IRP Production Cost Modeling with the Reference System Plan and the 2017 IEPR: SERVM model results

September 13, 2018

California Public Utilities Commission

Contents

Acronyms & Abbreviations

AAEE	Additional Achievable Energy Efficiency
AAPV	Additional Achievable Photovoltaics (BTMPV)
BANC	Balancing Area of Northern California
BTM	Behind-the-Meter
Btu	British thermal unit
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DR	Demand Response
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EO	Energy Only
EV	Electric Vehicle
FCDS	Full Capacity Deliverability Status
GHG	Greenhouse Gas
ICE	Internal Combustion Engine
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan (or) Planning
LOLE	Loss-of-load-expectation
LSE	Load Serving Entity

$MM	Millions of Dollars
MMBtu	Millions of British thermal units
MMT	Million Metric Tons
MT	Metric Tons
NOx	Nitrogen Oxide or Dioxide
NQC	Net Qualifying Capacity
OOS	Out-of-state
OTC	Once Through Cooling
PCC	Portfolio Content Category
PCM	Production Cost Model(ing)
PM 2.5	Particulate Matter, 2.5 microns
POU	Publicly-owned utility
PRM	Planning Reserve Margin
PV	Photovoltaics
RA	Resource Adequacy
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RPS	Renewables Portfolio Standard
SERVM	Strategic Energy Risk Valuation Model
ST	Steam Turbine
TOU	Time-of-Use (Rates)
TPP	Transmission Planning Process
TRC	Total Resource Cost
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle
ZNE	Zero Net Energy

Executive Summary

Purpose and Background

Purpose of this Work Product

1. To validate the production cost model (PCM) analytical framework with the Strategic Energy Risk Valuation Model (SERVM) to prepare for modeling of the aggregated load-serving entity Integrated Resource Plans (LSE plans)
2. To provide guidance to parties planning to model the aggregated LSE plans on how to work with Energy Division staff to compare and align inputs and modeling methods, and evaluate differences
3. To solicit feedback from parties on items #1 and #2 above.

Background

- This work product reflects the PCM activities conducted by Energy Division staff and which are described in the IRP Decision (D.18-02-018) Attachment B, “Guide to PCM in the IRP Proceeding”
- Staff has begun the process of reviewing LSE Plans and aggregating LSE portfolios to develop the Preferred System Plan

Conclusions and Recommendations

Staff conclusions:

- Significant progress has been made developing the SERVM model dataset and exercising Energy Division staff's PCM process in preparation for modeling the aggregated LSE portfolios
- Staff modeled the Reference System Plan calibrated to the 2017 IEPR demand forecast and found:
  - No system reliability issues and 19% reserve margin in 2030
  - Reasonable agreement between RESOLVE and SERVM on common production cost metrics
- Staff gained valuable insights by assessing key differences between RESOLVE and SERVM

Staff recommendations:

- Refining the SERVM dataset and completing investigations in the following areas prior to modeling the aggregation of LSE portfolios:
  - Unit region and capacity differences
  - Renewables modeling
  - Operational attributes
- Aligning inputs to RESOLVE and SERVM at the beginning of the next Reference System Plan development process
- Revising the Preferred System Plan PCM process outlined in Attachment B to the February 2018 IRP decision, D.18-02-018. The revisions are described in Attachment A to the ALJ ruling to which this work product is attached.

Purpose and Background

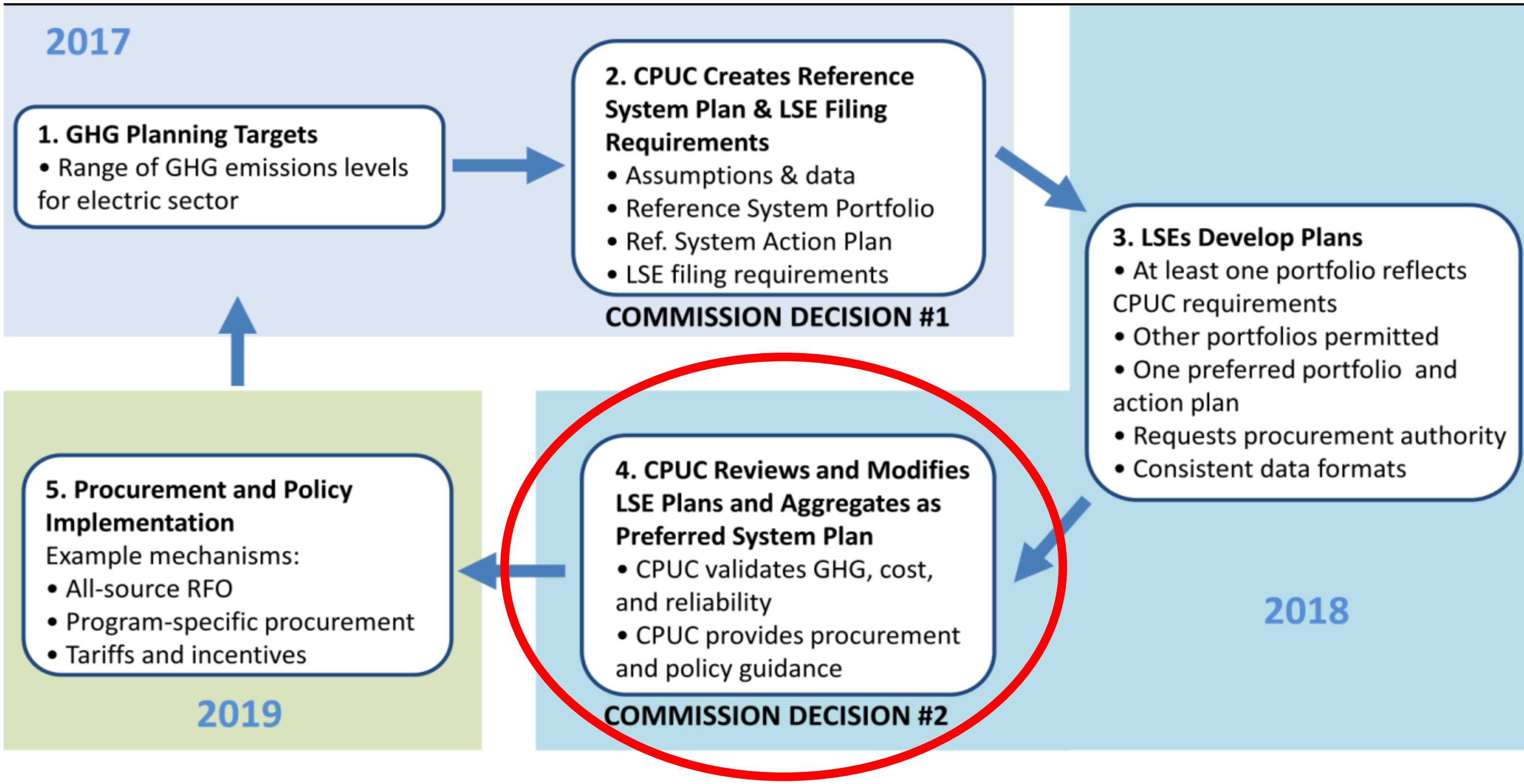
Purpose

- CPUC Energy Division staff is conducting the Production Cost Modeling (PCM) activities described in the IRP decision (D.18-02-018), Attachment B (Guide to PCM in the IRP Proceeding)
  - Validate the PCM analytical framework with the SERVM model to prepare for modeling of the aggregated load-serving entity Integrated Resource Plans (LSE plans)
    - The aggregation of LSE plans is the result of compiling resources assumed in individual LSE plans, removing duplication, assessing gaps, and reconciling with the baseline physical fleet, followed by aggregation into a total system portfolio
  - Document the PCM analytical work for others to use as a guide for their own analysis
    - Other parties who also plan to model the aggregated LSE plans should work with Energy Division staff to compare and align inputs and modeling methods, and evaluate differences
    - Aligning inputs and methods up front should enable subsequent modeling of the aggregated LSE plans to focus more on that task, rather than validating models or characterizing differences between models

Background

- The Commission Decision (D.18-02-018) established integrated resource planning (IRP) as a two-year planning cycle designed to ensure LSEs are on track to achieve GHG reductions and ensure electric grid reliability while meeting the state's other policy goals in a cost-effective manner
- In the 2017-18 IRP cycle, 2017 was spent developing the Reference System Plan using the RESOLVE capacity expansion model
- In February 2018, the Commission adopted the Reference System Plan corresponding to a 42 MMT GHG emissions target for the state's electric sector
- LSEs used the guidance provided by the Commission's decision to develop individual IRPs. The LSEs filed their IRPs with the Commission on August 1, 2018.
- In parallel with LSE IRP development, Commission staff have been exercising its PCM process with the SERVM model to prepare for modeling of the aggregated LSE portfolios to evaluate system reliability, emissions, and operational performance
  - Staff has completed modeling based on the Reference System Plan calibrated with the California Energy Commission's 2017 Integrated Energy Policy Report (IEPR) demand forecast. This work product presents the modeling results.
  - Staff is currently preparing to conduct PCM on the aggregation of the LSE portfolios

Currently in Step 4 of the IRP 2017-18 Process



- LSE Plans were filed on August 1st
- Staff has begun evaluation of the LSE Plans and aggregating LSE portfolios to develop the Preferred System Plan

Role of PCM within the IRP 2017-18 Process

PCM has an important role in Steps #2 and #4 of the IRP process.

1. CPUC staff evaluates a range of GHG emissions target levels for 2030
2. Commission adopts a Reference System Plan and IRP filing requirements in D.18-02-018
   - A Reference System Portfolio that achieves a GHG Planning Target of 42 MMT for the electric sector statewide
   - Directs staff to develop a PCM process to evaluate the aggregated LSE plans
     - Validate the process using a version of the Reference System Portfolio calibrated to the 2017 IEPR demand forecast
     - Provide for comment on the PCM approach and results on the record
3. LSEs file IRPs that reflect the Reference System Plan and conform to other IRP requirements
4. CPUC staff reviews LSE Plans, aggregates and reconciles LSE portfolios, and evaluates system reliability, emissions, and costs using PCM
   - Staff develops and proposes a Preferred System Portfolio bases on its PCM analysis
   - Other stakeholders make recommendations based on their own PCM or other analysis
5. Commission decides whether to authorize procurement based on approved, aggregated LSE plans (the Preferred System Plan)

Key IRP PCM Process Milestones

ACTIVITY	DATE (2018)
Ruling seeking comment on SERVM studies and revised PCM guidelines	**Mid September**
Deadline for comments on SERVM studies and revised PCM guidelines	**Beginning of October**
Ruling revising PCM guidelines for studying aggregated LSE portfolios	**Mid October**
Post aggregated LSE portfolios' physical unit data for PCM	**End of September**
SERVM studies on aggregated LSE portfolios	**October – November**
Propose Preferred System Plan based on SERVM studies and other analysis	**End of November**
Party comments and/or PCM study results presented to CPUC	**End of December**
Proposed Decision on Preferred System Plan	**Q1 2019**

Study Design

Overall Modeling Method

- Probabilistic reliability planning approach (e.g. security-constrained planning) – primary goal is to reduce risk of insufficient generation to an acceptable level
- Uncertainty considered – weather, economic load forecast, unit performance
- Simulate hourly economic unit commitment and dispatch
  - With reserve targets to reflect provision of subhourly balancing and ancillary services
  - With assumed generation fleet and load forecast in target study year
  - Across probability-weighted range of uncertainties
  - Multiple day look-ahead informs unit commitment
- Pipe and bubble representation of transmission system
  - 8 CA regions, 16 rest-of-WECC regions

Strategic Energy Risk Valuation Model (SERVM)*

- A system-reliability planning and production cost model designed to analyze the capabilities of an electric system during a variety of conditions under thousands of different scenarios
  - 35 historical weather year distribution (1980-2014)
  - 5 points of economic load forecast error
  - 35 x 5 = 175 probability-weighted ***cases***
  - Each ***case*** is run with tens or hundreds of unit outage draws creating thousands of iterations
  - Each iteration represents one realization of a year (8760 hours) of grid operations
  - Used for probabilistic loss-of-load studies, effective load-carrying capability (ELCC) studies, and forecasting production costs and market prices

*Commercially licensed through Astrape Consulting: http://www.astrape.com/servm/

Model outputs are probability-weighted distributions

- Outputs are reported as expected values (weighted average)
- Confidence intervals, percentiles, and full distributions can be extracted
  - To keep run times and file sizes manageable many outputs are aggregated up and/or only reported as an expected value
- Each weather year is equally weighted (non-equal weighting can also be assigned)
- Economic load forecast error has varying probability

Magnitude of forecast error (percentage)	Probability of error occurring (percentage)
2.5% error	6.68% probability
1.5% error	24.17% probability
0% error	38.29% probability
-1.5% error	24.17% probability
-2.5% error	6.68% probability

- Weight for case with 1980 weather and economic load forecast error +1.5%:

  $(1/35) \times (0.2417) = 0.006906$
- For “as-found” studies, each case is simulated with 50 equally weighted random draws of unit outages
- For calibrated loss-of-load and ELCC studies, each case is simulated with equally weighted random draws of unit outages until convergence at the LOLE target is achieved

Input Data Development

- The most recent version of the Unified RA and IRP Inputs and Assumptions document describes data development, sources, and modeling methods in detail (download here*)
  - Generator unit data
  - Load forecast
  - Fuel and carbon prices
  - Load, wind, solar, and hydro shapes
  - Transmission topology and constraints
  - System operating constraints
- SERVM input data (units, load forecast, shapes, prices) are available for download here

* A draft document was posted in February 2018. An updated version describing the revised assumptions in the studies reported here will be posted soon.

Generator Unit Data

- CAISO Masterfile (confidential) and Master Generating Capability List (public)
  - Generator capacity, location, and operating costs and attributes
  - Unit-specific heat rates, ramp rates, startup profiles, minimum up/down times
- TEPPC 2026 Common Case v2.0
  - Non-CAISO generation data
- IOU RPS contracts database
  - Planned projects not yet in CAISO Masterfile
- RESOLVE model output portfolio
  - Incremental resource portfolio based on IRP Reference System Plan 42 MMT scenario calibrated with the 2017 IEPR forecast
- Generator Availability Data System (GADS) database
  - Planned and forced outage data

Annual Load Forecast

- 2017 IEPR California Energy Demand Forecast for CA loads
  - Use “Single Forecast Set” mid demand, mid-mid AAEE, mid-mid AAPV
  - Annual consumption energy and peak demand used to scale and stretch weather-normalized synthetic hourly consumption load shapes
  - Annual installed capacity of “baseline BTM PV” plus AAPV used to create hourly BTM solar PV shapes
  - Annual load modifiers include growth from increased EV charging, AAEE savings, and load shifting from TOU rates
  - Non-PV self-generation is left embedded in the consumption load
- TEPPC 2026 Common Case v2.0 for non-CA load forecast
- Load modifiers (demand-side resources) are modeled as “generators”
  - AAEE, BTM PV including AAPV, EV load, and TOU rates are modeled as fixed-shape generators, thus their effects are removed from the load forecast prior to creation of load shapes. The PV shapes are weather-dependent while the other load modifier shapes are not.

Annual Fuel and Carbon Prices

- All costs are in 2016 dollars
- Fuel prices are derived from the Energy Commission April 2018 NAMGAS model mid case
- Carbon adder on both in-state generation and CA import hurdle rates is based on the 2017 IEPR low carbon allowance price forecast
  - $27.37 per metric ton of CO2 in 2030, translates to a $11.71 per MWh hurdle rate adder on CA unspecified imports (emissions factor 0.428 metric ton per MWh)
  - RESOLVE model output GHG shadow price ($190 per metric ton of CO2 in 2030 + $27.37) is included in a sensitivity study of 2030 (no sensitivities for 2022 and 2026)
    - $190 is the shadow price resulting from updating RESOLVE to use the 2017 IEPR forecast. The version of RESOLVE used for the adopted Reference System Plan used the 2016 IEPR forecast. The shadow price from that version of RESOLVE was $121.

Hourly Profiles

	How developed	Sources
Load	Based on relationship between historical hourly load and weather	CAISO EMS, FERC Form 714, EIA Form 861, National Climate Data Center hourly weather
Wind	Based on relationship between historical hourly production and wind speed	NREL Western Wind Resources Dataset, NOAA hourly wind speed
Solar	Calculated production from historical irradiance and assumed technology configuration	NREL PVWatts tool, NREL National Solar Radiation Database; Tracking vs. Fixed assignment based on historical late-afternoon generation (existing units) or 75%/25% assumption (new units)
Hydro	Based on historical production	Form EIA-923: Power Plant Operations Report, CEC historical hourly monitoring
Load-modifiers	Used as-is	2017 IEPR hourly shapes for EV charging, TOU rates, AAEE savings

Transmission and System Parameters

- Operational constraints
  - Spinning and non-spinning reserves, load-following, and regulation as defined in Attachment B to the February 2018 IRP decision, D.18-02-018
  - Frequency response constraint consistent with definition in RESOLVE model
  - Minimum thermal generation requirements are replaced within CAISO by the frequency response constraint but minimum thermal generation requirement of 25% is set for non-CAISO areas.

