SUMMARY OF BASELINE MODEL RESULTS for EPC-19-060

(Deliverable for Subtask 2.3)

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Executive Summary

This Summary of Baseline Model Results provides a preliminary summary of baseline results. This evaluation will be updated when the new version of RESOLVE is received and after the Multi-day model optimization is completed.

Key preliminary conclusions include:

- The SB100 targets can be met, but asking RESOLVE to reach zero emissions for the electricity that is lost in the system (not retail sales) results in an impractical solar build, motivating review of the model inputs
- Comparison between SWITCH and RESOLVE suggests that enabling use of out-of-state resources (in particular, wind resources) enables meeting the targets with a more practical solar build
- RESOLVE selects essentially all of the non-solar resources that were allowed in the 2018 RSP, further motivating a reconsideration of the available resources
- Comparison of our results with the latest SB100 Joint Agency Report confirms the value of adding additional candidate resources
- Increased loads from electric vehicles and electrolyzers increase the need for additional capacity buildout, but counter-intuitively reduce the use of pumped storage
- The description of the Li batteries has substantial effect on the selected storage and demand management resources

1. Introduction

This Summary of Baseline Model Results describes the implementation of the Baseline Description and Modeling Approach Description provided by Tasks 2.1 and 2.2 into the current version of RESOLVE and SWITCH.

The code for RESOLVE is currently being updated by E3 to introduce the ability to model multiple contiguous days. Such capability is necessary to capture the performance of multi-day storage. The new version of RESOLVE is not yet available, so this proposal of a baseline is considered to be preliminary. Nevertheless, the summary presented here will provide a starting point and useful information to be implemented in the new version of RESOLVE when it is ready.

We review both the results from RESOLVE and from SWITCH. In section 2 we review the changes made relative to the RESOLVE RSP baseline. In section 3 we present the results when all changes are made simultaneously and then explore the impact of removing each change one by one in order to see if the effect reflects the change that was associated with that change in Section 2. In Section 4 we compare the results from the new baselines for RESOLVE and SWITCH.

2. Changes made in RESOLVE baseline relative to RESOLVE RSP

The Baseline Description and Modeling Approach deliverables submitted to the CEC in February 2021 described several changes we propose to make relative to the Reference System Portfolio (RSP) from 2018. Table 2.1 provides a summary of these changes made in RESOLVE, the description of the change in the deliverables from February, and the result reported in this document.

Table 2. 1. Summary of changes made in RESOLVE relative to the Reference System Portfolio (RSP)

Change from RSP	Description of change	Modeling result
5-year intervals for periods and no financial calculation beyond the final year	Section 3.1 in Modeling approach	Section 2.1
Greenhouse gas targets set to zero in 2045	Table 7.1 Baseline description	Section 2.2
Add offshore wind as candidate	Section 3.2 Baseline description	Section 2.3
Add additional EV load	Section 2.4	Section 2.4
Add additional electrolyzer load (high hydrogen)	Section 6 Baseline description	Section 2.5
Increase planning reserve margin	Section 7 Baseline description	Section 2.6
Change Li-battery model	Section 4.1 Baseline description	Section 2.7

To create this baseline, the following steps were executed:

• Using the Scenario Tool, select the following options and create a set of input files:
  - 46MMT_20200527_2045_2GWPRM_NOOTCEXT_RSP_PD as starting point
  - Under “Load Assumptions” for “Hydrogen” select “CEC Pathways High Hydrogen”
  - Under “CAISO GHG Target (incl. BTM CHP emissions)” select “0 MMT by 2045 Statewide”
  - Under “Renewables” for “Off-shore wind available?” select “True”
  - Under “Simulation Years” select 2020, 2025, 2030, 2035, 2040, and 2045
  - Under “Financing Years Post Final Year” enter 0

• Modify the resulting files:
  - In the “zone_timepoint_params.tab” file, increase the CAISO loads for years 2025, 2030, 2035, 2040, and 2045 by the factors 1.028, 1.089, 1.156, 1.188 and 1.198, respectively to account for increased EV charging. Increase the annual load values in the “planning_reserve_margin.tab” by a similar value.[1]
  - File “resource_vintage_params.tab” replace “Annual_fixed_cost_by_vintage” for “CAISO_New_Li_Battery” (also for batteries 2-6) with values in Table 4.7 of Baseline Description.
  - File “resource_vintage_storage_params.tab” replace “Energy_storage_cost_ dollars_per_kwh_yr” for “CAISO_New_Li_Battery” (also for batteries 2-6) with values in Table 4.6 of Baseline Description.

[1] When considering electric vehicle charging and operation of an electrolyzer, we choose not to include these in the calculation of the power needed for the planning reserve margin since these are loads that could be shed in an emergency. However, we retain the electric vehicle charging in the annual load, but not the electrolyzer load. This assumption could be debated.

- Add 99999 GW capacity limits for CAISO_New_Li_Battery5 & 6 by changing the flag in "resources.tab" to 1 for "capacity_limited" and adding the 99999 limits for all periods to file "capacity_limits.tab".
- In the "planning_reserve_margin.tab" file, increase the "period_planning_reserve_margin" for years 2025-2045 from 0.15 to 0.207. Increase the values for "prm_peak_load_mw" for years 2025-2045 by a ratio of 1.207/1.15.[2]

2.1 Years modeled in RESOLVE

More detailed understanding of the evolution of the grid can be ascertained using 5-year increments in modeling. The periods used in the Reference System Portfolio (RSP) are designed for near-term planning, while we are exploring what will happen in later years. The comparison graphs were shown in the previous deliverable, but are shared again here for easy reference in Fig. 2.1.

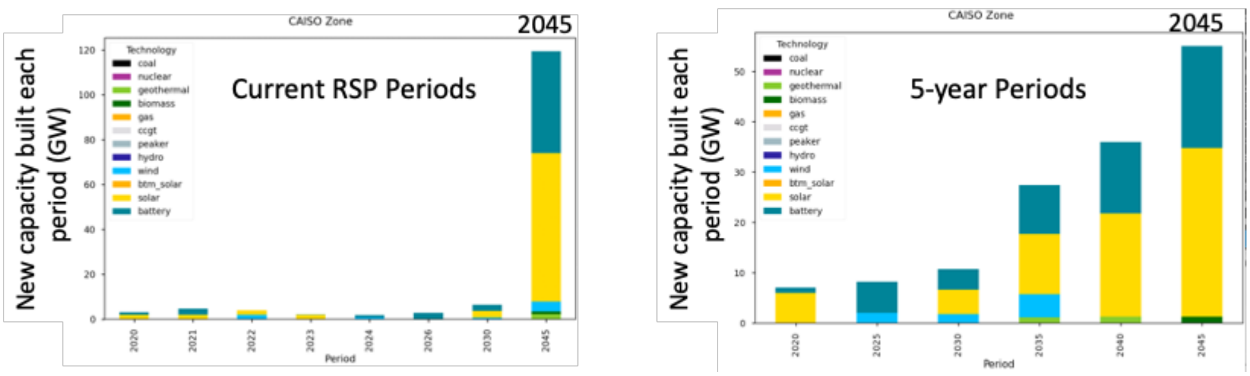


Fig. 2. 1 Comparison of RSP outputs using RSP periods (left) and 5-year periods (right)

We compared the objective function (total cost) for the RSP calculated from the original set of periods and the 5-y periods. The value was found to be consistent within 1%, as shown in Fig. 2.2. The RSP weights the final period more than others by adding 20 years past the final period. This is somewhat balanced by applying the 5% discount rate, but it also adds uncertainty by including costs extrapolated to 2065. We have chosen to count the final 2045 period as 3 years, effectively ending the simulation in the year 2045 with zero years appended. This reduces the calculated cost (objective function) by 34% (as shown in Fig. 2.2). If an additional 5-year period is added to include 2050, the reduction is only 21%. If 2050 is included with an additional 20 years appended beyond 2050, the value is increased by 7%. We also considered setting the discount rate to 0%, which places more emphasis on the later years. The cost of the scenario ending in 2045 is doubled when the discount rate is set to zero relative to 5% as shown in Fig. 2.3.

Most of the calculations reported in the rest of this report build on the scenario in Fig. 2.2 labeled "5-y 2045 end" which includes 2020, 2025, 2030,2035, 2040,and 2045, with no added years simulated beyond 2045. As we move into 2021 it is no longer appropriate to optimize the capacity expansion in 2020. We retained it here as a reference point, but note that the SB 100 report shifts to using 2027, 2030, 2035, 2040 and 2045 as the periods for optimization.[3]

[2] The decision to increase the planning reserve margin from 15% to 20.7% is not yet finalized and it is not clear whether it should include the EV and electrolyzer loads nor whether it should include behind-the-meter storage, etc. The effect of electrification on the needed planning reserve margin is a topic worth studying separately.

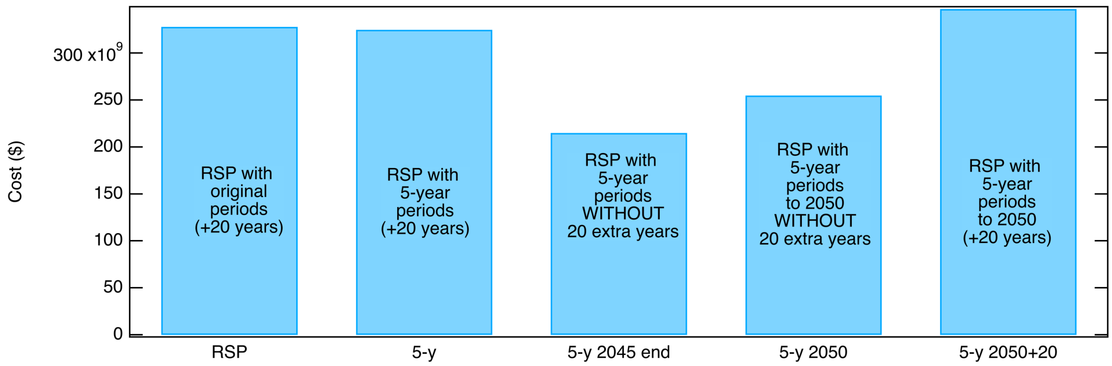


Fig. 2. 2 Objective function (total cost) optimized by RESOLVE for various period definitions.

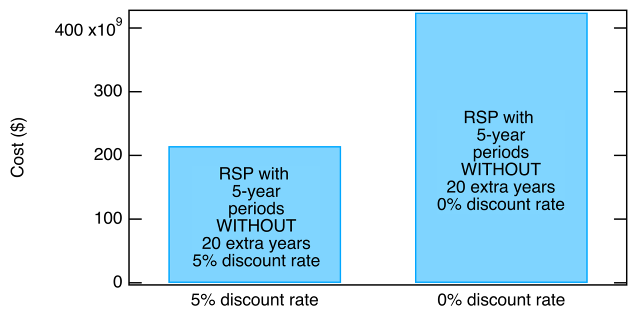
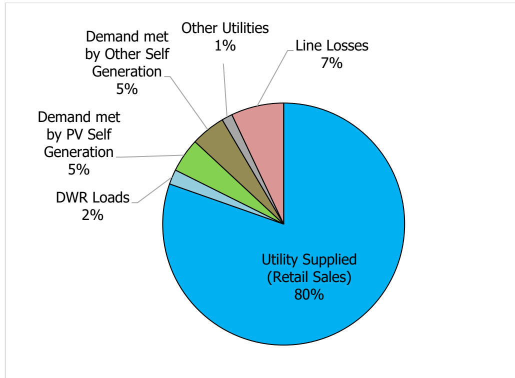


Fig. 2. 3 Objective function (total cost) with and without discount rate for 5-year scenario.

2.2 Greenhouse gas emissions targets set to zero in 2045

California Senate bill 100 sets the goal of zero-carbon emissions by 2045, but it left some ambiguity about what exactly that meant. The recent SB100 study concludes[3] that the modeling should include the retail sales, as explicitly indicated by SB100, but should exclude line losses, as shown in Fig. 2.4. While the "SB100 core" study excludes the line losses, we feel we will bring greater value if we include the line losses as this scenario better represents our aspirations. The SB100 study also includes a scenario with the more stringent goal. By defining what it would take to reach those, we can empower the CEC and CPUC to decide whether to take the corresponding action. So, we have selected to set the baseline to reach zero carbon emissions (including the line losses) in 2045. We will consider other targets in our sensitivity analysis. The stricter targets result in a very large increase in solar and storage built in 2045, as shown in Fig. 2.5. The build out in 2020 to 2040 is slightly greater, but the build in 2045 is almost five times greater. This results in a large amount of curtailment, as shown in Fig. 2.6 by the hatched part of the bar at the top. The electricity used to charge the battery is shown on a negative-going bar. Note the different scales on the graphs.

[3] https://efiling.energy.ca.gov/GetDocument.aspx?tn=237167&DocumentContentId=70349



Source: 2019 California Energy Demand and the Quarterly Fuels and Energy Report Demand filings

Fig. 2. 4 Breakout of electricity demand[4] to define the parts included in this study

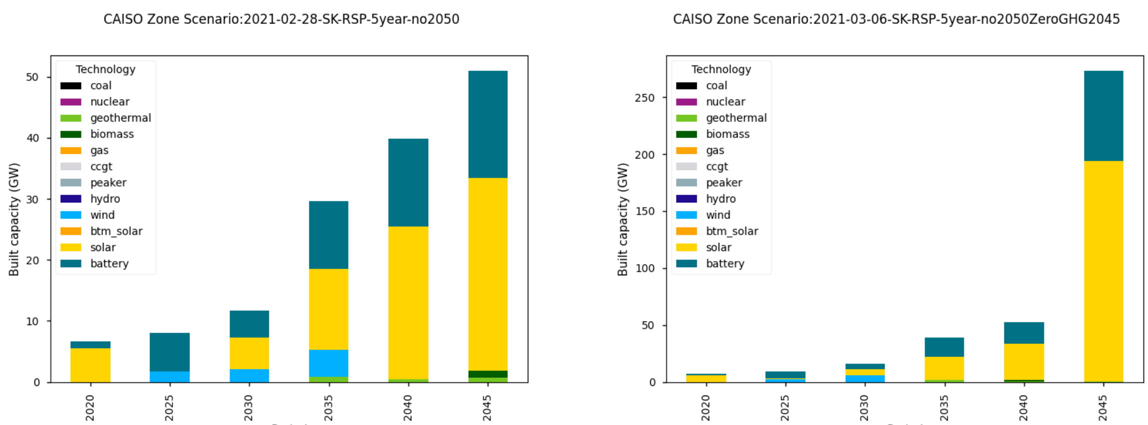


Fig. 2. 5 Comparison of resource builds for RSP (left) and RSP with zero emissions in 2045 (right).

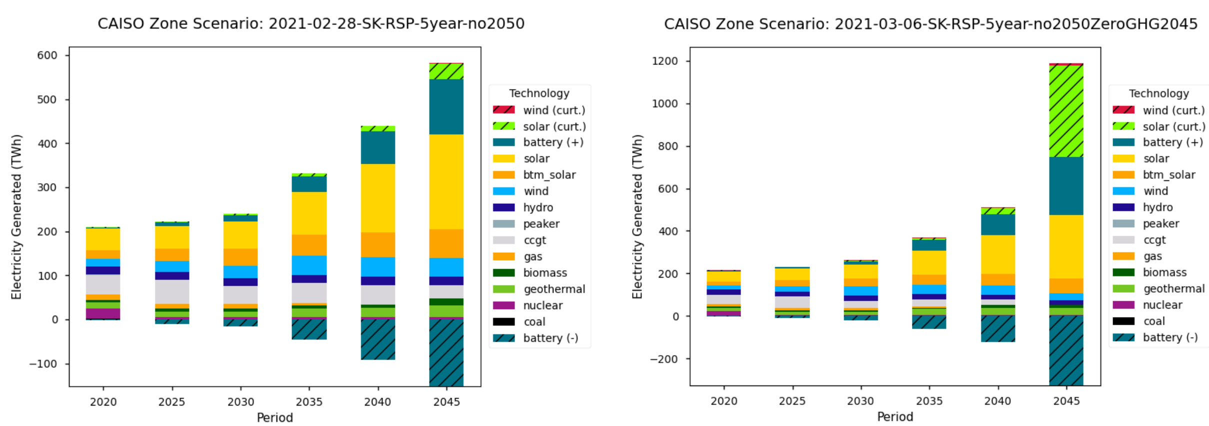


Fig. 2. 6 Comparison of electricity generation for RSP (left) and RSP with zero emissions in 2045 (right).

The fractional resource buildouts for these two scenarios are shown by technology for 2040 and 2045 in Figs. 2.7 and 2.8, respectively. The fractional buildout is relative to the resources that

[4] https://efiling.energy.ca.gov/GetDocument.aspx?tn=237167&DocumentContentId=70349

RESOLVE was allowed to build. In 2040, the zero-emissions scenario is found to build out all of the allowed biomass and more geothermal than the RSP. Surprisingly, it then selects to build less pumped storage in 2040.

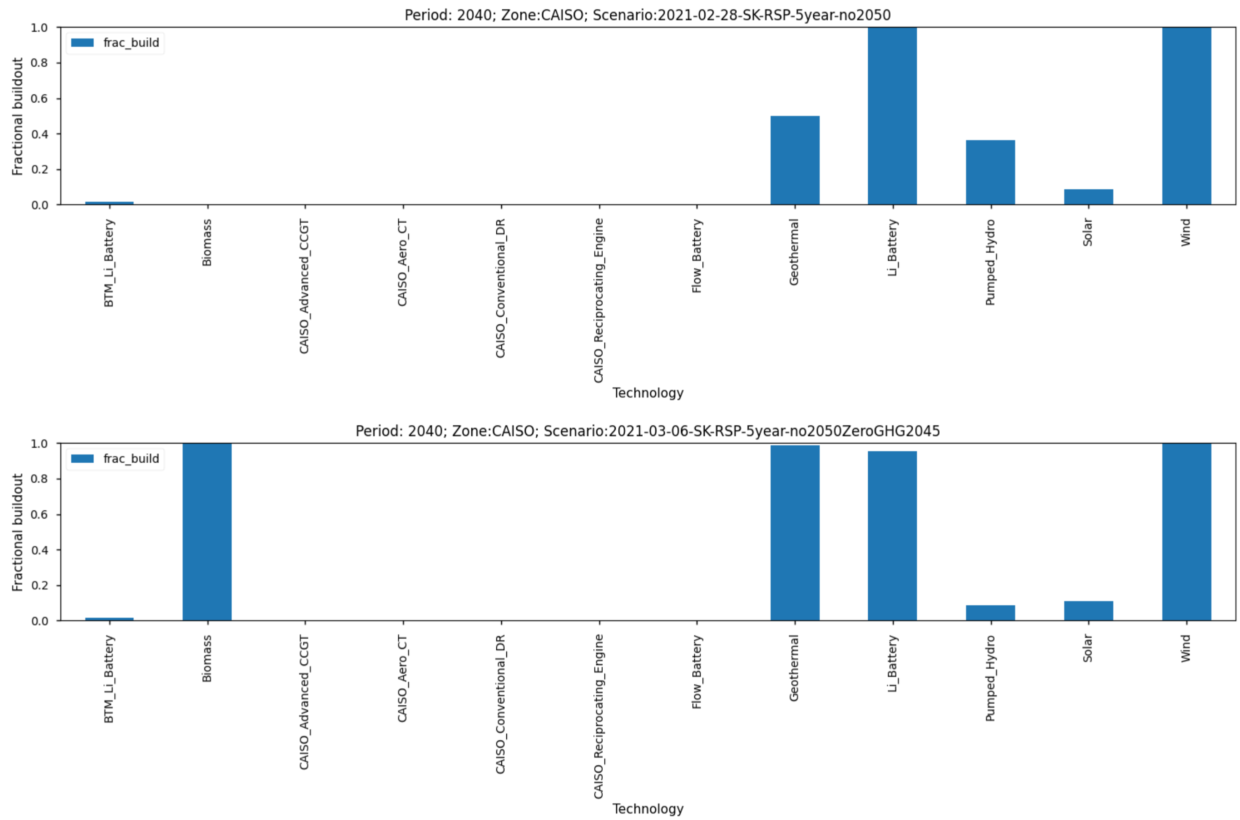


Fig. 2. 7 Fractional buildout for Period 2040 for RSP (top) and RSP with zero emissions in 2045 (bottom)

In the period 2045 (Fig. 2.8) both scenarios build all of the available biomass, and the RSP selects to build most of the geothermal while the zero-emissions scenario builds all available geothermal. Again, the amount of pumped-hydro that is built is substantially less than that built by the RSP. In this case, the reason is much more obvious: the solar build out is huge, requiring less storage.

The documentation of more storage buildout for the zero-emissions scenario in Fig. 2.5 and less fractional buildout in Fig. 2.8 at first appears to be contradictory. However, this is an artifact of batteries 5 and 6 being unlimited. The larger buildout of batteries 5 and 6 shows up in Fig. 2.5, but is not documented in Fig. 2.8 since these two candidate resources are flagged for unlimited build. In Section 3, when we explore the final version of the baseline, we add reasonable limits on batteries 5 and 6 to help us track their expansion in more detail using a graph like Fig. 2.8.

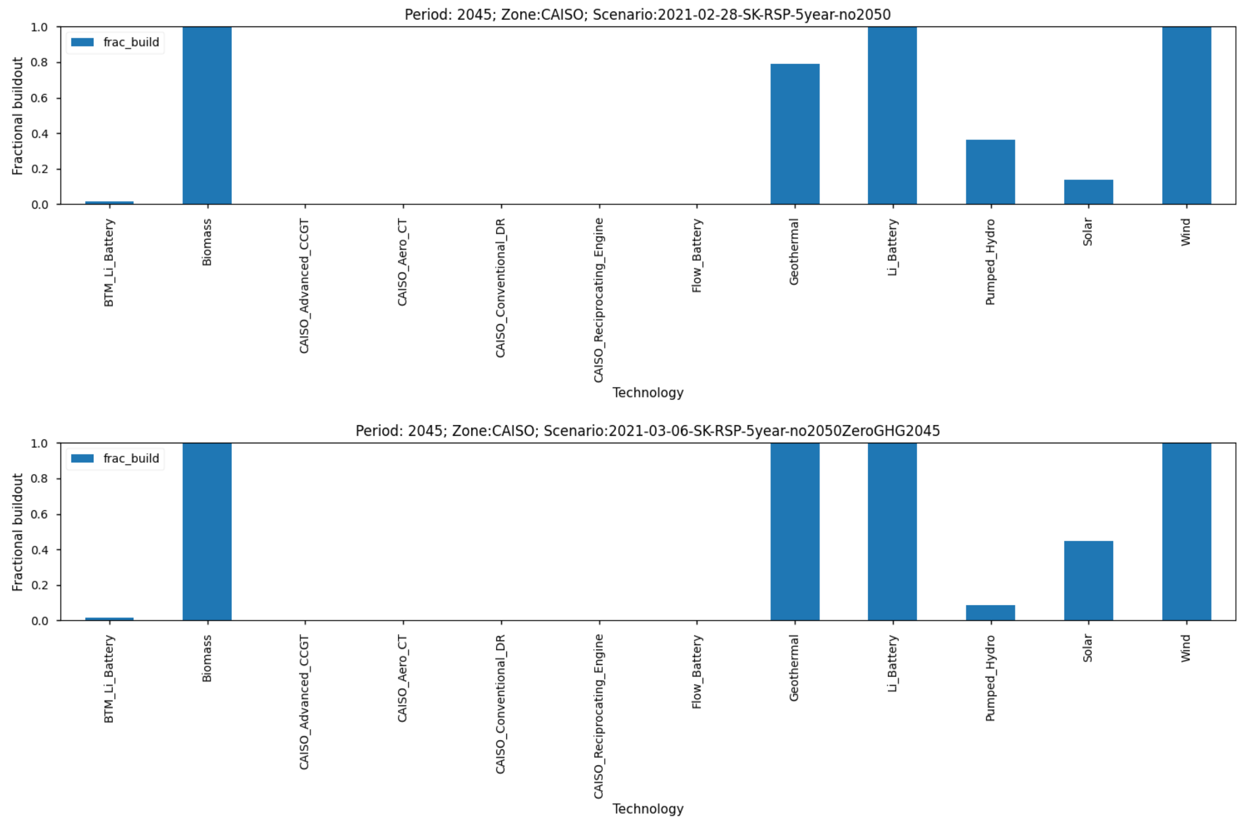


Fig. 2. 8 Fractional build out for Period 2045 for RSP (top) and zero-emissions-in-2045 scenario (bottom)

2.3 Addition of Offshore wind candidates

The addition of offshore wind as a candidate has been suggested by offshore wind companies to be of obvious value. Offshore wind is progressing quickly for Denmark and on the east coast of the United States. For consistency, we adopt in our baseline to use the same offshore wind candidate resources that have been identified in the RESOLVE Scenario Tool. The comparison of the RSP (same data as above, but repeated for ease of comparison) with a scenario with added offshore wind is shown in Fig. 2.9. RESOLVE selects to build the additional wind primarily in 2035 and 2040.

