ELECTRICITY GENERATION TECHNOLOGY SUMMARY for EPC-19-060

(Deliverable for Subtask 3.3)

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Executive Summary

This Electricity Generation Technology Summary gives an overview of renewable electricity generation technologies. It is organized to summarize:

- The generation resources available to California
- How these generation resources affect the amount and types of storage that California will need
- Data to use for modeling inputs in RESOLVE and SWITCH.

California is blessed with abundant solar resource that is widely estimated to be adequate to supply all of California's energy needs. California also has access to hydropower, wind energy, geothermal, and biomass as valuable, but less abundant, renewable generation resources. Electricity generated by wind in California has so far shown a seasonal variation very similar to that of solar (the monthly generation in the summer is about twice that in winter).

Based on the abundance of solar resource in California, we anticipate that a renewable-energy powered grid will be dominated by solar electricity, requiring substantial (0.2 to 0.5 TWh) diurnal storage. The amount of diurnal storage that is needed is unchanged when wind is added to the solar-dominant grid but adding significant wind generation (which may blow more at night) may reduce the frequency with which the diurnal storage is used. Increased use of wind will increase the duration of the storage that is optimal for the system.

California's renewable electricity generation in the summer is likely to be about twice that in the winter, requiring substantial season storage or seasonal balancing of some sort. The amount of seasonal storage needed can be reduced by adjusting the generation profiles in any of the following ways:

- Overbuild the generation,
- Select solar plant designs that give more consistent generation throughout the year by, for example, using latitude tilt or increasing the DC-AC ratio
- Use wind resources that generate more wind in winter – some of these exist in California, though they are easier to find in the Rocky Mountains
- Use high-capacity-factor offshore wind, which give more consistent output year round
- Use more geothermal or biomass; biomass coupled with the Allam cycle may enable negative carbon emissions while reducing need for storage
- Import electricity from other states that have electricity available at the needed times.

This summary, combined with the Storage Technology Summary lays the groundwork for subsequent modeling to quantify the value of long-duration storage. It does not discuss nuclear power, because if California chose to invest in nuclear, there would be little need or a very different type of need for long-duration energy storage. Natural gas used with the Allam cycle may provide a relatively clean alternative to all-renewable scenarios.

1. Introduction

Modeling grid operation to fully understand the potential value of long-duration storage is built on an understanding of the generation profiles. The sun shines during the day, though some days are cloudy. The wind blows more at night, but not every day and, in some locations, it blows more during the day. The storage that is needed to fill the gaps will be intimately dependent on the details of the generation and fluctuations of the load. Though the generation profiles will be unpredictable in some ways (we don't know when the wind will stop blowing), the profiles are very predictable in other ways (the sun never shines at night). Hourly resolution models can help for decades-scale planning of generation adequacy. While we don't know the minute-by-minute fluctuations of when wind and solar may be available due to weather, we are able to estimate on an hourly to annual scale good representations of the available resources, in addition to storage and transmission requirements.

Prices for solar and wind plants have dropped impressively. The prices for geothermal, biomass, and others could also drop in the coming years. So, in this report we discuss most types of renewable generation.

We also discuss some non-renewable generation sources. While California has made clear their preference for solar electricity, it is useful to understand the benefits and challenges of all clean options that might affect how we use storage.

There are many factors to consider when modeling the entire energy system. We have done preliminary work to identify factors that will greatly affect the outcome of our studies. For example, there is general agreement that the state of California can provide ample solar energy. In contrast, modeling often selects to build all wind that is offered to the model. The addition of wind generation to solar generation makes a large difference in the amount and usage of storage, so understanding the wind generation possibilities is a priority.

Additionally, solar generation profiles can vary according to the orientation of the solar panels and other system design elements. Given that solar electricity may be the primary source of renewable electricity in California, understanding these options may turn out to be key.

In the end, the types of generators that California installs will be a key determinant of the amount and types of storage that will be needed to manage daily, cross-day, and seasonal needs. This summary is complemented by a companion analysis of storage technology. Together, these two summaries lay the groundwork for modeling the roles and value of long-duration energy storage toward decarbonizing California's energy system.

2. Generation resources available in California

Figure 2.1 below shows the breakdown by source of the 2021, 2020, and 2019 net generation in California across all sectors, including utility scale generation and local production for on-site consumption. Solar production is broken up between utility scale production (both photovoltaic and solar-thermal) for large scale retail energy production and "Small Solar" for distributed production such as solar panels attached to residential or commercial/industrial buildings. In 2021, the total for solar increased to 25%. Over these years, the increases from solar have mostly replaced the decreased generation from hydropower due to the current drought.

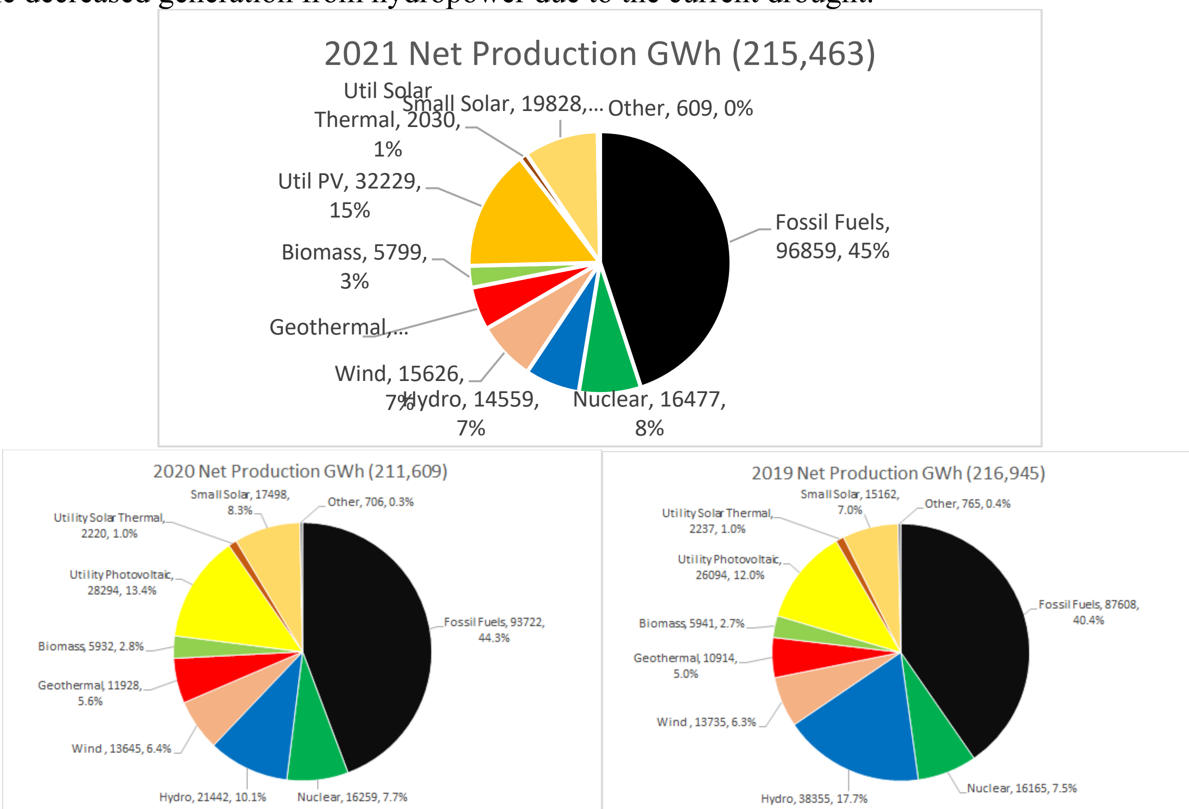

Fig. 2. 1 Energy generated within California for 2019 and 2020 by source.[1]

Fossil fuel electricity generation in California consists almost entirely of natural gas. Natural gas electricity production in 2020 increased over 2019 as generation from hydro dropped precipitously. Solar production grew, though not enough to make up the difference. Other sources remained relatively stable, with small increases in their proportion of the total due more to the drop in hydro than their own modest growth in production. Fig. 2.2 shows the broader trend over the past 20 years, with changes to fossil fuel generation driven primarily by the cyclic rise and fall of hydropower in response to drought, and to a secondary extent by the sudden drop in nuclear generation in 2012 (following the shutdown and closure of the San Onofre Nuclear Generating

[1] https://www.eia.gov/electricity/data/browser/

Station) and the steady growth of solar generation over the past 7 years. Geothermal, biomass, and wind have remained relatively flat over the same period.

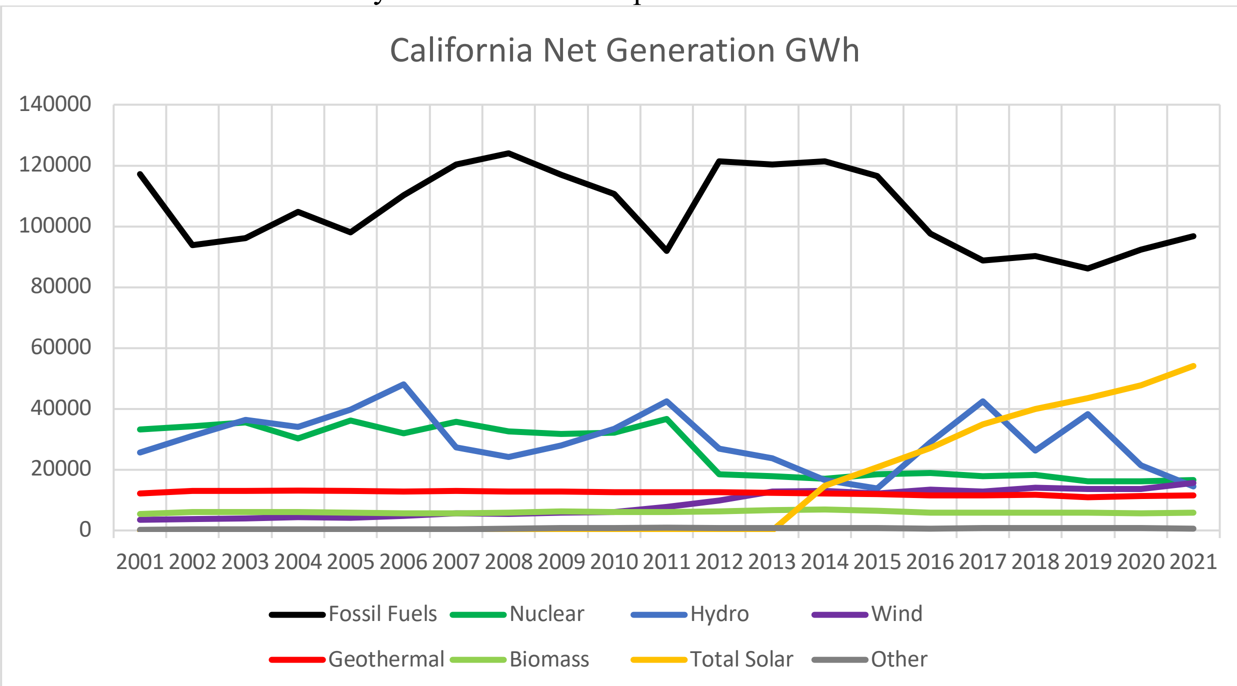

Fig. 2. 2 Net Annual Generation in California by source over past 20 years[2]

Prior to 2012, solar generation was dominated almost entirely by solar-thermal systems, which turn solar irradiance to heat that is then used to generate steam. After 2012, solar-thermal systems were quickly overshadowed by photovoltaic systems in the form of both large utility-scale solar farms and distributed small-scale systems, as shown in Fig. 2.3. Though this production is still dominated by utility-scale systems, Fig. 2.4 shows how the growth of small-scale systems has steadily been closing the gap over the past 5 years.

[2] https://www.eia.gov/electricity/data/browser/

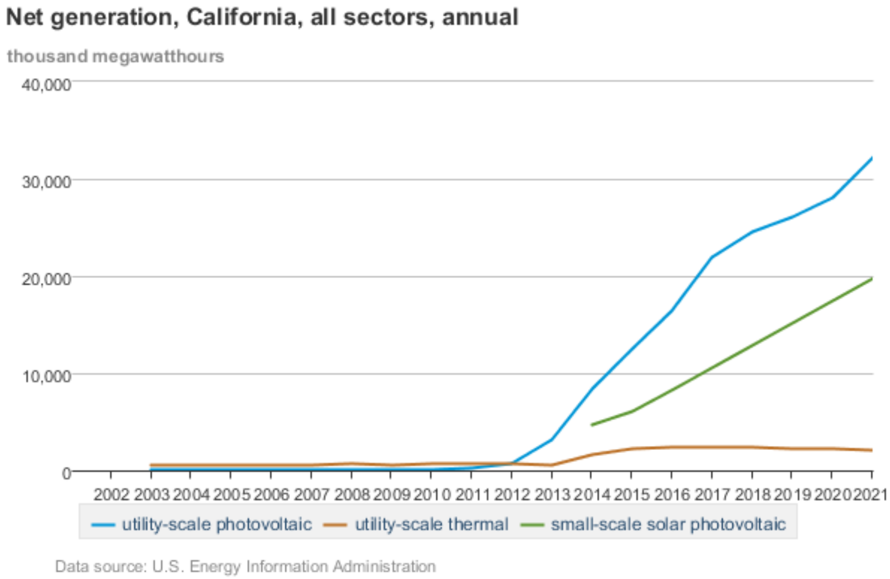

Fig. 2. 3 Solar growth in California

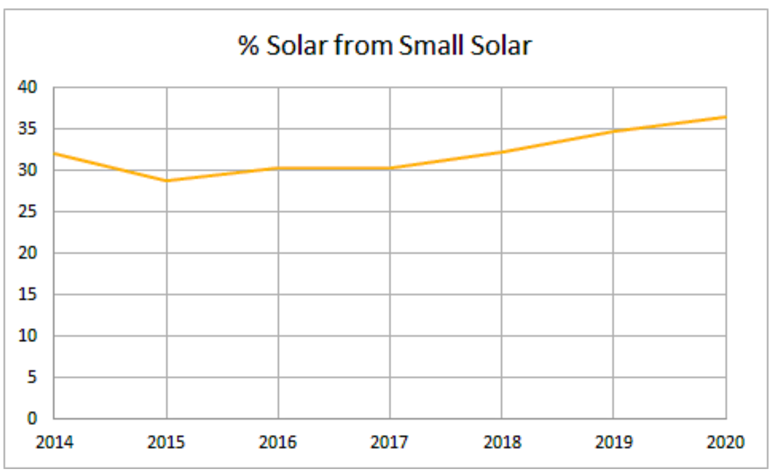

Fig. 2. 4 Proportion of California solar electricity reported by EIA to be from small solar

California also remains one of the top importers of electricity nationwide. The following figure (Fig. 2.5), based on CEC data, shows the breakdown of 2020 imported energy by source where known. Imported energy appears primarily split between wind, fossil fuels, and hydro, followed by nuclear and solar. This electricity comes from different states in the Western Electricity Coordinating Council (WECC), and some participating areas in Canada and Mexico.

In summer of 2020, CAISO began to document that during high loads, instead of increasing with higher load, the imports began to decrease slightly, presumably because of similarly high demand in nearby regions. This is shown in Fig. 2.6 taking the CAISO graph[3] at which reports the imports at the time of the daily peak load for the years 2019, 2020, and 2021. We have added data for hot days in 2022, plotting the 5-min data for the indicated four days, confirming the continued trend.

[3] http://www.caiso.com/Documents/2022-Summer-Loads-and-Resources-Assessment.pdf, Fig. 15.

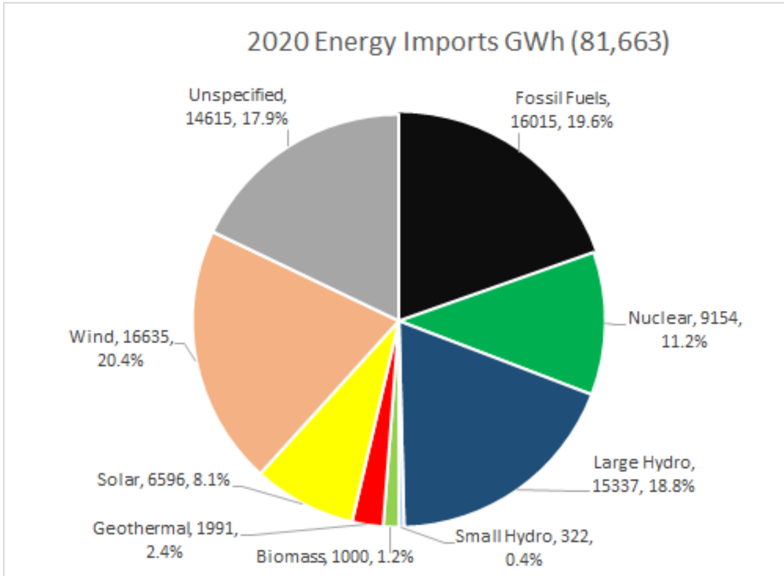

Fig. 2. 5 Electricity imported into California in 2020[4]

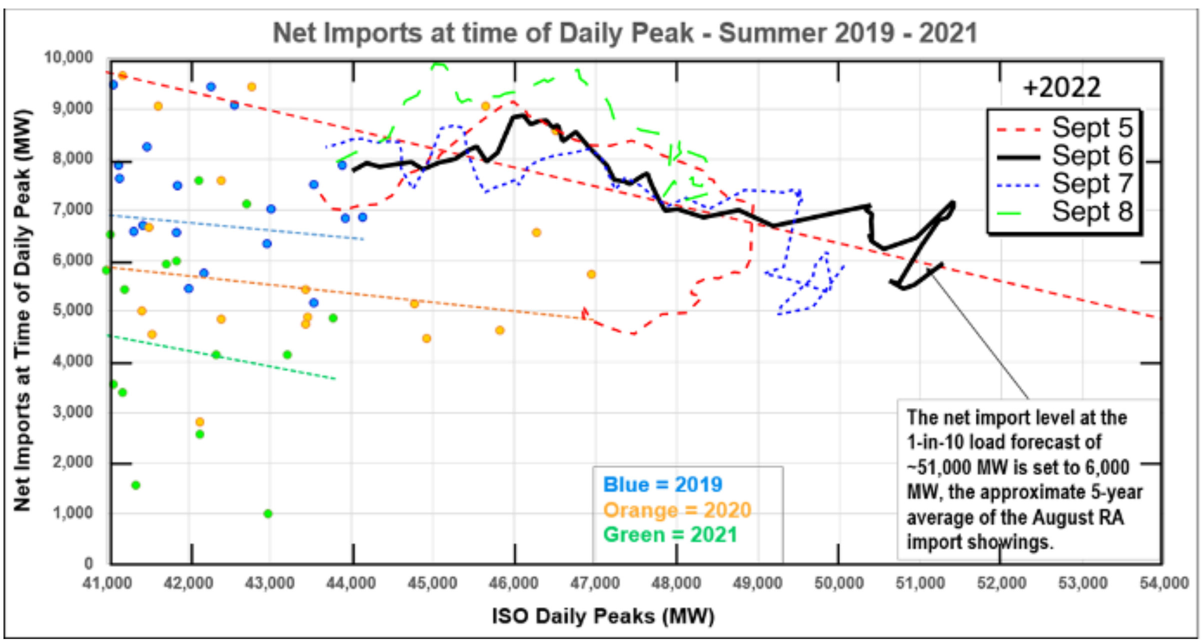

Fig. 2. 6 Net imports to CAISO as function of CAISO load

We anticipate that as neighboring states transition to using more solar electricity and reduce their reliance on natural gas, they will be less prepared to provide substantial electricity during times of high demand, which often occur around sunset in California, which is after the sun has set in WECC. The latest package for RESOLVE identifies multiple scenarios for the system resource adequacy (recorded in a file entitled “System RA.csv”) as summarized in Table 2.1 in which the Target is defined for each year for all scenarios and the adjustment is applied according to the

[4] https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2020-total-system-electric-generation

import scenario with no or low imports increasing the target and high imports decreasing the target. We propose to consider both the "Mid (MTR)" and "No Imports" cases.

Table 2. 1 Reduction in needed capacity for different import scenarios in RESOLVE

Scenario	Target adjustment	Target
PRM - No Imports	6578 MW	59,406 MW for 2030 62,444 MW for 2035 65,698 MW for 2040 69,165 MW for 2045
PRM - Low Imports	4578 MW	
PRM - Mid (MTR)	2578 MW	
PRM - Mid Imports	1578 MW	
PRM - High Imports	-5087 MW	

2.1 Solar

Solar energy is anticipated to continue to be the dominant source of renewable electricity within California. Fig. 2.7 shows how the southern part of California receives more than 7.5 kWh/m^2/day of direct normal irradiance. Even northern California receives more than 6 kWh/m^2/day of direct normal irradiance. As shown in Fig. 2.1, in 2020, solar represented > 22% of California's generation mix. As shown in Fig. 2.2, the rate of growth of solar has slowed in California, but it is still growing faster than any other renewable electricity source.

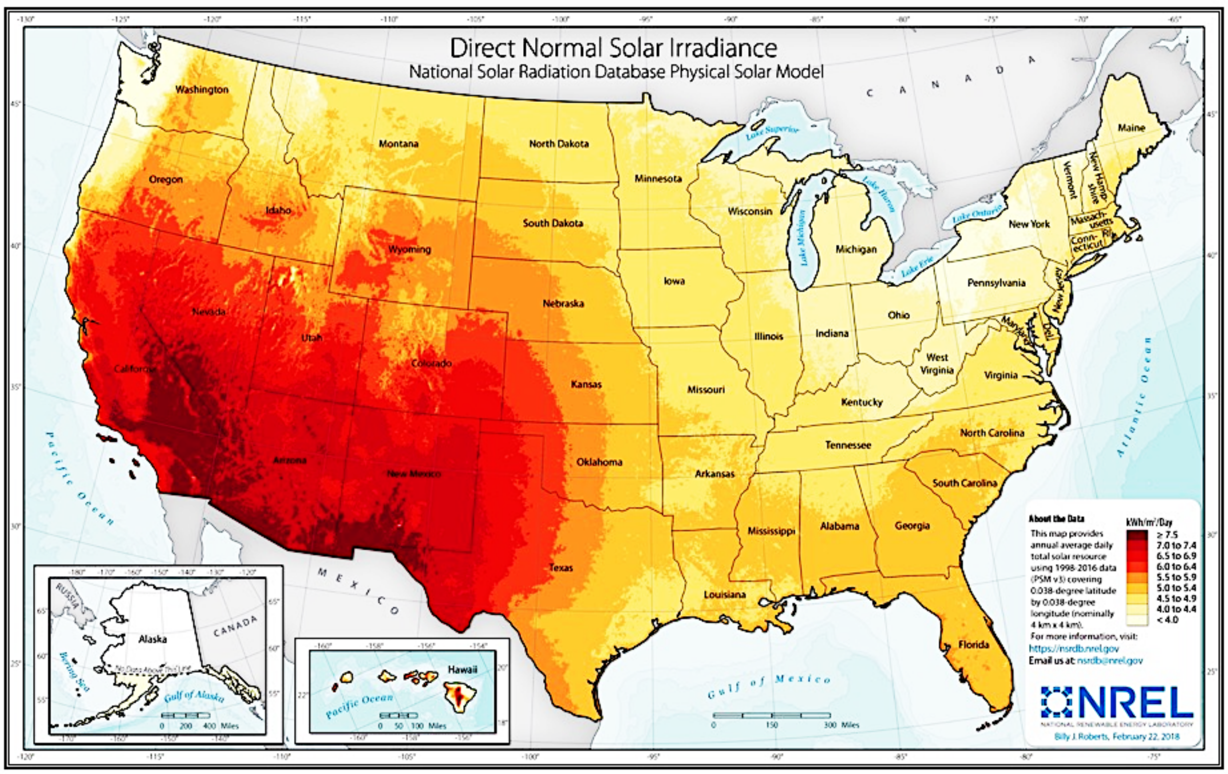

Fig. 2. 7 Annual direct-normal solar resource in U.S.[5]

[5] Sengupta, https://www.nrel.gov/gis/assets/images/solar-annual-dni-2018-01.jpg

The map in Fig. 2.7 helps to identify that the solar electricity generation in southern California is greater than that in northern California and that solar electricity generation inland is better than along the coast. However, more people live near the coast and fewer live in the desert, creating a need for transmission of the solar electricity if the solar resource in the desert is to be fully utilized.

All analyses we found of solar energy in California concluded that it would be possible to build as many solar plants as are anticipated to be needed. However, there is usually some opposition to building solar plants when the land is wanted for some other purpose, such as keeping the land undisturbed for the benefit of the natural ecosystem. The "Not In My Back Yard" (NIMBY) sentiment is being replaced (in some cases) by "Build Absolutely Nothing Anywhere Near Anyone" (BANANA) sentiment. Thus, while it will be possible to build enough solar to deliver the electricity needed for any scenario, it would be preferable to minimize the need for solar deployment on undisturbed lands.

California's movement toward requiring solar photovoltaic (PV) panels on buildings is one strategy for capturing the solar energy without needing to dedicate land, but other dual-use approaches may also be useful. Examples include floating PV, solar canals, agrivoltaics (when solar panels share farmland), and solar coverings of parking lots. Such installations may have different generation profiles than today's most common one-axis tracked systems. So, we discuss next the effect of the orientation of the solar on storage needs.

