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Cost-effective decarbonization of California's power sector by 2030 with the aid of battery storage

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ABSTRACT

The costs of solar photovoltaics (PV), wind, and battery storage have fallen by approximately 65% to 85% since 2010 and are projected to decline further in the near future—creating opportunities for aggressive power-sector decarbonization that were seldom envisioned even a few years ago. We assess the ability of large-scale PV and wind deployment in conjunction with modest amounts of battery storage to enable near-complete decarbonization of California's power sector by 2030. Our study improves on previous analyses by accounting for the dramatic recent cost reductions and therefore assessing the possibility of more rapid decarbonization. We find that, even if renewable energy and storage costs do not decline further, a carbon-free generation share of 80% can be achieved by 2030 in California at a total system cost lower than the cost in a baseline no-additional-clean-energy scenario. If costs decline at half the rate observed since 2010, 95% carbon-free generation is feasible at a total system cost similar to the cost in a baseline scenario. This is the first study to suggest California could cost-effectively achieve near-complete power-sector decarbonization by 2030 using existing technologies. The results also indicate potential for similar opportunities in other regions of the world. This is especially important because power-sector decarbonization could catalyze electrification-based decarbonization across other economic sectors such as transportation, buildings, and industry.

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If current trends continue, the world is on a path toward warming by 3 degrees C by the end of the century, likely resulting in irreversible environmental, social, and economic impacts [1]. Many studies suggest an accelerated transition to low-carbon energy systems is needed to avoid this scenario— including both the decarbonization of the electric power sector and widespread electrification of end uses such as vehicles, industrial operations, and buildings [2]. Producing carbon-free electricity is the key to enabling carbon-free electrification of these other sectors. Most analyses of near-complete power- sector decarbonization (80% decarbonization or greater) project achievement of this goal by no earlier than 2050 owing to high assumed renewable energy costs [3]–[5].[1] Such a timeframe provides little hope that climate change could be held to a manageable level in this century. However, these existing studies—even those published only a few years ago—do not adequately capture the dramatic declines in wind energy, solar energy, and battery energy storage costs that are apparent today. Accounting for current cost trends could shift decarbonization assumptions to a timeframe commensurate with climaterealities while transforming the policy dialog about the feasibility and cost of near-term decarbonization.

[1] The one study [6] that assesses complete decarbonization of the U.S. power sector by 2030 does not assume a significant role for battery storage, as our study does. Instead, it relies on expansion of the U.S. transmission network, which is technically and economically challenging [7].

In this article, we use the latest renewable energy and battery cost trends to analyze the costs, benefits, and operational feasibility of decarbonizing California's power sector by 2030. California is the world's 12th largest emitter of greenhouse gases (GHGs) and a leader in climate change mitigation, making its technology and policy choices important within the United States and worldwide [2], [8], [9]. The state's existing policies mandate a 40% GHG reduction by 2030 (compared with 1990 levels), targeting an 80% reduction by 2050 [10], [11]. Recently passed state legislation, SB 100, also requires that investor-owned utilities produce 60% and 100% of their power from renewable sources by 2030 and 2045 respectively, extending a prior mandate of 50% renewable energy by 2030 [12].

Our analysis employs an industry-standard electricity production cost model used by utility planners, a detailed, publicly available generation and transmission dataset for California, and forecasts of continued renewable energy and battery cost reductions based on current trends. For different scenarios of generation portfolios, we use the production cost model to evaluate the operational behavior and the operating cost, and also evaluate the total capital cost of added renewable capacity. Because the assumed cost reductions are a global phenomenon—and most countries and U.S. states have significant potential for generation from solar PV, wind, or both—the results can also inform rapid power-sector decarbonization efforts in other regions.

Cost Assumptions and Modeling Scenarios

Figure 1 shows our wind, solar PV, and lithium-ion battery capital cost assumptions, compared with historical costs and costs used in various recent studies. The solid lines represent historical unsubsidized average Purchasing Power Agreement (PPA) prices (paid by utilities for wind and solar PV) and overnight capital costs (battery). The broken lines represent our two cost-projection scenarios:

1) High cost (dotted line)—assuming no further cost reductions (i.e., using unsubsidized PPA prices or bids in 2017)
2) Low cost (dashed line)—assuming future costs decline at approximately one half the rate observed between 2010–2017

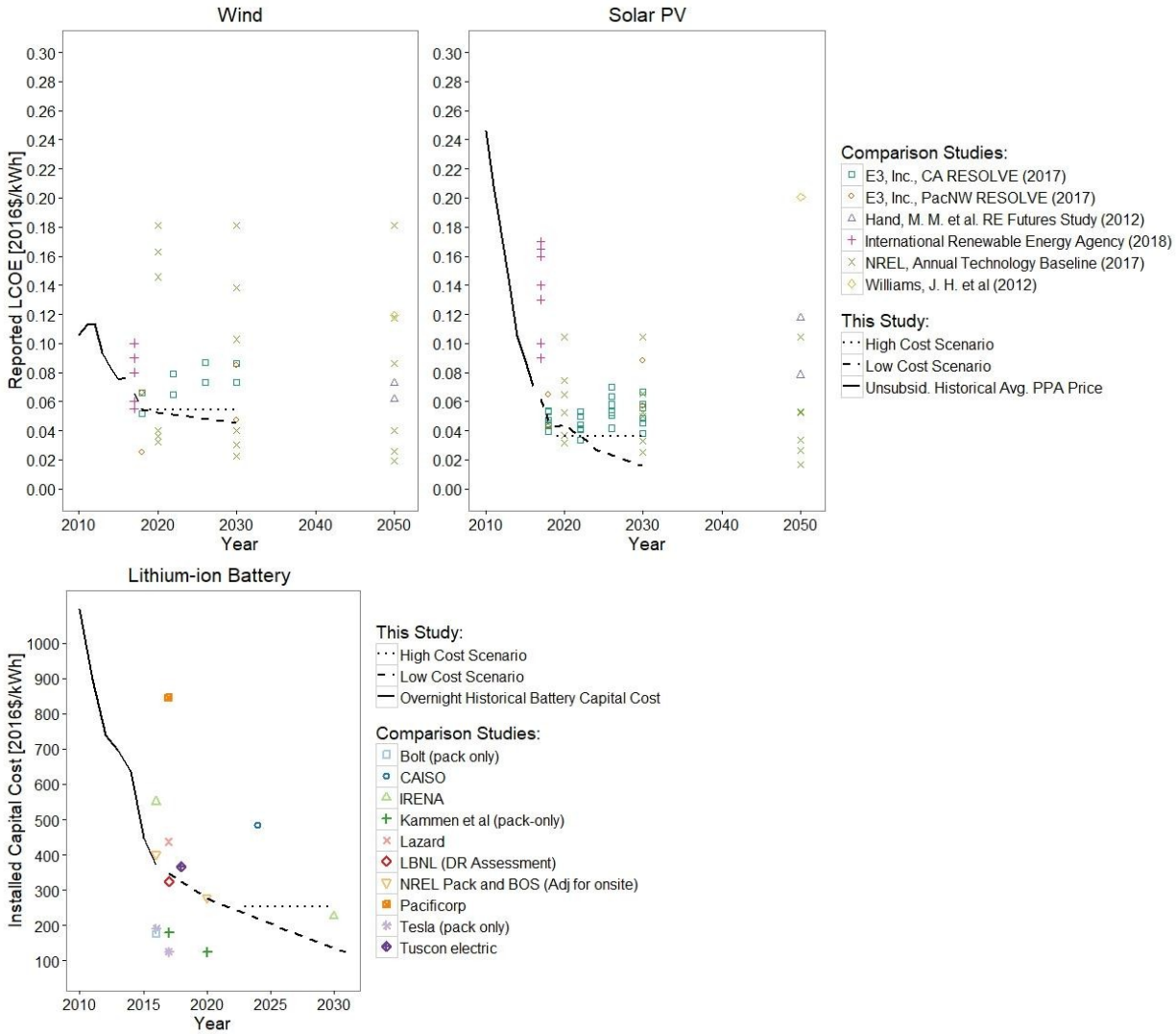


Figure 1: Historical and projected costs of wind (A), solar PV (B), and Li-ion battery storage (C), and cost assumptions from literature. Solid line indicates historical PPA prices. Dotted line indicates "High Cost" sensitivity assuming no change in PPA prices from 2017. Dashed line indicates "Low Cost" sensitivity assuming rate of decline at half the average rate during 2010-2017. The High Cost sensitivity in the (C) case is based on the median bid value from Xcel energy's 2017 solicitation: Xcel $/kW - month * 12 months/yr / 6.5 hours / CRF * 1.4 = $/kWh cap cost including charging cost and assuming standalone storage. The data from the comparison studies indicated the levelized cost of energy reported from other recent decarbonization or technology cost studies.

We use these costs as part of five modeled scenarios of clean energy generation in 2030: 1) a Baseline scenario that assumes no new clean energy is added between 2018 and 2030 (resulting in 34% total clean electricity), 2) a Current Policies scenario that has a target of 50% RPS by 2030 (resulting in 64% total clean electricity), 3) an 80% clean energy scenario, 4) a 90% clean energy scenario, and 5) a 95% clean energy scenario. In this analysis "clean energy" includes wind, solar, biomass, geothermal, and large hydro
sources, which have near-zero operational (not lifecycle) GHG emissions.[2] Because solar PV and wind are

[2] California's RPS legislation does not include large hydropower.

the lowest-cost clean energy resources, we only add new generating capacity into the system from these resources, above what is built or planned already for the 50% RPS. We exogenously specify solar PV and wind capacity additions in the same ratio as the existing and planned amounts to meet additional clean energy generation targets. Please refer to the SI for additional details on the method, data, and other assumptions.

Adding solar PV and wind capacity to a power system can substantially increase curtailment of these resources owing to the increasing temporal mismatch between renewable generation and electricity demand [13]. Various strategies can be used to reduce this curtailment including demand response, storage, and adding additional transmission capacity. In this analysis, we limit demand shifting via demand response to 683 MW (143 GWh), which is the level included in the California generation and transmission dataset. Otherwise our simulations address curtailment by using battery storage, based on the relative costs of solar PV, wind, and battery storage.

Lowest-Cost Energy Storage and Clean Energy Scenarios

For each scenario, and for both the high and low cost assumptions, we select the buildout of solar PV, wind, and battery storage with the lowest total system cost. These estimates of total cost are calculated as the annualized fixed and variable generation cost of the California power sector in 2030, including the capital cost of renewable generation and battery storage, operations (primarily natural gas fuel costs), imports, energy efficiency, ancillary services, capacity, and carbon regulations (floor price of carbon mandated in the California cap-and-trade program). We estimate the annualized fixed cost of conventional generation capacity using the current capacity market prices. We only consider costs of capacity that are needed to meet the resource adequacy requirements stipulated by the California Independent System Operator (CAISO). Although the current capacity market prices are lower than what are required to recover the fixed costs of conventional generators, they are likely to continue to stay low for the foreseeable future especially when battery storage provides significant additional capacity in the capacity market. We use higher capacity costs in a sensitivity case. We do not consider additional transmission costs, because our simulated grid dispatch (assuming the transmission system projected by CAISO) shows additional transmission is not required for near-complete decarbonization. Nor do we consider distribution system costs, because we assume most of our renewable energy additions are at the utility scale.

Figure 2 shows the costs of various combinations of clean energy penetrations and energy storage. Because curtailment increases as clean energy penetrations become high, adding storage becomes increasingly economical at these high penetrations. In the 80% clean energy low-cost scenario (Figure 2, left), for example, a clean energy capacity of about 80 GW and storage capacity of 50 GWh (equivalent to about 1.5 hours of average electricity demand) result in the lowest cost. In the 90% clean energy low-cost scenario, a clean energy capacity of about 100 GW and storage capacity of 100 GWh (equivalent to about 3 hours of average electricity demand) result in the lowest costs. Simulations using the capacity-expansion model employed by the California Public Utilities Commission, RESOLVE, yielded largely similar results for optimal wind, PV, and storage capacity investments for 2030 (see SI for more details).

The trends are similar in the high-cost scenarios (Figure 2, right). [14], [15] find that storage equivalent to 8–12 hours of average electricity demand enables near-complete decarbonization of the U.S. power system.

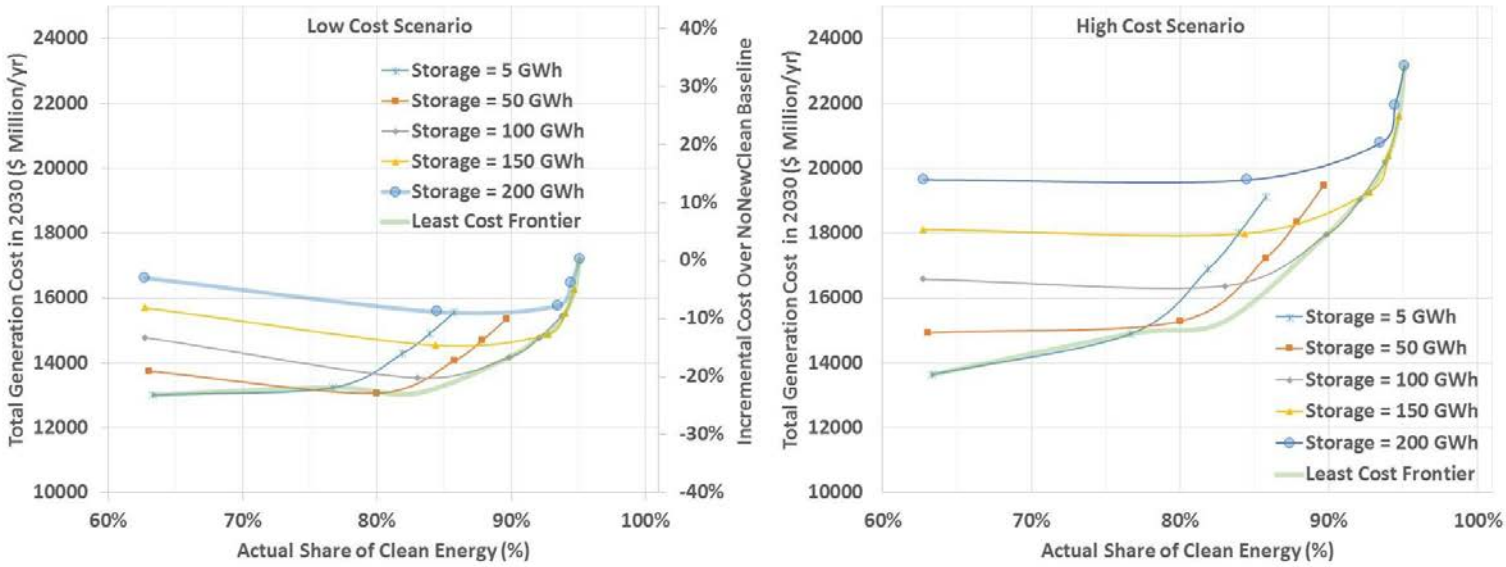


Figure 2: Total annual generation cost in 2030 (fuel and capital service) in California for a range of clean energy shares and storage levels

Figure 3 shows the resulting annual generation stacks in 2030 for the baseline (no new clean energy), current policies, and 80%, 90%, and 95% clean energy scenarios. Even with energy storage, curtailment increases substantially as the clean energy share rises above 80%. At the same time, natural gas generation decreases substantially.

