PRELIMINARY GRID SCENARIO ANALYSIS for EPC-19-060

(Deliverable for Subtask 5.1)

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- Inputs from EPC-19-060 Task 3.4 "Generation Scenarios Summary" and CAISO's Transmission 2022 California ISO 20-Year Transmission Outlook[3]

Scenario modifications will include:

- Evaluation of the effect of increased EV charging on the need for long-duration energy storage using scenarios D-1 ("Unconstrained" emphasizes evening charging), D-8 ("Happy Hour" emphasizes daytime charging) and D-3 ("High Residential Access" emphasizes nighttime charging) taken from California studies like the AB 2127 EVI PRO report[4]
- Evaluation of the impact of using solar and wind generators designed for higher output during the winter (as shown in Fig. 3.3 and 3.4 of "Generation Scenarios summary Task 3.4") on the need for long-duration energy storage
- Exploration of key transmission corridors[5] for decarbonized WECC and California by capping the expansion of transmission (varying the cap). This will enable us to understand how different transmission corridors should be prioritized for their expansion.
- Evaluation of the potential for electrolyzers to reduce the need for long-duration storage by acting as a flexible load while supplying hydrogen for transportation, industrial and other applications (using the assumptions described in Table 2.2 of the Grid Scenario Analysis)

The structure of this report is described in Section 1. The goal of this report is to document the approaches and preliminary data to demonstrate how our approach will elucidate the value of long-duration energy storage.

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[1] Using the 38MMT_20210812_PSP_LSEplan_2020IEPR_2020IEPRHighEV inputs to RESOLVE with 2021 IEPR loads taken from https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated- energy-policy-report

[2] See Section 2.4 of "Grid Scenario Analysis"

[3] 20 Year Transmission Outlook, 2022, California ISO, http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf

[4] Electric Vehicle Charging Infrastructure Assessment – AB 2127 – Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 (Commission Report). https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle- charging-infrastructure-assessment-ab-2127 with tables in https://efiling.energy.ca.gov/getdocument.aspx?tn=238851.

[5] Fig. 2.1-1 in http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf .

1. Introduction

This Preliminary Grid Scenario Analysis presents the baseline scenario we will study to elucidate the value of storage candidates with a range of attributes.

1.1 Background

The proposed scenarios were previously described in the deliverable "Grid Scenario Selection" submitted for Task 4.2. This document builds on that one, responding to directives from the California Energy Commission, analyzing the impacts of some of the changes we are proposing relative to the Preferred System Portfolio, and demonstrating the value of the work.

1.2 Structure of this report

Section 2 of this report provides a table listing the base line assumptions and scenarios that will be explored along with discussion explaining these. This repeats much of the information presented previously in the Grid Scenario Summary. Section 3 analyzes the accuracy of the use of critical time steps to shorten the calculation time while retaining the accuracy needed to understand how long-duration energy storage will be used. Section 4 evaluates the effects of the modifications we propose to some of the generation profiles included in the baseline scenario. Section 5 demonstrates our approach to modeling an array of storage technologies. Finally, Section 6 provides capacity expansion outputs for our baseline (before introducing low-cost long-duration energy storage).

2. Baseline and scenario definition

This section describes the baselines and scenarios that we will use in Phase II using RESOLVE (Section 2.1) and SWITCH (Section 2.2). These differ from what was described in Task 4.2 report "Grid scenario selection" and have been updated to reflect the guidance provided by the Energy Commission (repeated here for reference).

The final scenario determination was issued on January 5, 2023, providing the following guidance:

> **Background**
>
> University of California, Merced (UCM) is conducting research under the Electric Program Investment Charge (EPIC) grant titled "Modeling of Long-Duration Storage for Decarbonization of California Energy System". This research will identify a realistic and appropriate range of scenarios to assess the value of different energy storage durations, performance characteristics, and cost targets against a range of resource supply options and electricity demand conditions.
>
> On October 5, 2022, the CEC conducted a meeting with staff from CAISO, CPUC, NYSERDA, and DOE to collect feedback which included an expressed need to study the role of hydrogen in providing multi-day duration energy storage, connecting grid scale storage in a manner to minimize or alleviate grid congestion, availability of charging sessions to recharge LDES, and the effects of varying cost and incentive structures on the selected energy resource mix.
>
> The CEC conducted a literature review to identify modeling sensitivities which would provide value to current and future research evaluating a range of resource supply options and electricity demand conditions.
>
> - The 2021 SB100 Joint Agency Report contains recommendations for expanding the modeling work used to inform the IRP, including prioritizing efficiency and load flexibility to minimize the implementation costs and environmental impacts of transitioning to a 100 percent clean energy system.[6]
> - The 2021 Integrated Energy Policy Report – Volume IV[7] discusses additional achievable energy efficiency (AAEE) scenarios to support the SB 350 energy efficiency targets.
> - LBL's Phase 3: Final Report on the Shift Resource[8] compares the quantity, cost, and performance of Shift DR resources with energy storage resources.
> - EPIC 4 Investment Plan[9] includes research topics to advance geothermal generation, zero-carbon firm dispatchable resources, and the efficiency and load

[6] 2021 SB 100 Joint Agency Report, page 137, https://efiling.energy.ca.gov/EFiling/GetFile.aspx?tn=237167&DocumentContentId=70349

[7] 2021 IEPR Volume IV - California Energy Demand Forecast, https://efiling.energy.ca.gov/GetDocument.aspx?tn=241581

[8] The California Demand Response Potential Study, Phase 3: Final Report on the Shift Resource through 2030, https://emp.lbl.gov/publications/california-demand-response-potential

[9] EPIC 4 Investment Plan, https://www.energy.ca.gov/publications/2021/electric-program-investment-charge-proposed-2021-2025-investment-plan-epic-4

flexibility of grid-interactive efficient buildings and electric vehicle charging equipment.

Final Scenario Determination

- The Final Core Scenario will include baseline assumptions to reflect the 2021 CPUC IRP PSP[10] and the 2020 PATHWAYS High Electrification analysis for the growth of EV loads[11]
- Inputs from EPC-19-060 Task 3.4 "Generation Scenarios Summary" and CAISO's Transmission 2022 California ISO 20-Year Transmission Outlook[12]

Scenario modifications will include:

- Evaluation of the effect of increased EV charging on the need for long-duration energy storage using scenarios D-1 ("Unconstrained" emphasizes evening charging), D-8 ("Happy Hour" emphasizes daytime charging) and D-3 ("High Residential Access" emphasizes nighttime charging) taken from California studies like the AB 2127 EVI PRO report[13]
- Evaluation of the impact of using solar and wind generators designed for higher output during the winter (as shown in Fig. 3.3 and 3.4 of "Generation Scenarios summary Task 3.4") on the need for long-duration energy storage
- Exploration of key transmission corridors[14] for decarbonized WECC and California by capping the expansion of transmission (varying the cap). This will enable us to understand how different transmission corridors should be prioritized for their expansion.
- Evaluation of the potential for electrolyzers to reduce the need for long-duration storage by acting as a flexible load while supplying hydrogen for transportation, industrial and other applications (using the assumptions described in Table 2.2 of the Grid Scenario Analysis)

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[10] Using the 38MMT_20210812_PSP_LSEplan_2020IEPR_2020IEPRHighEV inputs to RESOLVE with 2021 IEPR loads taken from https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report

[11] EPC-19-60 Task 5.1 Deliverable "Preliminary Scenario Analysis" Section 2.4"

[12] 20 Year Transmission Outlook, 2022, California ISO, http://www.caiso.com/InitiativeDocuments/20-YearTransmissionOutlook-May2022.pdf

[13] Electric Vehicle Charging Infrastructure Assessment – AB 2127 – Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 (Commission Report). https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle- charging-infrastructure-assessment-ab-2127 with tables in https://efiling.energy.ca.gov/getdocument.aspx?tn=238851.

[14] Fig. 2.1-1 in http://www.caiso.com/InitiativeDocuments/Draft20-YearTransmissionOutlook.pdf.

2.1 Baseline for RESOLVE modeling

Table 2.1 provides more detail for the RESOLVE baseline based on the guidance given above. The RESOLVE modeling will use the New Modeling Toolkit version with modifications described in Section 3 and inputs described in the PSP scenario 38MMT_20210812_PSP_LSEplan_2020IEPR_2020IEPRHighEV. We only plan to study the years 2030, 2035, 2040 and 2045, so the LSEplan inputs are not critical. These inputs have been discussed with the CEC and external reviewers and some modifications have been made.

Table 2. 1 Summary of baseline for RESOLVE modeling

Model element	**Description**
Costs	PSP: 38MMT_20210812_PSP_LSEplan_2020IEPR_2020IEPRHighEV
Time resolution and time horizon	All 365 days using variable time step for capacity expansion and hourly time step to evaluate resource adequacy. Include 2030, 2035, 2040, and 2045.
Existing generators (all technologies except hydro)	PSP – Solar and wind profiles are used from 2007 with use of 2008 and 2009 available; the solar profiles were recalculated to reflect one-axis tracking with zero tilt
Hydro generators	Used fixed generation profiles instead of allowing these to be optimized[15]
Projected electricity demand	PSP but, for EV loads use the 2020 PATHWAYS High Electrification scenario for scaling and the 2021 IEPR profiles
Pumped Hydro	Turn off optimization and either make all built[16] or none built (only existing)
Transmission	PSP
Planning reserve margin	Do not include in analysis because it does not accurately represent how the grid will function if driven mostly by solar and other renewables working with storage

The PSP inputs were taken from the collection of input files shared by E3. Modifications made to these are described in Table 2.1 and in our previous reports.

As detailed in the introduction to Section 2, the Final Report will describe the effects of four sensitivities related to 1) EV charging profile shapes, 2) solar and wind generation profile shapes, 3) the use of key transmission corridors, and 4) the effect of using electrolyzers as a flexible load. However, we plan to study additional effects which will be published elsewhere – the details may be adjusted as we identify the results. The parameters that will be varied to explore key sensitivities using RESOLVE are listed in Table 2.2. These were selected to include the inputs we believe will have the greatest impact on how long-duration storage is used. EV:2020 PATHWAYS High Electrification is chosen for the growth of the EV load to reflect larger growth than the IEPR has predicted, as recommended by our Technical Advisory Committee. Three EV charging profiles are selected to reflect scenarios studied in the Assembly Bill 2127 study.

[15] See description of these in "EPC-19-06-Electricity Generation Technology Summary Task 3.3.pdf"

[16] See Table 2.2 in Draft Storage Technology Summary posted 11/10/2021 at https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-MISC

Table 2. 2 Variable ranges for RESOLVE modeling

Parameter	Low value	Baseline value	High value
EV charging profile	Not applicable	PSP	D-1 "Unconstrained" D-8 "EV Happy Hour" & D-3 "High Residential Access"[17]
South-facing solar	Not applicable	1-axis tracked, zero tilt	South-facing profiles (tracked and fixed)
Offshore wind	Not applicable	PSP	Lower cost or planned builds
Winter-dominant wind	Not applicable	PSP	Winter-dominant profiles
Electrolyzer	\$600/kW @ 2030 \$550/kW @ 2035 \$500/kW @ 2040 \$450/kW @ 2045 99% hydrogen price	No electrolyzer	\$400/kW @ 2030 \$300/kW @ 2035 \$200/kW @ 2040 \$150/kW @ 2045 99% hydrogen price
Constant generator such as nuclear, geothermal…	Not applicable	0 GW	5 GW
EV total load	IEPR 2021	EV: 2020 PATHWAYS High Electrification	Twice the baseline
Other loads		PSP	High heat pump
Carbon emissions cap	0 MMT by 2045 for CAISO 0 MMT WECC wide	38 MMT by 2030	Not applicable
Oxy-combustion	Not applicable	None	Oxy-combustion added

2.2 Baseline definition and sensitivities for SWITCH modeling

Table 2.3 summarizes the baselines that will be used in SWITCH.

[17] TN238853_20210714T100900_Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment Anal

Table 2. 3 Summary of baseline for SWITCH modeling

Costs	National Renewable Energy Laboratory Annual Technology Baseline 2020[13]
Existing generators (all technologies)	Energy Information Administration Form 860, all existing generators in the WECC
Candidate solar technologies	Residential PV (rooftop PV on homes), Commercial PV (rooftop PV on commercial buildings), Central PV (utility-scale), and Concentrating Solar Power with and without storage (solar thermal trough systems with or without thermal energy storage). Available land and capacity for Central PV and Concentrating Solar Power candidate generators were screened based on land exclusion criteria (including national parks, wildlife areas, and steep terrain), solar insolation from the System Advisor Model from the National Renewable Energy Laboratory
Candidate wind technologies	Onshore and offshore wind from 3TIER Western Wind and Solar Integration Study dataset. selection of prime sites based on criteria including high wind energy density, and proximity to transmission.[2] A portion of candidate generators were screened out in California if they were in "Category 3, high environmental risk" locations, which include areas legally excluded for development, protected areas with ecological or social value, conservation regions, and prime agricultural land.[9]
Planned hydropower plants	
Electricity demand	The future load represents a case of high energy efficiency and building electrification, as well as increased adoption of Zero Emissions Vehicles (ZEVs), primarily from electric vehicles.[4] The load forecast achieves a doubling of the rate of energy efficiency by 2030 in California, compliant with the state's SB 350 legislative targets, aggressive building electrification starting in 2020, growing industry electrification, and approximately 125,000 GWh in electricity demand from transportation. Hourly demand profiles from 2006 (consistent with the weather-year used for calculating solar and wind capacity factors) from FERC Form 714 and a dataset procured from ITRON were used as a base from which demand projects (residential, commercial, industrial, transportation) were created and scaled by sector to meet states' policy targets and reflect population growth.[17]
Carbon cap	Zero emissions by 2050
RPS	All current mandates for all states in the WECC
Time resolution and time horizon	All 365 days in 2050. Sampling hours every 4 hours per day.

