Low Carbon Grid Study: Analysis of a 50% Emission Reduction in California

Appendix: Modeling Assumptions and Results

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1 Modeling Assumptions

1.1 Portfolio

1.1.1 Baseline, Target, and Target High Solar Portfolios

Table 1 shows the renewable portfolios in the Baseline, Target, and Target High Solar portfolios. It shows the possible generation from each technology by region, assuming no curtailment.

Table 1. Renewable Portfolios

Type	Region (WECC Common Case naming convention)	Baseline generation (TWh)	Target generation (TWh)	Target High Solar generation (TWh)
Biomass	CIPB	0.6	0.6	0.6
Biomass	CIPV	6.9	8.2	6.0
Biomass	CISC	1.5	2.2	2.2
Biomass	CISD	0.4	0.4	0.4
Biomass	IID	0.0	0.1	0.1
Biomass	LDWP	0.0	0.1	0.1
Biomass	PACW	0.3	0.3	0.3
Biomass	SPPC	0.4	0.4	0.4
CSP	CISC	4.7	4.7	4.7
CSP	IID	0.1	0.1	0.1
CSP-TES	AZPS	0.0	1.0	0.0
CSP-TES	CISC	0.0	1.5	0.0
CSP-TES	IID	0.0	0.5	0.5
CSP-TES	NEVP	0.0	1.8	0.0
Geothermal	CIPV	7.5	7.5	7.5
Geothermal	CISC	2.3	2.3	2.2
Geothermal	IID	4.3	17.1	7.2
Geothermal	SPPC	1.4	1.4	1.4
Utility PV	AZPS	0.0	0.3	0.4
Utility PV	BANC	0.3	0.2	0.3
Utility PV	CIPB	0.5	1.6	2.5
Utility PV	CIPV	10.1	7.5	11.8
Utility PV	CISC	17.2	19.7	31.0
Utility PV	CISD	3.9	2.7	4.2
Utility PV	IID	2.8	4.2	6.5
Utility PV	LDWP	0.1	0.9	1.4

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Type	Region (WECC Common Case naming convention)	Baseline generation (TWh)	Target generation (TWh)	Target High Solar generation (TWh)
Utility PV	NEVP	1.6	2.6	4.1
Utility PV	PAUT	0.0	0.1	0.1
Utility PV	SPPC	3.0	1.9	3.0
Utility PV	VEA	0.4	0.5	0.7
Rooftop PV	BANC	1.5	1.5	1.6
Rooftop PV	CIPB	5.4	5.4	5.4
Rooftop PV	CIPV	3.6	3.6	3.6
Rooftop PV	CISC	8.3	8.3	8.3
Rooftop PV	CISD	1.9	1.9	1.9
Rooftop PV	IID	0.3	0.3	0.3
Rooftop PV	LDWP	2.4	2.4	2.4
Rooftop PV	PACW	0.1	0.1	0.1
Rooftop PV	TIDC	0.2	0.2	0.2
Wind	AESO	0.9	0.9	0.9
Wind	BANC	0.7	0.7	0.7
Wind	BPAT	8.1	8.1	8.1
Wind	CIPB	3.0	3.0	3.0
Wind	CIPV	2.9	3.3	3.3
Wind	CISC	9.2	18.0	18.0
Wind	CISD	0.2	0.2	0.2
Wind	IID	0.0	5.3	5.3
Wind	NEVP	0.0	0.1	0.1
Wind	PNM	0.0	7.5	0.0
Wind	WACM	0.0	11.9	11.9

CIPB - Pacific Gas & Electric Bay Area; CIPV - Pacific Gas & Electric Valley Area; CISC - Southern California Edison; CISD - San Diego Gas & Electric; IID - Imperial Irrigation District; LDWP - Los Angeles Department of Water & Power; BANC – Balancing Area of Northern California; TIDC – Turlock Irrigation District; PACW - PacifiCorp West; SPPC - Sierra Pacific Power; AZPS – Arizona Public Service; NEVP – Nevada Power; PAUT – PacifiCorp East Utah; VEA – Valley Electric Association; AESO – Alberta Electric System Operator; BPAT – Bonneville Power Administration; PNM – Public Service New Mexico; WACM – WAPA Colorado/Missouri

Because the Baseline portfolio is assumed to be an extension of existing procurement trends, there are a few regions with higher utility PV penetrations in the Baseline compared to Target portfolios.

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1.1.2 High West Penetration Portfolio

The High West penetration portfolio was applied to a number of scenarios to understand the impact of high renewable penetrations outside of California on the results of LCGS. In addition to higher renewable penetration, more energy efficiency was included and approximately one-third of rooftop PV generation included behind-the-meter storage (3 hours capacity). This is shown in Table 2.

Table 2. Load Reduction and Associated Energy Efficiency Assumptions in the High West Cases

	Annual Load (GWh)	Energy Efficiency in High West Case (GWh)	Annual Load in High West Case (GWh)	Behind-the-Meter Storage Associated with Rooftop PV (MW)
Pacific Northwest	164,000	20,100	144,000	1,850
Idaho	22,600	2,130	20,500	270
Colorado / Wyoming	92,100	11,800	80,300	1,580
Montana	11,000	386	10,700	160
Nevada	39,400	7,900	32,500	690
New Mexico	25,700	870	24,800	520
Arizona	93,600	13,100	80,500	1980
Utah	37,300	4,440	32,900	450

Table 3. Non-CA-Entitled Renewable Energy Generation in the High West Portfolio

	Annual RE Generation in Target Case (GWh)	RE Penetration in Target Case	Annual RE Generation in High West Case (GWh)	RE Penetration in High West Case
Pacific Northwest	24,200	17%	29,800	21%
Idaho	3,520	17%	4,250	21%
Colorado / Wyoming	12,600	16%	46,600	58%
Montana	1,970	18%	11,000	103%
Nevada	10,100	31%	12,700	39%
New Mexico	3,460	14%	13,100	53%
Arizona	12,200	15%	25,600	32%
Utah	1,830	6%	7,730	24%
Total	**69,880**	**16%**	**150,780**	**35%**

RE includes CSP, Wind, Biomass, Geothermal, and utility PV and distributed PV.

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Table 4. Renewable Generation by Type in the High West Portfolio

	Annual RE Generation in Target Case (GWh)	RE Penetration in High West Case	PV Penetration (%)	Wind Penetration (%)	Other Penetration[1] (%)
Pacific Northwest	29,800	21%	6.4%	10.3%	3.9%
Idaho	4,250	21%	5.9%	11.7%	3.1%
Colorado / Wyoming	46,600	58%	12.8%	44.4%	0.8%
Montana	11,000	103%	6.0%	97.3%	0.0%
Nevada	12,700	39%	7.7%	11.5%	19.7%
New Mexico	13,100	53%	18.7%	29.7%	4.6%
Arizona	25,600	32%	19.1%	4.3%	8.5%
Utah	7,730	24%	15.0%	5.8%	2.7%
Total	**150,780**	**35%**	**11.4%**	**18.7%**	**5.2%**

1.2 Electric Vehicles

Electric vehicles (EVs) represent a significant opportunity to reduce petroleum consumption. Furthermore, the California electricity system must bear a larger burden of total end-use energy to realize its long-term emissions reductions goals, likely including EVs (Williams et al. 2012). EVs create new load for the electricity system, and we consider this load as partially fixed and partially flexible, following previous studies (Appendix K of Renewable Electricity Futures Study).

To project total EV load in 2030, we extrapolate the California Energy Commission's (CEC's) High EV demand projection for 2024 (7,800 GWh) to 12,900 GWh in 2030 (Kavalec et al. 2013). At a composite daily average charging rate of 12 kWh/day, this corresponds to three million EVs on the road. The geographic distribution of the vehicles follows Melaina et al. (2014).

[1] CSP, Biomass, and Geothermal

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Table 5. Location of EV Load

Study Area	Balancing Authority	% of Total CA EVs
Southern CA	SCE	46.1%
Bay Area	PG&E Bay	24.7%
San Diego	SDGE	9.1%
Capital Area	SMUD	5.1%
Coachella Valley	SCE	4.3%
San Joaquin Valley	SCE	4.1%
Central Coast (S.)	LDWP	3.0%
Central Coast	PG&E Valley	1.6%
Monterey Bay	PG&E Valley	1.4%
Upstate	PG&E Valley	0.3%
North Coast	PG&E Valley	0.2%
	Total	**100%**

We assumed that half of EVs would exhibit fixed vehicle charging profiles, meaning that charging would occur on a predetermined schedule. Of the fixed-profile vehicles, 60% would follow an "unmanaged" charging pattern in which the EV is plugged in immediately after the vehicle is parked at the end of the day and charging continues until complete, or until another trip begins. The other 40% of fixed-profile vehicles follow an "opportunity" charging pattern in which charging infrastructure is prevalent enough such that the vehicle is plugged in whenever the vehicle is not in motion. Figure 1 illustrates the daily charging profiles for these two types of vehicles.

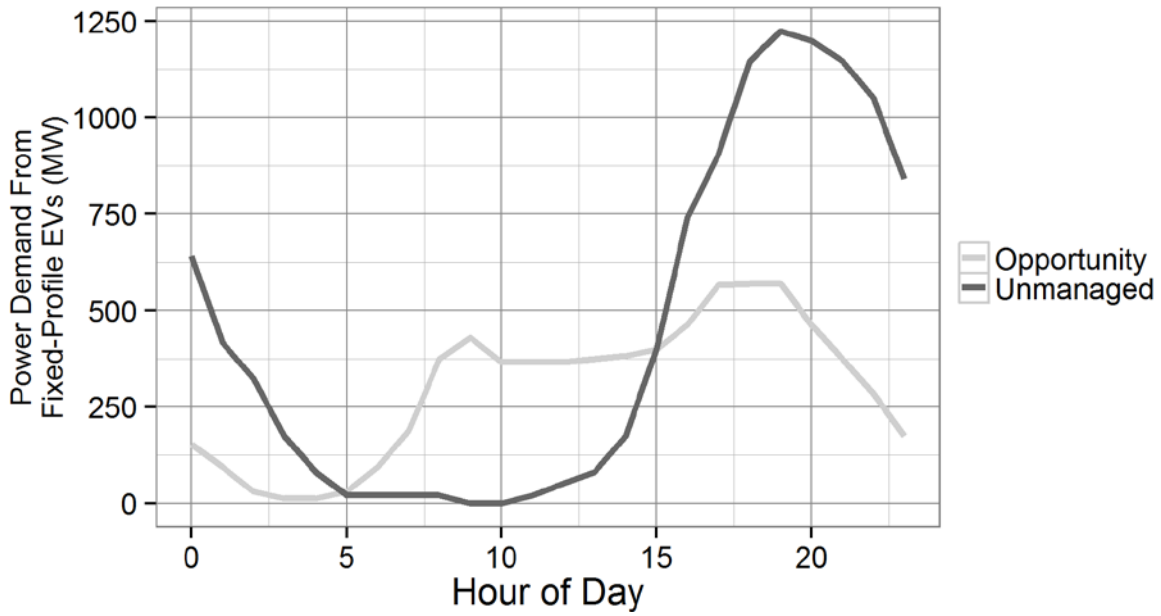

Figure 1. Charging profile for fixed-profile EV fleet in 2030

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Half of EVs did not exhibit a fixed charging profile. This 'flexible' EV load is considered a resource for the utility and the charging occurs when it is the most advantageous from the utility's perspective. In practice, the 'flexible' EV could either have its charging scheduled by the utility or respond to time-of-use electricity prices. From the perspective of the simulation, the flexible EV creates a demand that must be met during the day, but with no constraints on when it must be met, aside from the max power constraints of the EV battery itself. The rate of charge varies by time of day. We assume a 1 kW per vehicle charging rate overnight, meaning that most vehicles will be charging on a standard household 120-volt outlet, and that only a fraction of vehicles will be plugged in at any time. During the daytime, however, vehicles are assumed to be charging at 240-volt services at workplaces or businesses leading to a 2 kW/vehicle maximum rate.

The charging profiles for the flexible load are determined by the model. In contrast to the fixed-profile EVs shown in Figure 1, the charging profiles for the flexible EVs are an output of the model rather than an input. Despite the variation in load patterns, seasonal weather, and underlying assumptions in each of the scenarios modeled in this study, the optimized EV demand is predictable. Figure 2 shows the average daily charging profile for the Target case, in which EV demand occurs almost exclusively in the middle of the day when solar generation is high and drops off before the evening demand peak. Although the effect of schedulable EV load is not specifically analyzed here, increasing daytime EV demand ostensibly helps mitigate over-generation during the midday hours.