2.1.1 Effect of orientation on storage needs

The east-west orientation of solar panels affects the need for storage in the early evening and the morning as the sun is rising but has less effect on storage needed in the middle of the night or on longer time scales. The location and extent to which the systems are tilted toward the south[6] will have a greater effect on the seasonal storage, as shown in Fig. 2.8, which compares the average solar insolation as a function of month of the year for two locations using three mounting configurations. Arcata is located in northern California, so experiences greater variations in the length of the day between summer and winter compared with locations in southern California. Daggett is located in the desert in southern California, so receives more sunshine than Arcata. For solar panels mounted in a horizontal orientation with one-axis tracking, the ratio of the peak monthly average (summer) insolation to minimum monthly average (winter) insolation is 3.75 for Arcata and 2.9 for Daggett. If the daily load is relatively constant through the year, such variations in electricity generation will cause either an oversupply of electricity in the summer or an undersupply in the winter.

Near-horizontal mounting is often used on flat roofs, reducing cost because reduced wind loading enables use of less expensive mounting hardware. For solar panels mounted with south-facing latitude tilt, the ratio of the average summer insolation to average winter insolation is 2.0 for Arcata and 1.4 for Daggett. Latitude tilt mounting is often used on south-facing roofs that are sloped at an angle that matches the latitude. Despite giving more electricity generation, use of latitude tilt is not common. Latitude tilt on flat roofs or in a field can increase costs because wind loading requires

[6] Note that we speak of south-facing from California's perspective. Locations in the southern hemisphere would use north-facing mounting.

use of more expensive mounting hardware while added spacing between rows of panels is needed to avoid shading between rows. (Note that latitude tilt is not an issue for locations near the equator; it becomes increasingly important nearer the North and South Poles). Despite the challenges of using south-facing tilt, the seasonal variation in output is reduced by almost a factor of two, suggesting that mounting solar panels to face south may become more of a priority as wintertime electricity generation becomes a priority for a decarbonized grid. Siting nearer the equator helps to both increase the average output of the solar panels and to reduce the seasonal variation in the generation. In California, the seasonal variation is not only because of the length of the day and the position of the sun in the sky, but because seasonal weather patterns typically bring rain to northern California preferentially during the winter.

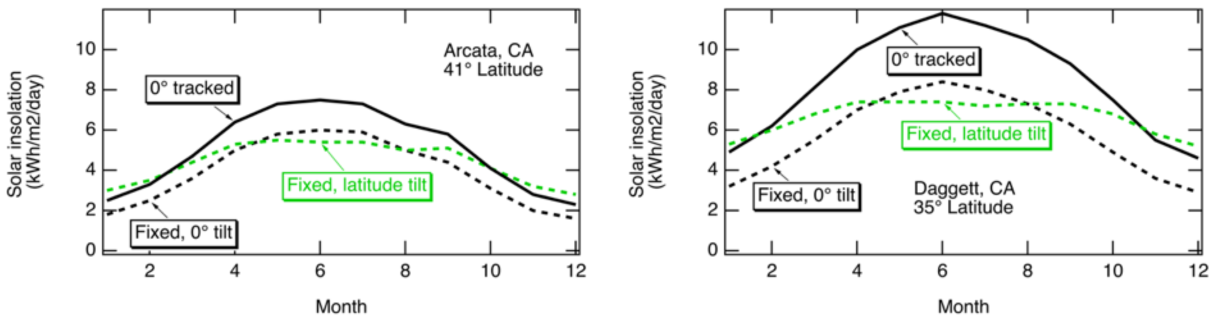

Fig. 2. 8 Monthly solar insolation as a function of mounting configuration (30-year median)[7]

The use of tracking increases the output near sunrise and sunset (affecting diurnal storage) but does not make a substantial difference in the seasonal variation as can be seen in Fig. 2.8. Most utility-scale systems today use one-axis tracking with no south-facing tilt, since this configuration has generally been found to optimize the ratio of the electricity generation to the system cost. This optimization may be revisited as storage is used more to facilitate use of solar electricity when the sun isn't shining.

The data in Fig. 2.8 compare the solar resource on different mounting surfaces. The solar electricity generation for a typical year was simulated by PV Watts[8] for a location with latitude of 37.29 and longitude -120.5 and is compared with the measured[9] solar generation for CAISO California 2019 in Fig. 2.9. The simulations used a DC-AC ratio (inverter-loading ratio) of 1.2. The current solar PV capacity for CAISO was estimated to be 12.75 GW based on CEC data.[10] The PV Watts simulations were scaled to the 12.75 GW for more direct comparison to the measured data. However, the measured CAISO data included some solar thermal data explaining why they exceed the simulated data. As would be expected, the shape of the observed data is similar to that of the simulated 1-axis tracked data. The latitude-tilt simulated data show a reduced seasonal effect.

[7] https://nsrdb.nrel.gov/data-sets/archives.html
[8] https://pvwatts.nrel.gov
[9] http://www.caiso.com/informed/Pages/ManagingOversupply.aspx
[10] https://ww2.energy.ca.gov/almanac/electricity_data/web_qfer/index_cms.php

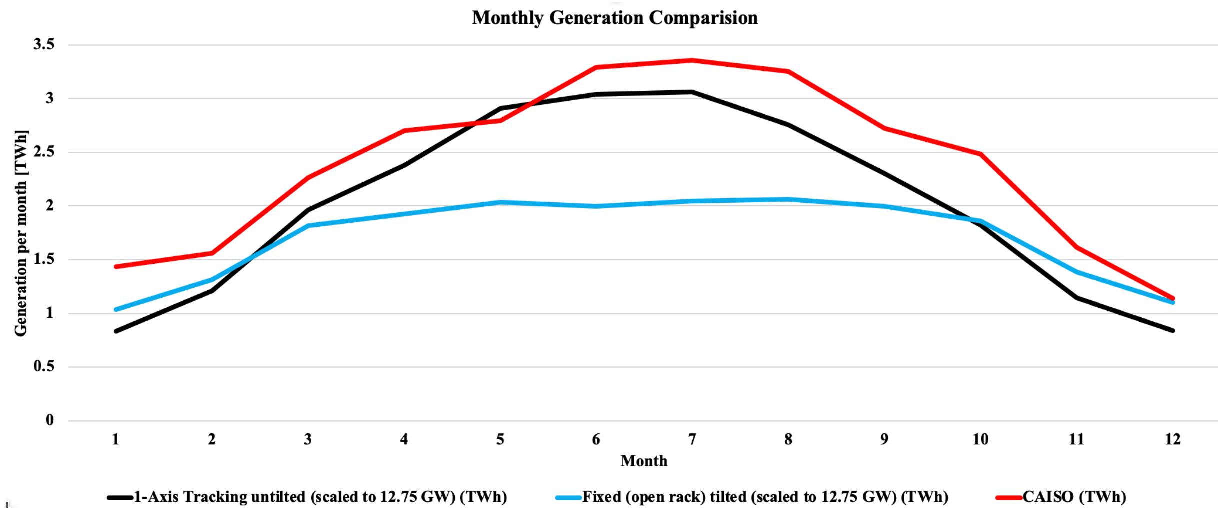

Fig. 2. 9 Simulated monthly solar electricity generation and solar electricity reported by CAISO (2019)

Using an energy balance approach[11] and adding solar generation as modeled in Fig. 2.9, the effect of orientation on the needed seasonal reservoir is shown in Figs. 2.10 and 2.11 for total generation of 105% and 135% relative to the total load respectively. The latitude tilt, in these cases, reduces the needed seasonal storage energy by about a factor of two or three.

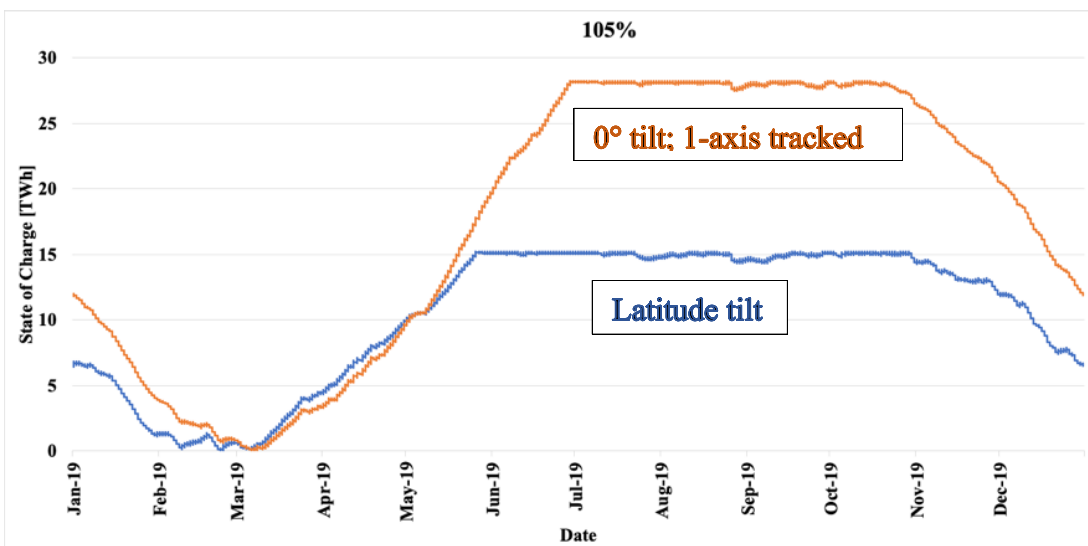

Fig. 2. 10 State of charge of storage using 2019 CAISO load and generation data, but replacing thermal and imported generation with the indicated solar generation to meet 105% of the load

We anticipate that the optimal orientation will depend on the cost, efficiency, and other properties of the available storage. Thus, instead of assuming 1-axis tracked, 0° tilt for all solar resources, we will also offer the model other orientations.

[11] M. Y. Abido, K. Shiraishi, P. A. Sánchez-Pérez, R. K. Jones, Z. Mahmud, C. Sergio, N. Kittner, D. M. Kammen and S. R. Kurtz, "Seasonal Challenges for a Zero-Carbon Grid," in 48th IEEE Photovoltaic Specialists (PVSC), Miami-Fort Lauderdale, FL, 2021.

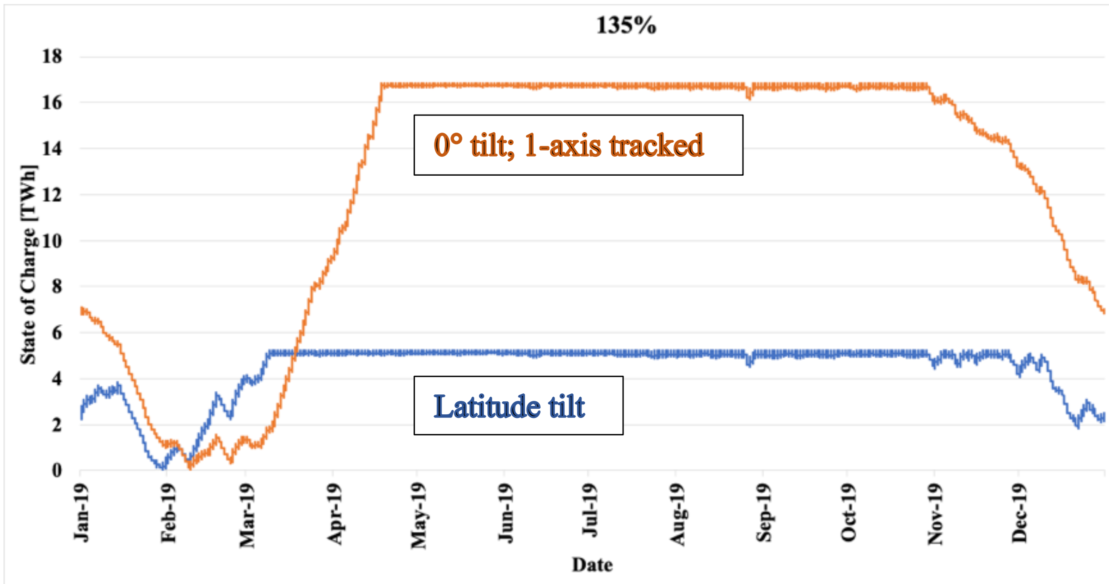

Fig. 2. 11 State of charge of storage using 2019 CAISO load and generation data, replacing thermal and imported generation with the indicated solar generation to meet 135% of the load

2.1.2 Effect of solar modeling assumptions on storage needs

A summary of the strategies that can be used that affect the amount of solar that can be accessed and how the solar generation profile affects the need for storage are summarized in Table 2.2.

Table 2. 2. Effects of solar generation on roles of storage

Storage type	**Storage need associated with solar-dominant generation**	**Modeling considerations that may affect conclusions about storage**
Diurnal storage	Required every day	Tracking: Use tracking for more consistent output during the day, but nighttime diurnal storage will always be needed Orientation: For fixed tilt, east- or west-facing orientation may increase output in the morning or evening, respectively Geographical diversity: spread installations across state from east to west to capture both early morning and late afternoon sunshine
Cross-day storage	Required intermittently	Geographical diversity: spread installations across state and connect with transmission
Seasonal storage	Substantial seasonal storage will be needed because generation in summer is about twice that in winter	South-facing tilt: Use south-facing latitude tilt to reduce seasonal variation Site in south: Southern siting may show smaller seasonal variations DC-AC ratio: High DC ratios tend to reduce the variability in the daily electricity generation
All types of storage	Storage needs can be reduced by building more solar than is needed to meet conventional electricity demand	Create flexible loads to meet energy needs not supplied by electricity today: EV charging can reduce diurnal storage needs; Summertime electrolysis can provide green hydrogen to meet other energy needs while reducing need for seasonal storage

2.2 Wind

The wind resource in California is far less than the solar resource, as shown in Fig. 2.12 compared with Fig. 2.7. While California is one of the best locations for solar resource, it is one of the worst locations in the U.S. for wind resource. It does have strong resource for offshore wind and in a limited set of locations associated with mountain ranges and especially in passes that guide movement of air from one side of a mountain range to the other.

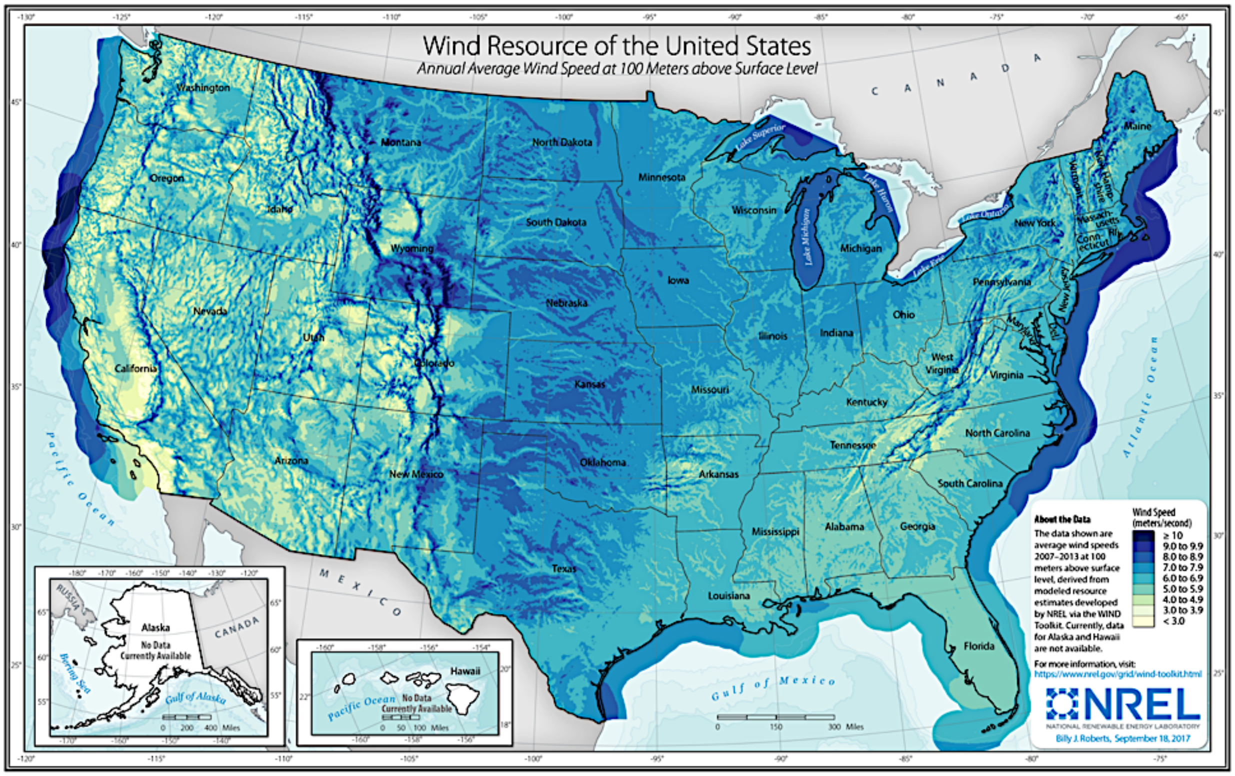

Fig. 2. 12 Wind resource based on average wind speed at 100 m above surface[12]

Despite the inferior wind resource, California currently generates 6 % to 7% of its electricity from wind. Studies typically assume that the onshore wind electricity generation in California may roughly double or triple in the coming years with additional offshore wind development and additional imports of wind electricity from Wyoming.[13]

Modeling of wind electricity generation is challenging because of the high spatial variability in wind resource. The wind blowing on one side of a mountain range may be very different from the wind blowing on the other side. Additionally, the wind resource tends to follow the mountain ranges, but the accessibility of sites along a mountain range may be challenged making deployment difficult even when the wind speed is adequate. Wind resource is site specific, much more than solar. It depends on hub height and characteristics of installed turbine. For instance, increasing the height of a turbine could access a steadier wind resource with non-linear increases in power output.

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[12] https://www.nrel.gov/gis/assets/images/wtk-100m-2017-01.jpg

[13] https://www.energy.ca.gov/sb100; https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html; https://www.2035report.com/electricity/data-explorer/?hsCtaTracking=aefa383f-f7b1-45c3-99c8-9413fdc3a3c7%7C98cb714c-8c3e-4475-b718-610a20b81491

2.2.1 Effect of implementation on storage needs

Wind electricity in California today complements solar electricity generation when the diurnal cycle is considered, as shown in Fig. 2.13, reducing the need for diurnal storage on windy nights. However, its seasonal variation follows that of solar and sometimes shows an even greater decrease in winter as shown in Fig. 2.14. Note that the relative scale used in Fig. 2.14 sets the maximum monthly generation to 100% with different scaling factors used for solar and wind.

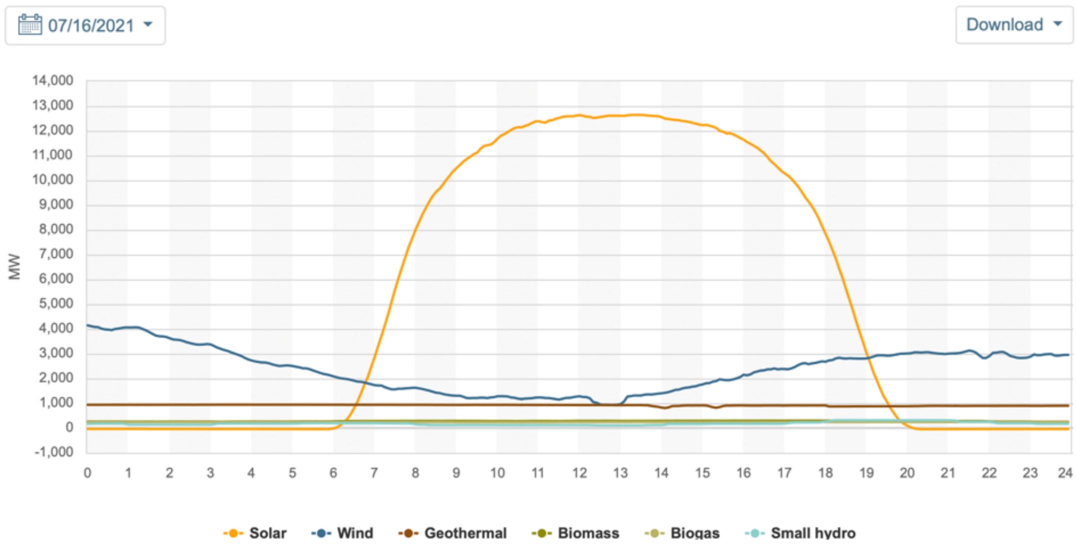


Fig. 2. 13 Renewable electricity generation reported by CAISO for July 16, 2021[14]

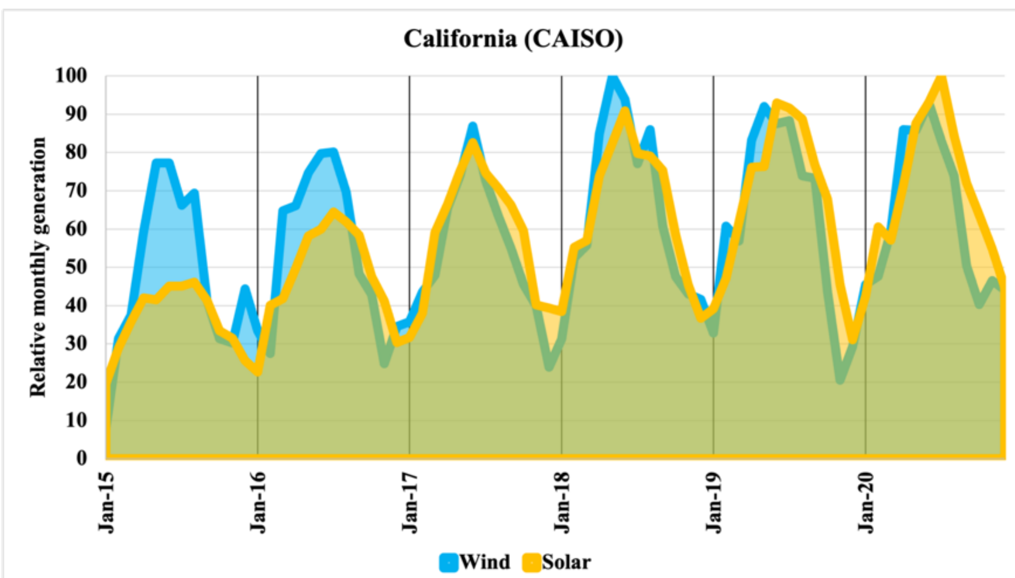


Fig. 2. 14 Monthly relative solar and wind electricity generation in California

[14] http://www.caiso.com/TodaysOutlook/Pages/supply.html

We observe[15] that some wind generators in California exhibit generation that differs greatly from that in Fig. 2.14. While more than 90% of California's wind generators are observed to provide maximum output in the summer, others generate more electricity in the winter, as shown in Fig. 2.15. The variability reflected by the blue-shaded regions in Fig. 2.15 mostly reflects that some plants show larger or smaller capacity factors. Although the variability indicated by the blue shaded region could imply variations from year to year, the variation between plants is larger than the variation from year to year.

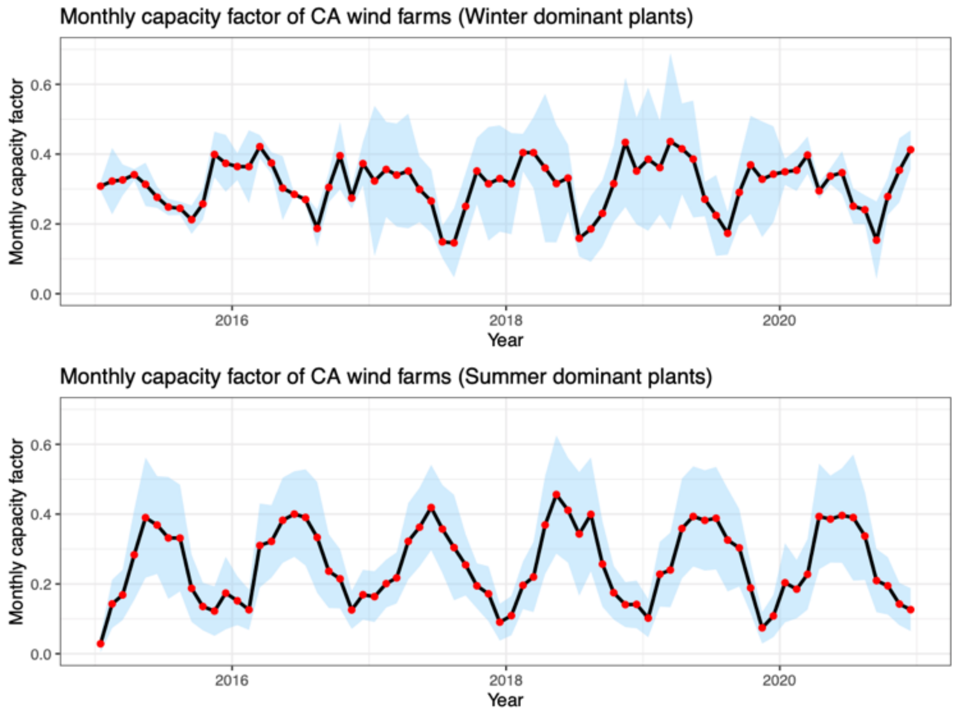


Fig. 2. 15 Monthly capacity factor for two populations of California wind generators; solid lines and blue-shaded regions represent the mean and one standard deviation of the two populations[15]

Our calculations[15] found that more than half of California has winter-dominant wind potential, but, consistent with Fig. 2.12, only a small fraction of those locations has strong wind resource, as shown in Fig. 2.16. We also explored a winter-summer difference as a more symmetrical metric than the winter-summer ratio.[15] The sites highlighted in the rightmost map of Fig. 2.16 are found to have high wind speeds during the winter. However, we have not evaluated which of these would be commercially viable. Nevertheless, we believe there is value in evaluating the effects on storage of selecting winter-dominant vs summer-dominant wind sites. Selecting the winter-dominant sites might reduce the need for seasonal storage as shown in Fig. 2.17. That simulation, which shows that the need for seasonal storage effectively disappears, introduces more wind than is practical. However, it underscores how wind in California comes in different flavors. Both the type of wind and the amount of wind we introduce will be important.

