Inputs and Assumptions (I&A)

Modeling Advisory Group (MAG) Webinar
Energy Division

September 22, 2022

California Public
Utilities Commission

1. Introduction

Logistics & Scope

- Webinar slides are available at the 2022 IRP Cycle Events and Materials web page
- The webinar will be recorded, with the recording posted to the same webpage
- The objectives of this webinar are to:
  - Provide an update on the overall schedule for 2022-2023 IRP inputs and assumptions development
  - Cover some specific IRP inputs and assumptions topics for this IRP cycle
  - Give opportunity to stakeholders to ask clarifying questions, in order to support preparation of their informal comments
  - Request stakeholders' written feedback on these topics to be incorporated in the draft inputs and assumption document to be released in Q4 2022

Questions

- We invite clarifying questions using the “Q&A” feature of this Webex
- If time allows, we invite verbal clarifying questions at regular intervals throughout this webinar.
  - All attendees have been muted. To ask questions:
    - In Webex:
      - Please “raise your hand”
      - Webex host will unmute your microphone and you can proceed to ask your question
      - Please “lower your hand” afterwards
    - For those with phone access only:
      - Dial *3 to “raise your hand”. Once you have raised your hand, you'll hear the prompt, "You have raised your hand to ask a question. Please wait to speak until the host calls on you“
      - WebEx host will unmute your microphone and you can proceed to ask your question
      - Dial *3 to “lower your hand”
- Should time not permit attention to every question please email your questions to IRPDataRequest@cpuc.ca.gov
- The discussion in this webinar will be recorded and posted online, as well as the written portion of the Q&A transcript. Stakeholders are also invited to submit informal comments after the webinar, per instructions to provided later. These comments, though will be informal and not part of the IRP proceeding record.

Agenda

Topic	Timing	Presenter(s)
1. Introduction	5 min	Nathan Barcic
2. Context and Timing	10 min	Ali Eshraghi - Donald Brooks
3. Resources & Cost Assumptions		
3.1. Resource Cost Update	20 min	Mengyao Yuan
3.2. Emerging Zero-Carbon Technologies	20 min	John Stevens
3.3. Shed DR and Shift DR	10 min	Mike Sontag
3.4. Vehicle-Grid Integration Analysis	20 min	Sumin Wang
3.5. Renewable Characterization Methodology - Resource Potential and Land-Use Constraints	10 min	Femi Sawyerr
4. Operating Assumptions		
4.1. Renewable Characterization Methodology-Generation Profile Creation	20 min	Charlie Duff
4.2. Hybrid / Paired Solar-Storage modeling	5 min	Jimmy Nelson
4.3. Transmission Constraint Implementation	5 min	Femi Sawyerr
4.4. Fuel Price Update	5min	Mengyao Yuan
5. Reliability Modeling in RESOLVE and SERVM		
5.1. Approach and Inputs	10 min	Neil Raffan
5.2. RESOLVE Reliability Updates	35 min	Jimmy Nelson
6. Next Steps	5 min	Nathan Barcic

2. Context and Timing

Inputs and Assumptions (I&A)

- The Inputs and Assumptions (I&A) document describes the key data elements, assumptions, and methodologies for CPUC IRP modeling within a given cycle
- The I&A document for the 2022-23 IRP cycle (2022 I&A) will be used for developing the 2023 Preferred System Plan (PSP) and 2024-25 Transmission Planning Process (TPP) portfolios for the CAISO electric system that reflect different assumptions regarding load growth, technology costs and potential, fuel costs, and policy constraints
  - Staff made limited I&A updates (e.g., updates to the load forecast to align with the 2021 IEPR, inclusion of more recent weather years (2018-2020) in RESOLVES's solar, wind and electric hourly shapes, and updated transmission constraints and resource costs) for the modeling needed to develop filing requirements
  - Staff will make limited I&A updates for developing the 2023-24 TPP portfolio(s) as well. An overview of these updates will be provided as part of the 2023-24 TPP portfolio(s) development process.

Inputs and Assumptions (I&A) (Cont'd)

- SERVM updates were also performed for further reliability modeling
  - Added 2018-2020 weather years to the existing 1998-2017 weather data set
    - Updates included new electric demand, wind and solar generation shapes
    - Included hydroelectric projections
  - Staff performed significant Baseline Reconcile work – updated existing Baseline with:
    - New resources online from the CAISO Master Generating Capability List
    - New Anchor Dataset generating list
    - August 1 LSE IRP plans (additional Development resources)
    - Updated existing resources with updated capmax, inservice dates and CAISO IDs.
  - Staff are performing LOLE modeling alongside the IRP reliability planning process
  - Data is posted to the CPUC Unified RA and IRP Modeling Datasets 2022 site here:
    - Unified RA and IRP Modeling Datasets 2022 (ca.gov)

Overall Process & Timing for 2022 I&A

- Staff expects to finalize the 2022 I&A document, including the stakeholder process, by late Q4 2022

Item	Schedule
2022 I&A MAG webinar	September 22, 2022
Stakeholders' informal comments to be submitted to Staff	October 6, 2022
Draft 2022 I&A document	November 2022
2022 I&A webinar	November 2022
Stakeholders' informal comments on the draft 2022 I&A document to be submitted to Staff	2 weeks after the release of the draft
Final 2022 I&A document	December 2022

Purpose of this Webinar
-Stakeholders' Informal Comments Process

- Staff Invite stakeholders to submit written feedback on these topics to be incorporated in the draft input and assumption document
- Stakeholders will have two weeks from the date of this webinar to submit their informal comments to Staff.
- Please submit comments to IRPDataRequest@cpuc.ca.gov by October 6, 2022.
  - Stakeholders are encouraged to include the IRP service list as well.
  - Please categorize your comments based on the topics presented in this webinar
- Stakeholders should support their input with data and/or explanations.
  - If referring to specific data, please provide the link(s) to those data.

3. Resources & Cost Assumptions

3.1. Resource Cost Update

Note: This presentation focuses on data sources and methodology. The results shown here are draft results and are subject to change as new data sources become available. Updates, if any, will be reflected in the Resource Costs and Build workbook and the resource costs section of the draft Inputs and Assumptions document to be released in Q4 2022.

California Public Utilities Commission

Overview

Note: Results shown in this section do <u>not</u> reflect impacts of the Inflation Reduction Act (IRA). Impacts of the IRA are shown on slides 21-23 and in Appendix B.

Summary of Resource Cost Updates

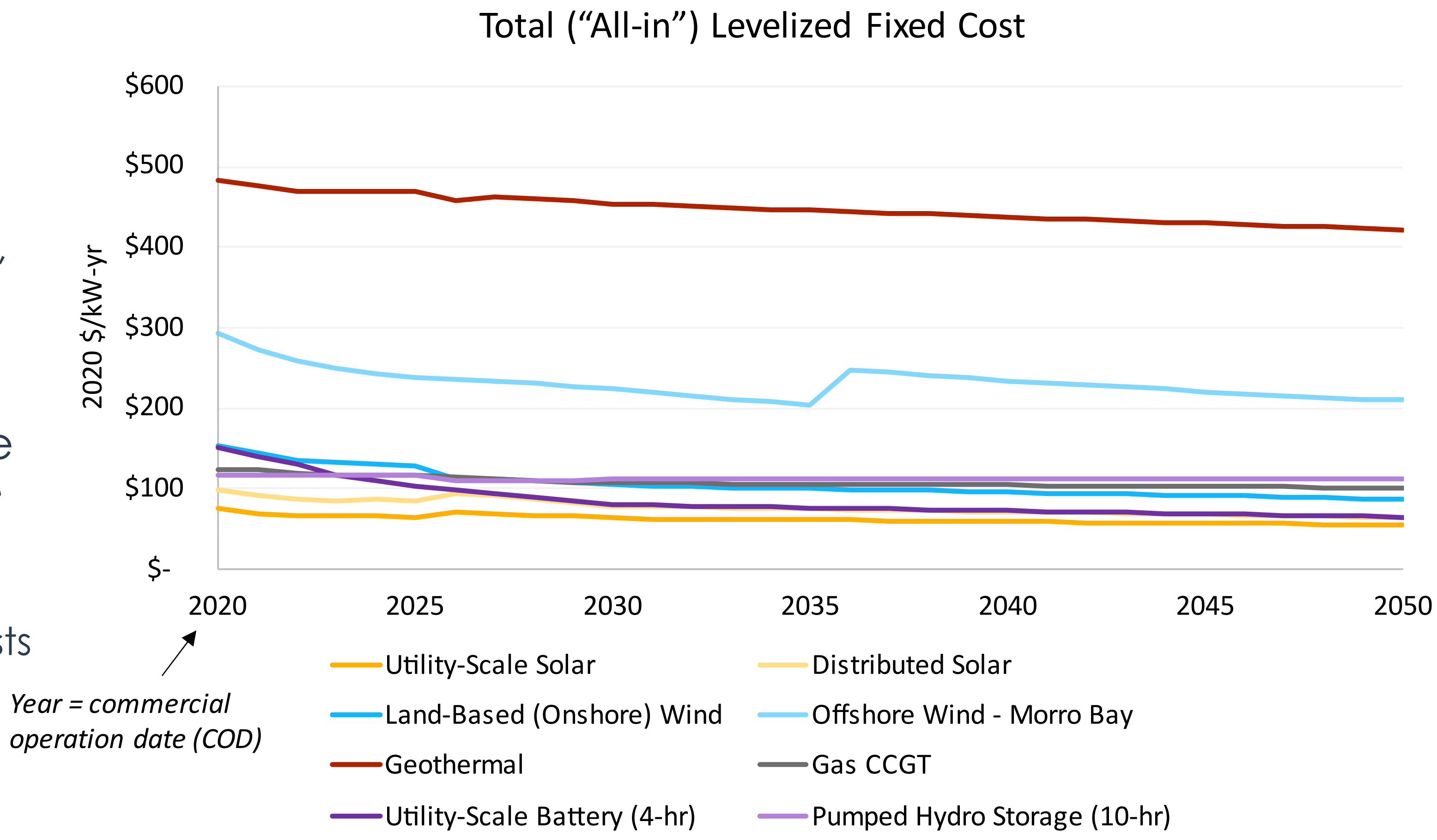
- **Update to NREL 2022 Annual Technology Baseline (ATB)**
  - Updated from cost inputs for 2022 LSE Filing Requirements RESOLVE analysis (referred to as "2022 LSE Filing Requirements" hereafter)
  - Technologies: generation technologies and pumped hydro storage[1]
  - Cost inputs: capital cost, fixed O&M cost
  - Financing assumptions: weighted average cost of capital (WACC), cost of debt (interest rate), cost of equity, debt fraction
- **Emerging zero-carbon technology review**
  - Review of zero-carbon firm generating capacity resources that could help transition California to a zero-carbon grid
  - Developed levelized fixed cost, installed cost and O&M costs for iron-air battery storage, natural gas with carbon capture and sequestration (CCS), advanced nuclear reactors (e.g., small modular reactors), enhanced geothermal systems (EGS) and electrolytic hydrogen/synthetic natural gas (SNG)
- **Updates in progress**
  - Updates to reflect Inflation Reduction Act – to be included in the draft Inputs & Assumptions document
  - Battery costs will be updated with Lazard Levelized Cost of Storage (LCOS) 8.0 data[2]