The parameters that will be varied to explore key sensitivities by SWITCH are listed in Table 2.4. These were selected to include the inputs we believe will have the greatest impact on how long-duration storage is used.

Table 2. 4 Scenarios for sensitivity analysis

Topic	SWITCH WECC
Varying costs of long duration energy storage (LDES)	Yes (study #1)
Transmission	
LDES technology clusters (Table 2.3)	Yes (study #2)
Value and LDES need depending on how much CA can rely on imports from the rest of the WECC	Yes (study #3)
Wind or solar dominant grids and LDES need:	Yes (study #1)
Cost savings in electricity prices from LDES energy capacity mandates	Yes (study #1)
Hydrogen and LDES	Yes (study #5)
Transmission deployment and impact on LDES	Yes (study #1)
Reserves and impact on LDES needs	Yes (study #4)
Hydropower availability and impact on storage	Yes (study #1)

2.3 Matrix of long-duration storage options

The parameters that will be used to describe candidate long-duration storage resources are listed in Table 2.5. The costs for these candidate resources will be varied to identify the cost reduction that is needed to motivate adoption of the candidate resource by the model. The table describes a total of 16 possible long-duration storage candidates. We will select candidates from these. Those that are selected in a favorable price range will be widely explored for the multiple scenarios. Those that are not selected by the model may be omitted so that the results of the modeling are most useful.

Table 2. 5 Minimum matrix of long-duration storage technologies

Efficiency	Duration (h)	Relevant technologies
80%	8, 12, 100	Pumped hydro, gravity, flow battery
70%	8, 12, 100	Geomechanical, flow battery, metal-air, exfoliated-metal, gravity
60%	8, 12, 100	Flow battery, metal-air, exfoliated-metal, compressed air, liquid air, thermal
50%	8, 12, 100	Thermal, hydrogen
30%	12, 100	Thermal, hydrogen

2.4 Analysis of RESOLVE inputs in the new-modeling-toolkit

The new implementation of RESOLVE in the new-modeling-toolkit uses a set of scenario tags to select which inputs are used. We are using many of those, but also modifying some. Table 2.6 summarizes the tags and how they are used. The lines in blue at the bottom of the table identify scenario tags added for our specific implementation.

Table 2. 6 Scenario tags defined in PSP baseline in the new-modeling-toolkit

Tag name	Implementation	Profiles identified by this tag
base	Used in many places to define baseline	
Baseline: CEC 2020 IEPR - Mid Demand	Defines the baseline (before adjustments) CAISO load using energy scaling with increases every year. (Power scaling is an option) 252 TWh in 2030; 274 TWh in 2045	CAISO Baseline-rep-period-workaround.csv
EV: CEC 2020 IEPR - Mid Demand	10.7 TWh in 2030; 30.5 TWh in 2045 for light-duty EV charging	iepr-LIGHT_EV-modeled-year.csv
	1.01 TWh in 2030; 11.9 TWh in 2045 for medium- & heavy-duty EV charging	iepr-MEDIUM_HEAVY_EV-modeled-year.csv
	0.164 TWh in 2030; 1.92 TWh in 2045 for bus charging	electric-buses-month-hour.csv
Other TE: CEC 2020 IEPR - Mid Demand	1.55 TWh in 2030; 13.1 TWh in 2045 for other EV charging	iepr-MEDIUM_HEAVY_EV-modeled-year.csv
BE: None Through 2030	Commercial cooking 0 in 2030; 4.49 TWh in 2045	BaseCommercialCookingCEC IOU-month-hour.csv
	Commercial space heating 0 in 2030; 2.67 TWh in 2045	BaseCommercialSpace HeatingE3 RESHAPE-month-hour.csv
	Commercial water heating 0 in 2030; 7.13 TWh in 2045	BaseCommercialWater HeatingE3 RESHAPE-month-hour.csv
	Residential cooking 0 in 2030; 3.64 TWh in 2045	BaseResidentialCookingCEC IOU-month-hour.csv
	Residential space heating 0 in 2030; 7.96 TWh in 2045	BaseResidentialSpace HeatingE3 RESHAPE-month-hour.csv
	Residential water heating 0 in 2030; 11.6 TWh in 2045	BaseResidentialWater HeatingE3 RESHAPE-month-hour.csv
	Residential clothes drying 0 in 2030; 2.45 TWh in 2045	BaseResidentialClothes DryingCEC IOU-month-hour.csv
Hydrogen: No Hydrogen	Not used	
BTM CHP: CEC 2020 IEPR	Planned installed behind-the-meter of combined heat and power. -11.56 GWh in 2030; 0 in 2040. Non-PV, non-CHP self-generation: -0.46 TWh in 2030; -0.67 TWh in 2045	CAISO Baseline-rep-period-workaround.csv
TOU: CEC 2020 IEPR	Changes to load from TOU rates: 0.12 TWh for all years after 2030	iepr-TOU_IMPACTS-modeled-year.csv
EE: CEC 2020 IEPR - Mid-Mid AAEE	Reductions in load - energy efficiency -10.2 TWh in 2030; -28.7 TWh in 2045	iepr-AAEE-modeled-year.csv
SB 100	Sets RPS target 120 TWh in 2030; 229 TWh in 2045	
Unspecified Carbon Adder - Low	Not used	
2021_PSP_22_23_TPP	Sets the costs and capacity build limits for solar, wind, and batteries	
2021_PSP_22_23_TPP_ITC_ext	Reduces costs for 2030-2035 for offshore wind to reflect the extended Investment Tax Credit	
PRM - Mid (MTR)	Not used	
38 MMT by 2030 statewide	Sets greenhouse gas emissions targets 31.3 MMT in 2030; 12.2 MMT 2045	

BTM PV: CEC 2020 IEPR - Mid PV + Mid-Mid AAPV	Defines the planned installed capacity of behind-the-meter PV. 21.1 GW in 2030; 34.9 GW in 2045	Customer_PV-rep-period-workaround.csv
BTM Storage: CEC 2020 IEPR	Planned installed capacity of behind-the-meter storage. 2584 MW after 2030	CAISO_BTM_Li_Battery.csv
UCM_Hydro_Dry	Selects generation profiles for dry years for all hydropower resources. The dispatch is not optimized when these profiles are used.	DRY-BANC_Hydro.csv DRY-CAISO_Hydro.csv DRY-IID_Hydro.csv DRY-LDWP_Hydro.csv DRY-NW_Hydro_for_CAISO.csv DRY-NW_Hydro.csv DRY-SW_Hydro.csv
PRM - None	Sets the planning reserve requirement to zero, effectively removing it	
OldPHS or WithNewPHS	Uses only existing PHS or does a planned build of new PHS by 2030 according to Table 4.1 in the "Storage Scenarios Summary Task 3.2" report	
1-axis-no-tilt	Selects solar profiles	Identifies UCM-generated solar generation profiles
4hLi	Sets lithium batteries to be 4-h batteries with a price that is $/kW + 4*$/kWh	
LDES	Allows the model to build 6 new long-duration energy storage (LDES) candidate resources	
LDES_8h, LDES_100h, etc.	Defines the duration of the LDES to be 8 h or another number	
LDEF80, LDEF70, etc.	Sets LDES efficiency to 80% or another number	
LD1, LD2, etc.	Used to vary the LDES cost	

The load profile used for the CAISO baseline load and to scale the behind-the-meter combined heat and power is shown in Fig. 2.1. Note that this shape matches the actual demand observed in 2007, 2008, and 2009, so matches the generation profiles defined for those same years. The total annual energy is shown in Fig. 2.2 and compared with the added electric vehicle (EV) load used in the 2020 IEPR.

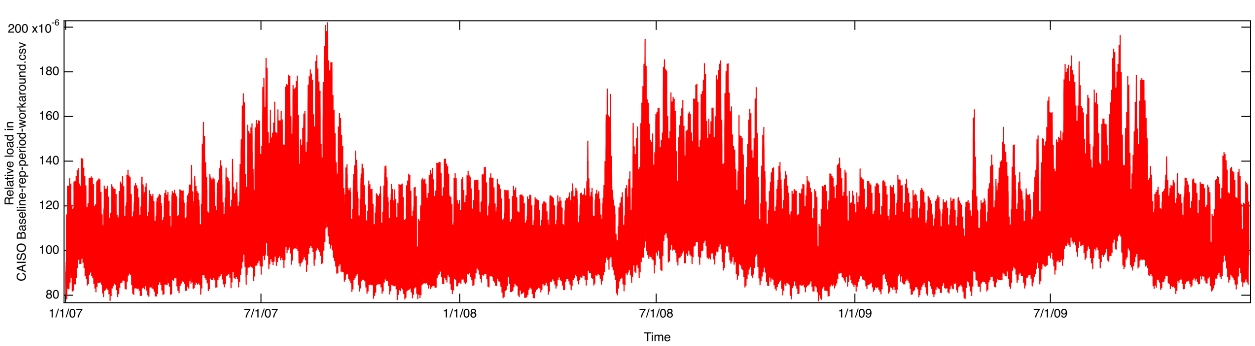

Fig. 2. 1 CAISO baseline load used to scale the behind-the-meter combined heat and power

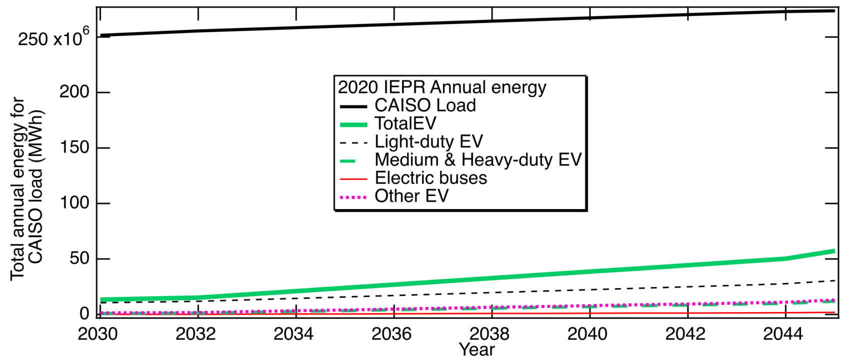

Fig. 2. 2 Total annual energy for CAISO load using Baseline: CEC 2020 IEPR – Mid Demand

The EV for electric bus charging is shown in Fig. 2.3. Previous years use the same shape as 2031 and 2032 and subsequent years use the shape shown for 2033 and 2034. The daily profile shape is shown in Fig. 2.4 along with the load shapes of other profiles (introduced next).

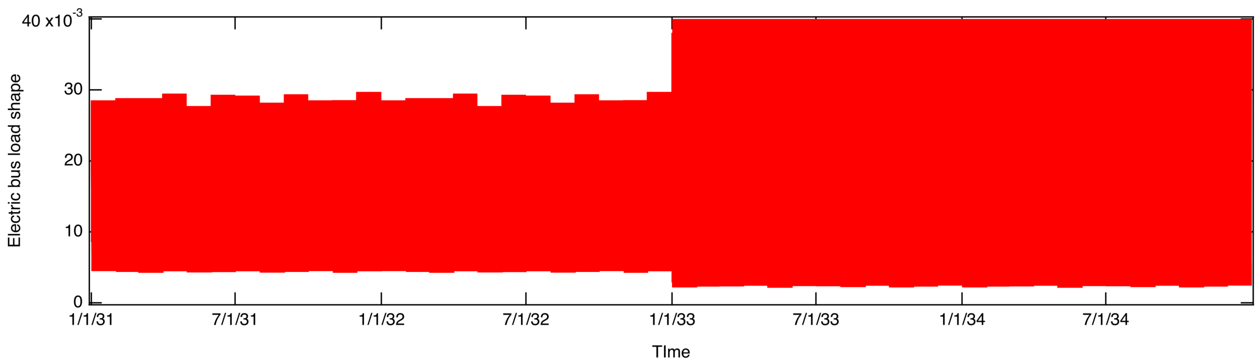

Fig. 2. 3 Relative profile for electric bus charging

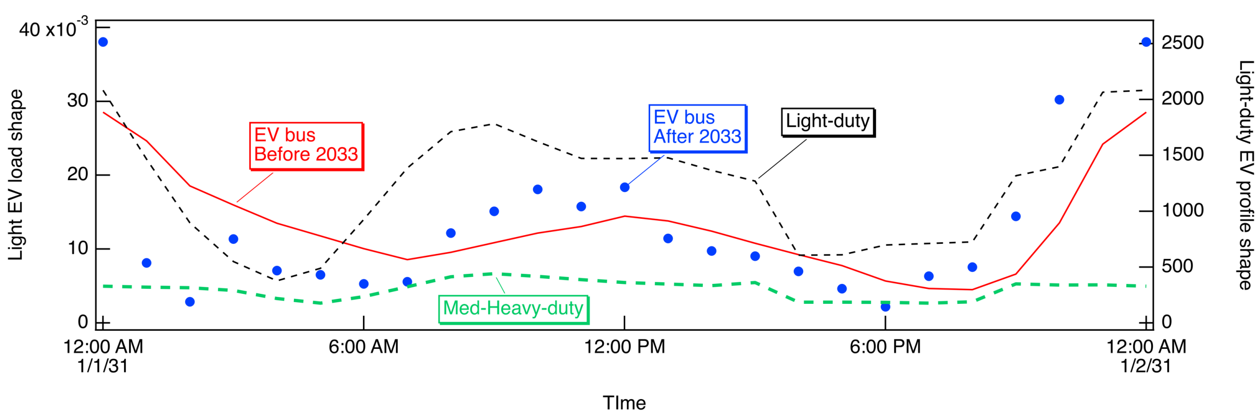

Fig. 2. 4 Daily (weekday) profile for EV charging of multiple types

The profile in iepr-LIGHT_EV-modeled-year.csv is shown in Fig. 2.5. The values increase to 2030, then are constant for each year after that. The data in Figs. 2.2-2.5 are taken from the 2020 IEPR. Updated values for the 2021 IEPR are discussed below.