The electricity generation for these two scenarios is shown in Fig. 2.10. The increased production from wind is evident in 2035, 2040, and 2045.

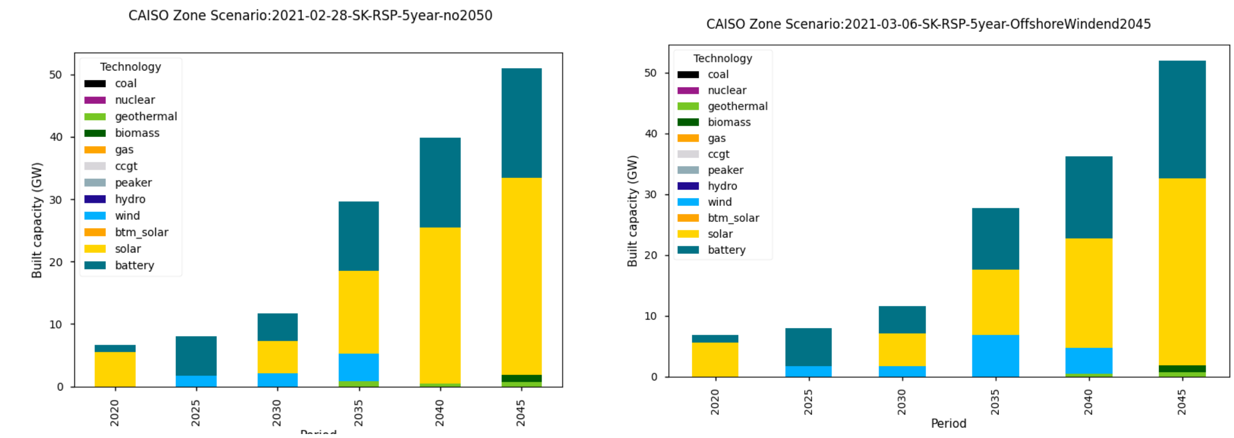


Fig. 2. 9 Comparison of resource builds for RSP (left) and RSP with offshore wind (right).

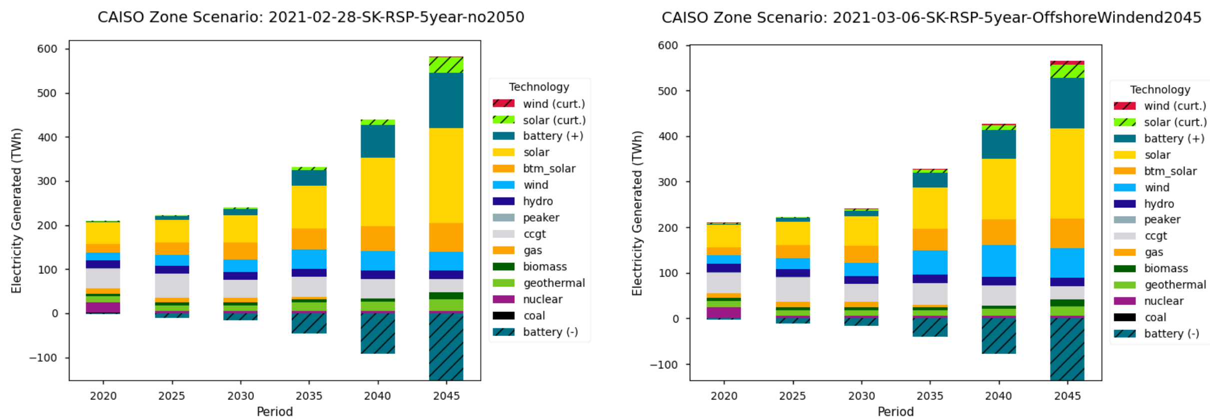


Fig. 2. 10 Comparison of electricity generation for RSP (left) and RSP with offshore wind (right).

The fractional buildout for the RSP and for the RSP with offshore wind added is shown for periods 2040 and 2045 in Figs. 2.11 and 2.12. In 2040, the buildout of geothermal and pumped hydro is selected to be less than half of that in the RSP. The on-shore wind is built out just slightly less. Similar observations are made for 2045, though the buildout of geothermal effectively doubles. The reduced buildout of solar (especially in 2035 and 2040) is more easily seen in Fig. 2.9 than in Figs. 2.11 and 2.12.

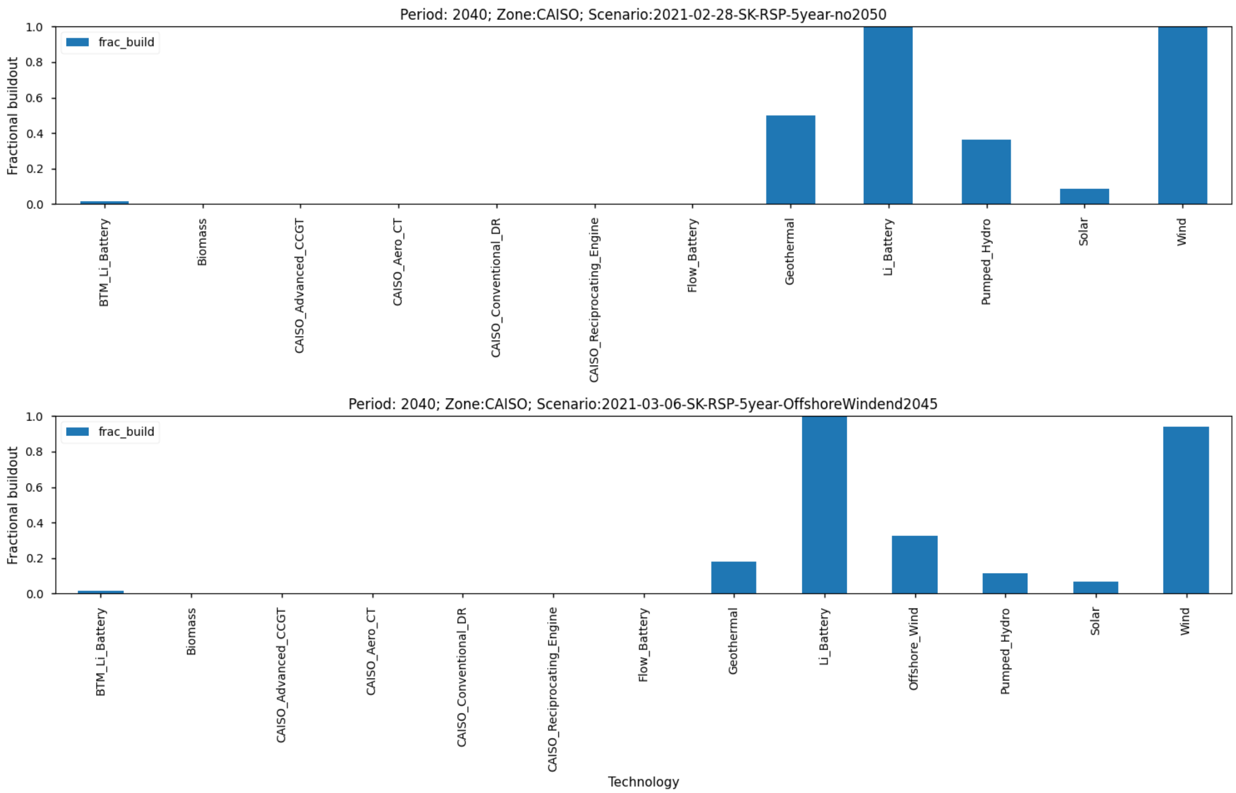


Fig. 2. 11 Fractional buildout for Period 2040 for RSP (top) and RSP with offshore wind (bottom)

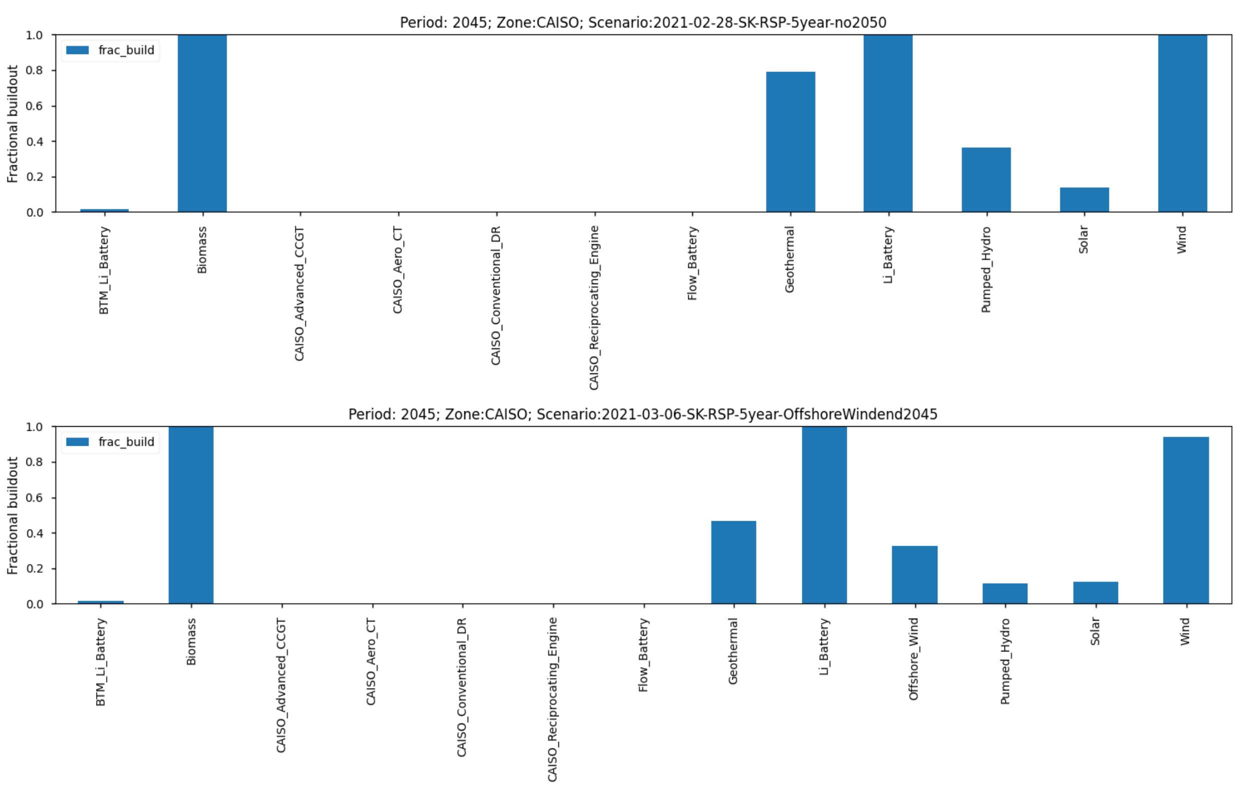


Fig. 2. 12 Fractional buildout for Period 2045 for RSP (top) and RSP with offshore wind (bottom)

2.4 High-electric-vehicle baseline

The governor's announcement in September of 2020 of a 2035 target for reaching 100% electric vehicles for sales of passenger cars motivated us to revisit the assumptions about the load associated with electric vehicles. We expect that the state will be identifying anticipated growth of the load associated with this transition and that we will be investigating a range of scenarios for electric vehicle (EV) charging. For our baseline estimate we have assumed 36 million vehicles on the road, with 1/15 of those vehicles replaced every year. We assumed linear growth in sales of EVs, reaching 100% in 2035. We assumed 4100 kWh annual electricity use per EV. These loads were compared with the EV-related loads documented for the RSP and the total loads were multiplied by a constant factor, simulating a flat charging profile. The calculated data are shown in Table 2.2 and in Fig. 2.13.

Table 2. 2 Annual load data (TWh) estimated for increased EV deployment (CAISO zone)

Year	Annual TWh for EVs	RSP EV load	RSP total CAISO load	Proposed baseline load
2020	NA	1.11	243	243
2025	12.4	5.0	254	261
2030	34.2	11.1	259	282
2035	63.7	17.6	302	349
2040	89.1	24.0	346	411
2045	107	30.5	383	459

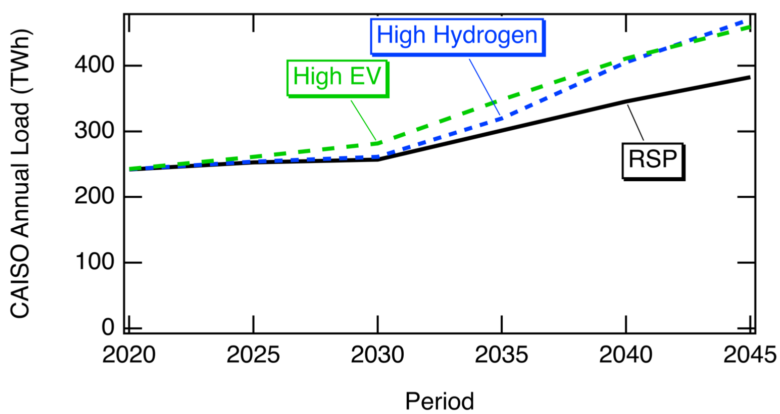


Fig. 2. 13 CAISO annual load for RSP and with added EV and hydrogen loads

The results of the higher EV load implemented in the RSP are shown in Figs. 2.14-2.17, presented similarly to the graphs in the previous section. We see that wind and geothermal are built earlier to meet the increased load. By 2045, the bulk of the added load is met by solar, since the other resources have been exhausted. The increase in load calculated from Table 2.2 (459/383) is 20% which is consistent with about 20% increase in electricity seen in Fig. 2.15. Fundamentally, the capacity limits set for geothermal, biomass, and wind in the RSP limit the ability of the grid to meet expanded loads in future years, resulting in solar being the only option.

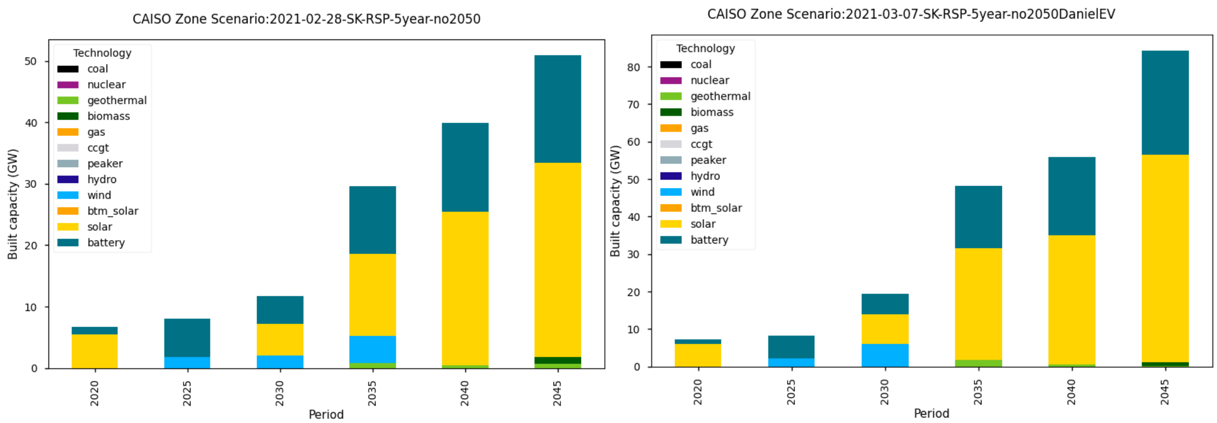


Fig. 2. 14 Comparison of resource builds for RSP (left) and RSP with higher EV load (right).

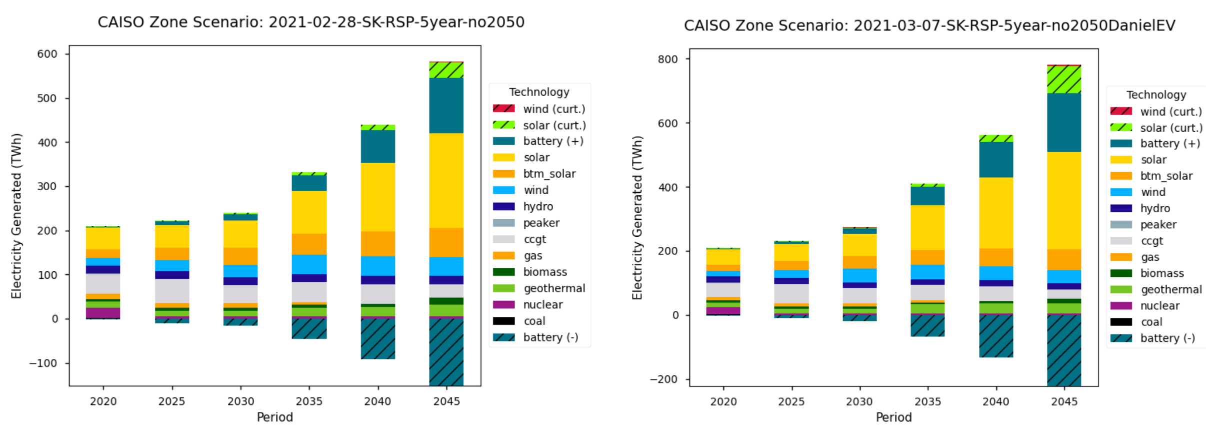


Fig. 2. 15 Comparison of electricity generation for RSP (left) and RSP with higher EV load (right).

The SB100 Report also increases the loads for EVs and electrolyzers. Similar to our conclusion that we would want additional wind to meet these larger loads, the SB100 Report identifies additional wind resources both onshore and offshore. These are an appropriate change for the baseline assumptions.

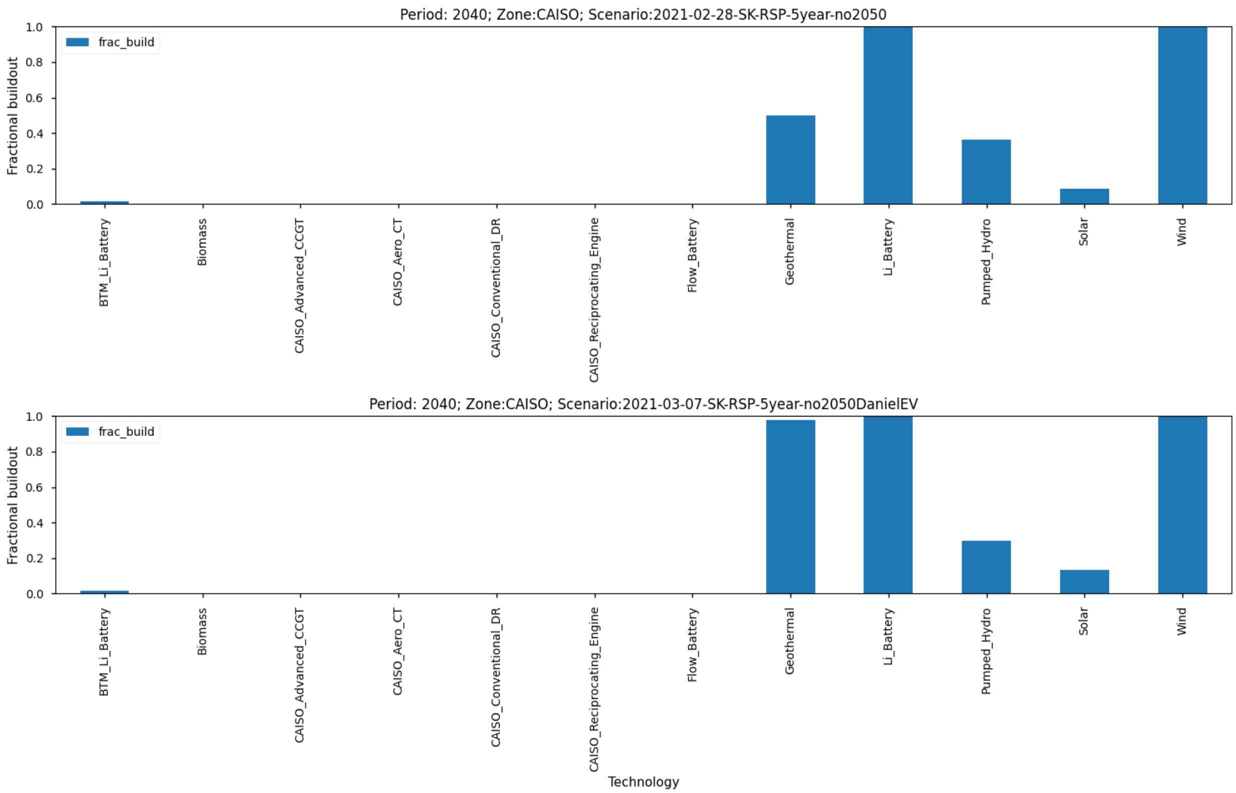


Fig. 2. 16 Fractional buildout for Period 2040 for RSP (top) and RSP with higher EV load (bottom)

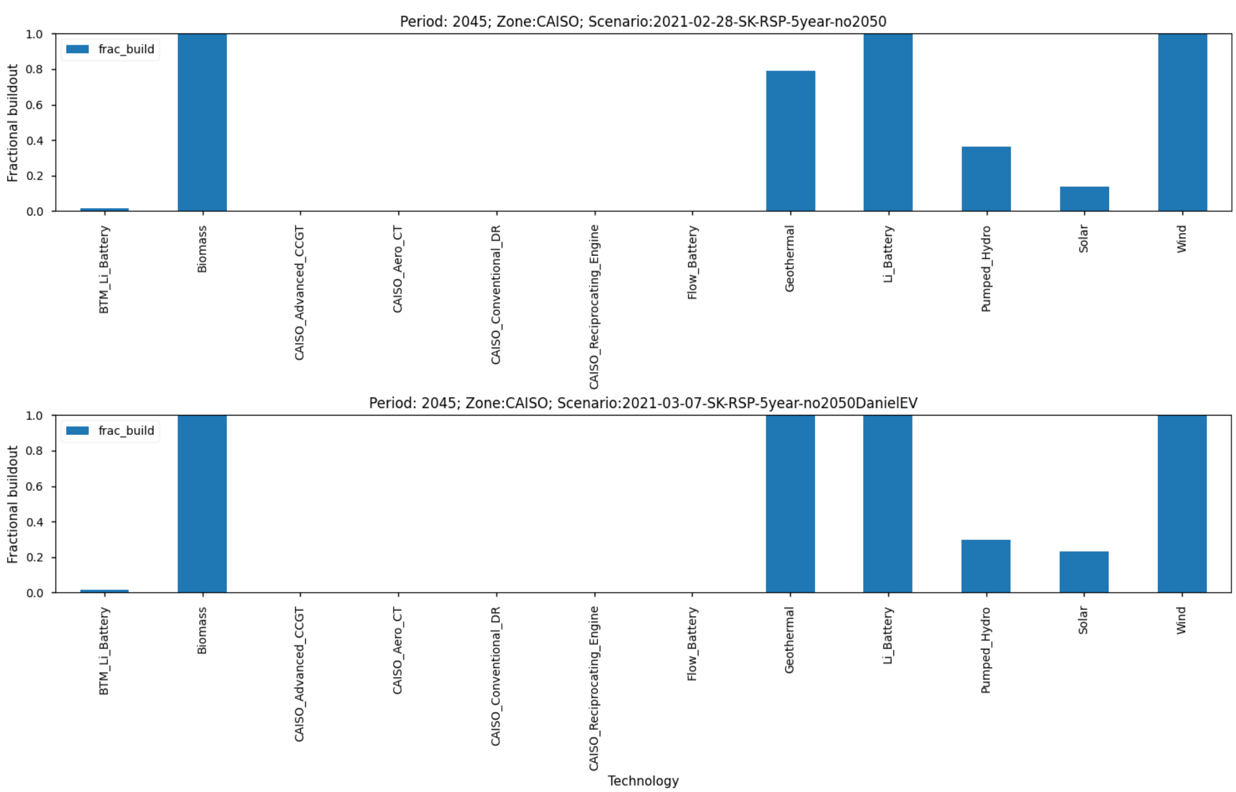


Fig. 2. 17 Fractional buildout for Period 2045 for RSP (top) and RSP with higher EV load (bottom)

2.5 High-hydrogen (high electrolyzer load) baseline

The high-hydrogen scenario provided by the Scenario Tool results in the increased CAISO load documented in Fig. 2.13. Based on the recent announcements of investments in hydrogen in multiple parts of the world, we anticipate that the deployment of electrolyzers to generate hydrogen will advance at a rate closer to the high-hydrogen baseline than to the baseline used in the RSP. The results of the high-hydrogen scenario are summarized in Figs. 2.18-2.21. The results differ from the higher EV load in that the build out occurs slightly later, but the net result is the same – biomass, geothermal, and wind are built to their limits and then solar expands in a large way to meet the additional load.