Figure 3: Modeled California electricity generation in 2030 by source including imports, total customer load, load with battery efficiency loss ("Load_incl_Pump"), and RE curtailment for key scenarios. The differences between the dark black lines and the tops of the generation stacks are total exports out of California. In all scenarios, the exports are lower than the dedicated and unspecified imports.

Costs and Benefits of Near-Complete Decarbonization by 2030

Our results suggest that near-complete decarbonization of California's power sector could be achieved cost-effectively by 2030 under most scenarios. As the low-cost results (Figure 4, top) show, total generation costs in 2030 are lower in the current policies, 80% clean, and 90% clean energy scenarios compared with the baseline scenario, and the 95% clean energy scenario is only 5.7% higher than the baseline scenario.

Under the high-cost assumptions (Figure 4, bottom), total costs are lower in the current policies and 80% clean scenarios but 10% higher in the 90% clean energy scenario and 43% higher in the 95% clean energy scenario, compared with the baseline scenario. In addition, average generation costs over the year in 2030 are about 20%–40% lower compared with the cost in 2016 (8.5 cents/kWh vs about 5-7 cents/kWh) in all scenarios, implying a similar range of bill reductions by 2030 (see SI)—owing to lower-cost RE and natural gas generation in 2030.

The CAISO transmission plan, which we take as given, is likely to be designed to meet the transmission needs in the current policy scenario and hence we may not be capturing the additional transmission costs over the baseline scenario even though we find that the transmission capacity in CAISO's plan is

sufficient to meet the transmission requirements of all the deep decarbonization scenarios we assessed. Since the annualized cost of the transmission investment is planned between now and 2027 is less than 0.1% of the total generation costs (*ref), it does not qualitatively influence our findings. Our analysis is at the zonal level and does not capture the potential additional intra zonal transmission requirements.

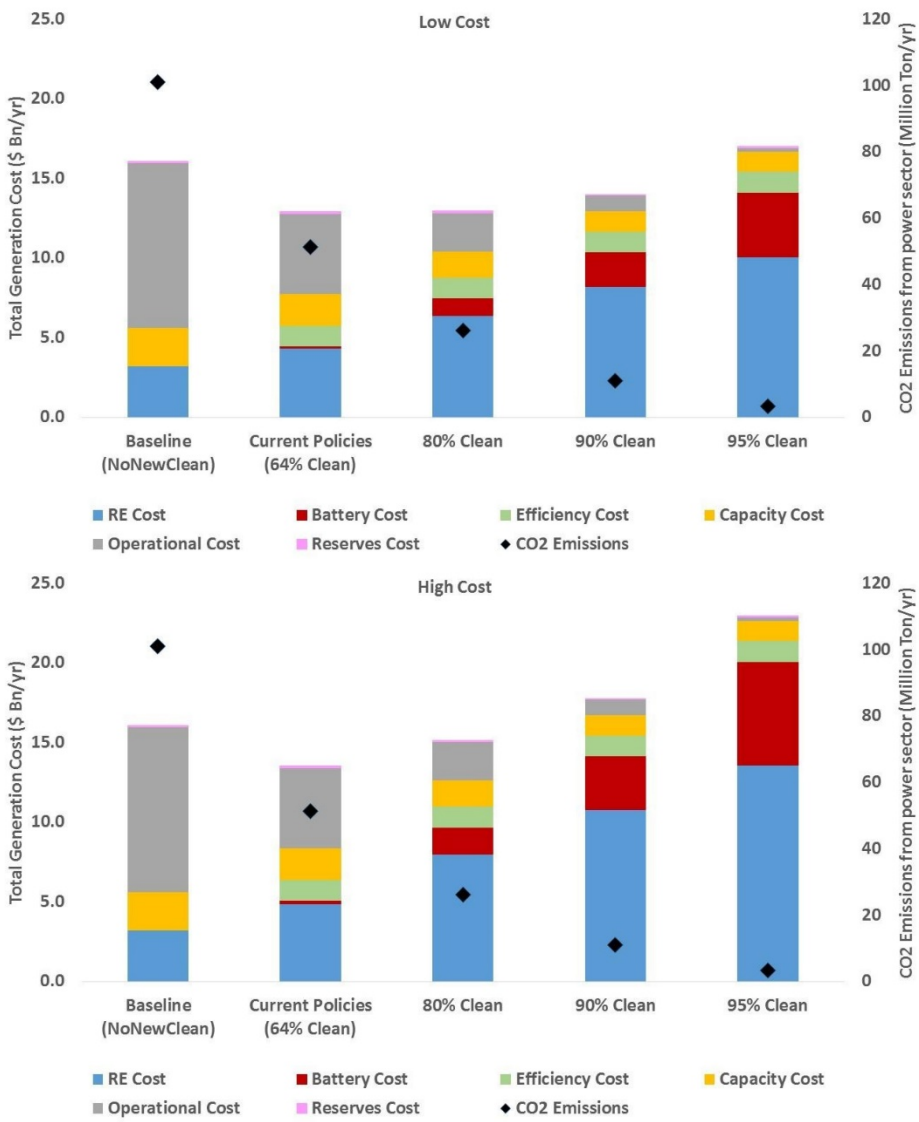


Figure 4. Annual total generation costs by major cost components. The chart also shows total CO_2 emissions from the power sector (black solid markers). With current policies, the state power sector is expected to reduce CO_2 emissions by nearly 50% relative to the baseline.

Figure 4 also shows the declining power-sector CO_2 emissions resulting from decarbonization. Figure 5 puts these results in terms of average and marginal abatement cost per metric ton of CO_2.

The average cost of reducing carbon emissions from the baseline scenario are lower than $ 20/MT up to 75% and 95% reductions for our low and high cost sensitivities. The floor price of CO_2 emissions in 2030 in the California cap-and-trade or Emissions Trading Scheme (ETS) will be $20/metric ton implying that utilities and consumers will incur lower or similar costs compared to the baseline scenario while achieving these emission reductions.

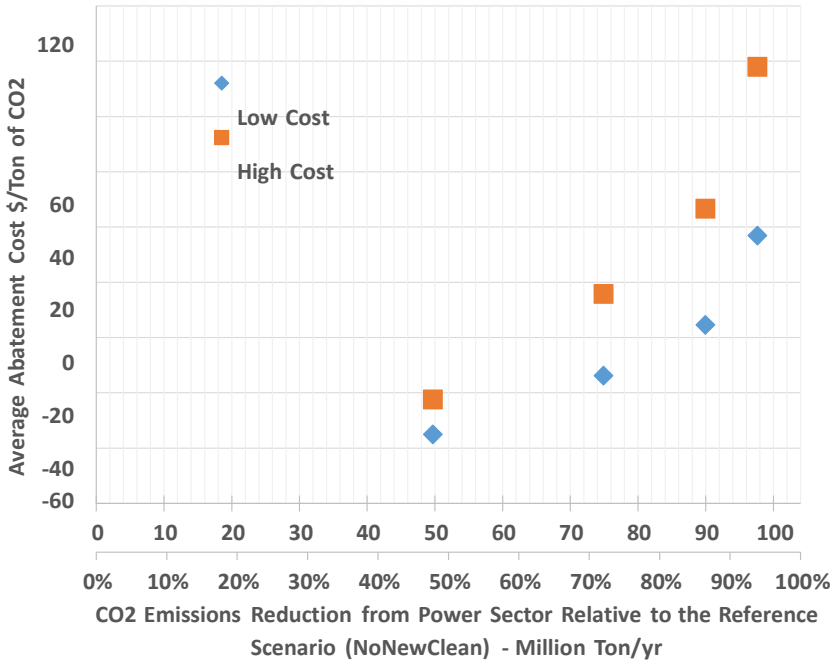


Figure 5: Average abatement cost of key scenarios against the total reduction in CO_2 emissions from the California power sector. For estimating the true abatement cost, we have removed the carbon price on fossil-based generation and imports exogenously.

We performed sensitivity analyses to check the robustness of our results to variations in key assumptions, which include assuming a higher ancillary services requirement for high renewable energy penetrations, a year of poor hydropower generation, and an inability to import and export power from neighboring states (for example, because other states in WECC implement clean energy policies similar to California's)—see SI for detailed descriptions of each sensitivity case. Figure 6 shows sensitivity results based on the original 90% clean energy scenario (low-cost). Effective clean energy share and total generation cost vary only modestly under the alternative assumptions, whereas CO_2 emissions rise by up to 63%.

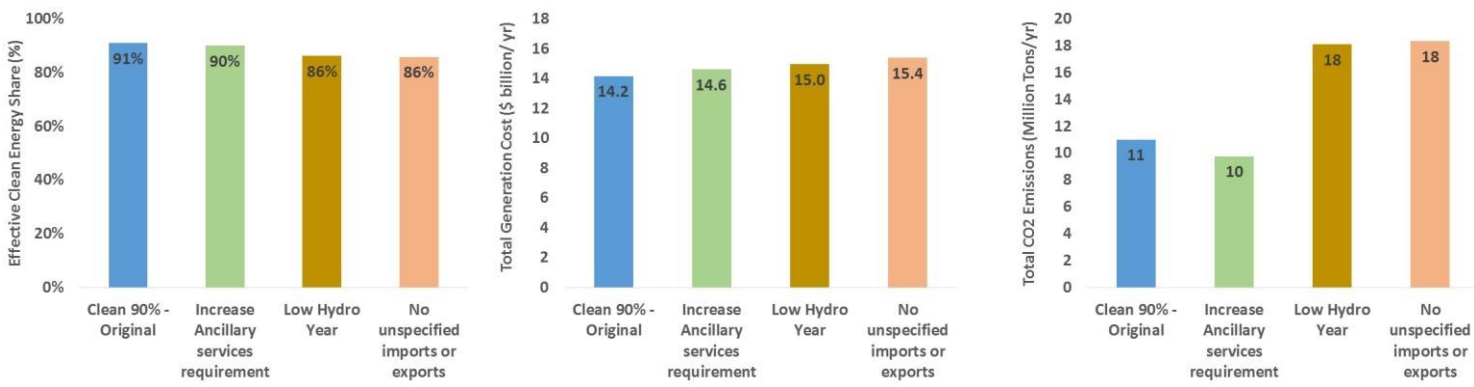
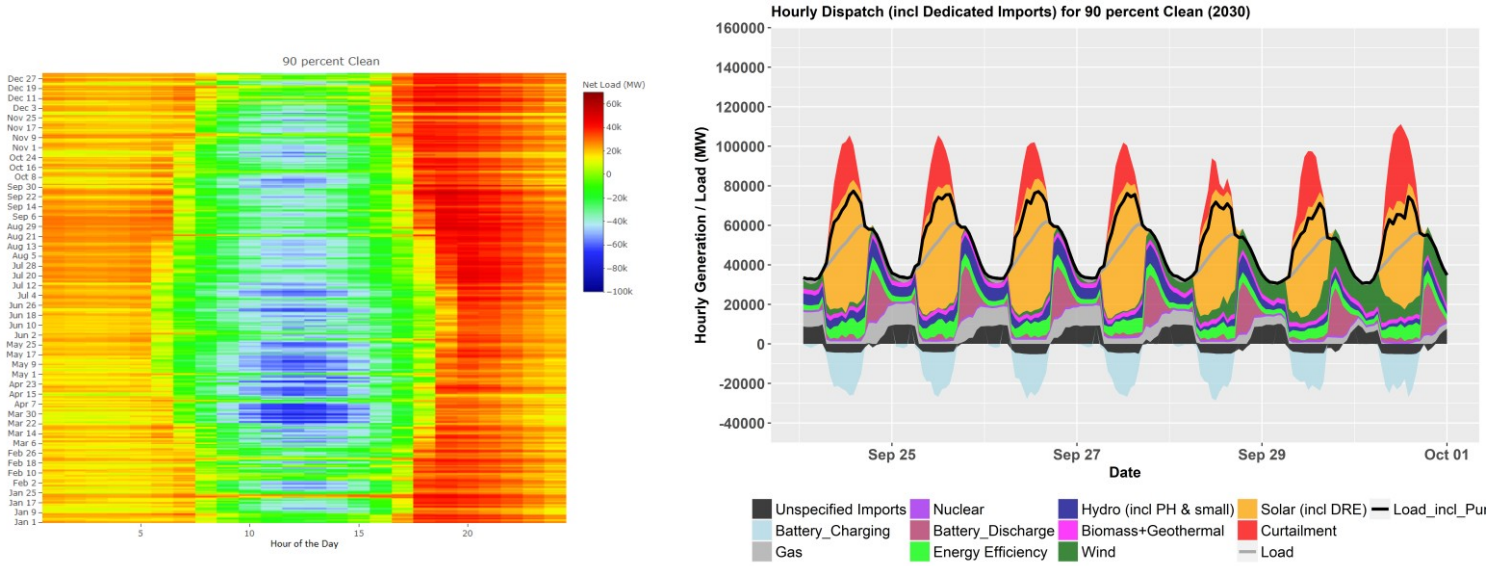


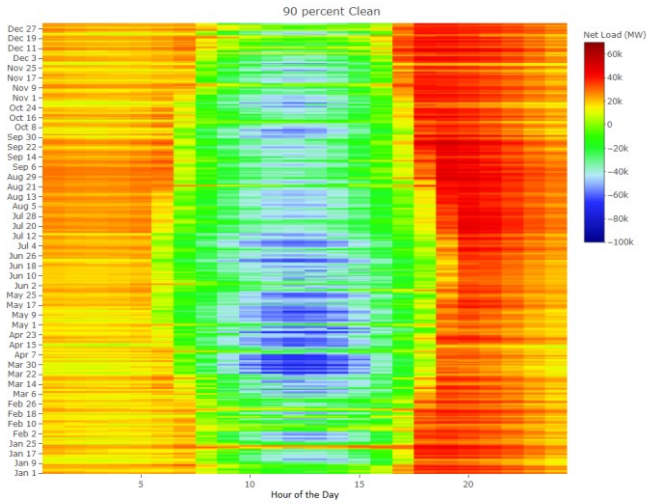
Figure 6. Sensitivity analysis on key uncertainties, 90% clean energy scenario (low cost)

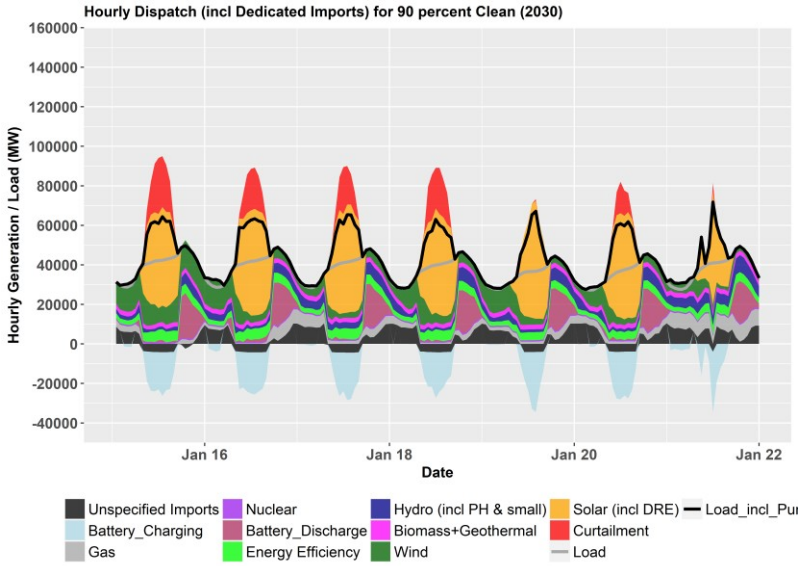
Operational Feasibility of the Decarbonized Electricity System

Production cost modeling verifies that electricity could be provided reliably during all hours of the year under our modeled decarbonization scenarios. Figure 7 shows hourly dispatch results for several important weeks under the 90% clean energy scenario, demonstrating that demand is met during the weeks with the highest and lowest hourly net load (which is defined as load minus renewable energy generation) (a and b), the week with the highest hourly gas generation (c), the week with the highest hourly unspecified imports (d), and the week with the highest hourly curtailment (e). In all our scenarios, every day during these critical weeks, more than 80% of the storage capacity is charged during solar generation hours and is fully discharged during hours when there is no solar generation, implying the battery storage is primarily used as diurnal storage (**Figure 7**f).