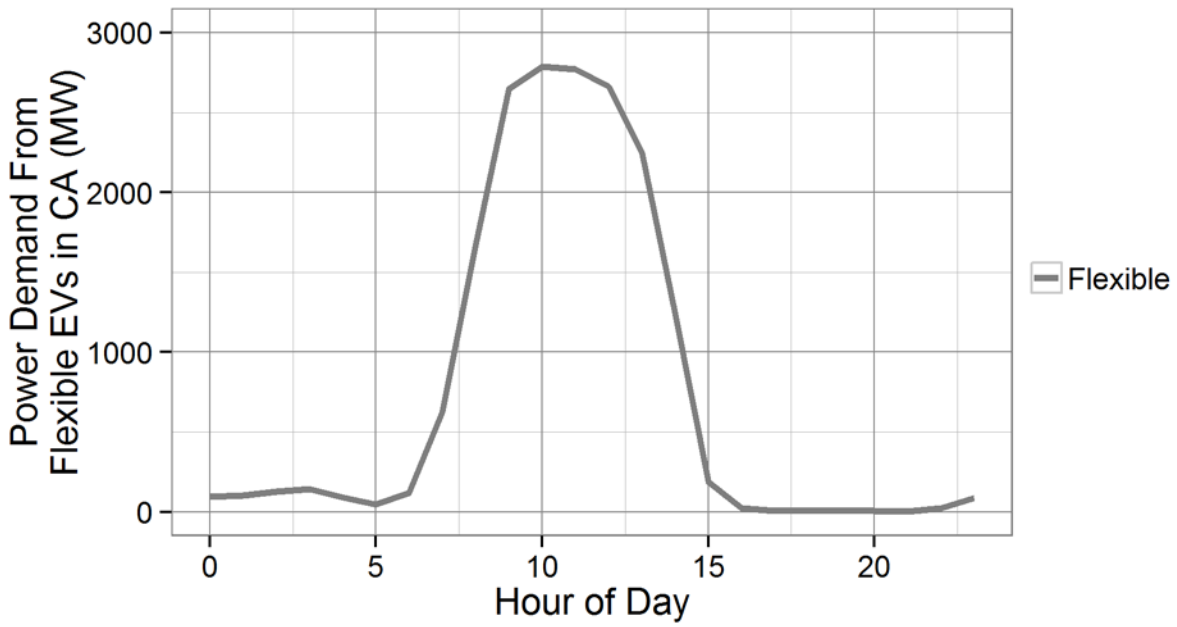

Figure 2. Charging profile for flexible EV fleet in 2030, which represents utility-controlled charging or price-responsive charging behavior

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1.3 Energy Storage

Energy storage can deliver electricity to the grid during times of need and store it during periods of abundant generation. In addition to energy arbitrage, storage may provide other grid services such as ancillary services (Kirby 2012; Denholm et al. 2013). The California Public Utilities Commission (CPUC) has mandated certain energy storage procurement targets by 2020 (CPUC 2013). We follow the modeling assumptions of TEPPC 2024 which adds 1,300 MW of energy storage in accordance with the ruling, with the following properties:

1. 550 MW have a two hour discharge duration (thus storing 1,100 MWh of energy), 83% round-trip efficiency
2. 520 MW have a four hour discharge duration (thus storing 2,080 MWh of energy), 83% round-trip efficiency
3. 220 MW have a six hour discharge duration (thus storing 1,300 MWh of energy), 83% round-trip efficiency

In reality, some portion of these storage devices will be behind-the-meter and therefore not directly controlled by the utility. Therefore, we allow only half of the storage capacity to provide ancillary services (regulation, load-following, and spinning contingency reserves).

In addition to the mandated storage procurement, we assume 1,000 MW of new pumped hydro storage (PHS) development in all Target scenarios with enhanced flexibility assumptions. The PHS facility is assumed to be located in the service territory of Southern California Edison, and has six hours of discharge duration with a round-trip efficiency of 76%. The generator has a minimum generation level of 400 MW and the pump has a minimum pumping level of 400 MW. In the Enhanced Demand Response and Storage case, the capacity of the pumped hydro storage facility is doubled.

In all Target scenarios with enhanced flexibility assumptions we also assume 1,200 MW of out-of-state storage development. Specifically, we implement a compressed air energy storage (CAES) facility at the location of the current Intermountain Power Plant in Utah.

1.4 Demand Response

Demand response is a method by which electric demand from various end-uses can be shifted in time to increase the correlation between demand and generation availability. In this study, we only include the load-shifting ability of demand response resources and not the ability of load to provide other grid services, such as regulation or spinning reserves (as documented in Olsen et al. 2013 and Hummon et al. 2013).

Table 6 shows the breakdown of the demand response by end use in all cases except for the enhanced demand response and storage case. In total, the responsive loads can shift 2.5% of total California load. It is worth noting that the largest modeled end use, electric vehicles, do not actually reduce load at any time since we did not assume any ability of the utility to draw upon the energy stored in grid-connected EV batteries.

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Table 6. Classification of California Demand Response by End Use in all Cases except the Enhanced Demand Response and Storage Case

End Use	Annual Shiftable Demand (GWh)	% Of Annual CA Load	Max Load Reduction in Target Enhanced Scenario (MW)	Load Reduction During Top 20 Load Hours (MW)	Max Load Increase (MW)
Agricultural Pumping	353	0.11%	92	65	184
Data Centers	276	0.09%	31	31	63
Refrigerated Warehouses	35	0.01%	8	6	16
Residential Water Heaters	201	0.06%	50	17	100
Wastewater Pumping	47	0.01%	5	5	10
Commercial Cooling	269	0.08%	442	380	443
Commercial Heating	9	0.003%	20	0	20
Municipal Pumping	31	0.01%	13	7	13
Residential Cooling	349	0.1%	474	381	474
Electric Vehicles (see section above)	6,500	2%	N/A	N/A	3,000
Total (non-coincident)	8,070	2.5%	1,140	905	4,320

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Table 7 shows the breakdown of the demand response by end use in the enhanced demand response and storage case. In total, the responsive loads can shift 5.2% of total California load, approximately double compared to the regular cases (non-EV demand response increases from 0.5% to 3.2%). The reduction of load during peak load hours is about seven times greater than in the regular cases, much larger than the overall doubling because the non-EV demand response is much more effective at peak mitigation.

Table 7. Classification of Demand Response by End Use in the Enhanced Demand Response and Storage Case

End Use	Annual Shiftable Demand (GWh)	% Of Annual CA Load	Max Load Reduction in Target Enhanced Scenario (MW)	Load Reduction During Top 20 Load Hours (MW)	Max Load Increase (MW)
Agricultural Pumping	2,400	0.75%	614	623	921
Data Centers	1,150	0.36%	131	157	156
Refrigerated Warehouses	620	0.2%	117	124	164
Residential Water Heaters	1,610	0.50%	139	122	400
Wastewater Pumping	161	0.05%	18	21	21
Commercial Cooling	1,020	0.31%	1,790	1,450	1,790
Commercial Heating	42	0.01%	82	0	85
Municipal Pumping	120	0.04%	52	28	52
Residential Cooling	3,900	1.2%	5,750	3,670	5,750
Electric Vehicles (see section above)	6,500	2%	N/A	N/A	3,000
Total (non-coincident)	17,500	5.2%	8,690	6,350	12,300

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Figure 3 illustrates the ability of demand response to shift load in all cases except for the enhanced demand response and storage case. Note that demand response tends to reduce the evening peak in the summer, shifting load to the middle of the day and overnight. During the off-peak seasons, however, demand response actually creates a new peak in the middle of the day to provide demand when generation from solar resources is high but total load is low. Figure 4 shows the more aggressive behavior of demand response in the enhanced demand response and storage cases. Most noticeably, some of the summer evening cooling load is shifted to mid-day and other load is shifted overnight.

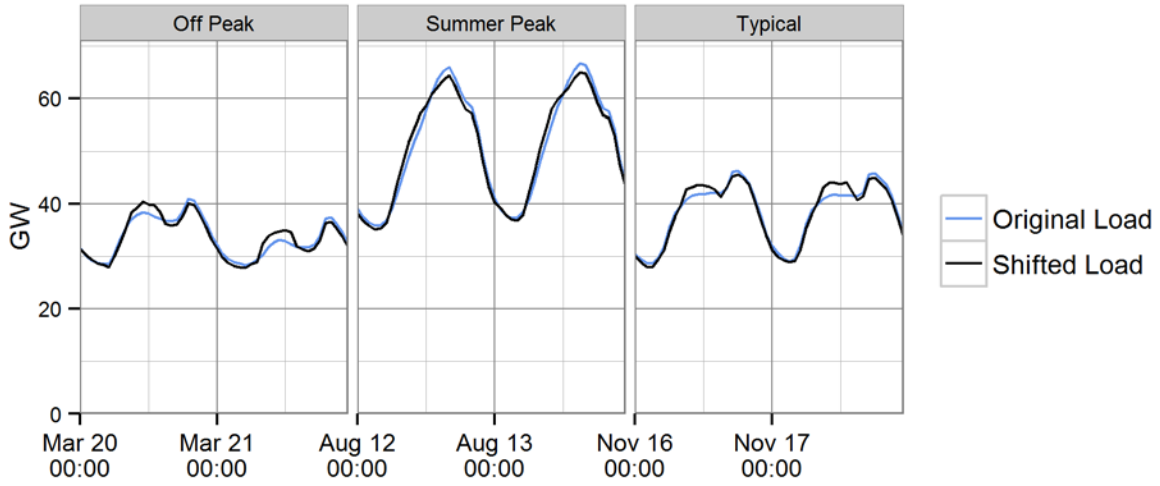

Figure 3. The ability of demand response to shift load in all cases except the enhanced demand response and storage case ("Off Peak" is the lowest load of the year, "Summer Peak" is the highest load of the year, and "Typical" is a randomly selected time in the fall)

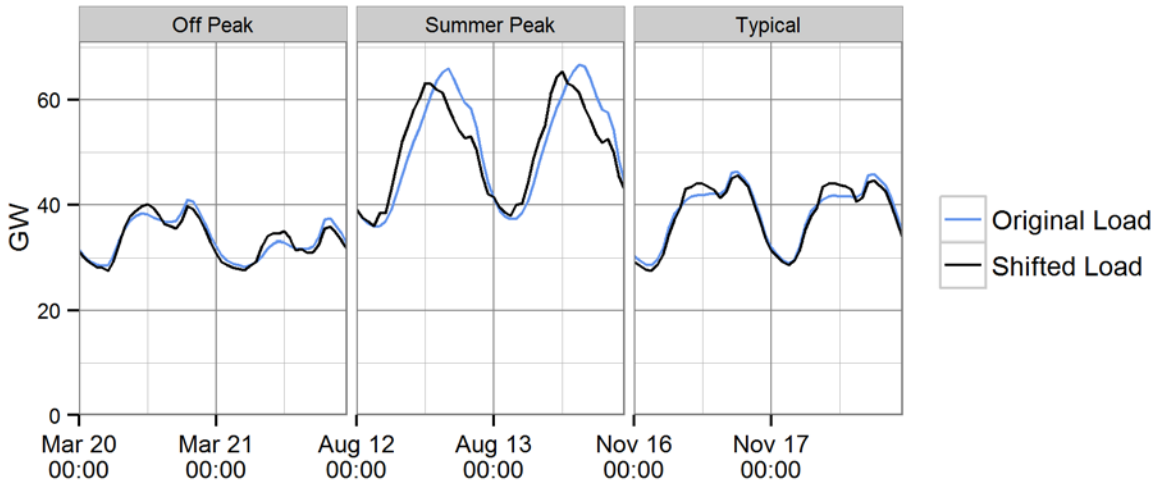

Figure 4. The ability of demand response to shift load in the enhanced demand response and storage case

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1.5 Determination of Reserve Requirements

Operations of the power system experience both variability (expected changes in the system) and uncertainty (unexpected changes) on various timescales. Operators prepare for these changes in the system by holding operating reserves, which reserve a certain amount of online generator capacity. Load is inherently variable and uncertain to a degree. Furthermore, wind and solar PV are both variable and uncertain since their resource is time-varying. Therefore, the presence of variable generation sources (VG) such as PV and wind generally increase the amount of reserves required.