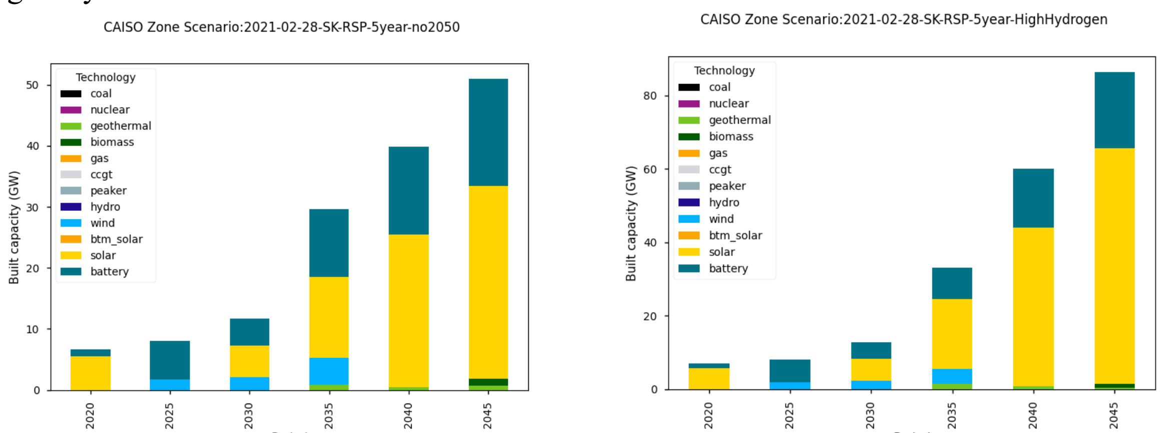


Fig. 2. 18 Comparison of resource builds for RSP (left) and RSP with higher electrolyzer load (right).

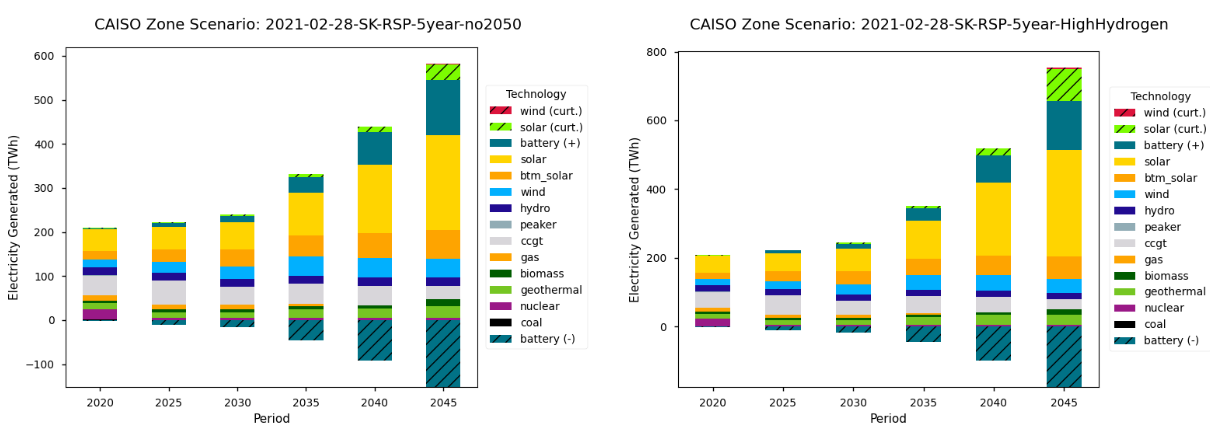


Fig. 2. 19 Comparison of electricity generation for RSP (left) and RSP with higher electrolyzer load (right).

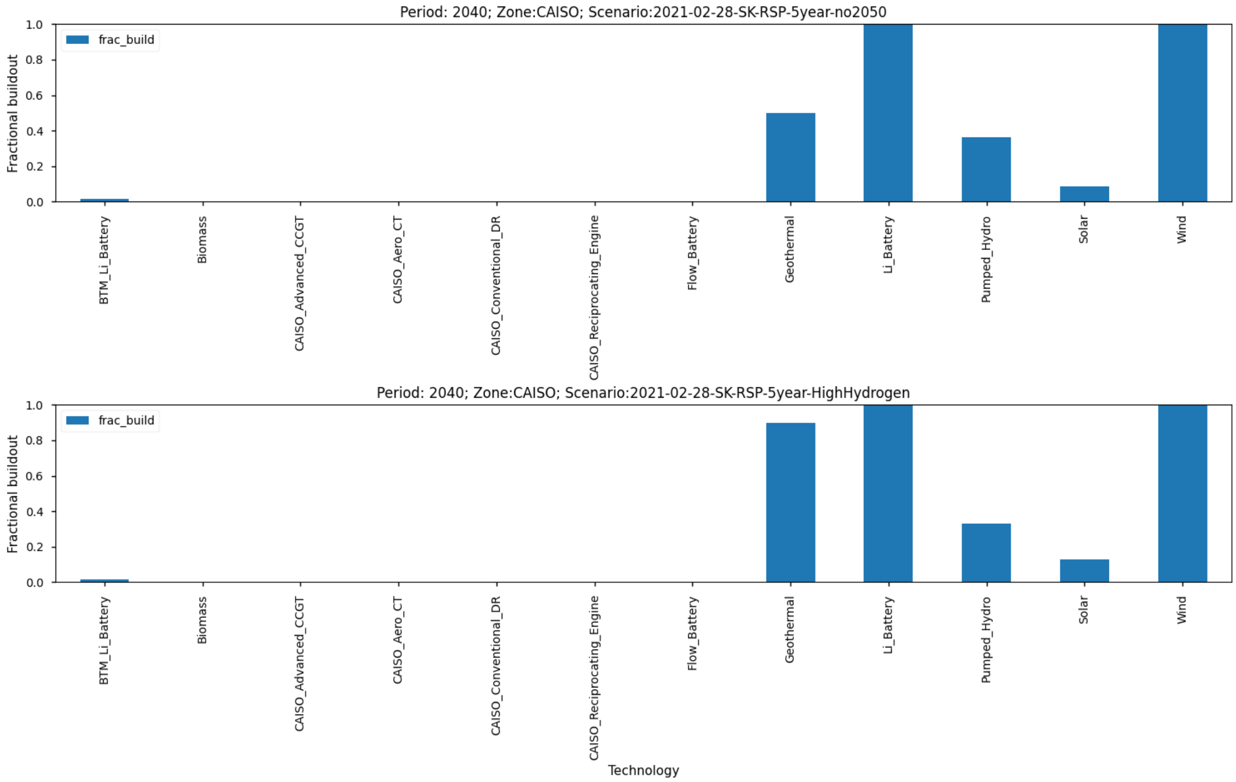


Fig. 2. 20 Fractional build for Period 2040 for RSP (top) and RSP with higher electrolyzer load (bottom)

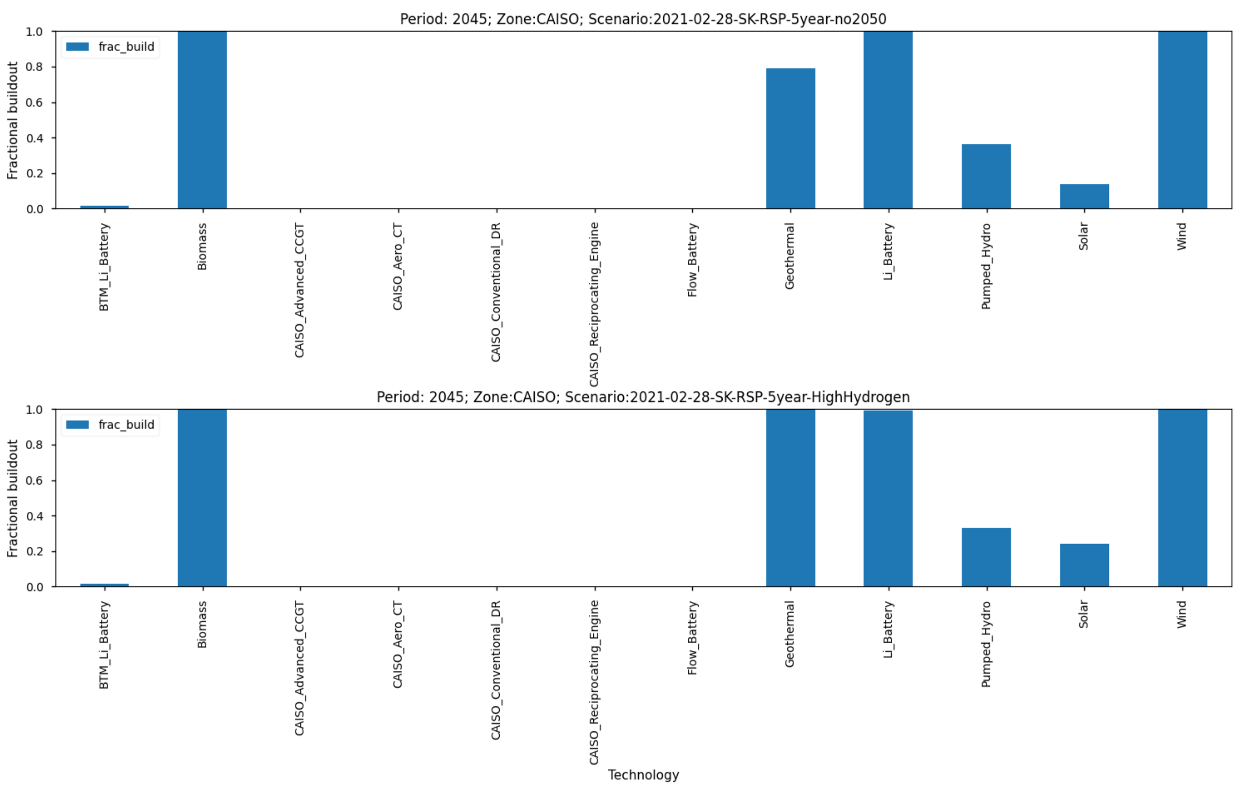


Fig. 2. 21 Fractional build for Period 2045 for RSP (top) and RSP with higher electrolyzer load (bottom)

2.6 Higher planning-reserve-margin baseline

There is current discussion to increase the planning reserve margin in the 2025 timeframe to 20.7% (from the current 15%). Although this decision has not been finalized, we believe that the change is likely to occur and that it will be wise to have a larger margin in the next years while we are transitioning the energy system and while climate change may create surprisingly extreme weather. Of course, if more extreme weather is used for planning, then it may not be as important to plan capacity expansion with such a wide margin.

This section describes the impact of increasing the planning reserve margin to 20.7% for the periods starting in 2025. An increase from 15% to 20.7% would increase the needed capacity by 120.7/115 = 5%. This is quite noticeable in 2025 when more batteries are built, then the build out in 2030 and 2035 changes slightly. This added investment in capacity increases the cost. However, it doesn't change the operating costs. The objective function is found to increase by about 3%.

The graphs are shown, as above, in Figs. 2.22-2.25. The difference is easy to see in 2025-2035 in Fig. 2.22, but very difficult to see in Fig. 2.23, since the generation of electricity is mostly unaffected. Most notably in Figs. 2.24 and 2.25 is the addition of demand response.

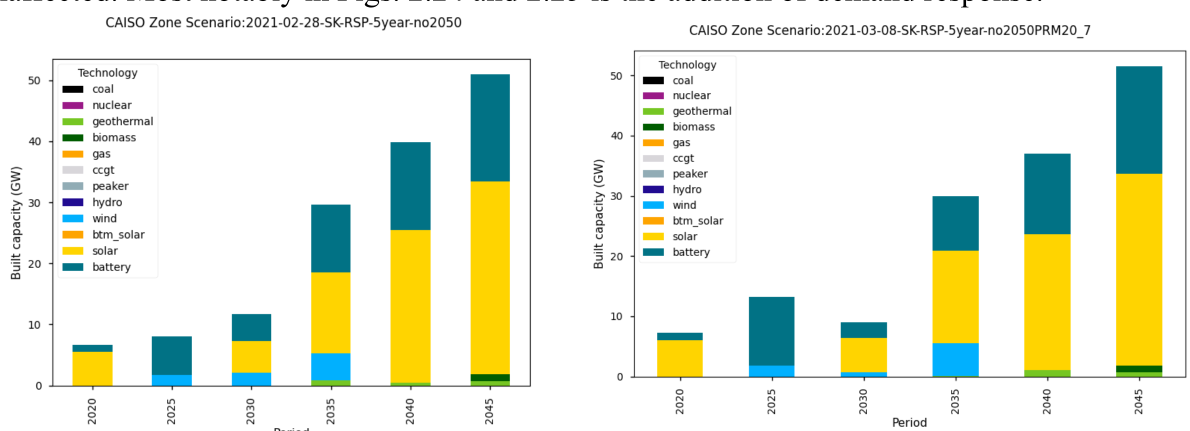


Fig. 2. 22 Comparison of resource builds for RSP (left) and RSP with 20.7% planning reserve (right).

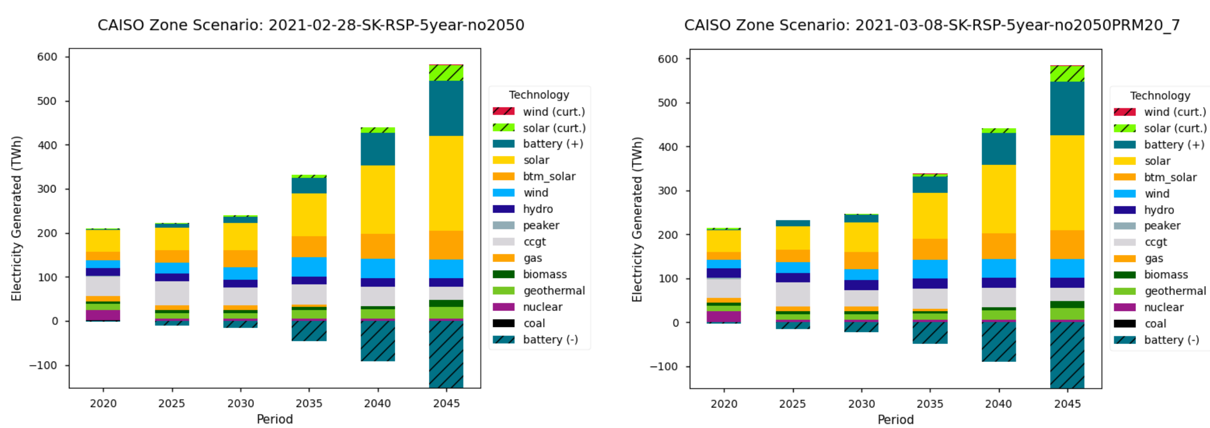


Fig. 2. 23 Comparison of electricity generation for RSP (left) and RSP with 20.7% planning reserve (right).

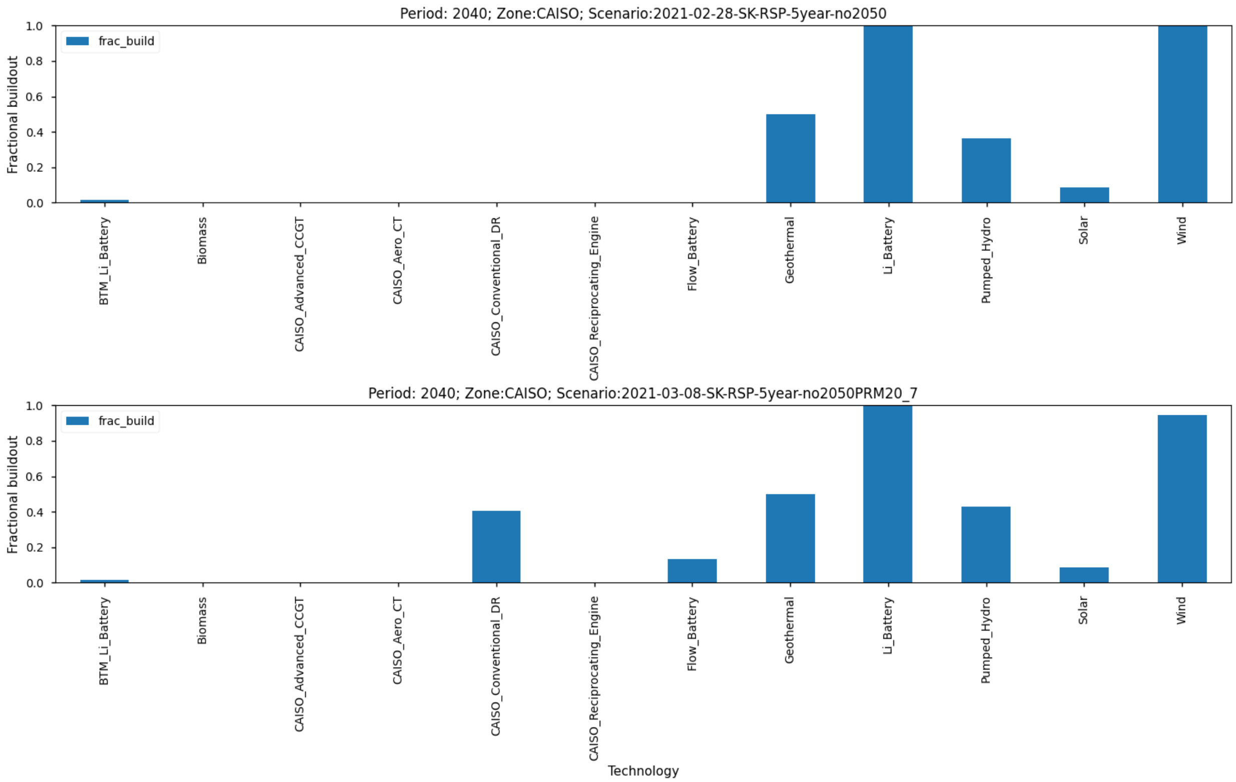


Fig. 2. 24 Fractional build for Period 2040 for RSP (top) and RSP with 20.7% planning reserve (bottom)

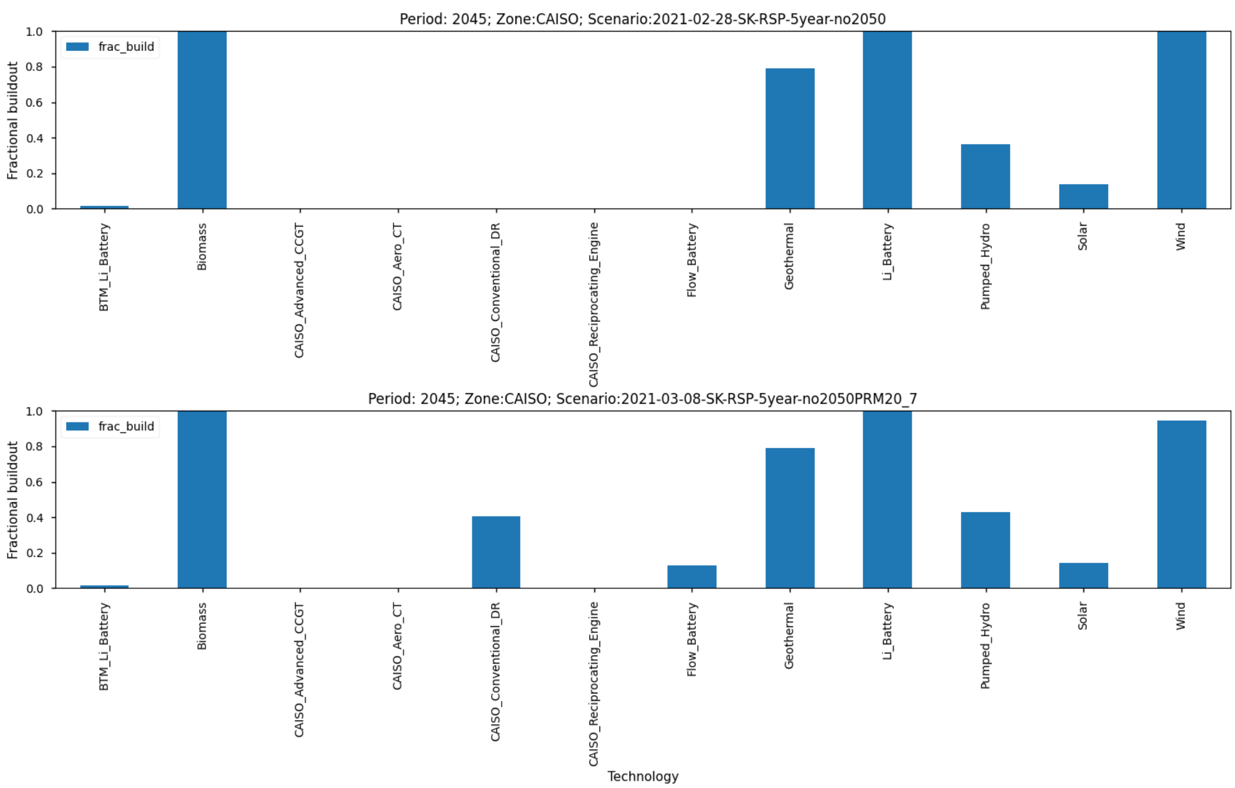


Fig. 2. 25 Fractional build for Period 2045 for RSP (top) and RSP with 20.7% planning reserve (bottom)

2.7 Four-hour lithium-ion battery baseline

New batteries being installed in California are mostly being installed as four-hour batteries to be able to benefit from increased capacity credit, as discussed in Section 4.1 of the Baseline Description. The RSP allows investment in lithium-ion batteries with any duration greater than 1 hour. The cost of installing the batteries in the RSP is split between the $/kW and the $/kWh, so is cheaper to build one 8-hour battery (1 X the cost per kW + 8 X the cost per kWh) compared with two 4-hour batteries (2 X (1 X the cost per kW + 4 X the cost per kWh)). As a result, the RSP selects to invest in batteries with long durations. Some of the cost of a battery is associated with the power rating (for example, the cost of the power electronics), but much of the cost is associated with the energy rating. We are unconvinced that one 8-hour battery costs so much less than two 4-hour batteries, so we modified the baseline to place 100% of the upfront cost with the $/kWh input, as described in Section 4.1 of the Baseline Description. The results of that change on the RSP outputs are shown in Figs. 2.26-2.29. The effect is surprisingly large, with significantly fewer batteries built in 2030 and 2035. Figs. 2.28-29 show that Li-ion batteries are replaced by pumped hydro storage, flow batteries and demand response.