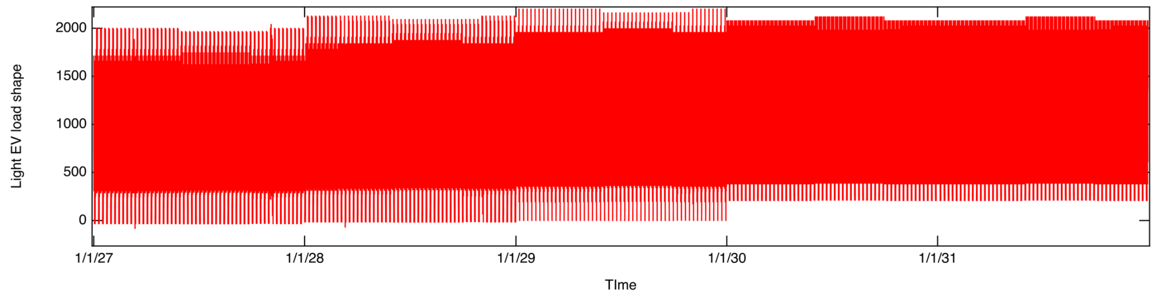

Fig. 2. 5 Light duty EV charging profile

The effects of anticipated time-of-use (TOU) rates have been estimated and are included in the new-modeling-toolkit in file "TOU_IMPACTS-modeled-year.csv". This profile is shown in Fig. 2.6 for one example year. The file includes data that differ for years before 2022, then repeat the 2022 year for subsequent years. The omission of a refinement of the extrapolation reflects the lack of clear information about planned revisions to TOU rates. It could be viewed as a major deficiency in the modeling. However, the shifting of load beyond what can be done today is captured by our modeling either by using alternative load profiles (which would occur because of the creation of TOU rates) or by the direct modeling of the short- and long-duration storage, which are the tools that would be used in response to the implementation of TOU rates. Thus, we suggest that our modeling may be used to define future TOU rates rather than trying to guess what those might be in advance, better reflecting the cost to the system.

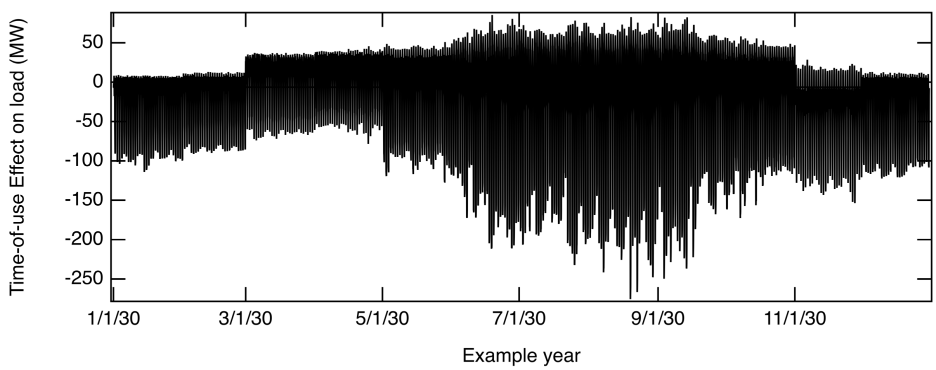

Fig. 2. 6 Effect of time-of-use rates on load. Profile repeats for later years

The energy efficiency profile is shown in Fig. 2.7. The profile increases before 2030, then repeats after that, as shown.

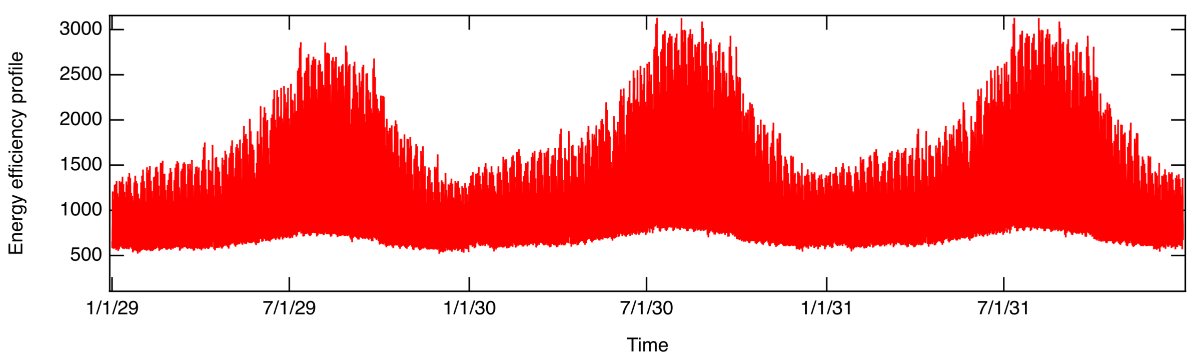

Fig. 2. 7 Profile for load reduction from improved energy efficiency

Also included in the new-modeling-toolkit data set are the 2020 IEPR – high and 2020 PATHWAYS – high demand scenarios. The annual EV loads for these scenarios are compared in Fig. 2.8. The integrated values for the 2021 IEPR profiles for 2030 and 2035 are included for reference, showing that the 2021 IEPR – mid values increased incrementally over the 2020 values.

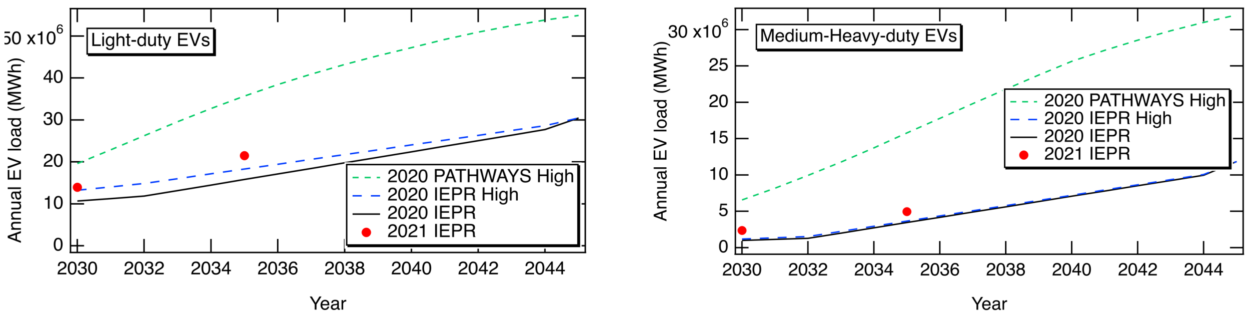

Fig. 2. 8 Annual EV charging loads in original new-modeling-toolkit

The 2021 and 2020 IEPR files created by E3 are compared in Table 2.7.

In Table 2.7, the selected implementation is indicated by bold green lettering. The reasoning behind the selections is described next. Orange lettering is used to indicate load profiles that may be considered for inclusion.

The BASELINE_NET_LOAD_203x.csv file combines the BTM_PV_2030.csv and BASELINE_CONSUMPTION_203x.csv profiles, simplifying the final calculation, so we will implement the 2021 IEPR files using the BASELINE_NET_LOAD files and delete BTM PV from the system description. The "managed" load discourages EV charging near sunset and assumes that EV charging at residences will be based on a timer that starts the charging at midnight. A comparison of the net load profile with and without the managed charging is shown in Fig. 2.9. We plan to vary the EV charging load profiles deliberately. Adjusting the load itself for modified EV charging will complicate the interpretation of the study, so we choose to stay with the BASELINE_NET_LOAD profile.

Table 2. 7 Comparison of IEPR 2020 and 2021 files created by E3 in RESOLVE format

IEPR 2020				IEPR 2021 implementation			
Tag name	**2030 (TWh)**	**2045 (TWh)**	**IEPR 2020 files**	**Tag name**	**IEPR 2021 files**	**2030 (TWh)**	**2035* (TWh)**
Baseline: CEC 2020 IEPR - Mid Demand	252	274	CAISO Baseline-rep-period-workaround.csv		BASELINE_CONSUMPTION_2030.csv BASELINE_CONSUMPTION_2035.csv	278	300
See note				2021 IEPR - UCM	BASELINE_NET_LOAD_2030.csv **BASELINE_NET_LOAD_2035.csv**	237	248
					MANAGED_NET_LOAD_2030.csv MANAGED_NET_LOAD_2035.csv	231	239
					UNADJUSTED_CONSUMPTION_2030.csv UNADJUSTED_CONSUMPTION_2035.csv	249	260
EV: CEC 2020 IEPR - Mid Demand	10.7	30.5	iepr-LIGHT_EV-modeled-year.csv	2021 IEPR - UCM	LIGHT_EV_2030.csv **LIGHT_EV_2035.csv**	14.0	21.5
	1.01	11.9	iepr-MEDIUM_HEAVY_EV-modeled-year.csv	2021 IEPR - UCM	MEDIUM_HEAVY_EV_2030.csv **MEDIUM_HEAVY_EV_2035.csv**	23.7	49.7
	0.164	1.92	**electric-buses-month-hour.csv**				
Other TE: CEC 2020 IEPR - Mid Demand	1.55	13.1	**iepr-MEDIUM_HEAVY_EV-modeled-year.csv**				
BE: None Through 2030	0	4.49	**BaseCommercialCookingCEC IOU-month-hour.csv**				
	0	2.67	**BaseCommercialSpace HeatingE3 RESHAPE-month-hour.csv**				
	0	7.13	**BaseCommercialWater HeatingE3 RESHAPE-month-hour.csv**				
	0	3.64	**BaseResidentialCookingCEC IOU-month-hour.csv**				
	0	7.96	**BaseResidentialSpace HeatingE3 RESHAPE-month-hour.csv**				

	0	11.6	**BaseResidentialWater HeatingE3 RESHAPE-month-hour.csv**				
	0	2.45	**BaseResidentialClothes DryingCEC IOU-month-hour.csv**				
BTM CHP: CEC 2020 IEPR	-0.012 -0.46	0 -0.67	**CAISO Baseline-rep-period-workaround.csv**				
TOU: CEC 2020 IEPR	0.12	0.12	iepr-TOU_IMPACTS-modeled-year.csv	2021 IEPR - UCM	TOU_IMPACTS_2030.csv **TOU_IMPACTS_2035.csv**	0.05	0.06
Additional achievable energy efficiency	-10.2	-28.7	iepr-AAEE-modeled-year.csv	2021 IEPR - UCM	AAEE_2030.csv **AAEE_2035.csv**	-10.3	-15.1
Additional achievable fuel substitution (new)					AAFS_2030.csv AAFS_2035.csv	3.5	5.9
BTM PV: CEC 2020 IEPR - Mid PV + Mid-Mid AAPV	21.1GW* 1769h/y =37.3 TWh	34.9	Customer_PV-rep-period-workaround.csv		BTM_PV_2030.csv BTM_PV_2035.csv	-41.1	-52.2
BTM Storage: CEC 2020 IEPR	2584 MW	2584 MW	CAISO_BTM_Li_Battery.csv gives **provide_power_potential=1**		BTM_STORAGE_NONRES_2030.csv BTM_STORAGE_NONRES_2035.csv BTM_STORAGE_RES_2030.csv BTM_STORAGE_RES_2035.csv	0.136 is net	0.202
Climate change					CLIMATE_CHANGE_2030.csv CLIMATE_CHANGE_2035.csv	0.59	0.91
Other					OTHER_ADJUSTMENTs_2030.csv OTHER_ADJUSTMENTs_2035.csv	3.56	3.77
Water pumping Dept. Water Res.					PUMP_DWR_2030.csv PUMP_DWR_2035.csv	6.96	6.96
Water pumping Municipal Water					PUMP_MWD_2030.csv PUMP_MWD_2035.csv	1.86	1.86

					VEA_LOAD_2030.csv VEA_LOAD_2035.csv	0.71	0.76

* The 2021 IEPR files are only defined for 2030 and 2035, while the new-modeling-toolkit included estimates to 2045.
Note: The net load combined with the BTM PV gives the total load, so implementation may choose to simplify by using net load and omitting the calculation of the BTM PV.