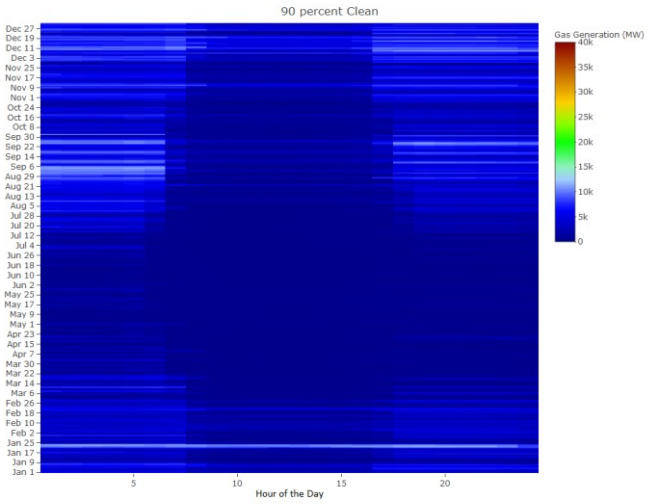


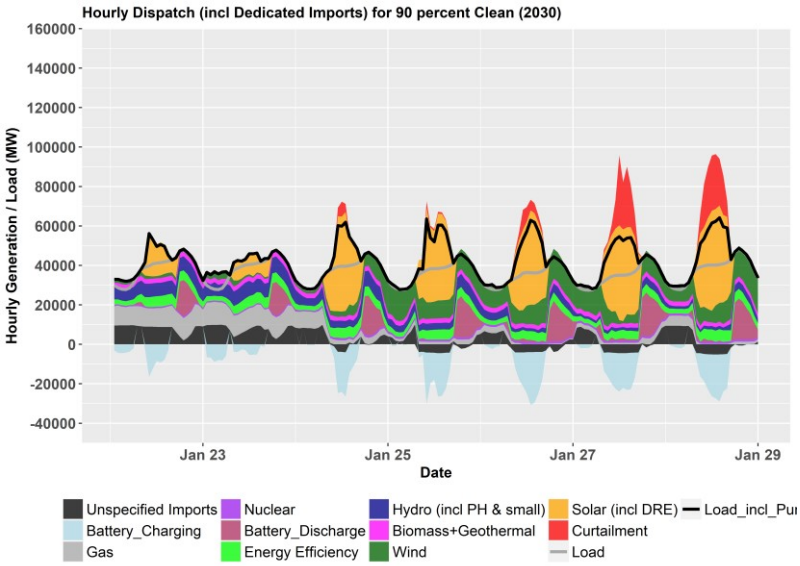
(a) Hourly net load heatmap and system dispatch during the week that has the highest hourly net load



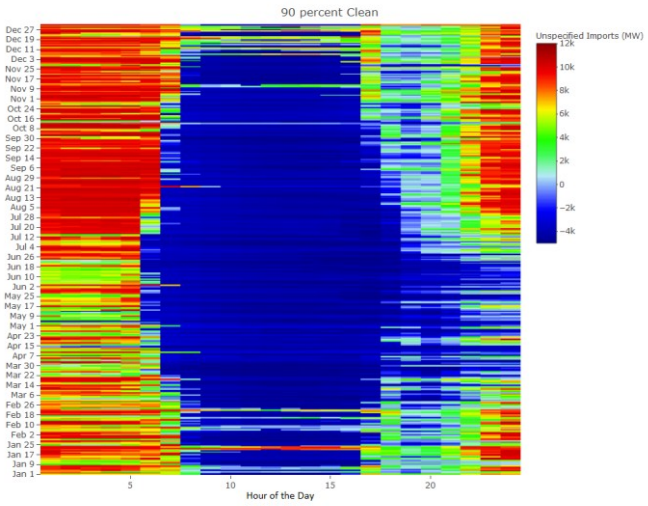


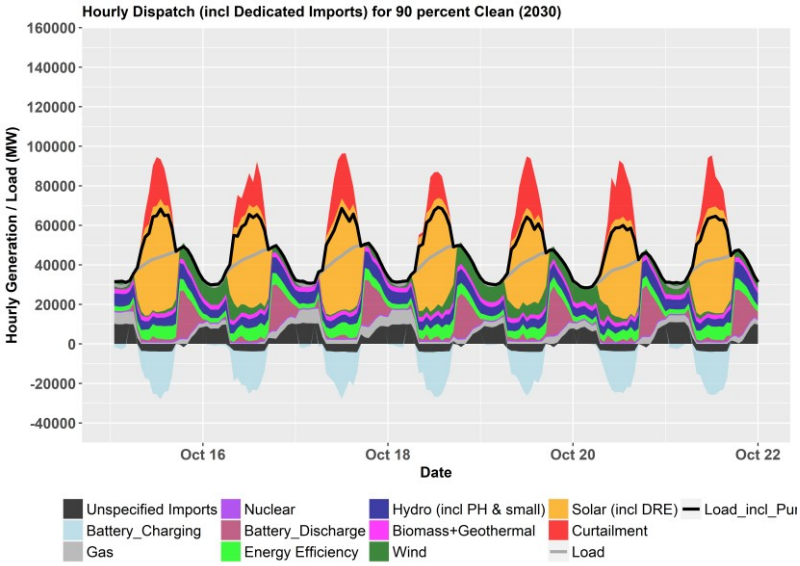
(b) Hourly net load heatmap and system dispatch during the week that has the lowest hourly net load



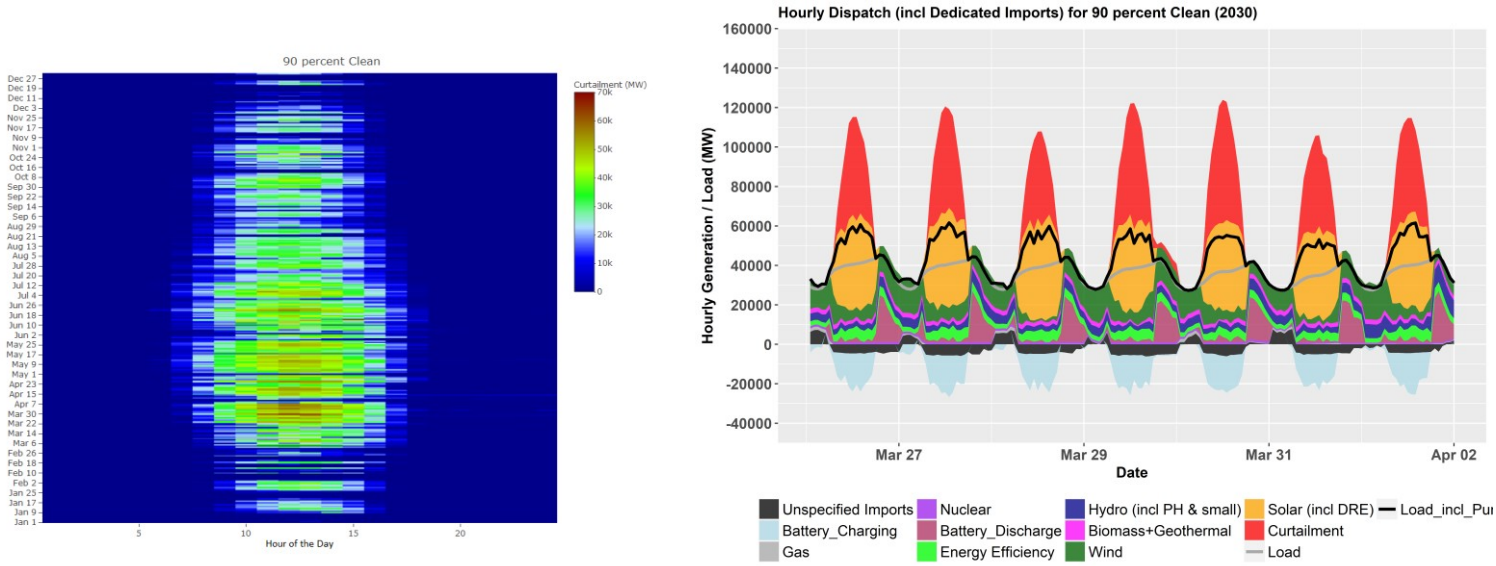


(c) Hourly in-state gas generation heatmap and system dispatch during the week that has highest hourly gas generation

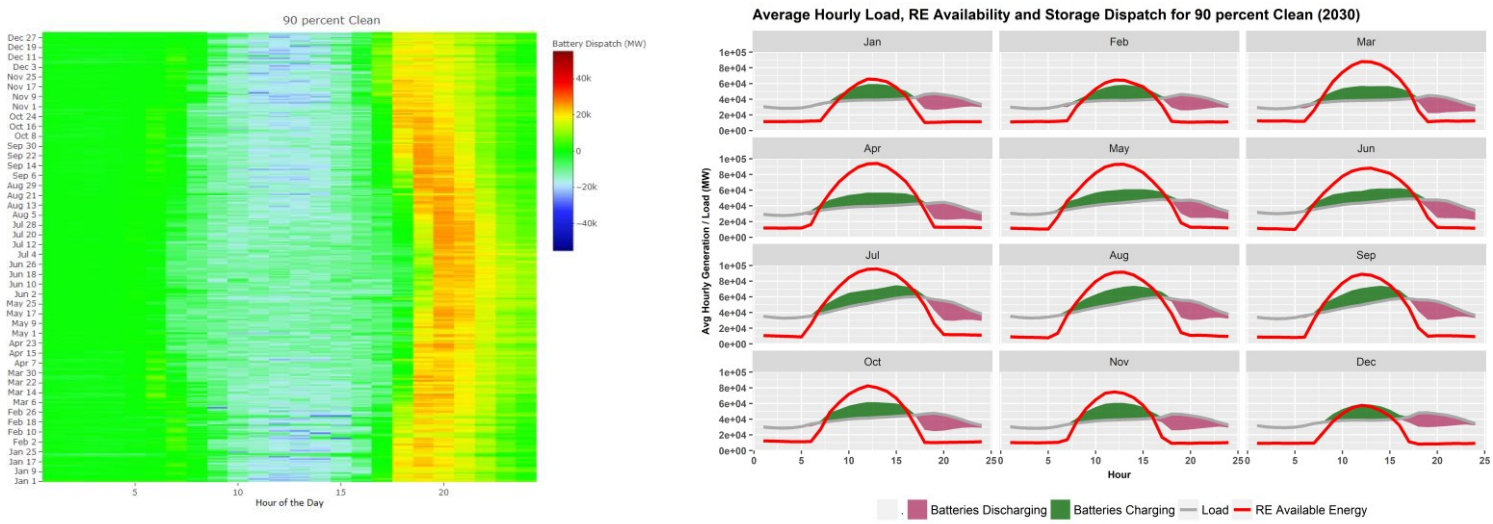




(d) Hourly unspecified imports heatmap and system dispatch during the week that has highest hourly unspecified imports



(e) Hourly renewable energy curtailment heatmap and system dispatch during the week that has highest hourly curtailment



(f) Hourly battery dispatch heatmap and average hourly load, RE availability, and storage dispatch

Figure 7. Modeled operation of California's power system with a 90% clean energy share

If solar and wind experience significantly reduced output over several consecutive days, RE generation and stored electricity may not meet demand. Such a situation does not arise in our simulation year, which represents an average weather year, and, for every hour of the year, the WECC and California power system operates reliably even if nearly 100% of California's load is met by renewable energy. However, simulating a typical year deterministically may not capture the low-probability, high-cost situation of extremely low RE generation during high demand periods that may occur once every several years. Assessing the period 1981–2015 [15] find the lowest solar output aggregated over the continental

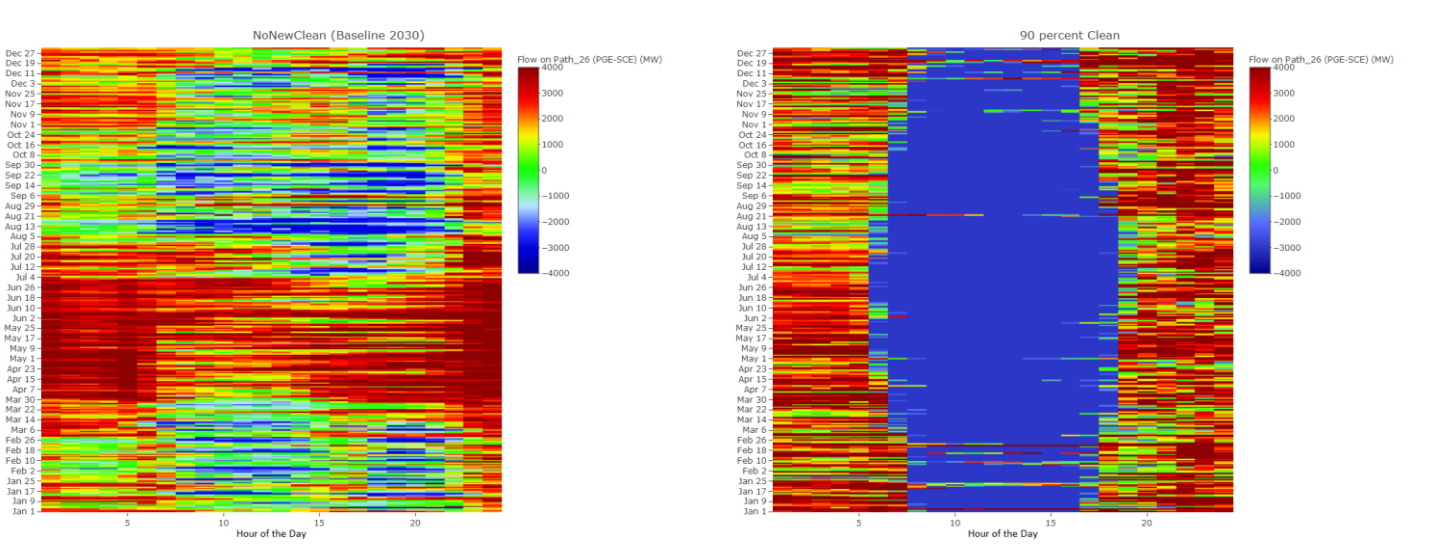
United States on any day is at most 20% lower than the mean solar output on that day of the year, whereas the wind output can be as much as 80% lower. They also find the temporal correlation in solar generation decreases relatively weakly with distance, implying limited diversity benefits of aggregation over a larger area, and that most of the benefits of aggregation accrue in an area much smaller than the state of California. Hence, as a first approximation, the solar output aggregated over California on any day likely will be at most 20% lower than the mean solar output on that day, similar to what is observed over the entire country. We identify three days during the year when the RE generation output is lowest and the net load is the highest. We then simulate dispatch by assuming solar and wind output to be 20% and 80% lower, respectively. We find that about 1.5 GW of additional gas capacity is dispatched to meet the load. California already has extensive gas generating capacity, which could serve as a backup to ensure reliable system operations during extreme events, even though this gas capacity is rarely needed. The cost of procuring 1.5 GW of additional gas capacity as backup at the current capacity prices in the resource adequacy market ($35/kW/yr) is about $53 million/year (less than 0.4 % of total generation costs). We also consider longer periods of very low solar and wind outputs and the additional costs are similar. Less expensive ways to cover for these extreme events might be available, such as demand response and electricity imports.