[1] *Offshore wind costs are based on the NREL OCS Study BOEM 2020-048 and have not been updated to NREL 2022 ATB (see slide 18).*
[2] *Lazard LCOS is typically published in November.*

Summary of Total ("all-in") Levelized Fixed Costs

2022 I&A

- Total levelized fixed costs are **cost inputs into RESOLVE** for candidate resources and impact resource build decisions
  - Include overnight capital cost, construction financing costs, fixed O&M costs, and any capital-based tax credits
- Utility-scale battery costs have been updated to incorporate property taxes
  - Property taxes are included in NREL 2022 ATB technology costs

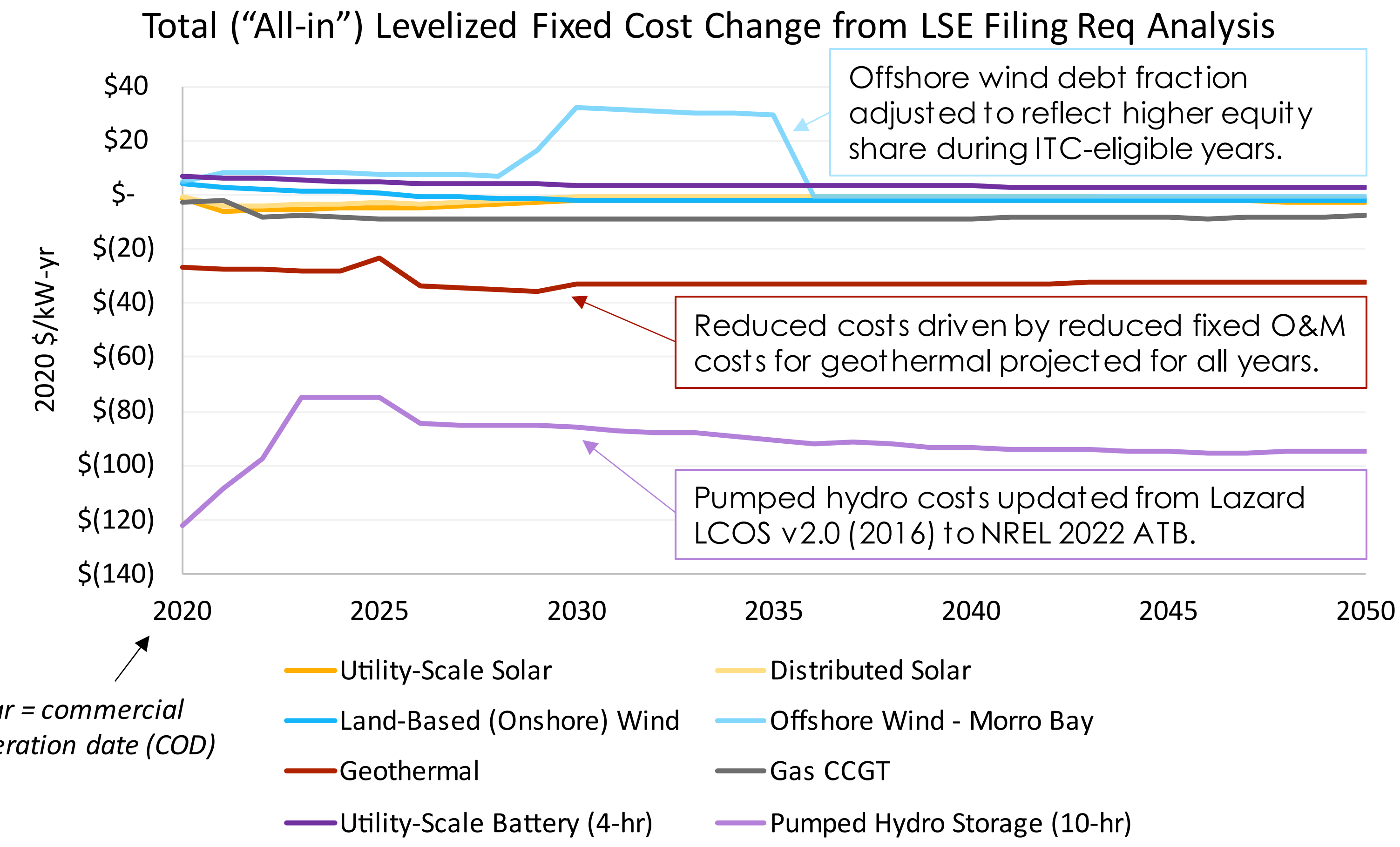


Note: Levelized cost estimates shown here <u>do not</u> reflect IRA. Impacts of IRA are shown on slide 23 and in Appendix B.

Levelized Fixed Cost Comparison of Key Technologies

2022 I&A vs. 2022 LSE Filing Requirements

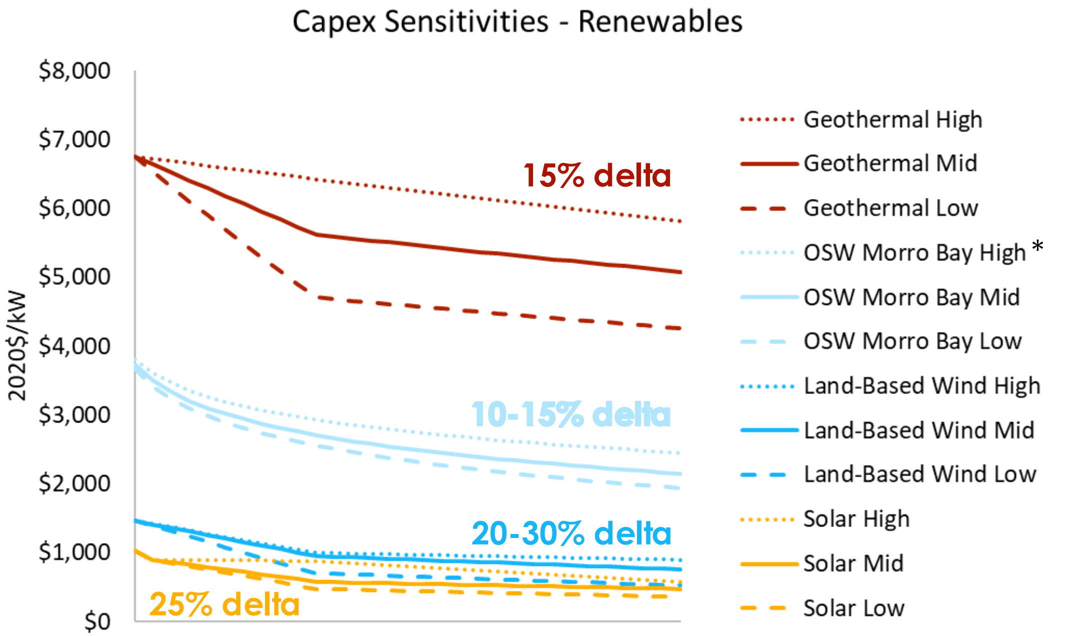
- Total levelized fixed costs for most technologies in this update ("2022 I&A") are lower than costs used in the LSE Filing Requirements RESOLVE analysis ("2022 LSE Filing Requirements")
- Changes in total levelized fixed cost are within about $10/kW-year for most technologies, mostly due to small updates to ATB capex trajectories
- Largest shifts in offshore wind, geothermal, and pumped hydro



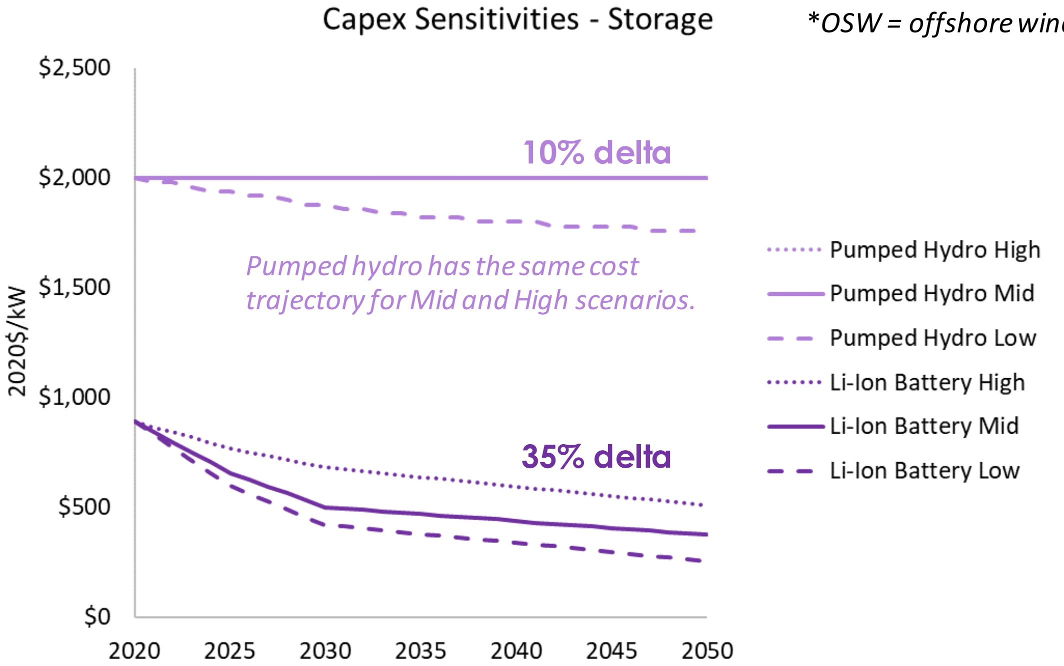
Note: Levelized cost estimates shown here do not reflect IRA. Impacts of IRA are shown on slide 23 and in Appendix B.