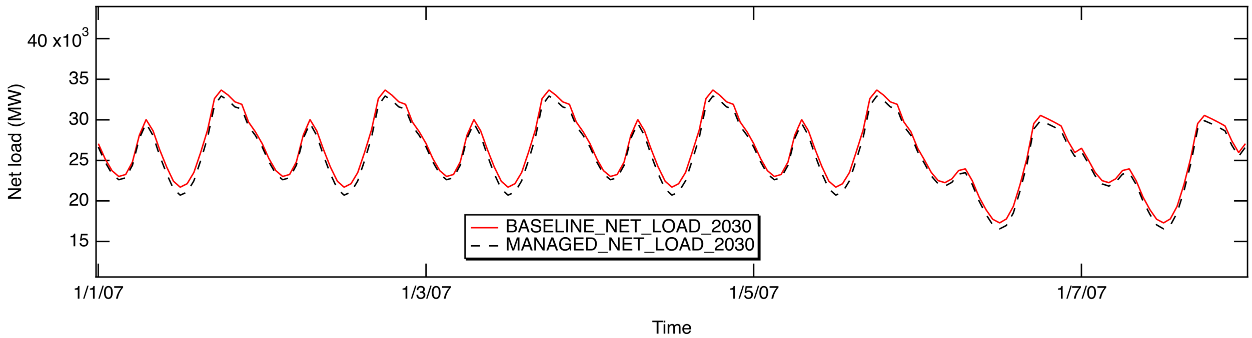

Fig. 2. 9 Comparison of net load with and without managed charging

The profiles for the EV charging in the 2020 and 2021 IEPRs are compared in Fig. 2.10, showing that the scaling has changed, but the shape has been kept the same. Nevertheless, for consistency, we will use the 2021 IEPR 2030 and 2035 profiles for the light-duty EV charging, continuing the use of the 2035 profile for 2040 and 2045. In every case, we will use scaling indicated by the 2020 PATHWAYS HIGH scenario tag, see Fig. 2.8.

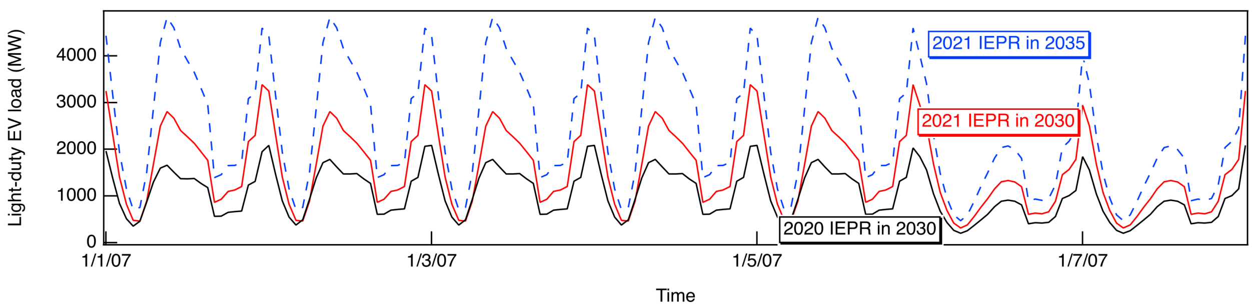

Fig. 2. 10 Light-duty EV profile shape from 2020 and 2021 IEPR

For aspects of the 2021 IEPR that did not change significantly we will retain the inputs used in the PSP. (see Table 2.7)

The Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment – Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 (Commission Report) studied multiple EV charging load shapes. Their 11 charging profiles are summarized in Fig. 2.11. Of these, the CEC has directed that we base our sensitivity analysis on 3 of them:

- D-1 Unconstrained: the charging is mostly initiated at the end of the workday
- D-8 Happy Hour: charging is mostly during the day, with some charging starting at midnight
- D-3 High Residential Access: emphasizes nighttime charging.

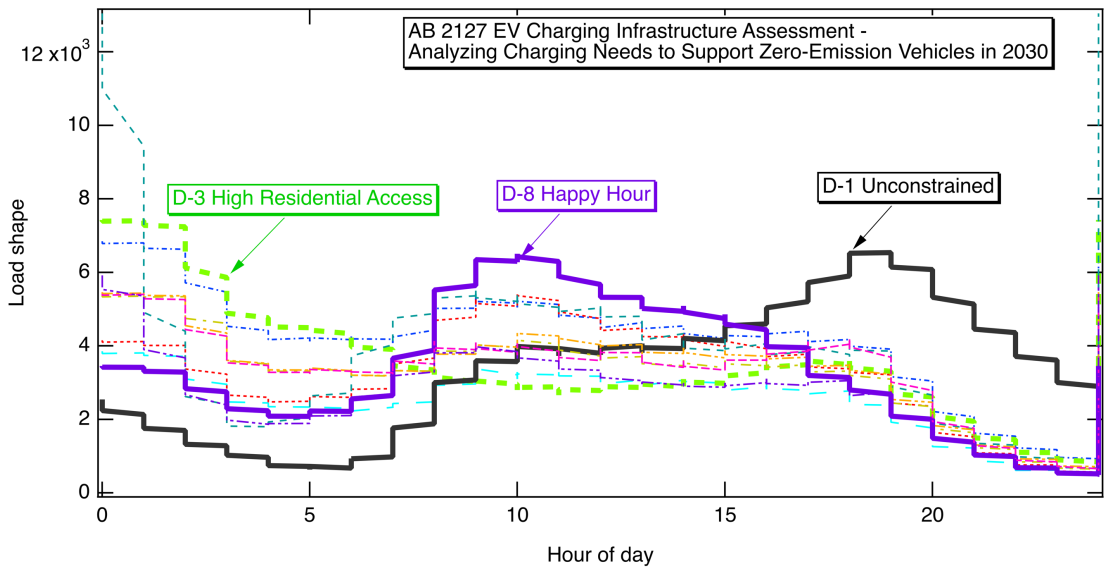

Fig. 2. 11 EV charging load shapes summarized for AB 2127

Based on this analysis, we suggest that the final report should focus on the baseline and scenarios defined in Tables 2.8 and 2.9.

Table 2. 8 Baseline scenarios for final analysis

Software	Description
RESOLVE	Use the Preferred System Portfolio with 2021 IEPR loads[18] and additional modifications described in the Grid Scenario Analysis, Table 2.1
SWITCH	As defined in Grid Scenario Analysis, Table 2.3.

Table 2. 9. Sensitivity scenarios to be studied

Topic	Description	Software
EV Charging	Evaluate the effect of increased EV charging on the need for long-duration energy storage using scenarios D-1, D-8 and D-11 taken from California studies like the AB 2127 EVI PRO report[19]	RESOLVE
Generation profiles	Evaluate the impact of using solar and wind generators designed for higher output during the winter on the need for long-duration energy storage	RESOLVE
Transmission	Explore key transmission corridors for decarbonized WECC and California by capping the expansion of transmission (varying the cap). This will enable us to understand how different transmission corridors should be prioritized for their expansion.	SWITCH
Electrolyzers as flexible loads	Evaluate the potential for electrolyzers to reduce the need for long-duration storage by acting as a flexible load while supplying hydrogen for transportation, industrial and other applications	TBD

[18] https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2021-integrated-energy-policy-report

[19] Electric Vehicle Charging Infrastructure Assessment – AB 2127 – Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030 (Commission Report). https://www.energy.ca.gov/programs-and-topics/programs/electric-vehicle-charging-infrastructure-assessment-ab-2127 with tables in https://efiling.energy.ca.gov/getdocument.aspx?tn=238851.

3. Documentation of Critical Time Steps implementation

We model 365 days of timepoints using weather data (including associated load shapes) from 2007, 2008, and 2009, but load sizes extrapolated to 2030, 2035, 2040, and 2045. We use variable time steps - selecting the critical time steps as one hour after sunrise and one hour before sunset. In this section we analyze the results of this approach specifically for the years 2031 (when little storage is selected) and 2045 (when the grid is largely dependent on solar and batteries) using the critical time steps identified for a 2045-like year. A more comprehensive study has been submitted for journal publication. These data were calculated before the baseline scenario was finalized, so reflect some small differences.

The 38MMT-PSP-benchmarking (PSP) scenario is used with weather data from 2007 for the results presented here. Later we will implement the calculations for other years of weather data. The procedure for modifying the PSP scenario to use variable timesteps requires several steps. The procedure starts with revisions to the settings files, described here as steps Prep-1 through Prep-4, then continues with subsequent calculations, described here as

1. Step 1 calculates the capacity-expansion plan (CTS-1 & CTS-2) [may be done for multiple modeled periods – for example, 2030, 2035, 2040, and 2045]
2. Step 2 calculates the hourly dispatch (hd-1 & hd-2) [is done for each period separately]

If the capacity-expansion plan is the end goal, then step 2 is not needed, greatly reducing the time for calculations.

Purpose of Prep steps – convert an existing “settings” folder (or a copy of one) to run an 8760-hour simulation. For our example, we have duplicated the settings folder called “38MMT-PSP-benchmarking”; we chose “38MMT-PSP-benchmarking-2007” as the name for the new settings folder, but any name may be used. All of the steps below are working within this folder.

Prep-1. Modify the temporal_settings/attributes.csv file to specify

timestamp	attribute	value
None	representative_periods_method	manual
None	representative_periods_amount	1
None	representative_periods_duration	365D
None	allow_inter_period_dynamics	FALSE

Also, the desired modeled_years are selected. For the results presented here, we have used 2031 or 2045.

Prep-2. Replace the temporal_settings/rep_periods.csv file with a file that lists a single rep period that includes the 8760 hours in 2007. The first few entries in that table are shown here:

period	0	1	2	3	4	5
1	1/1/07 0:00	1/1/07 1:00	1/1/07 2:00	1/1/07 3:00	1/1/07 4:00	1/1/07 5:00

We used period “1” but any number can be used as long as it matches the number used in step Prep-3.

Prep-3. Replace the temporal_settings/map_to_rep_periods.csv file and the temporal_settings/rep_period_weights with

period	0
1	1

making sure that the first column matches the first column in step Prep-2, as indicated by green lettering here.

Prep-4. In the scenarios.csv file delete any scenario tags that are related to 37-day operation (unless it is using a feature that is desired for your calculation). Then, add a scenario tag as a basis for identifying this series of scenarios. The value should be relatively short because it will be incorporated into the names of some files. For this set example we selected "PSP_test2007"

scenarios
base
… other lines
PSP_test2007

The Settings files resulting from the above 4 changes can be run directly in RESOLVE; the 2-step (including 1. Capacity expansion using the critical time steps and 2. Hourly dispatch using the step-1 capacity expansion plan) calculation for a single modeled year typically requires between 1-6 hours to complete, depending on the hardware.

Once the four preparatory steps are completed, the resulting files become the basis for further calculations and may be used for different modeled years, different critical time steps, or other changes. Although changes can be made to the _CTS scenario without updating the original 4 preparatory steps, if the CTS calculation to calculate the grid expansion plan is meant to be followed by the hourly dispatch calculation, it may be useful to revise the original files because the _hd calculation duplicates the original settings files and will not reflect changes made to the CTS settings files.

For the Critical Time Steps calculation using specific inputs (note that these are not easily tracked without creating a new set of Settings files with a different name), the following additional steps are taken

Step #1: Capacity expansion calculation

CTS-1. A python code (currently named "critical-time-points-parser.py") is run. If executing from a terminal in "Notebook/KurtzFileParser" folder, the relevant command is
"python critical-time-points-parser.py 38MMT-PSP-benchmarking-2007" if our example name is used.
This code:
a) Creates a new Settings folder with "_CTS" appended to the original settings folder name (duplicates that folder with all of the internal files).
b) Substitutes a prewritten file for the temporal_settings/rep_periods.csv file (this file identifies 2 critical hours during each day that characterize when we expect the storage to be at the lowest (hour after sunrise) and highest (hour before sunset) energy levels.)

c) Adds a new Scenario tag in the scenarios.csv file to flag these for the "_CTS" calculation
d) Recalculates the generation and load profiles to provide average values during each of the time intervals, stores these in the profiles folder, and points to these profiles using the "_CTS" scenario tag.

CTS-2. The resulting settings/scenario is optimized by RESOLVE using the command (from the new_modeling_toolkit/resolve folder): "caffeinate python run_opt.py 38MMT-PSP-benchmarking-2007_CTS --solver-name gurobi --log-level" For one modeled year, this takes about 10 minutes to run. These results are "First step of optimization."

Step #2: Hourly dispatch calculation

hd-1. A python code (currently named "Part_2_for_hourly_dispatch_files.py python") is run. Again, working from "Notebook/KurtzFileParser" folder, the relevant command is "python Part_2_for_hourly_dispatch_files.py --resolve-settings-name 38MMT-PSP-benchmarking-2007". It consults the results from CTS-2 and turns off RESOLVE's selection of the optimal build, replacing it with direction to build the expansion that was optimized in CTS-2. The python code identifies the input files for all of the assets identified for CTS-2 and makes the appropriate changes, flagging them with a scenario tag that ends in "_hd". Specifically, the steps include:
a) Creates a new Settings folder with "_hd" appended to the original settings folder name. (duplicates the original settings folder with all of the internal files).
b) Sets the "can_build_new" attribute to "0" for all of the candidate resources and adds directive for planned installation instead. To avoid infeasibility issues, several other changes are made as well.
c) Resets the scenario tags to use the 8760-hour profiles instead of the _CTS profiles
d) Adds a scenario tag (ending in "_hd") in the scenarios.csv file. The same scenario tag is used where needed to flag the desired scenario.

hd-2. The resulting settings/scenario is optimized for its hourly dispatch using all 8760 hours of the year by RESOLVE using the command (executed from the new_modeling_toolkit/resolve folder): "caffeinate python run_opt.py 38MMT-PSP-benchmarking-2007_hd --solver-name gurobi --log-level INFO --raw-results." For one modeled year, this takes about an hour to run, depending on the hardware.