Ancillary services in the form of frequency response, load-following, and contingency reserves are essential to maintain system reliability and stability. Uncertainty and variability of renewable generation is likely to increase the regulating and following reserve requirements in high-renewable systems as net load forecast errors increase [16]. Contingency reserves requirements—both secondary (spinning) and tertiary (non-spinning)—generally depend on the largest generating unit on the system, which in California's case is the Diablo nuclear power plant. In a high-RE system, these contingency reserve requirements will likely remain at the same level or increase depending on the level of primary reserve response. During a contingency, the primary contingency reserve, which depends on the system's inertial response and governor control, automatically responds to changes in frequency. A high- renewable or inverter-dominated system has low inertia and thus has a smaller primary reserve response available. A contingency in a high-renewable system could produce severe frequency excursions and could cause system oscillation and stability concerns [17].

To estimate frequency, following, and contingency reserves requirements, an analysis of sub-hourly, high-temporal-resolution load and RE data as well as power system transient stability analysis are essential, both of which are beyond the scope of this study. In this analysis, we assume the same level of reserves as CAISO's 50% renewable energy penetration analysis. The overall cost of reserves provision is less than 1%–2% of total system cost across all scenarios. Although simulations of scenarios with twice the level of reserves requirement increase the cost of reserves by nearly four times, the increase in overall system costs remains below 2.5%. Also, our scenario results show adding battery storage capacity decreases the overall costs of reserves provision. Further research on strategies to ensure system stability and increase inertia in high-renewable systems is necessary to reduce the impacts of inverter-dominated renewable energy systems.

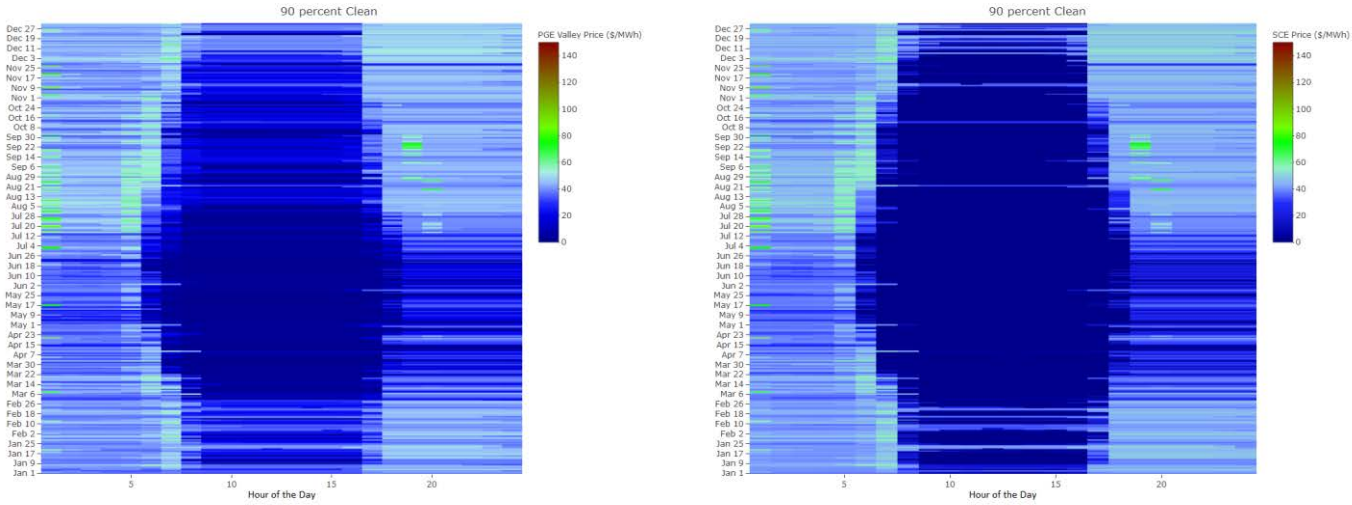
Transmission Requirements

We do not consider any additional transmission capacity over what is assumed in the CAISO database, which represents the transmission network that will exist in 2026 at the zonal level. That is, instead of modeling each individual transmission line, the WECC region is divided into 26 zones, each representing a major utility or sub-region and including current or planned interfaces (i.e., collections of multiple transmission lines) between them. All interfaces have binding limits on power flow as estimated by CAISO. Within California, there are 8 zones: Pacific Gas & Electric (PG&E) Bay, PG&E Valley, Southern California Edison (SCE), San Diego Gas & Electric (SDG&E), Sacramento Municipal Utilities District (SMUD), Los Angeles Department of Water and Power (LADWP), Imperial Irrigation District (IID), and Turlock Irrigation District (TIDC). As renewable energy penetration increases, transmission flows change significantly in 2030 (see SI). However, with the exception of Path 26 (connecting the PG&E_Valley and SCE zones), we do not find any additional congestion; during non-solar hours, path 26 tends to congest significantly more in high-RE scenarios than in the no new clean energy baseline scenario. Despite such congestion, the wholesale prices in both regions (PG&E_Valley and SCE) are significantly lower than the baseline prices, and their difference is small (less than $5/MWh), indicating that the additional transmission costs may be modest (Figure 8).



No New Clean (Baseline) 90% Clean (100 GW RE + 100 GWh storage)

(a) Path 26 flows in 2030 in no new clean (baseline) and 90% clean (100 GW RE + 100 GWh storage) scenarios



PG&E _Valley SCE

(b) 90% clean (100 GW RE + 100 GWh storage) scenario: day-ahead energy prices in PG&E Valley and SCE Zones in 2030*

Figure 8: As RE penetration increases, Path 26 (PG&E_Valley to SCE) starts getting congested, but the price differential between PG&E and SCE is small, indicating modest additional transmission costs

*Note: Weighted average price in PGE_Valley region = $26.2/MWh, in SCE region = $21.6/MWh. Weighted average prices in 2030 in the baseline scenario: PGE_Valley = $49.9/MWh, SCE = $50.1/MWh.

Stranded Assets

The use of gas generation drops by about 80%–90% in the deep decarbonization scenarios compared with the baseline scenario, 18 GW of gas capacity is never operated, and the average capacity factor of the gas fleet declines from 54% to 3%–8%. By 2030, of capacity will be more than 20 years old and thus a potential candidate for early retirement without significant stranded costs, because most will be depreciated fully. The reduced capacity factor is unlikely to have significantly adverse impacts because, by 2030, most gas generators are likely to sell power on the spot market (because their long-term PPA contracts with utilities would have expired) where prices and margins are likely to be low even in the reference and current policy scenarios, given projected excess capacity. However, further analysis of stranded assets and their implications is warranted.

Conclusions

Our study is the first to show that near-complete decarbonization of California's power sector by 2030 is feasible via additions of wind, solar PV, and energy storage, typically with cost savings or only minor cost increases compared with the costs of a no-additional-clean-energy scenario. The results are primarily driven by the current low cost trends of renewable energy and lithium-ion battery storage, which have not been accounted for in other studies to date. Thus our study informs the debate over the aggressiveness of California's power-sector policies as well as their economic and technical effects.

Perhaps most importantly, it suggests that the timeline of policy discussions about near complete decarbonization be shifted from 2050 to 2030. This is especially important because power-sector decarbonization can be the catalyst for decarbonization across all economic sectors via electrification of vehicles, buildings, industry, and so forth. Because of the global nature of renewable energy and battery markets, our study also indicates that cost-effective decarbonization could be a near-term reality for other regions and countries. However, more research is needed to definitively conclude possibilities of cost effective near complete decarbonization in the 2030 timeframe in these regions. Such rapid decarbonization, if applied by other high-emitting jurisdictions worldwide, increases the possibility of limiting global warming to 1.5 degrees C. Assessing system reliability issues such system stability in the case non-inverter based generation resources is the beyond the scope of this analysis and needs to be assessed rigorously prior to increasing the aggressiveness of power sector decarbonization policies.

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Supplementary Information (SI)

1. Methods

1.1 Data and Model

Studies assessing impacts of high renewable energy (RE) penetration on electric power systems have used various optimization tools (e.g., MARKAL, NEMS, WEM, ReEDs, SWITCH, US-REGEN, RE Note, PLEXOS), which are production cost models, capacity-expansion models, or a combination of both. Capacity-expansion models incorporate both fixed and variable costs of existing and planned generators and transmission infrastructure to choose an optimal mix of assets to meet electricity demand across future years. Production cost models simulate grid dispatch using only variable costs for a given power generation mix and transmission capacity to meet electricity demand at least cost. Typically, capacity-expansion models have lower temporal resolution and a less detailed representation of the electricity system as they optimize the system across multiple years. Production cost models have higher temporal resolution (minutes to hours) and a more detailed representation of the electricity system but typically simulate the system across only one year.

We use PLEXOS, an industry-standard optimization software by Energy Exemplar that is used by grid operators and utilities worldwide [18]. PLEXOS optimizes the unit-commitment and economic-dispatch decisions using mixed-integer programming to minimize an objective function of costs, subject to constraints including load, emissions, imports, and generator ramp rate limits. We use the Xpress-MP 28.01.13 mathematical solver for the optimization, with a mixed-integer programming gap of 0.5%. We simulate grid dispatch using only variable costs for a given power generation mix and transmission capacity to meet electricity demand at the least cost. We do not use a capacity-expansion model to optimally build future generation and transmission assets. Instead, we exogenously vary future wind, PV, and battery storage capacity to simulate several hundred scenarios and estimate system operation costs. We then account for the fixed costs of new generation and storage capacity and any potential generator retirements to estimate overall system costs and pick scenarios with lowest overall system costs to identify optimal capacity mixes. This methodology allows us to identify optimal mixes of generation and storage assets at different renewable energy targets while maintaining the detailed operational constraints of the California power system. As a cross check, we used the California Public Utilities Commission's capacity-expansion model, RESOLVE, to derive the optimal capacity mix and found largely similar results for optimal wind, PV, and storage capacity investments for 2030 [19].

Most input data on generators and transmission is from a publicly available and stakeholder-vetted database originally created by CAISO for the state's 2016 Long Term Procurement Plan (LTPP) for the year 2026 [20]. The CAISO database for the optimization covers the entire Western Electricity Coordinating Council (WECC) area and is a zonal model, such that the transmission network is aggregated as paths between utility zones and not represented with individual lines. There are 25 zones, including eight in California: Imperial Irrigation District (IID), Los Angeles Department of Water and Power (LADWP), Pacific Gas and Electric (PG&E) Bay Area, PG&E Valley, Southern California Edison (SCE), San Diego Gas and Electric (SDG&E), Sacramento Municipal Utility District (SMUD), and Turlock Irrigation

District (TIDC). A number of other studies have been conducted based on variants of the same database or earlier vintages.

For each scenario, we run PLEXOS deterministically for a full year, balancing load by dispatching generation for each hour. PLEXOS co-optimizes for energy and ancillary services to meet respective requirements and achieve a minimum cost result across the entire WECC area.

Table A1 summarizes our key assumptions about load, costs, and other parameters.

Table A1: Summary of Key Assumptions and Parameters

Parameter	Value	Details	Source
Load - California in 2030	CA total load (2030) = 273 TWh/yr; Peak Load (2030) = 56.5 GW	The load includes transmission and distribution losses. Also includes the savings due to new energy efficiency policies (SB350) and the reduction in consumption due to behind-the-meter solar PV generation.	CEC 2018 [21]
Load - WECC (non-California) in 2030	Total Non-CA WECC load (2026) = 708 TWh/yr; Peak Load (2026) = 114.2 GW	Rest of WECC load taken per CAISO's 2016 LTPP model. 2030 rest of WECC load is assumed to be the same as that in 2026.	CAISO 2016
Energy efficiency savings in 2030 (California)	38.2 TWh/yr	This is CEC forecast's mid-scenario of the Additional Achievable Energy Efficiency (AAEE) savings due to SB 350 policies. We assume that the energy efficiency programs pay for themselves and there is net additional cost or benefit associated with them. In most cases, the energy efficiency costs lower than supply side options. Therefore, our approach underestimates the net benefits of energy efficiency.	CEC 2018 [21]
Energy generation from behind-the-meter PV in 2030 (CA)	37.6 TWh/yr	CEC forecast's mid-scenario. Includes the Additional Achievable PV (AAPV) potential.	CEC 2018 [21]
Generation Capacity (2016)	Gas = 42 GW Nuclear = 1.2 GW Hydro = 12 GW Biomass = 1.3 GW Geothermal = 2.7 GW Small Hydro = 1.7 GW Solar (including behind-the-meter PV) = 9.7 GW Wind = 5.6 GW	This is the total installed capacity of all in-state generation and out-of-state dedicated imports in 2016. Excludes Diablo Canyon (PGE) nuclear plant which will be retired by 2026 and San Onofre (SCE) nuclear plant which has already been retired in 2014.	CAISO 2016

Electric vehicles	5 Million Zero Emission Vehicles (ZEVs) by 2030 Total Load in 2030 = 14.3 TWh/yr	Per California governor's executive order to have 5 million ZEVs by 2030 [Executive Order B-48-18]. 60% of the vehicles are assumed to be PHEVs while 40% assumed to be BEVs. Hourly charging load is estimated using BEAM - an agent-based mobility model. Only unmanaged charging is considered in this analysis.	Sheppard et al 2018
California Net import limit	11568 MW	Per current CAISO norms and CAISO's assumptions for their 2026	CAISO 2016
California Net export limit in 2030	2000 MW	We have relaxed the current constraint of no exports to allow for some exports in 2030. If all WECC regions follow California's aggressive RPS policies, exports may not be possible. We have run a sensitivity analysis.	CAISO 2016
Natural gas price	3.75 $/MMBTU	The projected gas price is the weighted average of the major California natural gas hubs.	CEC 2018 [21]
CO2 price in 2030	$ 25.6/ton of CO2 (estimated auction reserve price in 2030)	The auction reserve price in 2030 is estimated by increasing the 2017 auction reserve price ($ 13.57/ton) at a rate of 5% per year. The CO2 price is charged to all fossil generators located in California and to dedicated out-of-state fossil imports.	CARB 2018
Transmission network resolution	Reduced form (Zonal)	California is split into 8 zones (each representing a major utility or a region) - PG&E Bay, PG&E Valley, SCE, SDG&E, SMUD, LADWP, IID, and TIDC. The rest of WECC is split into 18 zones, each representing a major utility or a region. Refer to the map in the SI.	CAISO 2016

1.2 Load and Distributed PV Generation

The California hourly loads, additional energy efficiency savings due to Senate Bill 350, and distributed rooftop PV estimates for the analysis were taken from California Energy Demand (CED) Forecast (2018–2030) developed by the California Energy Commission (CEC) [21]. Hourly electric vehicle charging profiles (unmanaged) were taken from our previous study that uses BEAM, an agent-based model of the charging behavior by vehicle owners (Sheppard et al. 2018). Because 2030 hourly load forecasts for non-California utilities were unavailable, we used their 2026 load forecast per the WECC Transmission Expansion Planning Policy Committee's (TEPPC's) 2026 Common Case.