[15] Z. Mahmud, K. Shiraishi, M. Abido, D. Millstein, P. Sanchez, and S. Kurtz, *"Geographical variability of summer- and winter-dominant onshore wind"* Journal of Renewable and Sustainable Energy, Volume 14, 023303, 2022.

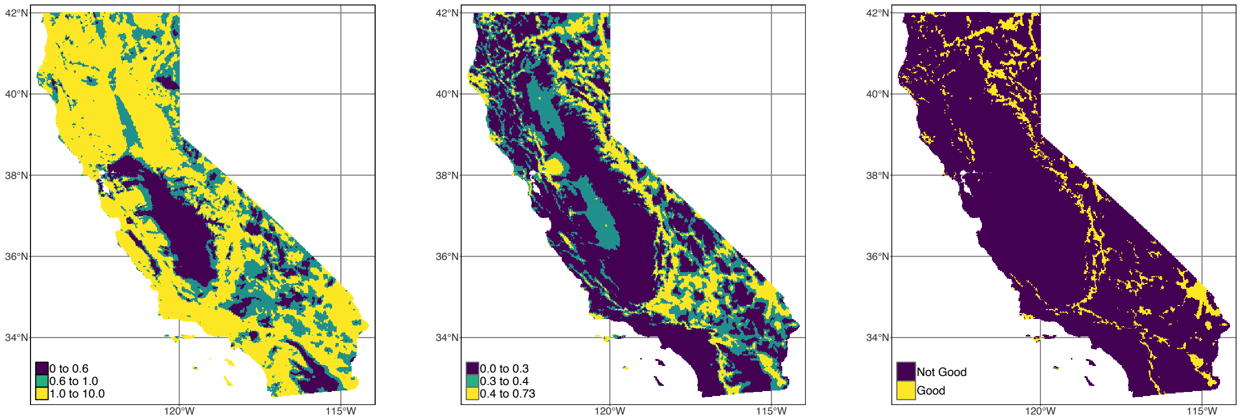


Fig. 2. 16 Maps of California wind potential. Left: Ratio of winter-to-summer wind potential; middle: simulated capacity factor; right: "Good"= winter-to-summer ratio > 1 and capacity factor > 0.4

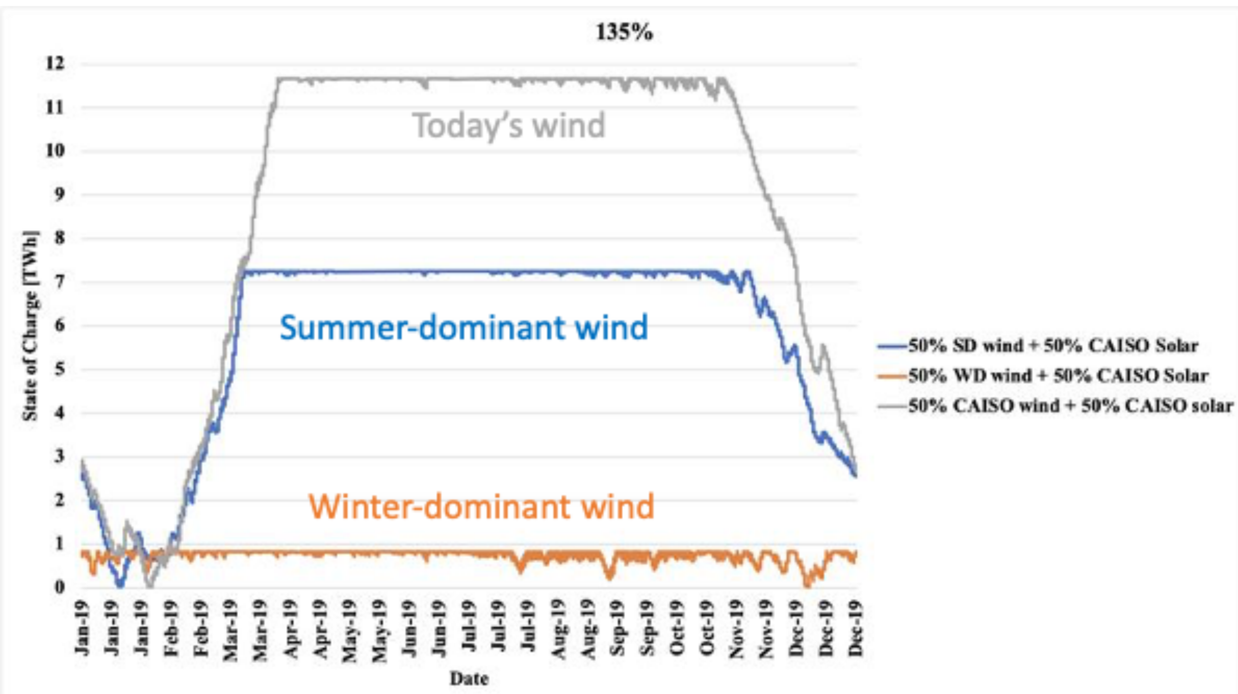


Fig. 2. 17 State of charge of storage using 2019 CAISO load and generation data, replacing thermal and imported generation with 50% solar and 50% wind generation to meet 135% of the load

Offshore wind also has the potential to provide relatively more electricity generation during the winter as shown by Fig. 2.18.

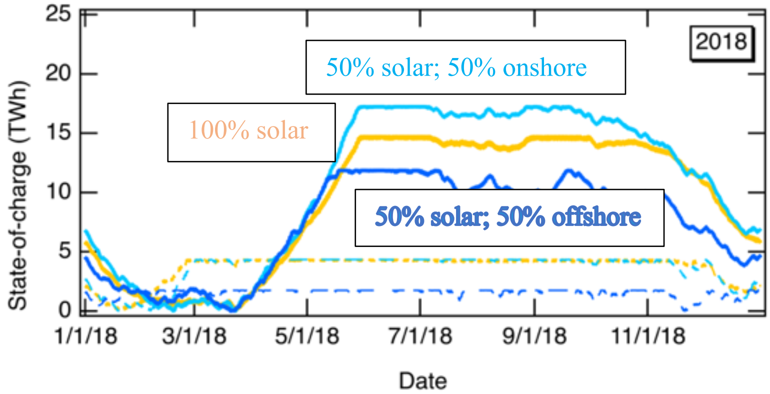


Fig. 2. 18 Calculated state of charge for stored energy using 2018 generation and load data with thermal, nuclear, and imports replaced with electricity generation as indicated to deliver 105% of load

The wind generation profiles are highly variable in different locations. Figs. 2.19 and 2.20 show the simulated wind generation for the entire year enabling the diurnal patterns to be observed on the vertical scale and the cross-day and seasonal patterns on the horizontal scale. The large diurnal value of the onshore wind is apparent in Fig. 2.13. This is especially obvious for the summer-dominant data (left of Fig. 2.19) showing that the wind farms operate at almost full potential most nights between the hours of about 17:00 and 6:00. Thus, these sites are very good for complementing the solar generation between the months of April and October. The onshore winter-dominant site shows a much smaller (but non-negligible) diurnal trend with very little output in the summer and variable output in the winter. (Note that other sites will show slightly different results.)

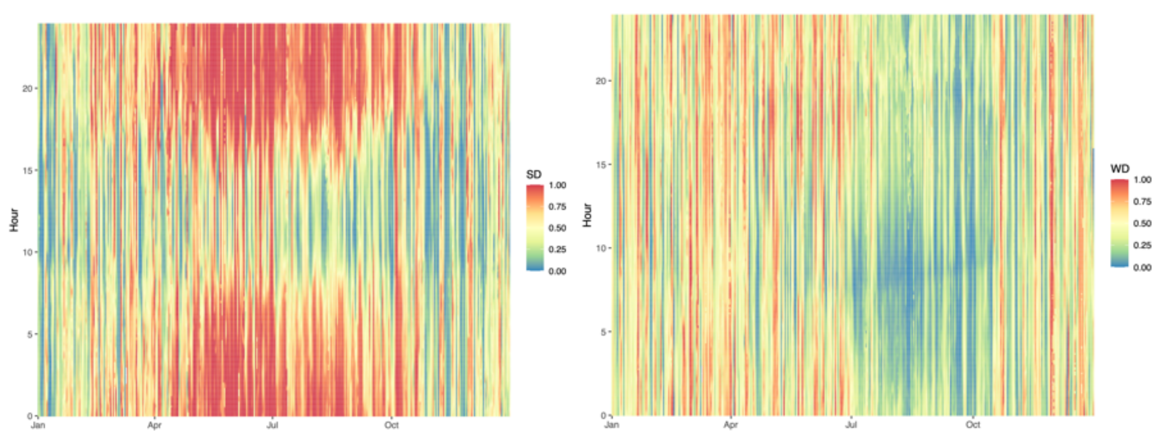


Fig. 2. 19 Wind generation profile for onshore wind (left: summer-dominant; right: winter-dominant)

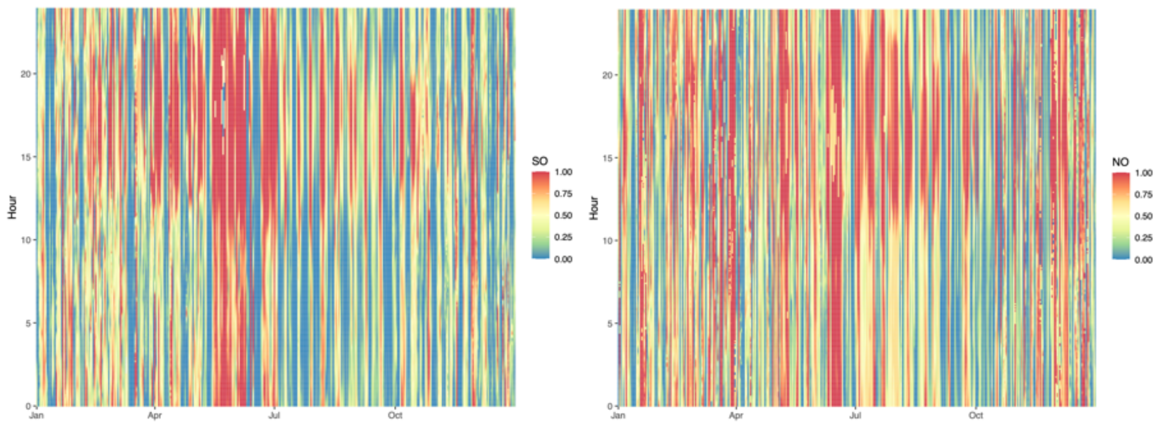


Fig. 2. 20 Wind generation profile for offshore wind (left: south; right: north)

The offshore wind shows substantially different generation, as can be seen by comparing Figs. 2.19 and 2.20. For the selected year (2019), the southern offshore wind (left Fig. 2.20) shows the greatest generation in the late spring. The nighttime generation seen so clearly for the summer-dominant wind in Fig. 2.19 is less clear for the offshore wind. The offshore wind in both the south and the north tend to increase approximately between the hours of 12:00 and 22:00. This period is usually a time of high electricity demand, suggesting that this electricity will be helpful in meeting California's peak loads, though in a different way than today's wind.

Colorado and Wyoming wind are also known for being strong in winter as shown for Colorado in Fig. 2.21. Importing substantial electricity from the other side of the Rocky Mountains will require investment in transmission lines but may prove to be one of the most cost-effective ways to supply electricity during the winter. However, recent data show (e.g. see Fig. 2.6) that relying on imports during times of high demand may not work as well in the future as it has in the past, so the use of imports should be approached cautiously.

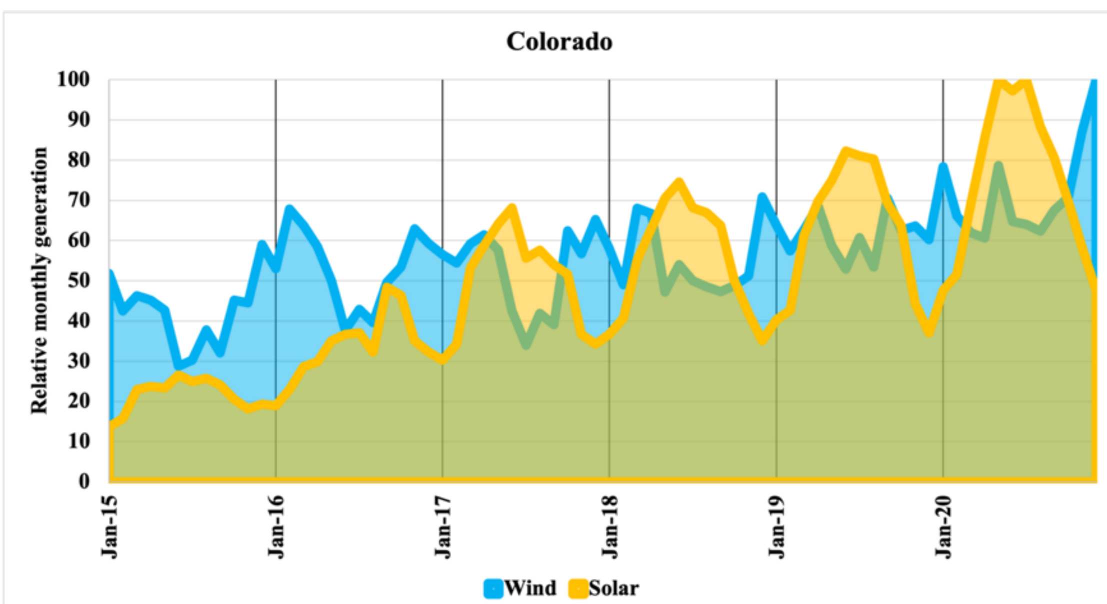


Fig. 2. 21 Monthly wind and solar electricity generation in Colorado as reported by EIA.

The effect of adding wind on the different types of storage (see Section 3 for the methodology) is summarized in Figs. 2.22 and 2.23. The available wind resource in some of these categories may be < 5 GW, but it may be possible to deploy > 10 GW of offshore wind if both the southern and northern resources are considered. The increase in the use of cross-day storage is linked to the decrease in seasonal storage as some storage that would only be cycled once per year begins to be cycled multiple times per year.

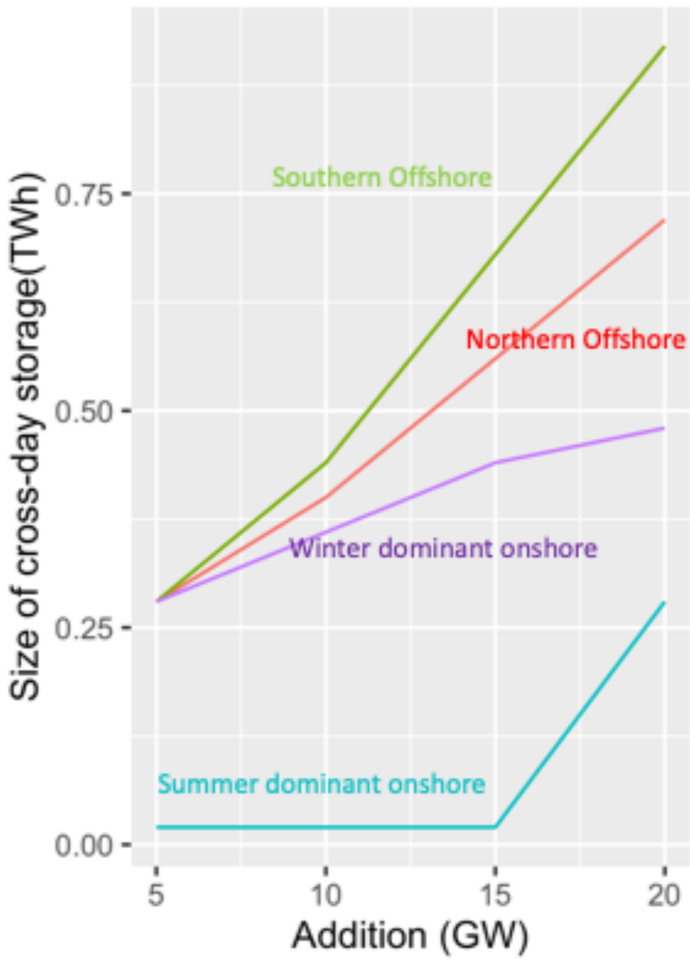


Fig. 2. 22 Effect of replacing solar generation with wind on the need for cross-day storage in California

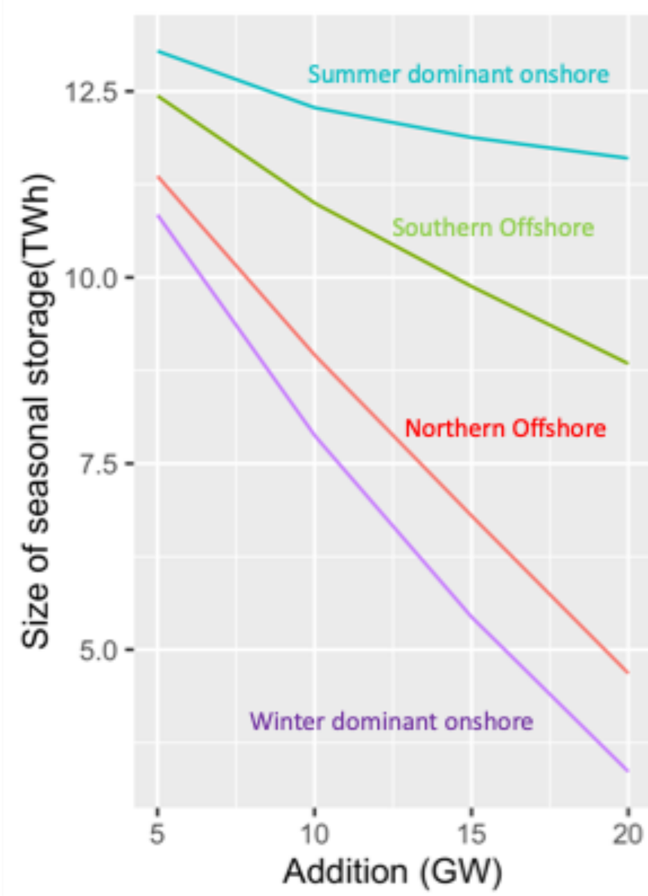


Fig. 2. 23 Effect of replacing solar generation with wind on the need for seasonal storage in California

2.2.2 Effect of wind modeling assumptions on storage needs

A summary of the strategies that can be used that affect the amount of wind that can be accessed and how the wind generation profile affects the need for storage is found in Table 2.3.

Table 2. 3 Effects of wind generation on roles of storage

Storage type	Storage need associated with wind generation for solar-dominant grid	Modeling considerations that may affect conclusions about storage
Diurnal storage	More wind reduces frequency of using diurnal storage	Siting: some locations complement solar better than others, see Figs. 2.19 & 2.20
Cross-day storage	More wind increases the need for and use of cross-day storage	Offshore wind tends to show greater fluctuations than onshore
Seasonal storage	Added wind can either increase or decrease need for seasonal storage	Siting: some locations have stronger wind in the winter; some have stronger wind in the summer
All types of storage	Storage needs can be reduced by building more generation than is needed to meet conventional electricity demand	Create flexible loads to meet energy needs not supplied by electricity today: EV charging can reduce diurnal storage needs; Offshore wind electrolysis can provide green hydrogen to meet multiple energy needs while foregoing the need for a transmission line

2.3 Hydropower

According to the CEC there is currently a total of 274 operational hydroelectric facilities in California, with a total installed capacity of 14,042 MW[16]. Facilities smaller than 30 MW are generally considered an eligible renewable energy resource and are referred to as small hydro, while all other hydro facilities are referred to as large hydro and are not counted toward renewable energy goals. This is a useful approach because of the large variability of the large hydro from year to year depending on rainfall. In special cases, some facilities larger than 30MW may also qualify as renewable energy resources under special eligibility criteria. Of the previously mentioned 274 facilities, 202 are considered small hydro, and account for 16% of the net hydropower generation in 2020.

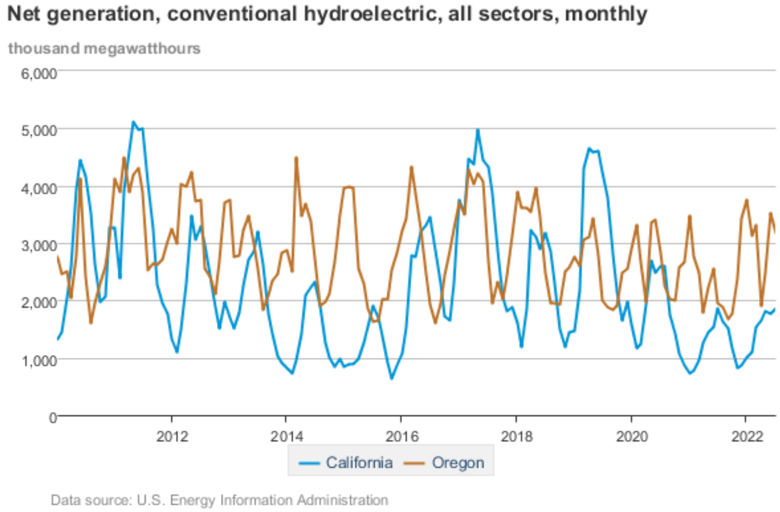
Hydropower has the potential to be a powerful tool in helping to meet California's decarbonization goals. However, the amount of hydroelectricity produced each year varies with rainfall and snowmelt runoff, making hydropower difficult to predict in the face of recurring drought. Figure 2.24 shows the monthly electricity generation in about the last 10 years (top) and the annual generation for about 20 years (bottom) from conventional large hydropower within California. Oregon and Washington (for the annual graph) are included to better understand the bigger picture. Though hydropower provides an average of around 2.5 TWh/month and reaches up to 5 TWh/month at times, only about 1 TWh/month has been reliably supplied as a minimum. We can see from Fig. 2.24 that we are currently in a drought of comparable severity to the drought in 2014-2015.[17]

2.3.1 Effect of implementation on storage needs

Both large and small hydro show higher production in the summer, following the energy demand (see Figs. 2.25-26). This is not surprising, but the ability of hydropower to respond to market demands is important in determining the potential for hydropower to reduce the need for storage. The flow of water out of a dam may be required to meet a minimum flow for a river or may need to be increased to avoid overfilling a reservoir (possibly without generating power). Within those constraints, the adjustment of the hydropower to respond to demand can translate directly into reduction in need for storage. From Fig. 2.24 (top) we observe that in wet years, Oregon and California both generate the most electricity from hydropower during the winter while during dry years, California inverts its use of hydropower and saves the generation for the summer, when the electricity is most needed.

[16] The CEC statistics and data page lists 274 producing facilities, but their downloadable list of hydro facilities (https://www.energy.ca.gov/data-reports/energy-almanac/data-renewable-energy-markets-and-resources) has 343 entries. Some of these have clearly been shut down at some point in the past, despite being erroneously listed as "operational" in the document, while the status of others is ambiguous. This report uses the 274 number for which yearly production data are readily available from the CEC. These values are constantly changing.