The details of the codes described in CTS-1 and hd-1 are quite involved and are best understood by looking at the python code (available on request).

The results of implementing this process are evaluated in the rest of this chapter. Please note that as we have been running the code and identifying pain points in the length of time it takes to run, we have been tweaking the code, so there may be some inconsistencies in the length of time documented for each to run. The times can also depend on whether the computer is being used for other tasks.

3.1 Implementation of Critical Time Steps modeling for 2045

In Table 3.1, we compare the results for the build-out and the hourly dispatch when both are optimized simultaneously and in the two-step process described above. The objective function values are calculated to be within 2% for the 8760-hour and CTS simulations summarized in Table 3.1. There are more substantial differences in the specifics of the build outs. Most notably, the energy selected for the storage build out is about 10% less for the CTS calculation. This may reflect imperfection in the selection of the critical times when the storage will be full and empty.

These results can be better understood through the comparison of the state of charge of the storage resources for the simultaneous and two-step optimizations as shown in Fig. 3.1. The data calculated for Fig. 3.1 reflect an updated set of critical time steps. The data are similar for the two simulations, though it appears that the details differ slightly.

Table 3. 1 Build out selected for PSP 8760-hour, Critical Time Steps, and hourly dispatch data sets for 2045

Output metric	Simultaneous optimization	First step of optimization	Second step of optimization
Objective function	46.145×10^9	45.258×10^9	27.692×10^9
Run time for calculation	4 h 30 min	10 min	1 h 7 min
Battery build	33740 MW	32786 MW	32786 MW
Solar build	49301 MW	49595 MW	49595 MW
Wind build	2563 MW	2453 MW	2453 MW
CCGT build	3657 MW	3261 MW	3261 MW
Shed build	441 MW	1111 MW	1111 MW
Geothermal build	102 MW	102 MW	102 MW
Pumped storage build	267 MW	0 MW	0 MW
Offshore wind build	1382 MW	1382 MW	1382 MW
Total build MW	91453 MW	90691 MW	90691 MW
Battery energy build	212814 MWh	195038 MWh	195038 MWh
Pumped hydro energy build	1947 MWh	0 MWh	0 MWh
Total storage build	214762 MWh	195038 MWh	195038 MWh

Simultaneous optimization data from 2022-06-18 11-23-16 (PSP 2007 package)
First step of optimization data from 2022-06-18 20-30-25 (PSP 2007 package) (CTS-2)
Second step of optimization data from 2022-06-20 21-55-27 (PSP 2007 package) (hd-2)
(the objective function for the second step doesn't include the planned builds so it is substantially lower than the others)

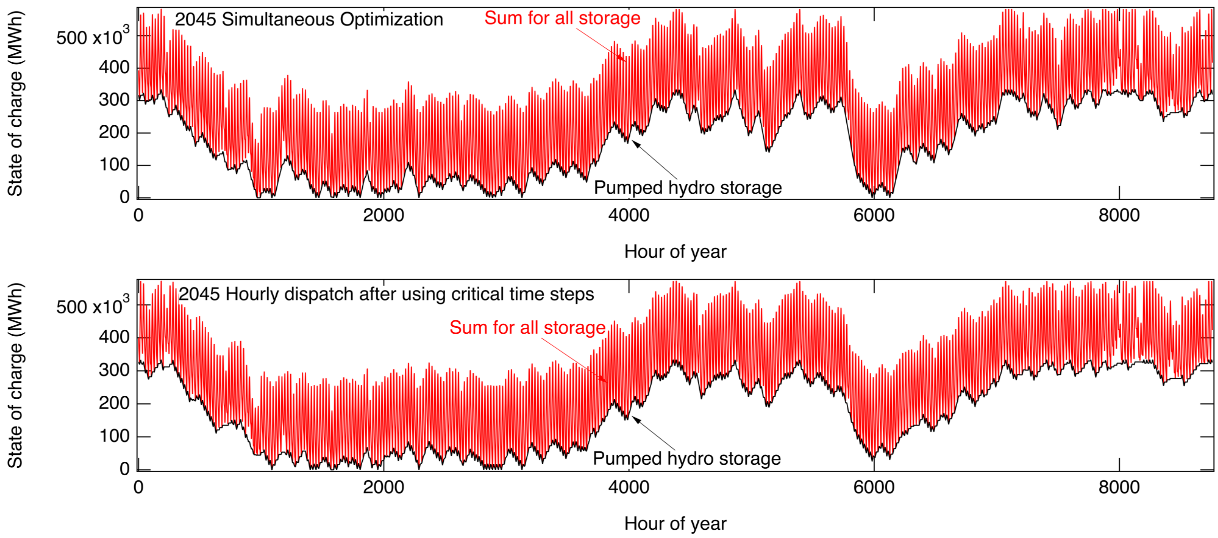

Fig. 3. 1. Comparison of simultaneous and two-step optimization for 2045

Simultaneous optimization data from 2022-06-18 11-23-16 (PSP 2007 package)
Hourly dispatch data from 2022-06-29 20-27-01 (PSP 2007 package) (hd-2)

3.2 Implementation of Critical Time Steps modeling for 2031

As for the data presented in 3.1, we compare the results for 2031, when the build out of solar and storage is much less, thereby influencing the critical time steps. These data are summarized in Table 3.2 and Fig. 3.2. In our submitted paper, this comparison was updated.

Table 3. 2 Build out selected for PSP 8760-hour and Critical Time Steps data sets for 2031

Output metric	Simultaneous optimization	First step of optimization
Objective function	50.054×10^9	45.671×10^9
Run time for calculation	1 h 28 min	8.5 min
Battery build	16525 MW	17563 MW
Solar build	11345 MW	13415 MW
Wind build	1040 MW	1040 MW
CCGT build	0 MW	0 MW
Shed build	441 MW	441 MW
Geothermal build	102 MW	102 MW
Pumped storage build	0 MW	0 MW
Offshore wind build	1426 MW	188 MW
Total build MW	30879 MW	32749 MW
Battery energy build	66078 MWh	70229 MWh
Pumped hydro energy build	0 MWh	0 MWh
Total storage build	66078 MWh	70229 MWh

Simultaneous optimization data from 2022-06-20 13-07-41
First step of optimization data from 2022-06-19 11-05-43 or 2022-06-20 16-24-21
Second step of optimization data from 2022-06-20 16-34-19

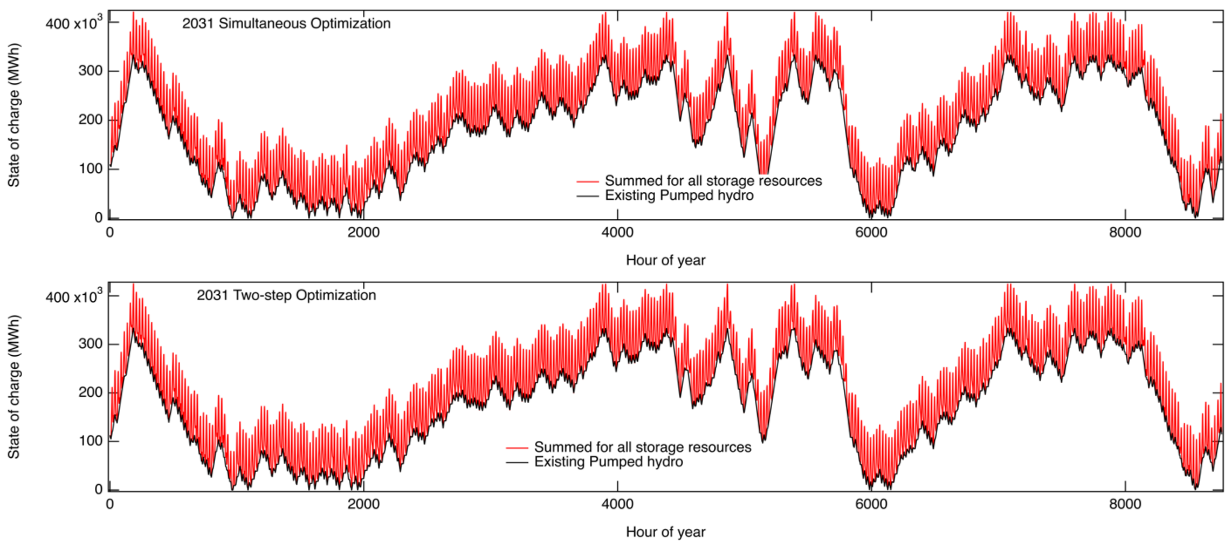

Fig. 3. 2. Comparison of simultaneous and two-step optimization for 2031
Simultaneous optimization data from 2022-06-20 13-07-41
Two-step optimization data from 2022-06-20 16-34-19

The similarity of the two approaches in terms of the charge state calculated for the storage is quite striking. This is especially remarkable because the capacity expansion plan is calculated in the first step of the two-step process in just 8.5 min compared with the 1 h 28 min calculation for the simultaneous optimization. The second step of the optimization process in this case took 45 min, implying that the 2-step process can be completed in under an hour for a single year, about 2/3 of the time of the simultaneous optimization. The advantage for simulations calculating for multiple years will be greater, especially given that it is often sufficient to do the first step of the optimization to identify the needed capacity expansion plan. When RESOLVE is run for 37 representative days, it is not standard practice to attempt to create the sort of graphs shown in Figs. 3.1 and 3.2, though the new version of new-modeling-toolkit constructs a full 3-year sequence of simulated days. Thus, if used in the same mode as RESOLVE has been used historically, we only need the first step, shortening the time by about a factor of 10, thereby enabling 10 times as many simulations to be run.

We propose to use this documented approach as an efficient way to model 365 days in RESOLVE for each of 2030, 2035, 2040, and 2045. The rapid turnaround enables exploration of a much broader parameter space.

3.3 Demonstration of the accuracy of the 2-point CTS approach

While the similarities of the results in Figs. 3.1 and 3.2 is encouraging, a question arises about how accurately the 2-point CTS approach will be at evaluating the adoption of long-duration energy storage. To test the accuracy relative to the hourly simulation, in Fig. 3.3 we compare the values obtained for a calculation of a 100-h storage product with 80% efficiency compared with a 4-h Lithium battery with 85% efficiency. We see that the CTS calculation systematically underestimates the 100-h storage product, but in terms of identifying the cost that must be reached for the 100-h product to compete with the 4-h product, the uncertainty is small compared to the question of whether we identify the cost needed to compete in terms of power or energy.

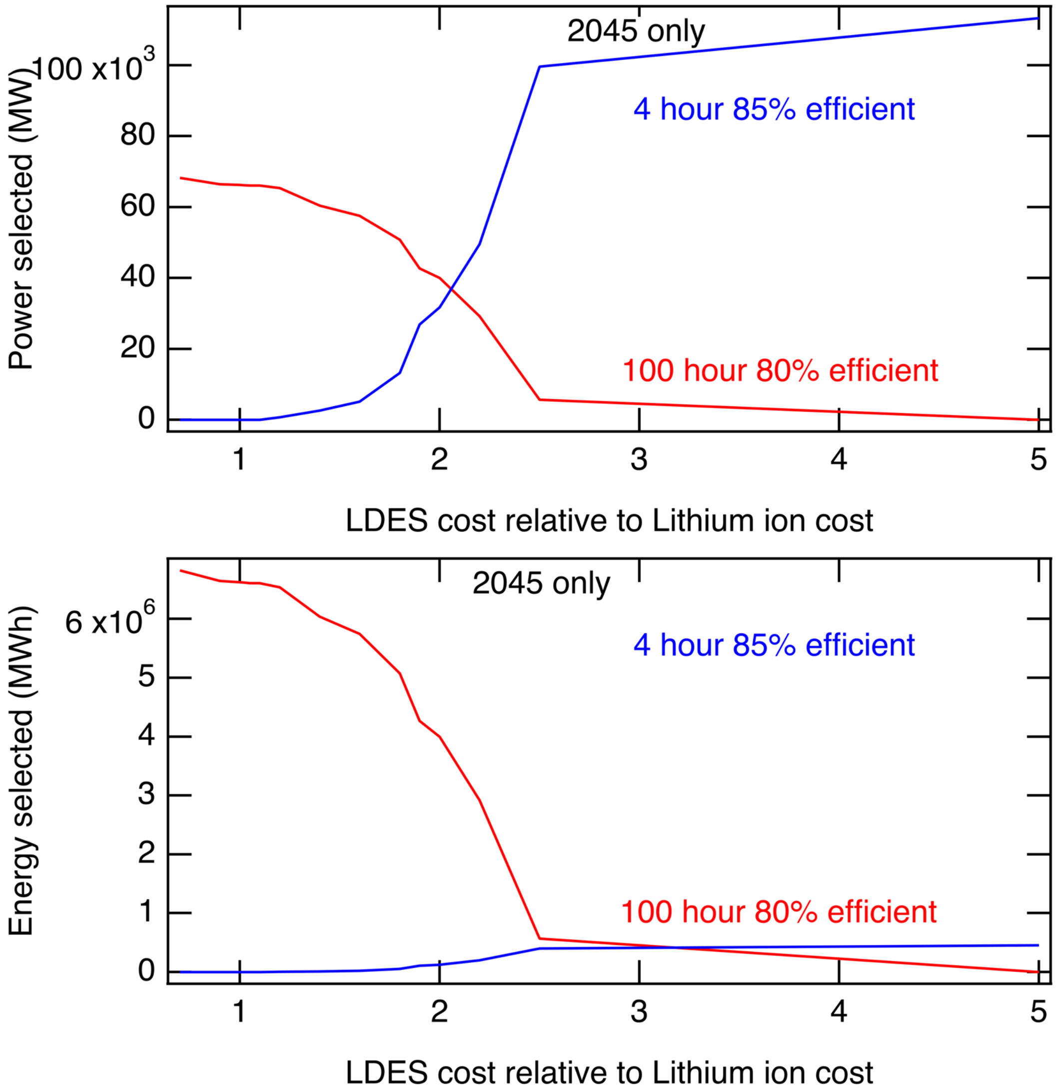

Fig. 3. 3 Comparison of results from the CTS and full calculations for 2045

4. Analysis of Changes to Baseline (PSP) Scenario

We listed the sensitivities we plan to study relative to the baseline scenario in Table 2.1. In this section, we document the impact of those changes. Specifically, we document the changes in the build out and state-of-charge of the storage when dispatched for the 8760 hours in a year. We anticipate that these changes may also affect the adoption of other types of long-duration storage, but that analysis will be done in the final evaluation.