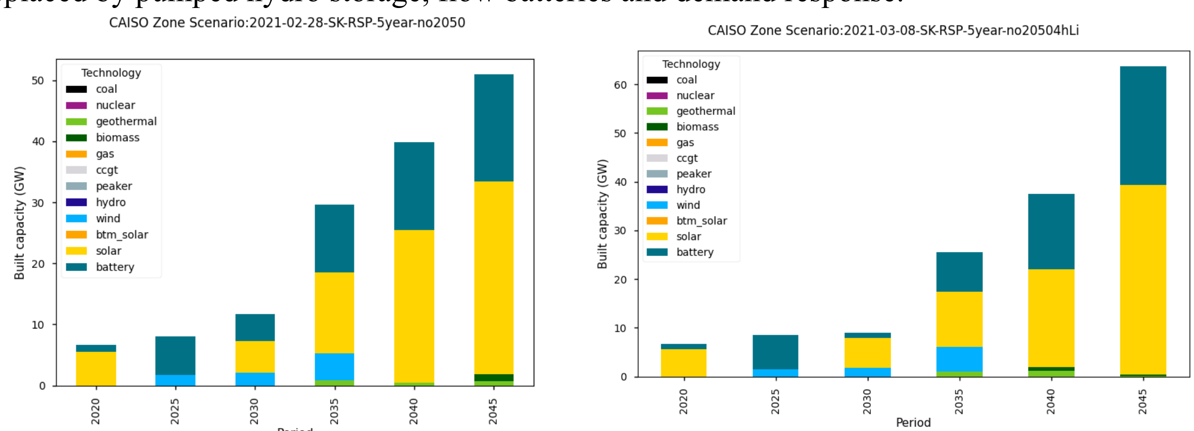


Fig. 2. 26 Comparison of resource builds for RSP (left) and RSP with 4-h lithium batteries (right).

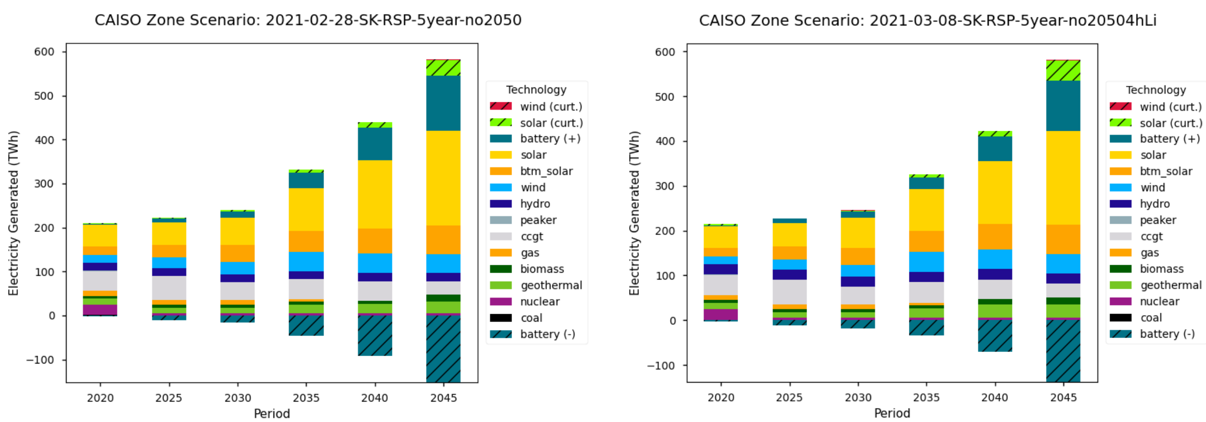


Fig. 2. 27 Comparison of electricity generation for RSP (left) and RSP with 4-h lithium batteries (right).

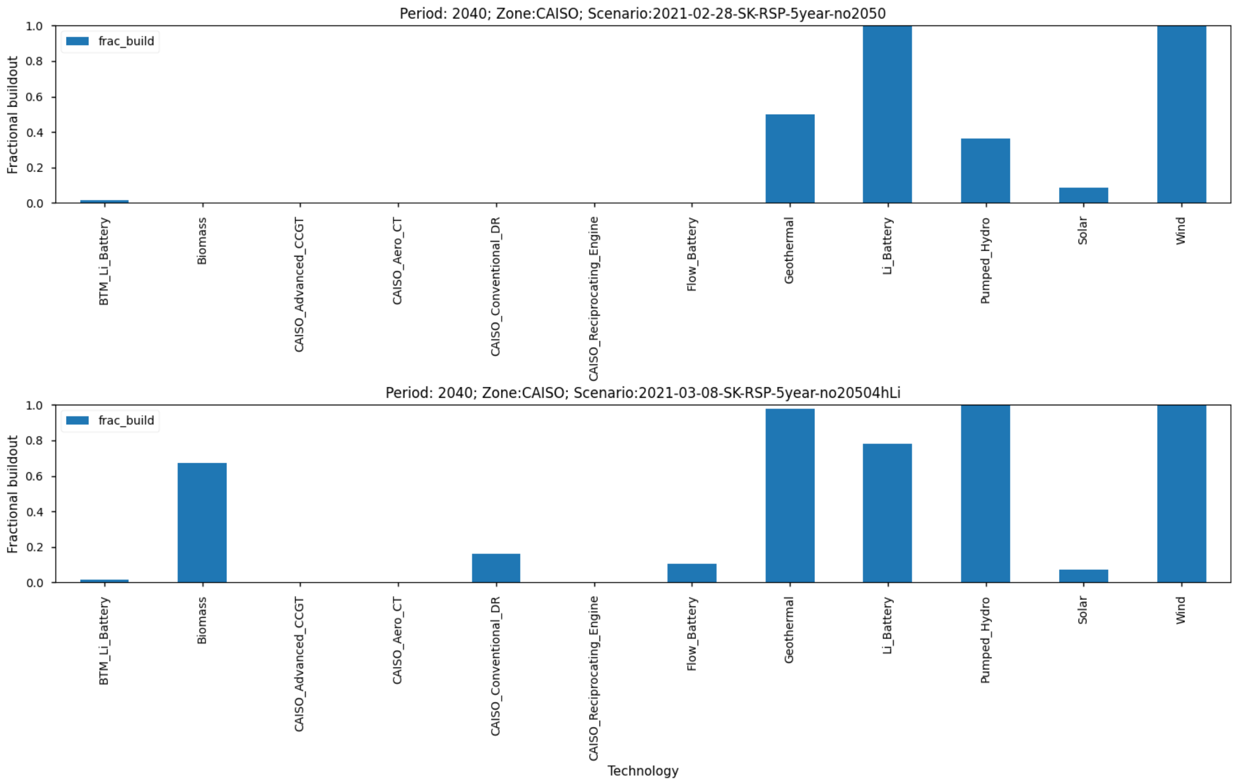


Fig. 2. 28 Fractional build for Period 2040 for RSP (top) and RSP with 4-h lithium batteries (bottom)

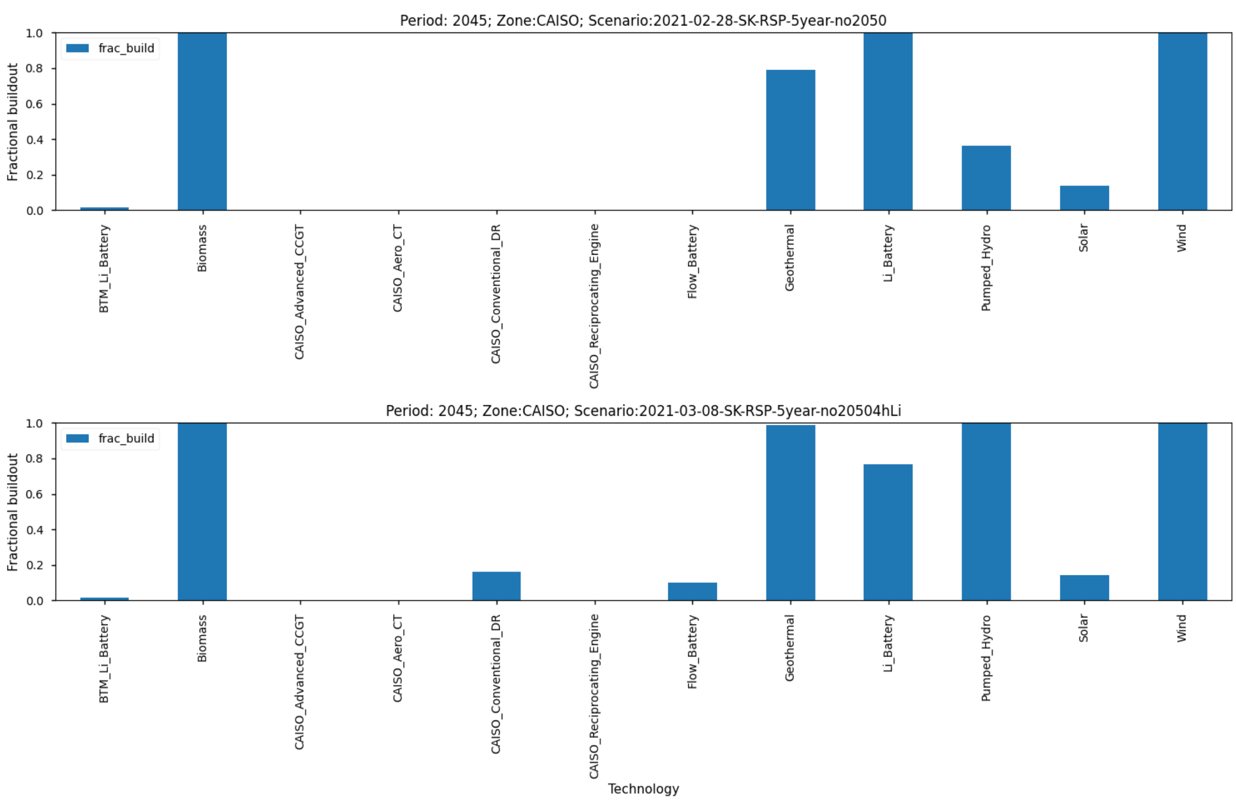


Fig. 2. 29 Fractional build for Period 2045 for RSP (top) and RSP with 4-h lithium batteries (bottom)

2.8 Effect of changes on cost of baseline

As each change was made to the 2018 RSP, the total cost, as optimized by the RESOLVE objective function sometimes increased and sometimes decreased as shown in Table 2.3 and Fig. 2.30.

Table 2. 3 Cost-sensitivity analysis for RESOLVE baseline scenario

Zero emissions in 2045	Add off-shore wind	Higher EV charging load	Higher electrolyzer load	20.7% planning reserve margin	4-h Li battery definition	Objective function (total cost) ($billions)	Relative total cost
Based on 2018 RSP with 5-year periods through 2045							
						215	100%
✓						260	121%
	✓					213	99%
		✓				254	118%
			✓			235	109%
				✓		223	103%
					✓	225	105%
New baseline							
✓	✓	✓	✓	✓	✓	391	100%
	✓	✓	✓	✓	✓	301	77%
✓		✓	✓	✓	✓	394	101%
✓	✓		✓	✓	✓	327	84%
✓	✓	✓		✓	✓	351	90%
✓	✓	✓	✓		✓	385	99%
✓	✓	✓	✓	✓		375	96%

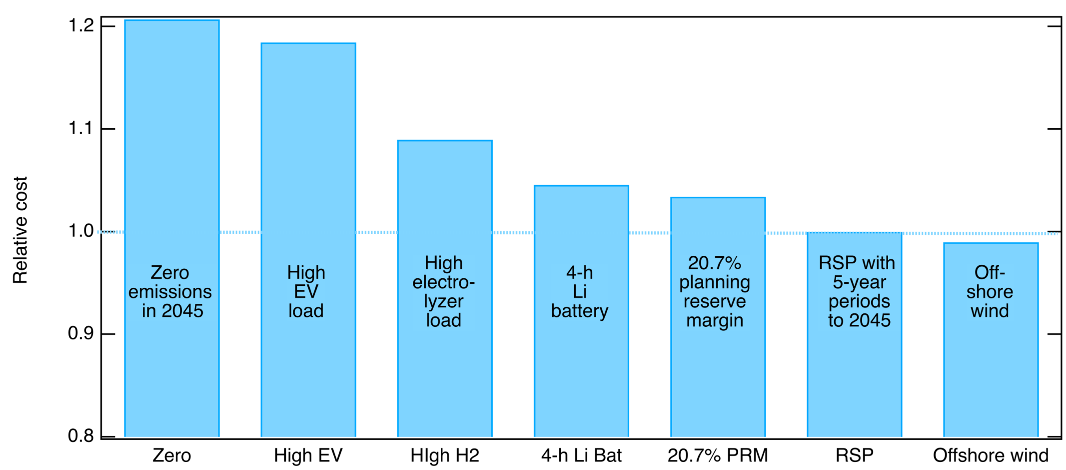


Fig. 2. 30 Relative costs of the 2018 RSP with each of the modifications made individually

In Section 3 we document the results of making all of the changes in a single scenario then consider the effect of removing each of the changes individually, reflecting the check marks in Table 2.3. As expected, the relative effects of each change are similar to what has been documented in Section 2, although removing each assumption in most cases decreases the cost. To aid in an easy visual comparison to Fig. 2.30, we have plotted the relative decrease (instead of increase) in cost in Fig. 2.31. The general trend is the same.

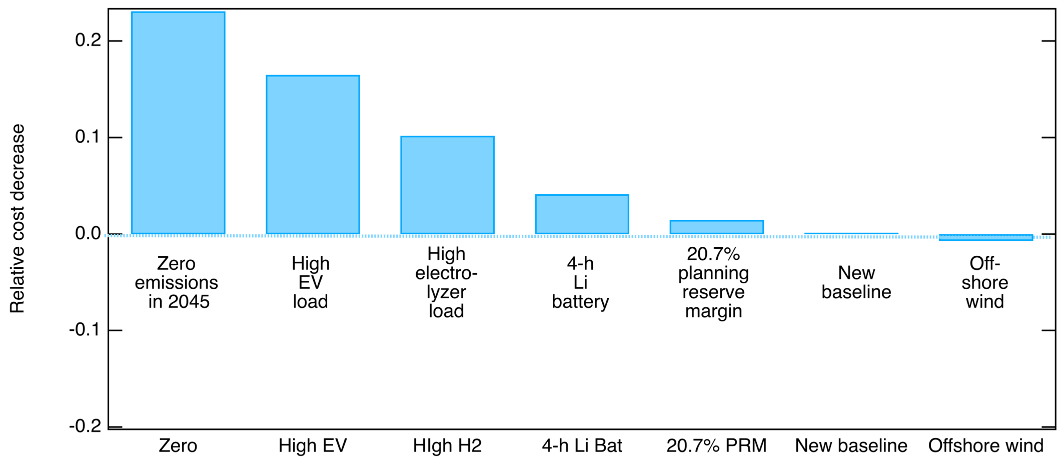


Fig. 2. 31 Relative costs of the new baseline with each of the modifications taken out individually

Of these costs, setting the target to deliver zero-carbon electricity for all of the electricity – including the line losses – has the biggest effect. The increased cost associated with a high EV load would be offset by the reduced need to use gasoline to power conventional cars. Similarly, the high electrolyzer load would result in generating hydrogen which would provide value to the system.

3. New RESOLVE baseline's sensitivity to changes

The new baseline (based on the changes summarized in Section 2) is substantially different from the RESOLVE RSP defined in 2018. This part of the report complements Section 2 to show the effect of removing each of these changes from the new baseline, enabling a fuller understanding of each change that complements how having that change affected the 2018 RSP.
We emphasize that these are preliminary results. The implementation of the baseline in a RESOLVE run that includes a full year of continuous simulation may give a different answer than this implementation that uses 37 independent days, preventing any use of cross-day energy storage.

3.1 Comparison of 2018 RSP with new RESOLVE baseline

The 2018 RSP results are compared with the new RESOLVE baseline results in Figs. 3.1 to 3.4. Note that the scales for the vertical axes of Figs. 3.1 and 3.2 differ. In particular, the build capacity axis for the new baseline is roughly seven times larger than the build axis for the 2018 RSP (Fig. 3.1). The bigger buildout partially reflects the higher electricity demand, as shown in Fig. 3.2. However, the total load only increases about 60%, requiring less than a factor of two increase in electricity generation, much less than the factor of seven higher buildout shown in Fig. 3.1. The suggested build of close to 300 GW in the 2045 period could translate to about 60 GW per year. It is not clear that this will be practical. Similarly, the build of close to 100 GW of storage in that same period may not be practical and is not likely to be needed in a scenario that enables more wind to be built.

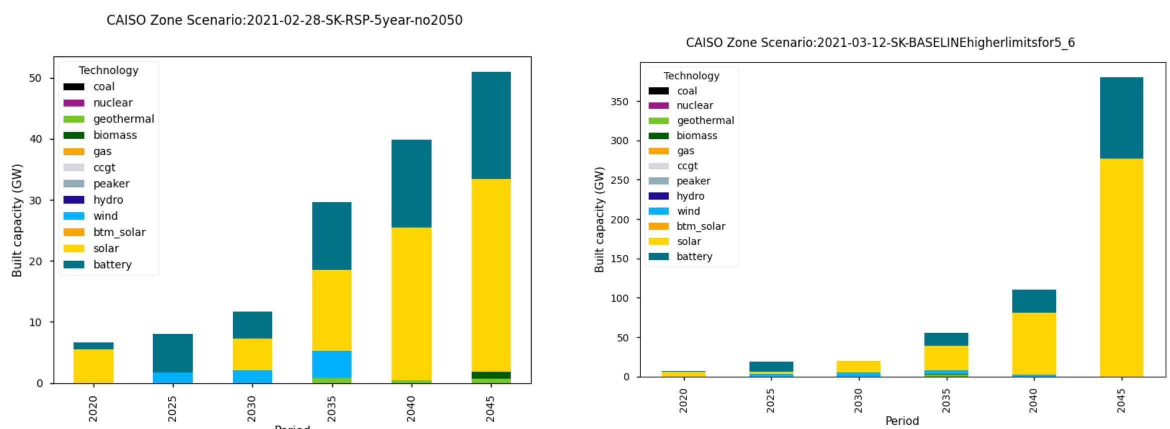


Fig. 3. 1 Comparison of resource builds for 2018 RSP (left) and new baseline (right).

The curtailment in the new baseline is much larger than in the 2018 RSP. As shown in Section 2, this comes largely from the requirement to strictly reduce emissions to zero (including the line losses) in 2045. We emphasize that we do not believe that this calculation correctly reflects the situation. Key conclusions to consider:

- The massive build of solar in 2045 is largely because that was the only option provided to the model. If more wind, geothermal, or other renewable generation source were offered, it is likely that they would be selected. This motivates revisiting the assumptions about the build limits for each of the zero-carbon generation technologies as has been done in the SB100 report.

- The current version of RESOLVE looks at 37 days independently, so does not provide the option of using cross-day storage. The availability of low-cost seasonal storage might reduce the amount of solar needed to meet load during a cloudy winter day.

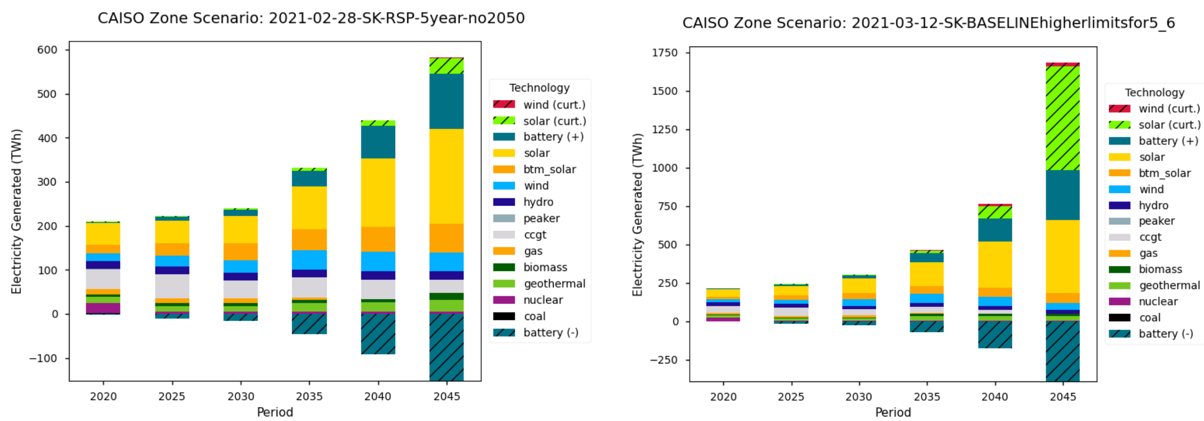


Fig. 3. 2 Comparison of electricity generation for 2018 RSP (left) and new baseline (right).

- We retained the 2018 RSP's assumption that there would be no imports to CAISO. This assumption is convenient because it avoids the reliance of neighboring regions to reach zero-carbon electricity in a similar time frame. We anticipate that imports of wind and other electricity from nearby states could help to meet California's targets. The results from SWITCH reported below support this anticipation.
- The model currently does not offer any natural gas plus carbon capture and sequestration or any mechanism to offset carbon dioxide emissions. It is modeled that a small amount of carbon sequestration will be very beneficial in meeting the zero-emissions target, but the uncertainty of how to model the carbon sequestration has moved that part of the model out of the baseline and into a sensitivity analysis (to be reported on later).

Thus, we anticipate that the high solar build and the associated large amount of curtailment will be reduced when we implement the baseline in the new RESOLVE code and provide more flexibility in how to meet the 2045 zero-emissions target. This is consistent with the latest SB100 report.

The details of the buildout are shown in Figs. 3.3 and 3.4. Biomass, geothermal and onshore wind are built to the limits given by the inputs. Pumped hydro is also built to its limit. It appears that the build of Li batteries is reduced, but this is an artifact of the lack of constraint on Li batteries 5 & 6 in the 2018 RSP. We have added a capacity limit of 9999 GW for Li batteries 5 & 6 in the new baseline to better track the buildout of these in Figs. 3.3 and 3.4. These limits are set high enough not to interfere with the optimization, but low enough that we can see the amount that is built. Some flow batteries and demand management are also now selected.