- Transmission topology, capacity limits, hurdle rates, and simultaneous flow constraints
  - Imports into CAISO limited by the CAISO Maximum Available Import Capability level derived for 2018 RA compliance and posted to the CAISO website
  - Import limits between other areas derived from TEPPC 2026 Common Case v2.0 for non-CAISO areas
  - CA is modeled as 8 regions
  - Rest of WECC outside CA is modeled as 16 regions

Simultaneous Flow Constraints

SERVM regions	Aggregation	Simultaneous flow constraint
• PGE_Bay • PGE_Valley • SCE • SDGE	CAISO	• Modeled as aggregate region – simultaneous import limit of 11,600 MW is applied near peak hours (hours where load is between 95% and 100% of peak) for all years • Net export limit of 5,000 MW is applied to all hours for all years • RESOLVE's net export limit increases slowly to 5000 MW in 2030
• IID • LADWP • PGE_Bay • PGE_Valley • SCE • SDGE • SMUD • TID	CA	• No simultaneous import or export limits applied to non-CAISO areas

Definition of Studies

Type of Analysis	3 Primary Studies: 2022, 2026, 2030	Sensitivity: 2030 only	Sensitivity: 2030 only
Production cost modeling (PCM)	Study the system "as found" and report typical PCM metrics. "As found" is the baseline electric system plus new resources selected in the RESOLVE model using the 2017 IEPR.	Adds RESOLVE GHG shadow price ($190/ metric ton CO2 in 2030) to CA generation fuel cost and CA import hurdle rates	
Monthly calibrated loss-of-load	Remove existing generation until expected loss-of-load converges on desired monthly reliability target		
Monthly average portfolio ELCC	Remove utility-scale solar and wind portfolio and incrementally add back perfect generation until expected loss-of-load converges on desired monthly reliability target. Ratio of total added perfect generation to removed wind and solar installed capacity is ELCC.		Repeat this study and include storage (i.e. ELCC for utility solar, wind, battery storage, and pumped storage hydro together)
Reserve margin calculation	Calculate reserve margin using average portfolio ELCC to derive the NQC of all utility-scale wind and solar together		Use ELCC of utility solar, wind, and storage together to derive NQC

RESOLVE and SERVM inputs and model comparison

- The RESOLVE and SERVM models both simulate hourly CAISO grid operation and can therefore be compared using common production cost model metrics such as annual production costs, emissions, import and export flows, curtailment, generation by resource type, month-hour dispatch patterns.
- Model inputs and methods were aligned where feasible, but the two models have differences in structure and purpose, so results are expected to differ. The comparison exercise seeks to understand differences and reconcile where possible. Findings can be used to improve the accuracy of one or both models in future studies. Recommended improvements are presented in the last section of these slides.

Differences in the Structure and Purpose of the RESOLVE and SERVM models

- RESOLVE is an optimal investment and operational model
  - Co-optimizes fixed-costs of new investments and costs of operating the CAISO system within the broader footprint of the WECC electricity system over a multi-year horizon
  - Simplifies temporal and spatial resolution to manage model complexity and run-time
    - 37 independent representative days are simulated, each weighted such that daily outputs can be summed up to represent an operating year
    - Units are aggregated into classes, WECC transmission topology is aggregated into 6 regions, with 4 representing CA
  - Simplifications or averaging of operating performance of generation
  - Designed to solve for an optimal portfolio of new investments while satisfying a range of policy and operational constraints
- SERVM is a probabilistic reliability and production cost model
  - Optimizes least-cost unit commitment and dispatch of entire WECC
  - Over wide range of conditions (many different realizations of one chosen study year)
  - Simulates full sequential 8760 hours of a year
  - Requires generating fleet and load forecast to be pre-determined for the study year
  - Unit-level dispatch, WECC transmission topology is aggregated into 24 regions, with 8 representing CA
  - Operating performance of generation more detailed and by unit

CAISO generation capacity comparison

	TOTAL SERVM RESOURCES, MW			TOTAL RESOLVE RESOURCES, MW			SERVM minus RESOLVE, MW		
Resource Type	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**	**2022**	**2026**	**2030**
Battery Storage	1,115	1,514	3,431	1,113	1,512	3,429	2	2	2
Biomass	676	676	676	1,107	1,107	1,107	-431	-431	-431
Geothermal	1,728	1,728	3,428	1,487	1,487	3,187	241	241	242
Nuclear	2,923	623	623	2,922	622	622	1	1	1
Utility-scale Solar	19,637	19,637	19,701	19,211	19,211	19,276	426	426	425
Thermal	26,539	26,539	26,539	27,561	27,561	27,561	-1,023	-1,023	-1,023
Wind	10,522	10,522	11,325	7,816	7,816	8,917	2,707	2,707	2,409
BTMPV	12,301	16,727	20,759	12,758	17,454	21,573	-457	-727	-814
Demand Response	1,754	1,754	1,754	1,752	1,752	1,752	1	1	1
Hydro	7,402	7,402	7,402	9,163	9,163	9,163	-1,761	-1,761	-1,761

- SERVM totals include all units serving CAISO load including must-take but not dynamically scheduled specified imports.
- RESOLVE totals include all units modeled as within CAISO, whether contracted to a CAISO LSE or not.
- Thermal includes CHP, CCGT, CT, reciprocating engine, and steam.
- Existing renewables based on contracted capacities reported in IOU RPS Contracts Database.
- SERVM BTMPV based on 2017 IEPR installed capacity. Grossed up for T&D losses.
- RESOLVE BTMPV based on calculated capacity from 2017 IEPR annual energy and an assumed capacity factor (that is slightly lower than assumed in the IEPR). Grossed up for T&D losses.
- For the “Hydro” category, Hoover was excluded and pumped hydro storage was included in both models’ totals. Hoover is modeled in both models, but excluded from this capacity comparison table.

Capacity Differences Between Models

- Thermal and renewable capacity totals differ partly due to the SERVM dataset being updated more recently. SERVM sourced capacities from the CAISO Masterfile, the IOU RPS Contracts Database, and TEPPC Common Case v 2.0. RESOLVE generally sourced from a preliminary 2017 NQC List, and older versions of the IOU RPS Contracts Database and TEPPC Common Case. Units in CAISO and across the WECC have recently come online or retired since the RESOLVE dataset was compiled.
- For the comparison shown, staff tabulated the capacity of hydro in RESOLVE by totaling up individual hydro facilities. In SERVM, hydro is modeled as a combination of profiles – run of river, scheduled hydro, and emergency hydro. Each region gets a profile for each of the three types, equaling a bank of available energy, and a max capacity. These profiles are created monthly to correspond to 1980 through 2014 actual hydro generation patterns. For these reasons, hydro capacity is difficult to compare – hydro is often expected to perform at below maximum capacity in low hydro weather years.
- Differences were also related to whether a model treated an out-of-state unit as “in CAISO” versus “out of CAISO,” as further explained below.

Modeling of generators located outside CAISO as "internal" to CAISO

- Both RESOLVE and SERVM model most renewable and specified import contracts (such as Palo Verde Nuclear Station) as internal to CAISO.
- RESOLVE and SERVM differed in treatment for certain out of state conventional thermal generators.
  - SERVM classified generation from these units (Mesquite, Arlington, Yuma, and Griffith CCGT facilities) as CAISO dynamically scheduled specified imports, whereas RESOLVE classified generation from these units as CAISO unspecified imports
  - In the CAISO generation capacity comparison table above, these out of state thermal generators are not included in the SERVM capacity total so that it is more comparable to the RESOLVE total
  - To serve CAISO load, RESOLVE tended to dispatch more in-CAISO thermal generation since these out of state thermal generators are subject to hurdle rates in RESOLVE. In SERVM these units are not subject to hurdle rates and tended to be dispatched more often. The net effect of this difference on total thermal generation to serve CAISO load, whether that generation is in-CAISO, specified import, or unspecified import, is expected to be small.
- RESOLVE and SERVM differed in whether several out-of-state renewables projects should be modeled as delivering to CAISO load (i.e. modeled as "internal" to CAISO) or not.
  - For example, SERVM modeled more OOS wind units as "internal" to CAISO than RESOLVE assumed (Blackspring Ridge, Goshen, Halkirk, Horseshoe Bend, Klondike, N. Hurlburt, S. Hurlburt, Vantage).

Generator Operational Differences

- Higher heat rates (HR) in SERVM relative to RESOLVE results in higher fuel use and emissions in SERVM. SERVM operational data is sourced from CAISO Masterfile information. RESOLVE derived class averages from similar technology units in the TEPPC Common Case.

Unit type	SERVM average HR* in 2030 (MMBtu/MWh)	RESOLVE average HR* in 2030 (MMBtu/MWh)
CCGT	7.57	6.91
CT	10.71	N/A (de minimis dispatch in 2030)
Cogen	9.21	7.61

*Average HRs calculated from modeled dispatch: total fuel burn in study year / total MWh produced in study year

SERVM Cogen heat rates derives from the CAISO Masterfile which does not separate fuel for useful heat vs. electricity production. This results in higher heat rates as some of the fuel goes towards useful heat. RESOLVE bases its Cogen heat rate only on fuel for electricity production.

- Relative to RESOLVE, SERVM units on average tend to have longer startup times, meaning more time spent in inefficient operating zones, resulting in higher fuel use and emissions. For example, RESOLVE CCGTs have uniform startup times of 1 hour to get from 0 to Pmin. SERVM CCGTs have a distribution of startup times but on average take about 1.5 hours to get from 0 to Pmin.

- For both heat rates and startup times, SERVM models individual units and there is a wide distribution of heat rates and startup times even within a resource type. RESOLVE, on the other hand models aggregated units, each with a uniform average heat rate or startup time. This is another source of operational difference between the two models.

Modeling of renewables generators

- RESOLVE matches to a renewable unit's expected annual energy production and assigns a class average capacity factor. RESOLVE then reports out a "calculated" nameplate MW.
  - The "calculated" MW may differ from the unit's contract or nameplate MW because the unit's capacity factor may differ from the assigned class average.
  - The expected annual energy production for a renewable is used to scale RESOLVE's generation profile for that class so that the output annual energy reported by RESOLVE always matches.
- SERVM matches to a renewable unit's contract or nameplate MW.
  - The contract or nameplate MW for a renewable is used to scale SERVM's generation profile for that class. The output annual energy reported by SERVM may not match the unit's expected annual energy production.
    - Capacity factor implied by SERVM generation profile may differ from the unit's capacity factor.
    - SERVM generation profiles vary across 35 weather years.
    - For solar PV units, greater than unity inverter loading ratio (DC MW/AC MW) results in more energy production per assumed AC nameplate MW and a higher capacity factor.
- Example comparing BTMPV capacity and energy

Model	2030 Nameplate Capacity (grossed up for T&D losses)	2030 Energy	Capacity Factor
SERVM	20,759 MW*	42,621 GWh	0.234
RESOLVE	21,573 MW	36,295 GWh*	0.192

*Directly from the IEPR demand forecast

Study Results

PCM of the "as-found" system

- Intended to assess operational performance of a given portfolio in a target study year, under a range of future weather and economic output
  - Given portfolio: RESOLVE 42 MMT core case aligned with 2017 IEPR
  - Three primary study years: **2022, 2026, 2030**
  - One sensitivity on the 2030 study year: Adds RESOLVE GHG shadow price ($190/metric ton CO2 in 2030) to CA generation fuel cost and CA import hurdle rates. The following slides label this sensitivity as "**2030+RGS**", short for "RESOLVE GHG Shadow price." This sensitivity explores SERVM dispatch with GHG price signals that are consistent with those in RESOLVE, since RESOLVE dispatches thermal units using its GHG shadow price ($190) in addition to an exogenously specified carbon price ($27).
- Annual Loss-of-Load Expectation (LOLE) and normalized Expected Unserved Energy (EUE) is effectively zero for all studies – consistent with the projected system capacity reserve margin being several percent higher than 15 percent
- Reported on the following slides:
  - System balance and generation by resource class in 2030
  - Monthly generation by resource class, import and export flows, and curtailment
  - Hourly dispatch and market price for selected days
  - CO2 and criteria pollutant emissions
  - Annual RPS % for CAISO region
  - Comparisons with RESOLVE outputs

CAISO system balance in 2030

CAISO System balance verification, GWh	SERVM: 2030	SERVM: 2030+RGS	RESOLVE: 2030
Generation serving CAISO load: includes BTMPV and direct imports; excludes storage discharge and non-PV load modifiers	269,484	268,211	254,749
Non-PV load modifiers (net effect of AAEE, EV, TOU)	18,276	18,276	N/A
Unspecified Imports	10,985	11,171	12,709
Load after reduction from non-PV load modifiers (net effect of AAEE, EV, TOU)	254,601	254,601	255,038
Non-PV Load Modifiers (net effect of AAEE, EV, TOU)	18,276	18,276	N/A
Unspecified Exports	13,862	13,509	5,686
Battery and Pumped Storage Hydro losses (net of charge and discharge)	949	1,245	3,811
Curtailment	11,055	10,025	2,923

- Green items are “credits” that increase energy in a region, red items are “debits.” Total credits – total debits = 0
- Generation serving CAISO load amounts are BEFORE curtailment
- RESOLVE uses the hourly net of charge and discharge (storage losses) for hourly energy balance (shown in table above). Subhourly charge and discharge is separately tracked in RESOLVE.
- RESOLVE models load as AFTER reductions from non-PV load modifiers (255,038 GWh above), whereas SERVM models load as BEFORE reductions from non-PV load modifiers (254,601+18,276 GWh above) and models the effects of non-PV load modifiers as a “generator.” Thus, for SERVM, non-PV load modifiers appears as both a credit and debit above. The breakout of load components in SERVM was done to be able to show a comparison to RESOLVE load (254,601 GWh compared to 255,038 GWh).

CAISO generation by resource class in 2030

Generation serving CAISO load by resource type in GWh including in-CAISO generation and direct (specified) imports	SERVM: 2030	SERVM: 2030+RGS	RESOLVE: 2030
Combined Cycle Gas Turbine (CCGT)	71,208	70,887	69,371
Combustion Turbine (CT)	2,328	1,496	26
Steam	141	129	0
Coal	0	0	0
Biomass	1,931	1,899	6,792
BTMPV	42,621	42,621	36,295
Solar PV Fixed + Tracking and Solar Thermal	52,560	52,560	50,248
Wind	28,060	28,060	22,579
Scheduled Hydro Plus Run-of-River Hydro	28,490	28,490	25,317
Geothermal	23,729	23,709	24,357
Cogeneration	12,779	12,725	14,759
Nuclear	5,459	5,459	5,004
Internal Combustion Engine (ICE)	179	176	0
Generation subtotal before curtailment	269,485	268,211	254,748
Curtailment	-11,055	-10,025	-2,923
Generation total after curtailment	258,430	258,186	251,825

- By default, RESOLVE reports wind and solar generation after curtailment and does not report generation before curtailment. Staff calculated RESOLVE wind and solar generation before curtailment to produce the comparison values in the table above.
- Storage charge/discharge, unspecified imports/exports, and non-PV load modifiers (net effect of AAEE, EV, TOU) are not included in this table.