In this study, we model three types of reserves in California: spinning contingency reserves, upward regulating reserves, and upward load-following reserves.[2] Each of these reserves can be held by partially-loaded generators with sufficient ramp to respond in a given time frame. The reserve requirements are divided geographically into four separate regions: Northern CAISO (PG&E), Southern CAISO (SCE and SDGE), Northern Municipals (SMUD and TIDC), and Southern Municipals (IID and LDWP). The total requirements, which must be provided independently by each reserve-sharing region, are calculated as follows:

- Spinning contingency reserves are calculated as 3% of regional load with no consideration of scenario or VG penetration. The response timeframe of spinning reserves is 10 minutes.
- Following the methodology adopted by the Western Wind and Solar Integration Study Phase 2, regulation reserves cover a geometric sum of 1% of load and 95% of ten minute forecast errors for wind and PV. The response time for regulation reserves is five minutes.
- Flexibility reserves cover 70% of one hour forecast errors of wind and PV, added geometrically. We account for load forecast errors by adding two standard deviations of the seasonal load forecast error in each timestep (Liu 2014). The response time for flexibility reserves is 20 minutes.

Non-spinning reserves are not modeled, as is common practice in other studies focused on operational analysis (e.g., WWSIS-2, ERGIS) because properly classifying quick-start units in 2030 is difficult and it is mostly useful for capacity planning. Using the methodology above, the total reserve requirement for each scenario is based on load patterns as well as VG penetration. Thus, the reserve requirement is different for all Baseline cases (which have a higher total load due to less aggressive assumptions about energy efficiency adoptions), Target cases (which have a higher VG penetration than the Baseline case), and the Target High Solar cases (which have a still higher VG penetration than the Target cases). Table 8 summarizes the reserve requirement by product and region for each scenario set.

[2] We do not consider the provision of downward reserves due to their historically lower price and the ability of renewables to provide downward reserves in the future. This issue has been studied in Nelson and Wisland (2015)

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Table 8. Modeled Reserve Requirements for California

Reserve Product	Baseline Cases (MW average)	Target Cases (MW average)	Target High Solar Cases (MW average)
Regulation – CAISO North	165	157	173
Regulation – CAISO South	197	213	233
Regulation – Muni North	43	35	41
Regulation – Muni South	58	82	94
Flexibility – CAISO North	198	180	223
Flexibility – CAISO South	301	434	488
Flexibility – Muni North	173	155	170
Flexibility – Muni South	259	400	425
Spinning Contingency – CAISO North	412	387	387
Spinning Contingency – CAISO South	508	477	477
Spinning Contingency – Muni North	79	74	74
Spinning Contingency – Muni South	126	118	118
Total	**2,520**	**2,710**	**2,900**

As the methodology suggests, the reserve requirement varies based on season of the year and hour of the day. Figure 5 shows the average daily reserve requirement by month of the year for each reserve product in the regular Target cases. Both flexibility and regulation have increased reserve requirements during daylight hours when PV penetration increases and in particular during the sunrise and sunset hours. Spinning contingency, however, is directly proportional to load and therefore is the highest during the evening peak in the summer and lowest in the early morning in the spring and fall.

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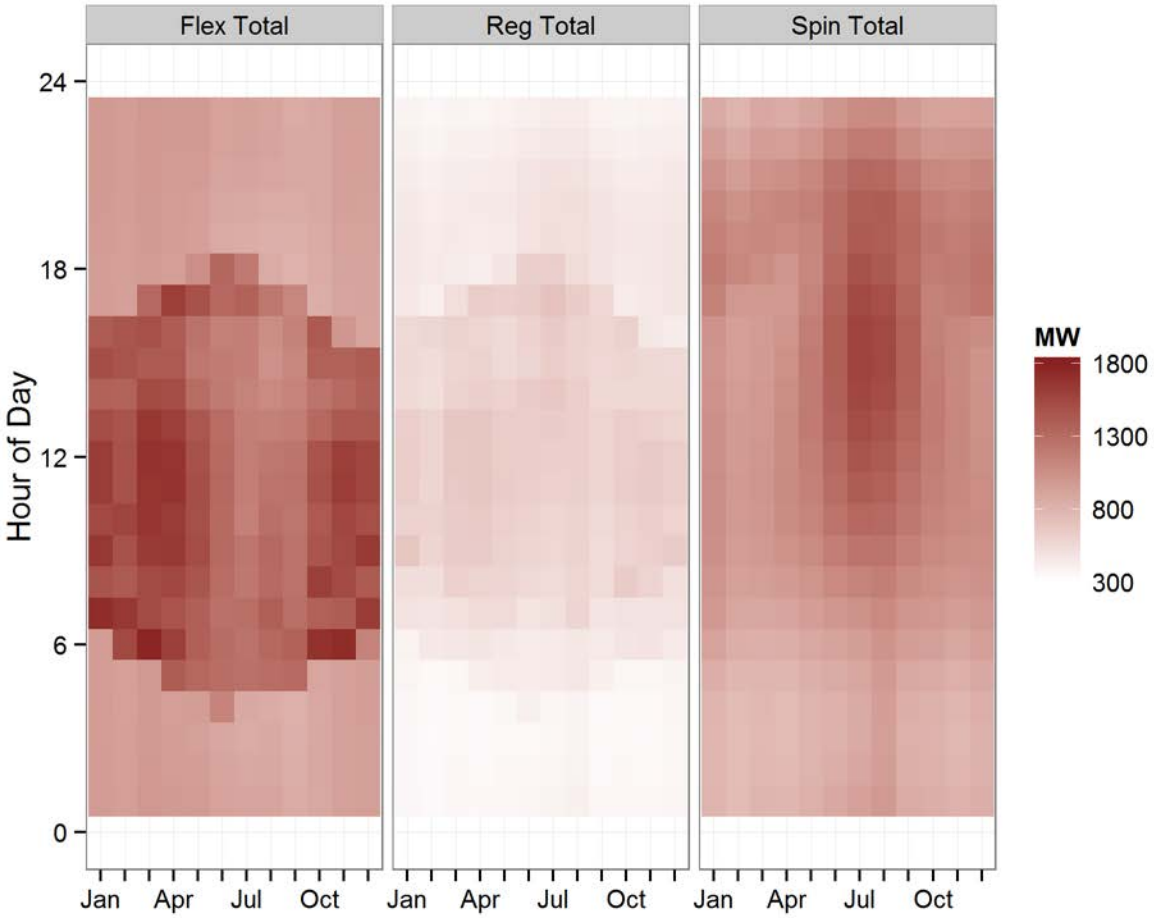

Figure 5. The average daily and monthly reserve requirements for California in all Target cases

We simplified the representation of reserves in the rest of the West to reduce computational demands. As such, we model just one reserve product for three distinct regions: the Rocky Mountain Region, the Southwestern US, and the Northwest/Basin Region. The composite reserve product has a response time of ten minutes, and must cover 4% of the hourly load for each balancing area in the reserve sharing regions.

1.6 Hydro Cases (Standard Hydro Case)

Hydro in the Western Interconnection is modeled in this study following the methodology of the TEPPC 2024 dataset. The hydropower production data comes from the year 2005. In the TEPPC dataset, a fraction of the hydro is non-dispatchable and has a fixed hourly schedule for the modeled year. The hourly schedule can either be time-varying or flat, and any downward deviation from the schedule would be considered spillage.[3] The dispatchable hydro generators have a max and min capacity that varies by month, and a monthly energy allowance. The unit

[3] Note that all hydro considered for inclusion in the California Renewable Portfolio Standard must meet certain criteria, including having a small nameplate capacity, not disrupting existing hydrological conditions in a conduit, and/or efficiency increases to existing hydroelectric facilities. Following these considerable constraints, all RPS-compliant hydro is modeled as a fixed-schedule resource.

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ramp rate for dispatchable hydro generators assumes that the generator can ramp 1.11% of its capacity per minute (or takes 90 minutes to ramp from zero output to max capacity). Table 9 shows the total distribution of California hydroelectric energy and maximum output for dispatchable and fixed-schedule hydro generators.

Table 9. Distribution of California Hydropower Generators

	Annual Energy (GWh)	Max Output (MW)
Dispatchable Hydro	19,900	5,030
Fixed-Schedule Hydro	13,900	2,980
RPS Hydro (modeled as fixed-schedule hydro)	4,890	923
Total CA Hydro	**38,100**	**8,770**

As noted above, water availability and output varies throughout the year. Figure 6 shows the hourly generation from hydroelectric generation in California for the entire modeled year and Figure 7 shows the monthly generation. Figure 6 shows that the hydro generation, especially from the dispatchable hydro resources, can vary widely within a month. Figure 7 indicates that water availability is the highest in the spring and summer months (May – July).

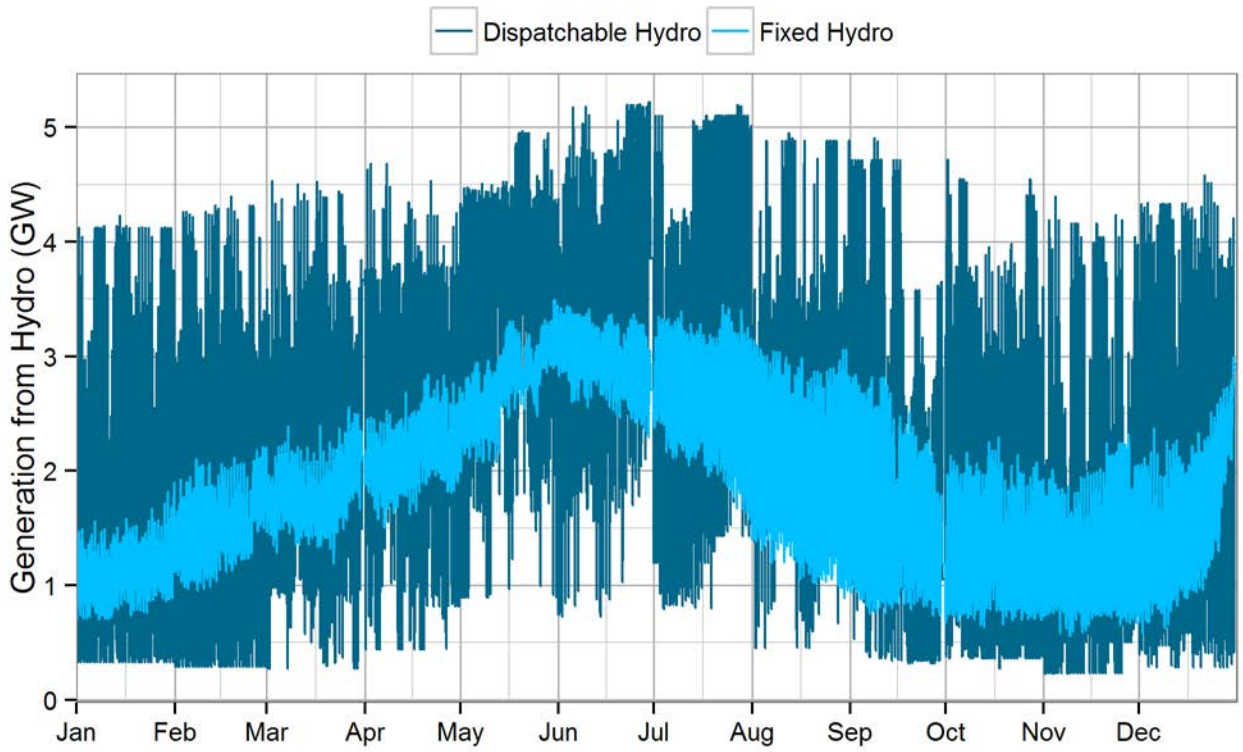

Figure 6. The hourly generation from hydroelectric generators in California throughout the modeled year