Substantial offshore wind is built, but it is not built to the limit (Table 3.1). Offshore wind built near the existing Diablo Canyon nuclear power plant (Diablo Canyon and Morro Bay) benefits from using the transmission lines now used by the nuclear plant. Currently, there are no plans for transmission lines that would accommodate the offshore wind sites in northern California beyond the use of the electricity locally. The addition of a robust transmission line for offshore wind in northern California would substantially reduce the pressure on the build of solar and storage.

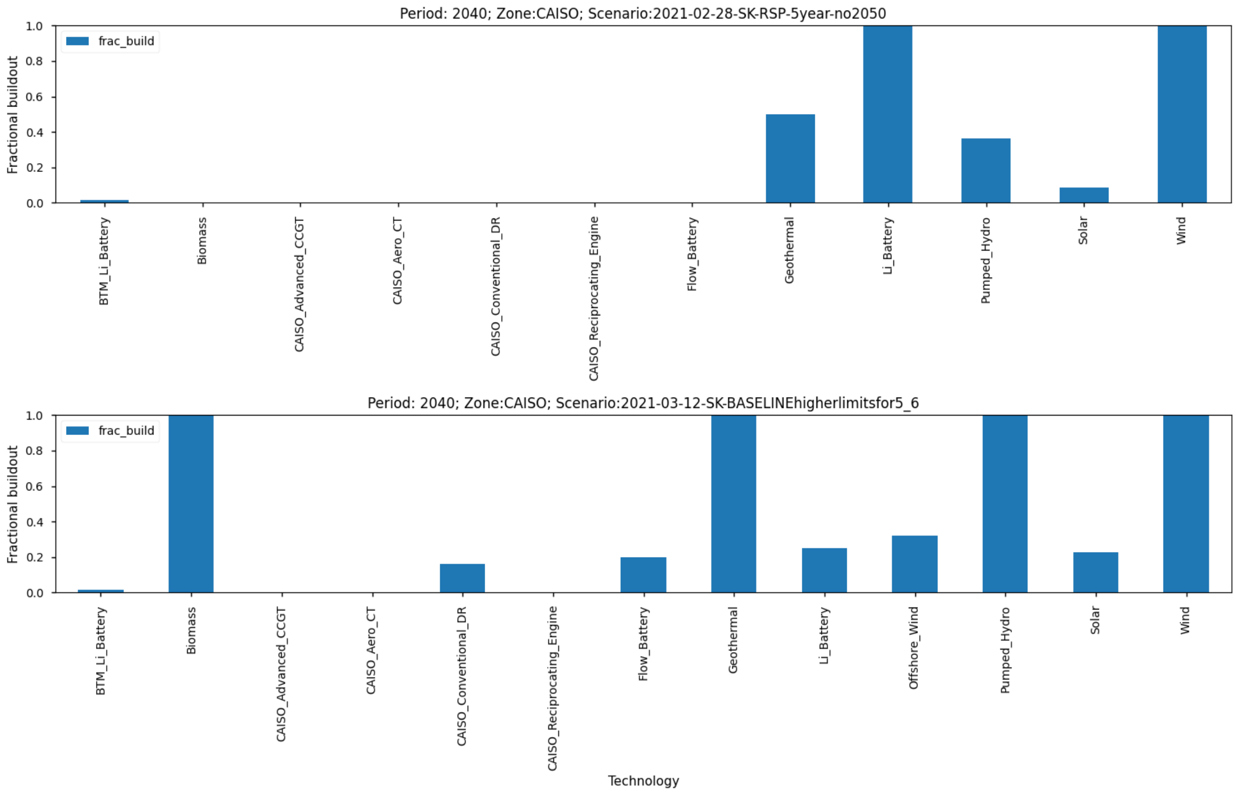


Fig. 3. 3 Fractional build for Period 2040 for 2018 RSP (top) and new baseline (bottom)

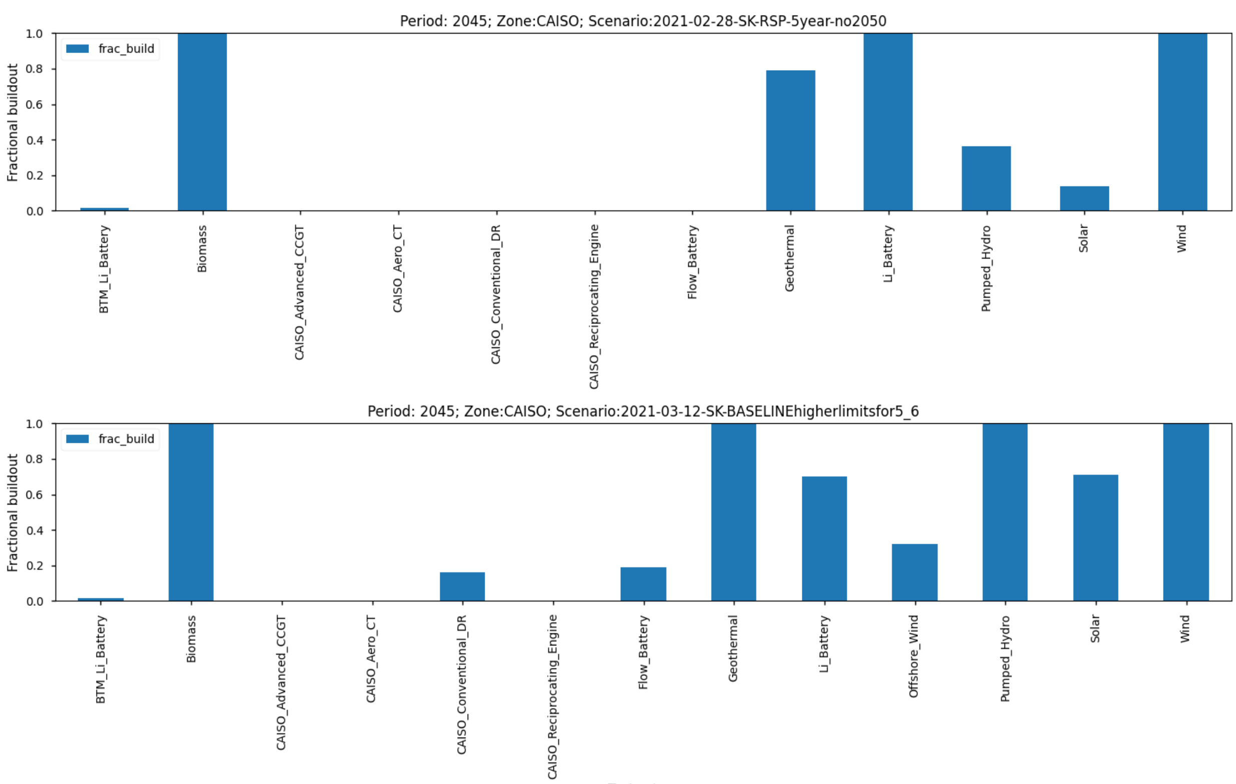


Fig. 3. 4 Fractional build for Period 2045 for 2018 RSP (top) and new baseline (bottom)

Table 3. 1 Offshore wind inputs and results for new baseline scenario

Resource	Build limit (MW)	Selected build	Transmission limited
Diablo_Canyon_Offshore_Wind	2324	2324	
Humboldt_Bay_Offshore_Wind	1607	66	X
Morro_Bay_Offshore_Wind	2419	2419	
Diablo_Canyon_Offshore_Wind_Ext_Tx	2000	2000	
Cape_Mendocino_Offshore_Wind	6216	0	X
Del_Norte_Offshore_Wind	6604	0	X

3.2 New baseline with zero-GHG targets vs original GHG targets

The new baseline is very demanding in year 2045. Section 2 showed that requesting to reach zero emissions in 2045 placed stress on the system resulting in a large buildout of solar and storage. Figs. 3.5-3.8 compare the new baseline with a similar scenario but using the 2018 RSP GHG targets. As expected, the solar and storage builds in 2045 are decreased. The decrease is by more than a factor of three. However, the total cost of implementing the scenario is decreased only by 23%. As anticipated, the generation in 2045 differs in several ways. Some thermal generation is restored (Fig. 3.6, right) and the use of storage decreases by almost a factor of two. The fractional generation from wind is greater and from solar is smaller.

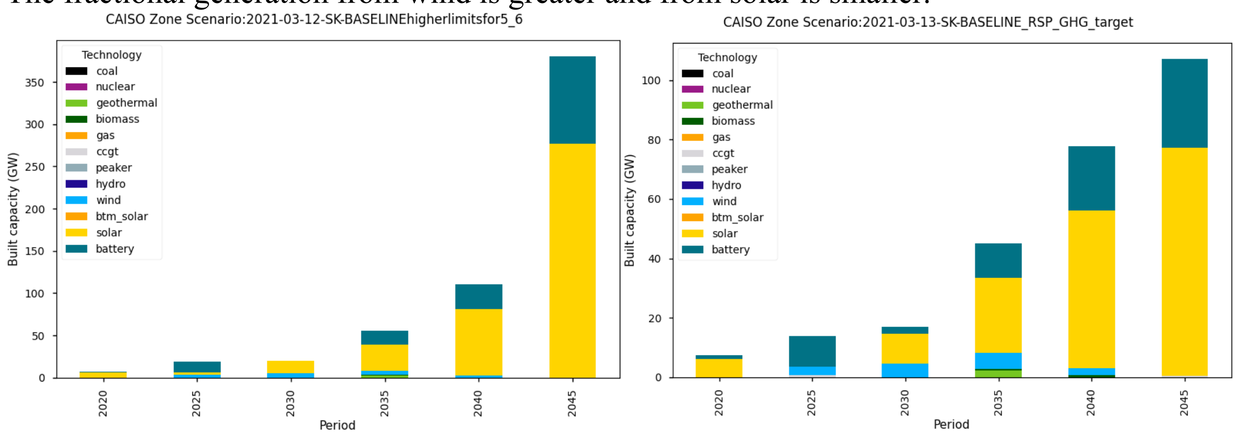


Fig. 3. 5 Resource builds for new baseline (left) and new baseline with 2018 RSP GHG targets (right).

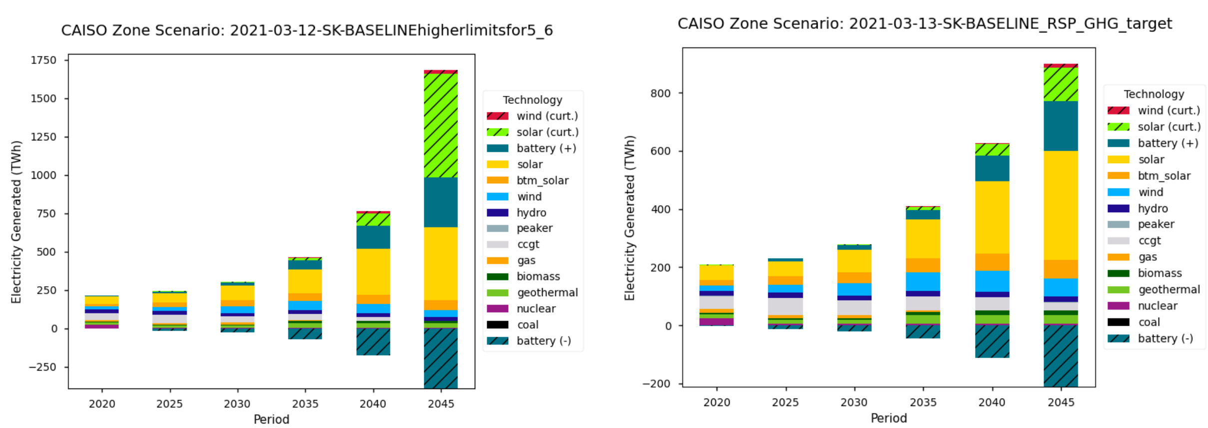


Fig. 3. 6 Electricity generation for new baseline (left) and new baseline with 2018 RSP GHG targets (right).

Figs. 3.7 and 3.8 show the detail of how the build of solar and of the Li batteries is reduced when the GHG target is relaxed. The use of flow batteries increases significantly, probably because of the reduced solar build, increasing the need for storage (though the use of Li batteries is reduced). The pumped hydro is built to the stated limit in both cases, underscoring the importance that the model places on storage, in general, in 2045.

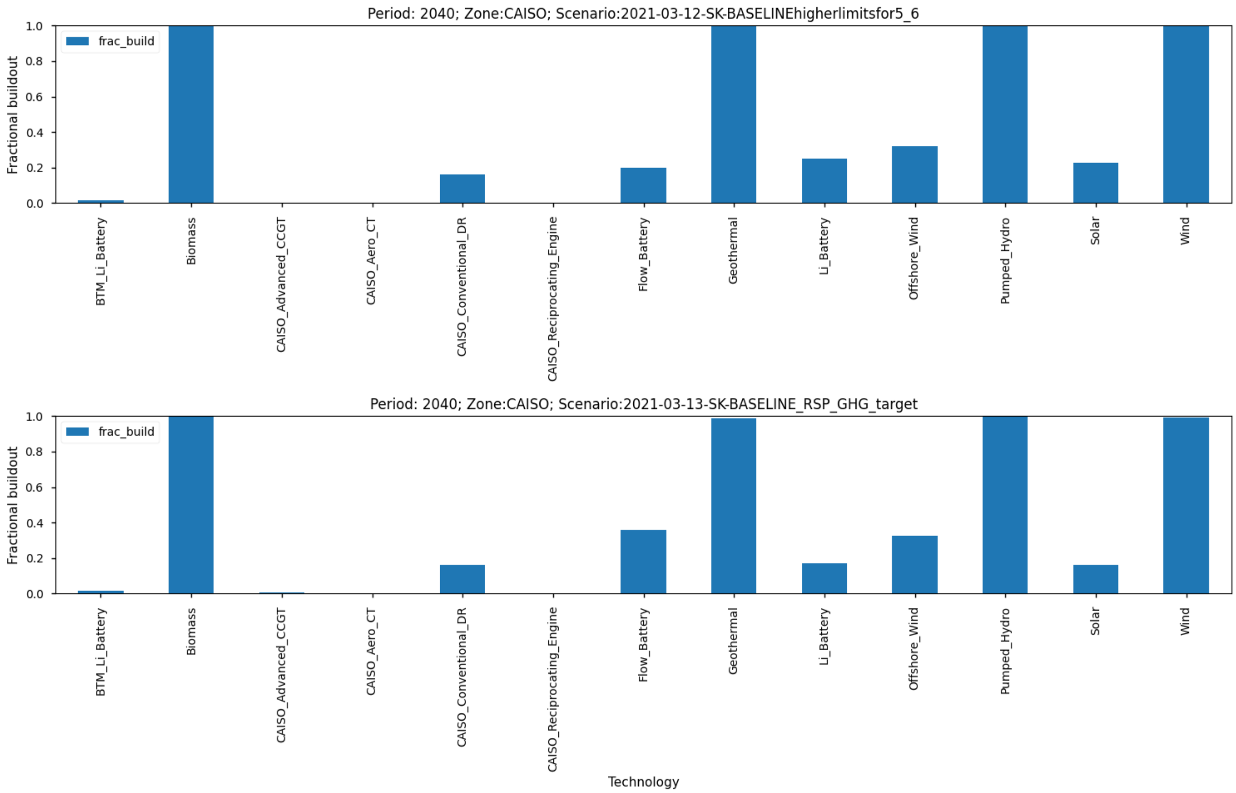


Fig. 3. 7 Fractional build in 2040 for new baseline with zero (top) and original (bottom) GHG targets

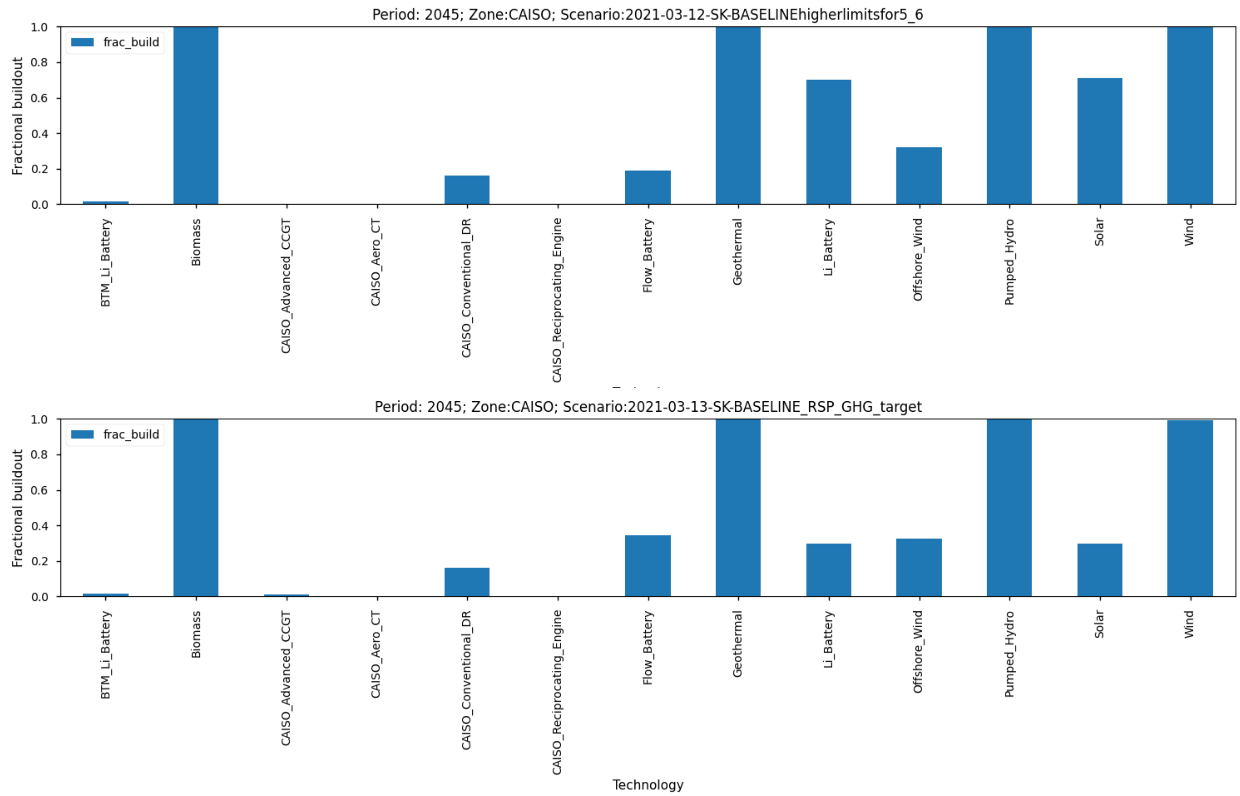


Fig. 3. 8 Fractional build in 2045 for new baseline with zero (top) and original (bottom) GHG targets

3.3 New baseline with and without offshore wind

The inclusion of offshore wind has very little effect on the build of solar and storage as shown in Fig. 3.9. Less wind is built, but, otherwise, it is difficult to see the difference between the left and right in Fig. 3.9. Greater electricity generation by wind is more obvious in Fig. 3.10, starting especially in 2035. The total cost of implementation increases less than 1% when the offshore wind is removed. Figs. 3.11 and 3.12 show the buildout in more detail with similar conclusions.

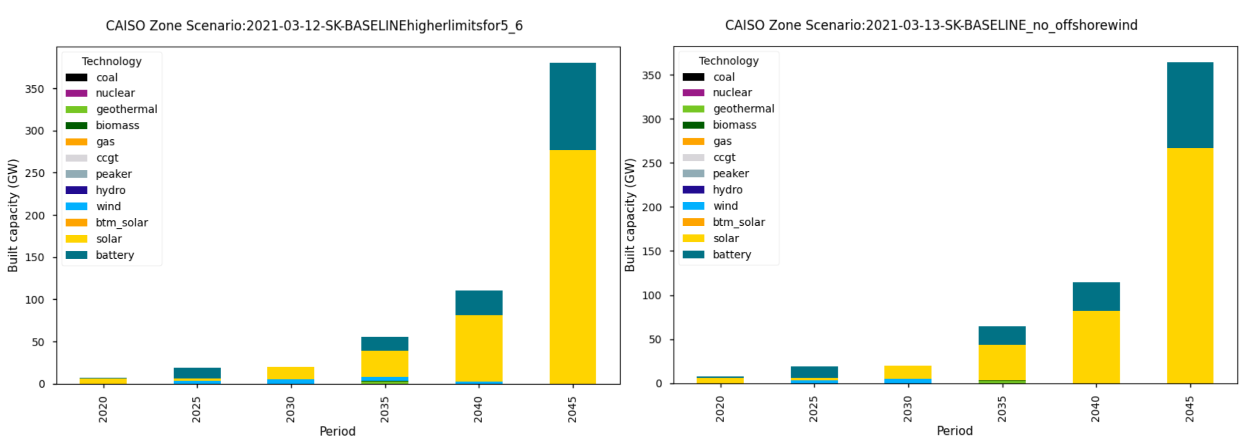


Fig. 3. 9 Resource buildout for new baseline with (left) and without (right) offshore wind.

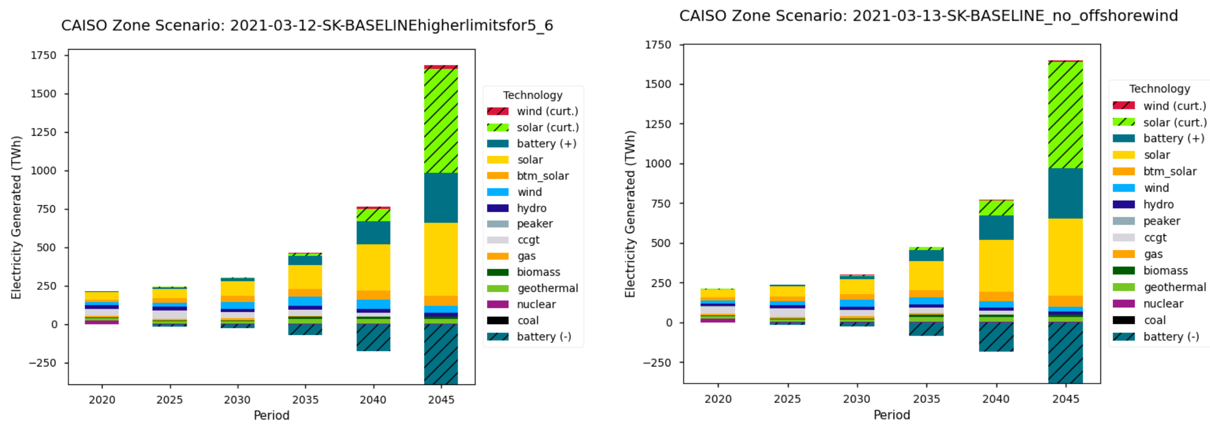


Fig. 3. 10 Electricity generation for new baseline with (left) and without (right) offshore wind.

While we note the relatively small effect of the addition of offshore wind, the offshore wind added in this baseline scenario is restricted to the southern part of California, since the resource is allowed to be built in the north, but the transmission is not provided as shown in Table 3.1. Offshore wind speeds are greater in northern than in southern California. The potential offshore wind resource if transmission were available would be substantially greater. The resource limits estimated in the Scenario Tool would enable about 3 times more offshore wind if transmission were available (see Table 3.1), which would reduce the need for solar build in 2045 by perhaps 10%.