1.3 Scaling Up of RE Generation

For this analysis, we start with the RE portfolio data (Table 2) that CAISO forecasted to meet the 50% RPS, which is part of our "current policies" scenario. For scenarios with deeper clean energy penetration, we start with the total load (customer load plus estimated battery-charging load assuming

1 cycle/day) and estimate the clean energy target in TWh/yr for that scenario. For example, if total load is 400 TWh/yr, then for the 80% clean energy scenario the clean energy target would be 320 TWh/yr. We then estimate the generation/load reduction from non-RE clean sources: savings due to new energy efficiency policies (SB 350), hydro generation and out-of-state imports, nuclear out-of-state imports, and distributed PV generation. To estimate the RE target, we subtract the non-RE clean contributions from the overall clean energy target for that scenario (Table 2). Note that non-solar and non-wind clean energy generation is assumed to be the same across all scenarios (except the No New Clean). The RE generation target is then split into solar and wind in the same ratio as that in the current policies scenario (Table A2 and A3).

Table A2: Method for Determining the RE Generation Targets in 2030 in the Deep Decarbonization Scenarios

	No New Clean Baseline	Current Policies	Formula	80% Clean	100% Clean
Customer Load in 2030	349,220	349,220	A	349,220	349,220
Approximate batteries charging load (including efficiency loss)	-	1,825	B	50,751	50,751
Total Load in 2030	349,220	351,045	C = A + B	399,972	399,972
Clean Energy Target %	-	-	D	80%	100%
Clean Energy Target for 2030 GWh/yr			E = D * C	319,977	399,972
Energy efficiency saving from new policies by 2030 (SB-350)	-	38,183	F	38,183	38,183
Distributed Solar PV Generation in 2030	7,380	37,552	G	37,552	37,552
Estimated large hydro generation and imports	35,854	35,854	H	35,854	35,854

Estimated nuclear imports	8,168	8,168	I	8,168	8,168
Total non-RE Clean generation	51,402	119,757	J = F + G + H + I	119,757	119,757
Total RE Generation Target			K = E - J	200,220	280,214
Biomass/Biogas	6,362	7,883		7,883	7,883
Geothermal	12,975	12,975		12,975	12,975
Small Hydro	3,958	4,909		4,909	4,909
Solar	18,936	56,673		125,984	189,261
Wind	20,188	30,158		48,468	65,185

Note: All numbers are in GWh/yr unless otherwise stated

Table A3: In-state Installed Capacities by 2030 (MW)

	2016 (Actual) - No New Clean Baseline	Current Policies	80% Clean	100% Clean
Natural Gas (incl CHP)	36,192	36,192	36,192	36,192
Coal	-	-	-	-
Nuclear	-	-	-	-
Large Hydro	11,556	11,556	11,556	11,556
Biomass	1,325	1,608	1,608	1,608

Geothermal	2,694	2,694	2,694	2,694
Small Hydro	1,743	2,086	2,086	2,086
Solar (includes thermal, distributed PV, and imports)	9,868	39,248	47939	72017
Wind (incl imports)	5,644	7,907	12295	16536
Batteries	-	1,325	12,500	25,000

The renewable energy target for each resource type is further split into each utility zone using the same ratio as in the current policies scenario. The RE targets, especially for solar, within each utility zone are well below the total resource potential for that utility, estimated using the public RPS Calculator tool provided by the California Public Utilities Commission (CPUC) and the tool creator Energy and Environmental Economics (E3) [22]. Also, most of the potential lies on the flat part of the resource supply curve, indicating that their resource costs may not be very different. Note that the RE numbers shown in Table A2 and A3 are only the "targets." If there is overgeneration in the system and the model cannot back down any conventional power plants, some RE generation would have to be curtailed. Therefore, actual RE "generation" would be lower than these targets.

1.4 Conventional Generation, Stationary Storage, and Other Grid Assumptions

We include the conventional thermal and hydro generators as specified in the CAISO database using data from CPUC, CAISO, and the WECC's Transmission Expansion Planning Policy Committee (TEPPC). This information includes start-up and shut-down times and costs, variable operations and maintenance (O&M) costs, fixed O&M costs, heat rate, emissions rates, and energy limits for hydropower. CAISO has also included several generic fossil generators in its database to represent authorized procurements of new plants in California expected to be built by 2025. We also include 1,325 MW of stationary storage ordered by the California storage mandate by 2020.

The regulation and load-following reserve requirements for the PLEXOS database are calculated by CAISO based on variability and forecast error in load, wind, and solar resources. Renewable generators can provide up to half of their energy as downward load-following reserves, satisfying up to half the downward load-following requirement.

Fuel prices in the CAISO database vary based on the location of the generators, using natural gas price forecasts from the CEC for California and natural gas and coal prices from TEPPC for the rest of WECC [20]The GHG price we include is $25.6/metric ton CO_2-eq, which is added to a fossil generator's variable cost of generation based on the generator's particular emissions rate. Per CAISO's methodology, for non-renewable resources imported from outside of California, except dedicated imports, a CO_2 cost adder is added to the transmission wheeling charge [23]

We constrain California's out-of-state net exports, such that exports minus imports cannot be more than 2,000 MW in any given hour [20]. We also model some dedicated imports to California entities, including from certain fossil and large hydropower resources, and 70% of out-of-state RPS renewable resources [23]. We do not model California nuclear generation, because all in-state nuclear generation is expected to be retired by 2030. We also do not include any out-of-state coal imports, because utilities are not seeking to renew their existing coal contracts beyond 2026.

2. Solar PV, wind, and storage 2017 costs and 2030 projections

2.1 Solar

To project the cost of capital cost of additional solar generation, we began with historical PPA prices, which would be the procurement cost paid by utilities. Starting with the 2006 - 2016 time series of historical U.S. average levelized [$/MWh] PPA prices for solar [24]in real 2016 dollars, we first removed the effect of the Investment Tax Credit subsidy (ITC) for each year's average price, assuming that the subsidy had reduced PPA prices on average about 25% from what they would have been otherwise [25] (Unsubsidized Price = Subsidized Price/0.75). The impact of the ITC on the PPA price is not the face value of the ITC because of a variety of factors including financing structure [25]. We calculated the average annual real reduction rate of these unsubsidized PPA prices as 17%. We assume that the rate of price reduction will slow in the future as the economies of scale and maximum achievable efficiencies are reached, and therefore future price reductions will only be 50% of the historical annual reduction rate (17%/2 = 8%). We forecast the prices for 2017 through 2030 by first starting with the unsubsidized 2016 price and applying an 8% annual reduction through 2030. We next account for the impact of the import tariff on solar panels in place for 2018 (30%) to 2021 (15%) [26]]. Approximating that panels account for about half of the overnight capital cost of a solar plant [24], we assume that the tariffs increase the total cost for solar PV by 15% in 2018 to 8% in 2021. Because no further tariffs beyond 2021 have been announced, we assume that there is no effect on the cost beyond 2021. Finally, to account for time (construction time) between the signing of a PPA contract and the RE generators' commercial online date, when the cost would begin to be applied for the utility, we lag the prices by 2 years (ie. the PPA prices as of 2020 would only be a considered a cost for the utility as of 2022). Under the above assumptions, the resulting solar cost for utilities for 2030 is 1.51 cents /kWh. This value is the 2030 solar cost assumed under the Low Cost scenario, and the 2030 solar value for the High Cost scenario is the 2017 historical PPA price (2015 price lagged two years).

2.2 Wind

As with solar PV costs, to project the cost of capital cost of additional wind generation, we began with historical PPA prices, which would be the procurement cost paid by utilities. Starting with the 2006 - 2016 time series of historical generation-weighted average levelized wind PPA prices for the Western US (the resource market for California) in real 2016 dollars [27], we first removed the effect of the Production Tax Credit subsidy (PTC) for each year's average price, assuming that the subsidy had reduced PPA prices on average about $15/MWh from what they would have been otherwise [25] (Unsubsidized Price = Subsidized Price + $15/MWh). The impact of the PTC on the PPA price is not the face value of the PTC because of a variety of factors including contract term, conversion to from tax

credit terms, and the impact on investment's the weighted cost of capital [25]. We calculated the average annual real reduction rate of these unsubsidized PPA prices as 3% (there are several years during this historical period that prices actually increased due to cost increases of the turbine components). We assume that the rate of price reduction will slow in the future as the economies of scale and maximum achievable efficiencies are reached, and therefore future price reductions will only be 50% of the historical annual reduction rate (3%/2 = 1.5%). We forecast the prices for 2017 through 2030 by first starting with the unsubsidized 2016 price and applying a 1.5% annual reduction through 2030. Finally, to account for time (construction time) between the signing of a PPA contract and the RE generators' commercial online date, when the cost would begin to be applied for the utility, we lag the prices by 2 years (ie. the PPA prices as of 2020 would only be a considered a cost for the utility as of 2022). Under the above assumptions, the resulting wind cost for utilities for 2030 is 4.53 cents/kWh. This value is the 2030 wind cost assumed under the Low Cost scenario. The 2030 wind cost for the High Cost scenario is the 2016 historical Western US PPA price (2014 price lagged two years).

2.3 Storage

Unlike with solar and wind costs, we forecasted storage costs based on the projected component costs, namely that of the battery pack and the balance of system (BOS). For historical trends (and the storage cost figure) we used the battery pack cost estimate in $/kWh terms for lithium-ion batteries from the Bloomberg New Energy Finance (BNEF) lithium-ion price survey, for 2010 to 2016 [28]. This price includes battery cells and packs. The BNEF survey also includes projections for 2017 and 2030, and we interpolate between these two years to project the battery pack prices for intervening years. Storage co-located with solar plants results in significant savings in balance of system (BOS) costs, up to 40% by one estimate [29], because the solar and storage plants share components such as the inverter. Given these savings, we assume that all of our storage is co-located with solar plants. Among the several configurations of coupling solar and storage, we assume that they are DC coupled where they share a bi- directional inverter allowing flexible charging of storage not just from PV but from the grid. Compared to an AC coupling, where the solar and storage plants do not share an inverter, there may be some lost economic opportunity because unlike the shared inverter, the AC coupling allows charging-discharging of the battery while the inverter is fully used by the solar plant. There is lost economic value if grid prices are high when solar generation is at peak and the battery cannot be discharged during these times as there is no capacity left in the shared inverter. However, this situation is unlikely to be common as grid prices are likely to be the lowest during peak solar generation hours. We find that battery is not discharged during solar generation hours and hence shared inverter is unlikely to pose any constraints on the operation of storage.

Therefore, to estimate the BOS costs, we primarily rely on BOS estimates provided in [29] ($398/kW by 2020), and also apply a cost reduction (about 40% by 2020 according to [29]) in BOS costs from building storage on-site with solar PV. Beyond 2020, we assume the same 40% cost savings for BOS costs. In order to translate the BOS costs from power terms to energy, we divide the $/kW cost by the number of hours of the battery, which we assume is 4 hours based on [29]. The sum of the $/kWh battery pack cost and $/kW $/kWh BOS cost is the overnight capital cost we assume for this study. The charging cost for storage is already included in the production cost or generation cost calculated from the system

dispatch of the batteries and the wholesale prices that result, and we therefore do not include that in the capital cost. Under the above assumptions, the resulting storage capital cost for utilities for 2030 is $134/kWh. This value is the 2030 storage capital cost assumed under the Low Cost scenario. The 2030 storage cost for the High Cost scenario is the $/kWh price calculated from the Xcel energy median bid ($11.3/kW-month * 12 months = $/kWh per year).

3. Sensitivity analysis

We conduct comprehensive sensitivity analysis to address the uncertainty in the future costs of RE, and gas based generation, generation from variable generation sources such as RE and hydro, additional load due to penetration of EVs, and ability import and export power.

3.1 Generation from RE

If solar and wind have significantly reduced output over several days, a situation could arise where there is not enough RE generation and stored electricity to meet the demand. Although we show that such situation does not arise in our 2030 simulation year and for every hour of the year, the WECC and California power system is able to operate reliably even if most of generation is from RE for the California power system. However, simulation for a typical year may not adequately capture a possibility of extremely low RE generation during high demand periods that may happen in once in several years. [15] assess the spatiotemporal solar and wind resource in the US for 35 years (1981-2015) and find that the lowest solar output on any day is at most 20% lower than the mean solar output on that day of the year whereas the wind output has been more than 80% lower. Hence, as a first approximation, the solar output aggregated over California on any day likely will be at most 20% lower than the mean solar output on that day, similar to what is observed over the entire country. We identify three days during the year when the RE generation output is lowest and the net load is the highest. We then simulate dispatch by assuming solar and wind output to be 20% and 80% lower, respectively. We find that about 1.5 GW of additional gas capacity is dispatched to meet the load. California already has extensive gas generating capacity, which could serve as a backup to ensure reliable system operations during extreme events, even though this gas capacity is rarely needed. The cost of procuring 1.5 GW of additional gas capacity as backup at the current capacity prices in the resource adequacy market ($35/kW/yr) is about $53 million/year. Less expensive ways to cover for these extreme events might be available, such as demand response and electricity imports.

3.2 Ability import and export power

In all our scenarios, at most 11,568 MW of power can be imported and 2,000 MW can be exported from California in an hour. The highest level of imports happens during winter evenings. If all the of the neighboring states follow similar policies of deep decarbonization, California may not be able to import power and export power cost effectively due to coincidence of high and potentially negative prices for import and export raising the cost of the decarbonization scenario. We estimate the upper bound of these additional costs and system requirements by fully restricting the unspecified imports and exports. In the 90% Clean scenario, if we do not allow any unspecified imports or exports, we find that about 10 GW of additional in-state gas generators would be dispatched. This increases the total generation cost

by nearly $1.2 billion/yr or ~3%. RE curtailment also increases significantly (from 22.7% in the original Clean 90% case to 25.2% in the sensitivity case) and as a result, the clean energy share reduces to 86%.

3.3 Low Hydro Year

Our model assumes the average year profile and monthly availability of hydro energy from the in-state plants and dedicated imports. Annually, we assume total hydro generation (or availability) of 38,500 to 40,700 GWh/yr (including pumped and small hydro). In 2017 (a wet or "good" hydro year) and 2016 (average hydro year), the actual hydro generation (including imports, pumped and small hydro) was 50,854 GWh/yr and 34,477 GWh/yr, respectively. In case of a drought, hydro generation reduces significantly. For example, in 2015 (one in 100 years drought in California), the total hydro generation was only 18,564 GWh/yr. We simulate a low hydro generation year by restricting the total hydro energy availability to 19,700-20,000 GWh/yr or – about 50% of the average year. In case of the 90% Clean scenario, we find that if hydro generation reduces by 50%, the share of clean energy in the total generation mix reduces to 86% and CO2 emissions increase to 18 million tons/yr (relative to 11 million tons/yr in the original scenario). The generation costs increase by 5.5% since additional gas generation or imports are needed.