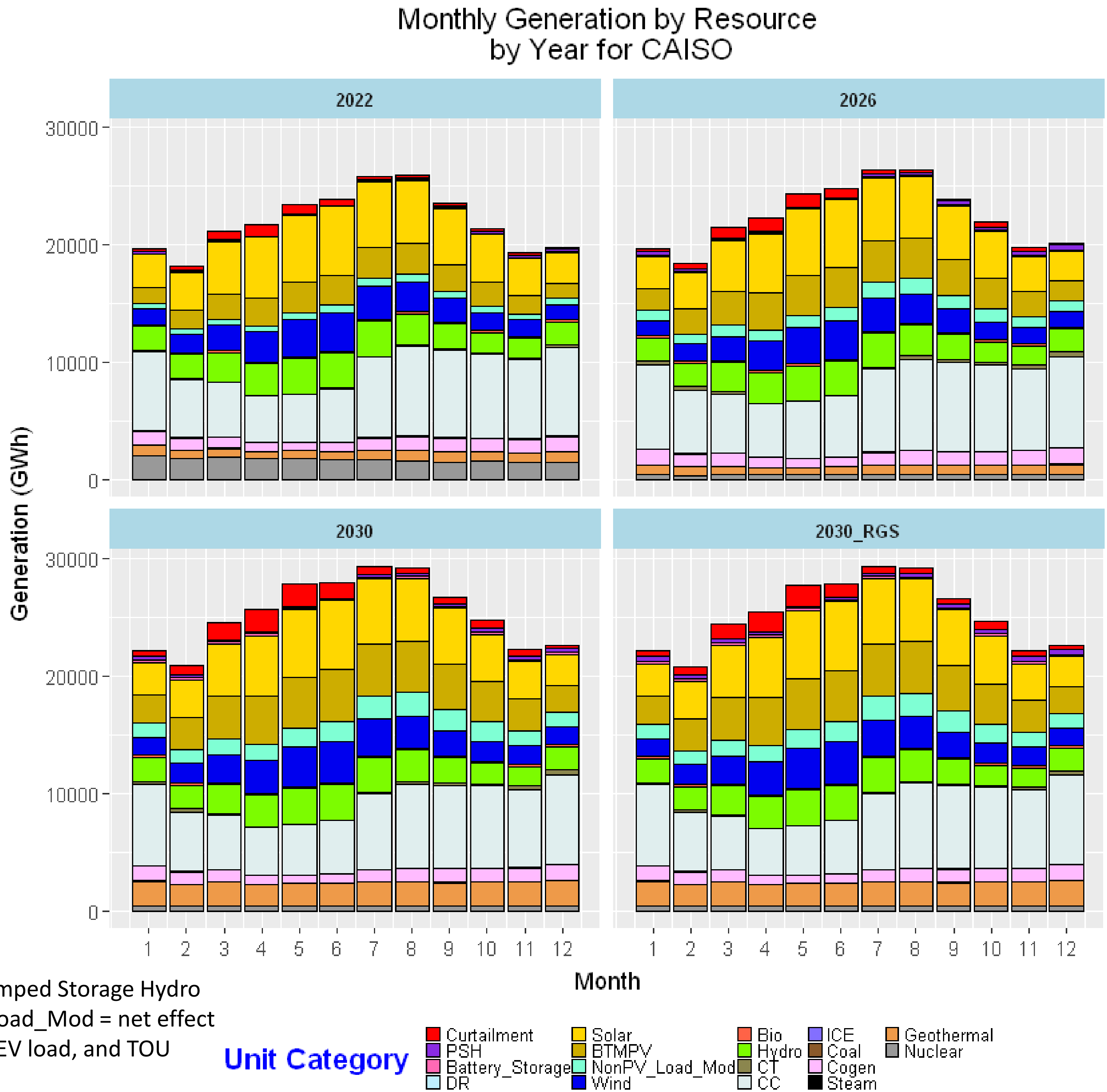
Factors contributing to major differences in generation by resource class

- SERVM generally uses unit-specific operational attributes (heat rate, start times, minimum up times, etc.) rather than relatively uniform class averages like RESOLVE. On average, SERVM units also tended to have less flexible attributes than RESOLVE. These factors may have contributed to higher peaker dispatch in SERVM rather than relying more on CCGTs for flexibility.
- RESOLVE models geothermal, biomass, and CHP as “must-run” generally at maximum capacity (Pmax). SERVM models these resource types as “must-run” at the unit’s minimum operating level (Pmin) and economically dispatching headroom above Pmin. Geothermal and CHP units tended to have little difference between Pmax and Pmin whereas biomass did, thus subjecting biomass to economic dispatch much more. Biomass also had a small variable cost component. These factors tended to depress SERVM biomass generation relative to RESOLVE.
- SERVM modeled more out-of-state renewables, most of which are wind units, as “internal” to CAISO, relative to RESOLVE. For example, RESOLVE’s OOS wind units for CAISO did not include certain existing OOS wind units with CAISO off-takers (about 1.7 GW capacity and 4,600 GWh energy). RESOLVE assumed these units served load in their home region outside CAISO, whereas SERVM assumed these units served CAISO load.

Detail on CAISO Storage Usage in 2030

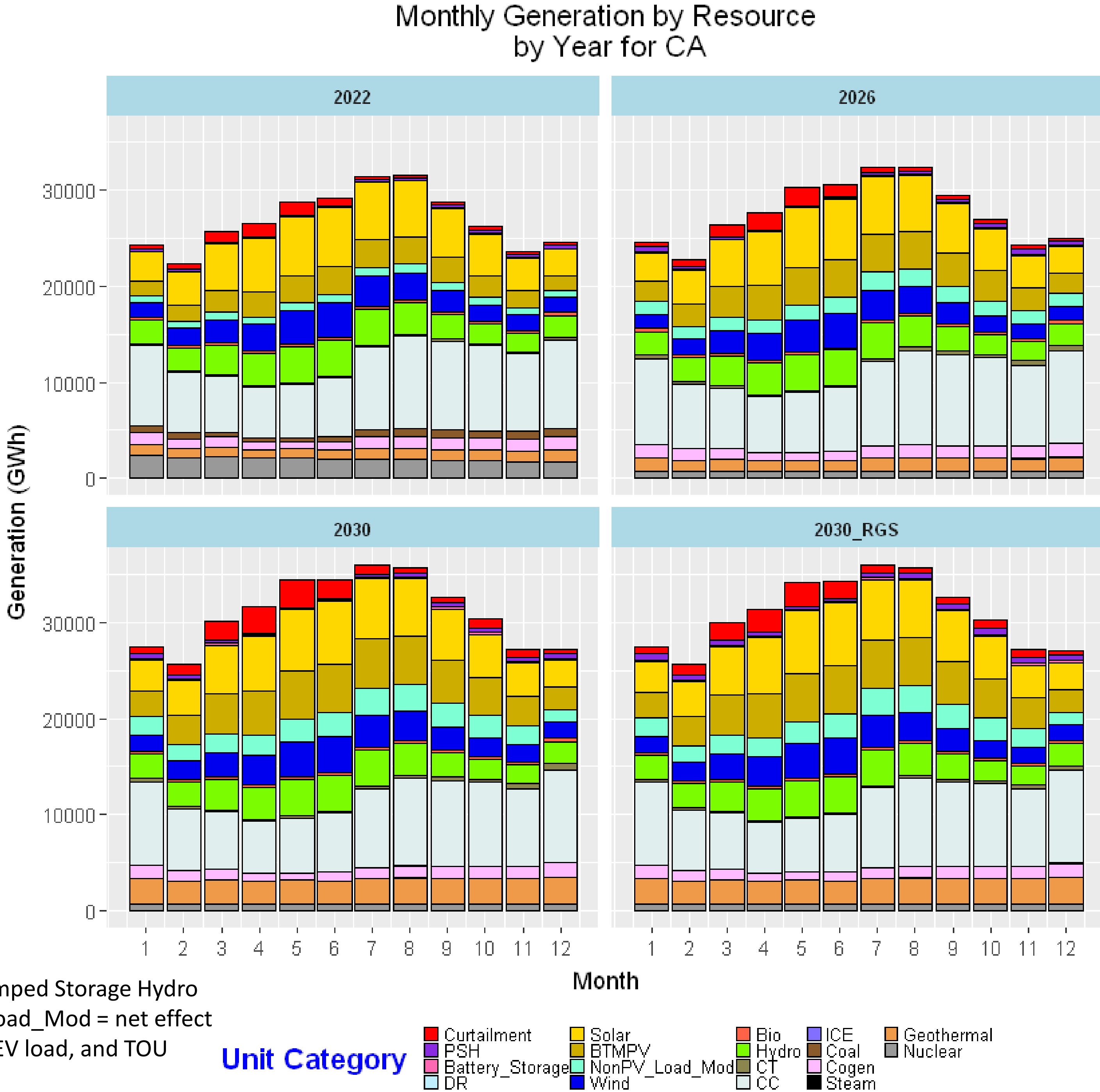
Charges (-), discharges (+), or net storage loss, GWh, by resource type		SERVM: 2030	SERVM: 2030 + RGS	RESOLVE 2030 hourly dispatch	RESOLVE 2030 subhourly dispatch	RESOLVE 2030 total dispatch
Pumped Storage Hydro	**charge**	-3,245	-4,608	-4,492	-576	-5,068
Pumped Storage Hydro	**discharge**	2,637	3,750	3,154	951	4,105
Battery Storage	**charge**	-2,314	-2,635	-4,817	-1,839	-6,656
Battery Storage	**discharge**	1,973	2,247	2,344	3,313	5,658
Pumped Storage Hydro	**Net storage loss**	-608	-857	-1,338	375	-963
Battery Storage	**Net storage loss**	-341	-388	-2,473	1,474	-998

- RESOLVE separately tracks hourly and subhourly charging and discharging of storage. RESOLVE uses the hourly net of charge and discharge (storage losses) for hourly energy balance. Subhourly storage use in RESOLVE tended to be more discharging to provide load following up. RESOLVE hourly and subhourly storage use must be combined to accurately reflect storage round-trip efficiency.
- Pumped storage dispatch and net losses lined up reasonably well between the two models
- Battery storage dispatch and net losses in SERVM are significantly lower than those in RESOLVE. Lower utilization of batteries in SERVM may result from dispatch algorithm differences between the two models. Further investigation would be necessary to identify key drivers of differences in battery dispatch.



PSH = Pumped Storage Hydro
NonPV_Load_Mod = net effect of AAEE, EV load, and TOU

Study Results: PCM of the "as-found" system



PSH = Pumped Storage Hydro
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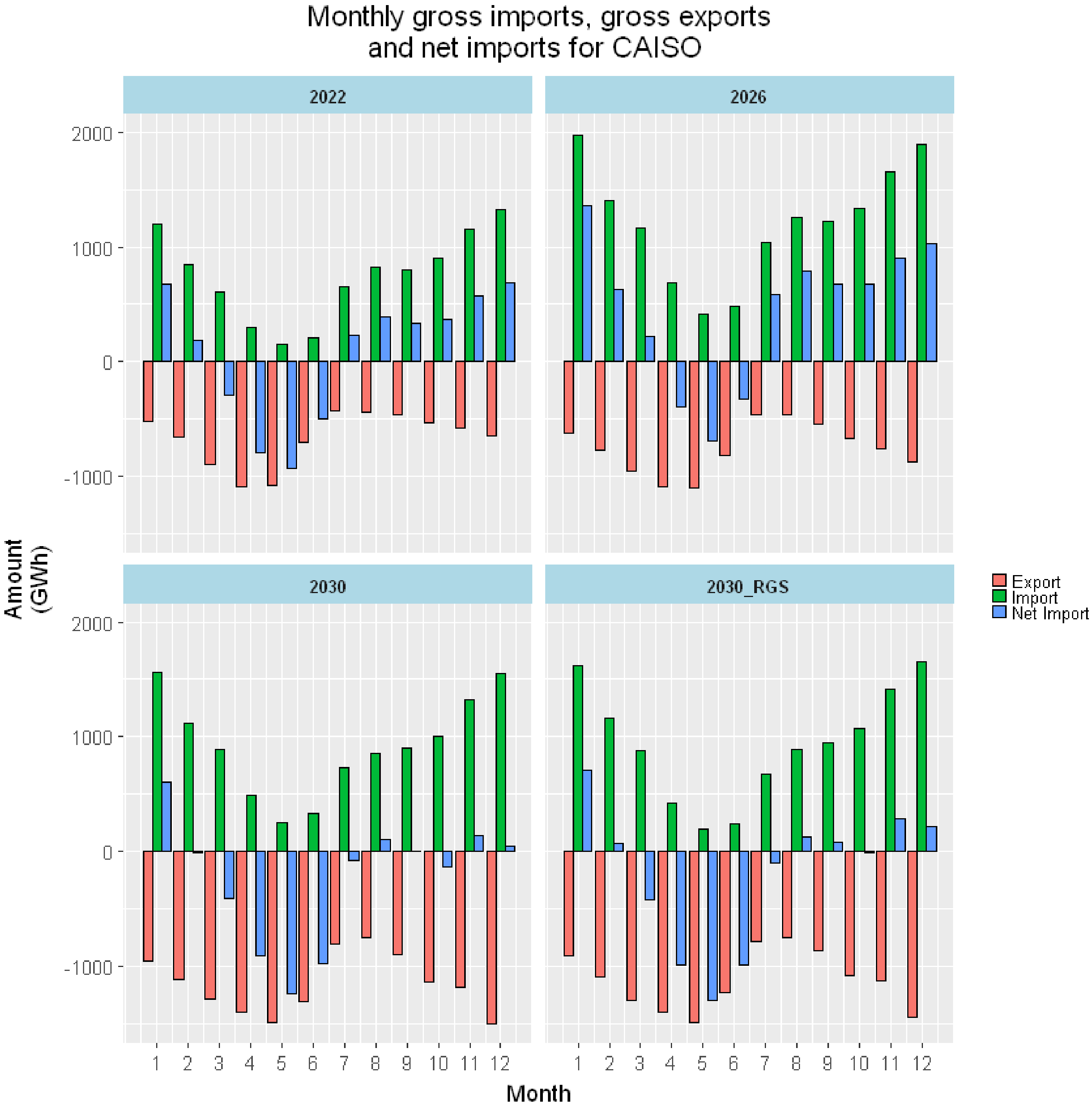
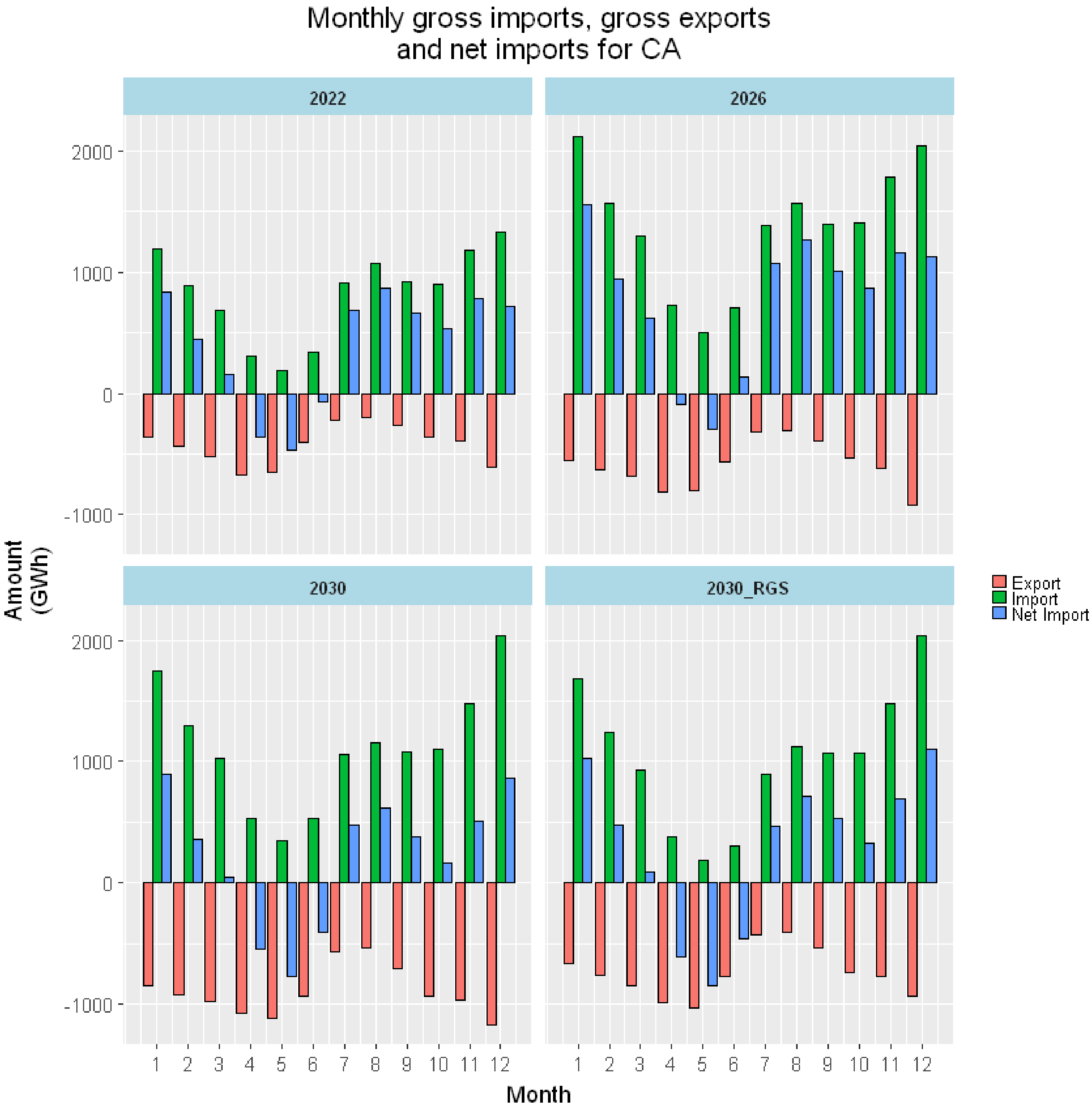
Study Results: PCM of the “as-found” system



Unspecified imports and exports

SERVM included a net export limit of 5,000 MW in any hour. This limit was only occasionally binding despite sizable monthly curtailment. Further investigation may be required to assess SERVM's modeling of high export flows and any interaction between periods of curtailment and the ability of CAISO neighbors to absorb CAISO's excess energy.