Cost Sensitivities

- Uncertainties in technology costs will have implications for planning studies, especially large-scale or long-lead-time resources
- Recent increase in commodity cost is not fully reflected in the "Mid" cost estimates in NREL 2022 ATB



*OSW = offshore wind

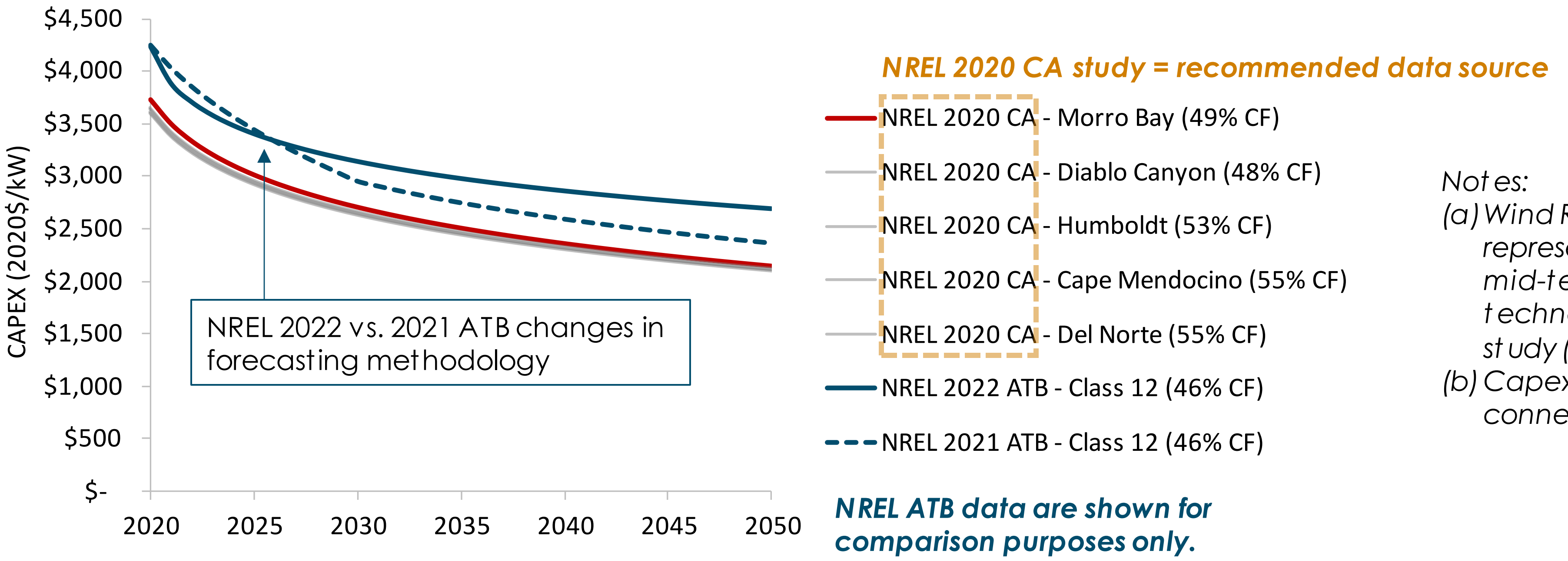


Note:
(a) Mid/High/Low cost sensitivities in the charts correspond to NREL ATB technology innovation scenarios:
- *Mid = Moderate*
- *High = Conservative*
- *Low = Advanced*

(b) Li-ion battery costs from Lazard Levelized Cost of Storage v7.0 (LCOS 7.0), with cost trajectories based on NREL's [Cost Projections for Utility-Scale Battery Storage: 2020 Update]

Offshore Wind Costs

- **Recommendation:** Continue to use NREL 2020 CA offshore wind study (NREL OCS Study BOEM 2020-048) for offshore wind resource costs in RESOLVE, as this study is relatively recent and provides California-specific costs
  - Notably, ATB adopted new cost reduction methodologies in 2022 for plant upsizing and supply chain efficiencies that align with the NREL 2020 CA offshore wind study (2022 ATB)



Notes:
(a) Wind Resource Class 12 most closely represents the resource characteristics of mid-term deployment for floating technology in the NREL 2020 California study (see: 2022 ATB).
(b) Capex shown here excludes grid connection costs.

Gas Fixed O&M Costs

- In RESOLVE, fixed O&M costs can be used separately to inform investment decisions (new generators) and plant retirements (existing generators)
  - Currently, fixed O&M costs for both new and existing gas generators are based on NREL ATB, which are believed to be lower than values indicated by some asset owners
- The 2018 CEC report on Estimated Cost of New Generation[1] carries a higher estimate for fixed O&M than NREL ATB
  - Used in CPUC Gas Plant Risk of Retirement study[2]
  - These costs align with ongoing fixed O&M for the existing gas fleet based on other E3 analyses
- **Recommendation** for modeling:
  - Use **NREL 2022 ATB** fixed O&M for **new** gas generators (new investments)
  - Use **CEC** data for **existing** gas fleet (retirement decisions)

Fixed O&M, 2020 $/kW-yr	NREL 2022 ATB	CEC 2018 Report
Combustion Turbine	$ 21.00	$ 34.26
Combined Cycle	$ 28.00	$ 43.05

New Gas Generators

Existing Gas Generators

[1] Estimated Cost of New Generation, *CEC* (2018), energy.ca.gov
[2] Considering Gas Capacity Upgrades to Address Reliability Risk in Integrated Resource Planning, *CPUC* (2021), cpuc.ca.gov

Inflation Reduction Act (IRA) Impacts on Resource Costs

Note: Results shown in this section are <u>draft</u> results to illustrate the potential IRA impacts on resource costs. The results are subject to change as updates are incorporated in the Resource Costs and Build workbook and the resource costs section of the draft Inputs and Assumptions document (to be released in Q4 2022).

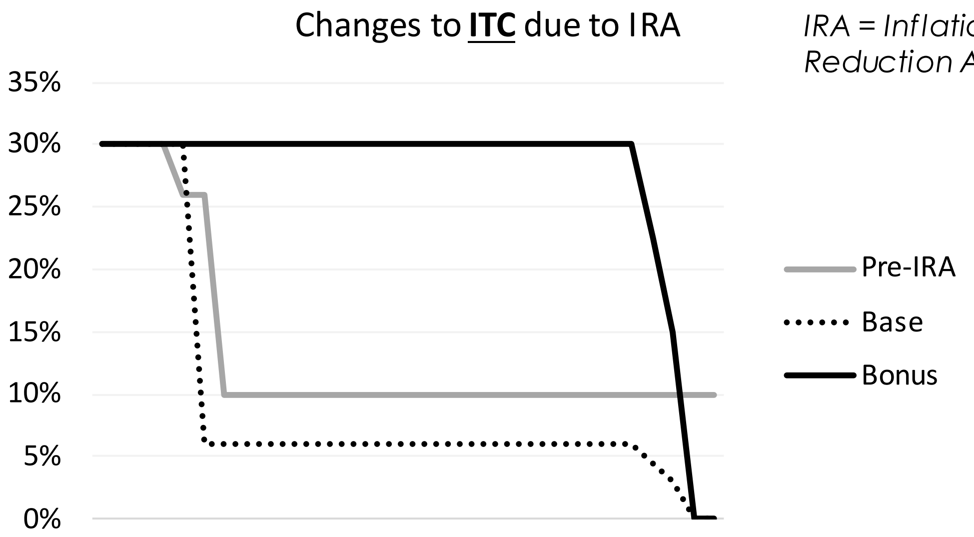
Highlights of Inflation Reduction Act (IRA) -Impacts on Resource Costs

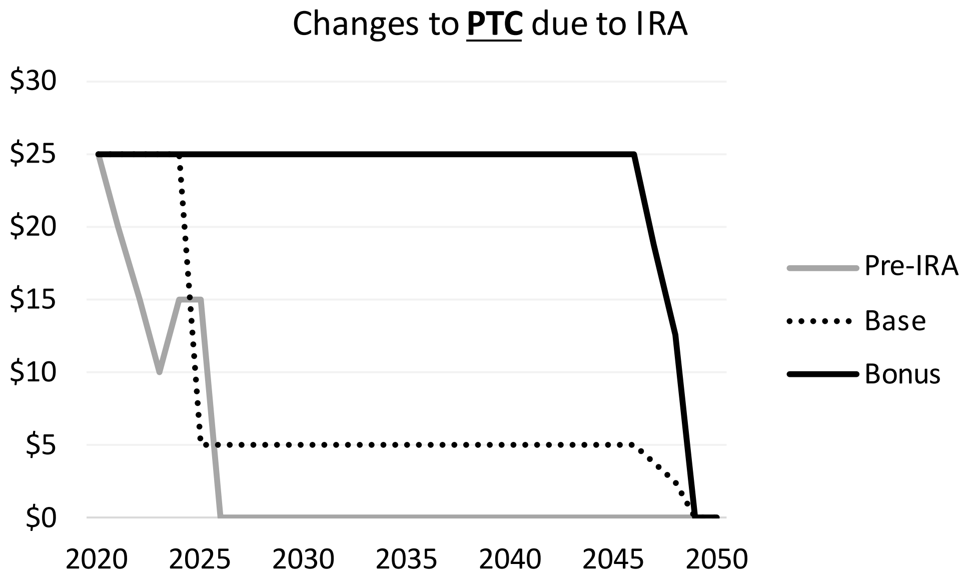
- Extends tax credits for renewables until the **early 2030s at a minimum**
- **Production tax credits (PTC)** applied to a broad range of technologies including **solar**
- Credit can be higher depending on location and whether it uses domestic content
  - Only applicable for projects placed in service or sold in 2023 or later
- **New credits** for **standalone storage**, **clean hydrogen**, **small modular nuclear reactors** among other technologies and various end-use measures
- PTCs for renewables can be **stacked with storage and fuels production**
- **Higher credits** for **carbon capture and storage (CCS)** including new credit for direct air capture (DAC)
- These all come with conditions
  - Higher IRA incentives have prevailing wage and qualified apprentice requirements
  - Given the resulting increase in incentives, we believe most project developers will strive to meet requirements to be able to be cost-competitive

Tax Credit Schedules pre- vs. post-IRA

- Solar now can choose to receive either the investment tax credit (ITC) or the production tax credit (PTC)
- Standalone storage is eligible to receive ITC
- Wind continues to receive PTC, but at a higher rate per IRA
- Offshore wind can access the IRA ITC, which is technology-neutral
- The IRA "Bonus" case shown here assumes projects meet prevailing wage and apprenticeship requirements
  - Additional upside ("Bonus +", see Appendix B) exists if certain criteria are met for (1) domestic content requirements and (2) energy community siting