3.4 Increased Ancillary Services Requirement

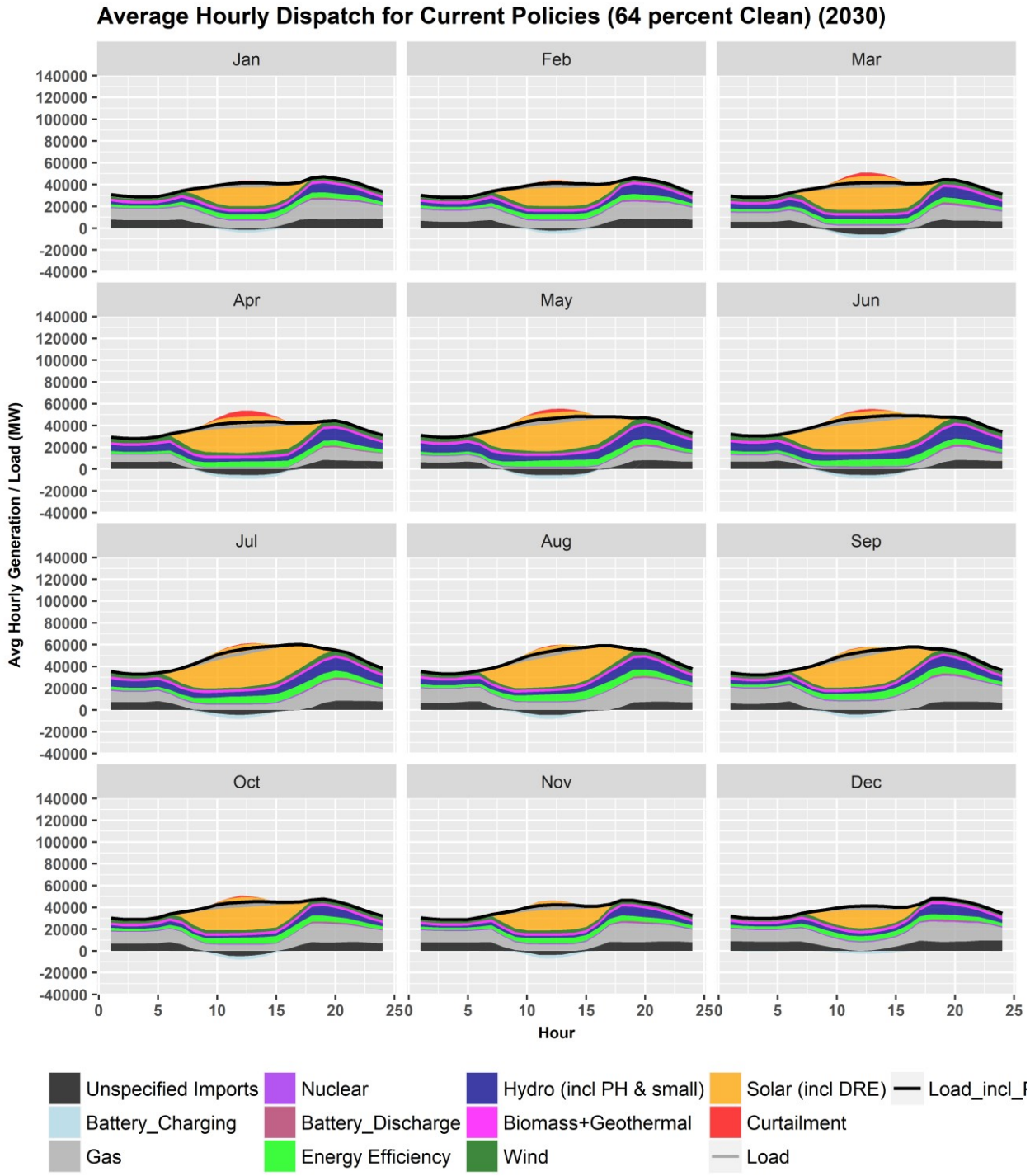
We have taken the ancillary services requirement by 2030 as planned by CAISO in their database. The CAISO estimate was based on the current policies (50% RPS or ~64% clean). However, if the RE penetration increases beyond 50%, the system may need to procure additional ancillary services. We run a sensitivity where we double the ancillary services requirement to see the impact on costs. In order to meet the additional ancillary services requirement, more in-state gas generation needs to be available. This increases the overall RE curtailment, reduces the clean energy share, and increases the costs. For example, in the 90% Clean case, if ancillary service requirement is doubled, RE curtailment increases by ~1 percentage point (from ~22.7% in the original case to ~23.8% in the sensitivity case) and the clean energy share drops to 90%. The ancillary services cost increases from the original $125 million/yr to $491 million/yr. Since ancillary services is small component (1%-2%) of the total costs, total generation cost increase by about 3% even after doubling the ancillary services requirement.

4. Capacity value of RE with storage: Implications for resource adequacy/capacity markets

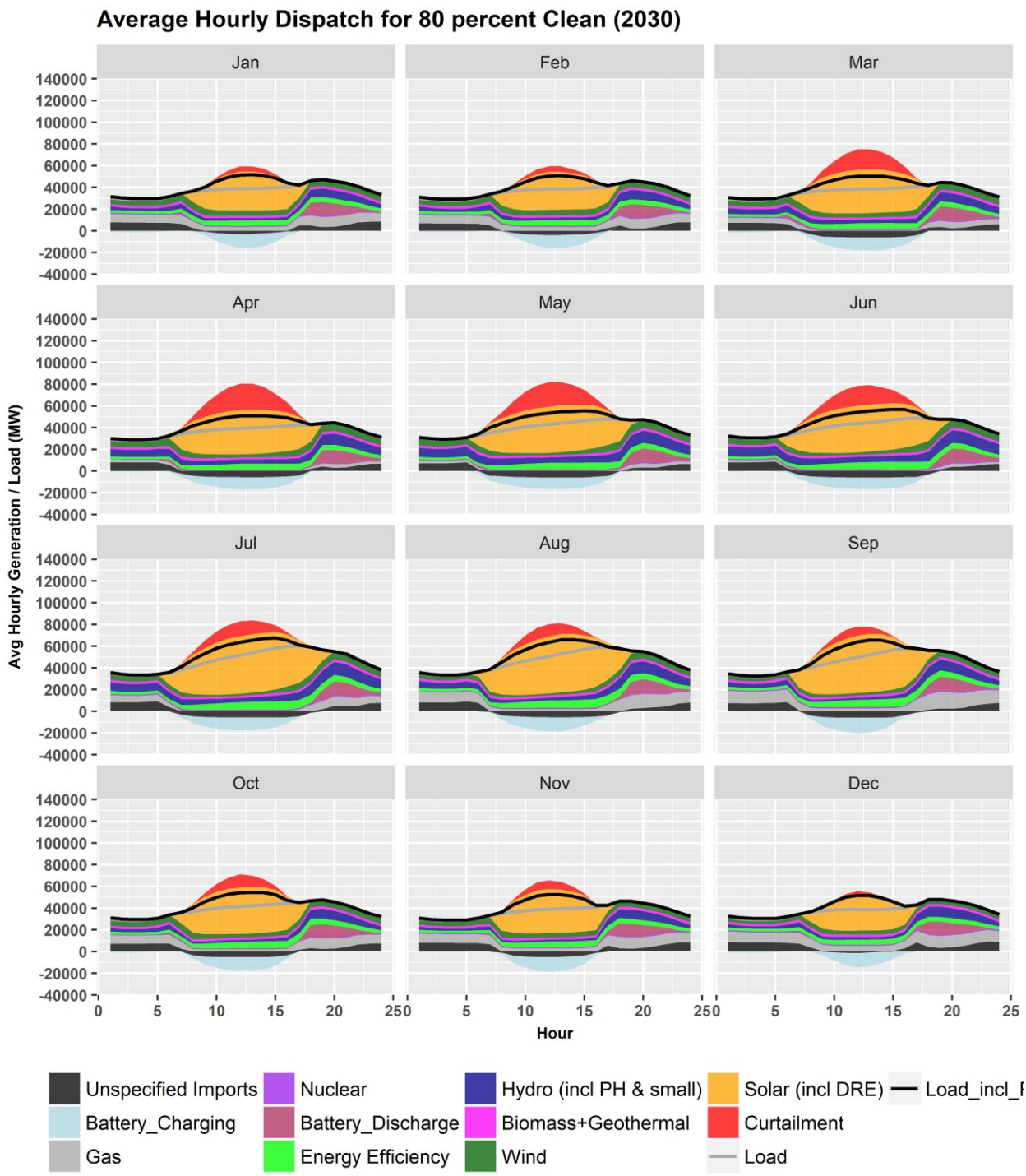
We find that to achieve more than 90% carbon free generation, it is cost effective to add about 100 GWh of storage. Given the current regulations of what qualifies as a capacity bid in the capacity market (ability to generate during the peak generation period), 100 GWh of storage can bid about 25 GW of capacity in the capacity market likely perpetuating the glut and therefore low prices in the capacity market. Given low capacity market prices, storage gets built not because it can provide capacity for meeting resource adequacy requirement but to meet carbon free generation share requirement beyond a certain threshold because it is less expensive to increase the share of carbon free generation by adding more storage than adding RE capacity.

5. Dispatch and system operations

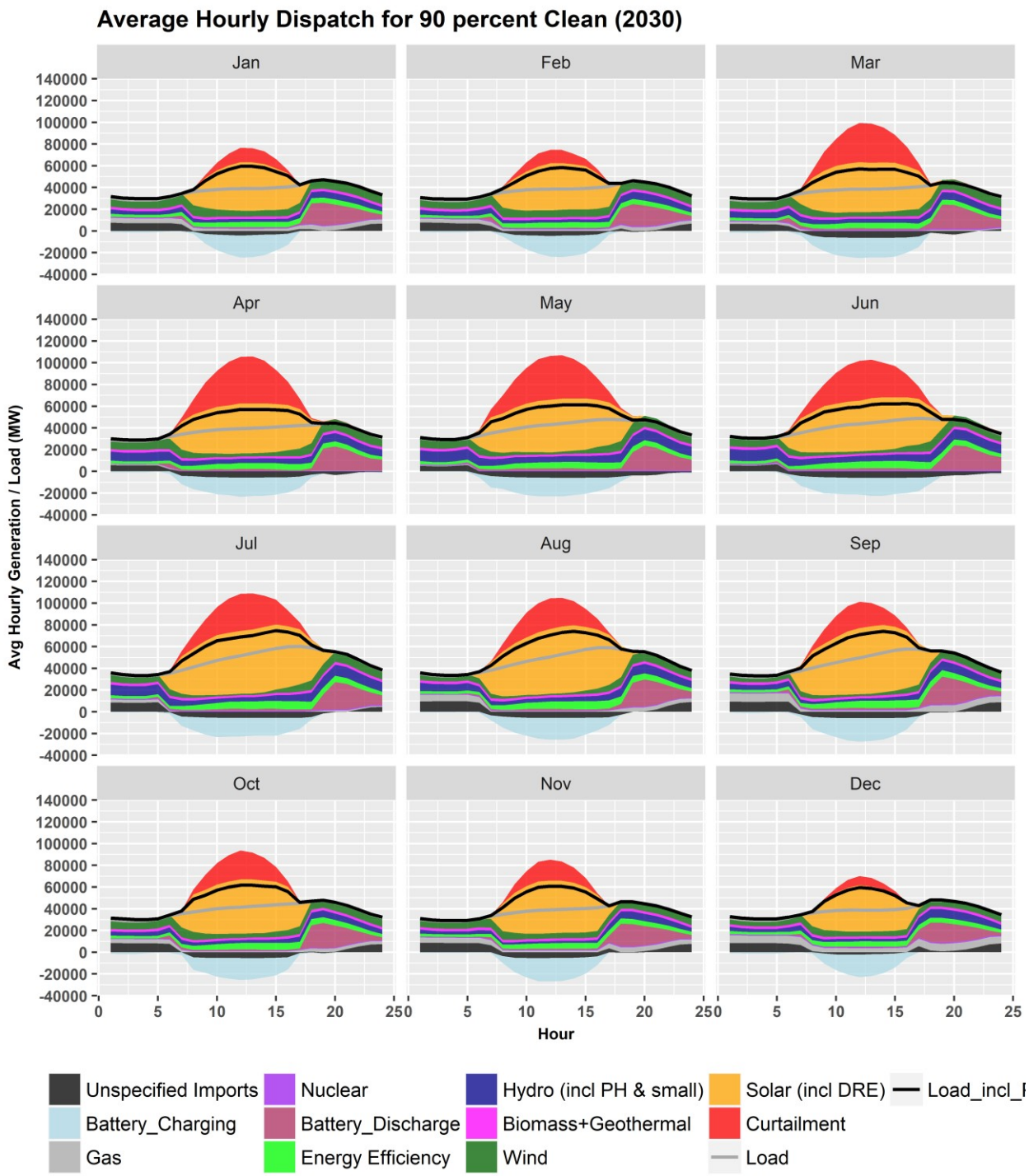
In this section, we show how the average hourly system dispatch in the key scenarios.