Unspecified imports and exports

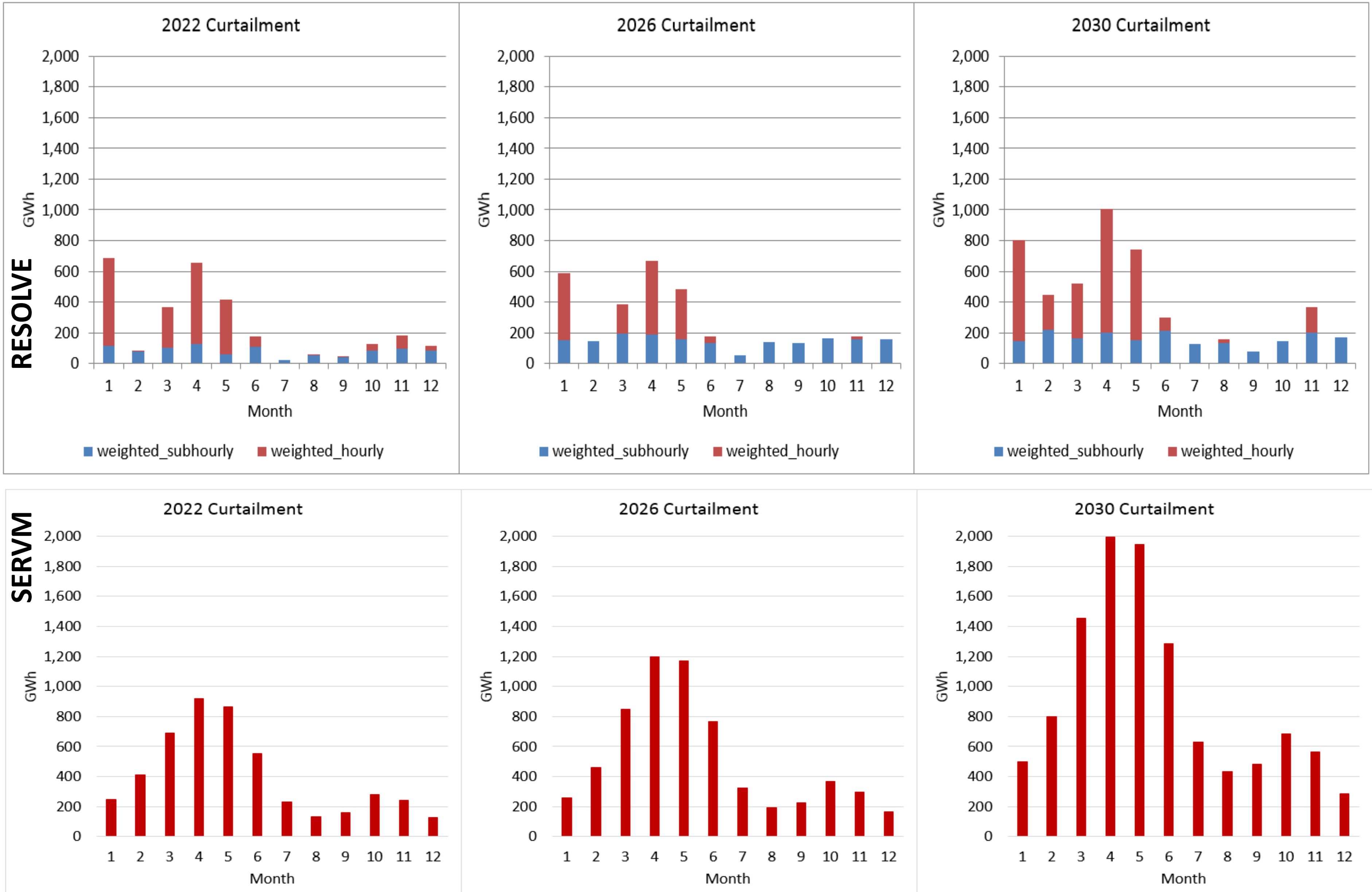
Comparing with the preceding slide, the CAISO area appears to export some of its excess to other CA areas as well as OOS. CAISO appears to mostly import from OOS since CA imports generally exceeds CAISO imports.

Study Results: PCM of the "as-found" system

Monthly CAISO curtailment comparison with RESOLVE

- RESOLVE reports scheduled (hourly) curtailment which is generally due to excess production, and estimates subhourly curtailment, generally due to downward load following provision
- Breakout of monthly curtailment in RESOLVE is a very gross estimate since the day-weighting scheme was designed to represent high and low load days within a year, but not within individual months
  - One of RESOLVE's 37 representative days is a January day with relatively high weight. That day also happened to have high curtailment, thus **overestimating** the amount of January curtailment due to the high day weight.
- SERVM reports only hourly curtailment, subhourly effects were not explicitly simulated
- The next slide graphically compares monthly curtailment extracted from RESOLVE results (top row) and monthly curtailment reported by SERVM (bottom row), for the CAISO area.

Monthly CAISO area curtailment comparison



Study Results: PCM of the "as-found" system

Factors contributing to higher curtailment in SERVM than RESOLVE

- SERVM curtailment overall is significantly higher than reported by RESOLVE, likely due to the interaction of multiple factors:
  - SERVM's thermal generation was modeled as less flexible with some units not turned off during excess supply conditions midday
  - SERVM had more renewable energy than was modeled in RESOLVE
  - SERVM storage on an annual basis had less charge/discharge mileage than RESOLVE
  - SERVM exported more excess energy than RESOLVE but still encountered curtailment, implying that CAISO neighbors were constrained in their ability to absorb it
- The next slide tabulates where SERVM models more renewable energy production than RESOLVE, contributing to the conditions for more curtailment in SERVM results:
  - BTM PV production (not curtailed in both models) is 42,621 GWh in SERVM and 36,295 GWh in RESOLVE, for similar installed capacity amounts. This is mostly driven by how RESOLVE aligns with the IEPR on annual energy whereas SERVM aligns with the IEPR on installed AC capacity.
  - Wind production before curtailment is 28,060 GWh in SERVM and 22,579 GWh in RESOLVE. This is driven by differing amounts of renewables capacity considered as inside CAISO – SERVM modeled more out-of-state wind units as "internal" to CAISO.

Detailed comparison showing greater CAISO area renewables generation in SERVM than RESOLVE

	Units	SERVM: 2030	RESOLVE: 2030
All generation before curtailment *	GWh	269,484	254,749
BTM PV + Utility solar + Wind generation before curtailment	GWh	123,241	109,122
Hourly curtailment	GWh	-11,055	-2,923
BTM PV + Utility solar + Wind generation after curtailment	GWh	112,186	106,199
All other generation (not curtailed) *	GWh	146,244	145,626
BTM PV generation (not curtailed)	GWh	42,621	36,295
BTM PV nameplate	MW	20,759	21,573
Utility solar generation before curtailment	GWh	52,560	50,248
Utility solar generation after curtailment	GWh	n/a **	47,990
Utility solar nameplate	MW	19,701	18,609
Wind generation before curtailment	GWh	28,060	22,579
Wind generation after curtailment	GWh	n/a **	21,914
Wind nameplate	MW	11,325	8,977

Large difference in renewables generation

Small difference in all other generation

Main components driving large renewables difference

* Does not include storage dispatch and non-PV load modifiers (which are modeled as generators in SERVM)

** SERVM does not estimate curtailment by resource type – it only reports system curtailment, assumed to come from utility-scale solar and wind in this comparison

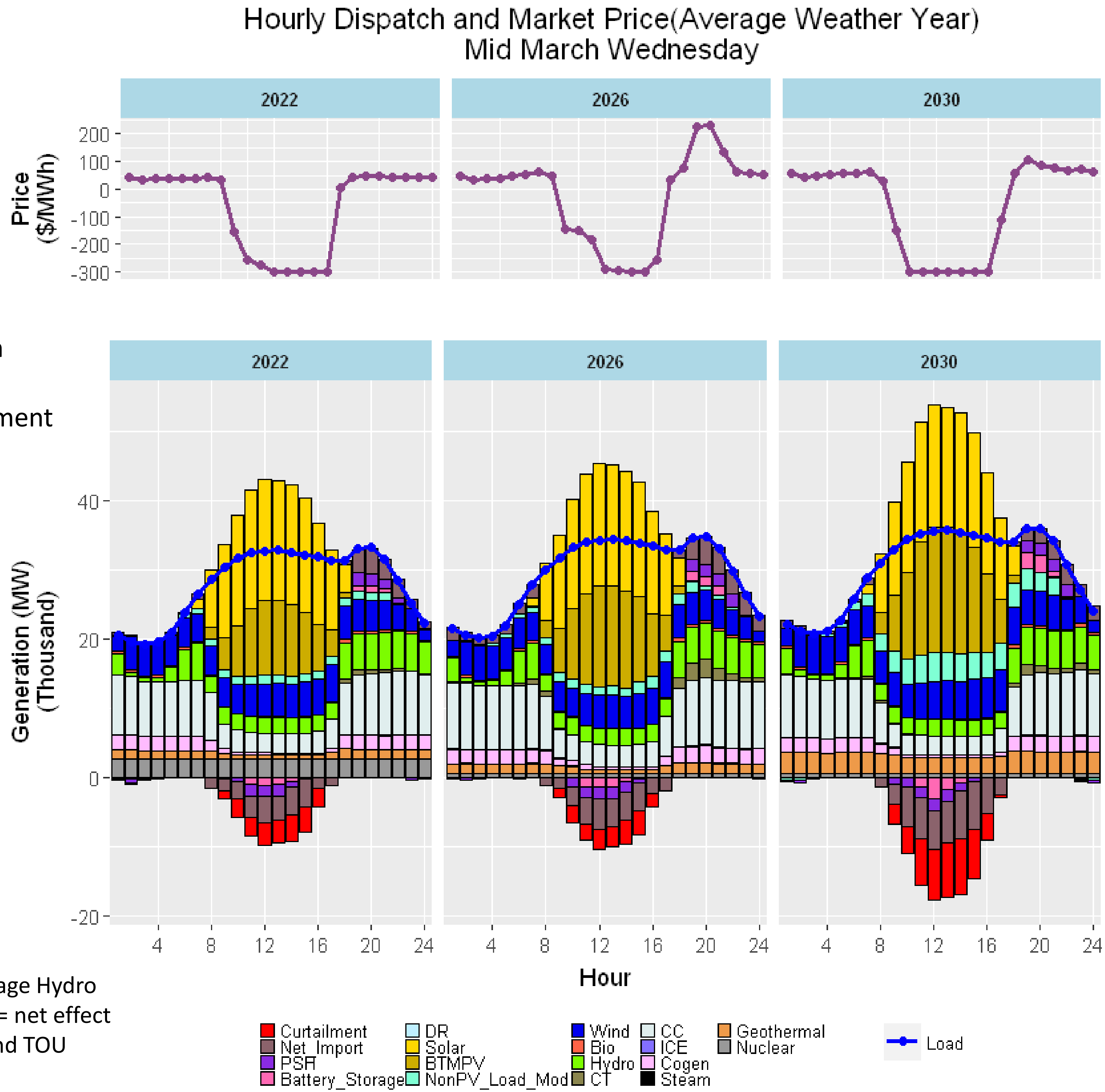
Explanation of how curtailment is modeled in SERVM

- Energy is dispatched to meet load, but when there is excess energy, some is curtailed.
  - SERVM attempts to sell excess generation over what is needed to meet load.
  - When that ceases to be economical, dispatchable generation is shut down to the extent possible, but sometimes generation cannot be immediately shut down or must be kept at minimum to enable it to serve load later in the day or to provide operational reserves.
  - When generation cannot be economically shut down and energy cannot be sold economically there is curtailment.
  - In the presence of curtailment, an overgeneration penalty is applied. At low levels of curtailment, the penalty does not overwhelm the other market transactions, but at high levels of curtailment, energy prices have fallen below zero with the penalty.
  - Market energy pricing as implemented is a gradient, and negative pricing depends on the quantity of curtailment.

Hourly generation mix and energy price

- The following slides show hourly generation mix and energy price for the 3 primary study years, under the following conditions:
  - Wednesday mid March, average weather
  - Wednesday mid March, hot weather
  - Wednesday mid August, average weather
  - Wednesday mid August, hot weather
- Storage usage volumes look similar across different seasons and weather
- Significant amounts of spring midday excess energy are exported and curtailed, consistent with monthly and annual observations shown on earlier slides

50th percentile March weather (1989, case 43 of 175)

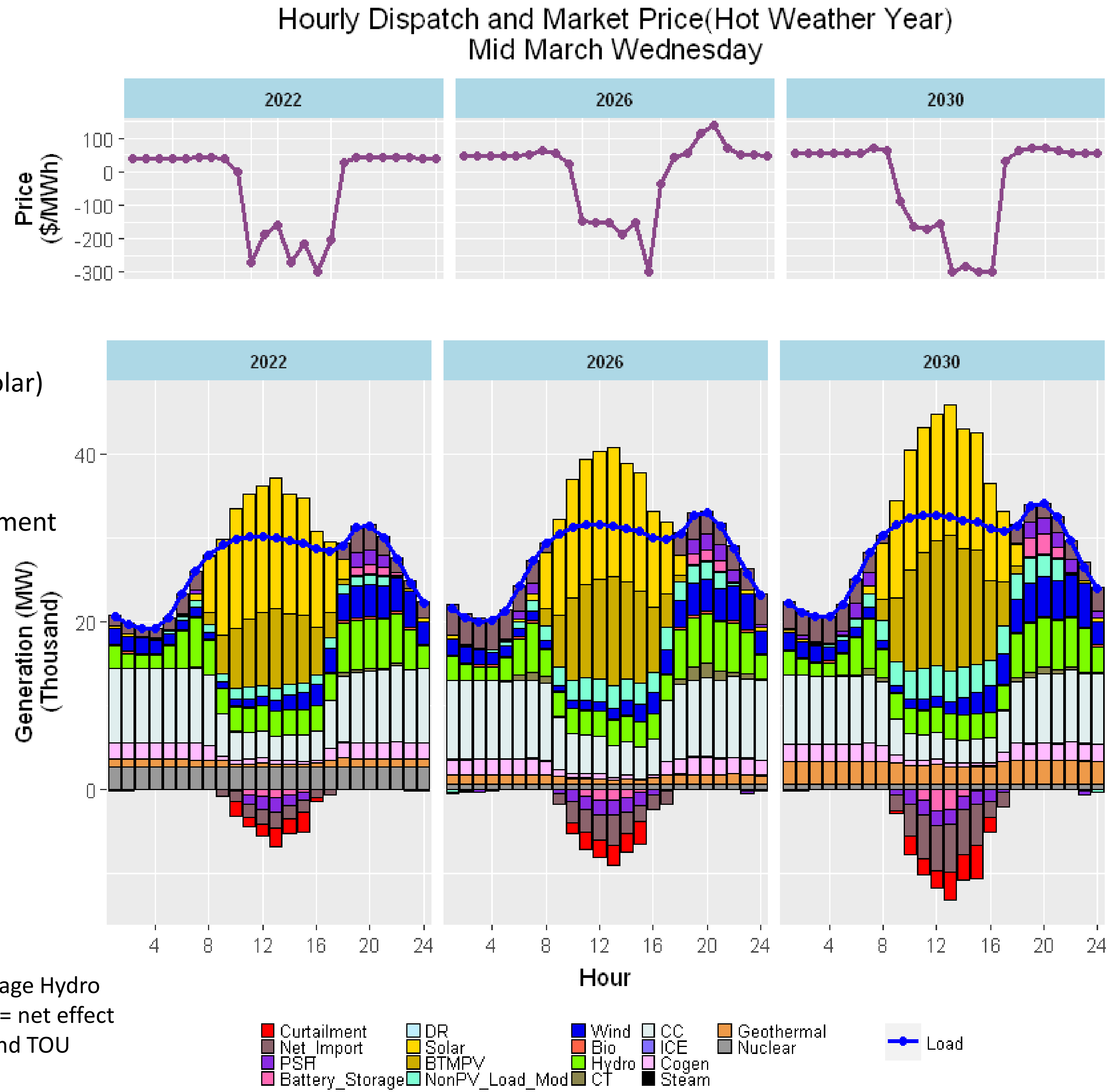


A spring day with negative midday price and curtailment in all years

PSH = Pumped Storage Hydro
NonPV_Load_Mod = net effect of AAEE, EV load, and TOU

Study Results: PCM of the "as-found" system

90th percentile March weather (2004, case 118 of 175)