[17] https://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,1,0&fuel=04&geo=000000000007&sec=g&linechart=ELEC.GEN.HYC-CA-99.A~ELEC.GEN.HYC-OR-99.A~ELEC.GEN.HYC-WA-99.A&columnchart=ELEC.GEN.HYC-CA-99.A&map=ELEC.GEN.HYC-CA-99.A&freq=A&start=2001&end=2021&ctype=linechart&ltype=pin&rtype=s&maptype=0&rse=0&pin=



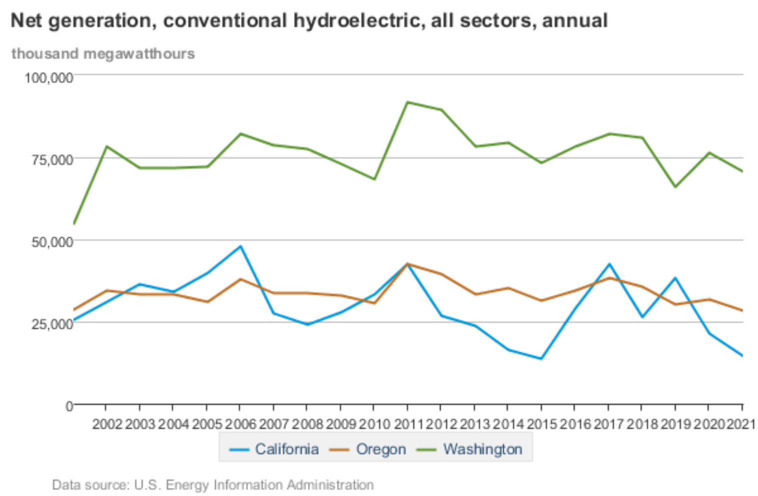


Fig. 2. 24 Electricity generation by hydropower: monthly data (top) and historical annual data (bottom)[17]

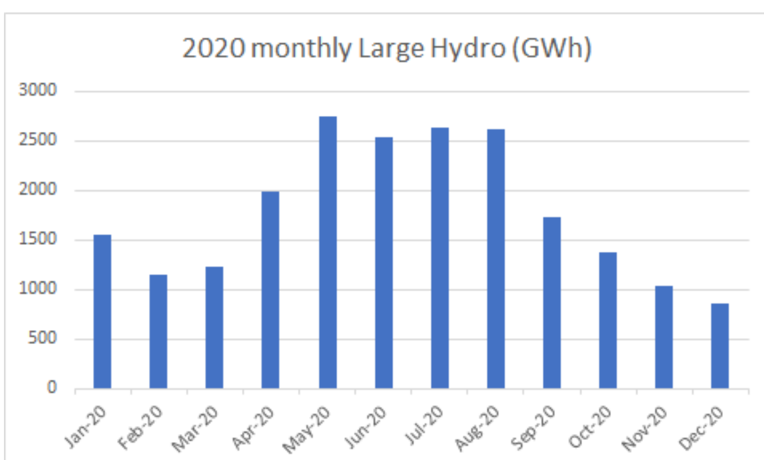


Fig. 2. 25 Large Hydro Monthly Generation (data from EIA)

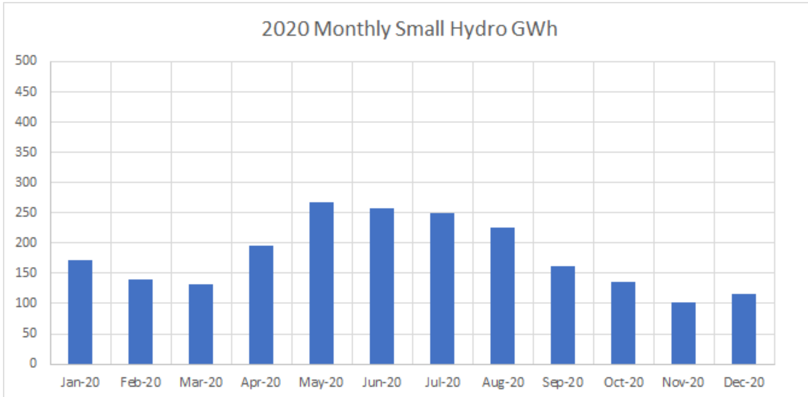


Fig. 2. 26 Small Hydro Monthly Generation (data from CAISO)

During a 24-hour cycle (Figs. 2.27-2.28), large hydro production is at a low during midday when solar is dominant, and a high during evening hours of peak demand when the sun is down. It also shows a strong degree of dispatchability, with production capable of rising and falling by several hundred MW to a GW in the span of 5-10 minutes, in response to shifting demand. While small hydro shows a similar high during evening hours, the overall behavior is flatter and less responsive. Figures 2.27 and 2.28 show daily profiles for the 15th of each month for large and small hydro, respectively. The data points are from CAISO's real time power mix monitoring in 5-minute intervals. The profile for Aug. 15, 2020 appears anomalous and corresponds to a day when CAISO declared an emergency because of a heat wave. Challenges in that heat wave resulted in load shedding despite many actions taken to avoid more extensive power outages.

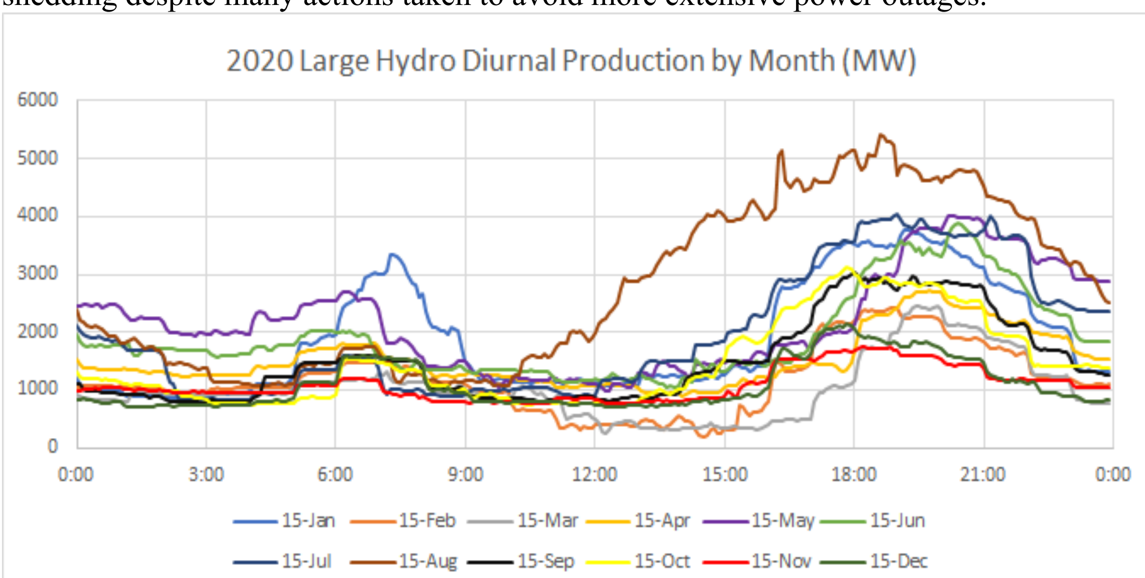


Fig. 2. 27 Large Hydro diurnal cycle by month

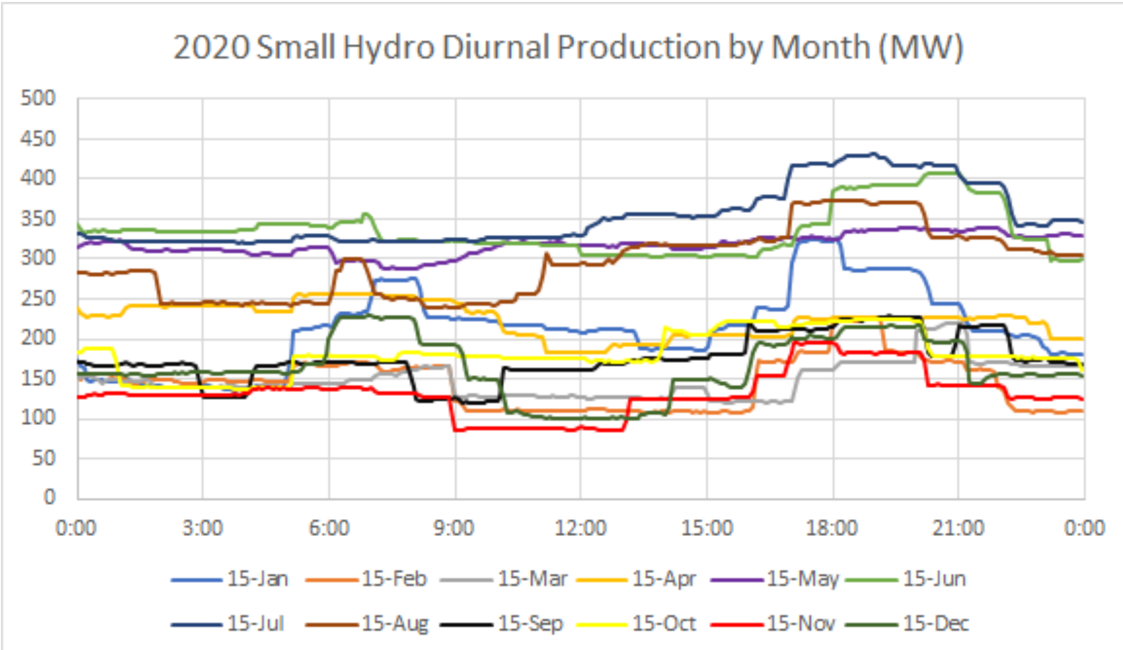
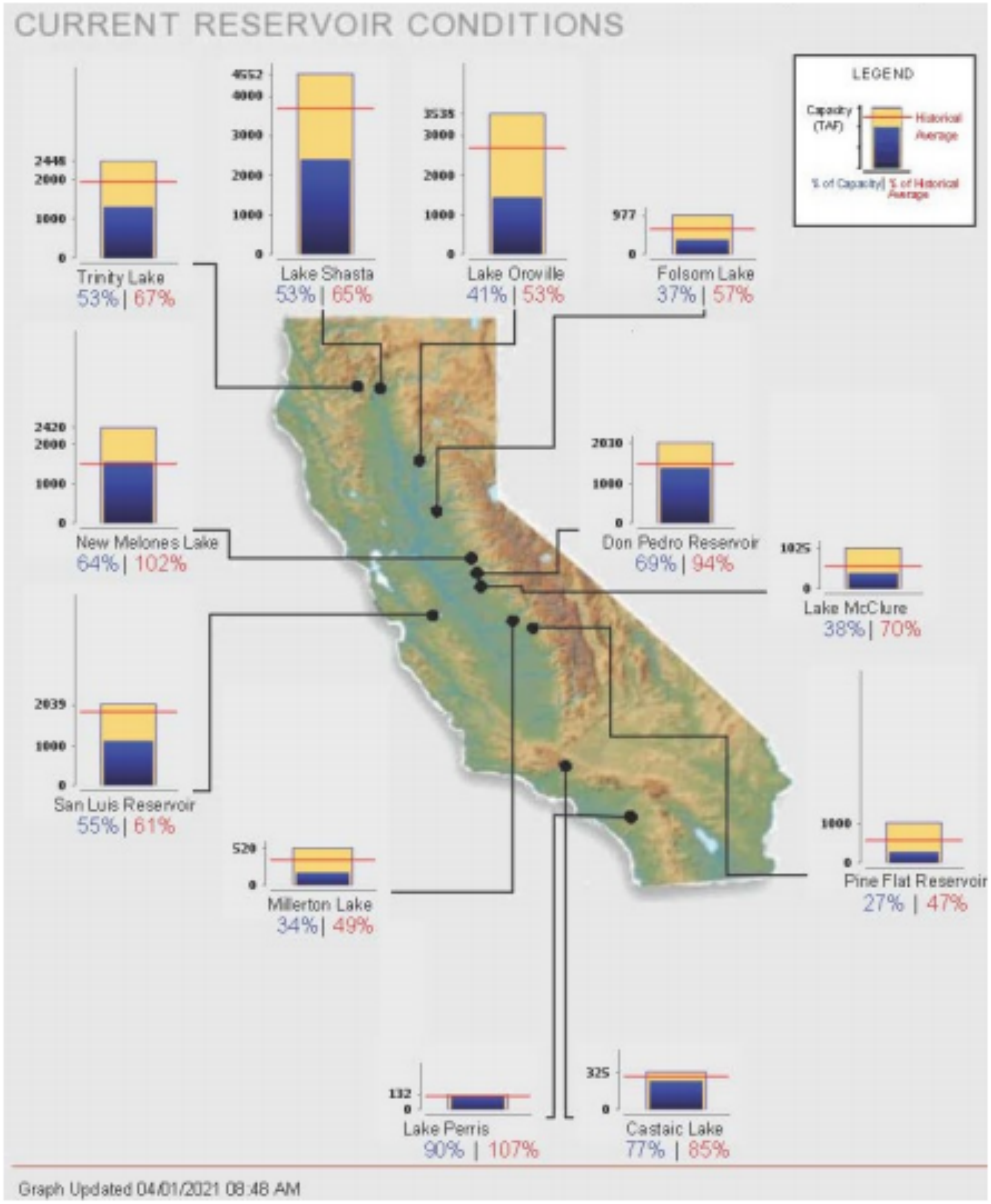


Fig. 2. 28 Small Hydro diurnal cycle by month

California ISO models hydro-generation resources as a combination of non-dispatchable "run-of-river" and dispatchable reservoir resources. The run-of-river represents what is naturally in place flowing through water systems in a given year, and has a fixed generation profile derived from historical data for north and south. Dispatchable hydro-generation is the capacity of large-scale reservoirs that can be tapped to provide additional power in response to system demand, and can be optimized subject to daily energy limits and maximum and minimum values governed by reservoir conditions.[18] Both large and small hydro systems can draw from either category depending on their system design. Water diversion facilities divert water from natural channels to another path with a turbine, usually returning it further downstream, and are thus highly dependent on run-of-river. Dam/pondage or pumped storage systems have a built-in reservoir, and are more dispatchable in design, even if their degree of dispatchability is limited by reservoir size, leading to the less dispatchable behavior of small hydro compared to large hydro. Figure 2.29 shows the location of major California reservoirs and their current capacity compared to weighted historical averages. As of April 2021, overall reservoir capacity sat at 70% of historical average.

[18] Caiso Summer Loads and Resources Assessment 2021



Source: California Department of Water Resources

Fig. 2. 29 California Major Reservoir Conditions as of 04/01/2021, from 2021 CAISO Summer Loads and Resources Assessment.

Capacity in 2022 was even lower as tabulated in Table 2.4. The variability over many years is dependent on the amount of rainfall, which can be highly variable. The current drought is even more concerning because increasing temperatures are slowly decreasing the amount of snow that is stored in the mountains. If the snow fields are decreased too much, they may disappear in late summer, leaving the state without this valuable resource just at the time when it is needed most!

Table 2. 4 Historical California Reservoir Water Storage[19]

Table 9

Historical California Reservoir Water Storage

End of March

Report generated: April 11, 2022 10:20

End-of-month Storage in Calendar Year:

REGION	NUM of RES	CAP	Hist Avg	1977	1983	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
STATE															
NORTH COAST	6	3,096	2,229	1,165	2,421	2,475	1,626	1,565	1,718	2,644	2,234	2,376	2,345	1,549	1,071
SAN FRANCISCO BAY	17	715	525	318	656	441	436	443	527	553	441	539	469	394	451
CENTRAL COAST	6	982	637	435	929	527	210	204	202	668	460	673	519	388	281
SOUTH COAST	29	2,122	1,433	921	1,920	1,242	1,143	864	1,036	1,422	1,270	1,458	1,355	1,243	1,082
SACRAMENTO RIVER	43	16,151	12,012	6,233	13,208	12,746	8,813	9,681	13,076	13,525	12,518	13,398	11,457	8,333	8,458
SAN JOAQUIN RIVER	34	11,483	7,640	2,918	9,045	7,150	5,009	4,641	5,394	8,960	9,075	8,881	7,970	6,378	5,705
TULARE LAKE	6	2,088	884	468	1,462	609	406	377	658	1,018	1,067	919	865	490	640
NORTH LAHONTAN	5	1,073	505	221	826	577	282	74	107	753	969	844	795	419	290
SOUTH LAHONTAN	8	412	264	168	293	249	245	226	240	245	287	272	291	265	236
STATE TOTAL	154	38,122	26,129	12,846	30,761	26,016	18,169	18,076	22,957	29,787	28,321	29,360	26,067	19,459	18,213
PCT OF AVG				49	118	99	69	68	87	114	108	112	100	74	70
						2-Year Ave	84	68.5	77.5	100.5	111	110	106	87	72.0
						3-Year Ave		78.7	74.7	89.7	103.0	111.3	106.7	95.3	81.3

Source: California Department of Water Resources

Figure 13 shows the storage levels of individual major reservoirs across the state.

2.3.2 Effect of hydro modeling assumptions on storage needs

Hydropower inherently has more possibility for alleviating needs for storage compared with wind and solar, which are instantaneously available only when the wind is blowing or the sun shining, respectively. As noted above, some hydropower is also uncontrollable (available when the water is flowing for other purposes). However, ultimately, the value of hydropower is most challenged because it varies substantially from year to year, so it is difficult to count on it (though a blessing when it is there). The current severe drought is an example of why we are hesitant to use dispatchable hydropower as a key element of resource adequacy in a zero-carbon grid.

The amount of hydropower identified to be adjustable (likely via some dispatchability factor applied to overall hydro-capacity), can be used to reduce the need for diurnal and cross-day storage. Large scale hydro-generation systems tied to major reservoirs essentially act the same as pumped hydro energy storage systems, though they are recharged naturally on a seasonal basis by rainfall and snowpack generation and melt rather than by the electrical grid. Such systems could be used as a form of seasonal storage by preferentially curtailing hydro-generation in the summer while relying on a solar dominated grid, to save water for use in the winter. In such a system, idle losses due to evaporation in summer months would have to be accounted for as part of the modeling. A significant complication to such a model would be the extensive patchwork of environmental regulations and legal contracts that govern water rights and access for various agricultural, municipal, and commercial actors. Some waterways are legally required to maintain minimum water levels, putting upper and lower bounds on how much water can be diverted or curtailed.

[19] http://www.caiso.com/Documents/2022-Summer-Loads-and-Resources-Assessment.pdf

A summary of strategies that can be used that affect the amount of hydropower that can be accessed and how the chosen hydropower generation profile affects the need for storage is summarized in Table 2.5.

Table 2. 5 Effects of hydropower generation on roles of storage

Storage type	**Storage need associated with hydro generation for solar-dominant grid**	**Modeling considerations that may affect conclusions about storage**
All types of storage	More hydropower will reduce need for all types of storage	Available volume: More hydropower, even if the generation is constant, reduces the need for storage Dispatchability: The amount of hydropower that is identified to be adjustable can be used to reduce the need for all types of storage

2.4 Geothermal

Geothermal plants follow one of three system designs. The simplest and oldest of these designs is known as “dry steam”, in which steam is collected directly from hydrothermal systems and sent up pipes to run a turbine before being recondensed and reinjected into the system. This acts as a closed system but requires the presence of steam within the hydrothermal system, creating a further constraint to siting. Such systems are concentrated in the Geysers geothermal area, located 115 km north of San Francisco, and represent California’s largest concentration of geothermal plants. The second, known as “flash” systems, pipe up the hydrothermal fluid directly and subject it to lower pressure in order to rapidly flash it to steam. This provides more flexibility, but the flash process releases dissolved gasses, including CO_2 that cannot be easily redissolved when the steam is recondensed and reinjected, creating non-zero carbon emissions that must be dealt with if the geothermal system is part of the zero-carbon emissions solution. “Binary” systems similarly pipe up fluid, then use a heat exchanger to heat a secondary fluid that then spins a turbine, while the hydrothermal fluid is returned in a closed system. This provides the flexibility of flash systems without the emissions but is typically associated with higher costs.

California has two of the largest geothermal reservoirs in the United States, the Salton Sea resource area and the Geysers (both shown in the Fig. 2.30), with an estimated generation capability of 2,200 MW and 1,800 MW respectively. There are a total of 41 geothermal power plants in California, with an installed capacity of 2,712 MW. Of these, 40 (2657 MW) are currently listed as operational. 16 plants (1579 MW) are dry steam, 17 (860 MW) are flash, and 7 (218 MW) are binary.

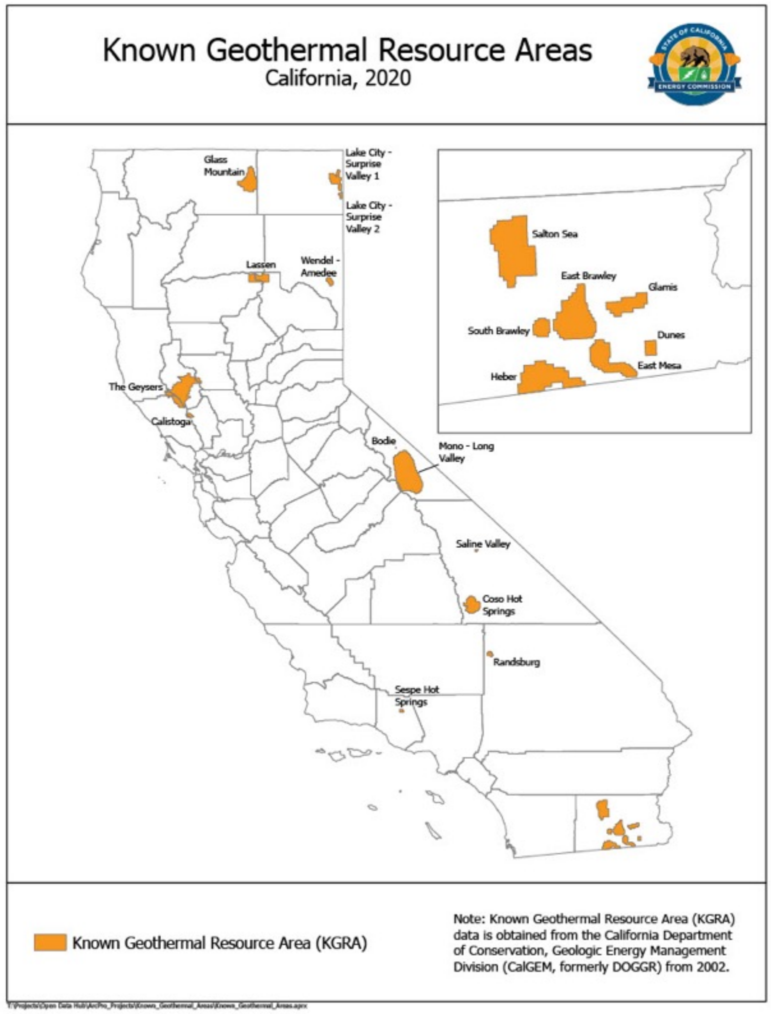


Fig. 2. 30 California Geothermal Fields[20]

Previous estimates suggest another 2.7 GW of untapped capacity within discovered systems, and mean estimates of 11.34 GW within as of yet undiscovered systems. The use of enhanced geothermal system techniques to create hydrothermal systems out of existing hot rock formations via hydrofracture could further expand this capacity by an additional theoretical 48 GW, though it should be noted that unless done at great depth, such enhanced systems would have very poor energy density (~0.5 MW/km^2) compared to traditional geothermal systems (10-20 MW/km^2).[21] Thus, near-term enhanced geothermal systems (EGS) would likely remain restricted to favorable areas. Figure 2.31 shows a map of areas favorable to deep EGS, along with already identified hydrothermal systems.

[20] https://cecgis-caenergy.opendata.arcgis.com/documents/CAEnergy::known-geothermal-resource-areas/explore

[21] https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf

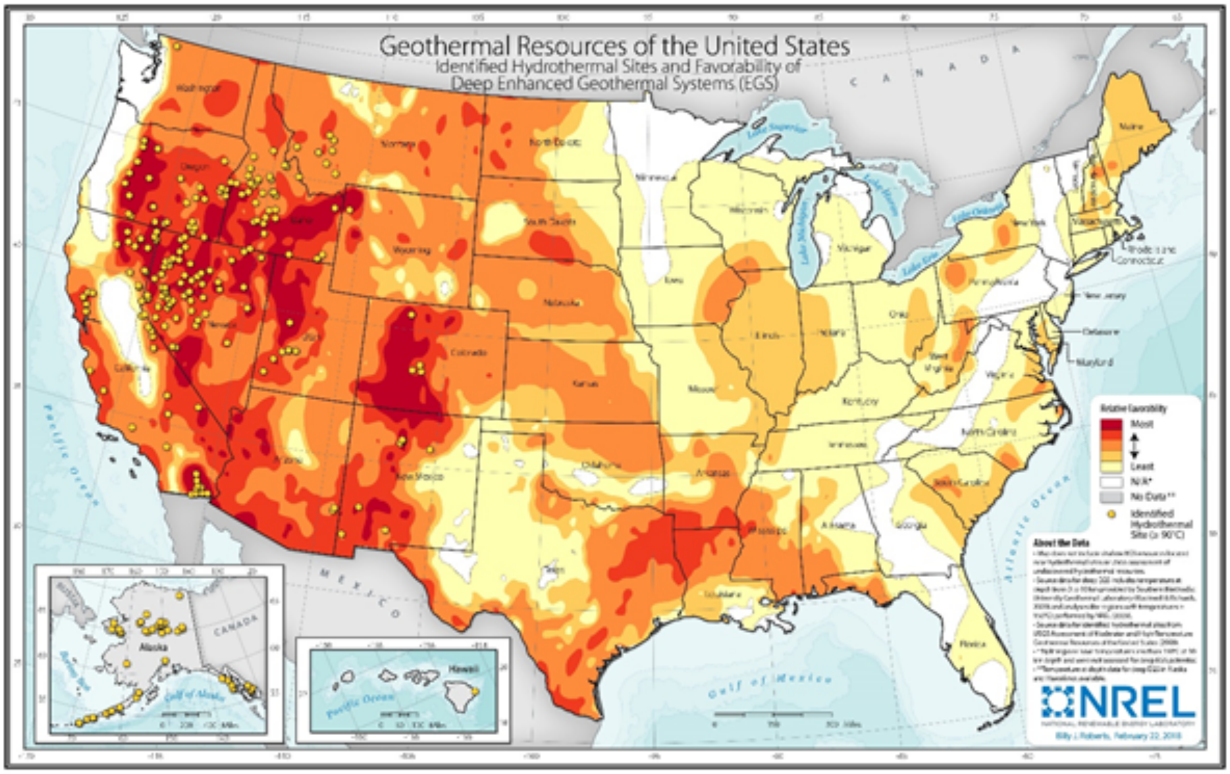


Fig. 2. 31 Identified Hydrothermal Systems and Deep EGS favorability[22]

Binary systems, in particular, could complement diurnal and cross-day storage by adjusting the heat exchanger to divert heat towards onsite thermal energy storage systems during the day when solar is dominant and switching back to steam generation using the turbine at night. Dry steam and flash systems are not as easily coupled to thermal storage as they rely on the mechanical energy of circulating the steam (or fluid flashed to steam) directly through the turbine rather than drawing off the heat. The flowrates of all three systems could possibly be throttled to allow for periods of thermal recharging after brief periods of increased output above standard operating conditions (such as if an emergency were declared), but this is not currently done as geothermal generators are typically designed to operate at constant steady outputs. Implementing functionality for such a "surge mode" would add additional cost when geothermal is already limited in its application by its higher cost. So, although we identify the possibility that geothermal could be used as a dispatchable generation source, we will limit our studies to accelerated deployment of plants that operate near capacity continuously. Nevertheless, we summarize the potential effect of geothermal electricity generation on the types of storage that are needed in Table 2.6. Also, we note that the funding for development of geothermal has been increasing and that increase in investment could be pivotal to launching geothermal power generation in a bigger way. If oil companies decided to apply their knowledge to geothermal, that could make a big difference. Also, we note that, while geothermal is more expensive than utility-scale solar, it can be comparable in cost to residential

[22] https://www.nrel.gov/gis/geothermal.html

solar, which is attracting substantial investment. Thus, investment in large amounts of geothermal is possible.