4.1. Effects of solar generation profiles on RESOLVE model results

The PSP implemented in the new-modeling-toolkit shared in May 2022 includes 19 solar resources, as tabulated in Table 4.1. Of these 19 resources, nine (indicated in Table 4.1 by being in bold) are offered as candidate resources that can be built out. Of those nine resources, five are selected by the PSP to be built to 3 GW or more. Of these new profiles, the four in-state candidate solar resources are summarized in Table 4.2. We may compare the generation profiles by using the scenario tags that are indicated in Table 4.2.

The annual capacity factors calculated for the profiles for 2007, 2008, and 2009 are summarized in Table 4.2. For those with tilt, latitude tilt was assumed. The three new profiles for each location were calculated assuming a DC-to-AC ratio of 1.3 and an inverter efficiency of 96%. The data are relative to the AC rating rather than relative to the higher DC rating. The capacity factors for the fixed tilt are lower than those for the tracked profiles, as expected. The highest capacity factors are for the tracked orientation with tilt. Tight agreement for the capacity factors is expected and observed because these are mostly in California.

Table 4. 1 Solar resources selected by PSP

Resource name	Profile name – 37-days	Profile name - base	Operational in 2045 (MW)*
Arizona_Solar	**Arizona_Solar.csv**	**Arizona_Solar-rep-period-workaround.csv**	**292**
BANC_Solar_for_Other	BANC_Solar_for_Other.csv	BANC_Solar_for_Other-rep-period-workaround.csv	3747
CAISO_Solar_for_CAISO	CAISO_Solar_for_CAISO.csv	CAISO_Solar_for_CAISO-rep-period-workaround.csv	16405
CAISO_Solar_for_Other	CAISO_Solar_for_Other.csv	CAISO_Solar_for_Other-rep-period-workaround.csv	12
Distributed_Solar	Distributed_Solar.csv	Distributed_Solar-rep-period-workaround.csv	125
Greater_Kramer_Solar	**Greater_Kramer_Solar.csv**	**Northern_California_Ex_Solar-rep-period-workaround.csv**	**4149**
Greater_LA_Solar	**Greater_LA_Solar.csv**	**Tehachapi_Solar-rep-period-workaround.csv**	**3000****
IID_Solar_for_CAISO	IID_Solar_for_CAISO.csv	IID_Solar_for_CAISO-rep-period-workaround.csv	50
IID_Solar_for_Other	IID_Solar_for_Other.csv	IID_Solar_for_Other-rep-period-workaround.csv	116
Imperial_Solar	Imperial_Solar.csv	IID_Solar_for_Other-rep-period-workaround.csv	**0**
LDWP_Solar_for_Other	LDWP_Solar_for_Other.csv	LDWP_Solar_for_Other-rep-period-workaround.csv	3459
Northern_California_Solar	**Northern_California_Solar.csv**	**Northern_California_Ex_Solar-rep-period-workaround.csv**	**0**
NW_Solar_for_Other	NW_Solar_for_Other.csv	NW_Solar_for_Other-rep-period-workaround.csv	2600
Riverside_Solar	**Riverside_Solar.csv**	**IID_Solar_for_Other-rep-period-workaround.csv**	**21063**
Southern_NV_Eldorado_Solar	**Southern_NV_Eldorado_Solar.csv**	**IID_Solar_for_Other-rep-period-workaround.csv**	**7865**
Southern_PGAE_Solar	**Southern_PGAE_Solar.csv**	**Northern_California_Ex_Solar-rep-period-workaround.csv**	**2930**
SW_Solar_for_CAISO	SW_Solar_for_CAISO.csv	SW_Solar_for_CAISO-rep-period-workaround.csv	65
SW_Solar_for_Other	SW_Solar_for_Other.csv	SW_Solar_for_Other-rep-period-workaround.csv	1637
Tehachapi_Solar	**Tehachapi_Solar.csv**	**Tehachapi_Solar-rep-period-workaround.csv**	**6289****

*Bolded items are enabled to be selected by the model to build more. The amount selected depends on the scenario that is run.
**These resources are selected to build out to the limiting potential specified by the PSP.

Table 4. 2 Candidate solar resources and annual capacity factors of new generation profiles

Resource name	Profile name	Scenario tag	2007	2008	2009
Arizona_ Solar	Arizona_Solar-rep-period-workaround.csv_	base	31.2%	31.4%	31.3%
	Arizona_1axis_notilt_Solar.csv	1axis_notilt	30.0%	30.3%	30.1%
	Arizona_1axis_tilt_Solar.csv	1axis_tilt	32.1%	32.2%	32.2%
	Arizona_fixed_tilt_Solar.csv	fixed_tilt	26.1%	26.1%	26.2%
Distributed_ Solar	Distributed_Solar-rep-period-workaround.csv	base	21.4%	21.3%	21.1%
Greater_ Kramer_ Solar	Northern_California_Ex_Solar-rep-period-workaround.csv	base	28.3%	27.9%	27.6%
	Greater_Kramer_1axis_notilt_solar	1axis_notilt	33.4%	33.3%	32.9%
	Greater_Kramer_tracked_tilt_solar	1axis_tilt	35.7%	35.4%	35.1%
	Greater_Kramer_fixed_tilt_solar	fixed_tilt	28.2%	28.0%	27.8%
Greater_LA_ Solar	Tehachapi_Solar-rep-period-workaround.csv	base	32.8%	32.2%	32.0%
	Greater_LA_1axis_notilt_Solar.csv	1axis_notilt	33.5%	33.2%	32.8%
	Greater_LA_1axis_tilt_Solar.csv	1axis_tilt	35.7%	35.3%	35.0%
	Greater_LA_fixed_tilt_Solar.csv	fixed_tilt	28.2%	27.8%	27.7%
Imperial_Solar	IID_Solar_for_Other-rep-period-workaround.csv	base	31.3%	31.4%	31.3%
	Greater_Imperial_1axis_notilt_solar.csv	1axis_notilt	32.3%	32.5%	32.2%
	Greater_Imperial_1axis_tilt_Solar.csv	1axis_tilt	34.4%	34.6%	34.4%
	Greater_Imperial_fixed_tilt_Solar.csv	fixed_tilt	27.4%	27.4%	27.4%
Northern_ California_ Solar	Northern_California_Ex_Solar-rep-period-workaround.csv	base	28.3%	27.9%	27.6%
	Northern_California_1axis_notilt_Solar.csv	1axis_notilt	28.7%	28.4%	28.0%
	Northern_California_1axis_tilt_Solar.csv	1axis_tilt	30.7%	30.3%	29.9%
	Northern_California_fixed_tilt_Solar.csv	fixed_tilt	24.5%	24.2%	23.9%
Riverside_ Solar	IID_Solar_for_Other-rep-period-workaround.csv	base	31.3%	31.4%	31.3%
	Riverside_1axis_notilt_solar	1axis_notilt	32.1%	32.2%	31.8%
	Riverside_tracked_tilt_solar	1axis_tilt	34.3%	34.4%	34.1%
	Riverside_fixed_tilt_solar	fixed_tilt	27.3%	27.3%	27.1%
Southern_ NV_ Eldorado_ Solar	IID_Solar_for_Other-rep-period-workaround.csv	base	31.3%	31.4%	31.3%
	Southern_NV_Eldorado_1axis_notilt_Solar.csv	1axis_notilt	31.7%	32.0%	30.6%
	Southern_NV_Eldorado_1axis_tilt_Solar.csv	1axis_tilt	34.0%	34.1%	32.7%
	Southern_NV_Eldorado_fixed_tilt_Solar.csv	fixed_tilt	27.1%	27.2%	26.3%
Southern_ PGAE_Solar	Northern_California_Ex_Solar-rep-period-workaround.csv	base	28.3%	27.9%	27.6%
	Central_Valley_North_Los_Banos_1axis_notilt_Solar.csv	1axis_notilt	30.4%	29.6%	29.7%
	Central_Valley_North_Los_Banos_1axis_tilt_Solar.csv	1axis_tilt	32.6%	31.4%	31.6%
	Central_Valley_North_Los_Banos_fixed_tilt_Solar.csv	fixed_tilt	25.8%	24.8%	25.1%
Tehachapi_ Solar	Tehachapi_Solar-rep-period-workaround.csv	base	32.8%	32.2%	32.0%
	Tehachapi_1axis_notilt_solar.csv	1axis_notilt	33.7%	33.3%	32.9%
	Tehachapi_tracked_tilt_solar.csv	1axis_tilt	35.8%	35.2%	34.9%
	Tehachapi_fixed_tilt_solar.csv	fixed_tilt	28.3%	27.8%	27.6%

We compare the three solar generation profiles for the Riverside_Solar data in Fig. 4.1 to better understand the differences between the observed capacity factors and the seasonal variations. The fixed, south-facing tilt frequently reaches full output during the winter, but never during the summer, as expected. The one-axis tracked, no tilt system frequently experiences full output during the spring and early summer, but then droops as the temperature increases during the later summer and the sun is lower in the sky in the fall. The difference between the winter outputs is most obvious, while the difference in the summer outputs is more difficult to see because it is related to the hours of generation during the day (the tracked system has greater output in the early morning and late afternoon.)

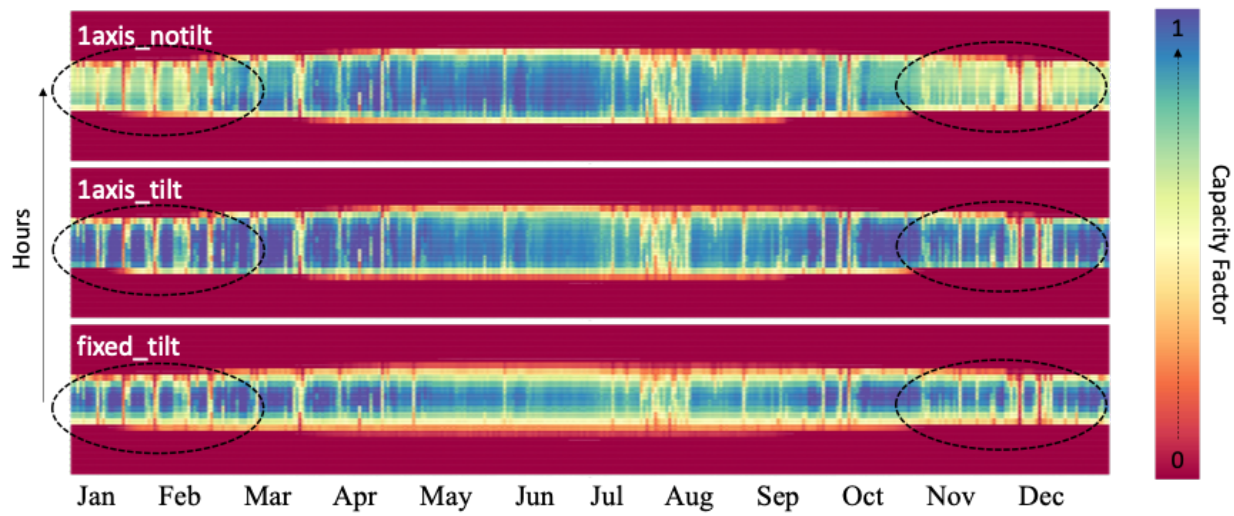

Fig. 4. 1 Comparison of solar generation profiles

We can easily select between using each set of profiles by selecting the desired scenario tag, as listed in Table 4.2 We have revised the resource files to add these scenario tags to point to the indicated profiles. In each case, most of the other attributes (build limits, etc.) of the indicated resource were kept. The primary exception was that for the fixed-tilt resources, we reduced the capex costs by 7% based on the analysis of Jones, et al[20] including a little additional for reduced maintenance costs. For the tracked-with-tilt profiles, we add 5% to the annualized cost. The cost assumptions are summarized in Table 4.3. We note that these cost assumptions will affect the results and should be evaluated further.