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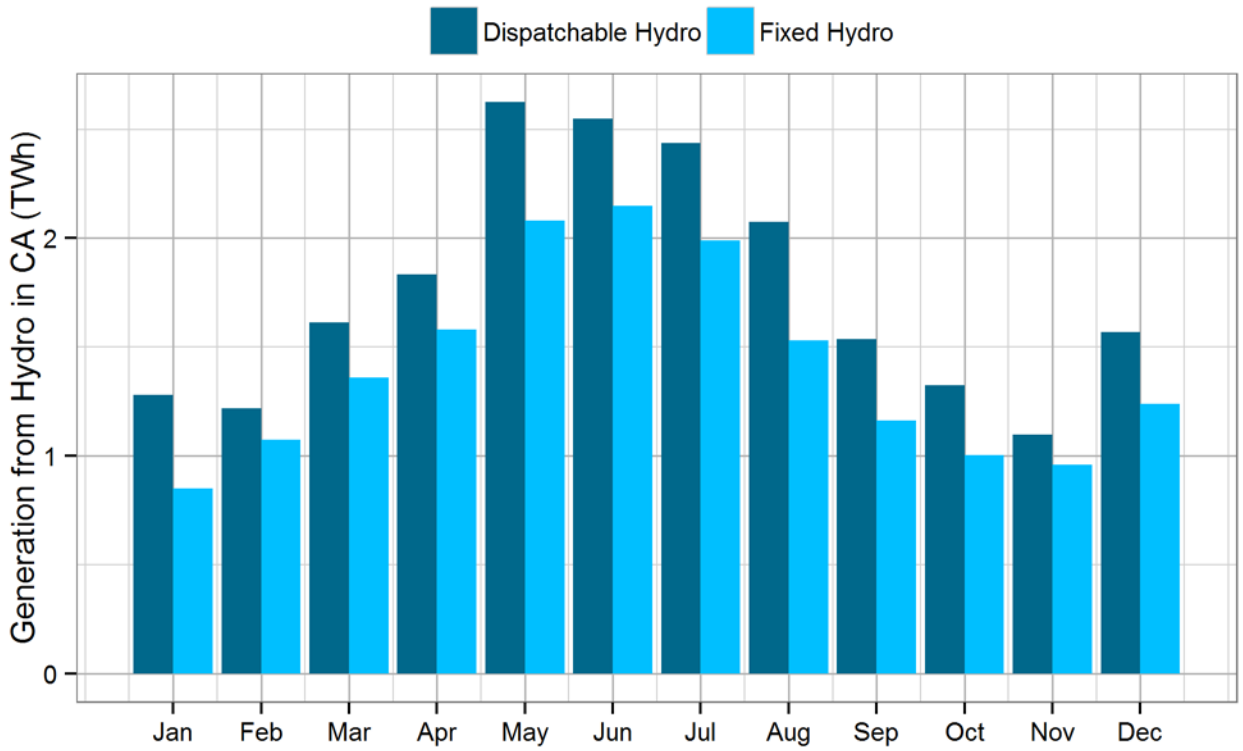

Figure 7. The total monthly generation from hydroelectric generators in California throughout the modeled year

As mentioned, the TEPPC 2024 dataset derives hydro information from a single year, 2005, which is considered a 'typical' hydro year. Given that water availabilities not only vary within a year, but also across years, we consider two additional sets of hydropower availability using data from the years 2001 and 2011. These two sensitivities, which represent a 'dry' hydro year and a 'wet' hydro year, respectively, apply a monthly and regionally-varying multiplier to water availability. Table 10 shows the average annual multiplier for each region.

Table 10. Average Annual Multipliers (Applied to the Typical 2005 Monthly Hydro Availabilities) Used for the Dry and Wet Hydro Sensitivities

	Dry Multiplier	Wet Multiplier
Northwest U.S.	0.77	1.28
California	0.70	1.08
Arizona, New Mexico, Nevada (AZ-NM-NV)	1.18	1.72
Colorado, Wyoming, Montana (CO-WY-MT)	0.98	1.61
Utah, Idaho (UT-ID)	0.61	1.86
Total (Average Multiplier)	**0.77**	**1.24**
Total (U.S. GWh)	**129 TWh**	**211 TWh**

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We applied the monthly multipliers to each hydro generator in the West according to the region. The monthly 'dry' hydro multiplier reduces the monthly energy allocation, minimum generation level, and maximum capacity for each generator. The multiplier was applied to capacity to simulate long-term dry hydro conditions. The monthly 'wet' hydro multiplier increases the monthly energy allocation and minimum generation level for each generator. We did not apply the 'wet' hydro multiplier to the maximum capacity of each hydro generator, assuming that hydro generators would not operate above designed maximum power output. Figure 8 shows the annual output for the dry, regular, and wet years in each of the regions. Figure 9 illustrates the variance in the monthly multipliers across the entire western U.S., and Figure 10 shows the monthly multipliers for California. Note that while the dry hydro generation is consistently lower than the regular hydro case in California, the high hydro case shows less variation and in fact has lower output than some 'regular' months. This underscores the fact that even in categorically 'wet' or 'dry' years, the water availability is still variable.

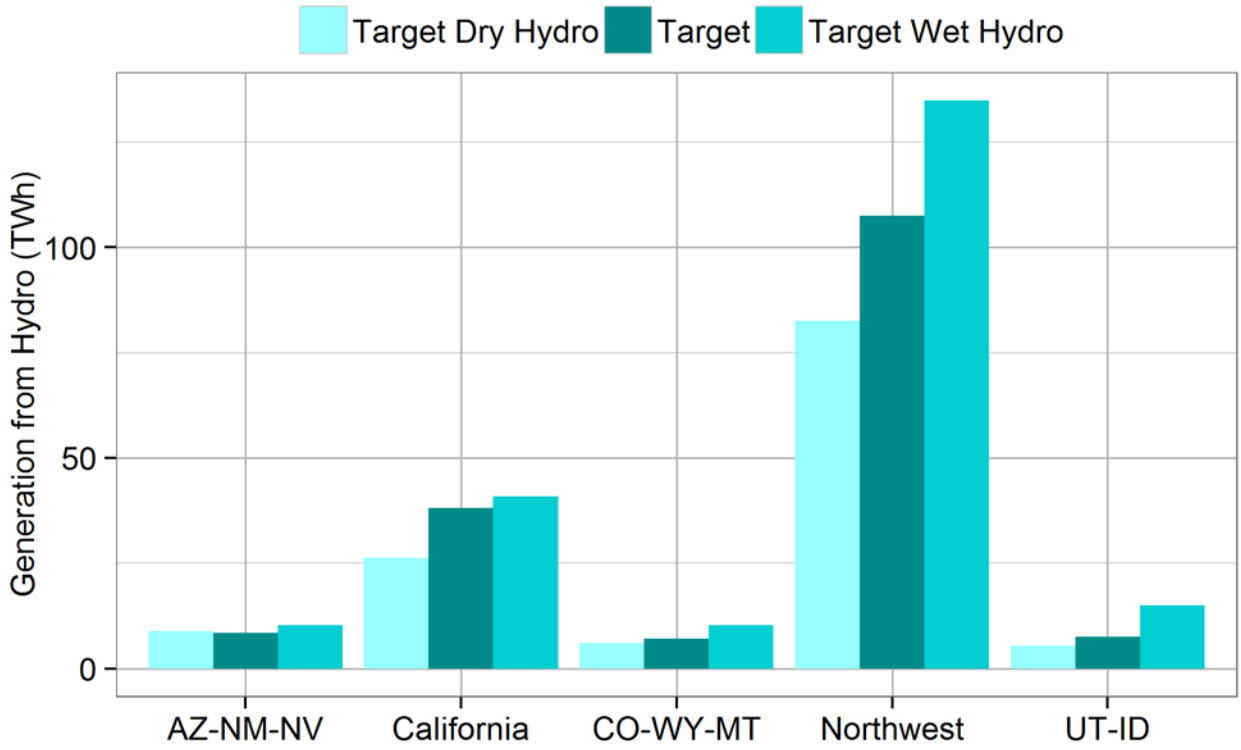

Figure 8. The annual regional generation from hydroelectric generators in the hydro sensitivity cases

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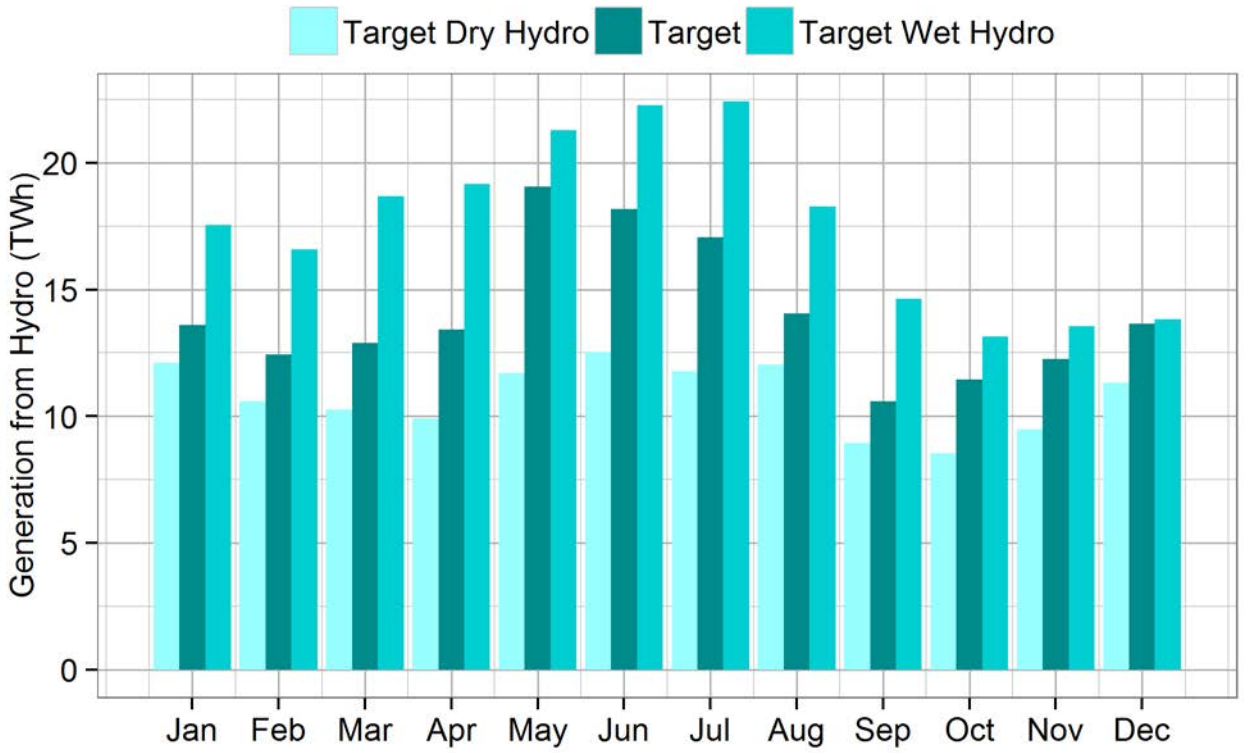

Figure 9. The total monthly generation from hydroelectric generators in the hydro sensitivity cases

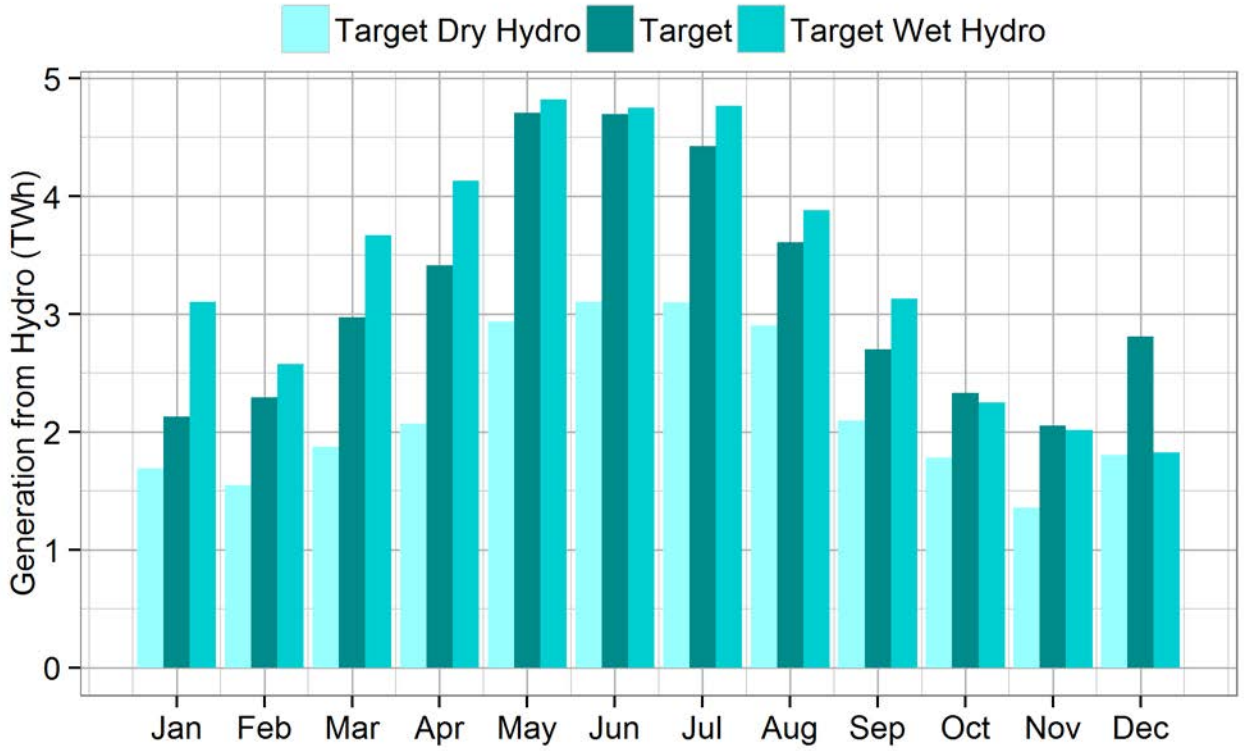

Figure 10. The total monthly generation from California hydroelectric generators in the hydro sensitivity cases

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1.7 Production Cost Modeling Penalty Prices

Table 11. Penalty Prices and Number of Violations in Two Scenarios

	Penalty Price ($/MW)	Number of Occurrences (Target Enhanced Case)	Number of Occurrences (Target Conventional, High Solar Case)
Exceeding maximum monthly energy for hydro generation	10,000,000	0	0
Failing to recycle energy for storage generators	100,000	0	0
Unserved Load Penalty	100,000	0	0
Failing to supply daily minimum energy to Electric Vehicle fleet	10,000	0	0
Violating transmission path limits	6,000	32	21
Violating local minimum generation requirements (on conventional flexibility cases only)	6,000	0	31
Regulation Reserve Violation	4,100	0	14
Spinning Contingency Reserve Violation	4,000	3	19
Flexibility Reserve Violation	3,900	128	400
Non-CA Reserve Violation	3,800	2	3
Failing to supply daily minimum energy to demand response participants	1,000		

Most of the reserve violations were less than 1 MW and all of the transmission violations were less than 0.1 MW.