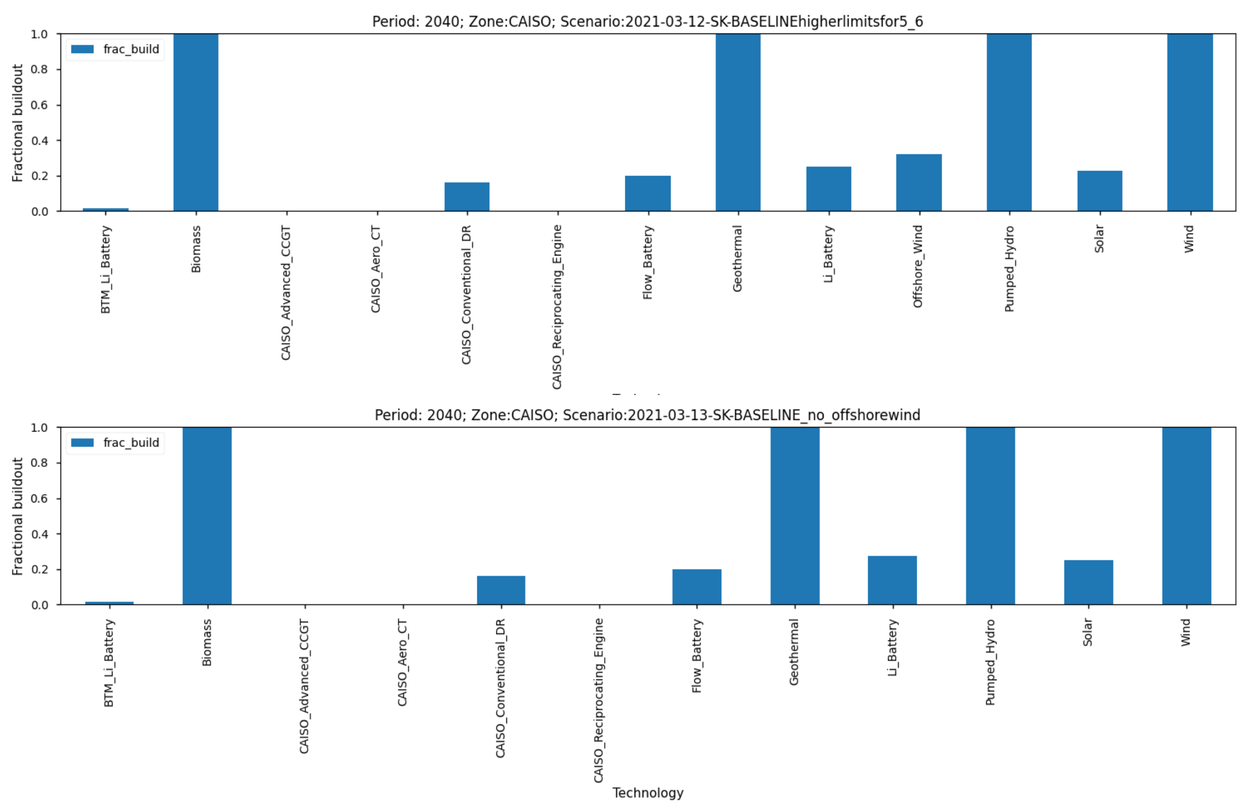


Fig. 3. 11 Fractional build in Period 2040 for new baseline with (top) and without (bottom) offshore wind

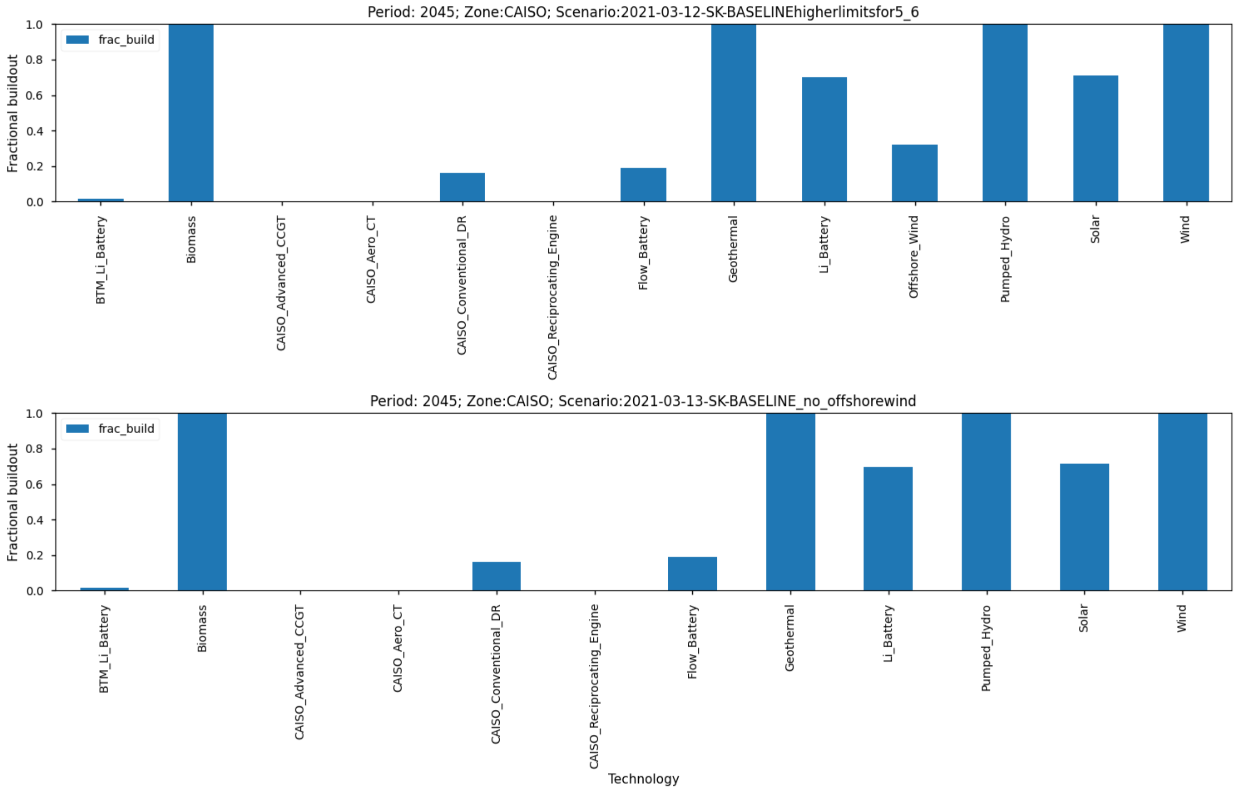


Fig. 3. 12 Fractional build for Period 2045 for new baseline with (top) and without (bottom) offshore wind

The latest SB100 studies indicate a plan to increase the available candidate wind resources in state, offshore and out of state. A comparison between the 2018 RSP and the proposals documented in the SB100 studies[5] is provided in Table 3.2. Some of the changes reflect the inclusion of additional balancing zones in the optimization process. Others reflect the expectation that new transmission lines will be built. The ability to expand wind beyond what is documented in the 2018 RSP is quite substantial. The question is not so much whether there should be additional candidate wind resource, but what is the accurate way to model it. The costs and timelines of building new transmission lines have high uncertainties.

We will proceed by following the publicly vetted inputs from the SB100 studies in our baseline, then consider modifications as explicit sensitivity analyses with emphasis on the impact of the change on the use of storage. Other modeling shows that offshore wind reduces the need for seasonal storage, while any wind reduces the need for short-duration and diurnal storage, but may increase the need for cross-day storage.

[5] https://efiling.energy.ca.gov/getdocument.aspx?tn=234532

Table 3. 2 Comparison of 2018 RSP and SB100 build limits on candidate wind resources

Wind resource	2018 RSP New Build Capacity Limit (MW)	SB100 New Build Capacity Limit (MW)
Carrizo_Wind	287	288
Central_Valley_North_Los_Banos_Wind	173	398
Greater_Imperial_Wind	-	785
Greater_Kramer_Wind	-	445
Humboldt_Wind	34	34
Kern_Greater_Carrizo_Wind	60	69
Kramer_Inyokern_Ex_Wind	-	81
New_Mexico_Wind	1,500	6,000
Northern_California_Ex_Wind	866	866
NW_Ext_Tx_Wind	1,500	1,500
SCADSNV_Wind	-	100
Solano_subzone_Wind	18	50
Solano_Wind	542	576
Southern_California_Desert_Ex_Wind	-	48
SW_Ext_Tx_Wind	500	500
Tehachapi_Wind	275	802
Southern_Nevada_Wind	442	442
Wyoming_Wind	1,500	6,000
Baja_California_Wind	600	600
Onshore Total	8,297	19,584
Cape Mendocino	-	6,216 (Full) 1,649 (Limited)
Diablo Canyon	-	4,324
Morro Bay	-	2,419
Humboldt Bay	-	1,607
Offshore Total	-	14,566 (Full) 10,000 (Limited)
Total Wind	8,297	34,150 (Full) 29,584 (Limited)

3.4 New baseline with higher and lower EV load

A change in the load assumed for electric vehicle (EV) charging affects the build out of solar and storage somewhat, with about 10% decrease in the 2045 buildout and electricity generation, as shown in Figs. 3.13 and 3.14. The total cost changes by more, being reduced by about 16% when the EV load is reduced to that in the 2018 RSP. The conclusions from the fractional buildout graphs in Figs. 3.15 and 3.16 are the same.

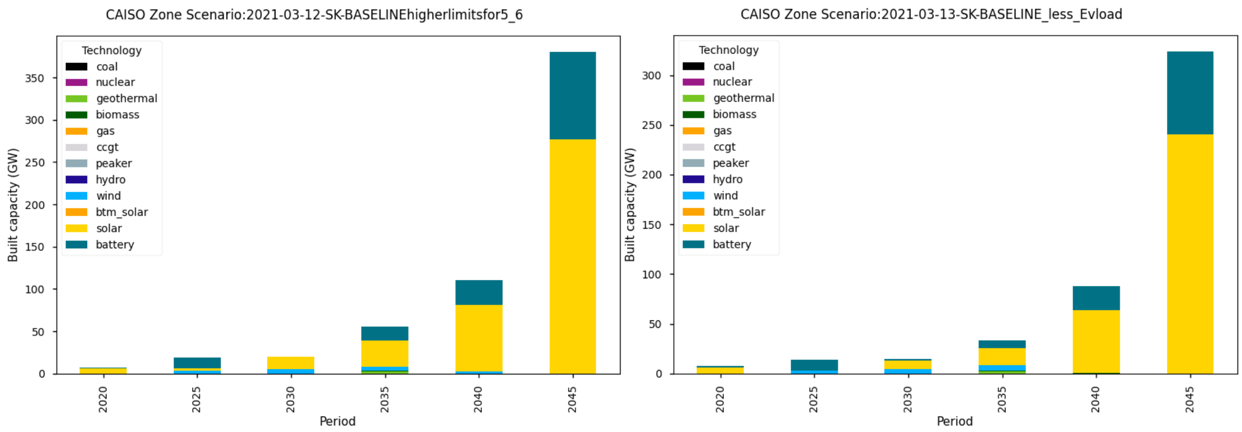


Fig. 3. 13 Resource buildout for new baseline with high (left) and low (right) EV load.

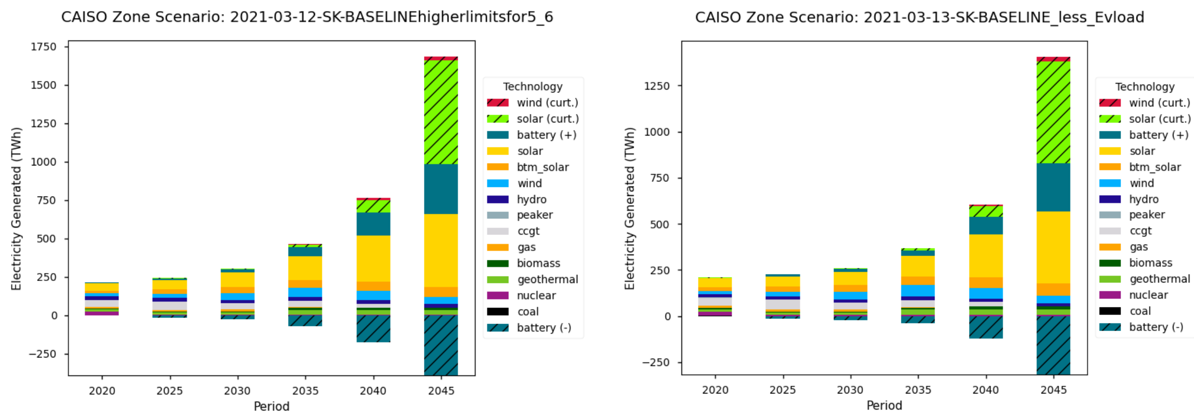


Fig. 3. 14 Electricity generation for new baseline with high (left) and low (right) EV load.

The added EV load was applied as a constant multiplier to the CAISO load. The benefit of adjusting the charging time to a time when electricity is more available is not included in this baseline and will be explored in the sensitivity analysis.

The detail shown in Figs. 3.14 and 3.15 identifies that not only is less solar built when the load is decreased, but less offshore wind and fewer Li batteries. More demand management is added.

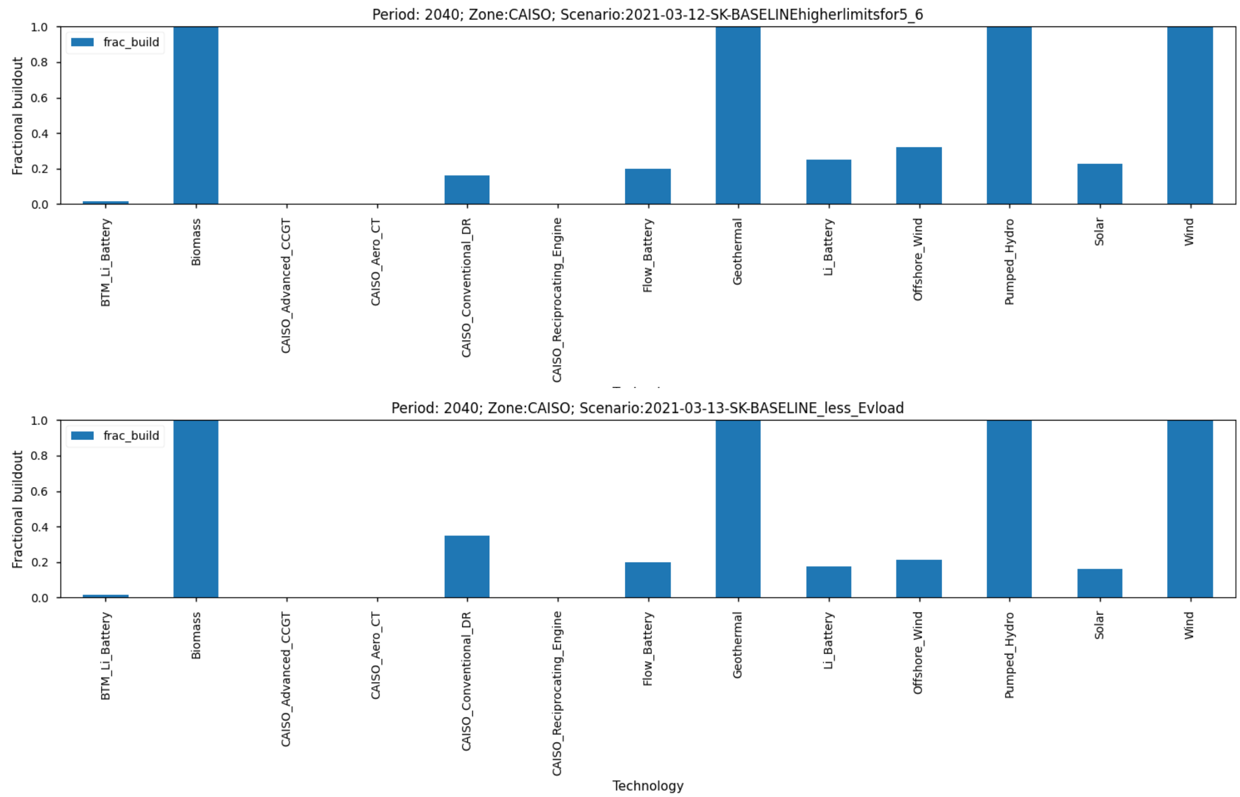


Fig. 3. 15 Fractional build in Period 2040 for new baseline with high (top) and low (bottom) EV load

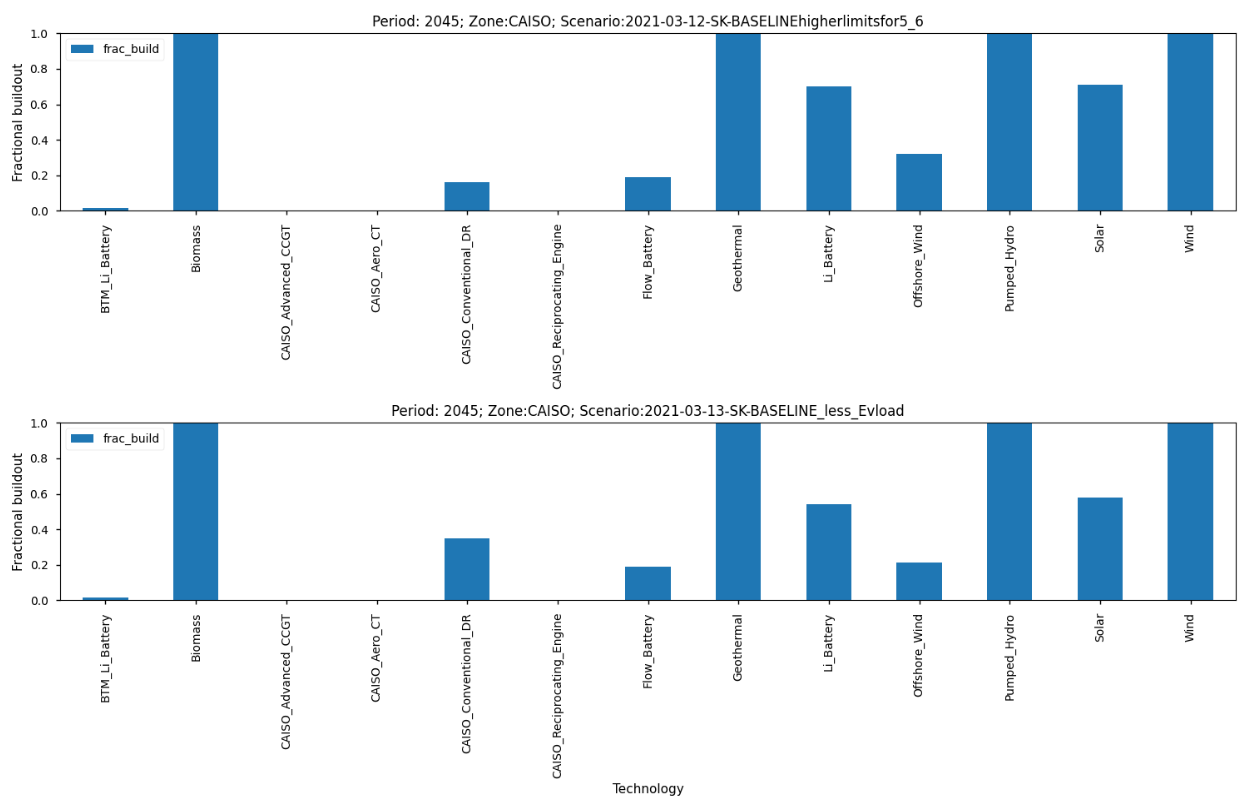


Fig. 3. 16 Fractional build for Period 2045 for new baseline with high (top) and low (bottom) EV load

3.5 New baseline with higher and lower electrolyzer (H_2) load

A change in the load assumed for electrolyzers affects the buildout of solar and storage somewhat, with about 15% decrease in the 2045 buildout and electricity generation, as shown in Figs. 3.17 and 3.18. The total cost changes by less, being reduced by about 10% when the electrolyzer load is reduced to that in the 2018 RSP.

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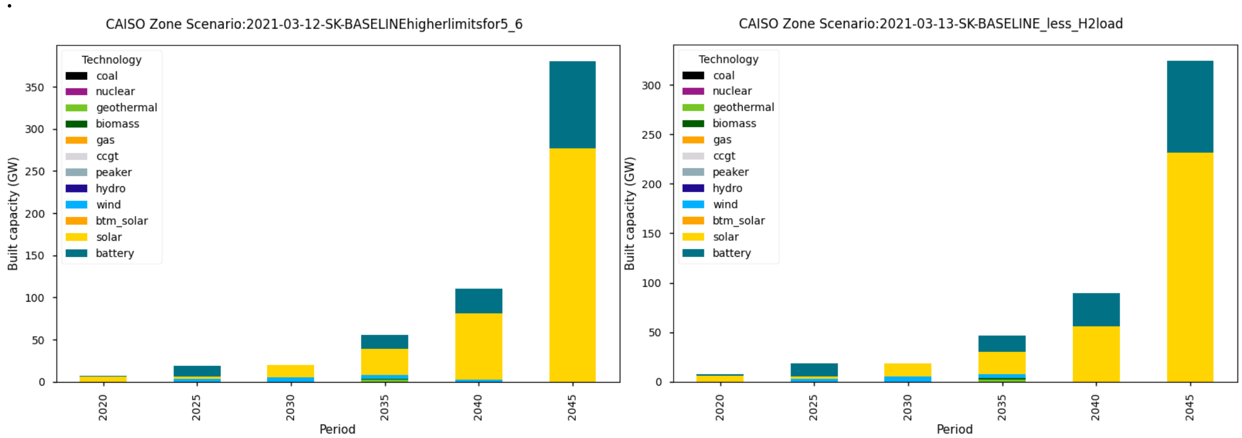

Fig. 3. 17 Resource buildout for new baseline with high (left) and low (right) H_2 load.

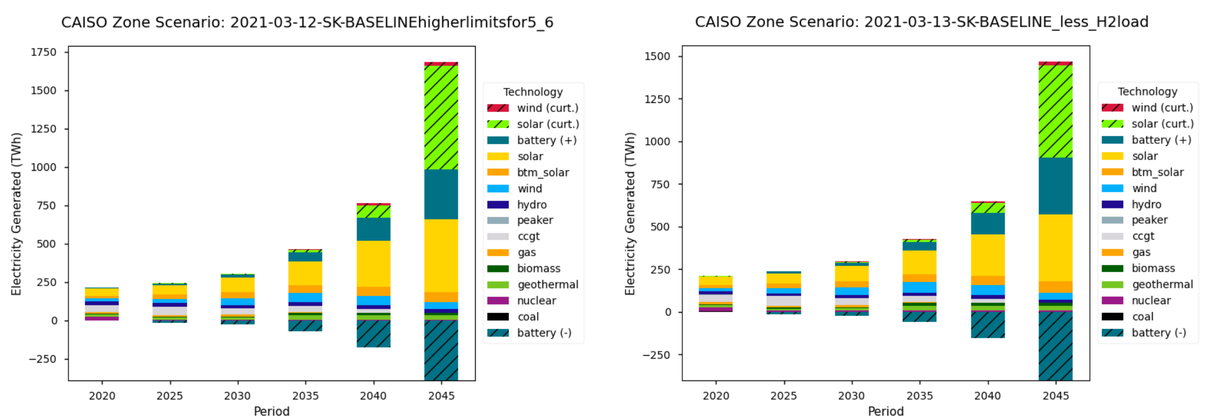

Fig. 3. 18 Electricity generation for new baseline with high (left) and low (right) H_2 load.

The fractional buildouts for the new baseline with and without the higher electrolyzer load are shown in Figs. 3.19 and 3.20. The changes are fairly similar to what was reported for the change in EV load, above, but the reduced electrolyzer load scenario requires more Li batteries than when the EV load is reduced.