IRA = Inflation Reduction Act



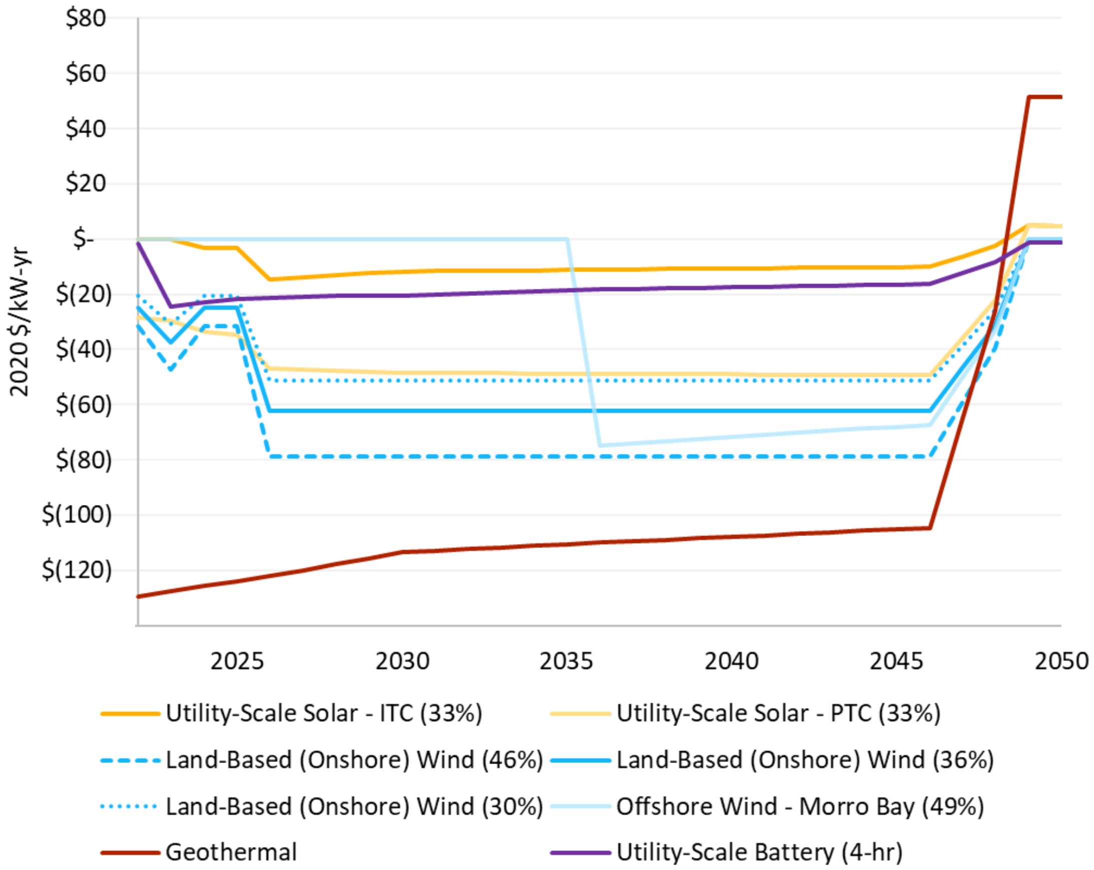


*Note: Assumes carbon emissions reduction targets are met in **2045** (75% reduction below 2022 levels for power sector per IRA), followed by a 3-year incentive step-down.*

IRA Impacts on Levelized Fixed Costs

- Relative ($/kW-yr) impact on levelized fixed cost due to the IRA
- Assumes "**Bonus**" incentive level for meeting prevailing wage and apprenticeship guidelines
- IRA tax credits end date is subject to **assumption** of IRA emissions reduction target year
- Impacts on LCOE and sensitivities on different IRA tax credit options can be found in Appendix B

Total "All-in" Levelized Fixed Cost Change due to IRA



**Note: Percentages in parentheses denote capacity factor.*

*Note: Assumes carbon emissions reduction targets are met in **2045** (75% reduction below 2022 levels for power sector per IRA), followed by a 3-year incentive step-down.*

3.2. Emerging Zero-Carbon Technology Review

What was the Emerging Zero-Carbon Technology Assessment Report?

- E3 performed an analysis of long-duration storage and generation technologies that can provide firm generation capacity with low- or zero-emissions
  - These technologies could help maintain low costs in a zero-carbon grid during longer periods of low renewable production and high load
  - The report is available here
- The assessment focuses on relatively mature technologies with the idea that they would be closer to commercial deployment, and potentially could be deployed at scale in California in the 2030-50 timeframe
- The analysis considered various, representative technologies but is not exhaustive of all new technologies being developed for this purpose
  - This was done to ensure reasonable modeling scope during future IRP work
  - In some cases, the alternative technologies not presented here did not have enough positive attributes (e.g. low cost, high round-trip efficiency) relative to those detailed here to merit inclusion

Technologies Considered in Assessment

- **These technologies will be implemented in RESOLVE:**
  - **Generation Technologies**
    - Carbon capture and storage (CCS)
      - Gas with CCS (90% and ~100% capture), Allam Cycle
    - Zero-carbon firm
      - Advanced nuclear, enhanced geothermal systems (EGS)
  - **Storage Technologies**
    - Zero-carbon “electrofuels”
      - Hydrogen from electrolysis, synthetic methane from electrolysis and direct air capture of carbon dioxide (DAC)
      - Turning fuels back to electricity: CTs and CCGTs (purpose built for hydrogen)
    - Long-duration mechanical and battery storage
      - Adiabatic compressed air energy storage (A-CAES), iron-air batteries

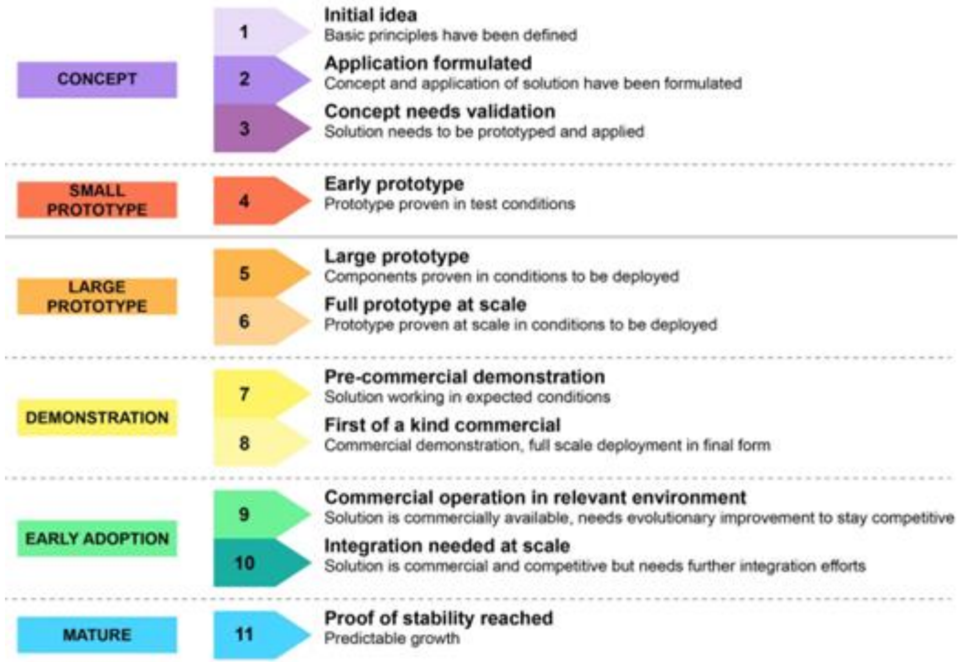
Key technology characteristics and policy challenges were considered, creating RESOLVE-type inputs

- **Initial known estimates of cost and/or potential**
  - Capital cost, fixed and variable operating costs
  - Cost trajectories or forecasts through 2050
  - Existing deployment
  - Technical potential
  - Siting and land use constraints
  - Technology Readiness Level
- **Technology and operating characteristics**
  - Ramping constraints, efficiency (thermal, roundtrip)
- **Policy and planning challenges**
  - Policy and planning considerations
  - Qualitative assessment of criteria pollutant emissions
  - Qualitative assessment of Infrastructure needs (e.g., hydrogen and CCS pipelines and storage)
  - Research, Design, and Development (RD&D) needs

Summary of Current Technology Readiness Levels and Global Deployment

- Hydrogen, A-CAES and CCGTs + CCS are reasonably mature technologies
- Iron-Air and EGS are least mature

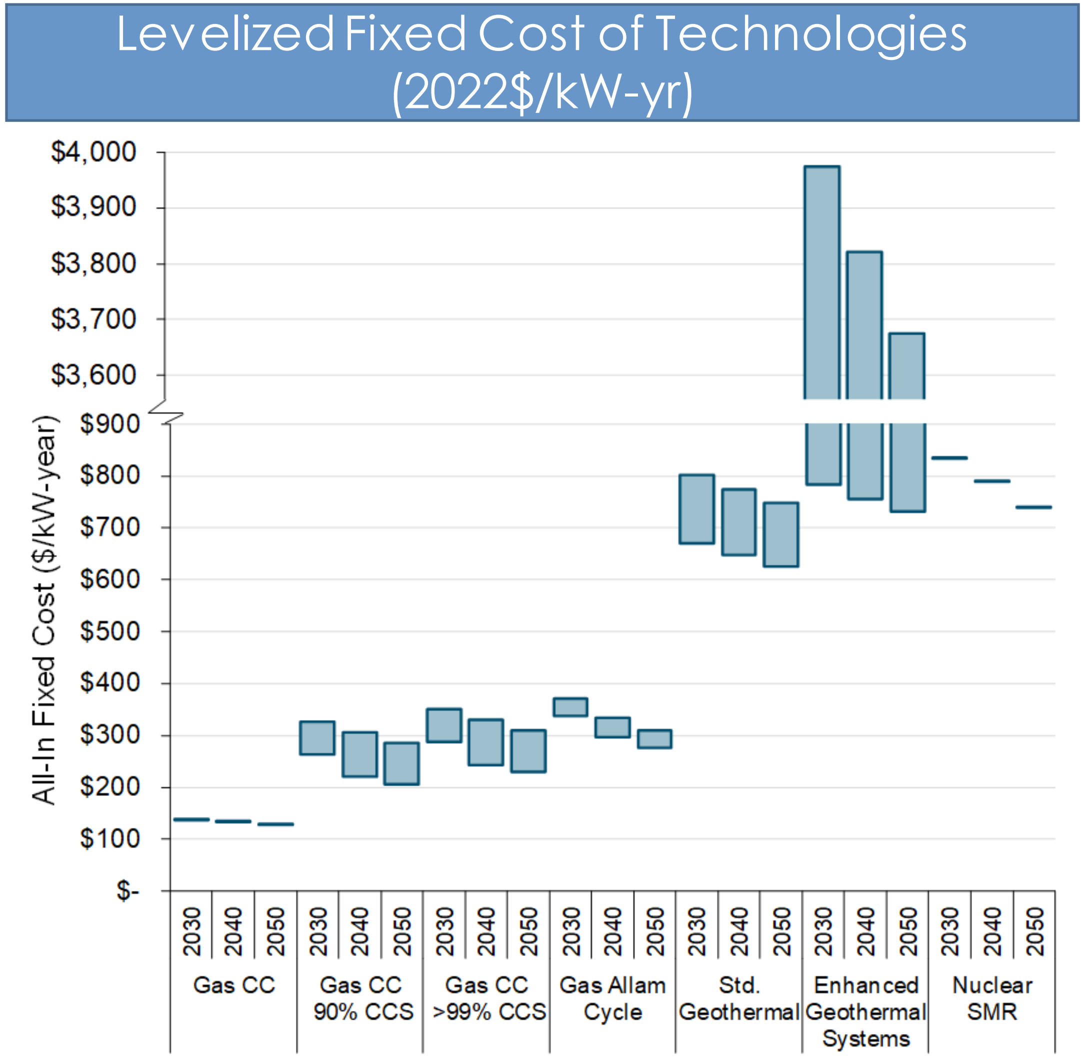
International Energy Agency Technology Readiness Level Guide