Table 2. 6 Effects of geothermal generation on roles of storage

Storage type	Storage need associated with geothermal generation for solar-dominant grid	Modeling considerations that may affect conclusions about storage
Diurnal storage	Added geothermal can decrease need for diurnal storage	Binary design: Geothermal plants with ability to store heat during the day and use it to generate electricity at night have the potential to reduce the need for separate diurnal storage.
All types of storage	Higher baseline generation from geothermal reduces the need for other generation and storage at all time scales.	Higher build limits: Theoretically, the potential for geothermal is very large. If a model is allowed to select more geothermal and if the cost is adequately low, the need for storage would be greatly reduced.

2.5 Biomass

Currently, about 3% of California's electricity is generated from biomass. Similar to geothermal, assumptions about the role of biomass and biogas have very high uncertainty. A recent report "Getting to Neutral" by Lawrence Livermore National Laboratory details how California can achieve its goal of carbon neutrality by 2045 through negative emissions with a key pillar being conversion of biomass to fuels with capture of carbon dioxide.[23] They investigated the many sources of biomass that are available as shown in Fig. 2.32.

As a key element of a zero-carbon grid, there are two primary challenges. The first is the cost of collecting the biomass. The second is that it is questionable whether biomass would be considered a zero-carbon technology without some form of carbon capture. Our assessment suggests that the best opportunity for using biomass and biogas for decarbonization of California's electricity grid would leverage the Allam cycle. We have described that in more detail in Section 2.6, including an estimate of the amount of electricity it could generate.

[23] https://www.llnl.gov/news/new-lab-report-outlines-ways-california-could-reach-goal-becoming-carbon-neutral-2045

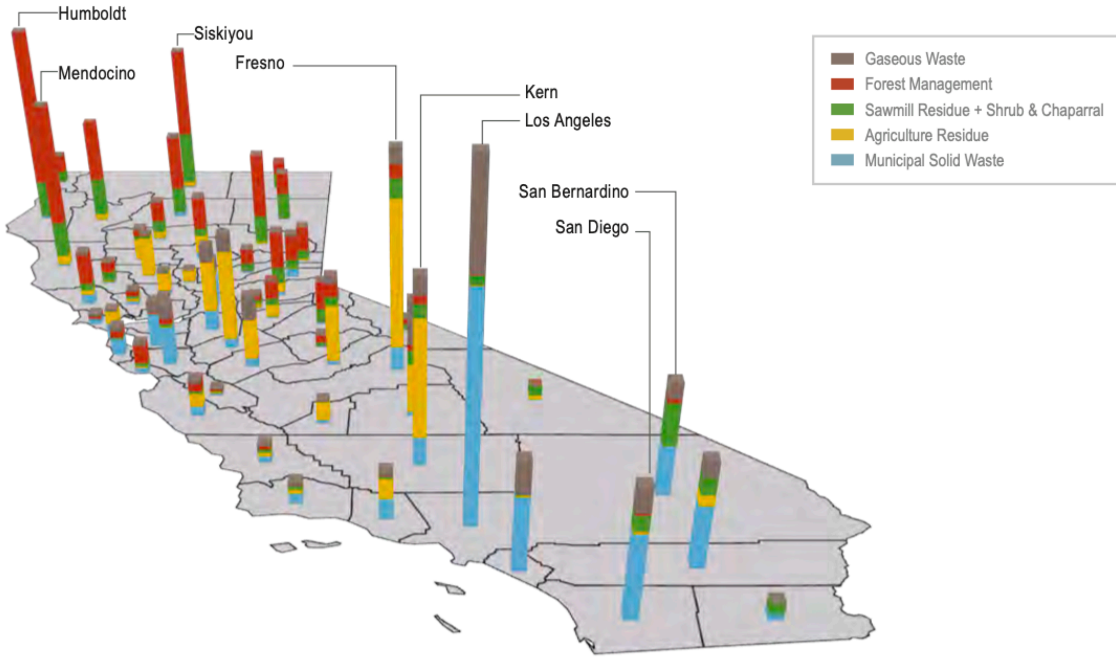


Fig. 2. 32 Biomass sources as reported in "Getting to Neutral"

2.6 Carbon sequestration coupled with biogas

The possibility of using carbon sequestration to enable natural gas plants to effectively operate in a zero-emissions mode has attracted a lot of attention. The approach is not a favorite of many clean-energy advocates because of the ongoing risk of methane leaks and related environmental impacts. However, there is growing concern that carbon dioxide levels are already dangerously high. This concern is motivating investment in carbon capture and sequestration for the purpose of reducing the current level of carbon dioxide in addition to identifying ways to slow emissions. If technology for carbon capture and sequestration is widely adopted, the development and maturation of carbon capture technology and of the associated infrastructure for sequestering the carbon dioxide is likely to result in a reduction in cost, suggesting that it will become more attractive to use in natural gas power plants.

The use of carbon capture on conventional natural gas power plants requires capture of the carbon dioxide from the flue gas which may be only 3%-6% carbon dioxide.[24] The capture of all 3%-6% concentration is energy intensive. Ironically, carbon dioxide capture is easier in a coal-fired plant because of the higher carbon dioxide concentrations.

The Allam cycle provides a compelling approach to overcoming the energy requirement for the carbon capture process. The Allam cycle combusts methane with a stoichiometric amount of oxygen using carbon dioxide as the working fluid in a closed loop, taking the place of steam in traditional power generation. Instead of tackling the task of removing all carbon dioxide from the flue gas, the Allam cycle tackles the simpler separation of extracting oxygen from air at the precombustion stage. The separation of CO_2 then becomes trivial as the net CO_2 product derived

[24] https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-20493.pdf

from the combustion of fuel with pure oxygen in the combustor is removed from the high-pressure stream recycle at a high purity and pressure for delivery to an export CO_2 pipeline. The cycle includes a high pressure oxy-fuel combustor that burns a fossil fuel (methane) in a pure oxygen stream to provide a high-pressure feed stream to a power turbine. The oxygen required for fuel gas combustion is provided from an industry standard pumped liquid oxygen cycle cryogenic air separation unit. The separation of oxygen is easier because oxygen starts at a higher concentration (about 20%). Air separators are already widely used, and oxygen is readily available to feed the methane combustion.

Completing the separation at the precombustion stage provides not only the advantage of the easier separation, but it avoids the formation of some criteria pollutants like NO_x during combustion. After the combustion step, the reaction products include only carbon dioxide and water. The water can easily be removed by cooling the gas and condensing the water. The carbon dioxide is then reused in the process as a working fluid for the next combustion cycle. The excess carbon dioxide (resulting from the combustion process) can be easily removed from the process. The high pressure (200 – 400 bar) of the working system results in the removed carbon dioxide being ready for sequestration without further pressurization. The use of carbon dioxide as a working fluid also avoids the need for using water in the power-generation process, which can have substantial environmental benefits.

The Allam cycle is ideal for coupling with biogas. One of the reasons biomethane is more expensive than natural gas obtained from the ground is that raw biogas is roughly half methane and half carbon dioxide. If biogas is used in the Allam cycle, the carbon dioxide does not need to be removed (though it is still important to remove sulfur compounds and other impurities). Thus, the Allam cycle and biogas are synergistic, and together, result in a clean electricity-generating process that is carbon negative.

The supply of biogas in California has typically been estimated to be too small to be of consequence. However, the CPUC is developing plans that would result in increased generation of biogas. Senate Bill 1440 (SB1440), "Energy: biomethane: biomethane procurement," directs the California Public Utilities Commission (CPUC) in consultation with the California State Air Resources Board (CARB) to "consider adopting specific biomethane procurement targets…consistent with the organic waste disposal reduction targets specified in Section 39730.6 of the Health and Safety Code."[25] Section 39730.6 sets targets of reducing landfill disposal of organics by 50 percent from 2014 to 2020 and by 75 percent by 2025.[26] The CPUC has been working on implementing these directives for some time and is now working on Phase 4a of Rulemaking 13-02-008 which recommends "approval of a mandatory biomethane procurement program for California's four large gas investor-owned utilities (IOUs) to procure on behalf of their core customers."[27]

[25] https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB1440

[26] https://codes.findlaw.com/ca/health-and-safety-code/hsc-sect-39730-6.html

[28]https://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Gas/SB1440_Staff_Proposal_FINAL.pdf

The current intention of SB1440 is to replace natural gas sold by IOUs. If the biogas continues to be combusted at the customer's location, it will continue to contribute carbon emissions. Biogas gives us the opportunity to move to negative carbon emissions. As electrification or replacement of natural gas with hydrogen reduces customer-sited use of methane, it may be possible to redirect the biogas to power plants using the Allam cycle. The R.13-02-008 Phase 4A staff proposal estimates that 75.5 million MMBTU of biomethane may be procured by 2030. We estimate that this could generate >10 TWh of electricity using the Allam cycle. This is approximately equal to the size of seasonal storage we calculate that California will need for a fully decarbonized grid and is about 5% of the annual electricity generation (about 200 TWh) in California. Thus, although this is a small fraction, this biogas would have great potential at meeting the state's seasonal storage needs. It would not be adequate to meet the diurnal storage needs we anticipate but could supplement other storage technologies to reduce the challenge of diurnal storage.

This vision of using waste to generate clean electricity with net negative carbon dioxide emissions still has several hurdles to overcome:
• Development: The Allam cycle is still in early stages of development. Several 250 MW plants are being planned. Results from those will help to establish confidence in the technology.
• Cost: The hardware for the Allam cycle is less complicated than conventional natural gas with carbon capture, but it will be more expensive than conventional natural gas technology and is expected to be economical if run 24/7. To be most useful, it should be operated as a peaker plant: be dispatched at large power for short amounts of time. This would require further cost reduction.
• Biogas: The infrastructure for making and collecting the biogas is only partially in place.
With a limited amount of biogas available, it is not clear whether it would be better to use that biogas to sell to customers or to use for power generation in the Allam cycle. Nevertheless, we view biogas as an important option for addressing storage and the Allam cycle as a potential mechanism for using the biogas in a clean way for power generation with negative emissions.

2.7 Natural gas coupled with carbon sequestration

One strategy to reduce carbon dioxide emissions from the power sector is to add carbon capture and sequestration (CCS) to the natural gas plants that now dominate California's fleet. Technology for CCS exists, but CCS has not been widely adopted because prices for carbon trading have not grown large enough to offset the cost and energy consumption associated with the CCS (or, conversely, the cost of the CCS has not dropped enough).

Some options for natural gas power generation are summarized in Table 2.7.[28] The combustion turbine technology is rapidly being replaced by the more efficient combined cycle. However, these traditional approaches to combustion result in both emissions of carbon dioxide and criteria pollutants such as NO_x. As noted above, CCS can be added to remove the carbon dioxide, but it increases both the capital expenditure for the plant and the operating costs (not summarized here) because of the increased energy use. Thus, although this technology is available, it is not frequently

[28] M. Abido and S. Kurtz "Optimal Strategy for Using Biomass to enable California High Penetration Solar" 49th IEEE PVSC (2022).

used. The Allam cycle described above appears to be quite attractive relative to the more conventional combined cycle coupled with CCS, so we have chosen to consider its addition rather than the more conventional approach to adding CCS.

Table 2. 7 Comparison of natural gas options

Technology	Efficiency (%)	Capital Cost ($/kW)	Footprint ratio	Carbon emissions (kg/kWh)	Criteria Pollutants	Development stage
Combustion Turbine	20-35	850	<1	0.3-0.5	>0	Mature
Combined Cycle	50-60	1000	1	0.1-0.3	>0	Mature
Combined Cycle-CCS	50-60	2000	>1	0.01-0.03*	--	Available
Allam Cycle	59	800-1000	1/3	Zero	Zero	Under development

3. Effect of generation on need for storage

Our study of long-duration storage is differentiated from the traditional capacity expansion planning in two ways: 1) our focus is on long-duration storage, which requires understanding seasonal storage in addition to short-duration storage, and 2) we are more focused on what happens as we approach the 2045 timeframe and how the market evolves to get there rather than the details of meeting the grid's needs in the next year or two. We note that California must place a high priority on preparing for reliable grid operation in 2021 and 2022, especially in light of the low reserves that were experienced in August 2020 and September 2022, but this study is focused on the longer term.

3.1 Types of storage – energy flows

To understand the multiple opportunities of energy storage and its different forms, a conceptual diagram is shown in Fig. 3.1. Green boxes in Fig. 3.1 represent the electricity flows to and from various types of energy storage reservoirs to meet both the immediate electrical load (red box in Fig. 3.1) and flexible loads to balance the electrical grid (green boxes). Demand management may be used to facilitate storage at the customer's site, as indicated by the Fig. 3.1 green box "Load – Stored energy."

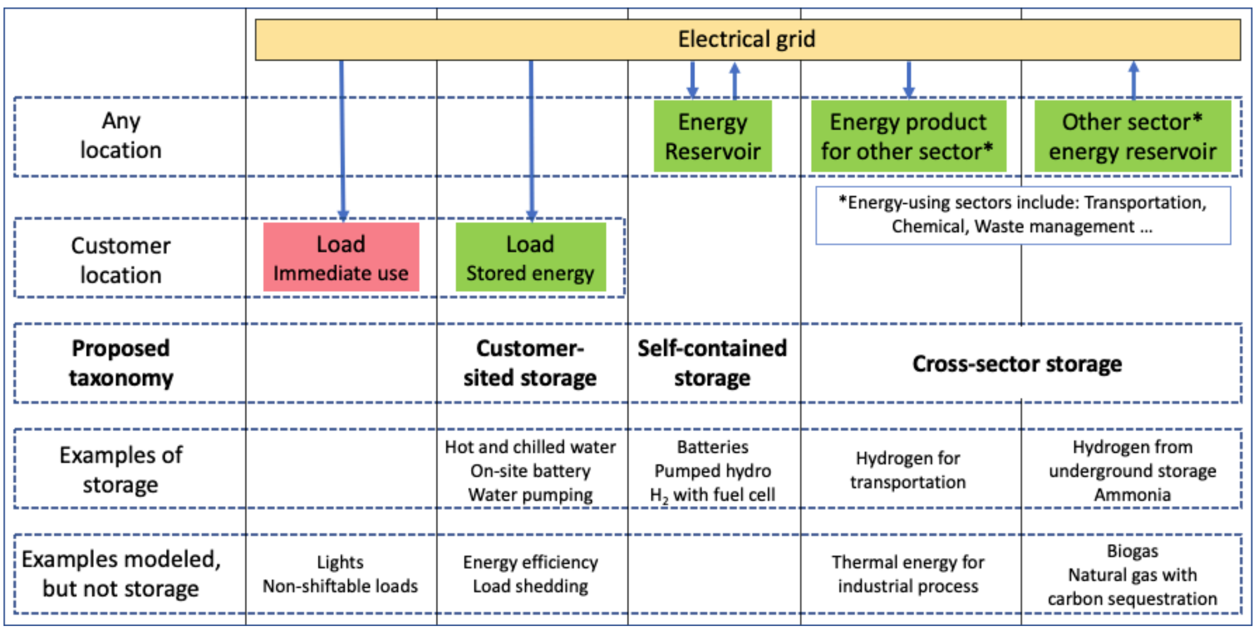


Fig. 3. 1 Electricity pathways for energy storage (green boxes) with suggested taxonomy

More generally, surplus electricity may be stored for later electricity generation (green box labeled "Energy Reservoir") or for creation of an energy product like hydrogen that may be stored at low cost until the energy is needed later for other applications (green box labeled "Energy product for other sectors"). Also, when electricity is in short supply, energy that is stored for use in other sectors may be used to generate electricity (green box labeled "Other sector energy reservoir"). A decarbonized grid may benefit from using all of these strategies.

Capacity-expansion models, which are used to evaluate low-cost long-term grid planning scenarios, commonly include batteries and pumped hydro storage, keeping track of their state-of-charge as they are charged or discharged (Fig. 3.1 green box "Energy Reservoir"). Going beyond these technical parameters and modeling the value of cross-sector storage opportunities, however, is less common. For example, some capacity-expansion models increase their input load profiles to simulate hydrogen production, which in turn dictates a larger volume deployment of electricity generation assets. A multi-sectoral capacity-expansion model would optimize the hydrogen production by considering the capital costs and operating costs of the electrolyzers offset by the value of the hydrogen that is generated, potentially turning curtailed electricity into a revenue stream. A multi-sectoral model would also calculate the cost of using hydrogen (that might be stored for transportation or chemical use) to generate electricity when electricity is in short supply. When studying the need for long-duration storage within conventional capacity-expansion model approaches, while focused studies may elucidate partial solutions, inclusion of multi-sectoral modeling will enable exploration of a wider range of solutions.

While there is no general agreement that all four green boxes in Fig. 3.1 should be called "long-duration energy storage" we assert that a full understanding of the roles of long-duration storage will require understanding the opportunities described by all four green boxes and that understanding the relative benefits of all of these will help policymakers identify the most effective actions to take.

3.2 Types of storage – taxonomy for discussing duration

As we work to envision the roles of storage in supporting tomorrow's grid, it is useful to develop a taxonomy for improved communication. For the purposes of modeling, it is useful to differentiate types of storage according to how they are modeled. We highlight here two aspects that are critical to the model implementation: a) the electricity paths (with associated costs) and b) the temporal resolution.

In Fig. 3.1 we proposed a taxonomy for the storage opportunities identified differentiating them according to the electricity paths. We suggest that "customer-sited storage" describe storage assets that are purchased and operated by the electricity customer (or business partner) at the customer's location. "Self-contained storage" assets may be connected to the grid, charged with surplus electricity, and discharged when electricity demand is high. Finally, "cross-sector storage" created to serve multiple sectors, may be charged or discharged to help balance the grid. In some cases, a storage technology may be implemented simultaneously in more than one of these ways as in the case for the transportation sector where an electric vehicle (EV) is charged for transportation purposes but might also supply electricity back to the grid (vehicle-to-grid). Hydrogen may also be used in both the "self-contained storage" and "cross-sector storage" approaches.

While it is clear that all of these energy pathways need to be modeled to fully understand the roles storage plays in balancing the grid, it is less clear that all of the opportunities should be called "storage." Fig. 3.1 gives examples of how to implement each storage opportunity and also suggests opportunities that need to be included in the modeling, but that are usually not labeled as "storage." We emphasize that in our study of "long-duration storage," we intend to model the potential of all of these, but recognize that, for example, biogas is usually viewed as a generation technology even though biogas represents a form of energy storage that may be useful for balancing the grid. We feel that it is less important to decide whether biogas is called a generation technology or storage technology and more important to agree that biogas has the potential to help balance the grid by providing a reservoir of energy.

We propose a second piece of the taxonomy (Fig. 3.2) related to the relative amount of energy stored, which is typically related to the time it takes to charge or discharge the storage using full power. When modeling the roles of storage, a short-time-resolution (hourly or even sub-hourly) model aids in understanding how storage may help meet instantaneous demand, or the peak load of the year or of the day. Reducing the peak demand is usually considered a "short-duration storage" application. We propose that long-duration storage applications include diurnal storage, cross-day storage, and seasonal storage as also shown in Fig. 3.2. The modeled contiguous timesteps need to span the time from when energy is added to a storage reservoir to when the energy is withdrawn from the reservoir, as indicated in Fig. 3.2, bottom line. For a given grid design and weather, a model can identify the cycling frequency of the short-duration and long-duration (diurnal, multi-day and seasonal) storage reservoirs. These define the storage applications that need to be met to achieve a resilient and stable grid, providing the foundation for taking actions to create a stable zero-carbon-emissions grid. Other applications such as ancillary services, emergency outage protection, and demand reduction also play a role, but are outside of this taxonomy.

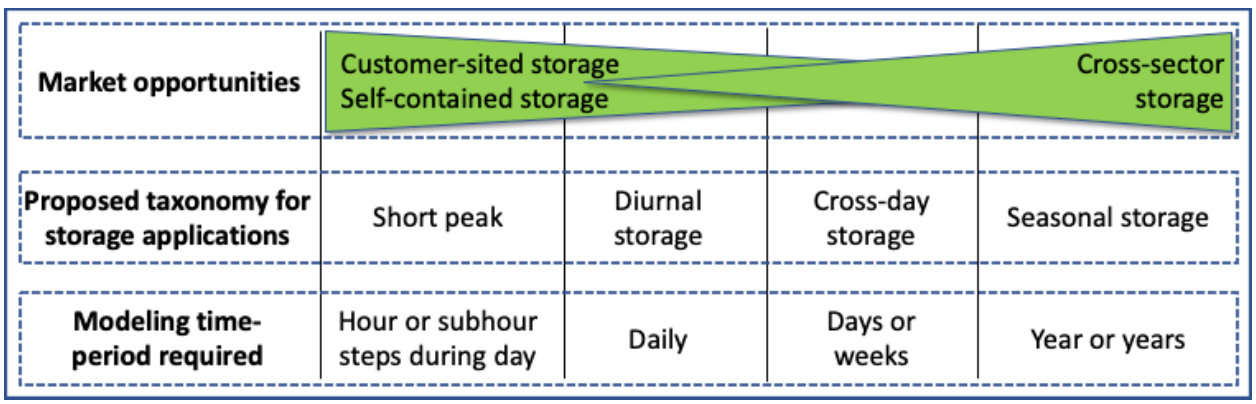


Fig. 3. 2 Taxonomy for storage applications by discharge time frame with modeling requirements for those time frames and mapping to the taxonomy in Fig. 3.1.

The grid's requirements for storage may be described in the context of these four storage applications or using more specific metrics related to the frequency of cycling and the discharge time. We anticipate that it will be useful to the grid to have access to many storage technologies to simultaneously meet all of the grid's needs. Many of those technologies may address multiple storage applications. While it is tempting to label a technology as a "short-duration" or "long-duration" storage technology, it could be possible for nearly any storage technology to address all storage applications. When policy is developed for incentive programs and for technology development, such policy should focus on the functionality that is desired (including cost calculated for a specific use case, efficiency, low idle losses, etc.) rather than applying a simplistic label that differentiates short- and long-duration storage. Focusing on the functionality rather than a preconceived vision of the solution can stimulate innovation and could lead to cross-sector solutions that aren't in the spotlight today.

3.3 Competition between types of storage including large-scale storage

The schematic in Fig. 3.2 suggests how different types of storage may compete to meet the range of storage applications. While a given storage technology may be designed to provide a small or large number of hours of discharge (defined by the energy rating divided by the discharge power rating), once the system is built, it may be used to meet any of the applications. A storage asset that can provide diurnal storage on one day and multi-day storage the next week may be more valuable to the system. Thus, when modeling storage, it is essential to include the full range of temporal applications (diurnal, cross-day, and seasonal, as shown in Fig. 3.2) in order to fully understand the value of a given storage asset to the system. Similarly, to fully understand the system, all of the electricity pathways described in Fig. 3.1 should be included. Fig. 3.2 shows how we anticipate customer-sited and self-contained storage are more likely to be used to meet applications with a shorter time frame, while cross-sector storage may be most effective for seasonal storage applications. Technology development efforts should define the desired storage applications and fund technology development to meet those needs.

Energy storage is an essential part of energy security. As shown in Fig. 3.3, the United States currently maintains energy storage mostly to supply the transportation sector (jet fuel, motor fuels, and oil to make these) and heating sector (oil and natural gas). In Fig. 3.3, the TWh of chemical energy on the left axis is translated into estimated months of electricity generation assuming 40% efficiency and U.S. use of 3800 TWh of electricity in 2020. The natural gas stored for heating applications was estimated from the depletion of the stored natural gas during the heating season. The 350 TWh "Natural gas" may be used for power generation, heating, or other uses. The "in vehicle" estimate assumed 300 million vehicles with 30 kWh of storage in each. Data were taken from EIA.[29]

The chemical industry and power sector also rely on storage described in Fig. 3.3, with chemicals and fuels sometimes mixed with those stored for the other sectors. Maintaining energy storage to simultaneously serve many sectors increases flexibility and reduces costs. If the energy represented in Fig. 3.3 were converted to electricity, it could yield more than five months of electricity for the U.S. as indicated on the right-hand axis, using a nominal efficiency of about 40%. A renewable-energy-based decarbonized energy system will require use of renewable electricity to provide energy for the non-power sectors. Including cross-sector storage in the modeling of the grid will be critical to understanding how the sectors can benefit by sharing storage.[30]

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[29] U.S. Stocks of Crude Oil and Petroleum Products https://www.eia.gov/dnav/pet/PET_STOC_WSTK_DCU_NUS_W.htm. Accessed on 02/17/2021. Weekly Natural Gas Storage Report - EIA https://ir.eia.gov/ngs/ngs.html. Accessed on 02/17/2021. Electricity data browser - Net generation for all sectors https://www.eia.gov/electricity/data/browser/. Accessed on 02/17/2021.