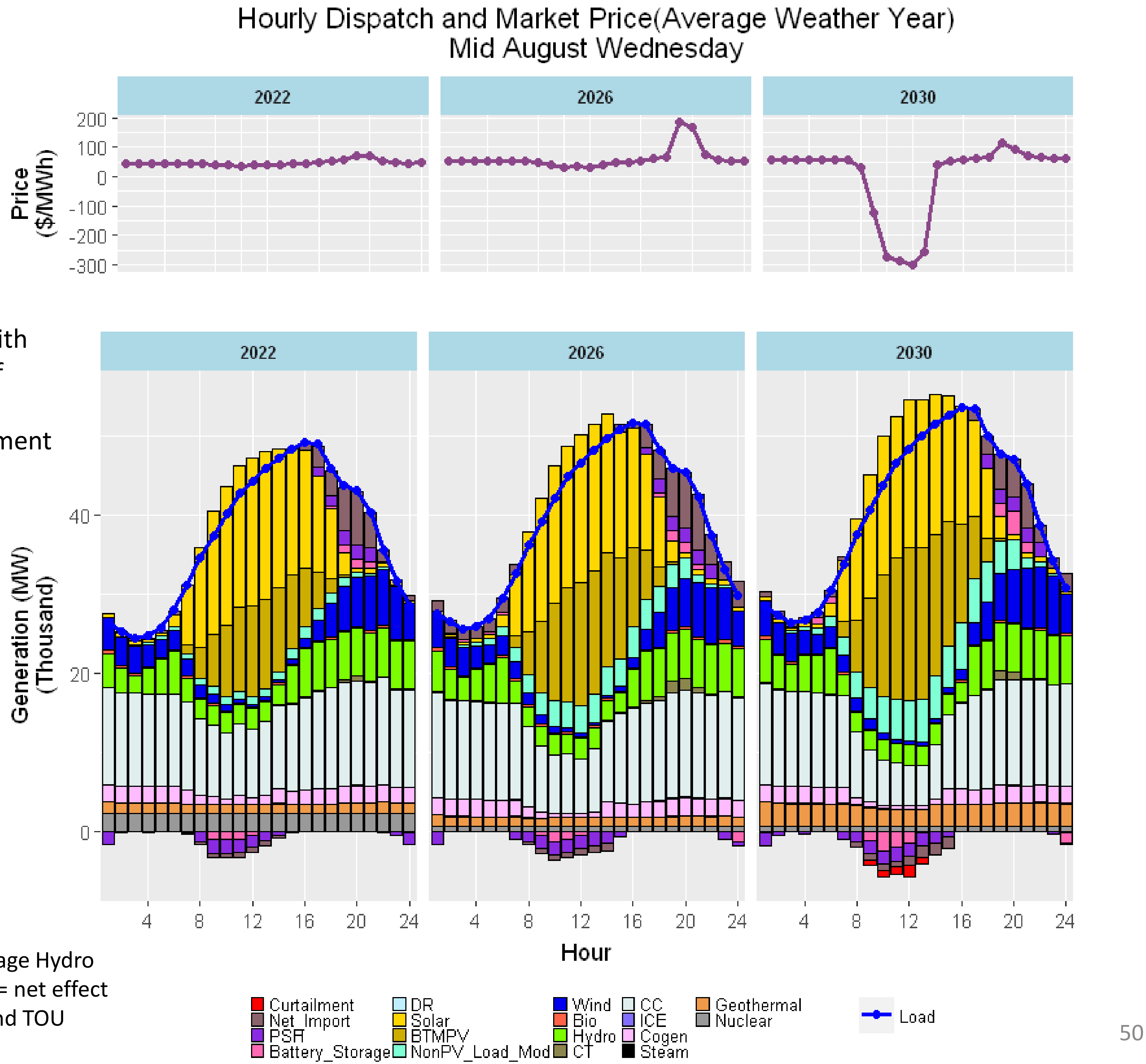


A hot (perhaps cloudy w/ less solar) spring day with somewhat less negative midday price and curtailment

PSH = Pumped Storage Hydro
NonPV_Load_Mod = net effect of AAEE, EV load, and TOU

Study Results: PCM of the "as-found" system

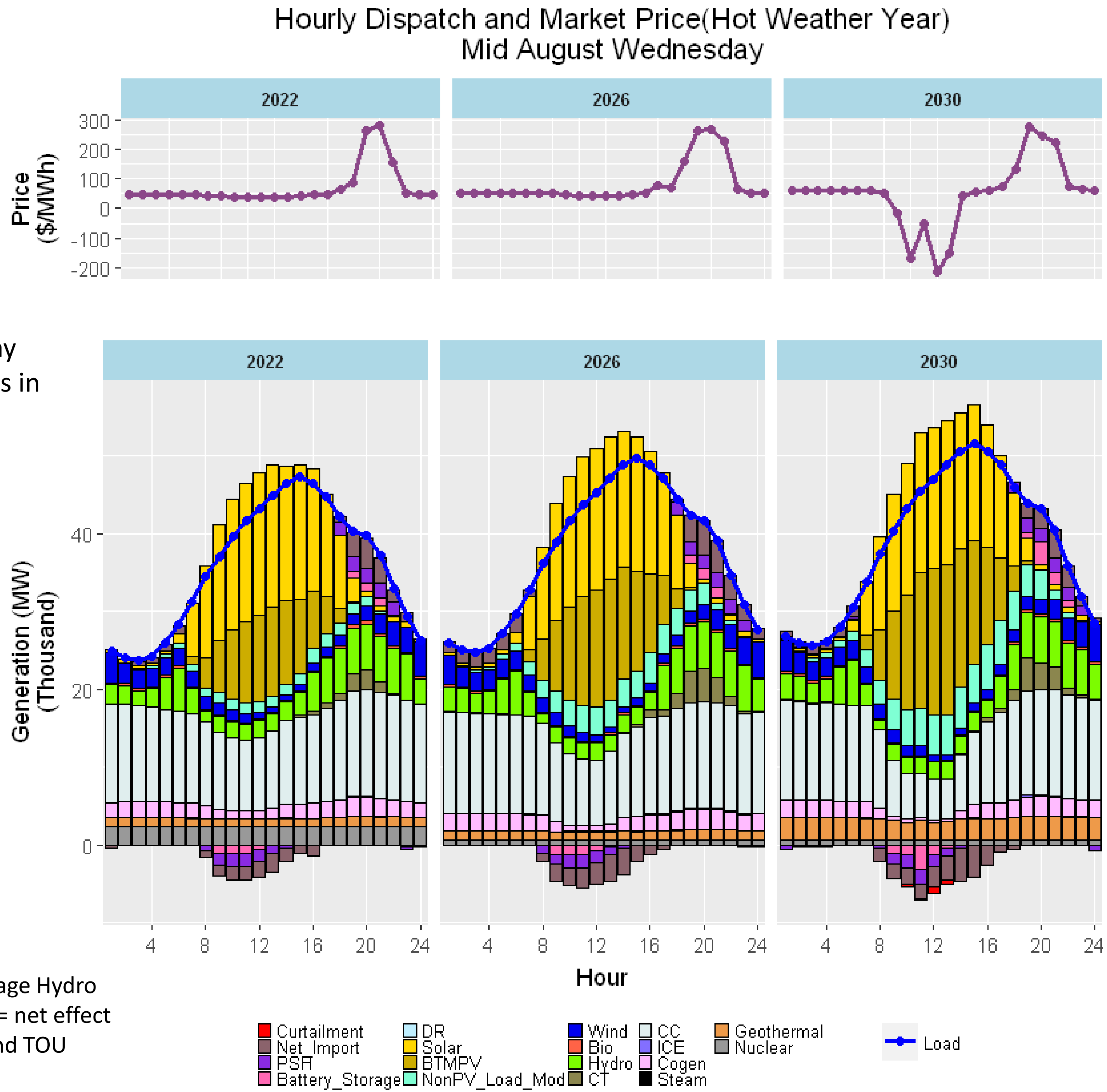
50th percentile August weather (1986, case 28 of 175)



A summer day with small amounts of negative midday price and curtailment in 2030

PSH = Pumped Storage Hydro
NonPV_Load_Mod = net effect of AAEE, EV load, and TOU

90th percentile August weather (2009, case 143 of 175)



A hot summer day with higher prices in the 6-9pm hours

PSH = Pumped Storage Hydro
NonPV_Load_Mod = net effect of AAEE, EV load, and TOU

Refresher: IRP GHG Planning Targets

- The February 2018 IRP decision, D.18-02-018, adopted an electric sector 42 MMT in 2030 planning target, statewide
- This translated to a 34 MMT in 2030 planning target for the CAISO footprint, assuming CAISO share of statewide electric sector emissions is about 81%
- RESOLVE does not count BTM CHP emissions as part of electric sector emissions, whereas CARB's California Greenhouse Gas Emissions Inventory and Scoping Plan does. Results compiled from SERVM attempt to follow the same counting convention as RESOLVE, excluding any emissions from BTM CHP (generally the non-PV self-generation component of the IEPR demand forecast).

SERVM emissions results

- The following slides describe methods and sources for estimating criteria pollutant emissions, and then present SERVM results for annual and monthly CO2 and criteria pollutant emissions.

Methods and assumptions for estimating criteria pollutant emissions

- CPUC staff estimated total NOx and PM 2.5 emissions as the sum of emissions from steady-state operations and hot, warm, and cold starts
  - Staff used fuel burn, number of hot/warm/cold starts, and MWh generation output from SERVM, applying appropriate emissions factors
  - For NOx, staff used higher emissions factors for hot, warm, and cold starts compared to steady-state
  - Where information on generator subtype was available (e.g. CCGTs can be divided into Aero CC, Single Shaft CC, Industrial CC, etc.), staff used that subtype to determine emissions factor, as emissions can vary substantially across subtype
- Criteria pollutant emissions were counted from in-CAISO thermal generation and specified imports serving CAISO load, including Intermountain (both current coal and future CC repower), Mesquite, and Arlington generators. Unspecified import criteria pollutants are not counted.
- No factors for "warm" starts were available, so staff used a simple average of hot and cold factors as an estimate

Data sources for criteria pollutant emissions estimation (1)

Generator Type	Item	Units	Quantity	Organization	Source Name	Page and table number	Hyperlink
Coal	Heat Content	MMBTU/US ton coal	19.78	EIA	EIA FAQ: What is the heat content of US Coal?	N/A	https://www.eia.gov/tools/faqs/faq.php?id=72&t=2
Coal	Ash Percentage	%	6.44%	US Geological Survey	Quality of Economically Extractable Coal Beds in the Gillette Coal Field as Compared With Other Tertiary Coal Beds in the Powder River Basin, Wyoming and Montana	p. 11 Table 3, Mean ash content from Powder River Basin	https://pubs.usgs.gov/of/2002/ofr-02-0174/ofr-02-0174po.pdf
Coal	PM 2.5 Emissions Factor	lbs/US ton of coal burn	0.4011592	Argonne National Labs	Updated Greenhouse Gas and Criteria Air Pollutant Emission Factors and Their Probability Distribution Functions for Electric Generating Units	p. 15 Table 5. Assumed scrubber, subtuminous coal, boilers, pulverized, dry bottom, flue gas desulfurization .	https://greet.es.anl.gov/publication-updated-elec-emissions
Coal	Steady-state NOx Emissions Factor	lbs/mmbtu	0.075	DOE National Energy Technology Laboratory	Cost and Performance Baseline for Fossil Energy Plants	p. 15, Exhibit ES-2, Colum B11B Nox Emissions (lb/MMBtu)	https://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Rev3Vol1aPC_NGCC_final.pdf

Data sources for criteria pollutant emissions estimation (2)

Generator Type	Item	Units	Quantity	Organization	Source Name	Page and table number	Hyperlink
All Non-Coal Thermal	PM 2.5 Emissions Factors	lbs/mmbtu	range depending on subtype: 0.0066 to .01	CAISO	Senate Bill 350 Study Volume IX: Environmental Study	p.98 Table 4.4-2	http://www.caiso.com/Documents/SB350Study-Volume9EnvironmentalStudy.pdf
All Non-Coal Thermal	Steady State NOx Emissions Factors	lbs/MWh	range depending on subtype: 0.07 to 0.5	CAISO	Senate Bill 350 Study Volume IX: Environmental Study	p.98 Table 4.4-2	http://www.caiso.com/Documents/SB350Study-Volume9EnvironmentalStudy.pdf
All Thermal	Hot Start NOx Emissions Factors	kg/MW nameplate/ start	range depending on subtype: 0.05 to 1.12	Renewable and Sustainable Energy Reviews	Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables	p. 1507 Table 14	https://www.sciencedirect.com/science/article/pii/S1364032117309206
All Thermal	Cold Start NOx Emissions Factors	kg/MW nameplate/ start	range depending on subtype: 0.07 to 1.57	Renewable and Sustainable Energy Reviews	Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables	p. 1507 Table 14	https://www.sciencedirect.com/science/article/pii/S1364032117309206
All Thermal	Warm Start NOx emissions factors	kg/MW nameplate/ start	range depending on subtype: 0.07 to 1.35	Renewable and Sustainable Energy Reviews	Review of the operational flexibility and emissions of gas- and coal-fired power plants in a future with growing renewables	Simple Average of Hot and Cold	https://www.sciencedirect.com/science/article/pii/S1364032117309206

Annual CO_2, NO_x, PM2.5 emissions*

CAISO	Units	2022	2026	2030	2030+RGS
CO2	MMT	37.4	43.4	38.2	37.6
NOx	Metric ton	4,100	4,393	4,114	3,933
Steady-state	Metric ton	3,758	3,916	3,651	3,558
Starts	Metric ton	342	477	462	375
PM2.5	Metric ton	2,109	2,204	2,056	2,019

California	Units	2022	2026	2030	2030+RGS
CO2	MMT	46.6	53.1	48.1	46.8
NOx	Metric ton	7,368	5,475	5,245	4,999
Steady-state	Metric ton	6,896	4,820	4,591	4,453
Starts	Metric ton	472	655	654	546
PM2.5	Metric ton	3,240	2,724	2,594	2,537

*CO2 emissions are from all generation to serve load including unspecified imports.
NOx and PM2.5 emissions are from in-state generation and specified imports only.