Technology Category	Technology	Tech. Readiness Level	Global Deployment
Generation	CCGT + >99% CCS	8	38 million metric tons (MMT) CO_2/yr large-scale CCS proj.
	Allam Cycle CCS	7	~25 MW Allam Cycle
	Small Modular Nuclear Reactor (SMR)	7	n/a
	Enhanced Geothermal Systems (EGS)	5	n/a
Storage	Hydrogen	9	168 MW
	Synthetic Natural Gas (SNG)	7	12 MW SNG, >0.01 MMT/yr DAC
	Adiabatic Compressed-Air Energy Storage (A-CAES)	8	1.75 MW
	Iron-Air Battery	5-6	n/a

Cost Comparison – Generation Technologies

- All-in fixed costs for generation show that all technologies considered show greater costs than conventional combined cycles (CC)
- Modest incremental cost to enable near-zero CCS emissions vs. 90% capture
- Enhanced geothermal systems have the highest cost projections of the generation technologies analyzed (note broken axis)
- Cost data do *not* show effects from Federal IRA
  - This will be included in the draft I&A document to be released Q4 2022

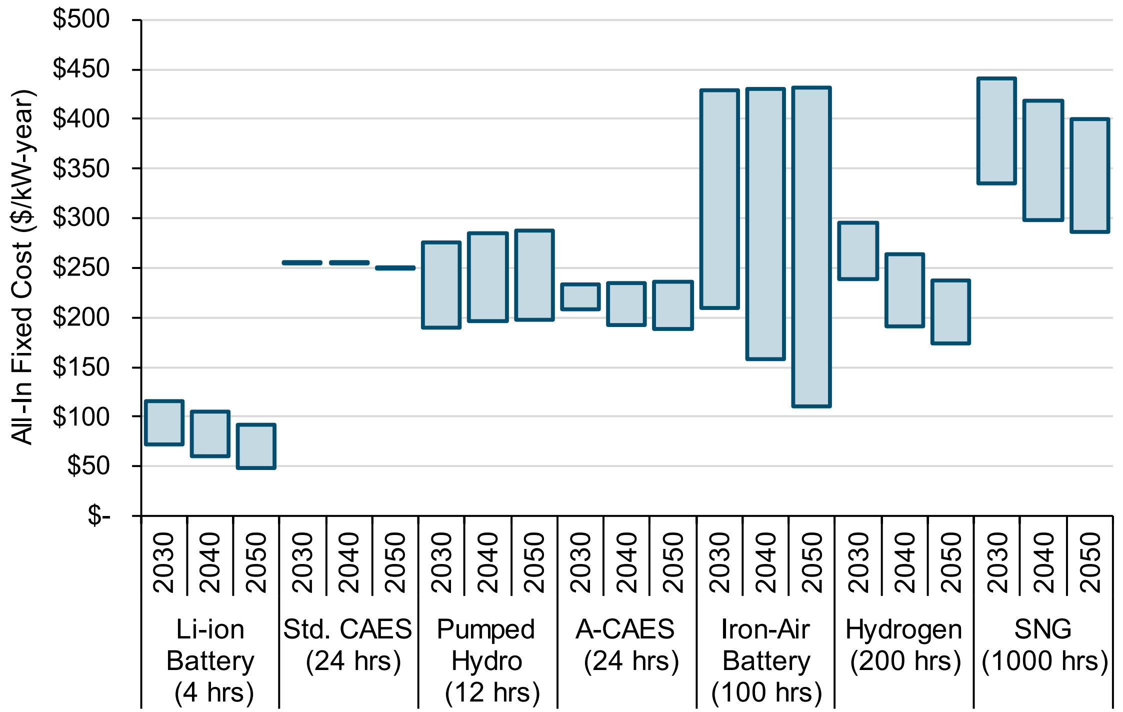


Note: Li-ion battery costs are from Lazard LCOS 6.0, pumped hydro costs are from Lazard LCOS 2.0, and both are shown for comparison purposes only. These costs are updated for 2022 I&A per earlier slides.

Cost Comparison – Storage Technologies

- All-in fixed costs for storage show that all technologies considered show greater costs than conventional Li-Ion, but will provide firm capacity
- Hydrogen and iron-air batteries may exhibit significant cost reductions, but we hold iron-air batteries' upper cost bound constant to reflect uncertainty in data
- Costs for hydrogen include pipeline costs from storage to Los Angeles Area and cost of new CT and underground storage
- Costs of Synthetic Natural Gas (SNG) include underground storage and CT, plus carbon-neutral methane-generating equipment
- Cost data do *not* show effects from Federal IRA
  - This will be included in the draft I&A document to be released Q4 2022

Levelized Fixed Cost of Technologies at Indicated Storage Duration (2022$/kW-yr)



Note: Li-ion battery costs are from Lazard LCOS 6.0, pumped hydro costs are from Lazard LCOS 2.0, and both are shown for comparison purposes only. These costs are updated for 2022 I&A per earlier slides.

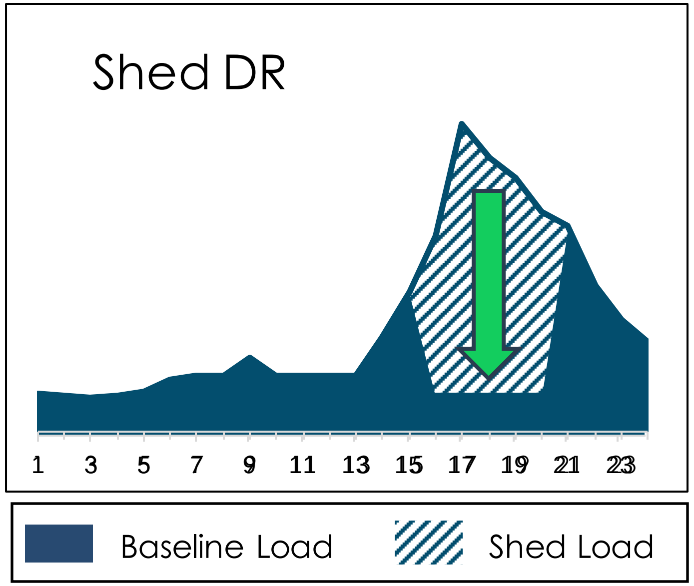
3.3. Shed DR and Shift DR

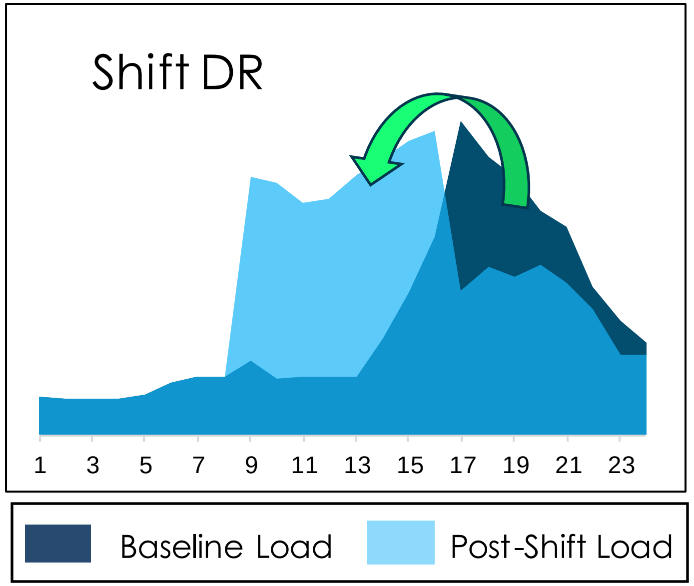
Contents

- Background - resource definitions
- Inputs and assumptions used in previous cycles
- Shed Demand Response (DR) supply curve
- Shift DR modeling updates and supply curve
- Conclusions

Shed DR and Shift DR

- **Shed (or "conventional") Demand Response (DR)** – Loads that can be curtailed to provide capacity reductions
- **Shift DR** – Loads that can be shifted between hours
- Lawrence Berkeley National Lab (LBNL) has created detailed load profiles and cost curves with achievable potential for both resources





Timeline of Shed DR and Shift DR in IRP

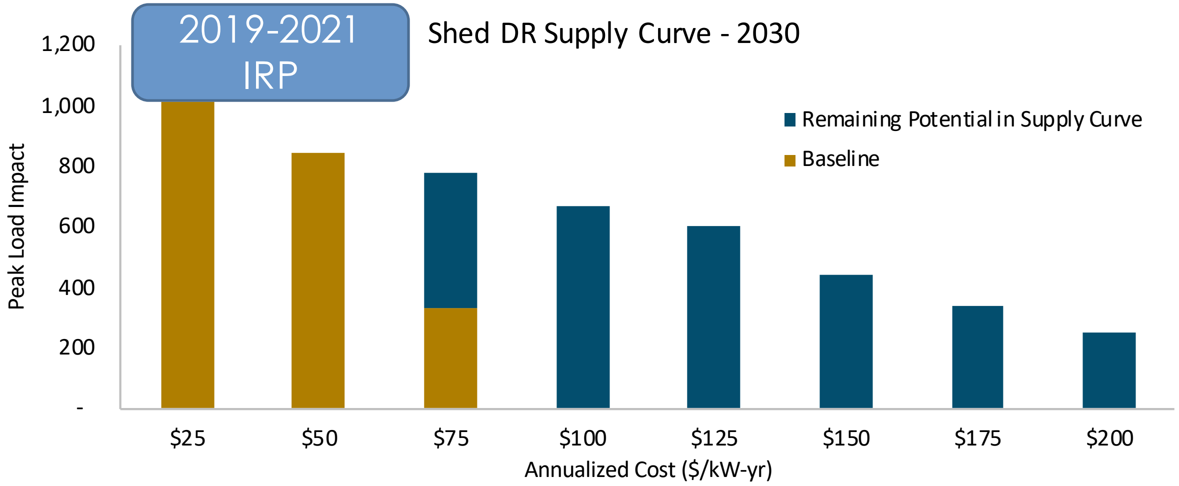
- IRP sources this data from LBNL's DR-Path model*
- Since last IRP cycle, E3 and LBNL collaborated on modeling and data updates to more accurately model load shifting resources in RESOLVE