Table 4. 3 Relative Costs for Tilted Solar

Mounting configuration	Relative annualized cost (capex + O&M)	Scenario tag
One-axis-tracked, no tilt	1	1axis_notilt
One-axis-tracked, latitude tilt	1.05	1axis_tilt
Fixed, latitude tilt	0.93	fixed_tilt

4.2. Effects of large hydro generation profiles on RESOLVE model results

The implementation of full-year calculations with the New-modeling-toolkit formulation is not straightforward because the "rep-periods" approach is intended to use a day for each representative period. Our replacement of the standard representative days with a single 8760-hour long representative period does not facilitate differentiation between days, months, and years. This creates a problem for the hydro generation. The New modeling toolkit is well designed to handle hydropower deployment using hydro budgets for different representative periods through the "extras" option. However, the "extras" option is not designed for the 365-day single representative period. If we run the calculation without using "extras" it will choose to deploy substantial amounts

[20] R.K. Jones & S. Kurtz, "Optimizing the Configuration of Photovoltaic Plants to Minimize the Need for Storage," IEEE J. of Photovoltaics, 2022.

of hydropower – almost reaching the full potential output of the hydropower, effectively implementing it as a base-load generator.

To address this problem, we considered multiple options and decided that using the hydropower output from a dry year would provide us a sort of worst-case scenario for the hydropower. In a dry year, the shape of the profile has already been adjusted for seasonal and diurnal considerations. In a future year, different choices might be made, but we are unlikely to be able to predict them better than to use the historical data. For completeness, we looked for multiple years and selected three recent years to provide a range: 2019, 2020, and 2021 for wet, medium and dry years.

Seven profiles were created according to Table 4.4.

Table 4. 4 Information used for creating hydropower generation profiles

Resource	Source	Power capacity (MW)	Year	Net Generation (MWh)	Decision
BANC_Hydro	EIA[21]	2724	2021	2,909,755	DRY
			2020	4,258,379	MEDIUM
			2019	6,491,647	WET
CAISO_Hydro	CAISO[22]	7073	2021	9,021,568	DRY
			2020	13,293,543	MEDIUM
			2019	25,944,572	WET
IID_Hydro	EIA	83.5	2021	228,646	WET
			2020	205,834	DRY
			2019	213,445	MEDIUM
LDWP_Hydro	EIA	1108*	2021	170,912	DRY
			2020	172,036	MEDIUM
			2019	220,918	WET
NW_Hydro	EIA	31,288	2021	122,106,072	DRY
			2020	137,393,187	WET
			2019	126,338,629	MEDIUM
NW_Hydro_for_CAISO	EIA (BANC_Hydro)	2852	2021	3,128,705	DRY
			2020	4,704,501	MEDIUM
			2019	7,725,329	WET
SW_Hydro	EIA	2532	2021	5,299,290	WET
			2020	5,173,506	MEDIUM
			2019	4,973,559	DRY

*Note: we used a power capacity of 1108 MW because the EIA data for LADWP showed a maximum generation of 1108 MW in 2019. However, we note that the EIA 680 documentation of plants in LADWP balancing area is much less. The E3 data suggest that the maximum power would be 234 MW, closer to the EIA 860 data than the hourly data set would imply.

[21] https://www.eia.gov/electricity/gridmonitor/dashboard/electric_overview/US48/US48
[22] http://www.caiso.com/informed/Pages/ManagingOversupply.aspx

5. Modeling of candidate long-duration energy storage resources

Modeling of candidate long-duration energy storage is complicated by the uncertainty in the characteristics of these products. In most cases, the thing that differentiates a long-duration storage technology from a short-duration storage technology is the ability to scale the size of the energy reservoir independently from the size of the power conversion. The term "duration" is commonly used to quantify the rated capacity of the energy reservoir (kWh) to the capacity of the power converter (kW), with the ratio commonly reported in hours.

Key questions to answer include:
• What duration(s) is most useful to the grid?
• For that duration and a specified efficiency, what cost target will a product need to meet?
This section describes our approach to answering these questions and gives some preliminary results.

5.1. Attributes to model long-duration energy storage

Our strategy, as described above, is to shorten the calculation time so that we can complete many calculations, enabling us to explore a wide range of parameter space. We will use a matrix approach such as that summarized in Table 5.1 (copied from Section 2.4 for completeness). Each efficiency and duration will be defined, and the cost varied to identify what cost needs to be reached for the model to select that product. It is our intent that the matrix will cover all technologies that are actively under development. If any are missed, our intent is to extend the matrix to include those.

Table 5. 1 Minimum matrix of long-duration storage technologies

Efficiency	Duration (h)	Relevant technologies
80%	8, 12, 100	Pumped hydro, gravity, flow battery
70%	8, 12, 100	Geomechanical, flow battery, metal-air, exfoliated-metal, gravity
60%	8, 12, 100	Flow battery, metal-air, exfoliated-metal, compressed air, liquid air, thermal
50%	8, 12, 100	Thermal, hydrogen
30%	12, 100	Thermal, hydrogen

5.2. Demonstration of the modeling of LDES

A capacity expansion model provides many outputs – our goal is to use RESOLVE in such a way as to answer questions like: "If I make a storage product with a longer duration, how much more can I expect to be able to sell it for?" We complete our analysis in three primary steps.

1. We identify the storage product we would like to explore. The storage products will be chosen from a matrix like that defined in Table 5.1. For our final analysis, we anticipate

being able to explore a large parameter space using the CTS approach. For the demonstration, we have chosen to consider two products: a) a storage product with 8 hours duration and 80% round trip efficiency and b) a similar product, but with 100 hours duration.

2. We execute the 2-points CTS RESOLVE optimization for four periods 2030, 2035, 2040, and 2045 offering the model one of the two long-duration products, varying the price of the product by a factor of more than 10, using 17 steps. We plot the data as a function of cost in Fig. 5.1. When the cost is low, the long-duration energy storage products completely displace the lithium batteries. Then, as the cost is increased, the lithium batteries are selected rather than the long-duration energy storage product.
3. We then plot the results in terms of the cost that the long-duration product needs to meet to compete with the lithium batteries, as discussed below.

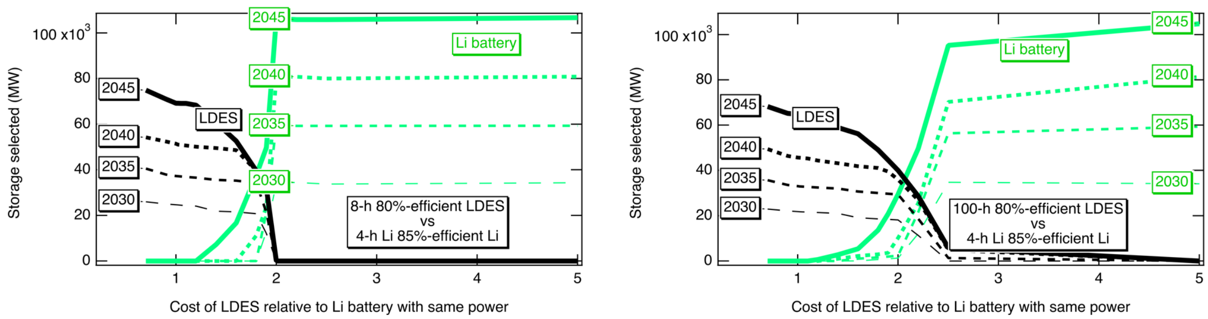

Fig. 5. 1. LDES selected by RESOLVE as a function of the cost relative to lithium battery with same power

Fig. 5.1 shows the GW of the long-duration energy storage (LDES) and the 4-h lithium batteries selected by the model as a function of the LDES cost input into the model. In Fig. 5.1, the cost is compared based on the power capacity of the products. Similar data are plotted in Fig. 5.2, using cost per energy capacity on the x axis and energy, instead of power, on the y axis.

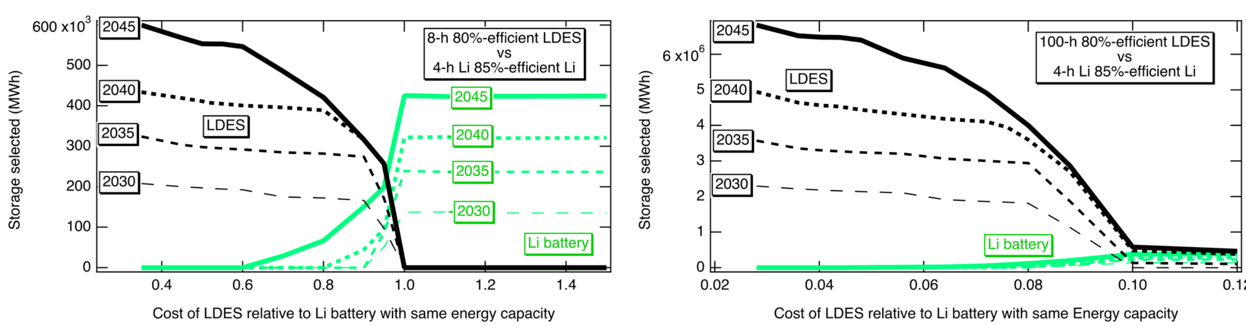

Fig. 5. 2 LDES selected by RESOLVE as a function of the cost relative to lithium battery with same energy

The left graphs show that when the cost of an 8-h LDES exceeds twice the cost of a 4-h lithium battery (and, therefore, the cost for the energy capacity is the same, as shown in Fig. 5.2), the model selects only lithium batteries. The market for the 8-h LDES product grows quite rapidly as the cost for the 8-h LDES product falls below twice the cost of the lithium battery. In later years, more market share can be captured as the cost per MW drops even below 150% of the lithium battery cost.

The adoption of the 100-h LDES is not as clearly defined. A small fraction of the power of the lithium batteries may be replaced by 100-h LDES if the 100-h LDES costs 2.5 times that of a 4-h lithium battery with same power rating (Fig. 5.1, right side) or one-tenth the cost of a lithium battery with the same energy rating (Fig. 5.2, right side). On the other hand, the energy capacity of those same LDES is comparable to the energy capacity of all of the lithium batteries. In this case, the number of lithium batteries has been reduced less than 10%, but the energy capacity of the LDES exceeds the total energy capacity of the lithium batteries.

The power capacity needed if all storage is supplied by LDES is about 70 GW, compared to about 105 GW needed for 4-h batteries. In this case, the 4-h batteries are being overbuilt to supply more energy. On the other hand, the energy capacity needed if all storage is supplied by LDES increases from about 400 GWh for the 4-h batteries to about 600 GWh for the 8-h LDES to about 6,000 GWh for the 100-h LDES.

We can take a slice of the data in Figs. 5.1 and 5.2 to identify the cost targets for an LDES product to displace 1% or 10% of the lithium batteries. An example of such a graph is shown in Fig. 5.3. This graph is derived based on displacing power capacity. For an 8-h LDES, the target price is effectively independent of the fraction of the market we are targeting. However, for the 100-h LDES product, a much higher price can enable market entry if we only wish to capture a small fraction of the market. Furthermore, capturing 1% of the market's power capacity may be very different from capturing 1% of the market's energy capacity. This analysis is not meant to give final answers to the questions we are asking, but it demonstrates the sort of approach we plan to pursue so that our results can be most useful to the CEC and to companies developing these products.

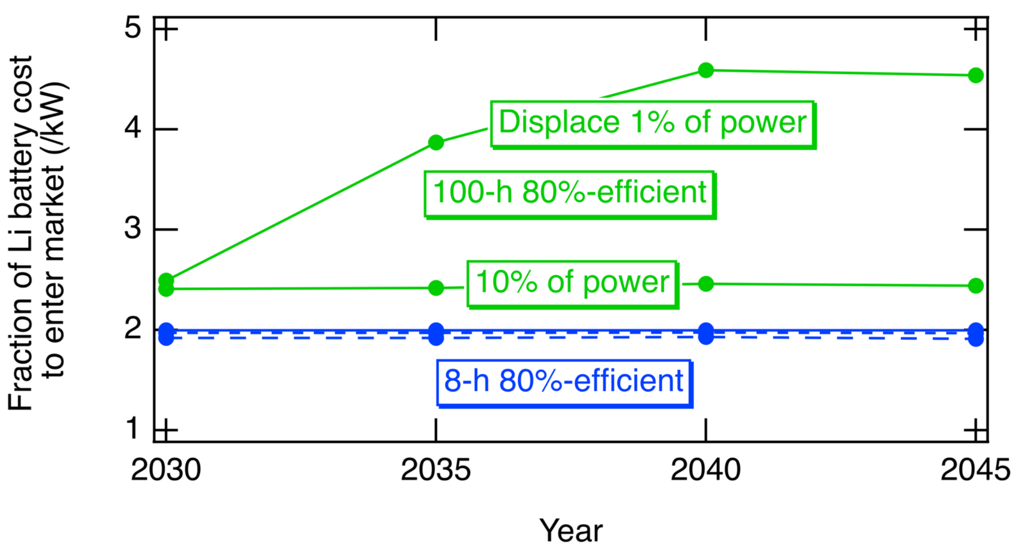

Fig. 5. 3 Target cost to enter market for 8-h and 100-h LDES

Feedback from meeting with TAC members and CPR#3 resulted in some revisions to the graphs. For example, Fig. 5.4 presents some data in a way that demonstrates the importance of the efficiency.