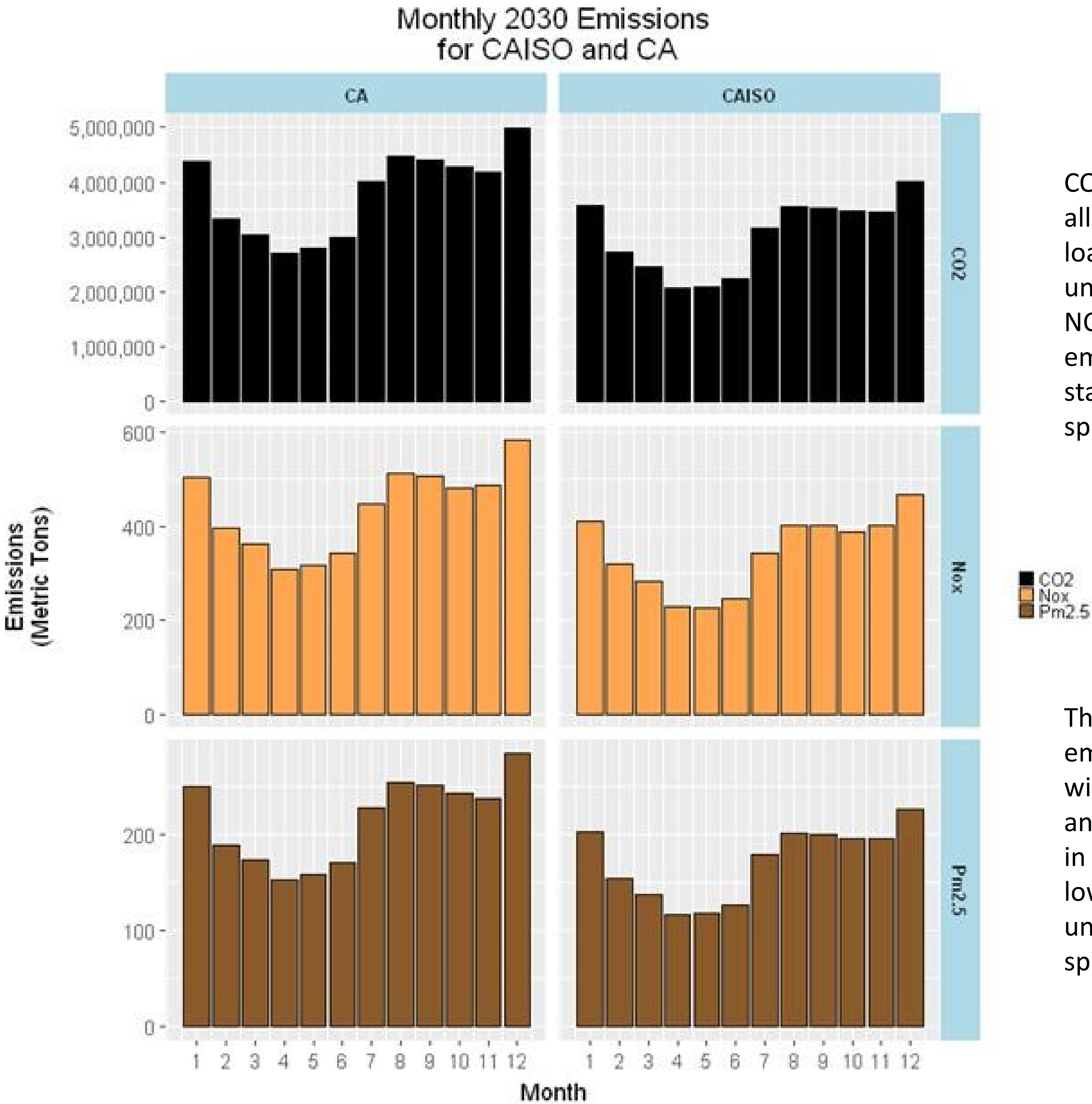
Details: 2030 California NOx, PM2.5 emissions*

NOx emissions in metric tons, by operation state and resource type						
	CC	CT	Coal	Cogen	ICE	Steam
steady state	3,135	335	-	1,071	40	10
hot start	154	36	-	4	2	0
warm start	54	310	-	23	17	0
cold start	18	29	-	5	2	0
total	3,362	709	-	1,103	61	10

PM 2.5 emissions in metric tons, by resource type						
	CC	CT	Coal	Cogen	ICE	Steam
steady state	2,062	130	-	387	8	7

*NOx and PM2.5 emissions are from in-state generation and specified imports only, for the 2030 study (not the sensitivity). CC = Combined Cycle, CT = Combustion Turbine, ICE = Internal Combustion Engine

The Sept 2017 Proposed Reference System Plan analysis estimated NOx from CCs in steady state as roughly 2,700 metric tons in 2030, statewide. The SERVM analysis here estimates 3,135 metric tons in 2030, statewide. SERVM's higher number is due to multiple factors: inclusion of specified fossil imports, some of SERVM's CCs were assigned higher NOx emissions factors based on technology, CCs run a bit more in SERVM than in RESOLVE.



CO2 emissions are from all generation to serve load including unspecified imports. NOx and PM2.5 emissions are from in-state generation and specified imports only.

The monthly pattern of emissions correlates with higher use of CCGTs and unspecified imports in winter months and lower use of CCGTs and unspecified imports in spring months.

Comparison to RESOLVE: 2030 CAISO CO2 Emissions

Thermal generation serving CAISO load and CO2 emissions	SERVM: 2030	SERVM: 2030+RGS	RESOLVE
In-CAISO and gross direct imports thermal generation in GWh	86,635	85,413	84,156
In-CAISO and gross direct imports CO2 emissions in MMT	36.29	35.60	31.38
In-CAISO and gross direct imports average emissions factor in MT/MWh	0.419	0.417	0.373
Gross unspecified imports in GWh	10,985	11,171	12,709
Gross unspecified imports CO2 emissions in MMT	4.70	4.78	5.44
Gross unspecified imports average emissions factor in MT/MWh	0.428	0.428	0.428
NW Hydro Credit in MMT	-2.8	-2.8	-2.8
Total CO2 emissions in MMT	**38.2**	**37.6**	**34.0**

- Higher emissions in SERVM appear to be driven by multiple factors including higher heat rates overall, more time spent in higher heat rate operating states, and more peaker dispatch
- Total thermal generation and unspecified import amounts are similar across models while the average emissions factors for thermal generation in SERVM are higher
- The NW Hydro Credit is an adjustment inherited from RESOLVE to account for assumed amounts of specified hydro imports coming from the Pacific Northwest into California

RPS percentage in 2030 from SERVM results

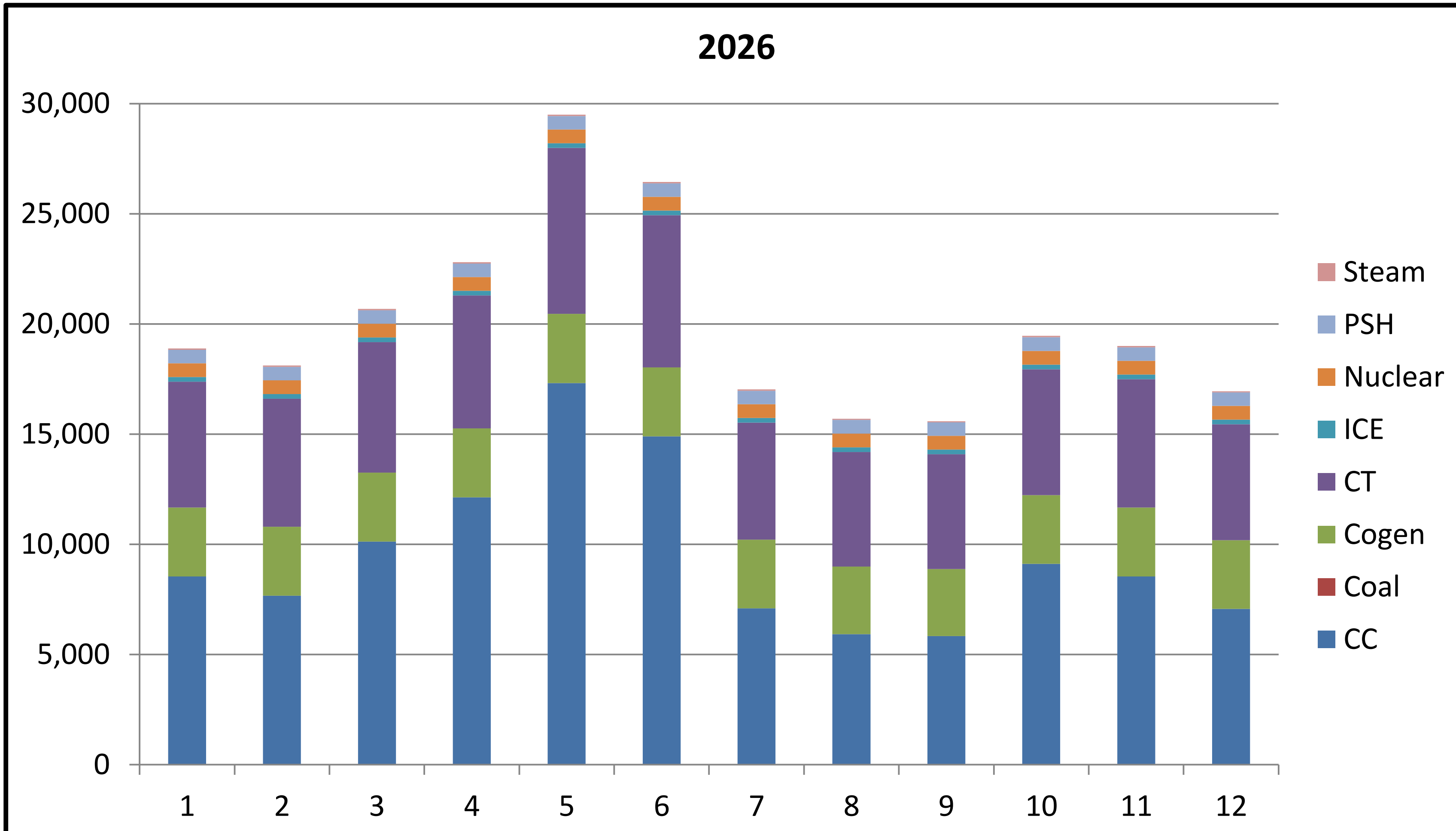
CAISO area RPS% calculation comparison		RESOLVE	SERVM
Metric	***Unit***	**2030**	2030
T&D Losses	*%*	7%	7%
Pumping Loads - not grossed up for losses	*GWh*	8,781	8,781
Customer_PV (btmpv)	*GWh*	36,295	42,621
System Load after non-btmpv load-modifiers & before btmpv reductions	*GWh*	255,038	254,601

Metric	Unit	2030	2030
Delivered RPS Renewables after Scheduled Curtailment	*GWh*	109,136	101,949
Non-Modeled RPS Renewables (AESO wind mainly)	*GWh*	2,655	
RPS Spent Bank	*GWh*	8,441	8,441
Storage Losses Subtracted from RPS	*GWh*	1,961	949
Scheduled Curtailment	*GWh*	2,923	11,055
Subhourly Curtailment	*GWh*	1,936	
RPS-bound Retail Sales	*GWh*	193,929	187,661
Curtailment (scheduled and subhourly)	*% of RPS Renew.*	4.2%	9.8%
Curtailment and Storage Losses	*% of RPS Renew.*	5.9%	10.6%
Delivered Effective RPS Percentage - Excl. Spent Bank	*% of Retail Sales*	55.6%	53.8%
Spent Bank	*% of Retail Sales*	4.4%	4.5%
Delivered Effective RPS Percentage - Incl. Spent Bank	*% of Retail Sales*	60.0%	58.3%

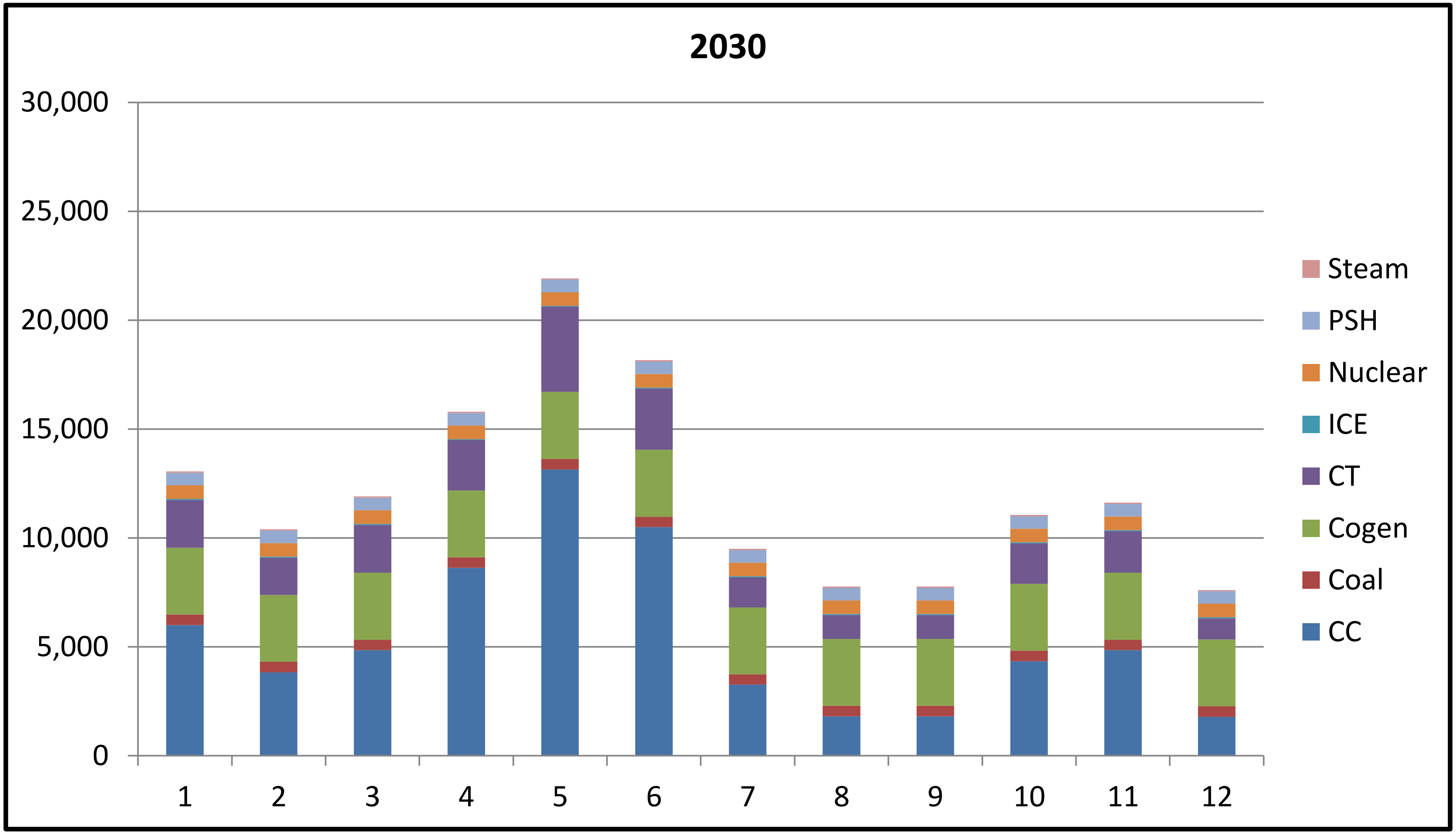
Calibrated loss-of-load studies

- Continuing with the steps outlined in Attachment B to the February 2018 IRP decision, D.18-02-018, staff performed monthly calibrated loss-of-load expectation (LOLE) studies for the CAISO area
- Calibrate the "as found" system to a known reliability target with which to perform monthly Effective Load Carrying Capability (ELCC) studies of the "as found" wind and solar portfolio
  - By month, remove capacity to surface loss-of-load events so ELCC can be measured, referenced to a set reliability target level
  - Generally oldest thermal capacity is removed first
  - Units are removed until the monthly LOLE is between 0.02 and 0.03
  - Report the capacity that was removed, by month
  - Study years 2026 and 2030 only – staff time and resources were insufficient to complete production of 2022 results
- The following charts illustrate the amounts of capacity removed by month

2026 capacity removed to calibrate to target LOLE, by month and resource type, in MW



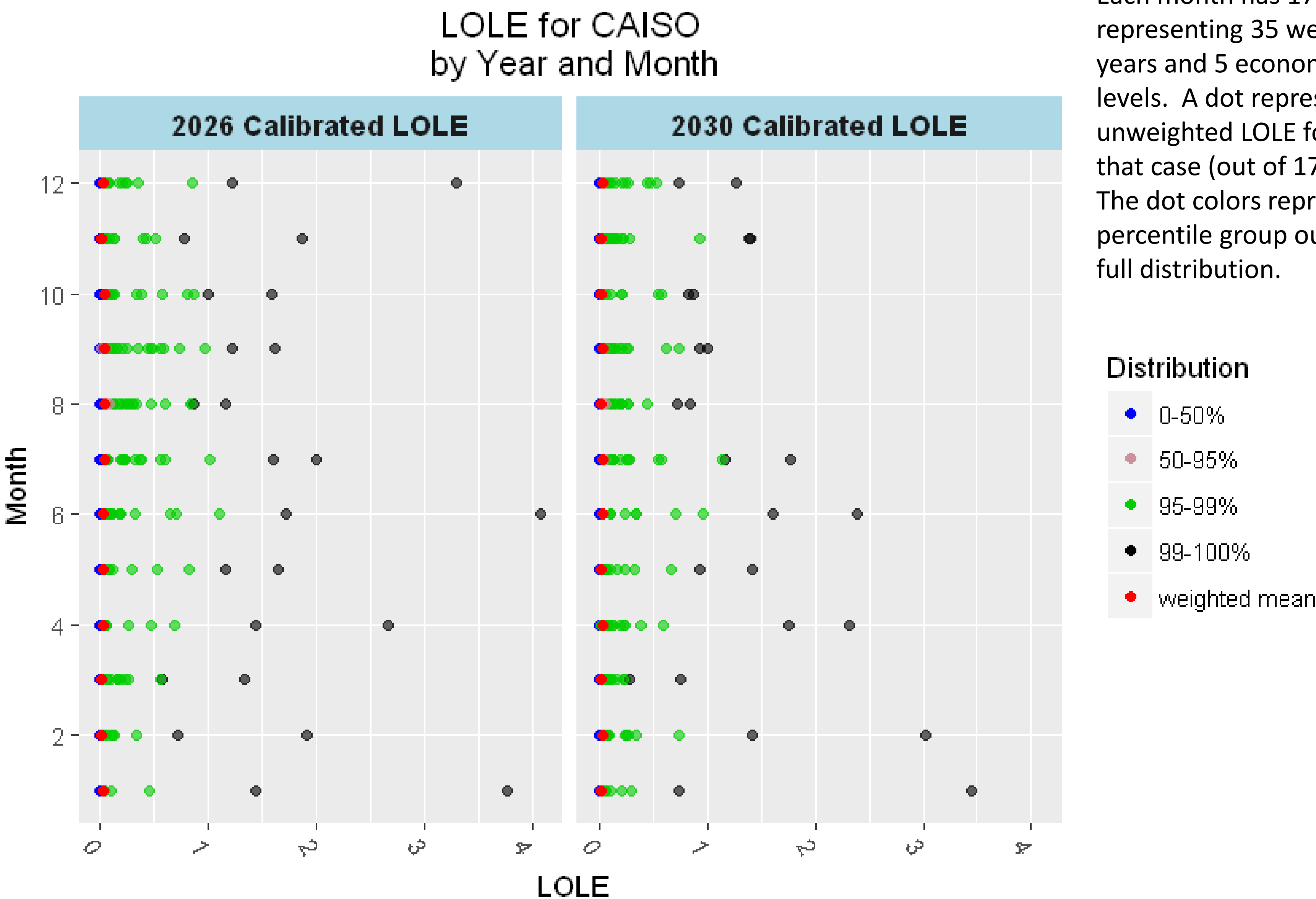
2030 capacity removed to calibrate to target LOLE, by month and resource type, in MW



