dispatchable zero-carbon resource. Even though the overnight capital costs of geothermal were approximately 377% of that for utility-scale solar PV, 149% of that for rooftop solar PV, and 262% of that for onshore wind on a capacity basis, in the main results, the scenario that maximized the use of this resource with dispatchable biogas for supporting wind and solar variability yielded the lowest system-wide LCOE. This outcome occurs because these resources reduce the temporal mismatch between supply and demand. In turn, this either reduces curtailment or reduces the capacity of energy storage needed to meet electricity demand under the zero-carbon goal. Further, as the zero-carbon threshold is tightened, the LCOE values of the scenario that relied most strongly on variable renewable generation and energy storage (Scenario 1) increase significantly due to modeled increases in energy storage capacities. The cost sensitivity analysis, however, highlights limits to this benefit. If high capacity factor zero-carbon generation is installed without complementary dispatchable zero-carbon generation for meeting net load peaks, energy storage capacity requirements for meeting the electric demand will not be reduced to the same extent as a scenario when both generation types are included. Under the former conditions, system-wide LCOE remains relatively high.

The cost results imply that in planning to meet California's SB100, an approach that (1) takes advantage of abundant variable renewable generation alongside high capacity factor zero-carbon resources and (2) incorporates at least a small percentage of dispatchable zero-carbon resources is preferred from a cost perspective since it reduces the scale of required energy storage capacity. Cost reductions in energy storage can enable a higher share of variable renewable energy capacity in a lowest-cost portfolio, but fundamentally avoiding the need for increasing energy storage capacity is still preferable. For California specifically, geothermal is suited to fulfill the role of a high capacity factor zero-carbon resource and biogas is suited to fill the dispatchable resource role, even with its limited technical potential for contributing to a large percentage of the overall delivered electricity mix. It is important to note that demand-side strategies could fill similar roles: for example, efficiency improvements can behave analogously to high capacity factor zero-carbon supply resources, and demand curtailment or shifting can behave like dispatchable supply resources.

5.2. Implications of meeting SB100 for freshwater consumption in California

The freshwater consumption levels for SB100-compliant realizations across the different scenarios range between 170 and 1600 Mm^3/yr. These levels correspond to between 0.2% and 2.1% of annual statewide freshwater demand during dry years (75.2 billion m^3) [56]. For context, the in-state freshwater consumption of the near present-day (year 2014) electricity system in California [28] is approximately 300 Mm^3/yr. Therefore, the potential future zero-carbon electricity systems modeled here for California represent a freshwater consumption range of 57% to 540% of the current electricity system's freshwater consumption levels.

It is also important to note the locations of the resources that contribute towards freshwater consumption. The high end of freshwater consumption among SB100-compliant realizations is driven by the strong reliance on geothermal power in Scenario 4. In California, new geothermal resource potential is strongly concentrated in the southeastern desert regions of the state [57,58], coinciding with areas that have historically experienced severe drought [59]. Water supply via the Colorado River in these regions is also an important source for the populated southern cities of the state. Therefore, while reliance on relatively cheap geothermal power could provide a cost benefit in meeting the goals of SB100, this strategy can potentially exacerbate local freshwater stress in California. By contrast, the lowest freshwater consumption for California is obtained when maximizing the use of renewable resources with low-water intensity, such as wind and solar PV resources. These resources consume a small amount of freshwater but require other grid resources (e.g., energy storage) and/or sufficient capacity to enable curtailments to effectively serve electric load. It is also important to note that although our modeling exercise does not focus on demand-side strategies, all four of the scenarios examined here include some strategies for matching load with variable generation, such as smart electric vehicle charging and dispatchable hydrogen electrolysis (Table S6).

5.3. Uncertainty in water data

Freshwater consumption data for California in this study are from Peer et al. [28] and retain the uncertainties associated with that work, most notably associated with the fact that freshwater consumption data are often not directly measured and reported. Thus, much of the information used here is not fully empirical, but rather extrapolated from limited empirical data or estimated based on physical relationships. Regionalizing highly uncertain national data also introduces additional uncertainty due to disaggregation. Note, however, that California's role as a major producer of renewable electricity as of 2014 means that much of the underlying data for [28] (the 2014 snapshot presented in Grubert and Sanders [27]) is based on Californian facilities. This California specificity is particularly relevant for geothermal resources. Further, as discussed in Peer et al. [28], point-of-generation level data are relatively simple to regionalize given information about specific power plant locations and the use of federally reported data for those facilities.