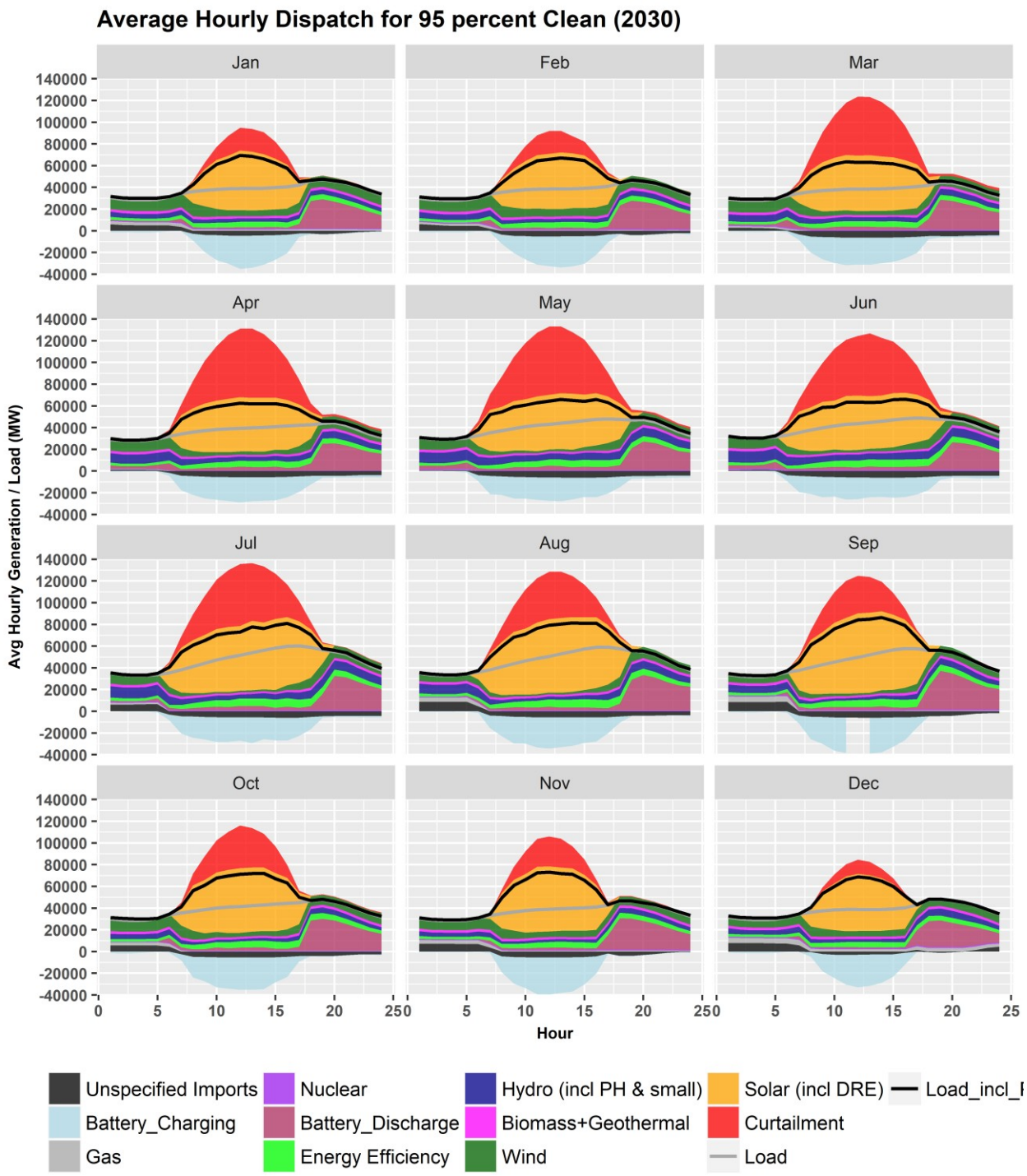
(a) Current Policies


Average Hourly Dispatch for 80 percent Clean (2030)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Avg Hourly Generation / Load (MW)
Hour
Unspecified Imports
Nuclear
Hydro (incl PH & small)
Solar (incl DRE)
Load_incl_
Battery_Charging
Battery_Discharge
Biomass+Geothermal
Curtailment
Gas
Energy Efficiency
Wind
Load

(b) 80% Clean


Average Hourly Dispatch for 90 percent Clean (2030)
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec
Avg Hourly Generation / Load (MW)
Hour
Unspecified Imports
Battery_Charging
Gas
Nuclear
Battery_Discharge
Energy Efficiency
Hydro (incl PH & small)
Biomass+Geothermal
Wind
Solar (incl DRE)
Curtailment
Load
Load_incl_

(c) 90% Clean

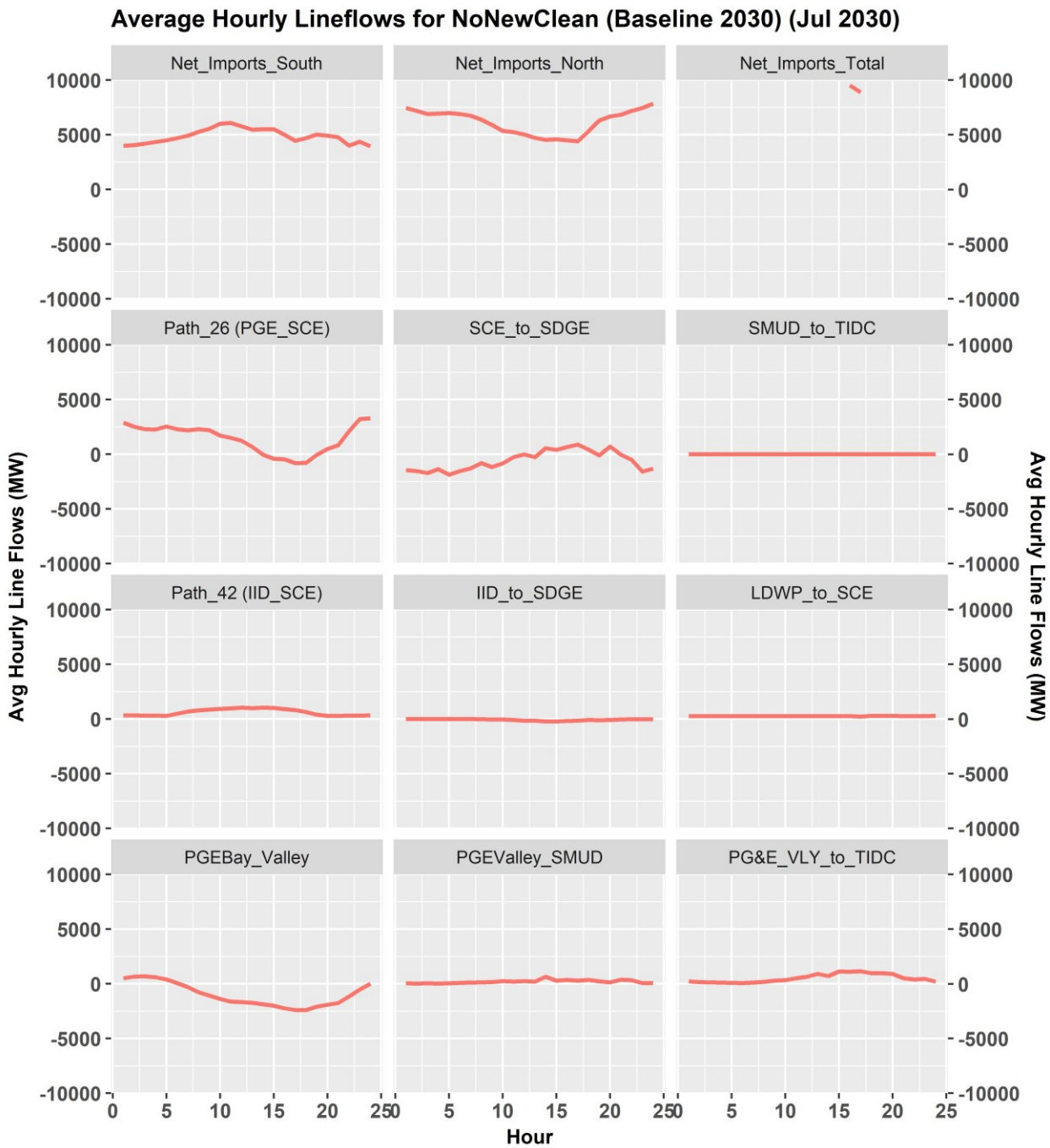


(d) 95% Clean

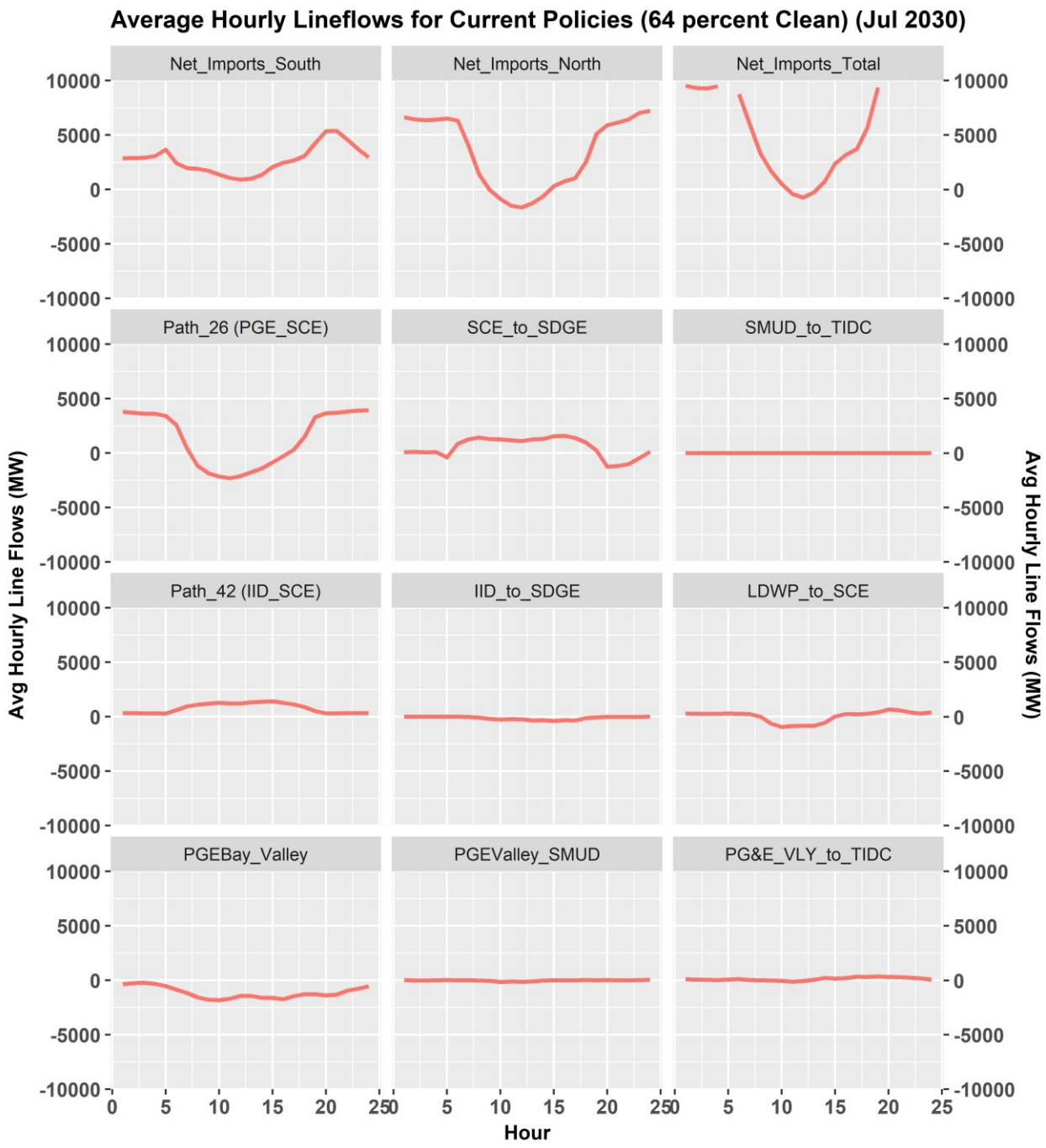
Figure A1: Average hourly dispatch for each month in key scenarios. In the deep decarbonization scenarios (90% and 95% clean), RE penetration is very high (100-120 GW) and as a result there is significant RE curtailment, especially in spring and early summer, despite adding battery storage.

6. Implications for transmission

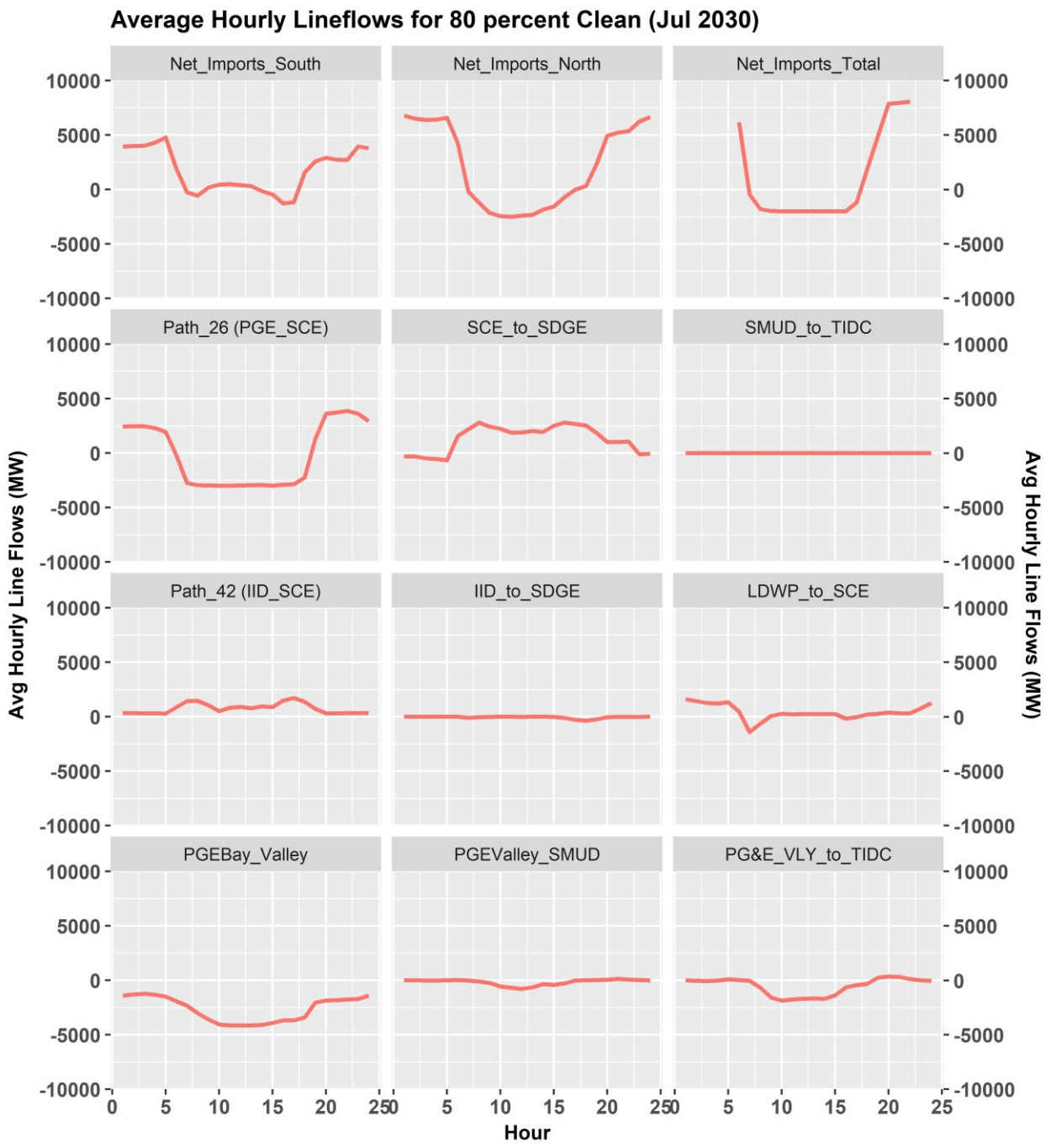
We have not assumed any additional buildout of the transmission capacity than what CAISO has already planned in their 2026 database. In Figure A2 and A3, we show the average hourly zonal flows for key scenarios for July 2030 (peak load month).