Implications of large range of monthly capacity removals

- Capacity removed by month varies significantly, exceeding 20,000 MW in spring and as low as 7,500 MW in summer
- Large capacity removals were necessary in order to calibrate LOLE to a level that allowed ELCC analysis on a monthly basis. Important caveats to this analysis:
  - This does not represent an adequate reliability assessment, as CPUC staff did not explicitly evaluate sub-hourly flexibility (ramping) needs nor Local Resource Adequacy (RA) needs
  - Capacity was removed according to the steps outlined in Attachment B to D.18-02-018. This was only a modeling convention and is not meant to predict retirement of units individually or in aggregate. The calibrated LOLE system does not represent a projection of future resource levels or mixes.
- This analysis suggests that from an LOLE standpoint, the system is currently long on capacity. As more GHG free capacity is installed, it may be possible for other capacity to be removed (at least in certain months) without significant reliability consequences. However, more analysis and information is needed to evaluate other aspects of reliability.

Distribution of LOLE for the “as found” system calibrated to weighted average monthly target reliability of 0.02 to 0.03 LOLE



Each month has 175 dots representing 35 weather years and 5 economic load levels. A dot represents the unweighted LOLE found in that case (out of 175 cases). The dot colors represent its percentile group out of the full distribution.

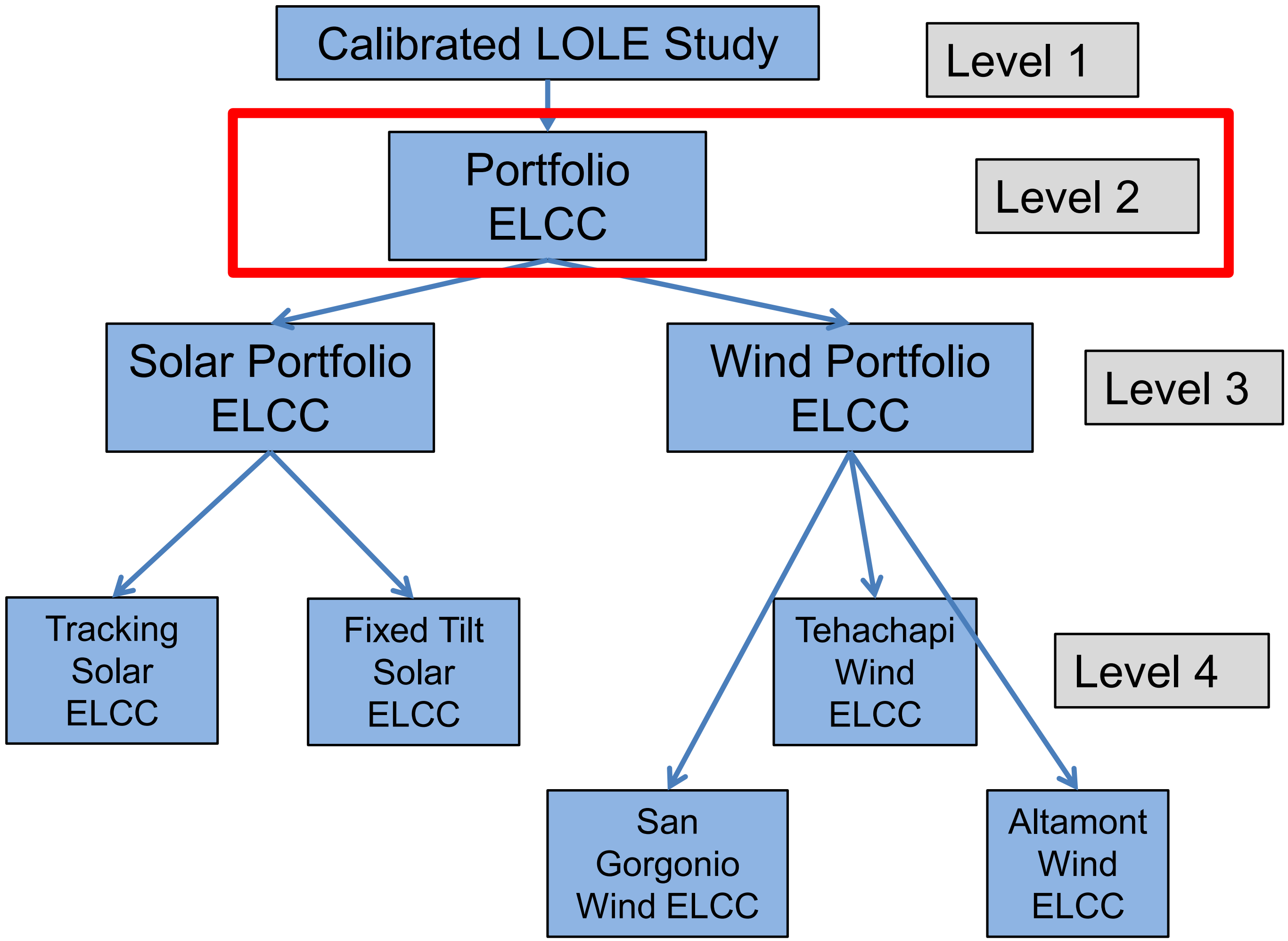
Average portfolio ELCC studies

- Starting with the monthly calibrated LOLE systems, perform monthly Effective Load Carrying Capability (ELCC) studies
  - Remove all utility solar and wind units
  - Incrementally add back perfect capacity until the monthly LOLE is between 0.02 and 0.03
  - Report the perfect capacity added back for each month
  - Calculate monthly ELCC as the perfect capacity added back divided by the nameplate of wind and utility solar units removed
  - Study years 2026 and 2030 only – staff time and resources were insufficient to complete production of 2022 results
  - BTM PV is excluded from the ELCC calculation
- Repeat the process above for utility solar + wind + all storage (battery & pumped storage hydro), still excluding BTM PV, and only for 2030
  - The presence of significant amounts of storage appears to play a key role in increasing the load carrying value of wind and solar, even if the storage is not explicitly tested for ELCC. Wind and solar ELCC is higher due to the ability to store extra generation and use it later as needed

Diagram of generalized sequence of ELCC studies

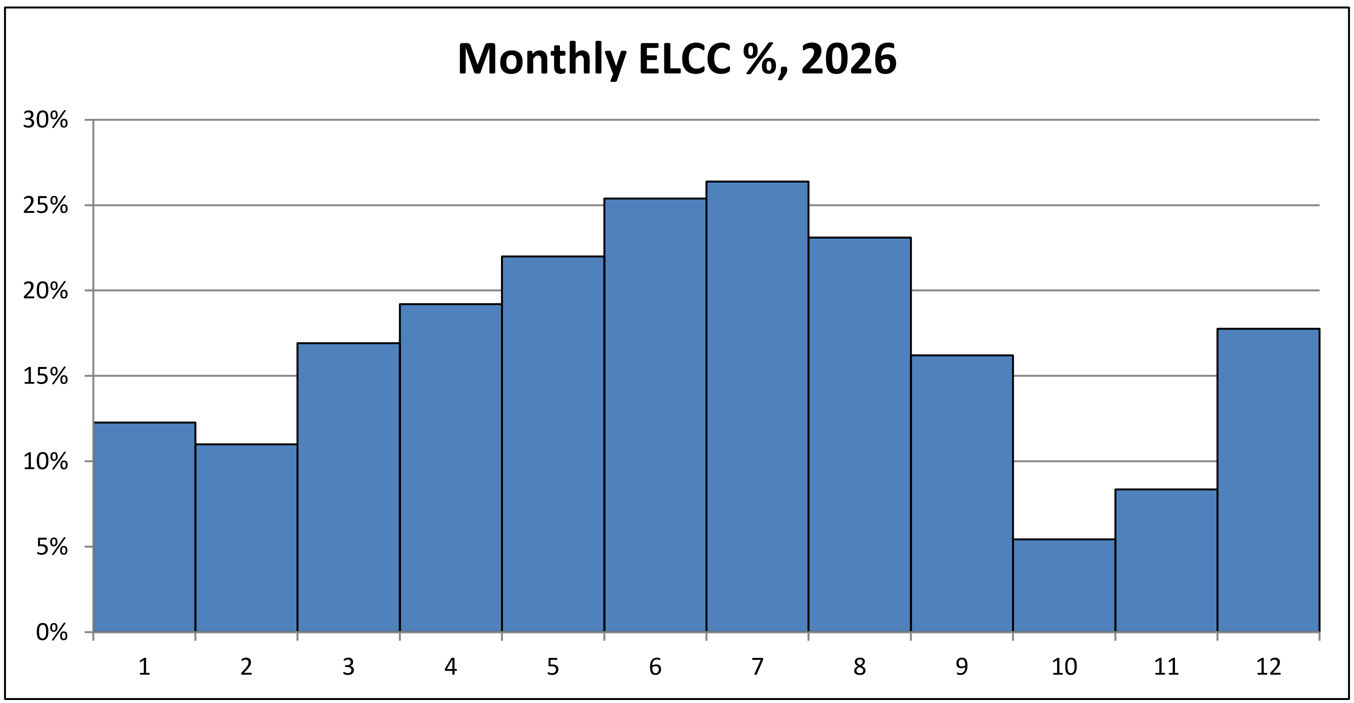
IRP studies stop at Level 2, Portfolio ELCC

- ELCC studies follow an order – results cascade
- Results of one level serve as control totals for the lower
- Each level is more granular than the previous – can be broken into technological or locational subcategories



2026 Monthly Portfolio ELCC calculation

Item	Units	1	2	3	4	5	6	7	8	9	10	11	12
Perfect capacity added	MW	2,901	2,600	4,000	4,538	5,200	6,000	6,236	5,461	3,830	1,283	1,977	4,200
Wind removed	MW	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867
Utility-scale solar removed	MW	15,773	15,773	15,773	15,773	15,773	15,773	15,773	15,773	15,773	15,773	15,773	15,773
Monthly ELCC	%	12%	11%	17%	19%	22%	25%	26%	23%	16%	5%	8%	18%



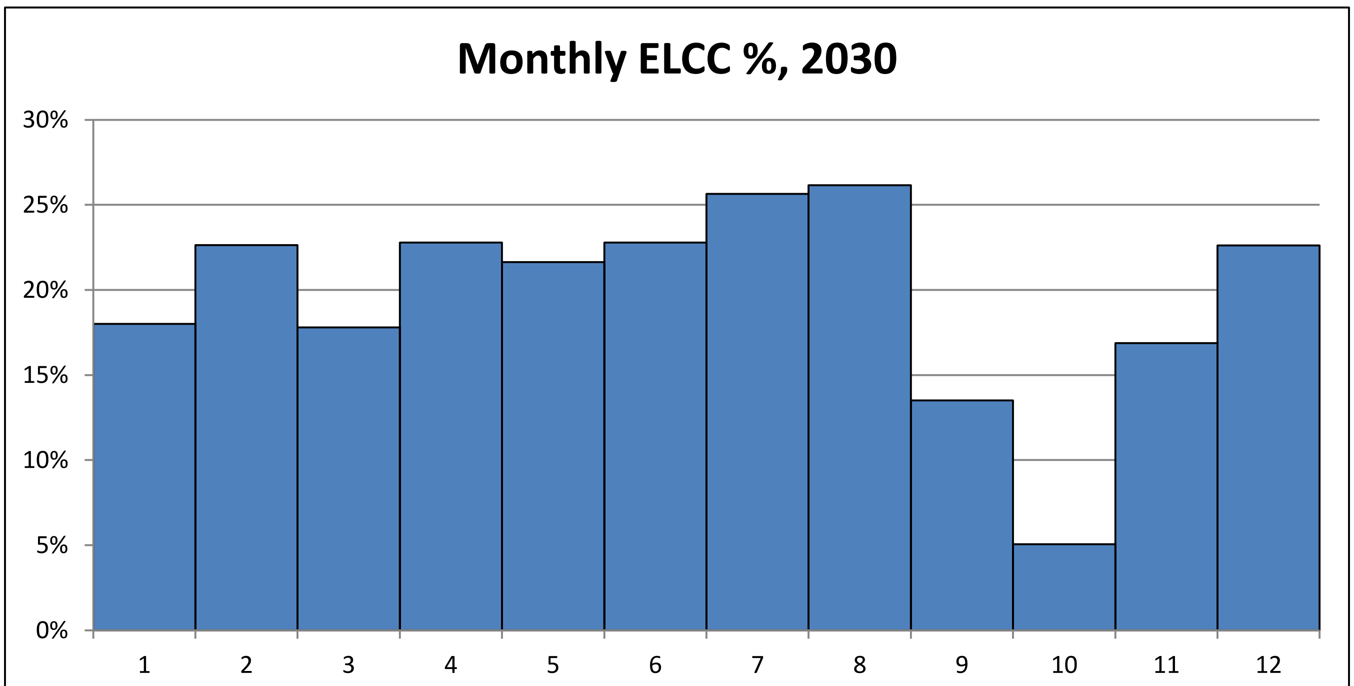
Wind and solar studied (removed) together

BTMPV not removed but present in system

About 1500 MW of battery storage present – possible effect on ELCC in offpeak months

2030 Monthly Portfolio ELCC calculation

Item	Units	1	2	3	4	5	6	7	8	9	10	11	12
Perfect capacity added	MW	4,269	5,367	4,221	5,400	5,127	5,400	6,078	6,200	3,200	1,200	4,000	5,360
Wind removed	MW	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867
Utility-scale solar removed	MW	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837
Monthly ELCC	%	18%	23%	18%	23%	22%	23%	26%	26%	14%	5%	17%	23%