[30] M. Kittner, S. Castellanos, P. Hidalgo-Gonzalez, D. Kammen, and S. Kurtz, *"Cross-sector Storage and Modeling Needed for Deep Decarbonization"*Joule, 2021; S. Kurtz, N. Kittner, S. Castellanos, P. Hidalgo-Gonzalez, and D. Kammen, *"For Cleaner, Greener Power, Expand the Definition of "Batteries""* Issues in Science and Technology, 2021.

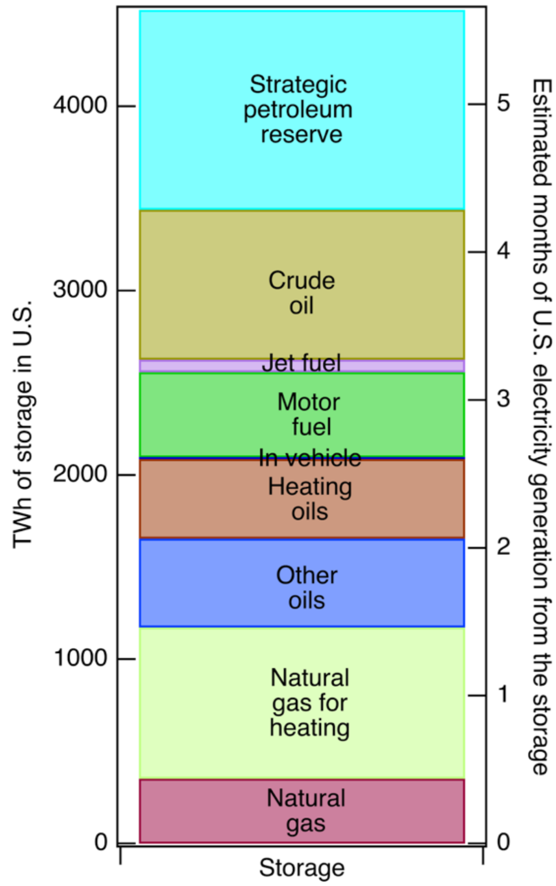

Fig. 3. 3 Eenergy storage used to supply the transportation, heating, power, and chemical sectors today

The long-duration storage needed for seasonal storage applications may require many TWh. Just as a peaker plant today is idle much of the year, some long-duration storage assets of a decarbonized grid will be used infrequently. Thus, the storage cost for such applications will need to be low, and electricity markets will need to be redesigned to reflect the value storage provides. We suggest that inclusion of attractive cross-sector storage opportunities (such as shown on the right side of Fig. 3.1) will be helpful in keeping storage costs low while being prepared for extreme conditions such as the hot weather that occurred in August 2020 (resulting in rolling black outs in California), the cold weather in February 2021 (resulting in millions of people without power for days in Texas and elsewhere), and the heat wave in September 2022 (narrowly avoiding black outs). Today, natural gas is used both for heating and for electricity generation, so the cost of maintaining the natural gas storage and distribution infrastructure is shared by both the power and heating sectors. In a decarbonized world, hydrogen (or other fuel) storage and distribution infrastructure may be established to support the transportation, chemical, and heating sectors. The power sector may be able to ensure resource adequacy at lower cost by leveraging such infrastructure rather than creating its own large energy storage that is infrequently used.

Thus, the study of long-duration storage should consider how the different types of storage defined in Fig. 3.1 will compete for different storage applications as described in Fig. 3.2 and should also consider how cross-sector storage approaches may reduce cost by leveraging infrastructure developed for other sectors. Policy development should be technology agnostic but technically grounded so that the lowest cost, cleanest path is chosen to keep the lights on even in the most challenging times.

3.4 Approach for analyzing energy-balance model results

The effects of variable renewable electricity generation profiles were provided in section 2 by plotting the state-of-charge of a single storage reservoir that filled and emptied on a daily basis, as well as seasonally. When plotted in this way, the seasonal trends were most apparent. We can also use the energy balance approach to understand diurnal and cross-day storage. However, the accounting of these is not obvious when all storage is done in a single storage reservoir.

The diurnal and cross-day storage were evaluated by creating a set of hierarchical storage bins[31] for which both charging and discharging is always prioritized for bin #1 and then for subsequent bins. Thus, if electricity is available for charging, we first fill bin #1 and then move on to bin #2. Similarly, when electricity is needed, discharging begins from bin #1 and then moves on to bin #2 rather than discharging from the most recently filled bin. The state of charge is tracked for all bins with more storage bins created as needed. The state-of-charge of all bins at the end of the year is rolled into the initial state of charge of the bins at the beginning of the year to provide an appropriate boundary condition, as shown in Fig. 3.4. As can be seen along the top edge of the graph, bin #1 is emptied and filled every day, but the majority of the bins are emptied and filled only once per year. In this example, we used 40 GWh as the size of each bin, but the size of the bin is arbitrary. Once the calculation shown in Fig. 3.4 is completed, the statistics for each bin may be considered in terms of the number of times that bin was fully filled and emptied as shown in Fig. 3.5. Each bin may be only partially cycled each day, but by calculating the statistics in this way, we can quantify the cumulative use of the storage over the year.

[31] A modified version of this study (presented in Section 3.4&5) has been submitted to *iScience* for publication.

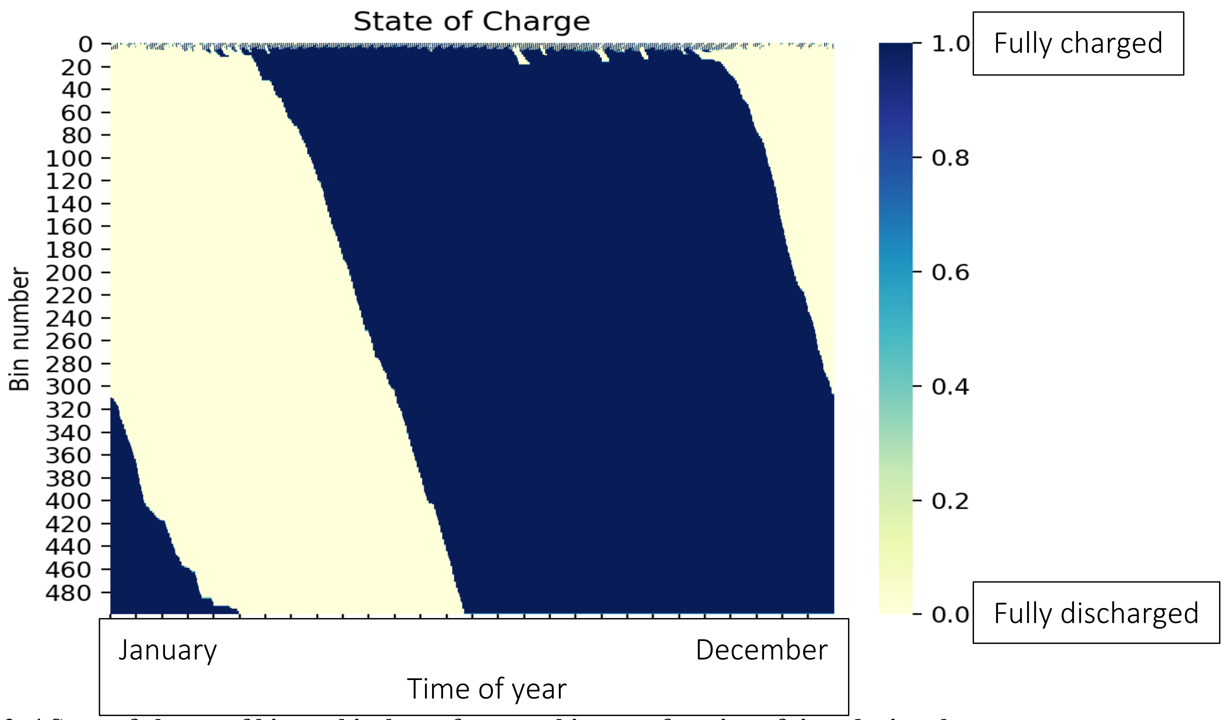

Fig. 3. 4 State of charge of hierarchical set of storage bins as a function of time during the year.

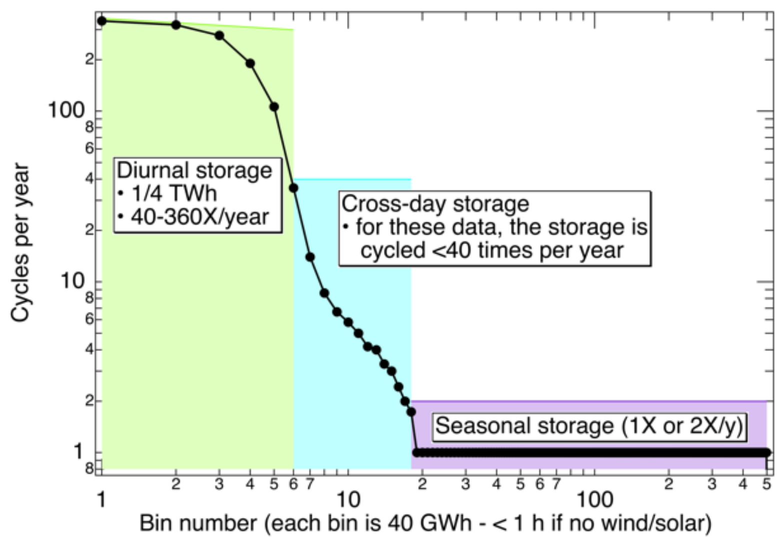

Fig. 3. 5 Number of times each storage bin is fully filled and emptied during a year

Fig. 3.5 uses logarithmic scales to better contrast the small and large numbers. Shaded regions are applied somewhat arbitrarily to differentiate the different types of storage applications. The number of bins in the diurnal storage section was determined by calculating a histogram of the energy put into storage during each night of the year. The largest energy amounts were about 0.25 TWh, or about six 0.04 TWh bins, as shown by the green shaded region on the left. Seasonal storage is taken to be those bins that are used 1 or two times per year (purple highlight in Fig. 3.5).

The bins between the diurnal and seasonal storage are labeled as cross-day storage and highlighted by the blue shaded region. This data set shows bins 1 and 2 to be fully filled and emptied > 300 times/year. Bins 5 and 6 are only fully filled and emptied tens of times per year. Thus, although we have labeled all 6 bins as being "diurnal" storage, not all of the bins should be considered to be equivalent because the economics of a storage asset that is cycled every day is quite different from one that is cycled tens of times per year. While the value of analyzing the hierarchical data set is primarily found in the statistics found for each individual bin, the somewhat arbitrary categorization of the bins provides an easier way to discuss the results. For other data sets, the number of bins falling into the cross-day and seasonal storage categories will vary. From the curve, we can quantitatively define the minimum usage of storage to implement the identified generation and load profiles. Additional storage will be needed to match local supply and demand when transmission is not perfect.

While the differentiation between the diurnal and cross-day storage is somewhat arbitrary, the shape of the curve suggests an inflection point that differentiates between the diurnal application and the cross-day storage application, suggesting that our use of 0.24 TWh for the diurnal storage is a reasonable boundary to define. The boundary between seasonal and cross day storage may also be considered arbitrary. We have selected to define seasonal storage as that cycled less than two times per year as shown by the purple rectangle in Fig. 3.5. We consider the rest to be cross-day storage for the point of discussion, as highlighted by the blue rectangle in Fig. 3.5.

The use of this hierarchical approach anticipates that there will be some favored storage assets that will tend to be cycled before other resources. The reasons for using them first may depend on the operating cost, the efficiency and the degradation caused by cycling them. Our energy modeling should be sure to account for such drivers. In the meantime, the graphs of data using the approach shown in Fig. 3.5 is very helpful in developing intuition about the ramifications for storage when the generation mix is varied.

3.5 Energy-balance modeling results by storage type

The hierarchical storage calculation was applied to some of the scenarios discussed above. The details of the calculations will be published separately. Here we share the resulting trends as a way to inform the capacity expansion optimization we will complete in the next stage of the project.

The storage needed to support generation mixes from multiple wind resources is shown in Fig. 3.6. In this simulation, as described above, the thermal, nuclear, and imported generation from reported values is replaced with an expansion of the current solar generation profile, resulting in the "solar only" curve in Fig. 3.6. Then, 10 GW of wind was substituted for however much solar would have generated the same electricity as the 10 GW of wind, to create the curves for the other scenarios. Focusing attention on the left side of the graph (first six bins that are likely to be needed to provide electricity through a windless night), the "solar-only" scenario cycles these bins more frequently while the summer-dominant wind cycles them less frequently. The other scenarios lie between the "solar-only" and "summer-dominant wind" results and are not easily differentiated in the graph. In general, replacing some solar generation with wind generation tends to create a need for up to 0.5 TWh of storage that may be cycled a handful of times per year. The biggest variation we see is in the amount of seasonal storage that is needed. The "solar-only" scenario required almost 400 bins, or about 16 TWh of seasonal storage. The addition of 10 GW of winter-dominant onshore wind could reduce that need to < 10 TWh of storage.

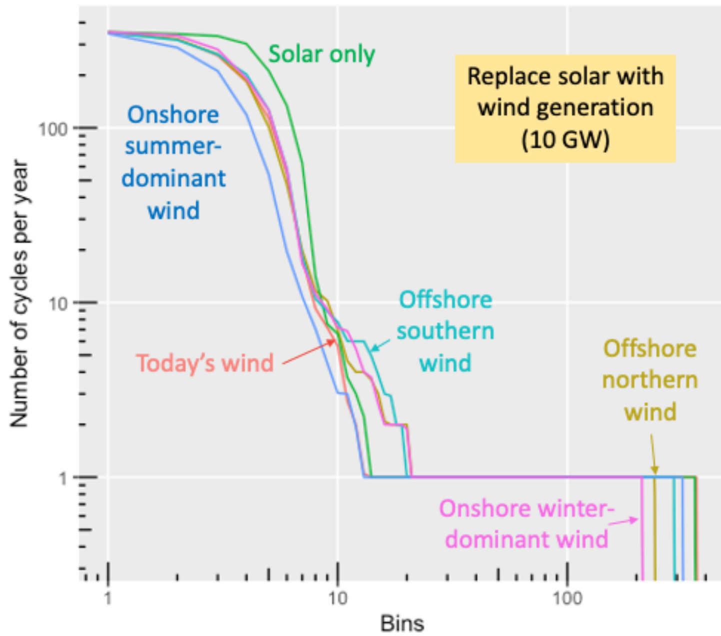

Fig. 3. 6 Storage requirements for six generation-mix scenarios

As shown in Figs. 2.22 and 2.23 above and repeated in Fig. 3.7 for convenience, replacing solar generation with 5 to 20 GW of most types of wind would increase the storage that would be cycled a handful or even tens of times per year (labeled as "cross-day" storage), but would decrease the need for seasonal storage. The exception is the summer-dominant onshore wind that has little effect on the cross-sector and seasonal storage relative to the use of solar.

The addition of 20 GW of any of these types of wind is implausible, but 5 GW to 10 GW may be plausible. The calculation of the additional 20 GW underscores the very large effect that would be possible if more wind resource could be found. For example, it may be possible to find more wind in the Rocky Mountains.

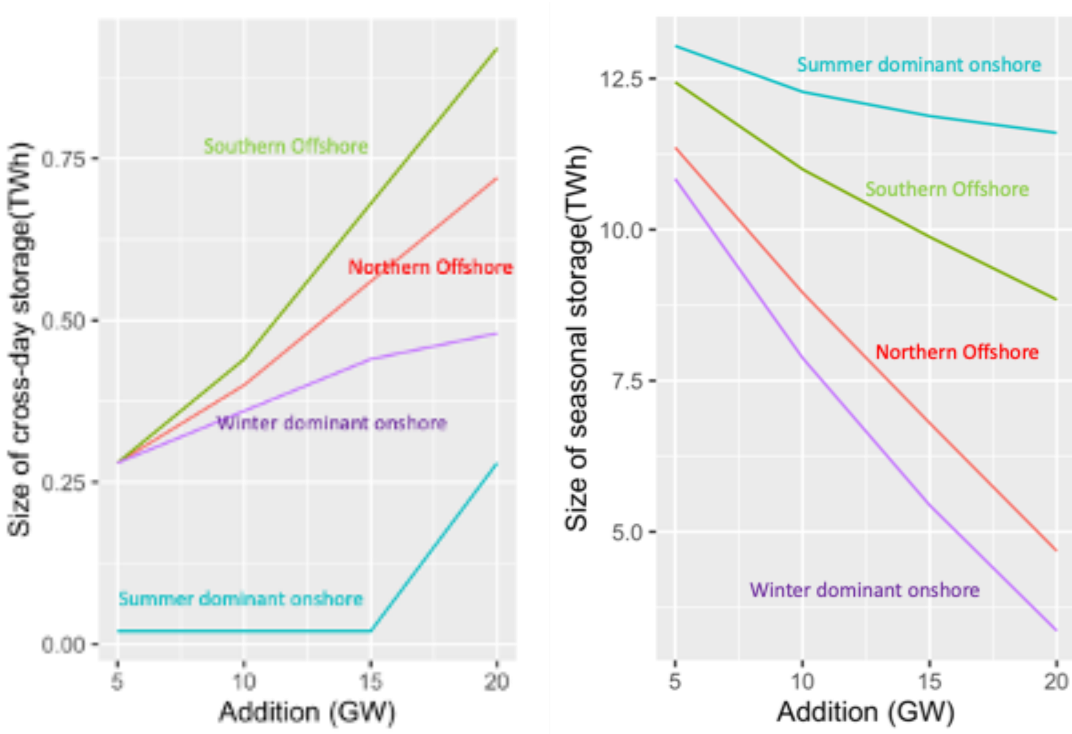

Fig. 3. 7 Effect of wind generation on needed cross-day and seasonal storage reservoirs

3.6 Modeling requirements for understanding types of storage

The stability of the grid requires instantaneous balancing of supply and demand but understanding long-duration storage is focused on longer time horizons. Inspecting Fig. 2.18 where all storage is treated as one large reservoir, we see that the storage can be maintained as mostly full during the summer, then is depleted in an annual cycle reflecting the reduced availability of solar energy in the winter. The data suggest that the following time horizons may be differentiated:

- **Seasonal:** Understanding seasonal issues requires full-year modeling with an emphasis on October to March.
- **Daily**: The diurnal cycle of charging during the day and discharging at night can be studied by considering 24-hour days, but the statistics of the diurnal cycle vary throughout the year. The interaction between the nighttime storage (requiring 10-15 hours of storage) with the seasonal storage will affect the use of the diurnal storage.
- **Events**: In Fig. 2.18, we can see that there are irregular dips in the data. Satellite photos show how clouds can lead to a temporary depletion of the storage. We anticipate that the dips seen in Fig. 2.18 arise from clouds, smoke, or other events that lead to a net shortage of electricity over a few days. The dips are seen to vary from a short time (a day or two) to about a month or even to multiple months.

Our goal of quantifying the relative amounts of short- and long-duration storage (including the relative amounts of variable types of long-duration storage) requires that we simultaneously model these. However, it is not clear that hourly calculations are required since California's fleet of storage is currently comprised of 4-hour and longer-duration storage.

The daily charging and discharging of the storage typically results in a minimum state of charge one to two hours after sunrise and a maximum state of charge one to two hours before sunset. While the details of the dispatch of that storage may depend on the hourly simulation, the calculation of the needed storage capacity depends primarily on these minima and maxima. Thus, in general, we may select two timesteps each day to define the resource adequacy for the amount of energy needed to be retained in storage. We also need to include the hour of the day when the power demand is a maximum in order to appropriately size the generators to meet that peak demand.

After the capacity expansion is optimized, we may optimize the dispatch on an hourly basis using the selected capacity expansion. The linear optimization of the dispatch can be done a year at a time using the full 8760 hours of data. Because the computational challenge scales closer to the square of the number of timepoints/calculations, we may complete the calculations faster by calculating the optimal dispatch one year at a time. Thus, we propose to reduce the computational complexity by completing the capacity expansion optimization using two to four timesteps per day, then optimizing the hourly dispatch in a second calculation, preferably using variable weather data sets to test the reliability. This approach is consistent with the way results would be implemented in the real world. Any surprises that occur during the dispatch will inform an improved version of the capacity expansion modeling, perhaps by revising the approach to determining the needed reserve, as discussed in the next section.

4. Modeling inputs

This section describes model details for each generation technology. We follow the Preferred System Portfolio (PSP) developed as part of the IEPR process and implemented by E3 in the New-modeling-toolkit with some modifications. The toolkit uses Scenario tags to identify assumptions used for each aspect of the model. Our baseline uses the PSP mostly, as described in Table 4.1.

Table 4. 1. Description of Scenario tags used in our RESOVLE baseline

Scenario tag	Description
base	Base description
Baseline: CEC 2020* IEPR - Mid Demand	Mid demand developed by IEPR
EV: CEC 2020* IEPR - Mid Demand	Mid EV demand developed by IEPR
Other TE: CEC 2020* IEPR - Mid Demand	Mid Transport electrification demand
BE: None Through 2030	Building electrification scenario
Hydrogen: No Hydrogen	No hydrogen used for power generation
BTM CHP: CEC 2020* IEPR	Behind the meter combined heat & power demand
TOU: CEC 2020* IEPR	Effect of time of use rates on load
EE: CEC 2020* IEPR - Mid-Mid AAEE	Electrical efficiency effects on load
SB 100	Sets the renewable portfolio standard target timeline
Unspecified Carbon Adder - Low	Is not used
2021_PSP_22_23_TPP	Defines transmission planning process
2021_PSP_22_23_TPP_ITC_ext	Includes lower costs associated with ITC extension
PRM - Mid (MTR)	Drop this constraint – see below
38 MMT by 2030 statewide	Greenhouse gas policies allow 38 MMT emissions
BTM PV: CEC 2020* IEPR - Mid PV + Mid-Mid AAPV	Specifies planned build of behind-the-meter PV
BTM Storage: CEC 2020* IEPR	Specifies planned build of behind-the-meter storage
PSP_test2007	Use weather data from every day of 2007
UCM_Hydro_Dry	Fixed load profile representing the year 2021 hydro
PRM – no PRM	Set PRM target to zero to remove requirement

*At the time of writing of this report, we are using 2020 IEPR, but plan to update these to the 2021 values.

4.1 Solar

Cost of solar, like many other things right now, is constantly changing. Some recent variations are summarized in Table 4.2, comparing data from NREL's Annual Technology Baseline (ATB) to the data adopted in the Preferred System Portfolio (PSP). Key considerations are the extension and expansion of incentive programs, especially in the Inflation Reduction Act (IRA). Interest rates are increasing, increasing the effective cost of the systems.

Table 4. 2 Summary of recent cost estimates

Data source	Year	CapEx	Calculated annualized cost
NREL ATB 2021	2025	$1076/kW	$62.2/kW*
NREL ATB 2022	2025	$982/kW	$56.8/kW*
NREL ATB 2022	2025	$982/kW	$87.2/kW*+
2021_PSP_22_23_TPP	2025		$59.9/kW**
NREL ATB 2021	2045	$672/kW	$38.9/kW*
NREL ATB 2022	2045	$651/kW	$37.6/kW*
2021_PSP_22_23_TPP	2045		$57.2/kW***

*30-year capitalization; 4% interest rate
*+30-year capitalization; 8% interest rate
**Assumes ITC
***Assumes no ITC

An example set of inputs for a solar candidate resource is tabulated in Table 4.3. We follow the PSP for our baseline solar cost, but we may adopt lower costs or expanded adoption scenarios to reflect the anticipated effects of the IRA (which are still being evaluated). For example, we suspect that it would be appropriate to increase the planned build of behind the meter solar to reflect the increased rate of adoption of rooftop solar that the IRA will inspire (but that the model would not predict because of the higher cost.)

Table 4. 3 RESOLVE inputs for candidate solar resource

timestamp	attribute	value
None	can_retire	FALSE
None	can_build_new	TRUE
2030	new_capacity_annualized_all_in_fixed_cost_by_vintage	64.2
2035	new_capacity_annualized_all_in_fixed_cost_by_vintage	61.9
2040	new_capacity_annualized_all_in_fixed_cost_by_vintage	59.6
2045	new_capacity_annualized_all_in_fixed_cost_by_vintage	57.2
2030	new_capacity_fixed_om_by_vintage	10.13
2035	new_capacity_fixed_om_by_vintage	9.68
2040	new_capacity_fixed_om_by_vintage	9.23
2045	new_capacity_fixed_om_by_vintage	8.79
2030	planned_fixed_om_by_model_year	19.40
2035	planned_fixed_om_by_model_year	19.40
2040	planned_fixed_om_by_model_year	19.40
2045	planned_fixed_om_by_model_year	19.40

The costs are assumed to be the same for all RESOLVE solar candidate resources in California. Out-of-state resources have slightly different costs. For example, Arizona Solar candidate resource has costs that are about 97% of those in Table 4.3. These candidate resources use the same names and locations as RESOLVE has used in the past, but we now use hourly generation profiles for the entire year.

In addition to the generation profiles provided by E3, we have added calculations for three mounting configurations including south-facing latitude fixed tilt, south-facing latitude tilt with one-axis tracking, and one-axis tracked with no tilt. Although we have calculated these profiles for 2015-2020 we do not have complete load data for those years, so have not decided whether to study those years. E3 has provided load data for 2007-2009, so we focus our initial calculations on those years. These data are lengthy, so are not shown here.

We adjust the costs for solar plants installed with different mounting configurations to reflect the difference in cost, as described in Table 4.4.