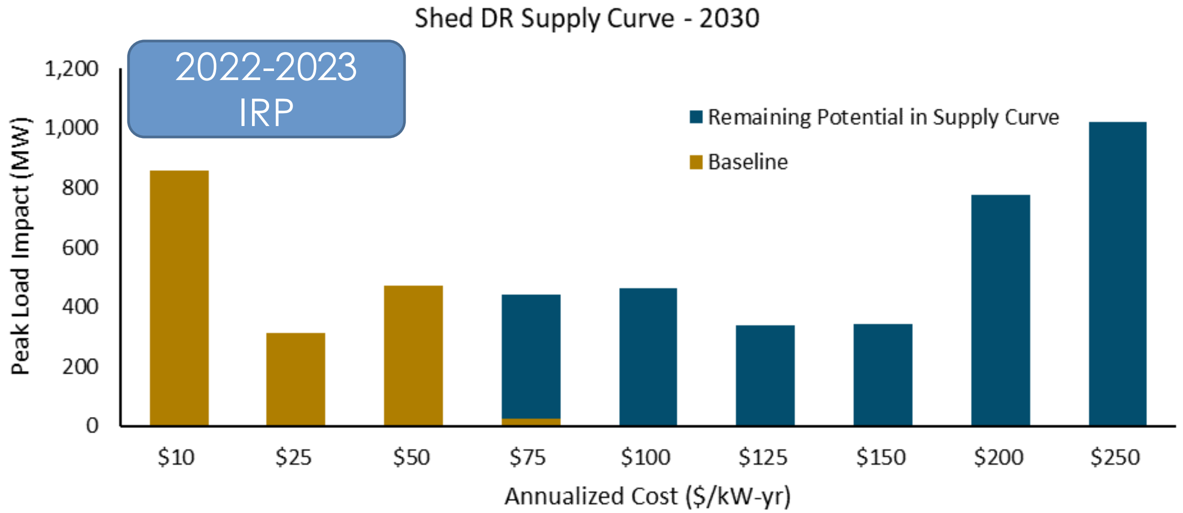
	2017-2018 IRP Cycle	2019-2021 IRP Cycle	2020 Modeling and Functionality Improvements	2022-2023 IRP Cycle
Shed DR	Candidate resource in Reference System Plan	Candidate resource in Reference System Plan		Candidate resource
Shift DR	Candidate resource in sensitivity case	Not included in any sensitivity	RESOLVE Code updated for more accurate modeling	TBD
Data Source	Shed Baseline: Statewide DR Load Impact Report Remaining supply curves: LBNL's DRPATH model with data from 2025 California Demand Response Potential Study (Phase 2 Results)[1]		LBNL's California Demand Response Potential Study, Phase 3[2]	Shed Baseline: CAISO 2022 Summer Loads and Resource Assessment[3] Remaining supply curves: LBNL updated supply curves and load profiles

*DR-Path is a model developed by LBNL to produce supply curves for variety of demand response technologies, based on assumed costs and technical potential

1) Alstone et al, 2017 https://eta-publications.lbl.gov/sites/default/files/lbnl-2001113.pdf
2) Gerke et al, 2020 https://eta-publications.lbl.gov/sites/default/files/ca_dr_potential_study_-_phase_3_-_shift_-_final_report.pdf
3) CAISO: http://www.caiso.com/Documents/2022-Summer-Loads-and-Resources-Assessment.pdf

Shed DR Updates for 2022 I&A





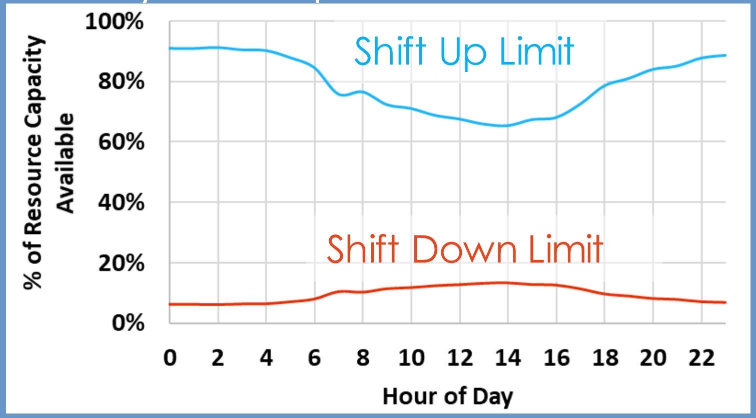
- Assumed Baseline Shed DR has decreased from 2,195 MW to 1,644 MW[1]
- Changes in LBNL supply curve:
  - $10/kW-yr cost tranche
  - Supply curves evolve over time (2025, 2030, 2040, 2050)
  - Specific technologies (ex. commercial space cooling, industrial processes) can be disaggregated from potential, if deemed appropriate
  - Light Duty Electric Vehicles (LDEV) potential will be considered in VGI workstream

1 2019-2021 Baseline Shed DR of 2,195MW based on 443 MW of interruptible pumping loads and 1,752MW of IOU-procured DR from 2017 Statewide Demand Response Load Impact Report (April 2018). 2018 CAISO Summer Study reported 1,763 MW of capacity from Reliability Demand Response Resource (RDRR) and Proxy Demand Resource (PDR) products https://www.caiso.com/Documents/Briefing_2018SummerLoads_ResourcesAssessment-Report-May2018.pdf.
2022 CAISO Summer Loads and Resources Assessment reports 1,221MW of capacity from RDRR and PDR. Additional 443 MW of interruptible pumping loads added to match previous cycle http://www.caiso.com/Documents/2022-Summer-Loads-and-Resources-Assessment.pdf

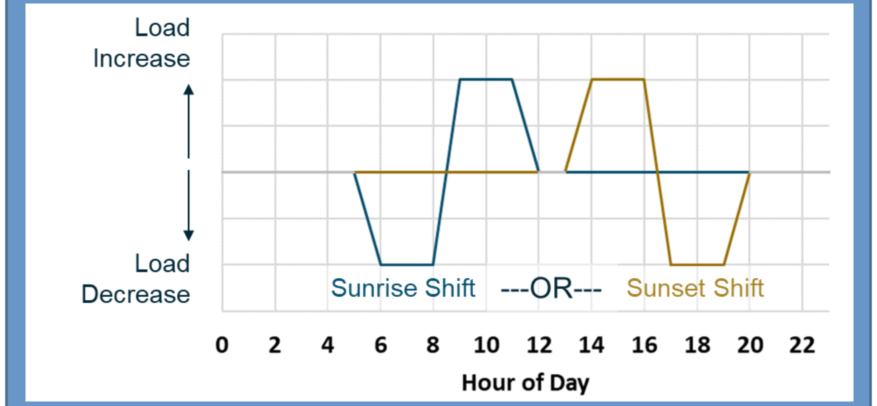
Shift DR Modeling Updates – RESOLVE Constraints

- New Shift RESOLVE Resource includes data inputs for hourly availability, based on underlying load profiles
- Model updates create more realistic bounds on load shifts
- LBNL dataset includes inputs for all of these fields, by technology

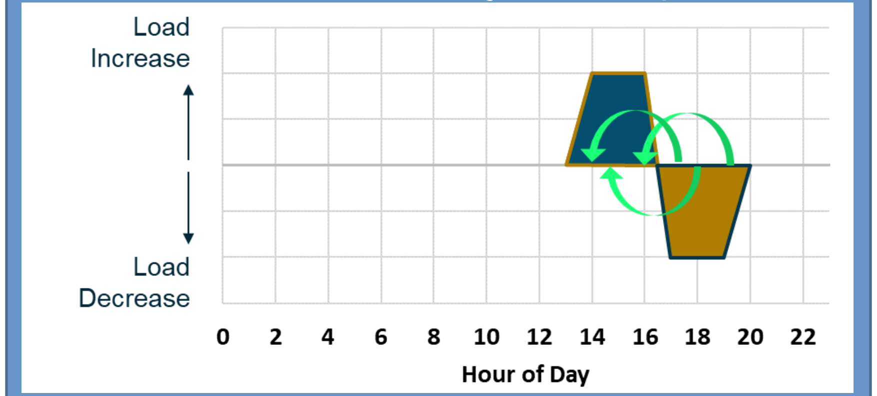
Hourly Shift Up and Down Limits



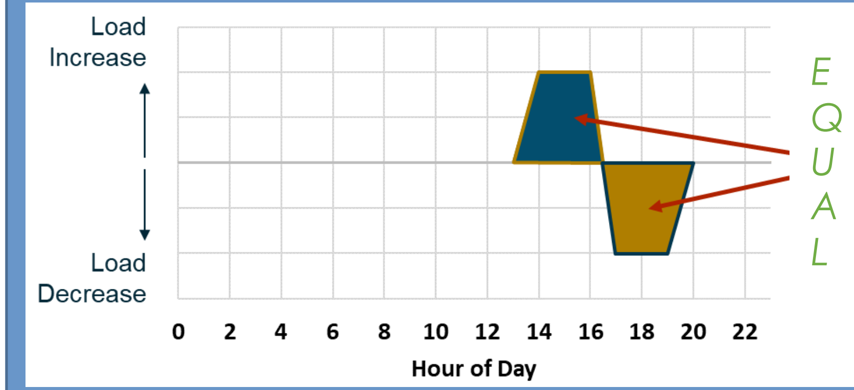
Daily Mileage



Shift Hour Adjacency



Daily Energy Neutrality



Illustrative Example: 2030 HVAC Shift DR RESOLVE Dispatch

Hour of Day

0	10.4	0	0	12.6	9.11	15.8	21.1	21	0	17.3	0	0	0	15.3	39.1	0	0	0	5.19	0	0	19.3	0	0	0	0	0	0	8.59	9.41	3.32	0	0	16.2
1	0	24.2	0	0	0	0	0	0	27.9	0	22.8	23.1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	31.2	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	57.4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	63.6
8	0	0	0	0	36.9	0	0	20.1	80	0	0	67.4	0	0	57.4	0	0	0	0	59.9	144	91.7	24.5	0	0	0	0	0	0	37.2	0	0	40.1	43.7
9	0	14.8	0	37.8	150	145	81.5	87	39.9	91.1	39.3	43.4	98.2	95.6	46.9	137	48.6	0	48.6	106	107	48.7	112	116	164	0	0	0	57.8	115	113	48.9	41.9	22.7
10	96.7	90.2	143	93.8	104	102	41.6	45.7	0	50	0	0	52.5	51.4	6.83	75.2	91.5	83.4	3.36	55.1	55.3	0	58.6	61.3	75.7	115	100	0	65.8	0	0	43.2	0	0
11	16.8	48.9	99.6	50.8	55.5	55.3	0	0	0	0	0	0	0	0	6.83	52.4	53.9	58	58.8	0	0	0	0	0	58.8	60.1	59.4	73.7	0	0	0	0	0	0
12	66	62	49.9	0	0	0	0	0	0	0	0	0	0	0	6.83	35.4	51.2	0	0	0	0	0	0	23.2	92.7	92.8	0	0	0	0	0	0	0	0
13	126	120	55.4	65.2	0	79.6	36.5	73.5	0	38.5	0	0	82.4	0	69.6	0	125	102	96.7	0	13.2	0	0	110	71.1	205	102	68.3	0	98	121	0	0	0
14	50.7	0	35.1	126	0	34.3	90.7	138	54.1	106	54.9	65.4	105	71.3	6.29	63.8	10.7	0	14.3	91.1	15.9	86.6	0	0	0	68.8	0	0	189	153	127	72.9	65.3	0
15	0	41.5	0	56	105	57.1	141	105	105	109	106	122	47.9	132	40.8	0	74.2	0	224	65.8	70.2	157	77.8	0	0	0	48.1	0	161	68.1	87.2	62.4	123	0
16	0	0	0	0	44.8	0	0	0	121	0	153	101	0	26.4	6.31	0	0	15.8	0	0	0	45.8	0	0	0	0	0	0	0	0	0	0	177	0
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
18	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16.8	0	0	0	0	0	0	0	0	0
22	0	0	18.7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	19.1	0	0	0	0	0	0	0	0
23	0	0	0	1.91	0	0	0	0	0	0	0	0	11.2	0	0	0	0	0	0	9.05	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Load **increased** during daytime hours to absorb solar