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2 Results

2.1 Sub-hourly Modeling

While many production cost models focus on hourly chronology, generator output and load can change on a much shorter timescale. This study considers a large number of scenarios and therefore sub-hourly modeling for all scenarios was computationally infeasible. Instead, we simulated three representative scenarios (the Baseline Enhanced, Target Enhanced, and Target Conventional High Solar cases) in an attempt to observe the possible effects of sub-hourly (in this case, 5-minute) simulations.

In all cases, when modeling at a sub-hourly resolution, we see a marked increase in total production cost, shown in Table 12. Capturing the sub-hourly variability generally requires an increase in output from the quick-start, flexible, and generally higher cost generators. This is true for the Baseline and Target portfolios. For two of the three production cost calculation methods (methods two and three) the costs of all cases increased by approximately the same amount after increasing temporal resolution. This results in a similar calculated production cost differential for both the hourly and sub-hourly simulations. Table 13 shows the difference in production cost between the Target scenarios and the Baseline for the hourly and sub-hourly runs. The 5-min runs showed production cost savings (from the Baseline) that were $18m and $144m larger than the hourly runs (for the Target Enhanced and the Target High Solar Conventional, respectively). The savings provided by energy efficiency and renewable energy were higher by all calculation methods in both scenarios because more CTs were online in the Baseline 5-min runs (compared to hourly), and therefore more CTs were displaced.

Method 1 resulted in the most significant difference between the hourly and sub-hourly runs. This difference is largely due to the generally higher locational marginal prices, which are used to calculate the costs of imports and exports. West-wide production costs have much smaller differences in costs. Ongoing NREL work has seen similar impacts of sub-hourly modeling compared to hourly. Marginal results (such as prices) change more between hourly and sub-hourly modeling techniques than summary variables, such as cost, curtailment, and fuel usage.

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Table 12. Annual Production Cost for the Hourly and Sub-hourly Simulations (millions of 2014$ per year)

Scenario	Method 1: CA-Centric		Method 2: West-Wide		Method 3: West-Wide Plus OOS Emissions	
	Total Production Cost	% Difference to Hourly	Total Production Cost	% Difference to Hourly	Total Production Cost	% Difference to Hourly
Baseline Enhanced	12,713	-	23,723	-	33,656	-
Baseline Enhanced (5min)	14,506	**12%**	24,730	**4.1%**	34,463	**2.3%**
Target Enhanced	7,866	-	19,031	-	28,819	-
Target Enhanced (5min)	9,641	**18%**	19,779	**3.8%**	29,456	**2.2%**
Target Conventional, High Solar	8,642	-	19,942	-	29,738	-
Target Conventional, High Solar (5min)	10,291	**16%**	20,731	**3.8%**	30,438	**2.3%**

Table 13. Annual Production Cost Differentials (millions of 2014$ per year)

	Production Cost Differential from Baseline (hourly)	Production Cost Differential from Baseline (5-min)	Difference between hourly and 5-min
Target Enhanced	-4,848	-4,865	18
Target Conventional, High Solar	-4,071	-4,215	144

Table 14 and Figure 11 show the curtailment in the hourly and sub-hourly runs. In the sub-hourly run, curtailment is calculated during every 5-minute interval. Although the Baseline and Target cases still show low curtailment of less than 0.5%, the curtailment increases between the hourly and sub-hourly runs, especially in relative terms. In absolute terms, however, curtailment in California only increases by approximately 0.2% in the Baseline and Target cases. Curtailment rises by about 0.5% from 9.7% to 10.2% in the most constrained case, Target High Solar with conventional flexibility assumptions.

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Table 14. Curtailment in Hourly and Sub-hourly simulations

	Curtailment in CA	Curtailment outside CA	Total West-Wide Curtailment
Baseline Enhanced	0.004%	0.04%	0.02%
Baseline Enhanced (5min)	0.22%	0.32%	0.28%
Target Enhanced	0.23%	0.03%	0.17%
Target Enhanced (5min)	0.45%	0.37%	0.41%
Target Conventional, High Solar	9.7%	0.02%	6.7%
Target Conventional, High Solar (5min)	10.2%	0.31%	7.1%

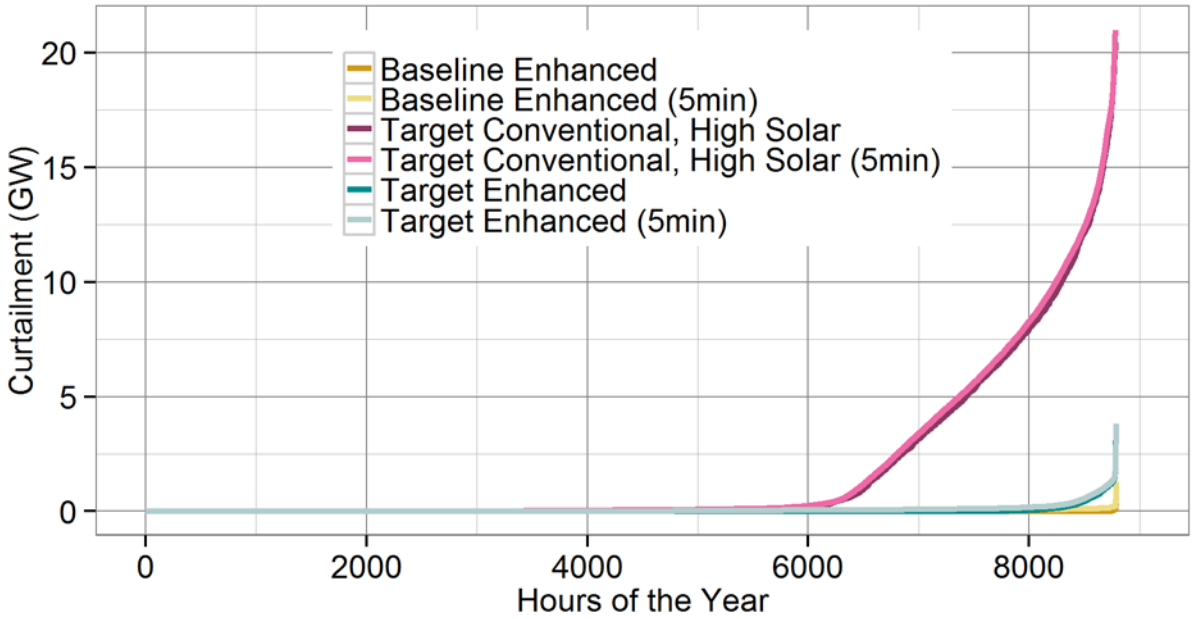

Figure 11. Curtailment duration curve for hourly and sub-hourly (5-minute) simulations

The time-series fleet plots (Figure 12 through Figure 21) show the commitment and dispatch of the Gas CC and Gas CT fleet. The commitment of the Gas CC fleet looks identical in the hourly and sub-hourly runs. The Gas CC fleet dispatch (the shaded area) looks slightly different, but the difference between the hourly and sub-hourly runs is more apparent in the commitment and dispatch of the CT fleet. For all cases and both seasons pictured here, the capacity of committed Gas CTs (and energy from the fleet) is much higher in the sub-hourly runs than the hourly simulations. The hourly resolution model does not capture and explicitly model the full need for CT usage (although it does hold back reserves) for intra-hour net load ramps. The high utilization of the flexible Gas CT, as mentioned, causes the increase in production cost between

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the hourly and sub-hourly runs. Note, however, that the gas fleet duration curve looks similar between the hourly and sub-hourly runs.

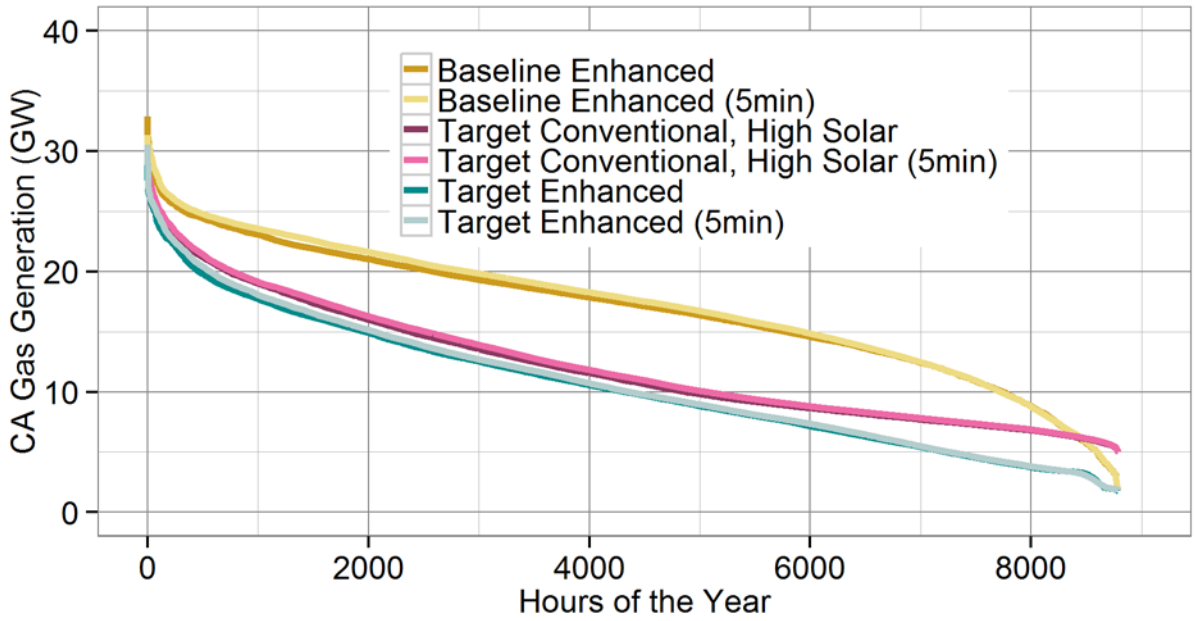

Figure 12. Gas fleet duration curve for hourly and sub-hourly (5-minute) simulations