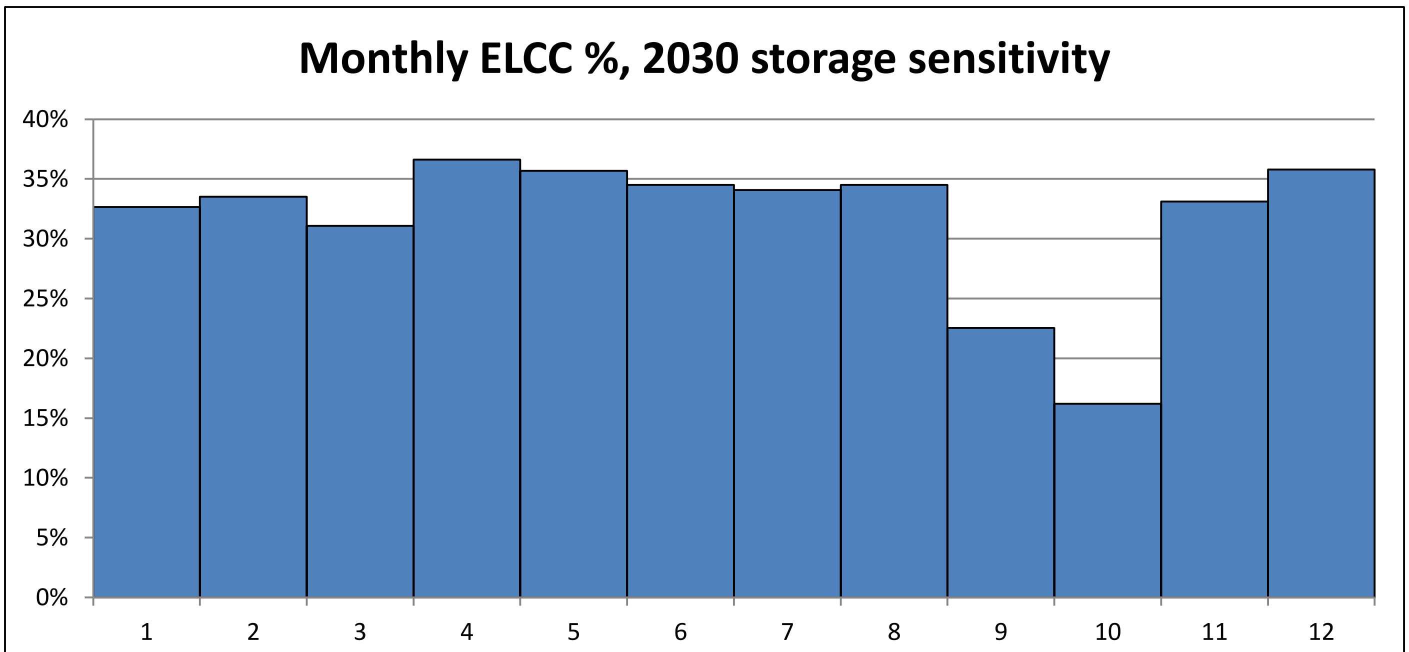
Wind and solar studied (removed) together

BTMPV not removed but present in system

Increase to 3400 MW of battery storage present – noticeable effect on ELCC in offpeak months

2030 Storage Sensitivity, Monthly Portfolio ELCC calculation

Item	Units	1	2	3	4	5	6	7	8	9	10	11	12
Perfect capacity added	MW	9,269	9,517	8,821	10,400	10,127	9,800	9,678	9,800	6,400	4,600	9,400	10,160
Wind removed	MW	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867	7,867
Utility-scale solar removed	MW	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837	15,837
Battery Storage removed	MW	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431	3,431
Pumped Storage Hydro removed	MW	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,258	1,258
Monthly ELCC	%	33%	34%	31%	37%	36%	35%	34%	35%	23%	16%	33%	36%



Wind, solar, and storage studied (removed) together

BTMPV not removed but present in system

Storage resources have clear diversity effect throughout year, particularly in offpeak months

Value of storage to portfolio ELCC

	1	2	3	4	5	6	7	8	9	10	11	12
Total MW removed, 2030 (wind and solar only)	23,704	23,704	23,704	23,704	23,704	23,704	23,704	23,704	23,704	23,704	23,704	23,704
Total MW removed, 2030 storage sensitivity (wind, solar, batteries, pumped hydro)	28,393	28,393	28,393	28,393	28,393	28,393	28,393	28,393	28,393	28,393	28,393	28,393
MW of perfect capacity added, 2030	4,269	5,367	4,221	5,400	5,127	5,400	6,078	6,200	3,200	1,200	4,000	5,360
MW of perfect capacity added, 2030 storage sensitivity	9,269	9,517	8,821	10,400	10,127	9,800	9,678	9,800	6,400	4,600	9,400	10,160
Difference in added perfect capacity between 2030 storage sensitivity and 2030 wind and solar only	5,000	4,150	4,600	5,000	5,000	4,400	3,600	3,600	3,200	3,400	5,400	4,800
Difference in removed resources between 2030 storage sensitivity and 2030 wind and solar only	4,689	4,689	4,689	4,689	4,689	4,689	4,689	4,689	4,689	4,689	4,689	4,689
Storage effective MW per MW of installed capacity	1.07	0.89	0.98	1.07	1.07	0.94	0.77	0.77	0.68	0.73	1.15	1.02

- Storage has the dual benefit of providing discharge at peak and absorbing excess solar generation during the day
- There appears to be significant diversity benefit created in a system with more storage relative to a system with less storage, even when storage is not removed and valued individually. Storage appears to increase the ELCC of solar relative to a no-storage or less storage system.
- Adding 1 MW of storage installed capacity to the system results in a greater than 1 MW effective capacity contribution to ELCC in months with substantial overgeneration relative to load. In months with less overgeneration, the effective capacity contribution is less than 1 (but still pretty high at about 0.7 or better). Storage increases average ELCC of all intermittent generation, but depends on overgeneration for highest value.

Reserve margin calculations

- Attachment B to the February 2018 IRP decision, D.18-02-018, described high-level steps for calculating the system reserve margin using the average portfolio ELCC to represent the Net Qualifying Capacity (NQC) of wind and utility solar.
- To align with the monthly Resource Adequacy (RA) compliance framework, it was desired to produce monthly ELCC values and calculate the monthly system reserve margin, projected through 2030.
- Though important to show how ELCC varies by month, precise reserve margin calculations by month through 2030 is of less value to the overall IRP planning exercise. Monthly calculations are also impractical due to lack of a long-term monthly peak demand forecast from the IEPR process.
- For these reasons, staff performed only annual system reserve margin calculations for each of the study years examined.

How reserve margin is calculated

- System reserve margin can be expressed as the effective capacity to meet peak demand divided by the forecast peak demand
  - A ratio of 115% or greater equates to meeting the 15% system Planning Reserve Margin (PRM) requirement in the RA compliance framework
  - The numerator is generally the sum of the NQC of all units plus the CAISO maximum simultaneous import limit
    - Only "supply-side" unit NQCs are summed because load-modifier contributions are counted in the denominator
    - Rely on the August values from the March 15, 2018 NQC List where possible
    - Count only fully-deliverable units, not energy-only units
  - The denominator is the IEPR 1-in-2 year coincident peak demand
    - 2017 IEPR mid demand, mid-mid AAEE, mid-mid AAPV case of the CAISO area sales forecast, grossed up to system level

Reserve margin calculation: numerator details (1)

Resource Type	How to represent its NQC
Nuclear	Use August value from NQC List
Fossil (cogen, CCGT, CT, ICE, steam, coal)	Use August value from NQC List, otherwise use SERVM capmax value. Units not found on the NQC List are planned units not yet online, e.g. from recent CPUC authorized LCR procurement.
Demand Response	Use SERVM August capmax value (which were derived from DR Load Impact Reports)
Hydro (large and small)	Use August value from NQC List, otherwise use SERVM capmax value. Units not found on the NQC List are planned units not yet online, e.g. listed in the IOU RPS Contracts Database.
Biomass	Use August value from NQC List, otherwise use SERVM capmax value. Units not found on the NQC List are planned units not yet online, e.g. listed in the IOU RPS Contracts Database.
Geothermal, not RSP new units	Use August value from NQC List, otherwise use SERVM capmax value. Units not found on the NQC List are planned units not yet online, e.g. listed in the IOU RPS Contracts Database.
Geothermal, RSP new units, FCDS portion*	Use SERVM capmax value
Geothermal, RSP new units, EO portion*	Do not count because Energy-Only

* For Reference System Plan (RSP) new geothermal units, RESOLVE breaks down selected resources by Full Capacity Deliverability Status (FCDS) or Energy Only (EO) designation.

Reserve margin calculation: numerator details (2)

Resource Type	How to represent its NQC
BTM PV (includes AAPV)	Do not count because it will be counted on load side
Non-PV Load Modifiers	Do not count because it will be counted on load side
Wind and Utility Solar (existing and RSP new units), FCDS portion*	Multiply the average of Jun, Jul, Aug, Sep monthly average wind and utility solar portfolio ELCC % by the sum of the nameplates of wind and utility solar that are FCDS
Wind and Utility Solar (existing and RSP new units), EO portion*	Do not count because Energy-Only
Pumped Storage Hydro**	Use August value from NQC List
Battery Storage, not RSP new units**	Use August value from NQC List, otherwise use SERVM capmax value. Units not found on the NQC List are planned units not yet online, e.g. from recent CPUC storage target procurement.
Battery Storage, RSP new units**	Use SERVM capmax value, proportionally derated by [duration hours/4 hours]
Contribution from Imports	Use SERVM CAISO Simultaneous Import Flow Limit, reduced by Existing Transmission Contracts

* For existing wind and utility solar units, the FCDS and EO designation can be found on the NQC List. For planned units, staff assumed FCDS designation. For RSP new units, RESOLVE breaks down selected resources by FCDS or EO designation.

** For the 2030 Storage Sensitivity, PSH and Batteries are not separate line items because its value is included in the portfolio ELCC

Reserve margin by study year, NQC MW

	2026	2030	2030 Storage Sensitivity
Hydro	5,289	5,289	5,289
Wind	1,607	1,554	2,217
PV Single Axis Tracking	1,386	1,341	1,913
Solar PV Fixed Tilt	1,724	1,681	2,399
Solar Thermal	284	275	392
CCGT	14,891	14,891	14,891
Cogeneration	2,890	2,890	2,890
Coal	0	0	0
CT	7,599	7,599	7,599
ICE	211	211	211
Steam	51	51	51
Nuclear	0	0	0
Geothermal	1,381	2,513	2,513
Biogas and Landfill Gas	259	259	259
Biomass and Wood	306	306	306
Battery Storage	1,345	1,982	632
Pumped Storage Hydro	1,514	1,514	651
Demand Response	1,754	1,754	1,754
Imports	10,193	10,193	10,193
Total NQC MW	52,683	54,303	54,160
1-in-2 Coincident Peak (MW)	45,601	45,577	45,577
Reserve Margin	16%	19%	19%

- Note: out-of-CAISO specified import resources such as Palo Verde are subsumed in the maximum import constraint of 10,193 MW, so they are not counted in the individual resource class line items

Conclusions and Recommendations

High level conclusions

- Significant progress has been made developing the SERVM model dataset and exercising Energy Division staff's production cost modeling process in preparation for modeling the aggregated LSE portfolios from the August 2018 IRP filings
- Staff modeled the Reference System Plan calibrated to the 2017 IEPR demand forecast and found:
  - No reliability issues and 19% reserve margin in 2030 – using the same assumption from RESOLVE that thermal plants with no announced or planned retirement remain online through 2030
  - Reasonable agreement between RESOLVE and SERVM on common production cost metrics
- Staff assessed key differences between RESOLVE and SERVM and gained valuable insights
  - Majority of differences can be attributed to lack of data input development alignment at the beginning of the process – many RESOLVE and SERVM inputs were developed independent of each other rather than sourcing from the same data vintage or aggregating up from the same sources
- Staff recommends:
  - Refining the SERVM dataset and completing investigations in the following areas prior to modeling the aggregation of LSE portfolios:
    - Unit region and capacity differences
    - Renewables modeling
    - Operational attributes
  - Aligning inputs to RESOLVE and SERVM at the beginning of the next Reference System Plan development process
  - Revisions to the Preferred System Plan PCM process outlined in Attachment B to the February 2018 IRP decision, D.18-02-018. The revisions are described in Attachment A to the ALJ ruling to which this work product is attached.

Recommended improvements prior to modeling the aggregation of LSE portfolios (1)

- Unit region and capacity differences
  - Correct treatment of certain out-of-state wind generators (about 1.7 GW). RESOLVE assumed these units' contracts with CAISO entities were for RPS purposes only but not serving CAISO load, whereas SERVM assumed these units served CAISO load.
  - Determination of whether an out-of-state renewable is REC-only or delivering energy to CAISO could also be informed by contract data reported by the LSEs in their IRP filings
- Renewables modeling
  - Consider resizing renewables units to better align with projected annual amounts of energy production, including BTM PV
    - RESOLVE "sizes" renewable units to match with projected annual energy production, whereas SERVM "sizes" units according to nameplate capacity. In SERVM, this can lead to modeled annual energy production differing from the projected production for a given renewables unit. This effect is accentuated for solar PV units with greater than unity inverter loading ratio (DC MW/AC MW), which results in more energy production per assumed AC nameplate MW.
    - Staff proposes to consider scaling down the capacity factor of BTM PV modeled in SERVM because it showed the largest difference between 2030 modeled production (42,621 GWh) and projected production from the IEPR demand forecast (36,295 GWh).
  - Staff is implementing minor improvements to SERVM's solar shapes (capping production at the AC nameplate) in addition to considering scaling down capacity factor of BTM PV shapes. The results presented in these slides do not reflect any of these proposed improvements.

Recommended improvements prior to modeling the aggregation of LSE portfolios (2)

- Operational attributes
  - SERVM models CCGTs with less flexibility than RESOLVE. In SERVM, these may be contributing factors to higher curtailment, more start hours, and higher peaker dispatch, relative to RESOLVE. Staff recommends pursuing further investigation in both models to understand the drivers of these effects.
    - Pick specific days from each model to rerun and compare hourly dispatch:
      - In SERVM, test whether increasing CCGT flexibility or reducing reserve requirements results in more or all CCGTs being shut down midday
      - In RESOLVE, test whether decreased CCGT flexibility results in some CCGTs not shutting down midday
    - Determine whether changes to SERVM's modeled CCGT flexibility are required prior to modeling the aggregated LSE portfolios
  - SERVM models thermal units with somewhat higher heat rates than RESOLVE, contributing to higher emissions results and probably differences in dispatch decisions. Staff believes SERVM heat rates to be reasonably accurate since they are sourced from the CAISO Masterfile at the unit level.
  - SERVM uses CAISO Masterfile-based CHP heat rates inclusive of fuel burn for host heat, whereas RESOLVE's CHP heat rate only includes fuel burn for the electricity production portion of a CHP unit.
    - For the remainder of this IRP cycle, staff proposes to continue using CAISO Masterfile CHP heat rates but post-process results such that only electric sector emissions are counted and industrial sector emissions are excluded. Staff will consider revising CHP heat rate assumptions (to improve the accuracy of emissions and dispatch decisions) at the beginning of the next IRP cycle.

Recommended data alignment work prior to development of the next Reference System Plan

- SERVM and RESOLVE input data should be assembled from the same source data and of the same vintage where possible
  - CPUC staff will determine the list of units in both models, their locations, where and how they are scheduled, and the aggregation up to RESOLVE resource types. Avoids lengthy reconciling of units included in each model and increases transparency of how aggregate resource types are compiled.
  - CPUC staff will generate class average operational attributes for RESOLVE from the unit-level operating attributes in SERVM. Improves alignment in heat rates, operating flexibility, and dispatch patterns between models.
  - Align CHP dispatchability and heat rate between models:
    - SERVM currently uses the dispatchability flag in the CAISO Master Generating Capability List to classify whether a CHP facility is modeled dispatchable or must-take. For the next IRP cycle, staff will use available data on whether a facility still has a thermal host to determine dispatchability.
    - Heat rates will be revised to exclude fuel burn for useful heat, thus eliminating the post-processing step of excluding useful heat emissions (which should be attributed to the industrial sector).
  - Transmission flow limits and hurdle rates will be extracted from SERVM and aggregated up as needed to update the inputs to RESOLVE

Recommended data updates prior to development of the next Reference System Plan

- Incorporate the 2018 IEPR Update forecast when available
- Incorporate the WECC Anchor Data Set 2028
- Improvements to hourly profiles
  - CPUC staff is planning to update SERVM's hourly profiles, especially the solar profiles which require more longitudinal resolution to more accurately model solar production including inverter overloading and clipping effects
  - Staff will investigate the feasibility of having RESOLVE draw its 37 representative days and corresponding load, wind, and solar shapes from the library of hourly profiles in the SERVM database. At a minimum comprehensive benchmarking of shapes between the two models should be done at the beginning of Reference System Plan development.

Recommended revisions to PCM process

- Attachment B to the February 2018 IRP decision, D.18-02-018, is superseded by a revised “Guide to Production Cost Modeling in the IRP Proceeding” (Attachment A to the ALJ ruling to which this work product is attached)
  - Removes process and schedule language that would change from year to year and would be more appropriate to present in an Administrative Law Judge ruling
  - Retains and revises the core description of analytical framework that should not change from year to year
    - Modeling Scope and Conventions
    - Reference System Plan Modeling Steps
    - Preferred System Plan Modeling Steps
- Proposed changes to the analytical framework
  - Annual reserve margin calculations, rather than monthly
    - NQC values from peak months are used if available, otherwise use SERVM capmax value
    - Annualized average portfolio ELCC shall be used for wind and solar – calculated as the average of June, July, August, and September ELCC values
  - Monthly calibrated LOLE studies are performed for a monthly target of 0.02 to 0.03 LOLE. No studies are performed with a yearly target of 0.1 LOLE.
  - Describes high-level steps to validate the aggregation of LSE filings into a system portfolio