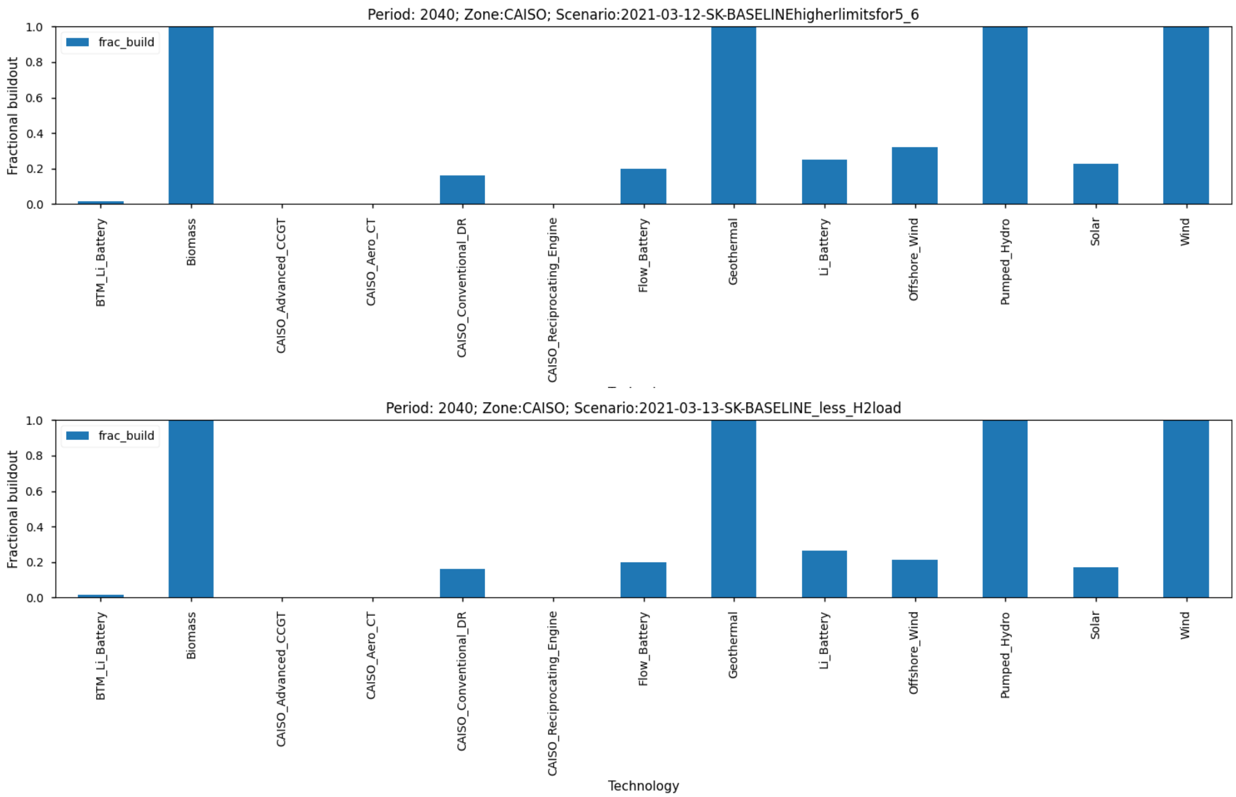

Fig. 3. 19 Fractional build in Period 2040 for new baseline with high (top) and low (bottom) H_2 load

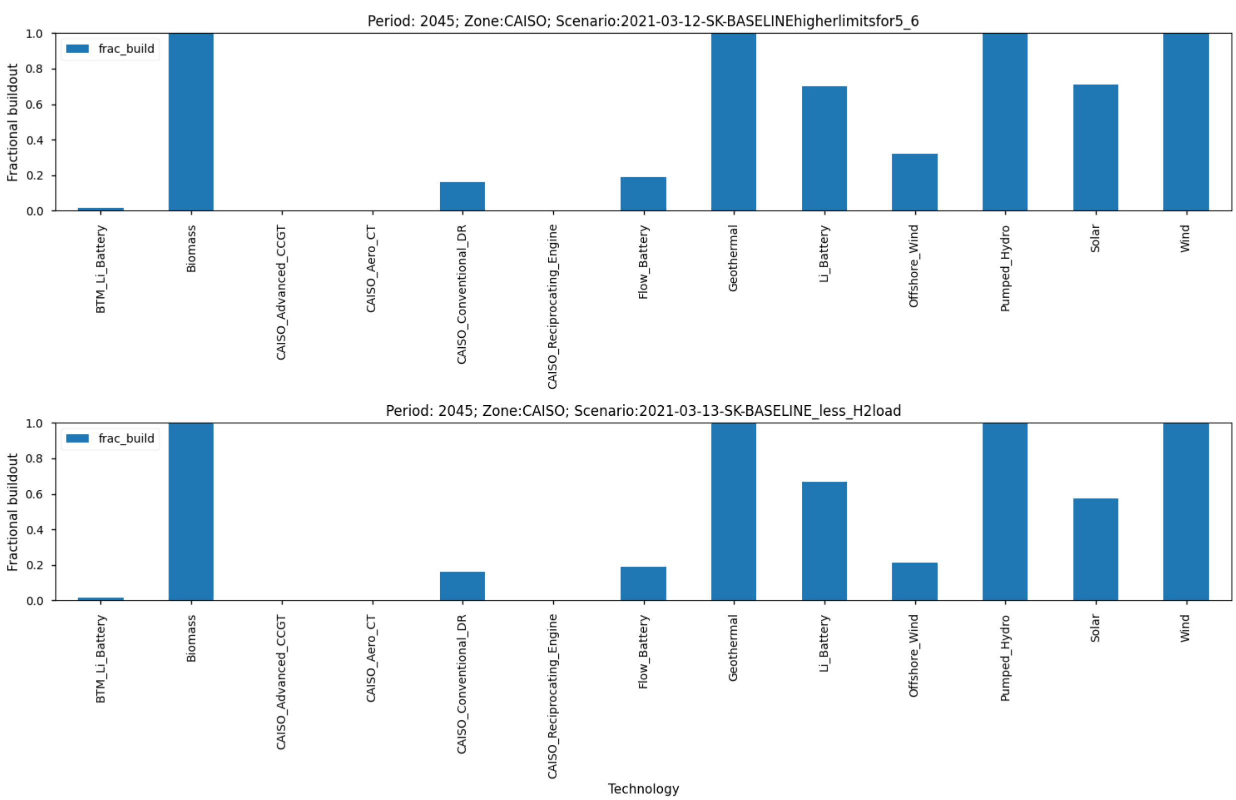

Fig. 3. 20 Fractional build for Period 2045 for new baseline with high (top) and low (bottom) H_2 load

3.6 New baseline with 20.7% and 15% planning reserve margin

When implementing the 20.7% planning reserve margin (PRM) along with the higher load scenarios, a question arises about whether we need to have resource adequacy associated with the additional electrolyzer and EV charging loads. There is a high probability that the electrolyzers will be designed to operate when electricity prices are low, so are likely to be turned off whenever there is a resource adequacy problem. Similarly, we would be wise to design EV charging to be shifted to a time of low demand, assuming that the low demand time comes within hours, rather than days. These assumptions may differ from others' assumptions. A change in the planning reserve margin has a smaller effect than the above changes. The small changes are shown in Figs. 3.21 – 3.24. Primarily, more storage is built starting in 2025.

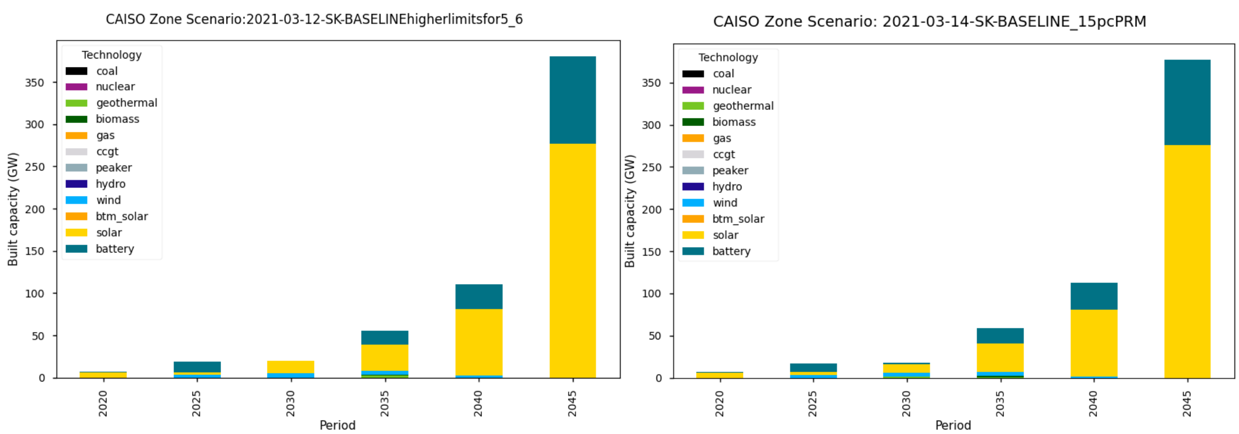

Fig. 3. 21 Resource buildout for new baseline with 20.7% (left) and 15% (right) planning reserve margin.

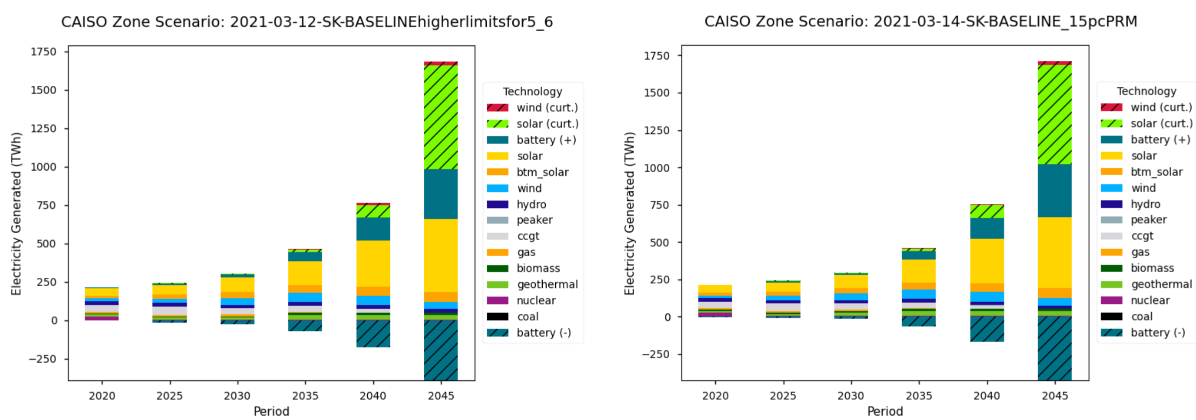

Fig. 3. 22 Electricity generation for new baseline with 20.7% (left) and 15% (right) PRM.

The primary effect of reducing the planning reserve margin (PRM) to 15% is shown in Figs. 3.23 and 3.24 to be the removal of the demand management that is selected in the baseline. Also, slightly fewer flow batteries and Li batteries are built for the 15% PRM case.

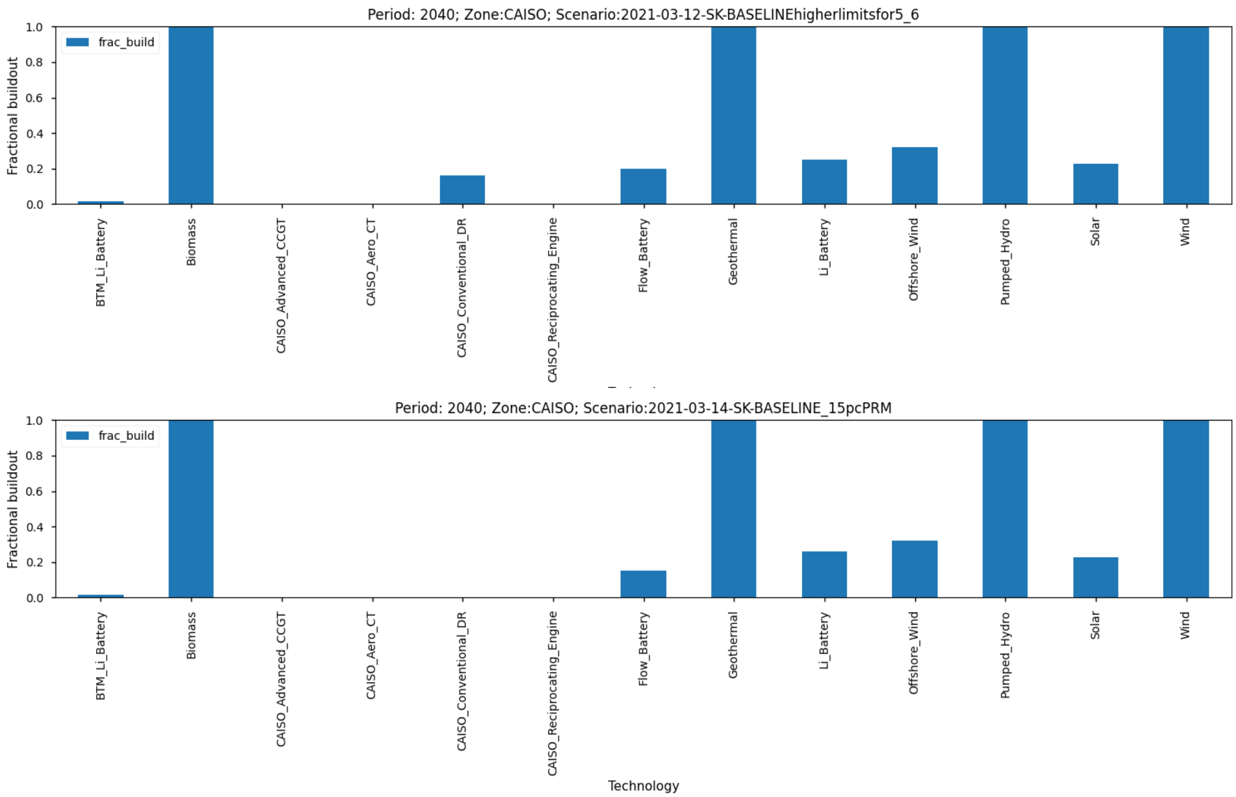

Fig. 3. 23 Fractional build in Period 2040 for new baseline with 20.7% (top) and 15% (bottom) PRM

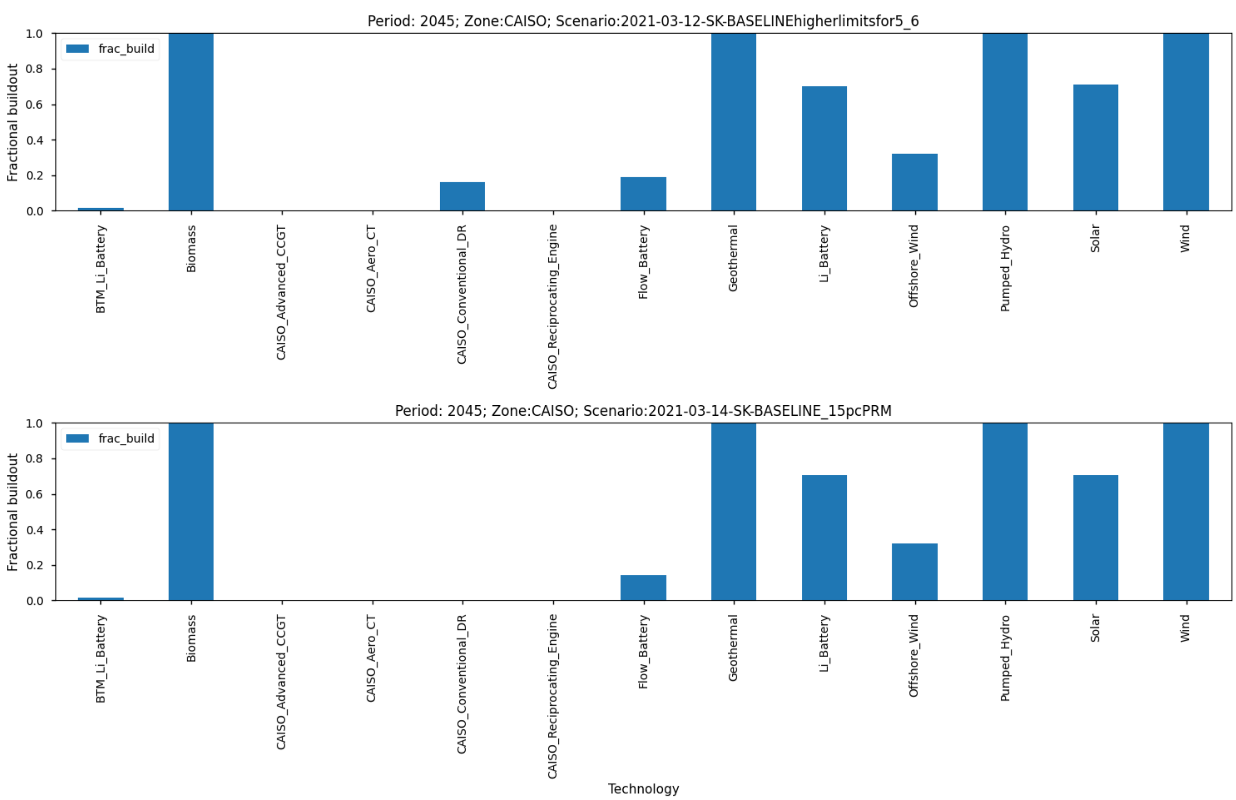

Fig. 3. 24 Fractional build for Period 2045 for new baseline with 20.7% (top) and 15% (bottom) PRM

3.7 New baseline with and without the 4-hour Li battery model

A change in the Li battery model affects the buildout very little, as shown in Figs. 3.25 and 3.26. The total cost is reduced by about 4% when the 2018 RSP Li battery model is used.

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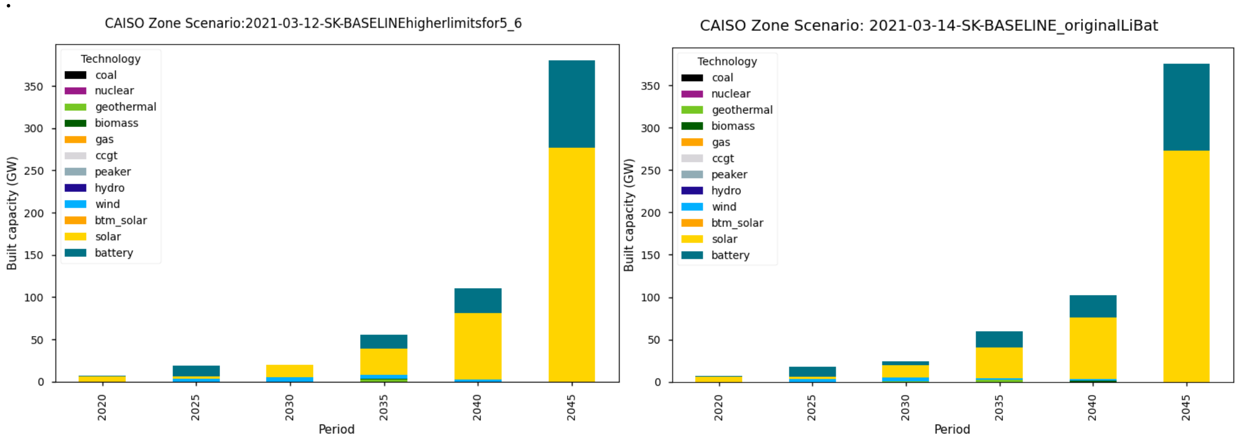

Fig. 3. 25 Resource buildout for new baseline with 4-h (left) and original (right) Li-battery models.

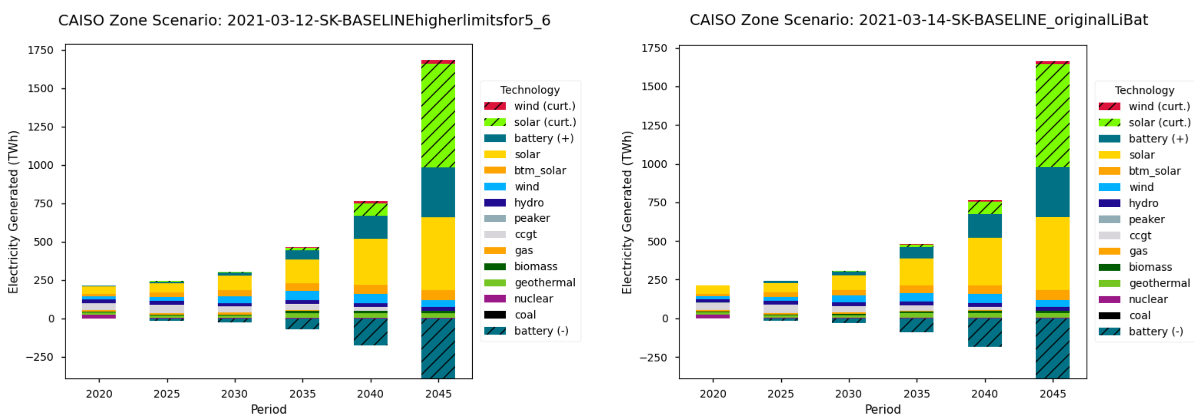

Fig. 3. 26 Electricity generation for new baseline with 4-h (left) and original (right) Li-battery models.

The fractional buildouts for the new and original Li battery models in the new baseline are shown in Figs. 3.27 and 3.28. The detail shows that, although the total storage build out is almost the same, the selection of the type of storage is sensitive to the details of the Li battery model, with the original model favoring the build of more Li batteries and the 4-h Li battery model favoring the build of pumped hydro storage and flow batteries.