RESOLVE sample day (not ordered)

Hour of Day

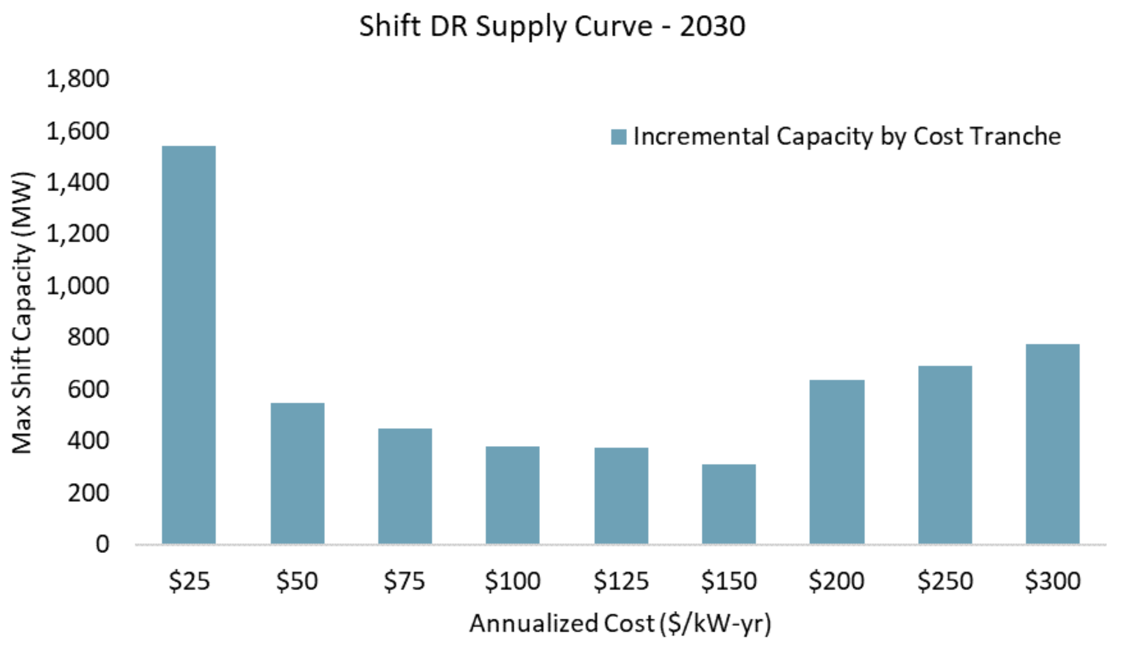
0	10.4	0	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	16.2
1	10.4	0	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	16.2
2	10.4	0	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	0	19.1	0	0	8.59	9.41	3.32	0	31.2	16.2
3	10.4	0	0	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	0	0	0	0	8.59	9.41	3.32	0	31.2	19.9
4	10.4	0	0	12.6	46	15.8	21.1	41.1	40.1	17.3	22.8	42	0	15.3	10.5	0	0	0	5.19	42.5	43	41.1	0	0	0	0	0	0	8.59	46.6	3.32	0	41.3	21
5	0	39.1	0	37.8	46.1	43	39.9	41.3	39.9	41.1	39.3	43.4	45.7	44.2	40.1	37.4	48.6	0	48.6	51.2	51.5	50.7	53.1	55.2	51.2	0	0	0	57.8	52.5	51.6	48.9	41.9	22.7
6	42	41.3	43.2	43	48.7	46.9	41.6	45.7	0	50	0	0	52.5	51.4	0	47.6	48.8	51.9	51.9	55.1	55.3	0	58.6	61.3	54.2	54.5	52	0	65.8	62.2	61.7	43.2	0	0
7	54.7	45.6	49.7	50.8	55.5	55.3	0	0	0	0	0	0	0	0	0	52.4	53.9	58	58.8	0	0	0	0	0	58.8	60.1	59.4	73.7	0	0	0	0	0	0
8	0	0	49.9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6.83	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	0	3.3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	66	58.7	0	0	0	0	0	0	0	0	0	0	0	0	0	99.2	51.2	0	0	0	0	0	0	84.5	92.7	106	0	0	0	0	0	0	0	0
17	59.5	58.1	55.4	65.2	71	79.6	36.5	73.5	0	38.5	0	0	82.4	0	62.7	63.8	93.5	102	96.7	0	99.3	0	5.24	110	87.9	99.2	102	68.3	111	98	121	0	0	0
18	50.7	41.5	53.8	61	63.2	65.1	54.2	64	54.1	67.8	54.9	65.4	67.6	71.3	53.4	63.8	84.9	15.8	82.2	91.1	86.1	86.6	77.8	0	16.8	87.9	48.1	0	91.3	78	100	72.9	65.3	0
19	0	41.5	18.7	57.9	57.5	57.1	50.8	56.9	50.5	59.6	51	56.9	59.1	60.3	47.1	0	74.2	15.8	66.5	74.9	70.2	70.2	77.8	0	16.8	19.1	48.1	0	78.8	68.1	87.2	62.4	58	0
20	10.4	0	18.7	14.5	53.9	15.8	21.1	21	48.1	17.3	47.9	53.5	11.2	41.7	45.4	0	0	15.8	5.19	9.05	0	65.1	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	53.8	0
21	10.4	24.2	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	39.1	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	0
22	10.4	24.2	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	39.1	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	0
23	10.4	24.2	18.7	14.5	9.11	15.8	21.1	21	27.9	17.3	22.8	23.1	11.2	15.3	0	0	0	0	5.19	9.05	0	19.3	0	0	16.8	19.1	0	0	8.59	9.41	3.32	0	31.2	0

Load **decreased** during sunrise and sunset hours to mitigate ramps.

Note: example dispatch is based on data from previous cycle and may not reflect current data.

Shift DR Data Inputs for 2022 I&A

- Supply curve and hourly shift potential vary by technology
  - Ex. Residential space cooling has different underlying load profiles and technical constraints compared to industrial processes
- Light duty electric vehicles (LDEV) potential will be considered in VGI workstream
- Technology types will be aggregated. Aggregated portfolios will be presented in I&A document



**Max shift capacity is the maximum hourly shiftable load for each technology. Shiftable load in a given hour depends on the underlying load profiles and technical constraints for each technology*

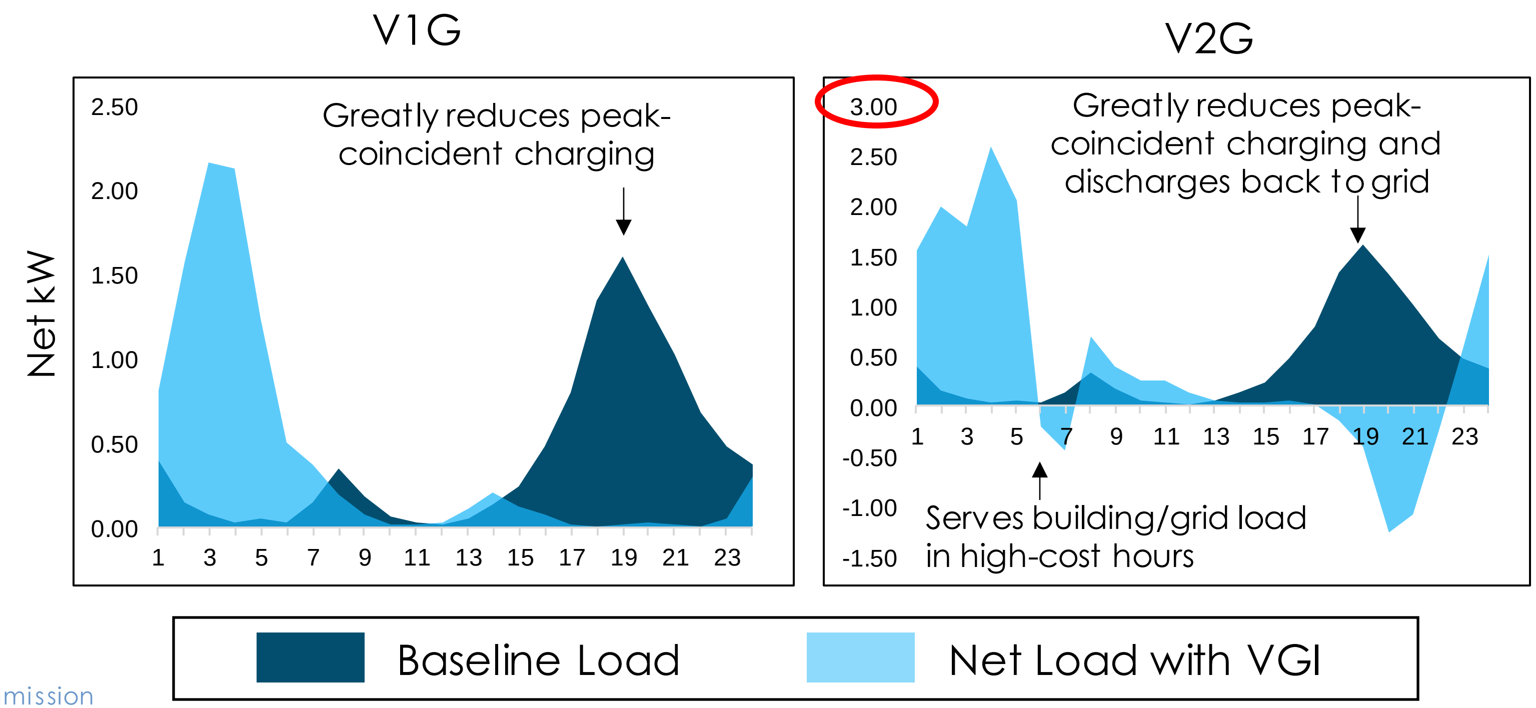
Conclusions

- Shed Demand Response will be included as a candidate resource, based on LBNL Shed DR supply curve
- Shift Demand Response data and updated functionality is available to be included in IRP analysis
- We invite stakeholder comments on these updates and how to characterize them in the I&A document