Table 4. 4. Costs assumed for solar candidate resources with different mounting configurations

Data source	Mounting orientation	Relative Capex cost	Relative O&M cost
E3 distribution	One-axis tracked; zero-degree tilt	1	1
NREL API	One-axis tracked; zero-degree tilt	1	1
NREL API	Fixed, south-facing latitude tilt	0.94 change to 0.93	0.9
NREL API	One-axis tracked; latitude tilt	1.07 change to 1.05	1

Table 4. 5 Annual generation (kWh/kW) for solar resources documented in RESOLVE

Profile name (resource name)	Annual Generation			Annual Capacity Factor			Can build
	2007	**2008**	**2009**	**2007**	**2008**	**2009**	
Arizona_Solar	2736	2760	2745	0.312	0.314	0.313	TRUE
Baja_California_Solar	2719	2732	2711	0.310	0.311	0.310	
BANC_Solar_for_Other	2577	2566	2534	0.294	0.292	0.289	FALSE
CAISO_Solar_for_CAISO	2497	2486	2455	0.285	0.283	0.280	FALSE
CAISO_Solar_for_Other	2446	2436	2405	0.279	0.277	0.274	FALSE
Carrizo_Solar	2705	2717	2674	0.309	0.309	0.305	
Central_Valley_North_Los_Banos_Solar	2631	2556	2554	0.300	0.291	0.292	
Distributed_Solar	1874	1873	1849	0.214	0.213	0.211	TRUE
Greater_Imperial_Solar	2746	2759	2737	0.313	0.314	0.312	
IID_Solar_for_CAISO	2960	2974	2951	0.338	0.339	0.337	FALSE
IID_Solar_for_Other (Imperial_Solar) (Riverside_Solar) (Southern_NV_Eldorado_Solar)	2746	2759	2737	0.313	0.314	0.312	FALSE (TRUE)
Inyokern_North_Kramer_Solar	2845	2829	2800	0.325	0.322	0.320	
Kern_Greater_Carrizo_Solar	2705	2717	2674	0.309	0.309	0.305	
Kramer_Inyokern_Ex_Solar	2845	2829	2800	0.325	0.322	0.320	
LDWP_Solar_for_Other	2611	2611	2590	0.298	0.297	0.296	FALSE
Mountain_Pass_El_Dorado_Solar	2704	2695	2676	0.309	0.307	0.305	
New_Mexico_Solar	2642	2727	2639	0.302	0.310	0.301	
Northern_California_Ex_Solar (Northern_California_Solar) (Greater_Kramer_Solar) (Southern_PGAE_Solar)	2481	2454	2416	0.283	0.279	0.276	(TRUE)
North_Victor_Solar	2845	2832	2797	0.325	0.322	0.319	
NW_Solar_for_Other	2077	2066	2078	0.237	0.235	0.237	FALSE
Riverside_Palm_Springs_Solar	2746	2769	2727	0.313	0.315	0.311	
Sacramento_River_Solar	2468	2457	2426	0.282	0.280	0.277	
SCADSNV_Solar	2739	2747	2676	0.313	0.313	0.306	
Solano_Solar	2603	2551	2523	0.297	0.290	0.288	
Solano_subzone_Solar	2603	2551	2523	0.297	0.290	0.288	
Southern_California_Desert_Ex_Solar	2728	2728	2706	0.311	0.311	0.309	
Southern_Nevada_Solar	2768	2794	2680	0.316	0.318	0.306	
SW_Solar_for_CAISO	2832	2857	2841	0.323	0.325	0.324	FALSE
SW_Solar_for_Other	2383	2405	2391	0.272	0.274	0.273	FALSE
Tehachapi_Ex_Solar	2870	2829	2799	0.328	0.322	0.320	
Tehachapi_Solar (Greater_LA_Solar)	2870	2829	2799	0.328	0.322	0.320	TRUE (TRUE)
Utah_Solar	2544	2581	2490	0.290	0.294	0.284	
Westlands_Ex_Solar	2735	2696	2666	0.312	0.307	0.304	
Westlands_Solar	2735	2696	2666	0.312	0.307	0.304	

Profile name (resource name)	Annual Generation			Annual Capacity Factor			Can build
	2007	2008	2009	2007	2008	2009	
Arizona_Solar	2631	2661	2637	0.300	0.303	0.301	TRUE
BANC_Solar_for_Other	2577	2566	2534	0.294	0.292	0.289	FALSE
CAISO_Solar_for_CAISO	2497	2486	2455	0.285	0.283	0.280	FALSE
CAISO_Solar_for_Other	2446	2436	2405	0.279	0.277	0.274	FALSE
Distributed_Solar	1874	1873	1849	0.214	0.213	0.211	TRUE
Greater_Imperial_Solar	2746	2759	2737	0.313	0.314	0.312	
IID_Solar_for_CAISO	2960	2974	2951	0.338	0.339	0.337	FALSE
IID_Solar_for_Other (Imperial_Solar) (Riverside_Solar) (Southern_NV_Eldorado_Solar)	2746	2759	2737	0.313	0.314	0.312	FALSE (TRUE)
Inyokern_North_Kramer_Solar	2845	2829	2800	0.325	0.322	0.320	
Kern_Greater_Carrizo_Solar	2705	2717	2674	0.309	0.309	0.305	
Kramer_Inyokern_Ex_Solar	2845	2829	2800	0.325	0.322	0.320	
LDWP_Solar_for_Other	2611	2611	2590	0.298	0.297	0.296	FALSE
Mountain_Pass_El_Dorado_Solar	2704	2695	2676	0.309	0.307	0.305	
New_Mexico_Solar	2642	2727	2639	0.302	0.310	0.301	
Northern_California_Ex_Solar (Northern_California_Solar) (Greater_Kramer_Solar) (Southern_PGAE_Solar)	2481	2454	2416	0.283	0.279	0.276	(TRUE)
North_Victor_Solar	2845	2832	2797	0.325	0.322	0.319	
NW_Solar_for_Other	2077	2066	2078	0.237	0.235	0.237	FALSE
Riverside_Palm_Springs_Solar	2746	2769	2727	0.313	0.315	0.311	
Sacramento_River_Solar	2468	2457	2426	0.282	0.280	0.277	
SCADSNV_Solar	2739	2747	2676	0.313	0.313	0.306	
Solano_Solar	2603	2551	2523	0.297	0.290	0.288	
Solano_subzone_Solar	2603	2551	2523	0.297	0.290	0.288	
Southern_California_Desert_Ex_Solar	2728	2728	2706	0.311	0.311	0.309	
Southern_Nevada_Solar	2768	2794	2680	0.316	0.318	0.306	
SW_Solar_for_CAISO	2832	2857	2841	0.323	0.325	0.324	FALSE
SW_Solar_for_Other	2383	2405	2391	0.272	0.274	0.273	FALSE
Tehachapi_Ex_Solar	2870	2829	2799	0.328	0.322	0.320	
Tehachapi_Solar (Greater_LA_Solar)	2870	2829	2799	0.328	0.322	0.320	TRUE (TRUE)
Utah_Solar	2544	2581	2490	0.290	0.294	0.284	
Westlands_Ex_Solar	2735	2696	2666	0.312	0.307	0.304	
Westlands_Solar	2735	2696	2666	0.312	0.307	0.304	

The annual generation of solar candidate resources in RESOLVE is summarized in Table 4.5 using the generation-profile data shared from E3's new-modeling-toolkit package. The candidate resource with the largest annual generation is highlighted in green and the second highest in yellow. The lowest is highlighted in orange. The rightmost column indicates whether the profile is associated with a resource file that enables that resource to be selected by the model for new builds. In multiple cases a profile was supplied without a corresponding resource file. These have no entry in the rightmost column. In some cases, resource files were provided linked to profiles with a different name than the resource file. For these cases, we have added the resource name underneath of the profile name (in parentheses) and indicated that these can be selected for new builds by the model by adding a "(TRUE)" to the rightmost column. We note in Table 4.5 that of the resources that can be selected for new builds, only five profiles are used despite nine candidate resources being included in the system definition. We find that shifting these resources to use a greater variety of resources, as indicated in Table 4.6 has a small effect on the storage that is selected. So, we propose to use the linkages in Table 4.6 rather than those in Table 4.5. We note that the Distributed solar resource is both more expensive and generates less electricity per installed kW. Thus, although the model is allowed to build distributed solar, we don't expect it will choose to do so beyond the minimum specified (especially because none of the soar resources are built to their capacity limits).

Table 4. 6 Annual generation (kWh/kW) for solar resources modified in RESOLVE

Resource	Annual generation			Annual Capacity Factor			Can build
	2007	**2008**	**2009**	**2007**	**2008**	**2009**	
Arizona_Solar	2736	2760	2745	0.312	0.314	0.313	TRUE
Baja_California_Solar	2719	2732	2711	0.310	0.311	0.310	
BANC_Solar_for_Other	2577	2566	2534	0.294	0.292	0.289	FALSE
CAISO_Solar_for_CAISO	2497	2486	2455	0.285	0.283	0.280	FALSE
CAISO_Solar_for_Other	2446	2436	2405	0.279	0.277	0.274	FALSE
Carrizo_Solar	2705	2717	2674	0.309	0.309	0.305	
Central_Valley_North_Los_Banos_Solar (Southern_PGAE_Solar)	2631	2556	2554	0.300	0.291	0.292	(TRUE)
Distributed_Solar	1874	1873	1849	0.214	0.213	0.211	TRUE
Greater_Imperial_Solar	2746	2759	2737	0.313	0.314	0.312	
IID_Solar_for_CAISO	2960	2974	2951	0.338	0.339	0.337	FALSE
IID_Solar_for_Other (Imperial_Solar)	2746	2759	2737	0.313	0.314	0.312	FALSE (TRUE)
Inyokern_North_Kramer_Solar (Greater_Kramer_Solar)	2845	2829	2800	0.325	0.322	0.320	(TRUE)
Kern_Greater_Carrizo_Solar	2705	2717	2674	0.309	0.309	0.305	
Kramer_Inyokern_Ex_Solar	2845	2829	2800	0.325	0.322	0.320	
LDWP_Solar_for_Other	2611	2611	2590	0.298	0.297	0.296	FALSE
Mountain_Pass_El_Dorado_Solar	2704	2695	2676	0.309	0.307	0.305	
New_Mexico_Solar	2642	2727	2639	0.302	0.310	0.301	
Northern_California_Ex_Solar (Northern_California_Solar)	2481	2454	2416	0.283	0.279	0.276	(TRUE)
North_Victor_Solar	2845	2832	2797	0.325	0.322	0.319	
NW_Solar_for_Other	2077	2066	2078	0.237	0.235	0.237	FALSE
Riverside_Palm_Springs_Solar (Riverside_Solar)	2746	2769	2727	0.313	0.315	0.311	(TRUE)
Sacramento_River_Solar	2468	2457	2426	0.282	0.280	0.277	

SCADSNV_Solar	2739	2747	2676	0.313	0.313	0.306	
Solano_Solar	2603	2551	2523	0.297	0.290	0.288	
Solano_subzone_Solar	2603	2551	2523	0.297	0.290	0.288	
Southern_California_Desert_Ex_Solar	2728	2728	2706	0.311	0.311	0.309	
Southern_Nevada_Solar (Southern_NV_Eldorado_Solar)	2768	2794	2680	0.316	0.318	0.306	(TRUE)
SW_Solar_for_CAISO	2832	2857	2841	0.323	0.325	0.324	FALSE
SW_Solar_for_Other	2383	2405	2391	0.272	0.274	0.273	FALSE
Tehachapi_Ex_Solar	2870	2829	2799	0.328	0.322	0.320	
Tehachapi_Solar (Greater_LA_Solar)	2870	2829	2799	0.328	0.322	0.320	TRUE (TRUE)
Utah_Solar	2544	2581	2490	0.290	0.294	0.284	
Westlands_Ex_Solar	2735	2696	2666	0.312	0.307	0.304	
Westlands_Solar	2735	2696	2666	0.312	0.307	0.304	

Table 4. 7 Annual generation (kWh/kW) for solar resources modified in RESOLVE

Resource	Annual generation			Annual Capacity Factor			Can build
	2007	**2008**	**2009**	**2007**	**2008**	**2009**	
Arizona_Solar (1-axis no tilt)	2631	2661	2637	0.300	0.303	0.301	TRUE
Arizona_Solar (1-axis tilt)							
BANC_Solar_for_Other	2577	2566	2534	0.294	0.292	0.289	FALSE
CAISO_Solar_for_CAISO	2497	2486	2455	0.285	0.283	0.280	FALSE
CAISO_Solar_for_Other	2446	2436	2405	0.279	0.277	0.274	FALSE
Central_Valley_North_Los_Banos_Solar (Southern_PGAE_Solar)	2631	2556	2554	0.304	0.296	0.297	(TRUE)
Distributed_Solar	1874	1873	1849	0.214	0.213	0.211	TRUE
IID_Solar_for_CAISO	2960	2974	2951	0.338	0.339	0.337	FALSE
IID_Solar_for_Other (Imperial_Solar)	2746	2759	2737	0.313	0.314	0.312	FALSE (TRUE)
Inyokern_North_Kramer_Solar (Greater_Kramer_Solar)	2845	2829	2800	0.325	0.322	0.320	(TRUE)
LDWP_Solar_for_Other	2611	2611	2590	0.298	0.297	0.296	FALSE
Northern_California_Ex_Solar (Northern_California_Solar)	2481	2454	2416	0.283	0.279	0.276	(TRUE)
NW_Solar_for_Other	2077	2066	2078	0.237	0.235	0.237	FALSE
Riverside_Palm_Springs_Solar (Riverside_Solar)	2746	2769	2727	0.313	0.315	0.311	(TRUE)
Southern_Nevada_Solar (Southern_NV_Eldorado_Solar)	2768	2794	2680	0.316	0.318	0.306	(TRUE)
SW_Solar_for_CAISO	2832	2857	2841	0.323	0.325	0.324	FALSE
SW_Solar_for_Other	2383	2405	2391	0.272	0.274	0.273	FALSE
Tehachapi_Ex_Solar	2870	2829	2799	0.328	0.322	0.320	
Tehachapi_Solar	2870	2829	2799	0.328	0.322	0.320	TRUE

(Greater_LA_Solar)							(TRUE)
Utah_Solar	2544	2581	2490	0.290	0.294	0.284	
Westlands_Ex_Solar	2735	2696	2666	0.312	0.307	0.304	
Westlands_Solar	2735	2696	2666	0.312	0.307	0.304	

The WECC-wide inputs to SWITCH include 598 existing central PV resources and 380 candidate solar (central PV) resources with example data shown in Tables 4.7-4.9 SWITCH also offers commercial and residential PV as well as concentrating solar power, but these are not selected because they have higher costs, so aren't summarized here. Because of the large number of resources, the inputs selected for our SWITCH studies sometimes use a subset of resources.

Table 4. 8 SWITCH generation_projects_info file format

GENERATION_PROJECT	gen_tech	gen_energy_source	gen_load_zone	gen_max_age	gen_is_variable	gen_is_baseload	gen_variable_om	gen_connect_cost_per_mw
1118810	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	72476
1118822	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	60417
1118825	Central_PV	Solar	CA_IID	20	TRUE	FALSE	0	61468
1118828	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	82354
1118831	Central_PV	Solar	CA_IID	20	TRUE	FALSE	0	48229
1118849	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	82640
1118852	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	60732
1118855	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	52937
1118861	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	73991
1118867	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	71385
1118870	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	67982
1118876	Central_PV	Solar	CA_IID	20	TRUE	FALSE	0	77831
1118879	Central_PV	Solar	CA_IID	20	TRUE	FALSE	0	67995
1118882	Central_PV	Solar	CA_SCE_SE	20	TRUE	FALSE	0	92449

gen_scheduled_outage_rate	gen_forced_outage_rate	gen_capacity_limit_mw	gen_min_build_capacity	gen_is_cogen	gen_storage_efficiency	gen_store_to_release_ratio	gen_can_provide_cap_reserves
0	0	307.7	0	FALSE	.	.	1
0	0	445.9	0	FALSE	.	.	1
0	0	244.5	0	FALSE	.	.	1
0	0	222.8	0	FALSE	.	.	1
0	0	38.5	0	FALSE	.	.	1
0	0	144.7	0	FALSE	.	.	1
0	0	732.25	0	FALSE	.	.	1
0	0	43.5	0	FALSE	.	.	1
0	0	380.8	0	FALSE	.	.	1
0	0	222. 1	0	FALSE	.	.	1
0	0	77.2	0	FALSE	.	.	1

0	0	69.5	0	FALSE	.	.	1
0	0	684.45	0	FALSE	.	.	1
0	0	170.1	0	FALSE	.	.	1

Table 4. 9 SWITCH gen_build_costs file format

GENERATION_PROJECT	build_year	gen_overnight_cost	gen_fixed_om
1118810	2050	702650	8229
1118822	2050	702650	8229
1118825	2050	702650	8229
1118828	2050	702650	8229
1118831	2050	702650	8229
1118849	2050	702650	8229
1118852	2050	702650	8229
1118855	2050	702650	8229
1118861	2050	702650	8229
1118867	2050	702650	8229
1118870	2050	702650	8229
1118876	2050	702650	8229
1118879	2050	702650	8229
1118882	2050	702650	8229
1118885	2050	702650	8229
1118888	2050	702650	8229
1118891	2050	702650	8229

Table 4. 10 SWITCH gen_build_predetermined file format

GENERATION_PROJECT	build_year	gen_predetermined_cap
154342	1987	199.8
154359	1972	99.8
154363	1971	54.3
154501	1973	271
154501	1974	271
154501	1976	271
154501	1977	542
154501	1978	271
154546	1968	195.4
154546	1969	97.7
154554	1967	12.6
154554	1968	12.6

154556	1967	318
154556	1968	106
154566	1967	300
154607	1954	8.5

4.2 Wind

4.2.1 Onshore Wind

Cost of wind, like solar, is constantly changing. Some recent variations are summarized in Table 4.10, comparing data from NREL's Annual Technology Baseline (ATB) to the data adopted in the Preferred System Portfolio (PSP). The PSP has adopted substantially higher cost values than NREL's ATB would suggest.

Table 4. 11 Summary of recent cost estimates for wind electricity

Data source	Year	CapEx	Calculated annualized cost
NREL ATB 2021	2025	$1171/kW	$67.2/kW*
NREL ATB 2022	2025	$1206/kW	$69.7/kW*
2021_PSP_Tehachapi	2025		$109.5/kW
NREL ATB 2021	2045	$808/kW	$46.7/kW*
NREL ATB 2022	2045	$808/kW	$37.6/kW*
2021_PSP_Tehachapi	2045		$122.8/kW
2021_PSP_Wyoming	2045		$224.3/kW
2021_PSP_Baja_California	2045		$125.8/kW

*30-year capitalization; 4% interest rate

An example set of inputs for a wind candidate resource is tabulated in Table 4.11. We follow the PSP for our baseline wind cost, but we may adopt lower costs or expanded adoption scenarios to reflect the anticipated effects of the IRA (which are still being evaluated). The costs for wind vary more with location because the cost of a wind turbine optimized for high winds can differ from the cost of a wind turbine designed for low winds. We have not documented this variation here. The performance also varies substantially, both in terms of the total generation and the temporal variations (both diurnal and seasonal). As we have noted in other reports, the exact cost of the wind turbines may not be important for the model selection because the wind generators are so valuable, many of them are built to the specified capacity limit.

Table 4. 12 RESOLVE inputs for candidate wind resource (Tehachapi_Wind)

timestamp	attribute	value
None	can_retire	FALSE
None	can_build_new	TRUE
2030	new_capacity_annualized_all_in_fixed_cost_by_vintage	145.0
2035	new_capacity_annualized_all_in_fixed_cost_by_vintage	137.8
2040	new_capacity_annualized_all_in_fixed_cost_by_vintage	130.4
2045	new_capacity_annualized_all_in_fixed_cost_by_vintage	122.8
2030	new_capacity_fixed_om_by_vintage	41.23
2035	new_capacity_fixed_om_by_vintage	39.68
2040	new_capacity_fixed_om_by_vintage	38.14

2045	new_capacity_fixed_om_by_vintage	36.59
2030	planned_fixed_om_by_model_year	45.73
2035	planned_fixed_om_by_model_year	45.73
2040	planned_fixed_om_by_model_year	45.73
2045	planned_fixed_om_by_model_year	45.73

The WECC-wide inputs to SWITCH include 1857 candidate and existing onshore wind resources with a possible deployment limit approaching 500 GW. Within California, SWITCH documents 310 existing and candidate onshore resources with a total of 15.6 GW offered to the model. Example onshore wind data are shown in Tables 4.12-14. As for solar, a subset of generators may be selected depending on the calculation being done.

Table 4. 13 SWITCH generation_projects_info file format

GENERATION_PROJECT	gen_tech	gen_energy_source	gen_load_zone	gen_max_age	gen_is_variable	gen_is_baseload	gen_variable_om	gen_connect_cost_per_mw
77333	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87089.1
77334	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87075.45
77335	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87080.7
77336	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87088.05
77337	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87089.1
77338	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87088.05
77339	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	55266.75
77340	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	55288.8
77341	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	55288.8
77342	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86989.35
77343	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86779.35
77344	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86801.4
77345	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86816.1
77346	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87034.5
77347	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86790.9
77348	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86827.65
77349	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	86827.65
77350	Wind	Wind	CA_SCE_CEN	20	TRUE	FALSE	0	87046.05

gen_scheduled_outage_rate	gen_forced_outage_rate	gen_capacity_limit_mw	gen_min_build_capacity	gen_is_cogen	gen_storage_efficiency	gen_store_to_release_ratio	gen_can_provide_cap_reserves
0	0	43	0	FALSE	.	.	1
0	0	50	0	FALSE	.	.	1
0	0	49	0	FALSE	.	.	1
0	0	92	0	FALSE	.	.	1
0	0	66	0	FALSE	.	.	1
0	0	72	0	FALSE	.	.	1
0	0	38	0	FALSE	.	.	1

0	0	44	0	FALSE	.	.	1
0	0	37	0	FALSE	.	.	1
0	0	52	0	FALSE	.	.	1
0	0	40	0	FALSE	.	.	1
0	0	64	0	FALSE	.	.	1
0	0	81	0	FALSE	.	.	1
0	0	49	0	FALSE	.	.	1
0	0	44	0	FALSE	.	.	1
0	0	96	0	FALSE	.	.	1
0	0	47	0	FALSE	.	.	1
0	0	34	0	FALSE	.	.	1

Table 4. 14 SWITCH gen_build_costs file format

GENERATION_PROJECT	build_year	gen_overnight_cost	gen_fixed_om	gen_storage_energy_overnight_cost
77333	2050	1042433.457	33692	.
77334	2050	1042433.457	33692	.
77335	2050	1042433.457	33692	.
77336	2050	1042433.457	33692	.
77337	2050	1042433.457	33692	.
77338	2050	1042433.457	33692	.
77339	2050	1042433.457	33692	.
77340	2050	1042433.457	33692	.
77341	2050	1042433.457	33692	.
77342	2050	1042433.457	33692	.
77343	2050	1042433.457	33692	.
77344	2050	1042433.457	33692	.
77345	2050	1042433.457	33692	.
77346	2050	1042433.457	33692	.
77347	2050	1042433.457	33692	.
77348	2050	1042433.457	33692	.
77349	2050	1042433.457	33692	.
77350	2050	1042433.457	33692	.

Table 4. 15 SWITCH gen_build_predetermined file format

GENERATION_PROJECT	build_year	gen_predetermined_cap
154948	1994	13.2
154948	2006	24
154948	2007	63
154948	2012	128
155004	1988	17.4
155030	1984	8.7
155074	1984	59.6
155075	1984	29
155092	1985	11.7
155169	1986	5.9
155170	1983	31

155185	1982	15.3
155201	1981	17.3
155201	2000	1.5
155202	1984	29.9
155203	1991	76.9

4.2.2 Offshore Wind

A recent study by NREL describes the six best offshore wind candidate sites for California.[32] These are summarized in Table 4.15. Based on the mean water depth, we have assigned an ATB class, but recognize that the categorization should also reflect the distance to the interconnection and a number of other things.

Table 4. 16 Candidate California offshore wind sites identified by NREL study

Identified area	Latitude (°)	Longitude (°)	Mean Depth	Potential Capacity (MW)	ATB Class
Channel Islands South	**33.734614**	120.18475	746 m	2259	14
Channel Islands North	34.188565	120.66088	575 m	1335	13
Morro Bay	35.458256	121.50439	713 m	3702	14
Bodega Bay	38.355489	123.52929	446 m	2397	13
Humboldt Bay	40.133304	124.73094	870 m	1293	14
Crescent City	41.699739	124.76659	805 m	5256	14

The following inputs have been created by E3 as part of the new-modeling-toolkit release. The annualized costs for CapEx and operations and maintenance are tabulated in Table 4.16. The costs for offshore wind are higher than for on-shore wind.

Table 4. 17 RESOLVE inputs for candidate offshore wind resource (Humboldt Bay)

timestamp	attribute	value
None	can_retire	FALSE
None	can_build_new	TRUE
2030	new_capacity_annualized_all_in_fixed_cost_by_vintage	271.1
2035	new_capacity_annualized_all_in_fixed_cost_by_vintage	248.7
2040	new_capacity_annualized_all_in_fixed_cost_by_vintage	232.2
2045	new_capacity_annualized_all_in_fixed_cost_by_vintage	219.1
2030	new_capacity_fixed_om_by_vintage	63.30
2035	new_capacity_fixed_om_by_vintage	54.74
2040	new_capacity_fixed_om_by_vintage	48.39
2045	new_capacity_fixed_om_by_vintage	43.35
2030	planned_fixed_om_by_model_year	124.4

[32] https://www.boem.gov/sites/default/files/environmental-stewardship/Environmental-Studies/Pacific-Region/Studies/BOEM-2016-074.pdf

2035	planned_fixed_om_by_model_year	124.4
2040	planned_fixed_om_by_model_year	124.4
2045	planned_fixed_om_by_model_year	124.4

The inputs to SWITCH include 33 candidate offshore wind resources with a possible deployment limit approaching 3.5 GW. All of these are associated with California. The offshore wind sites with generation capacity limit > 30 MW are shown in Tables 4.17-19.