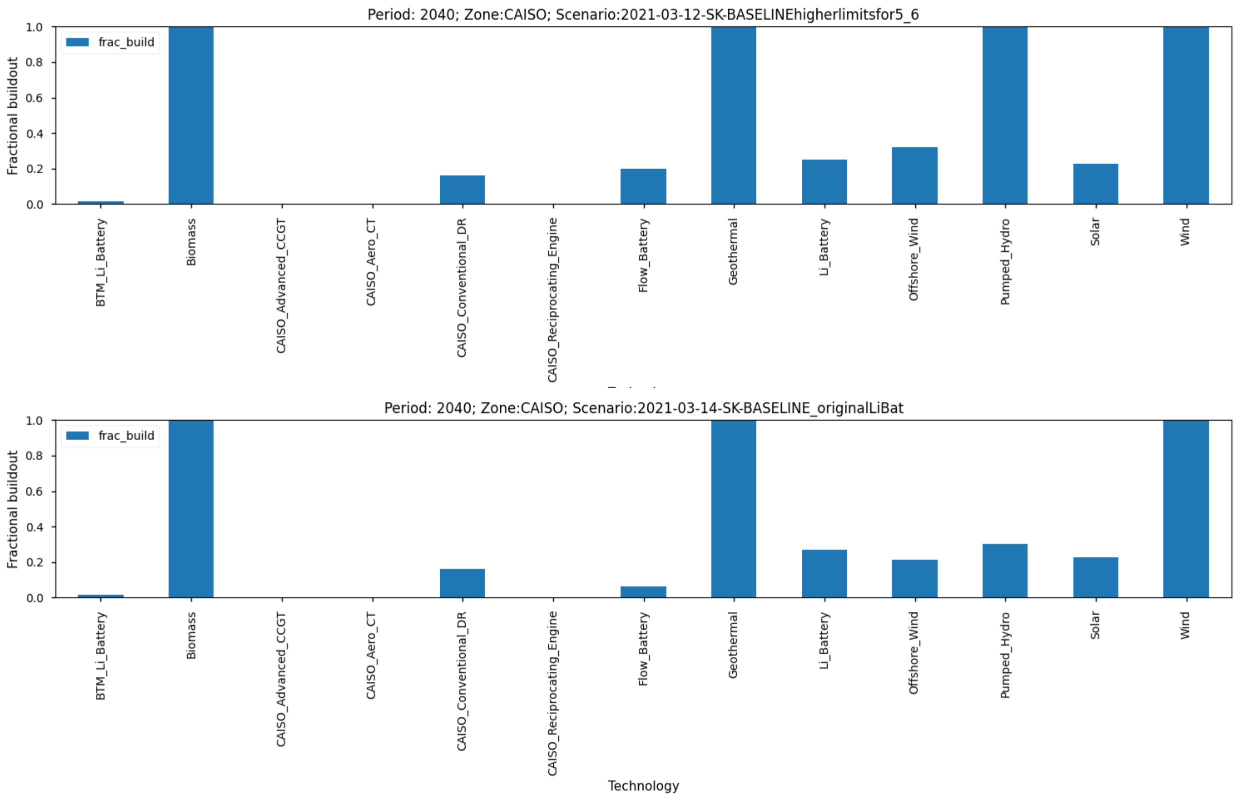

Fig. 3. 27 Fractional build in 2040 for new baseline with 4-h (top) and original (bottom) Li-battery models

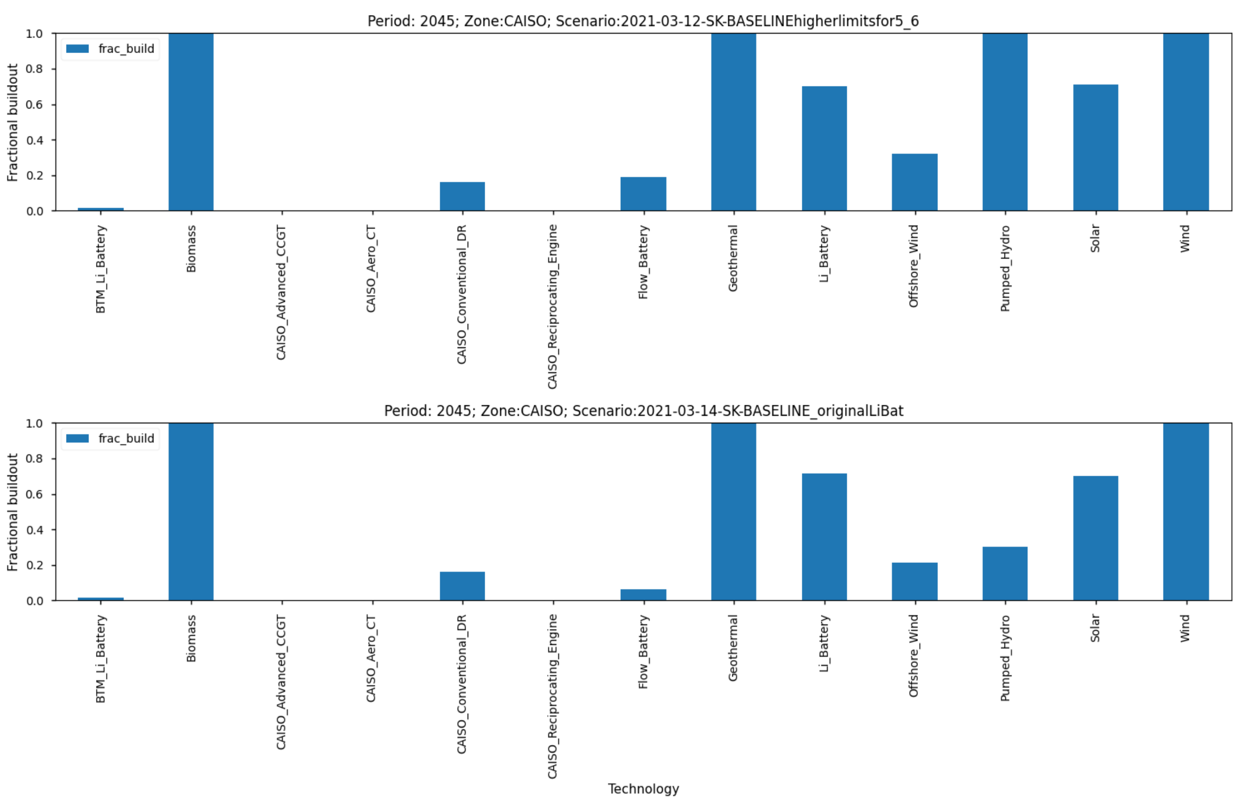

Fig. 3. 28 Fractional build in 2045 for new baseline with 4-h (top) and original (bottom) Li-battery models

4. SWITCH baseline development

Substantial work was completed in updating the SWITCH-WECC model. Here, we include an update on that work in two sections (software and baseline development) before presenting the modeling results.

4.1 SWITCH software development

Updated to Python 3.7+ from Python 2.7

The SWITCH-WECC model code was updated using the most recent version of Python. This update required modification to all the modules that were previously written in Python 2.7 to a more recent stable and maintained version 3.7. This allows the use of new features such as formatted strings (f-strings), faster model constructions, and additional speedup gains through the core packages utilized by the SWITCH model.

Long-duration storage module

Although the current version of SWITCH 2.0 was designed with the capability to use flexible timepoints (which will be useful for studying long-duration storage) it was not originally designed to study long-duration storage. We have begun adding the appropriate analytical formulation to capture the operations of different long-duration storage technologies, for example, separate charging and discharging efficiencies and different balancing decisions by a range of consecutive days. Additionally, we are improving the efficiency of how we define the Sets and Variables constructed inside of the module for the analysis of long-duration storage. We anticipate that this code will have additional room for improvement and expansion as we introduce new storage constraints to be modeled.

Time sampling strategies for Long-duration Energy Storage

Although SWITCH 2.0 was designed with the capability to use flexible timepoint and timeseries selection, the methodology for selecting these has not been developed in the context of studying long-duration storage. For this, we will study the impact of different sampling strategies on the overall resulting capacity-expansion. We want to capture different (probable) business models of long-duration energy storage resources (daily balancing, multi-day balancing, seasonal balancing) and how does the model adjust the buildout as we move forward a zero-carbon grid.

This work has begun and is expected to produce a peer-reviewed journal publication due to the lack of literature on this topic. It will be completed as part of Task 4.1 “Multi-day Model Optimization.”

Module to model California policies imports constraints from other states

We are using the SWITCH 2.0 with scenario data for the entire WECC. The interpretation of these results in the context of California's energy use requires being able to track imports and exports between California and the rest of WECC load zones.

We created a new module that will incorporate California's policies aligned with the latest IRP and SB-100 results. For example, we created a constraint that will force the model to produce at least 80% of the retail sales withing California footprint. This constraint will force the model to reduce the imports to California which is important considering that other load zones inside of the WECC region have different energy policy goals that might not align with California's aggressive targets.

Module to model assumptions on residential PV growth in California

The SWITCH model includes a candidate technology that represent the residential PV installations. However, the cost of residential PV is always higher than centralized PV for each of the periods, so the model will not select residential PV as the most economical option. Therefore, we decided to use the same assumption from the latest IRP modeling results and remove residential PV from the pool of candidate resources. Instead of optimizing it, we included it using an expected growth rate for California and used the same values as reported from the IEPR and IRP.

Module to track and restrict air pollutants

The SWITCH model has a built-in module that calculates the CO_2 emission for each of the power plants provided and constrains operations to a given carbon cap. To capture additional benefits of a zero-carbon grid, we have added the capability to track and restrict additional air pollutants (NOx, SOX, CH_4.) by calculating the annual emissions per power plant and assuming a carbon. This module and restriction is currently tracking CO_2 emission, but we will explore the impact of the different pollutants as part of the sensitivity analysis

4.2 SWITCH baseline development

The SWITCH baseline development was reported in the deliverables completed last month, but an update is given here for completeness:

Updated model inputs and assumptions

We updated the set of existing and planned generators using the latest EIA-923 and EIA-860 forms, technology costs (based on NREL-ATB), and the regional costs for new expansion of transmission lines. Also, we updated the hydropower generation to be the historical average of 2004 - 2018 data which is the most recent and complete set of years at the time.

We included a planned reserve margin of 15% across the entire WECC. This value was assigned to each of the utilities as a total number across all the load-zones they provide service. We did not exclude any generators from contributing capacity to meet the PRM. However, we are aware that there is a current ruling of the IRP mid-term reliability analysis proposing to increase the

PRM to 20.7%. This value may be incorporated into the baseline as part of the sensitivity analysis.

WECC database at UC San Diego and UC Merced

The current version SWITCH-WECC is designed to pull the required scenario inputs from a central database. This database has been hosted at UC Berkeley but was not available at either UC San Diego or UC Merced. We were unsuccessful in obtaining easy access to the UC Berkeley database from outside of UC Berkeley because of firewall issues. Therefore, we have now set up the needed hardware and have transferred the data so that it can now be accessed easily on all 3 campuses using UC San Diego as the latest version of the database for scenario constructions.

Configuration selection

Consistent with the description above for RESOLVE, we selected to reach zero carbon emissions in 2045, including zero carbon emissions for line losses as shown in Fig. 2.4 above. We had some discussion about what to assume for the rest of WECC. There is substantial evidence that California's neighbors will be reducing carbon emissions, but the timeline is unclear. Reaching zero emissions is much easier when regional transmission is available. However, it is difficult to track electrons between the different regions to determine whether California's goals were met if California is importing electricity from adjacent regions that have not yet met zero-emissions targets. For the baseline, we have agreed to set a zero-emissions target for all WECC enabling us to identify what would be needed to reach that target, while exploring other options during the sensitivity analysis. We find that allowing imports of wind from Wyoming, for example, can be very helpful as California strives to meet aggressive goals.

Timepoint and period selection

As described above, we have begun the study of the optimal tradeoff between run time and accuracy of calculation when considering the number of timepoints to use in the simulation. For this set of results, we used the previous timepoint and period selection from the previous WECC version which is 6 timepoints per day for two days per month (peak and median day) and 10-year periods. The final selection of timepoints and periods will depend on the results of the Task 4.1 "Multi-day Model Optimization" as we aim to capture most of the business models for long-duration energy storage.

Baseline implementation

The resulting baseline results are explored in comparison with the RESOLVE baseline results in the next section.

5. Comparison of SWITCH and RESOLVE baselines

In this section we show some of the results of the baseline model for SWITCH and its comparison with the RESOLVE baseline. As mentioned in the previous section, we updated most of the inputs for the SWITCH-WEECC model incorporating the most updated version of current and planned generators from the EIA dataset, 15% PRM and the latest technology costs from the NREL-ATB. As noted in the Baseline Description these updates align the two models in terms of capturing a recent snapshot, but are not aligned according to the definition of location since RESOLVE includes some generators outside of California in the CAISO zone if there is a contract with CAISO. This comparison will allow us to understand the benefits of having extra geographical and temporal resolution to quantify the value of long-duration energy storage.

Key differences in the baseline model definition of the two models include:

- SWITCH includes California as a subset of WECC, while RESOLVE focuses on California
- SWITCH defines zones according to state lines, while RESOLVE defines balancing zones
- The EV and electrolyzer loads were increased for RESOLVE, but not as much for SWITCH
- The PRM for RESOLVE was increased to 20.7%, while SWITCH is still using 15%

5.1 Operational capacity for the entire WECC

The Baseline Description compared the assumptions of SWITCH and RESOLVE about the legacy power plants highlighting the differences in the zone definitions. In reviewing the results of the simulation, we again find notable difference between the baselines. This relates to the additional geographical spread that SWITCH-WECC has. As mentioned before, the SWITCH model considers in total 52 load-zones for the entire WECC while RESOLVE considers only seven (7). With the additional spatial resolution, we can observe transmission flows between important load zones that might provide electricity back to California (e.g., Wyoming wind).

The operational capacity for the entire WECC baseline results is shown in Fig. 5.1. As expected, solar, wind and energy storage dominate most of the cumulative capacity in the WECC region. Also, we observe that energy storage is installed in most of the load-zones with high solar penetration. The operational storage for this scenario is used mostly to balance solar generation and for planned reserve margins. There is also some remaining additional natural gas in some load-zones, but it is only used for PRM purposes.

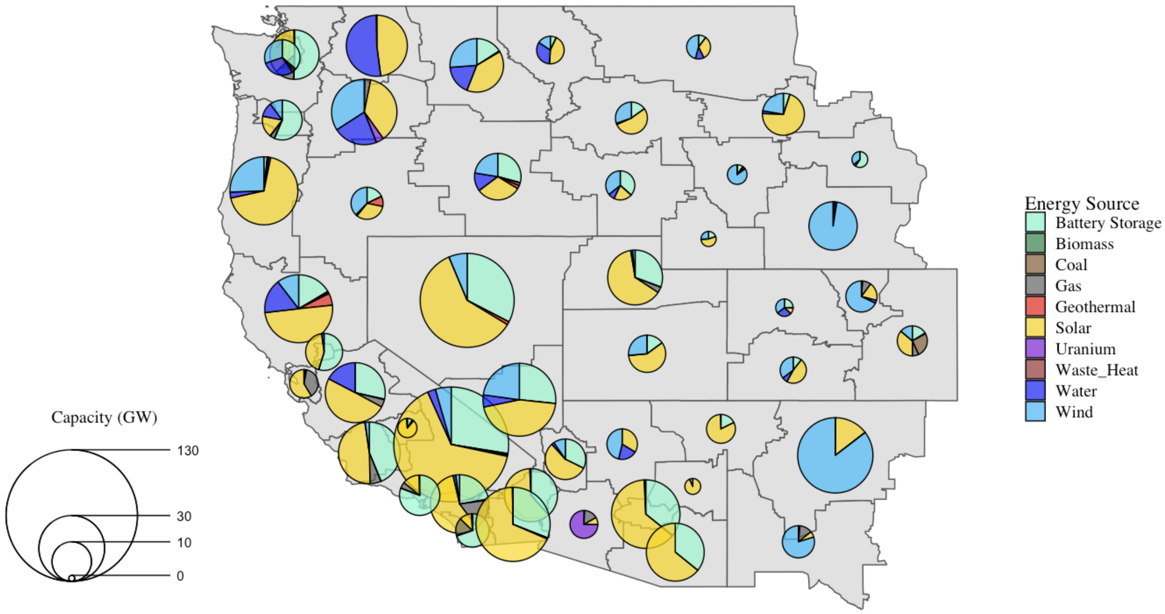

Fig. 5. 1 WECC operational capacity by energy source for each load-zone in 2050. Baseline scenario WECC-wide zero carbon cap and a 15% PRM.

5.2 Operational capacity RESOLVE vs SWITCH

The baseline proposal for SWITCH includes a zero-carbon cap WECC wide by 2050. For this aggressive carbon goal, the model chooses to install zero-carbon technologies across the entire WECC and end's up with less operational capacity in California's load-zones (see Figure 5.2). On the other hand, the latest version of RESOLVE aims to show a future of a self-sufficient California with most of its retail sales being produced within California footprint. Additionally, RESOLVE does not consider capacity expansion outside of the CAISO footprint which will result in substantial new capacity within California to meet the carbon goal.

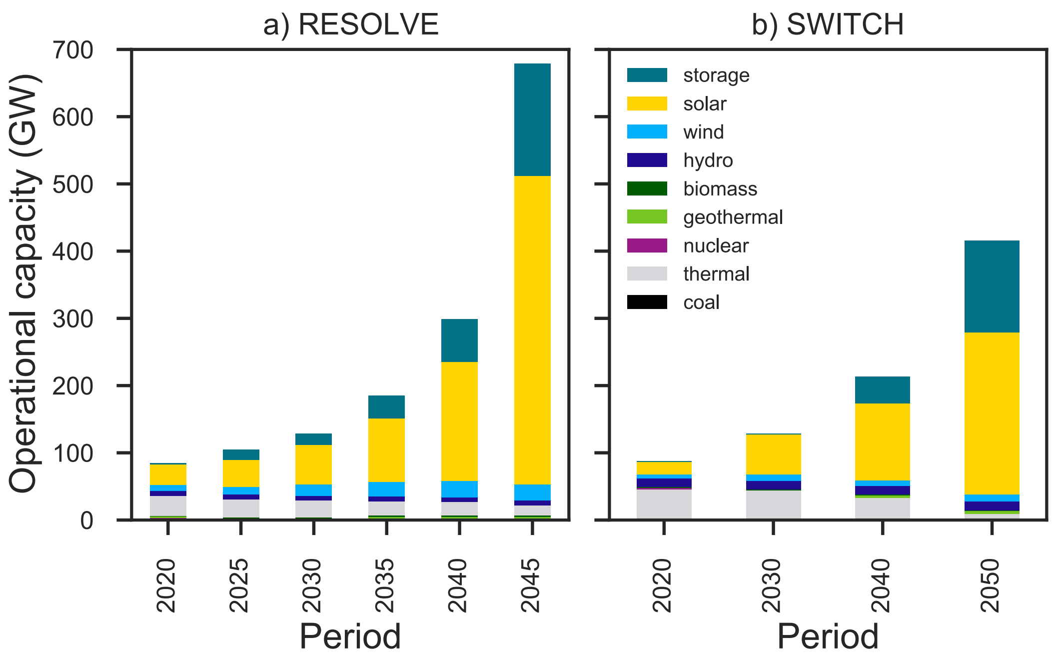

Fig. 5. 2 Operational capacity calculated by RESOLVE and SWITCH for all of California.

5.3 Transmission flows

The baseline proposal for SWITCH allows us to see in more detail the transmission flows between the entire WECC (see Figure 5.3). All the transmission lines modeled by SWITCH are legacy transmission but with the capability of additions if optimal. We expect that as the entire WECC moves to zero-carbon, some load-zones with more available renewable resources will perform as net-exporters. We can observe this on Figure 5.3 in the load-zones with more than 40 TWh of transmission flow.

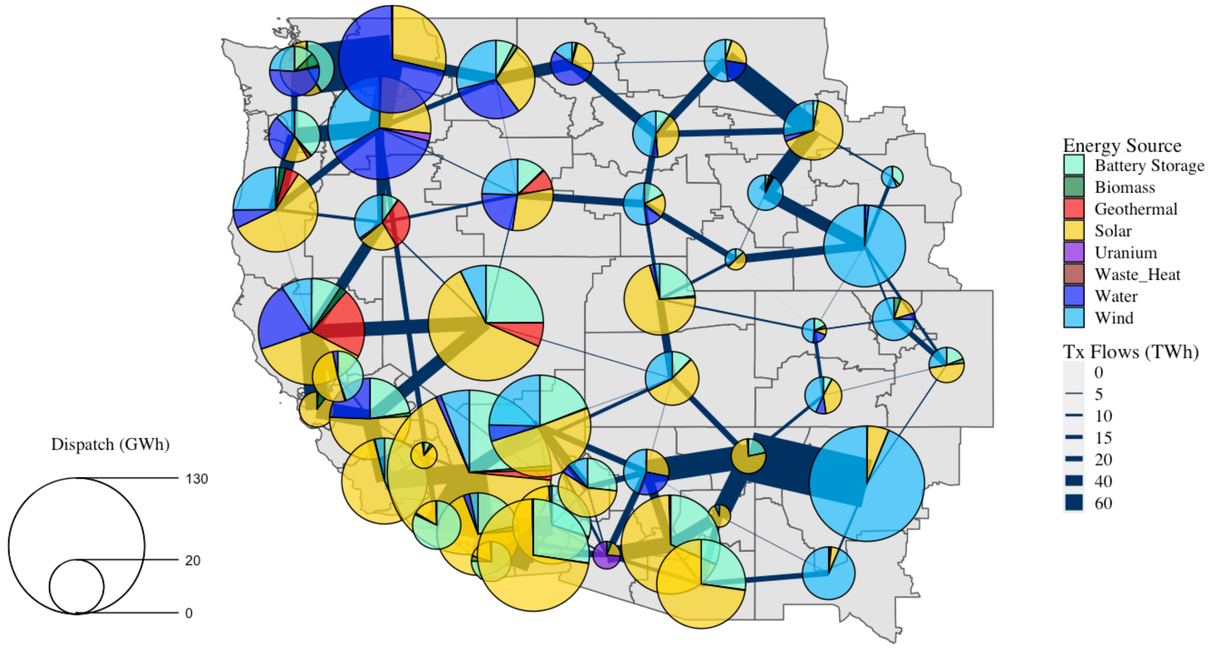

Fig. 5. 3 WECC-wide annual dispatch and transmission flows for 2050. Baseline scenario WECC-wide zero carbon cap and a 15% PRM.

5.4 Imports constraint results

An assumption that we wanted to study in detail is the imports constraint for California. This reflects a scenario where other regions in the WECC will not reduce carbon emissions as quickly as California. In simpler words, we model a zero-carbon California that will not consume any out-of-state electricity to avoid having California use electricity generated with carbon emissions. This assumption affects the overall operation capacity due to the lack of imports. Most of the electricity must be generated inside of California footprint and we end up with more cumulative additions as shown in Figure 5.4. From the results, we can see that as we limit the availability of imports, the total operational capacity increases for SWITCH. However, there is an evident difference between the equivalent scenario for SWITCH (zero-carbon California and import constraints) and the proposed RESOLVE baseline scenario. We suspect that this difference is due to the larger EV and electrolyzer loads used by the RESOLVE baseline. Also, with the additional spatial resolution and capacity-expansion in other zones, there is not a need for additional required capacity.

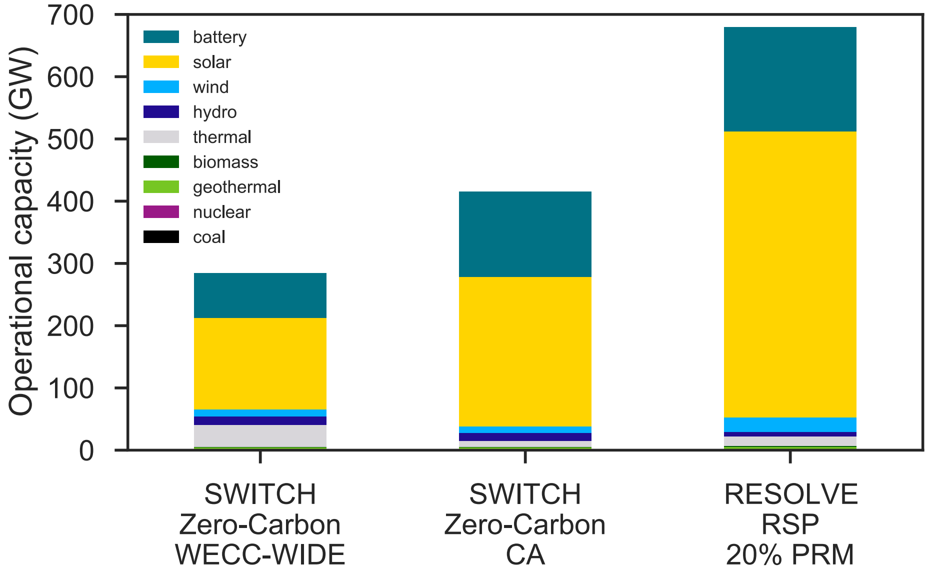

Fig. 5. 4 Operational capacity for the latest modeled period under different scenarios assumptions.

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