Several uncertainties are particularly relevant in the context of this study. Most importantly, this work assumes that estimates for 2014 freshwater consumption intensity by resource in CAMX are static through the projection period. In some cases, this assumption is likely to hold: for example, operating solar photovoltaic panels requires almost no water, and there is little evidence that condition will change. In other cases, however, technology or climatic changes could lead to very different future freshwater intensity outcomes relative to 2014 levels. The most significant examples for this work are hydroelectricity, where evaporation is mediated by characteristics like reservoir area (dependent on reservoir depth), temperatures, wind patterns, and others that are highly sensitive to droughts and climate change; and geothermal, where future technological deployment might not match present assumptions. For example, closed-loop geothermal plants could consume far less water than flash or dry steam plants, where reservoir groundwater is released to the atmosphere as steam. Any new nuclear plants would similarly be expected to have characteristics very different from California's last operating coastal nuclear plant, Diablo Canyon, expected to retire in the early 2020 s. Such plants would likely increase freshwater pressure given restrictions on the future use of ocean water for cooling.

6. Conclusions and policy suggestions

This study assesses the in-state freshwater consumption implications of meeting California's Senate Bill 100 goal by 2045, how Senate Bill 100-compliant electricity resource mixes vary in terms of composition, levelized cost of electricity, and freshwater consumption, and evaluates whether prioritizing freshwater consumption reductions significantly adds to the cost of electricity. These questions were assessed by combining life cycle freshwater consumption data for electricity generating technologies with electric grid dispatch modeling of scenarios for future zero-carbon electricity systems in California. The primary conclusions of this study are as follows:

- **The lowest cost approach to developing a zero-carbon electricity system in California deploys both high capacity factor and dispatchable zero-carbon resources alongside wind, solar and storage.** Installing high capacity factor zero-carbon resources reduces the maximum extent of misalignment between variable renewable generation and load, thus reducing the energy storage capacity required to compensate. Dispatchable zero-carbon resources also enable a zero-carbon electricity system to meet net peak load events without increasing energy storage needs.
- **The lowest cost modeled approach to meeting Senate Bill 100 increases Californian freshwater consumption by an order of magnitude compared to the lowest freshwater consumption approach.** Geothermal resources contribute to low costs but high freshwater consumption in California. The scenario with the lowest cost yielded the highest freshwater consumption, 8.4 times greater than the modeled lowest freshwater consumption outcome.
- **Cost and water consumption tradeoffs are asymmetrical: the lowest freshwater consumption modeled approach to meeting Senate Bill 100 exhibits a 31% increase in LCOE compared to the lowest cost approach.** These higher costs are driven by curtailments on a larger variable renewable capacity and increased energy storage capacity in order to meet a zero-carbon goal using resources with low freshwater consumption intensities (e.g., wind and solar).

Based on these results, we put forward the following policy suggestions:

To reduce the water consumption of low-cost zero-carbon electricity resources, increased support for reducing the water consumption of high capacity factor zero-carbon resources such as geothermal will be important. This can be potentially accomplished through providing incentives for low or zero water use technologies for geothermal power plants such as dry or hybrid cooling to overcome the potential added costs associated with implementing these systems. Alternatively, funding for research and development programs that develop low-cost, low or zero-water use cooling technologies or methods to mitigate water loss in geothermal power plants can also contribute to this goal.

We do not recommend increasing the price of water strictly to compensate for the difference in cost between the lowest cost and lowest water consumption electricity resource mixes. In the lowest freshwater consumption mix, electricity costs represent a premium above the lowest cost mix of about $336/year for an average California household using approximately 7 MWh/year [60]. If water savings are assumed to be the only benefit of the modeled lowest freshwater consumption mix over the modeled lowest cost mix, the implied avoided cost of freshwater consumption is $13 per cubic meter, or $16,000 per acre-foot. This is approximately 8 times the cost of water from the Carlsbad seawater desalination plant in California [61], which is among the most expensive sources of water in California [61]. Therefore, increasing the price of water to compensate is not recommended.

CRediT authorship contribution statement

Brian Tarroja: Writing - original draft, Writing - review & editing, Conceptualization, Methodology, Software, Formal analysis, Resources. **Rebecca Peer:** Writing - review & editing, Methodology, Resources, Data curation, Visualization. **Kelly T. Sanders:** Writing - review & editing, Data curation, Methodology, Resources. **Emily Grubert:** Writing - review & editing, Data curation, Methodology, Resources.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary material

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