Table 4. 18 SWITCH generation_projects_info file format

GENERATION_PROJECT	gen_tech	gen_energy_source	gen_load_zone	gen_max_age	gen_is_variable	gen_is_baseload	gen_variable_om	gen_connect_cost_per_mw
1191185654	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	121107
1191185656	Offshore_Wind	Wind	CA_PGE_S	30	TRUE	FALSE	0	348677
1191185658	Offshore_Wind	Wind	CA_PGE_S	30	TRUE	FALSE	0	57835
1191185660	Offshore_Wind	Wind	CA_PGE_S	30	TRUE	FALSE	0	72275
1191185661	Offshore_Wind	Wind	CA_PGE_CEN	30	TRUE	FALSE	0	70904
1191185663	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	85333
1191185664	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	115691
1191185665	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	114783
1191185667	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	104638
1191185668	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	120954
1191185682	Offshore_Wind	Wind	CA_PGE_S	30	TRUE	FALSE	0	375515
1191185683	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	116664
1191185686	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	104584
1191185687	Offshore_Wind	Wind	CA_SCE_CEN	30	TRUE	FALSE	0	448128
1191185688	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	56241
1191185691	Offshore_Wind	Wind	CA_PGE_N	30	TRUE	FALSE	0	95115

gen_scheduled_outage_rate	gen_forced_outage_rate	gen_capacity_limit_mw	gen_min_build_capacity	gen_is_cogen	gen_storage_efficiency	gen_store_to_release_ratio	gen_can_provide_cap_reserves
0.01	0.05	150	0	FALSE	.	.	1
0.01	0.05	270	0	FALSE	.	.	1
0.01	0.05	60	0	FALSE	.	.	1
0.01	0.05	60	0	FALSE	.	.	1
0.01	0.05	90	0	FALSE	.	.	1
0.01	0.05	330	0	FALSE	.	.	1
0.01	0.05	60	0	FALSE	.	.	1
0.01	0.05	60	0	FALSE	.	.	1
0.01	0.05	270	0	FALSE	.	.	1
0.01	0.05	60	0	FALSE	.	.	1
0.01	0.05	180	0	FALSE	.	.	1

0.01	0.05	270	0	FALSE	.	.	1
0.01	0.05	210	0	FALSE	.	.	1
0.01	0.05	420	0	FALSE	.	.	1
0.01	0.05	150	0	FALSE	.	.	1
0.01	0.05	330	0	FALSE	.	.	1

Table 4. 19 SWITCH gen_build_costs file format

GENERATION_PROJECT	build_year	gen_overnight_cost	gen_fixed_om
1191185654	2050	2226775.53	112297.5
1191185656	2050	2226775.53	112297.5
1191185658	2050	2226775.53	112297.5
1191185660	2050	2226775.53	112297.5
1191185661	2050	2226775.53	112297.5
1191185663	2050	2226775.53	112297.5
1191185664	2050	2226775.53	112297.5
1191185665	2050	2226775.53	112297.5
1191185667	2050	2226775.53	112297.5
1191185668	2050	2226775.53	112297.5
1191185682	2050	2226775.53	112297.5
1191185683	2050	2226775.53	112297.5
1191185686	2050	2226775.53	112297.5
1191185687	2050	2226775.53	112297.5
1191185688	2050	2226775.53	112297.5
1191185691	2050	2226775.53	112297.5

Table 4. 20 SWITCH gen_build_predetermined file format

GENERATION_PROJECT	build_year	gen_predetermined_cap
1191185654	2050	
1191185656	2050	
1191185658	2050	
1191185660	2050	
1191185661	2050	
1191185663	2050	
1191185664	2050	
1191185665	2050	
1191185667	2050	
1191185668	2050	
1191185682	2050	
1191185683	2050	
1191185686	2050	
1191185687	2050	
1191185688	2050	
1191185691	2050	

4.3 Hydropower

Neither SWITCH nor RESOLVE has been configured to allow build of new hydropower resources as shown in Tables 4.20 and 4.21. CAISO reports 1232 MW of small hydro as of Jan. 1, 2021,[33] which agrees well with the value used in RESOLVE PSP. The assumption that new hydropower will not be built may be relatively realistic because new hydropower projects usually take multiple years to design and permit. We anticipate that a small amount of repowering will occur with some capacities reduced slightly because of aging and some increased with higher efficiency hardware in the same location. Thus, we agree with and follow what has been done before in not considering addition of new hydropower.

Table 4. 21 Comparison of small hydropower resources

Zones for SWITCH*	SWITCH Existing	SWITCH Allowed new	Resources for RESOLVE*	RESOLVE Existing	RESOLVE Allowed new
CA_IID	**	0 MW	IID_Small_Hydro_for_Other	0 MW	0 MW
CA_LADWP	**	0 MW	LDWP_Hydro_for_Other	56 MW	0 MW
Other CA zones	**	0 MW	CAISO_Small_Hydro & CAISO_Small_Hydro_for_Other	958 MW	0 MW
CA_SMUD	**	0 MW	BANC_Small_Hydro_for_Other	41 MW	0 MW
			NW_Small_Hydro_for_CAISO & NW_Small_Hydro_for_Other	48 MW	0 MW

*The zones used by SWITCH and RESOLVE do not directly map onto each other. These are approximated.
**SWITCH does not differentiate large hydro and small hydro, so all are reported in Table 4.21.

Table 4. 22 Comparison of hydropower resources

Zones for SWITCH*	SWITCH Existing**	SWITCH Allowed new	Resources for RESOLVE*	RESOLVE Existing	RESOLVE Allowed new
CA_IID	88 MW	0 MW	IID_Hydro_for_Other	84 MW	0 MW
CA_LADWP	45 MW	0 MW	LDWP_Hydro	234 (1108)[34] MW	0 MW
Other CA zones	9573 MW	0 MW	CAISO_Hydro	7073 MW	0 MW
CA_SMUD	212 MW	0 MW	BANC_Hydro	2724 MW	0 MW

[33] http://www.caiso.com/Documents/Key-Statistics-Dec-2020.pdf

[34] LDWP is built to 234 MW for the PSP. The EIA 860 documents 315 MW of hydropower generators, but the EIA grid monitor shows hydro in LDWP exceeding 234 MW about 1/6 of the time with the largest generation being 1108 MW. To be able to duplicate the generation profile reported by the EIA grid monitor, we scale the data to 1108 MW, even though we can't document that the existing power generators are capable of delivering that. It seems strange that EIA reports more generation than is feasible with the reported generators unless the generators are able to generate at a rate that is greater than their rated capacity.

			SW_Hydro	2532 MW	0 MW
			NW_Hydro	31288 MW	0 MW
			NW_Hydro_for_CAISO	2852 MW	0 MW

*The zones used by SWITCH and RESOLVE do not directly map onto each other. These are approximated.
**SWITCH does not differentiate large hydro and small hydro, so both are reported here.

The bigger uncertainty with hydropower is the availability of the water to drive the turbines. The variability of electricity from hydropower is obvious in Fig. 2.1. A grid that has adequate storage for a dry year will be more easily able to deliver the needed reliability in a wet year, so we choose to study primarily the dry years. We note that this misses a key assessment for a company that is looking for a return on investment over many years, some of which are likely to be wet and some of which are likely to be dry.

The method we have developed for tracking energy storage throughout an entire year is incompatible with the method that the new-modeling-toolkit uses for defining the seasonal variations in hydropower usage. Instead of address this by modifying the code, we have chosen to use the historical dispatch of hydropower in a way that is similar to how solar and wind are expected to generate according to the available resource that was measuring.

Hydro profiles were constructed as summarized in Table 4.22. Data were downloaded for 2019, 2020, and 2021. The data were normalized to the power indicated in Table 4.21 for each resource to provide the generation profile in a data set that does not exceed unity. For data points that would have exceeded unity, the data were capped at 1.0. The LDWP data were inconsistent as described in the footnote. For each balancing area, the wettest year of the three is used for the "wet" scenario and the driest year of the 3 taken for the "dry" scenario, as indicated in Table 4.23. The resource file for each hydropower resources was then modified to identify the profile taken from 2019, 2020, or 2021, depending on the scenario tag (indicating dry, medium, or wet) used for the run. The dry hydro profiles significantly increase the cost of delivering the energy system (by almost a factor of 2).

Table 4. 23 Source of hydropower generation profiles

Profile/Resource	Source of data	Details
BANC_Hydro	EIA*	
NW_Hydro	EIA*	
SW_Hydro	EIA*	
LDWP_Hydro	EIA*	
IID_Hydro	EIA*	
CAISO_Hydro	CAISO**	5-minute data averaged to create hourly data
NW_CAISO_for_Hydro	EIA	Duplicated BANC_hydro

* https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48
** http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

Table 4. 24 Generation from hydropower used for dry, medium, and wet scenarios.

Resource	Year	Net Generation (GWh)	Scenario
BANC_Hydro	2021	2910	DRY

	2020	4258	MEDIUM
	2019	6492	WET
CAISO_Hydro	2021	9022	DRY
	2020	13294	MEDIUM
	2019	25945	WET
IID_Hydro	2021	228646	WET
	2020	205834	DRY
	2019	213445	MEDIUM
LDWP_Hydro	2021	596	DRY
	2020	651	MEDIUM
	2019	1401	WET
NW_Hydro	2021	122106	DRY
	2020	137393	WET
	2019	126339	MEDIUM
NW_Hydro_for_CAISO	2021	3129	DRY
	2020	4705	MEDIUM
	2019	7725	WET
SW_Hydro	2021	5299290	WET
	2020	5173506	MEDIUM
	2019	4973559	DRY

4.4 Geothermal

The costs of geothermal plants can be highly variable. For example, the 2025 Moderate CAPEX cost for Hydro/Flash is $6033, while Hydro/Binary is $7902, and NF EGS/Binary is $39,426. By 2045, these are expected to decrease a little, but not a lot with the Moderate CAPEX cost for Hydro/Flash being $5148, with Hydro/Binary is $6888, and NF EGS/Binary is $31,729. The uncertainties conveyed in the NREL ATB are quite substantial, noting that the Moderate $31,729 could drop to $7050, more than a factor of 5 decrease. Lower costs will be explored based on the value of geothermal generation to the bigger system. The inputs taken from the PSP are tabulated in Table 4.24.

Table 4. 25 RESOLVE inputs for candidate geothermal resource (Greater Imperial)

timestamp	attribute	value
None	can_retire	FALSE
None	can_build_new	TRUE
2030	new_capacity_annualized_all_in_fixed_cost_by_vintage	501.8
2035	new_capacity_annualized_all_in_fixed_cost_by_vintage	493.0
2040	new_capacity_annualized_all_in_fixed_cost_by_vintage	484.5
2045	new_capacity_annualized_all_in_fixed_cost_by_vintage	476.1
2030	new_capacity_fixed_om_by_vintage	135.2
2035	new_capacity_fixed_om_by_vintage	135.2
2040	new_capacity_fixed_om_by_vintage	135.2
2045	new_capacity_fixed_om_by_vintage	135.2
2030	planned_fixed_om_by_model_year	146.8
2035	planned_fixed_om_by_model_year	146.8

2040	planned_fixed_om_by_model_year	146.8
2045	planned_fixed_om_by_model_year	146.8

Current and candidate geothermal resources will use the same names and locations as the PSP. These are summarized in Table 4.25.

Table 4. 26 Summary of geothermal plants

Resource	Planned installed capacity (MW)	Capacity limit (MW)	Note
BANC_Geothermal_for_Other	31		No new builds
CAISO_Geothermal_for_Other	8.7		No new builds
IID_Geothermal_for_Other	401.2		No new builds
LDWP_Geothermal_for_Other	0		No new builds
NW_Geothermal_for_Other	154.1		No new builds
SW_Geothermal_for_Other	778.1		No new builds
CAISO_Geothermal_for_CAISO	1579		No new builds
IID_Geothermal_for_CAISO	83		No new builds
NW_Geothermal_for_CAISO	0		No new builds
Greater_Imperial_Geothermal		1352.1	
Inyokern_North_Kramer_Geothermal		24	
Northern_California_Geothermal		469	
Pacific_Northwest_Geothermal		0	
Riverside_Palm_Springs_Geothermal		32	
Solano_Geothermal		135	
Southern_Nevada_Geothermal		320	
Total	3035	2332	

The WECC-wide inputs to SWITCH for geothermal include about 100 existing geothermal installations and about 250 candidate geothermal resources with example data shown in Tables 4.26-4.28.

Table 4. 27 SWITCH generation_projects_info file format

GENERATION_PROJECT	gen_tech	gen_energy_source	gen_load_zone	gen_max_age	gen_is_variable	gen_is_baseload	gen_variable_om	gen_connect_cost_per_mw
1191209229	Geothermal	Geothermal	CA_PGE_N	20	FALSE	TRUE	0	43110
1191209239	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	48294
1191209241	Geothermal	Geothermal	CA_PGE_N	20	FALSE	TRUE	0	132769
1191209244	Geothermal	Geothermal	CA_PGE_N	20	FALSE	TRUE	0	46634
1191209249	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	60538
1191209250	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	72816
1191209251	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	76974
1191209264	Geothermal	Geothermal	CA_SCE_CEN	20	FALSE	TRUE	0	44302

1191209268	Geothermal	Geothermal	CA_SCE_CEN	20	FALSE	TRUE	0	45462
1191209324	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	47472
1191209329	Geothermal	Geothermal	CA_PGE_N	20	FALSE	TRUE	0	135628
1191209334	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	56452
1191209342	Geothermal	Geothermal	CA_IID	20	FALSE	TRUE	0	62627
1191209360	Geothermal	Geothermal	CA_SCE_CEN	20	FALSE	TRUE	0	58687
1191209370	Geothermal	Geothermal	CA_PGE_N	20	FALSE	TRUE	0	147125

gen_scheduled_outage_rate	gen_forced_outage_rate	gen_capacity_limit_mw	gen_min_build_capacity	gen_is_cogen	gen_storage_efficiency	gen_store_to_release_ratio	gen_can_provide_cap_reserves
0	0	80	0	FALSE	.	.	1
0	0	180	0	FALSE	.	.	1
0	0	10	0	FALSE	.	.	1
0	0	25.5	0	FALSE	.	.	1
0	0	20	0	FALSE	.	.	1
0	0	200	0	FALSE	.	.	1
0	0	50	0	FALSE	.	.	1
0	0	30	0	FALSE	.	.	1
0	0	40	0	FALSE	.	.	1
0	0	32	0	FALSE	.	.	1
0	0	8	0	FALSE	.	.	1
0	0	32	0	FALSE	.	.	1
0	0	1170	0	FALSE	.	.	1
0	0	24	0	FALSE	.	.	1
0	0	8	0	FALSE	.	.	1

Table 4. 28 SWITCH gen_build_costs file format

GENERATION_PROJECT	build_year	gen_overnight_cost	gen_fixed_om	gen_storage_energy_overnight_cost
1191209229	2050	6970164.4	173105	.
1191209239	2050	6970164.4	173105	.
1191209241	2050	6970164.4	173105	.
1191209244	2050	6970164.4	173105	.
1191209249	2050	6970164.4	173105	.
1191209250	2050	6970164.4	173105	.
1191209251	2050	6970164.4	173105	.
1191209264	2050	6970164.4	173105	.
1191209268	2050	6970164.4	173105	.
1191209324	2050	6970164.4	173105	.
1191209329	2050	6970164.4	173105	.
1191209334	2050	6970164.4	173105	.
1191209342	2050	6970164.4	173105	.
1191209360	2050	6970164.4	173105	.

1191209370	2050	6970164.4	173105	.

Table 4. 29 SWITCH gen_build_predetermined file format

GENERATION_PROJECT	build_year	gen_predetermined_cap
154432	1971	110
154432	1972	110
154432	1975	110
154432	1979	110
154432	1980	251
154432	1982	118
154432	1983	118
154432	1985	236
154597	1983	78
154928	1983	110
154929	1985	55
154929	1986	55
155099	1989	53.9
155115	1988	60
155116	1989	90
155117	1988	60

4.5 Biomass

The costs for biomass can be highly variable depending on the technology (biogas vs wood pellets, etc.) The inputs assumed for one of the candidate biomass resources are summarized in Table 4.29. These CapEx costs are substantially higher than those found in the NREL ATB. Although, the Instate biomass plant is expected to pay variable operating costs that are five to six times bigger than what is expected of a more conventional thermal plant, this higher cost replaces the much higher fuel cost for a conventional plant. Thus, a biomass plant is generally not found to be a competitive option. The state is interested in reducing wildfires: clearing forest and combusting the cleared fuel could increase the interest in biomass coupled with forests. Also, the state is avoiding methane emissions from waste through the Low Carbon Fuel Standard, increasing the creation of biogas, which may be used for power generation. We believe that this pathway is not adequately explored, so we propose to add a candidate technology, as described in section 4.6.

Table 4. 30 RESOLVE inputs for the one candidate biomass resource (Instate)

timestamp	attribute	value
None	can_retire	FALSE
None	can_build_new	TRUE
2030	new_capacity_annualized_all_in_fixed_cost_by_vintage	754.0
2035	new_capacity_annualized_all_in_fixed_cost_by_vintage	745.8
2040	new_capacity_annualized_all_in_fixed_cost_by_vintage	736.7
2045	new_capacity_annualized_all_in_fixed_cost_by_vintage	728.8
2030	new_capacity_fixed_om_by_vintage	135.1
2035	new_capacity_fixed_om_by_vintage	135.1
2040	new_capacity_fixed_om_by_vintage	135.1
2045	new_capacity_fixed_om_by_vintage	135.1
2030	planned_fixed_om_by_model_year	135.1

2035	planned_fixed_om_by_model_year	135.1
2040	planned_fixed_om_by_model_year	135.1
2045	planned_fixed_om_by_model_year	135.1
(all)	variable_cost_provide_power	1.6778

The WECC-wide inputs to SWITCH for biomass include about 20 Biogas and 3 Biosolid existing resources but does not give option to build new plants. Data for existing plants is shown in Tables 4.30-32. (Not all data are shown for brevity).

Table 4. 31 SWITCH generation_projects_info file format

GENERATION_PROJECT	gen_tech	gen_energy_source	gen_load_zone	gen_max_age	gen_is_variable	gen_is_baseload	Heat rate	gen_variable_om	gen_connect_cost_per_mw
155161	Bio_Gas_Internal_Combustion_Engine_Cogen	Bio_Gas	CA_SCE_CEN	20	FALSE	TRUE	40.353	16.04	0
155171	Bio_Solid_Steam_Turbine	Bio_Solid	CA_PGE_N	20	FALSE	FALSE	9.486	12.72	0
155248	Bio_Solid_Steam_Turbine	Bio_Solid	CA_PGE_N	20	FALSE	FALSE	18.127	12.72	0
155352	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	17.931	5.75	0
155352	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	17.931	5.75	0
155352	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	17.931	5.75	0
155461	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_SCE_CEN	20	FALSE	FALSE	12.539	5.75	0
155484	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	8.445	5.75	0
155485	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	6.799	5.75	0
155501	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	11.166	5.75	0
155680	Bio_Gas	Bio_Gas	CA_SCE_CEN	20	FALSE	FALSE	10.849	9.18	0
155751	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	11.478	5.75	0
155751	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	11.478	5.75	0
155758	Bio_Gas	Bio_Gas	CA_SCE_CEN	20	FALSE	FALSE	7.732	9.18	0
155979	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	10.152	5.75	0
156065	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	10.563	5.75	0
156065	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	10.563	5.75	0
156172	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	12.894	5.75	0
156198	Bio_Gas	Bio_Gas	CA_SCE_CEN	20	FALSE	FALSE	11.787	9.18	0
156357	Bio_Gas_Internal_Combustion_Engine_Cogen	Bio_Gas	CA_PGE_N	20	FALSE	TRUE	15.94	16.04	0
156434	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	12.039	5.75	0
156531	Bio_Solid_Steam_Turbine_Cogen	Bio_Solid	CA_PGE_N	40	FALSE	TRUE	15.151	16.85	0
156585	Bio_Gas_Internal_Combustion_Engine	Bio_Gas	CA_PGE_N	20	FALSE	FALSE	8.147	5.75	0

gen_scheduled_outage_rate	gen_forced_outage_rate	gen_capacity_limit_mw	gen_min_build_capacity	gen_is_cogen	gen_storage_efficiency	gen_store_to_release_ratio	gen_can_provide_cap_reserves
0.04	0.11	1.5	.	TRUE	.	.	1
0.06	0.04	29.1	.	FALSE	.	.	1
0.06	0.04	54.9	.	FALSE	.	.	1

0.06	0.04	2.2	.	FALSE	.	.	1
0.06	0.04	2.2	.	FALSE	.	.	1
0.06	0.04	2.2	.	FALSE	.	.	1
0.06	0.04	3	.	FALSE	.	.	1
0.06	0.04	3.2	.	FALSE	.	.	1
0.06	0.04	3.2	.	FALSE	.	.	1
0.06	0.04	1.6	.	FALSE	.	.	1
0.06	0.04	9.2	.	FALSE	.	.	1
0.06	0.04	3.5	.	FALSE	.	.	1
0.06	0.04	3.5	.	FALSE	.	.	1
0.06	0.04	9.2	.	FALSE	.	.	1
0.06	0.04	2.3	.	FALSE	.	.	1
0.06	0.04	4.8	.	FALSE	.	.	1
0.06	0.04	4.8	.	FALSE	.	.	1
0.06	0.04	1.6	.	FALSE	.	.	1
0.06	0.04	23	.	FALSE	.	.	1
0.04	0.11	4.4	.	TRUE	.	.	1
0.06	0.04	4	.	FALSE	.	.	1
0.09	0.13	30.2	.	TRUE	.	.	1
0.06	0.04	8	.	FALSE	.	.	1

Table 4. 32 SWITCH gen_build_costs file format

GENERATION_PROJECT	build_year	gen_overnight_cost	gen_fixed_om	gen_storage_energy_overnight_cost
155161	1981	0	0	.
155171	1989	0	0	.
155248	1987	0	0	.
155352	1990	0	0	.
155352	1993	0	0	.
155352	1998	0	0	.
155461	2000	0	0	.
155484	1993	0	0	.
155485	1996	0	0	.
155501	2004	0	0	.
155680	2010	0	0	.
155751	2009	0	0	.
155751	2013	0	0	.
155758	2010	0	0	.
155979	2013	0	0	.

Table 4. 33 SWITCH gen_build_predetermined file format

GENERATION_PROJECT	build_year	gen_predetermined_cap
155161	1981	1.5
155171	1989	29.1
155248	1987	54.9
155352	1990	1.2
155352	1993	0.6
155352	1998	0.4

155461	2000	3
155484	1993	3.2
155485	1996	3.2
155501	2004	1.6
155680	2010	9.2
155751	2009	1.9
155751	2013	1.6
155758	2010	9.2
155979	2013	2.3
156065	2004	2.4

4.6 Carbon capture and sequestration coupled with biogas

As described in section 2.7, we have identified the Allam cycle (that is being developed by NET Power) as the most attractive approach to implementing natural gas with carbon capture and sequestration. However, the technology is not yet advanced well enough to be confident in defining the costs that will be achievable in the next decades. We propose to model its use with biogas as the preferred approach but modeling it with use of natural gas will also be considered.

In choosing appropriate modeling parameters we note that the Allam cycle has the potential to match advanced combined cycle technology, so we propose to start with the CAISO_Advanced_CCGT.csv inputs (Table 4.33) as an appropriate template using either biogas or natural gas as the fuel. We anticipate that the minimum stable level, minimum down time, and start/stop costs may be higher when using carbon dioxide as the working fluid. We will explore adjustment of these numbers as information becomes available. We will revise the policy inputs to reflect the avoidance of GHG emissions. When biogas is used, it would also count as a renewable source.

Table 4. 34 RESOLVE inputs for the CAISO_Advanced_CCGT resource

timestamp	attribute	value
None	can_build_new	TRUE
None	can_retire	TRUE
None	fuel_burn_intercept	500
None	fuel_burn_slope	6
None	min_down_time	1
None	min_stable_level	0.2
None	min_up_time	2
1/1/30 0:00	new_capacity_annualized_all_in_fixed_cost_by_vintage	109.22
1/1/35 0:00	new_capacity_annualized_all_in_fixed_cost_by_vintage	107.55
1/1/40 0:00	new_capacity_annualized_all_in_fixed_cost_by_vintage	106.14
1/1/45 0:00	new_capacity_annualized_all_in_fixed_cost_by_vintage	105.01
1/1/30 0:00	new_capacity_fixed_om_by_vintage	14.31
1/1/35 0:00	new_capacity_fixed_om_by_vintage	14.31
1/1/40 0:00	new_capacity_fixed_om_by_vintage	14.31
1/1/45 0:00	new_capacity_fixed_om_by_vintage	14.31

None	ramp_rate	1
None	shutdown_cost	16236
None	start_cost	16236
None	start_fuel_use	2742
None	unit_commitment_linear	TRUE
None	unit_size_mw	600