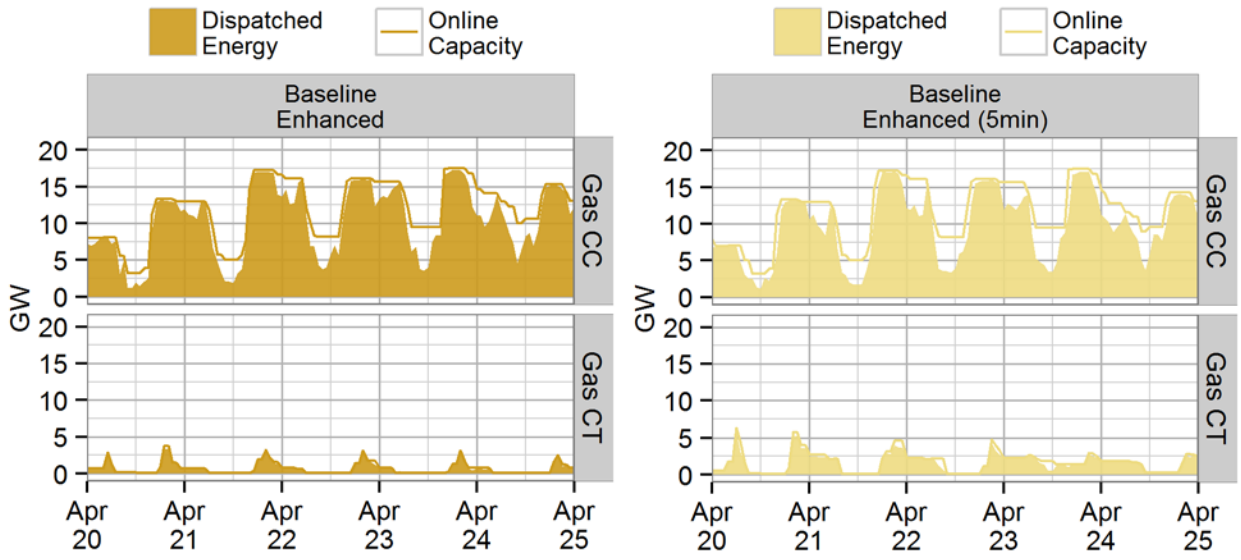

Figure 13. Committed and dispatched capacity for Baseline Enhanced hourly and sub-hourly (5-minute) simulations during spring

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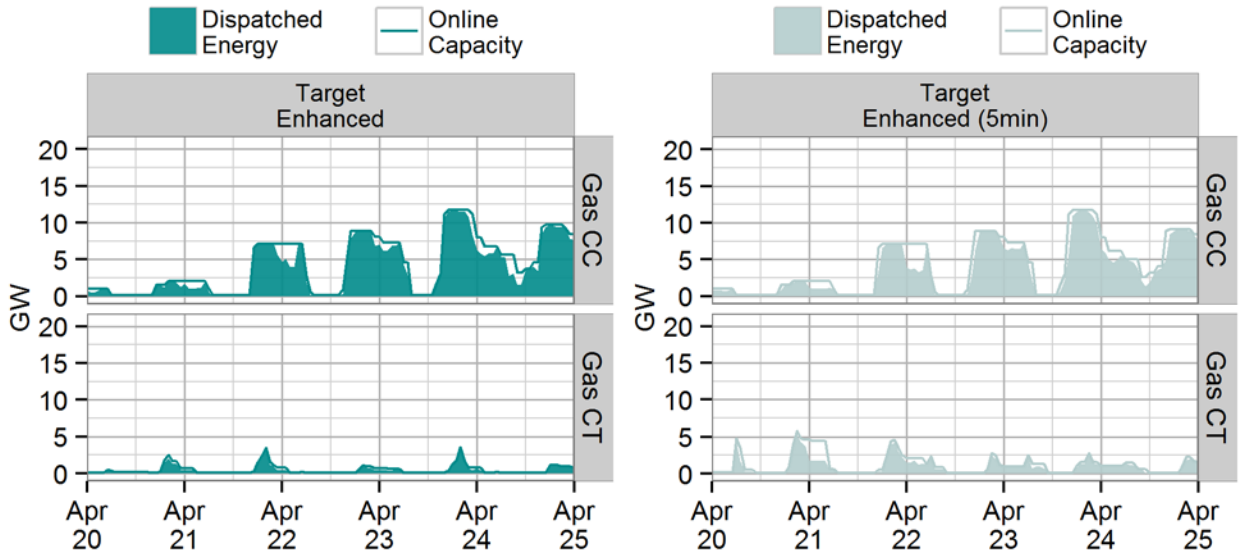

Figure 14. Committed and dispatched capacity Target Enhanced for hourly and sub-hourly (5-minute) simulations during spring

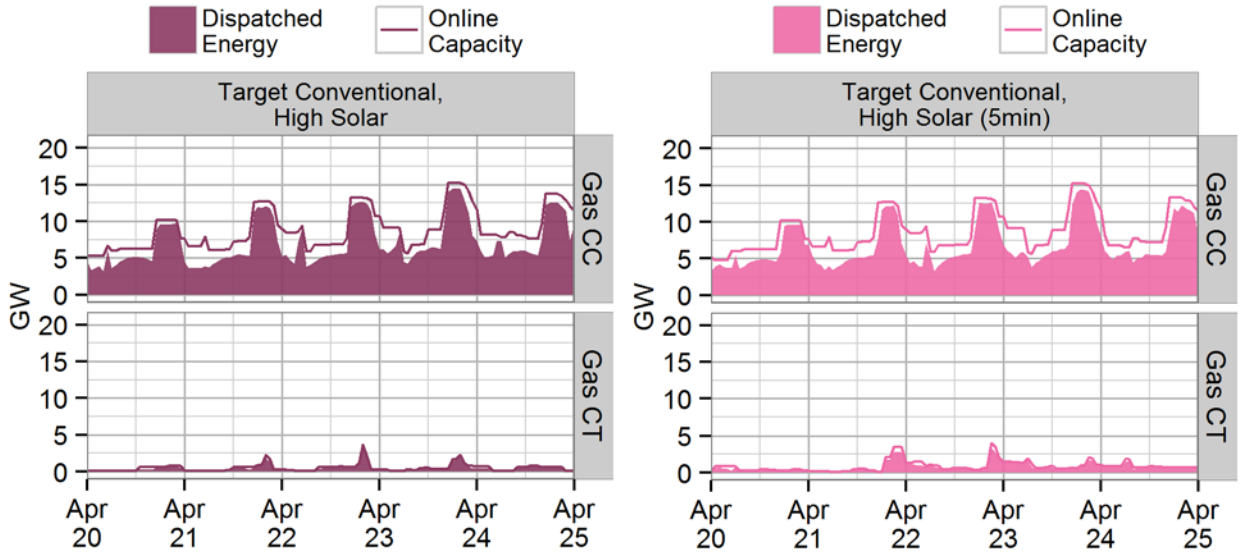

Figure 15. Committed and dispatched capacity for Target Conventional, High Solar hourly and sub-hourly (5-minute) simulations during spring

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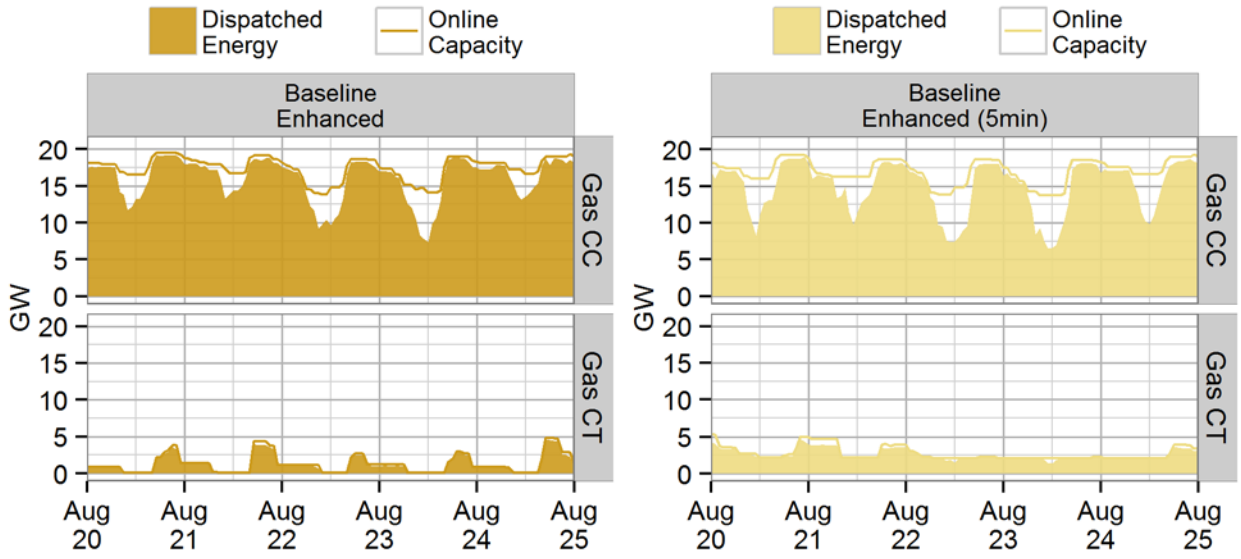

Figure 16. Committed and dispatched capacity for Baseline Enhanced hourly and sub-hourly (5-minute) simulations during summer

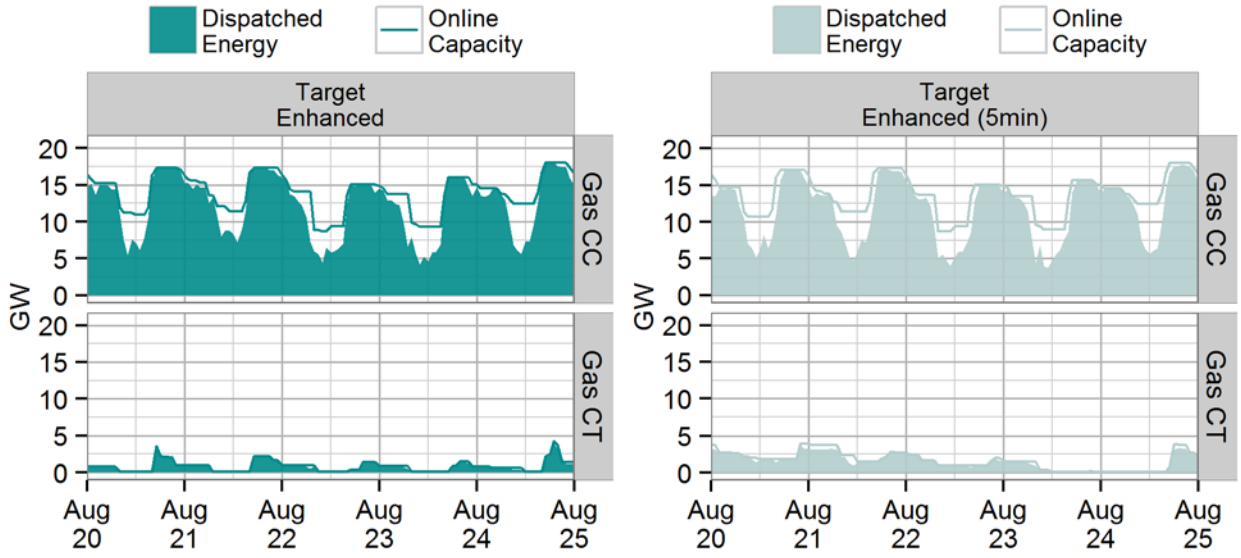

Figure 17. Committed and dispatched capacity for Target Enhanced hourly and sub-hourly (5-minute) simulations during summer

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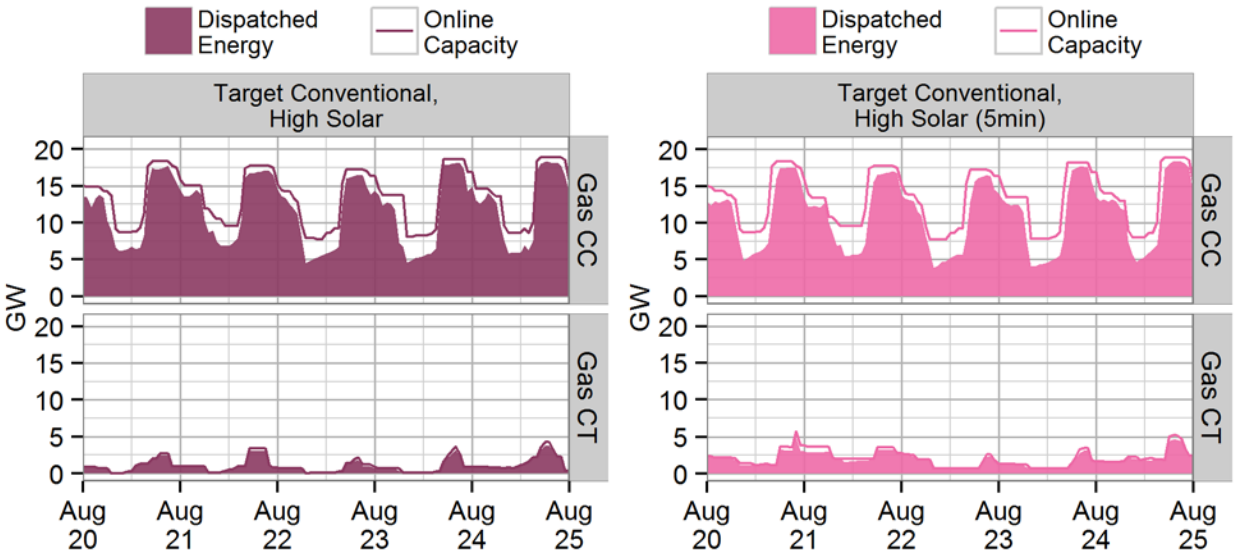