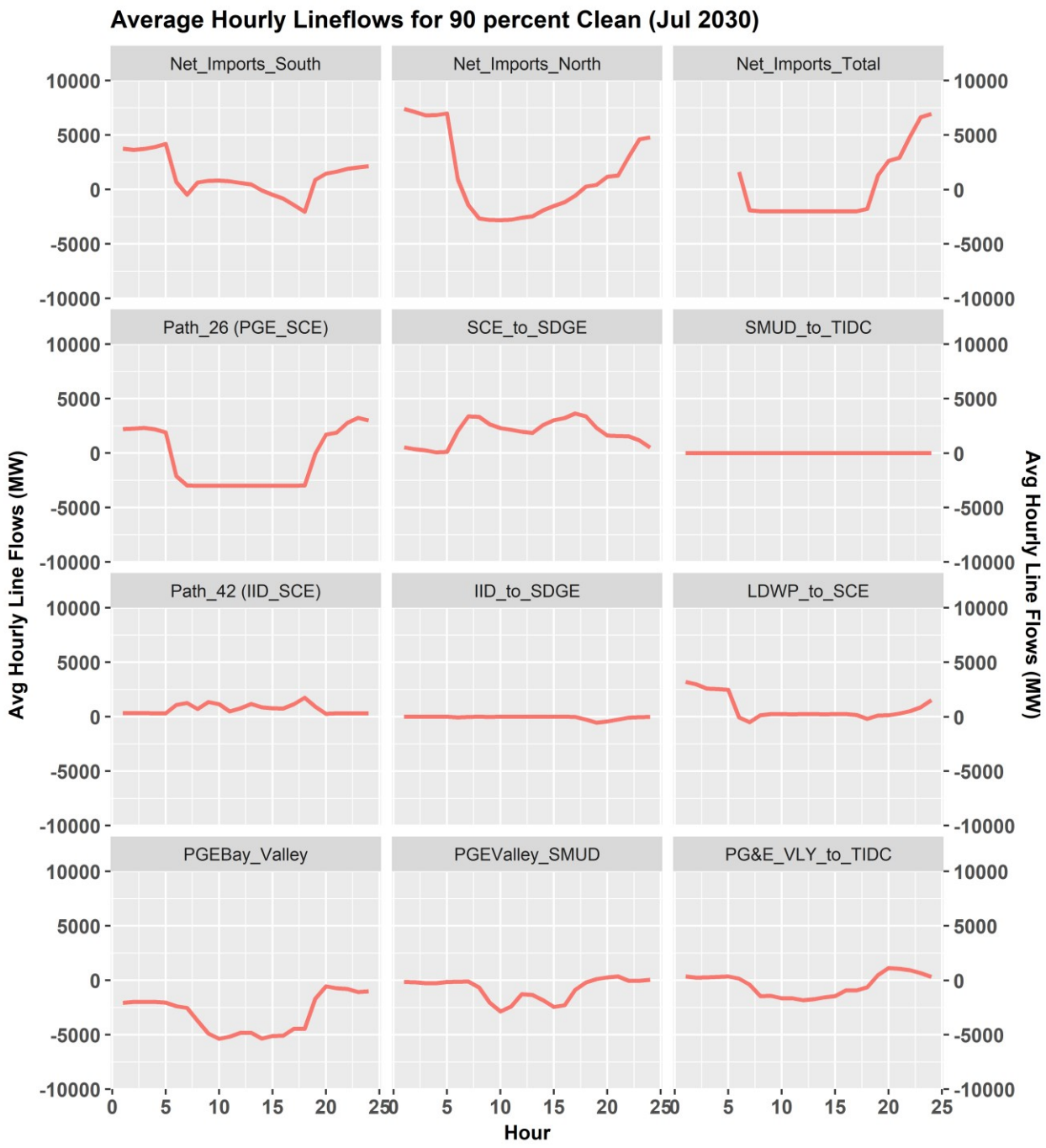
(a) No New Clean (Baseline for 2030)



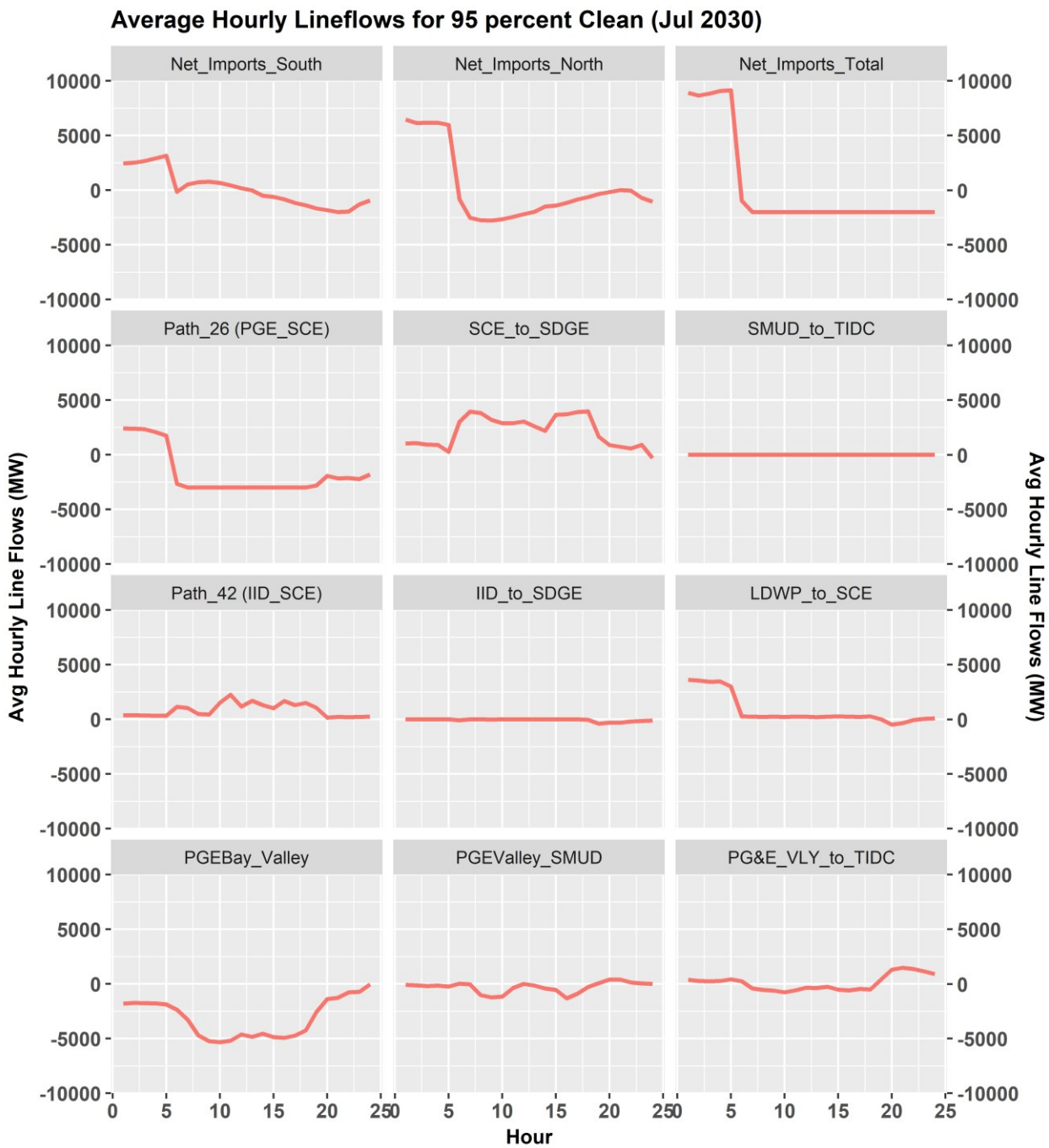
(b) Current Policies


Average Hourly Lineflows for 80 percent Clean (Jul 2030)
Net_Imports_South
Net_Imports_North
Net_Imports_Total
Path_26 (PGE_SCE)
SCE_to_SDGE
SMUD_to_TIDC
Path_42 (IID_SCE)
IID_to_SDGE
LDWP_to_SCE
PGEBay_Valley
PGEValley_SMUD
PG&E_VLY_to_TIDC
Avg Hourly Line Flows (MW)
Hour
10000
5000
0
-5000
-10000
0
5
10
15
20
25

(c) 80% Clean


Average Hourly Lineflows for 90 percent Clean (Jul 2030)
Net_Imports_South
Net_Imports_North
Net_Imports_Total
Path_26 (PGE_SCE)
SCE_to_SDGE
SMUD_to_TIDC
Path_42 (IID_SCE)
IID_to_SDGE
LDWP_to_SCE
PGEBay_Valley
PGEValley_SMUD
PG&E_VLY_to_TIDC
Avg Hourly Line Flows (MW)
Hour

(d) 90% Clean



(e) 95% Clean

Figure A2: Average hourly transfer between regions for key scenarios

Note that the net imports are restricted to 11,800 MW while the net exports are restricted to 2000 MW. As RE penetration increases, export of the excess RE generation becomes important for managing the curtailment. We find that as RE penetration increases, none of the zonal interfaces congest, except Path 26, which connects the PGE_Valley region to SCE. However, as shown in the main text, despite

congestion, the day-ahead wholesale electricity prices in both regions are found to be similar indicating only modest additional transmission needs.

7. Comparison with current generation costs

In 2016, the weighted average generation cost for the California Investor Owned Utilities (IOUs) was about 8 cents/kWh while the average retail tariff was about 15.5 cents/kWh.[3] Municipal utilities also had similar costs. For the IOUs, although the price for spot purchases was less than 3 cents/kWh, the price of power from natural gas contracts was about 15 cents/kWh whereas the price of power from renewable energy (RE) was about 12 cents/kWh, and those together constituted more than 60% of the total cost of power purchase.

Figure 3.5: Average Cost for Select Purchased Power[24]

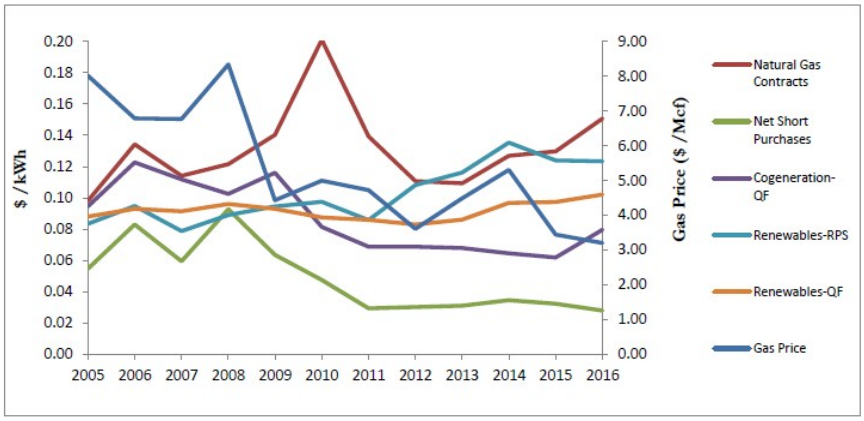


Figure 3.3: Trends in Purchased Power Revenue Requirements

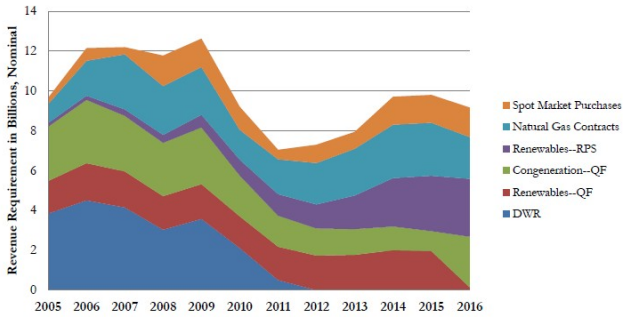
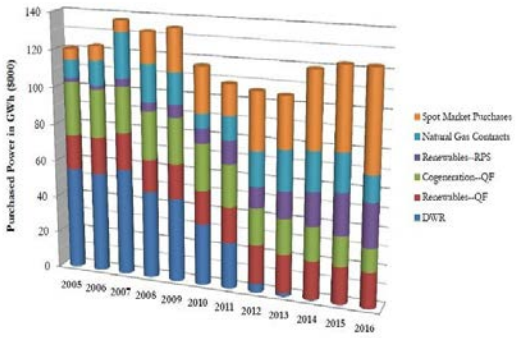


Figure 3.2: Trends in Purchased Power Supply (GWh)



[3] California Electric and Gas Utility Cost Report: http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/About_Us/Organization/Divisions/Office_of_Governmental_Affairs/Legislation/2017/AB67_Leg_Report_PDF_Final_5-5-17.pdf

[4] Add cost data on Munies ??

Figure A3: California power purchase costs in 2016

Source: California Electric and Gas Utility Cost Report

By 2030, most of the existing contracts for renewable energy (RE) and natural gas based power generation (NG) are likely to expire.

In our analysis of a 90% carbon free generation scenario in 2030, ~ 10% of the demand is supplied by hydro, 10% by gas and unspecified imports, 10% by energy efficiency (EE), and the rest 70% by wind and solar (out of which, ~ 80% is solar).

The weighted average solar power purchase agreement (PPA) price in CA in 2017 was 3 cents/kWh indicating an unsubsidized price of about 4 cents/kWh. Even if we assume no further reduction in solar prices, the price of RE in a solar dominated RE scenario is likely to be around 4.4 cents/kWh, assuming about 10% curtailment.[5] The cost of hydro power was about 3 cents/kWh in 2016 and is likely to be the same in the future. The cost EE net of the savings in transmission and distribution costs due to EE is unlikely to be higher than 4 cents/kWh. Spot purchase of gas based power in 2017 was about 3 cents/kWh and is unlikely to be higher than 4 cents/kWh in the future. Hence one plausible scenario is that the average generation cost is ~ 4.2 cents/kWh for the 90% carbon free scenario in 2030. This could be much lower if assume that RE prices continue to decline in the future.

To reach 90%+ clean generation, we find that the CA power system needs about 100 GWh of storage. The storage price revealed by Xcel energy bids is $ 20/kWh-year.[6] Assuming no further decline in costs, the annual cost storage is ~ 2 billion/year.

For meeting the peak demand of ~ 50 GW, resource adequacy requirement (with a 15% margin requirement) is about 60 GW. We find that storage enables RE to have capacity value of ~ 25GW. Hence ~ 35GW of additional capacity needs to be bought in the market. The price for capacity in the resource adequacy markets are about $ 30 kW/year.[7] Although this price of capacity is less than half of its long run marginal cost, we anticipate that that the capacity glut and therefore low capacity prices will continue for the foreseeable future because about 25 GW of additional capacity will be available due to 100 GWh of storage which will lot more than the increase in peak demand due to very modest load growth. Hence the cost acquiring this capacity is ~ $ 1 billion/year. Hence the cost of additional capacity and storage is ~ $ 3 billion/year, which is about 1.2 cents/kWh.

Hence the total generation cost are likely to be 5.5 cents/kWh, ~ 2.5 cents/kWh lower than today's generation costs which is ~ $ 7 billion/year reduction. If RE costs continue to decline and reach 2.5 cents/kWh whereas storage costs decline to $100/kWh, the total generation costs could be as low as 4

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[5] With 100 GWh storage, less than 10% of RE is curtailed indicating ~11% increase the effective cost of RE.

[6] Median bid of $11/kW-month ~ $130/kW-year. Median storage duration 6.5 hours, hence ~ $20/kWh-year - see https://www.documentcloud.org/documents/4340162-Xcel-Solicitation-Report.html

[7] 2016 Resource Adequacy Report - see http://www.cpuc.ca.gov/RA/

cents/kWh which is ~ 4 cents/kWh lower than today's generation cost ~ $10 billion lower than today's generation costs. This implies that CA is likely to be in period of declining generation costs, which potentially creates a cushion to aim for 90% clean energy generation target by 2030.