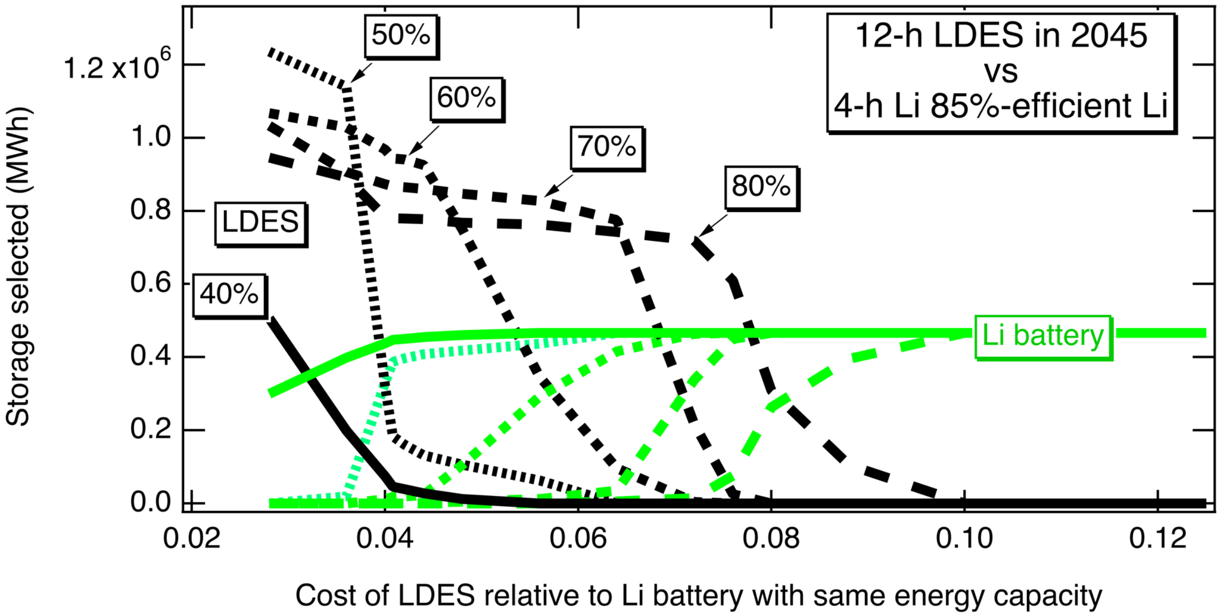

Fig. 5. 4 Storage selected by the model as a function of LDES cost and efficiency

6. Baseline results

Implementation of the baseline (without offering new types of LDES) is described in Section 6.1.

6.1. Capacity Expansion Calculated for Baseline

The operational capacity selected by the model when the LDES is too expensive to be selected is shown in Fig. 6.1.

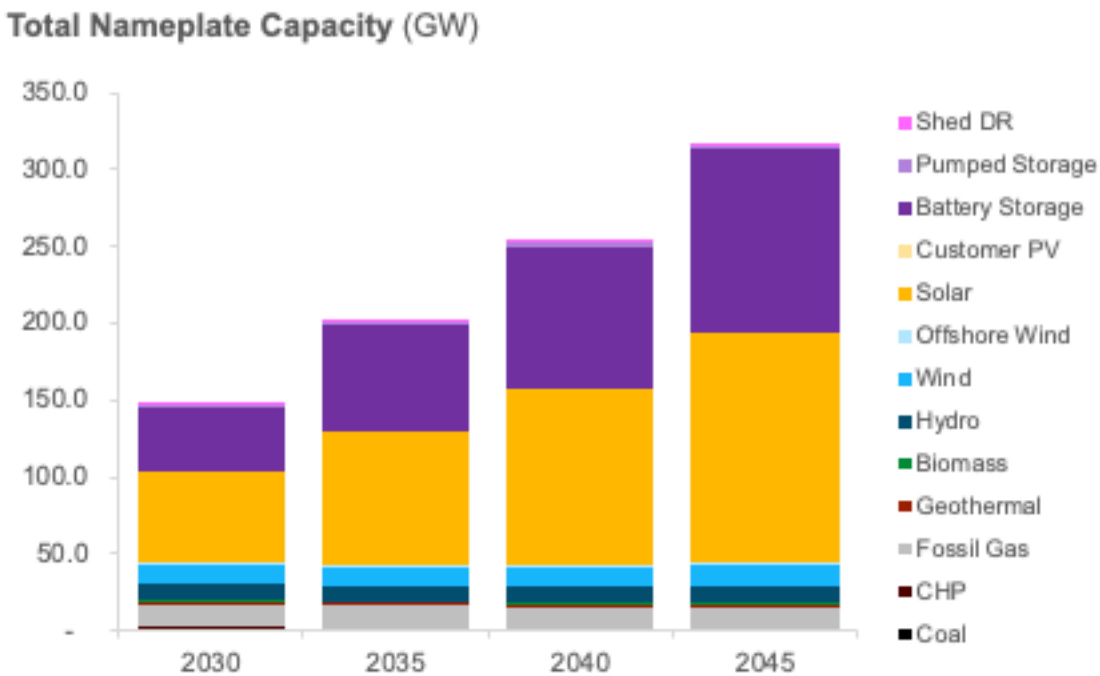

Fig. 6. 1 Selected operational capacity (GW) for baseline scenario

The capacity that is selected to be newly built for the baseline scenario is shown in Fig. 6.2.

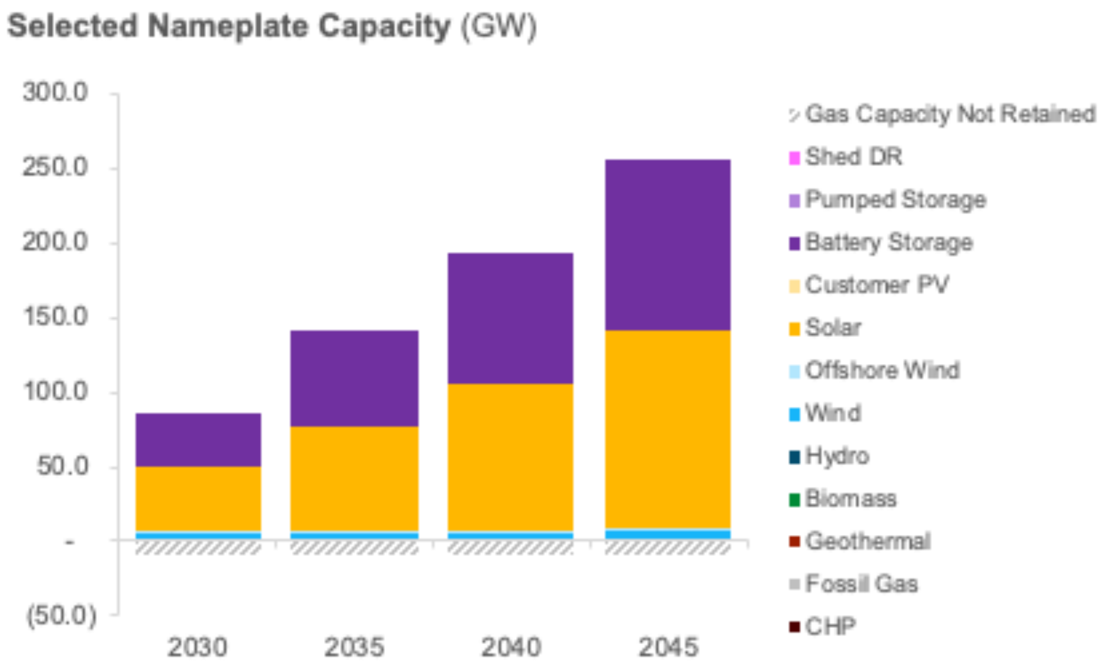

Fig. 6. 2 Resources selected to be built in each time period for the baseline scenario (GW)

The revenues associated with the capital and other costs are summarized in Fig. 6.3 for the baseline scenario.

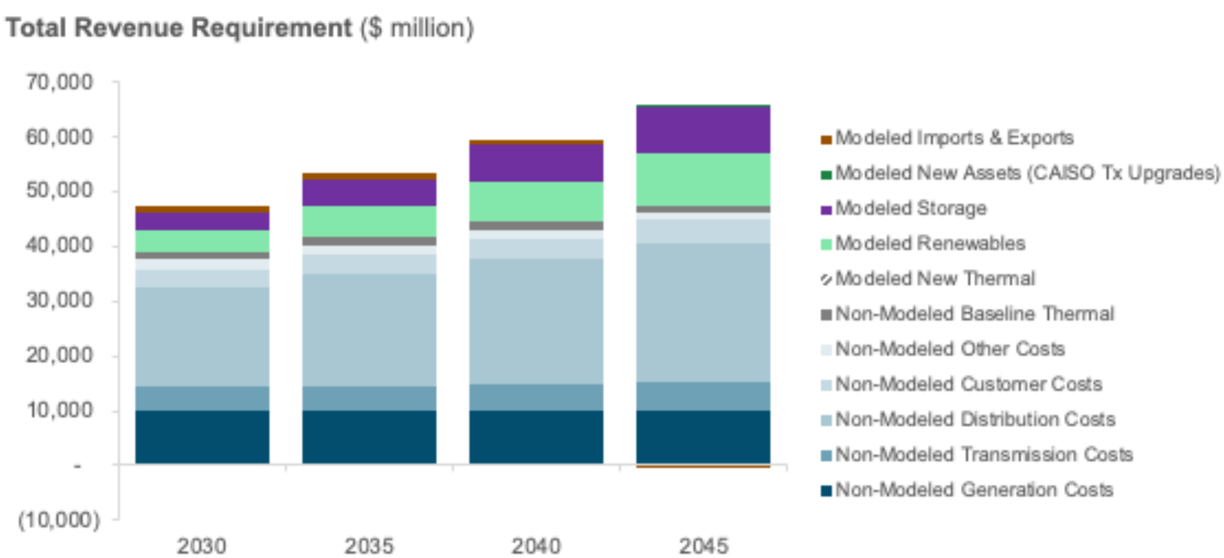

Fig. 6. 3 Costs calculated for the baseline scenario

The electricity generated and used for charging is summarized in Fig. 6.4 for the baseline scenario.

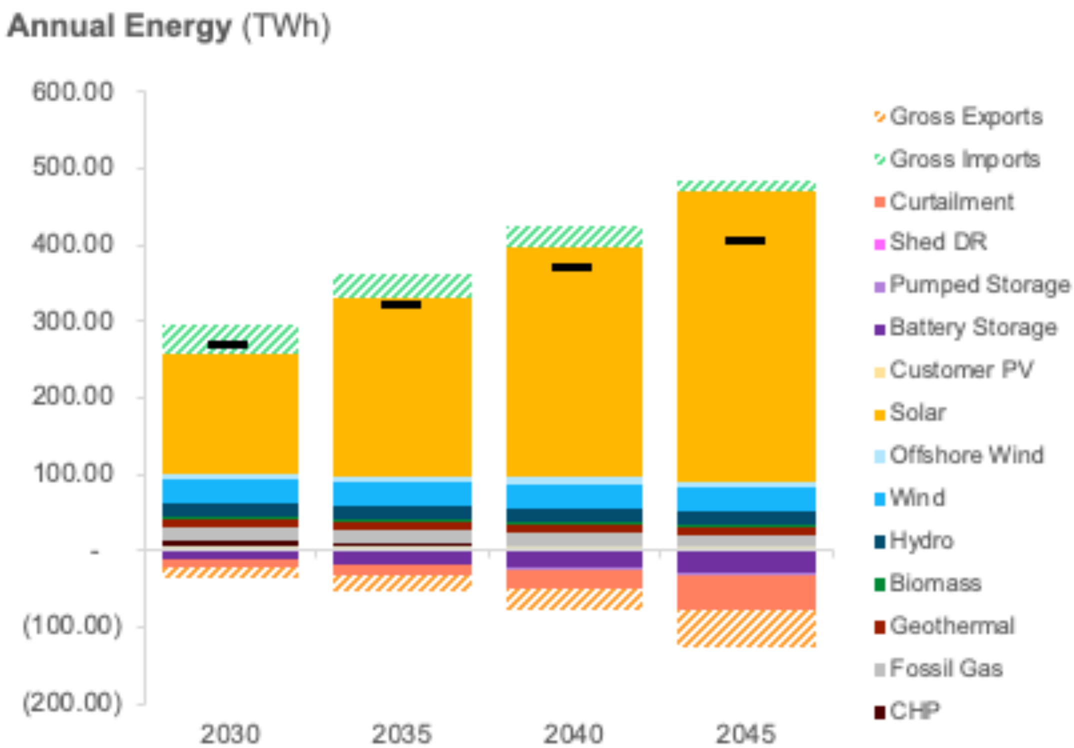

Fig. 6. 4 Electricity modeled for the baseline scenario.