Figure 18. Committed and dispatched capacity for hourly and sub-hourly (5-minute) simulations during summer

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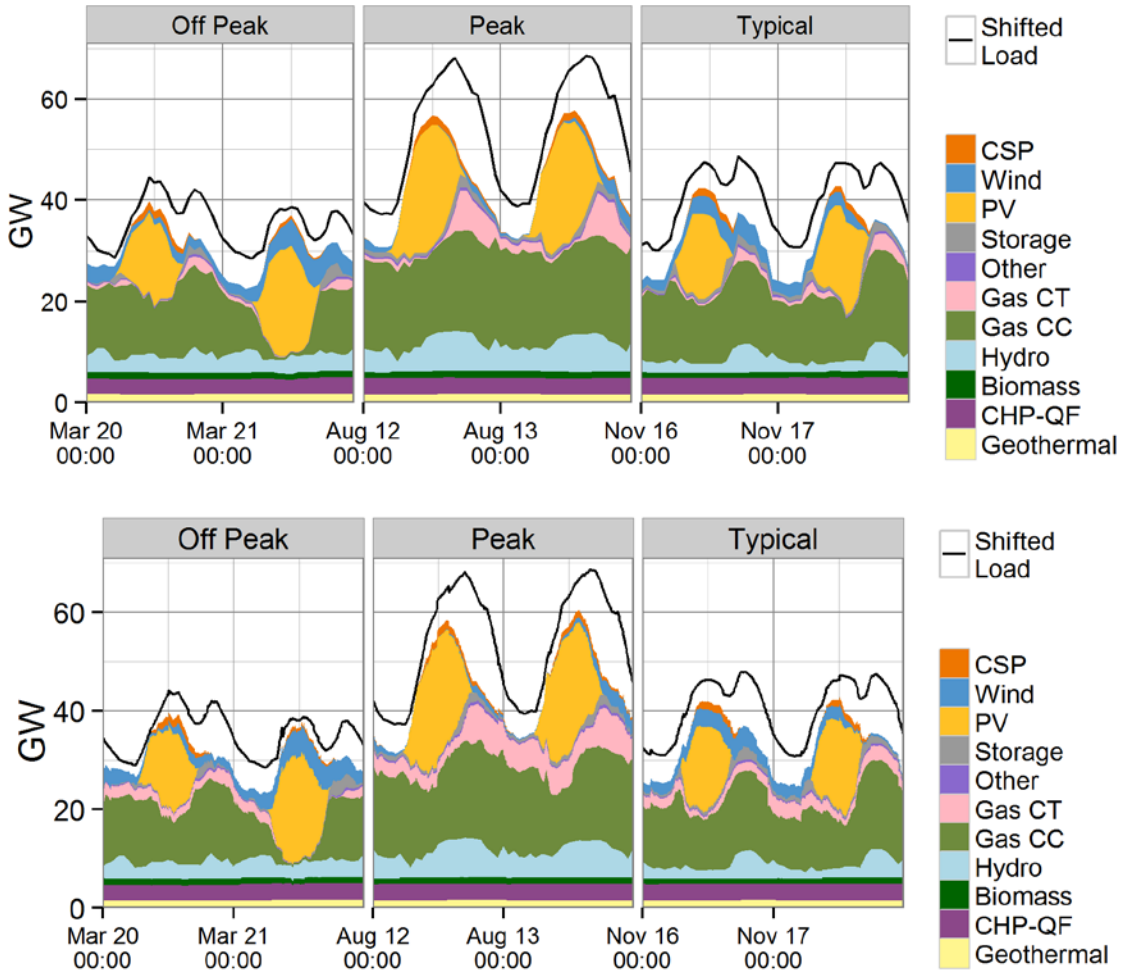

Figure 19. Baseline Enhanced dispatch stack for hourly (top) and 5-minute (bottom) simulations

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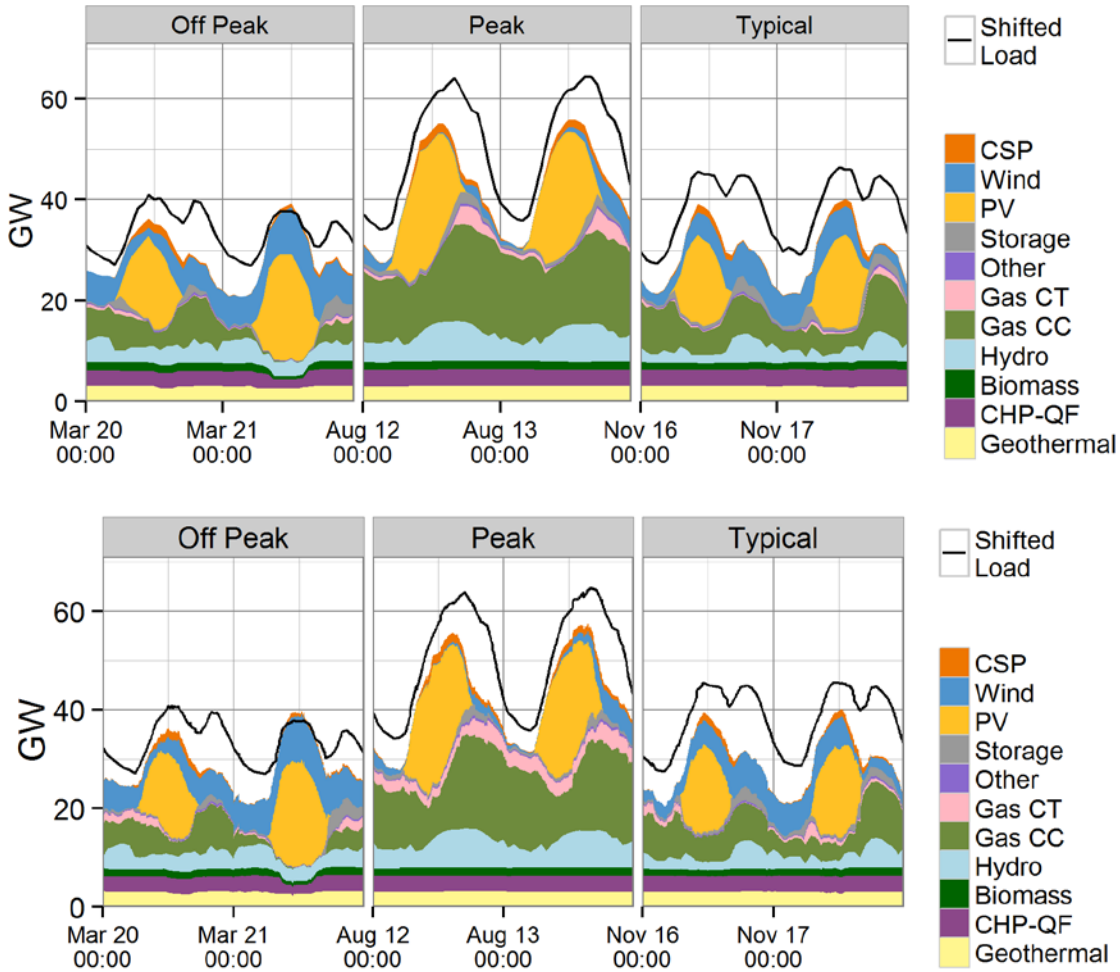

Figure 20. Target Enhanced dispatch stack for hourly (top) and 5-minute (bottom) simulations

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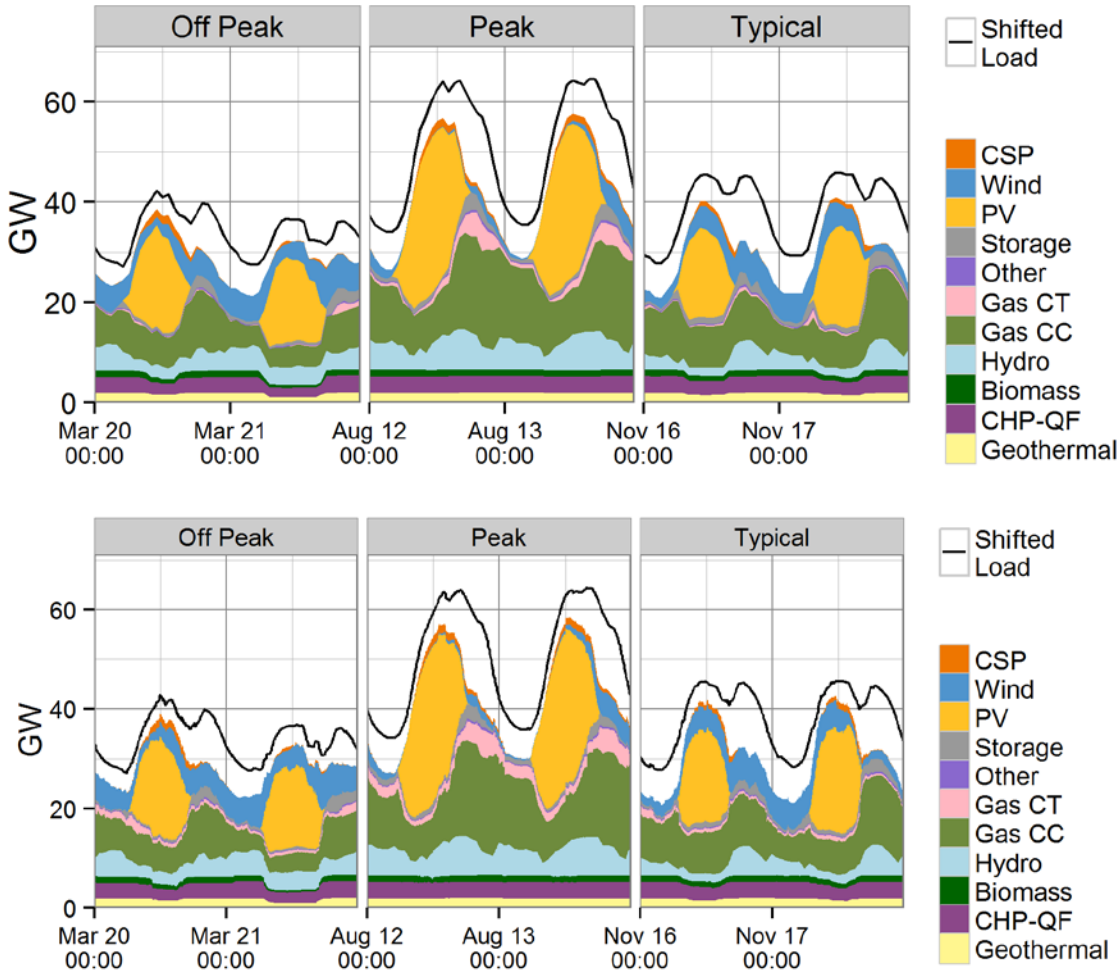

Figure 21. Target Conventional, High Solar dispatch stack for hourly (top) and 5-minute (bottom) simulations

The variables of primary interest to this study (changes in production cost due to renewable penetration, curtailment, usage of the gas fleet, and imports) changed very little in the sub-hourly modeling. The largest change occurred due to the marginal price of imports and exports to California, but we did not perform a full quality analysis on the prices coming from the import regions in the sub-hourly model, so the isolated California production costs should be viewed with some caution. There was no unserved load and a very small amount of unserved reserves (less than 1 GW-h and less than 0.01% of the reserve requirements) in all of the hourly and sub-hourly models (including the dry hydro scenarios).

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2.2 Results for all Scenarios

Table 15. Operational Cost Components in all Scenarios (billion dollars)

Scenario	CA Production Cost (A)	CA Emission Costs (B)	OOS Production Cost (C)	OOS Emission Costs (D)	Import Energy Accounting Cost (E)	Import Emissions Accounting Cost (F)	Adjusted CA Production Cost (ABE)	West-wide Production Cost, including Emissions (ABCD)	West-wide Production Cost, only CA Emissions (ABCF)
Baseline Enhanced	8.61	1.99	12.90	10.16	2.12	0.23	12.71	33.66	23.72
Baseline Conventional	8.74	2.02	12.87	10.13	2.01	0.21	12.78	33.76	23.85
Baseline Enhanced, High West	7.54	1.70	9.01	7.52	3.24	0.49	12.48	25.77	18.74
Baseline Enhanced, High West, Low Gas + High CO2	7.57	4.10	8.85	3.30	0.59	0.03	12.26	23.82	20.55
Baseline Enhanced, Low Gas + High CO2	8.03	4.39	12.80	5.62	-0.12	0.03	12.30	30.83	25.24
Target Enhanced	5.83	1.28	11.93	9.78	0.76	-0.01	7.87	28.82	19.03
Target Conventional	6.46	1.44	11.82	9.72	0.52	-0.06	8.41	29.43	19.65
Target Enhanced, High Solar	5.95	1.30	12.06	9.72	0.83	0.07	8.08	29.03	19.38
Target Conventional, High Solar	6.52	1.46	11.97	9.78	0.66	-0.02	8.64	29.74	19.94
Target Enhanced, With Import Rule	5.88	1.29	12.59	9.41	0.83	-0.03	8.00	29.17	19.73
Target Conventional, No Import Rule	6.55	1.46	11.48	9.50	-0.11	-0.02	7.91	28.99	19.47
Target Enhanced, With 25% Gen Rule	6.47	1.44	11.52	9.53	0.12	-0.03	8.03	28.96	19.40
Target Conventional, No 25% Gen Rule	5.93	1.30	12.17	9.68	0.77	-0.02	8.00	29.09	19.38
Target Conventional, High Storage + DR	6.07	1.36	11.69	9.68	0.31	-0.08	7.74	28.80	19.04
Target Conventional, Locked DA Imports	6.86	1.52	11.55	9.64	0.12	-0.08	8.51	29.58	19.86
Target Enhanced, High West	5.05	1.09	7.79	6.68	1.61	0.14	7.75	20.62	14.07

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Scenario	CA Production Cost (A)	CA Emission Costs (B)	OOS Production Cost (C)	OOS Emission Costs (D)	Import Energy Accounting Cost (E)	Import Emissions Accounting Cost (F)	Adjusted CA Production Cost (ABE)	West-wide Production Cost, including Emissions (ABCD)	West-wide Production Cost, only CA Emissions (ABCF)
Target Conventional, High West	5.84	1.30	7.66	6.79	1.11	0.07	8.25	21.59	14.87
Target Enhanced, Dry Hydro	6.68	1.48	14.40	10.52	0.67	-0.02	8.82	33.07	22.53
Target Enhanced, Wet Hydro	5.49	1.19	11.02	9.23	1.01	0.01	7.69	26.94	17.72
Target Conventional, Dry Hydro	7.19	1.61	14.33	10.50	0.47	-0.07	9.26	33.63	23.06
Target Conventional, Wet Hydro	6.24	1.38	10.86	9.04	0.62	-0.05	8.24	27.53	18.44
Target Enhanced, High West, Low Gas + High CO2	5.33	2.72	7.92	3.00	-0.62	-0.08	7.44	18.97	15.90
Target Enhanced, Low Gas + High CO2	5.94	3.10	12.14	5.03	-1.42	-0.04	7.61	26.21	21.13

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Table 16. Curtailment, Emissions, and Imports in all Scenarios

Scenario	CA Curtailment	OOS Curtailment	CA Carbon Accounting Method (MMT)	West-wide Carbon Emissions (MMT)	Physical Imports (TWh)	Physical Exports (TWh)	Unspecified Imports (TWh)	Specified Imports that are not Imported (TWh)	Specified Imports that are Imported (TWh)
Baseline Enhanced	0.0%	0.0%	74.4	380.9	56.8	0.0	29.2	0.8	27.5
Baseline Conventional	0.6%	0.0%	75.2	381.0	55.5	0.0	28.1	0.8	27.5
Baseline Enhanced, High West	0.0%	1.3%	72.9	289.7	80.3	0.0	52.1	0.0	28.2
Baseline Enhanced, High West, Low Gas + High CO2	0.0%	0.3%	79.1	181.9	32.7	0.3	8.5	4.4	23.9
Baseline Enhanced, Low Gas + High CO2	0.0%	0.0%	80.1	259.0	21.5	1.4	5.6	13.9	14.4
Target Enhanced	0.2%	0.0%	41.1	345.1	60.5	0.1	14.5	5.1	46.0
Target Conventional	4.2%	0.0%	45.0	348.4	56.1	0.0	10.9	4.8	45.2
Target Enhanced, High Solar	0.5%	0.0%	42.2	344.2	53.4	0.9	18.5	9.8	34.0
Target Conventional, High Solar	9.7%	0.0%	46.8	351.2	58.6	0.0	13.8	5.6	44.8
Target Enhanced, With Import Rule	0.9%	0.0%	41.8	334.0	61.7	0.0	13.7	3.0	48.0
Target Conventional, No Import Rule	0.6%	0.0%	42.3	342.5	48.8	1.2	11.1	14.2	36.5
Target Enhanced, With 25% Gen Rule	0.5%	0.0%	42.2	342.9	49.9	0.9	10.9	12.8	38.1
Target Conventional, No 25% Gen Rule	1.2%	0.0%	42.2	342.7	61.3	0.0	13.8	3.0	47.5
Target Conventional, High Storage + DR	3.1%	0.0%	41.7	344.8	54.3	0.0	8.9	4.8	45.4
Target Conventional, Locked DA Imports	5.4%	0.0%	46.8	349.1	47.5	0.0	6.1	5.7	41.3
Target Enhanced, High West	0.7%	1.2%	40.5	243.3	76.7	0.0	27.9	2.3	48.8
Target Conventional, High West	4.9%	3.1%	45.1	253.5	66.6	0.0	21.6	2.7	45.0
Target Enhanced, Dry Hydro	0.2%	0.0%	47.0	374.6	56.4	0.1	11.9	6.2	44.4
Target Enhanced, Wet Hydro	0.3%	0.1%	39.5	325.3	65.3	0.1	17.8	3.8	47.4
Target Conventional, Dry Hydro	4.2%	0.0%	50.3	378.4	53.9	0.0	9.6	5.0	44.3
Target Conventional, Wet Hydro	4.4%	0.1%	43.7	325.8	58.5	0.0	12.6	4.6	45.9
Target Enhanced, High West, Low Gas + High CO2	0.4%	0.3%	44.4	146.0	39.3	0.3	3.7	15.4	35.3
Target Enhanced, Low Gas + High CO2	0.3%	0.0%	45.3	216.0	23.9	2.3	1.4	30.5	20.2

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Table 17. California Generator Fleet Statistics in all Scenarios

	Capacity Factor			Average Output when Committed			Hours Online per Start		
Scenario	**Gas CC**	**Gas CT**	**CHP-QF**	**Gas CC**	**Gas CT**	**CHP-QF**	**Gas CC**	**Gas CT**	**CHP-QF**
Baseline Enhanced	0.46	0.10	0.97	0.86	0.83	1.00	48	6	1,141
Baseline Conventional	0.46	0.10	0.96	0.84	0.83	0.98	49	6	1,141
Baseline Enhanced, High West	0.38	0.09	0.97	0.84	0.84	0.99	27	5	1,141
Baseline Enhanced, High West, Low Gas + High CO2	0.57	0.15	0.97	0.88	0.86	1.00	47	7	1,141
Baseline Enhanced, Low Gas + High CO2	0.57	0.16	0.97	0.89	0.84	1.00	58	9	1,141
Target Enhanced	0.30	0.07	0.96	0.88	0.82	0.99	28	5	1,141
Target Conventional	0.32	0.06	0.90	0.81	0.78	0.93	35	6	1,141
Target Enhanced, High Solar	0.27	0.07	0.94	0.84	0.83	0.97	20	5	1,141
Target Conventional, High Solar	0.33	0.06	0.87	0.80	0.79	0.90	28	5	1,141
Target Enhanced, With Import Rule	0.30	0.07	0.95	0.87	0.83	0.97	25	5	1,141
Target Conventional, No Import Rule	0.32	0.06	0.94	0.81	0.80	0.97	38	5	1,141
Target Enhanced, With 25% Gen Rule	0.33	0.06	0.95	0.86	0.81	0.97	37	5	1,141
Target Conventional, No 25% Gen Rule	0.27	0.06	0.94	0.80	0.79	0.96	27	5	1,141
Target Conventional, High Storage + DR	0.31	0.04	0.91	0.83	0.80	0.94	53	6	1,141
Target Conventional, Locked DA Imports	0.32	0.06	0.91	0.84	0.82	0.93	33	5	1,141
Target Enhanced, High West	0.20	0.05	0.95	0.89	0.84	0.97	23	4	1,141
Target Conventional, High West	0.27	0.04	0.89	0.84	0.82	0.92	43	5	1,141
Target Enhanced, Dry Hydro	0.31	0.07	0.97	0.91	0.87	1.00	30	5	1,141
Target Enhanced, Wet Hydro	0.28	0.06	0.95	0.88	0.82	0.97	26	5	1,141
Target Conventional, Dry Hydro	0.32	0.06	0.92	0.83	0.83	0.94	35	6	1,141
Target Conventional, Wet Hydro	0.27	0.05	0.89	0.84	0.79	0.91	35	6	1,141
Target Enhanced, High West, Low Gas + High CO2	0.32	0.07	0.96	0.90	0.85	0.99	35	5	1,141
Target Enhanced, Low Gas + High CO2	0.37	0.08	0.97	0.91	0.87	1.00	48	7	1,141

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Table 18. Out-of-state Generator Fleet Statistics in all Scenarios

Scenario	Capacity Factor			Average Output when Committed			Hours Online per Start		
	Coal	Gas CC	Gas CT	Coal	Gas CC	Gas CT	Coal	Gas CC	Gas CT
Baseline Enhanced	0.92	0.33	0.09	0.99	0.89	0.86	791	37	5
Baseline Conventional	0.92	0.33	0.08	0.99	0.88	0.85	757	36	5
Baseline Enhanced, High West	0.66	0.23	0.08	0.92	0.86	0.86	349	16	4
Baseline Enhanced, High West, Low Gas + High CO2	0.30	0.46	0.14	0.91	0.91	0.89	212	44	9
Baseline Enhanced, Low Gas + High CO2	0.36	0.60	0.17	0.94	0.93	0.89	200	140	20
Target Enhanced	0.86	0.24	0.07	0.99	0.90	0.87	668	38	6
Target Conventional	0.86	0.25	0.06	0.98	0.87	0.83	644	36	5
Target Enhanced, High Solar	0.84	0.22	0.07	0.98	0.87	0.85	635	33	5
Target Conventional, High Solar	0.86	0.25	0.06	0.98	0.86	0.83	694	33	5
Target Enhanced, With Import Rule	0.78	0.26	0.08	0.99	0.90	0.86	284	43	6
Target Conventional, No Import Rule	0.85	0.24	0.06	0.97	0.87	0.84	613	32	5
Target Enhanced, With 25% Gen Rule	0.86	0.25	0.06	0.98	0.89	0.84	603	33	5
Target Conventional, No 25% Gen Rule	0.83	0.23	0.06	0.99	0.87	0.84	489	39	6
Target Conventional, High Storage + DR	0.83	0.25	0.05	0.98	0.88	0.84	620	39	6
Target Conventional, Locked DA Imports	0.86	0.25	0.06	0.98	0.88	0.85	644	36	5
Target Enhanced, High West	0.56	0.13	0.04	0.92	0.89	0.86	255	24	6
Target Conventional, High West	0.58	0.16	0.03	0.84	0.87	0.85	317	22	7
Target Enhanced, Dry Hydro	0.89	0.31	0.12	0.99	0.92	0.88	729	49	9
Target Enhanced, Wet Hydro	0.82	0.20	0.06	0.97	0.90	0.85	521	32	7
Target Conventional, Dry Hydro	0.87	0.28	0.12	0.99	0.88	0.87	747	48	9
Target Conventional, Wet Hydro	0.77	0.18	0.06	0.97	0.88	0.83	446	30	6
Target Enhanced, High West, Low Gas + High CO2	0.07	0.31	0.08	0.65	0.90	0.86	115	65	12
Target Enhanced, Low Gas + High CO2	0.18	0.50	0.13	0.80	0.93	0.91	177	131	22

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