3.4. Vehicle-Grid Integration (VGI) Analysis

Transportation electrification (TE) is a key input to California's integrated resource planning

- Policy goals of 1.5 million EVs by 2025, 5 million by 2030, and 100% of vehicle sales by 2035 will introduce substantial load growth as reflected in IEPR forecasts. **It is essential for the IRP proceeding to consider strategies to manage charging load and reduce its peak impact**
- Vehicle-Grid Integration (VGI) are strategies to integrate charging needs with grid needs:
  - **Passive VGI**: implemented with Time-of-Use (TOU) or dynamic rates to shift load (V1G)
  - **Active VGI**: enabled by third-party aggregator to shift load (V1G) or charge/discharge back to the grid (V2G)



Goals

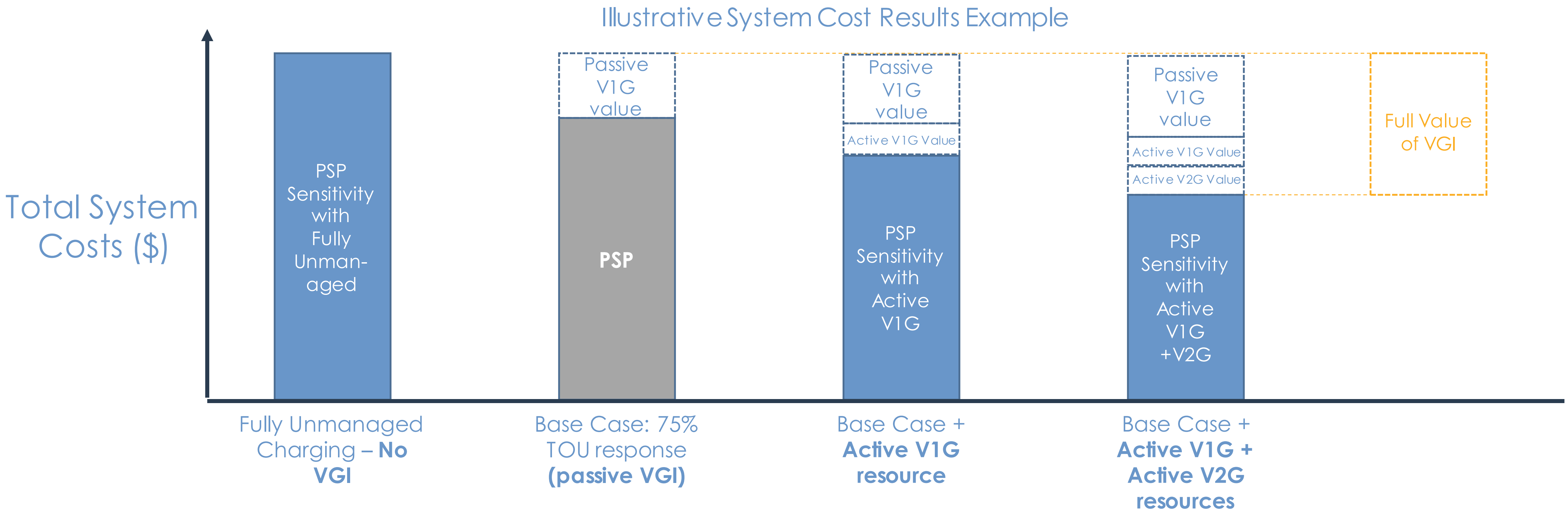
- **Goals of the VGI Analysis**
  - Develop a methodology to model VGI as a resource in IRP modeling
  - Gather stakeholder feedback on inputs
    - Validate the size and timing of the VGI supply curve
  - Determine the value of passive and active VGI

- **The analysis is designed to quantify the value of VGI in the context of system planning and the impact of VGI on resource portfolio**

- **It's _**not**_ designed to inform the design of a specific VGI program**

Passive vs. Active VGI Valuation in IRP

- **What has been done in IRP**: Passive VGI values are embedded by using the IEPR load shapes
  - This analysis will estimate passive VGI values using the latest IEPR load shapes for the 2022-2023 PSP compared to an unmanaged baseline
- **What is new in 2022 I&A**: Active VGI values will be estimated by modeling VGI as dispatchable resources

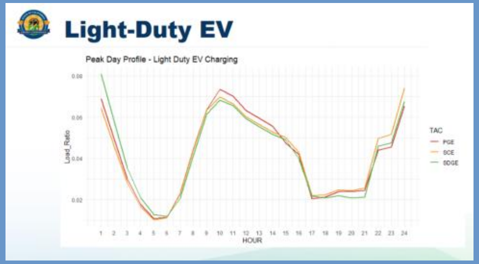


Active VGI Methodology

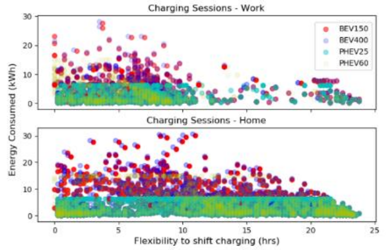
- IEPR load shapes used in IRP will serve as the baseline shapes for this analysis
- To model active VGI, we need to know when people are plugged in and how much load can be shifted around
  - E3 will simulate charging behaviors in its EV Load Shape Tool (EVLST) to mimic the latest IEPR load shapes and generate corresponding flexibility parameters to shape the dispatch of active VGI in RESOLVE

Baseline Shapes

IEPR Load Shapes

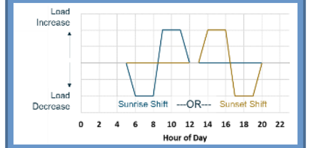


E3 Simulated Charging Session Data

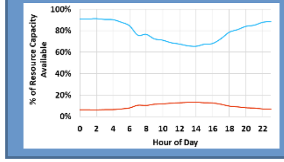


RESOLVE Flexibility Inputs

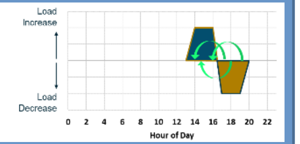
Daily Energy



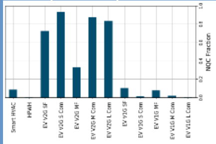
Hourly Shift Limits



Shift Window

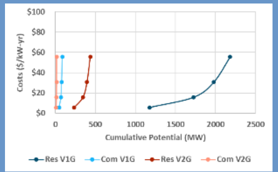


Capacity Value



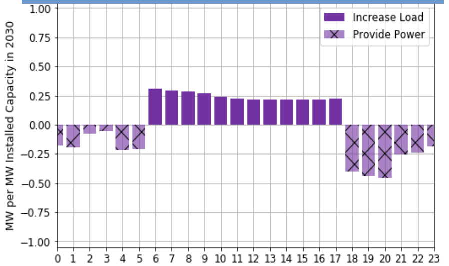
RESOLVE VGI Supply Curve (LBNL)

Costs & Potential

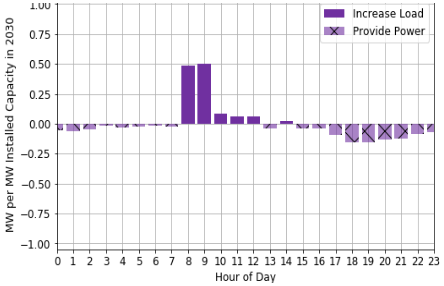


RESOLVE Dispatch Outputs

V2G



V1G



Active VGI Resources & Flexibility Parameters

- Active VGI added will **focus on only light duty vehicles (LDV)** as LDV have the largest amount of load to shift. MDV/HDV can be included in the future
  - Active VGI resources will be modeled as a statewide aggregated resource with four types

Resource Types	Definition
V1G Residential	Shifting EV charging load beyond TOU rates
V1G Workplace	
V2G Residential	Shifting EV charging load beyond TOU rates + Capable of charging and discharging back to the grid
V2G Workplace	

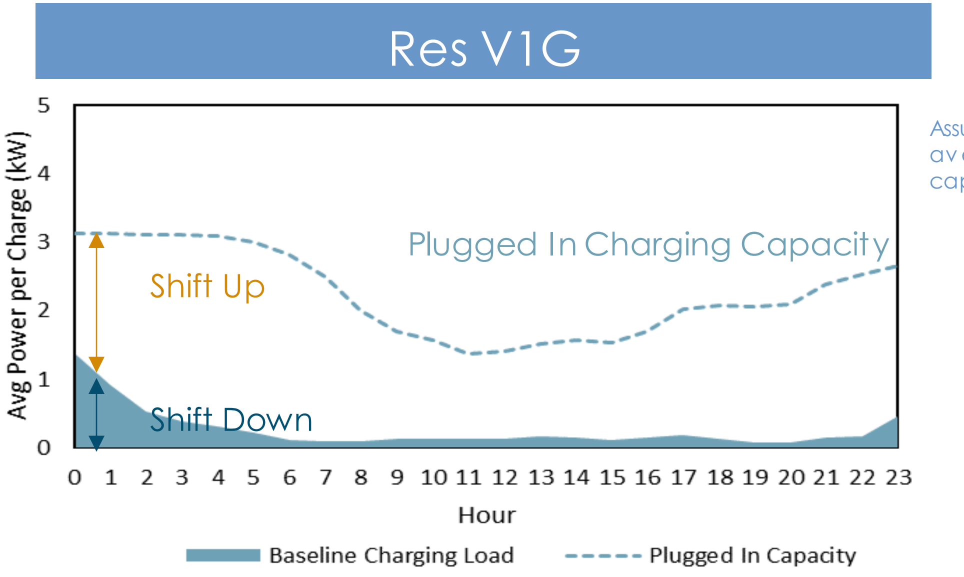
- Active VGI requires flexibility parameters in RESOLVE

Flexibility Parameters	Definition
Shift Window	Average window when vehicle is plugged in and able to change its charging behavior
Daily Energy	The amount of energy that can be shifted in a day
Hourly Shift Up Potential	Hourly potential to further increase EV charging load compared to TOU baseline
Hourly Shift Down Potential	Hourly potential to further decrease EV charging load compared to TOU baseline

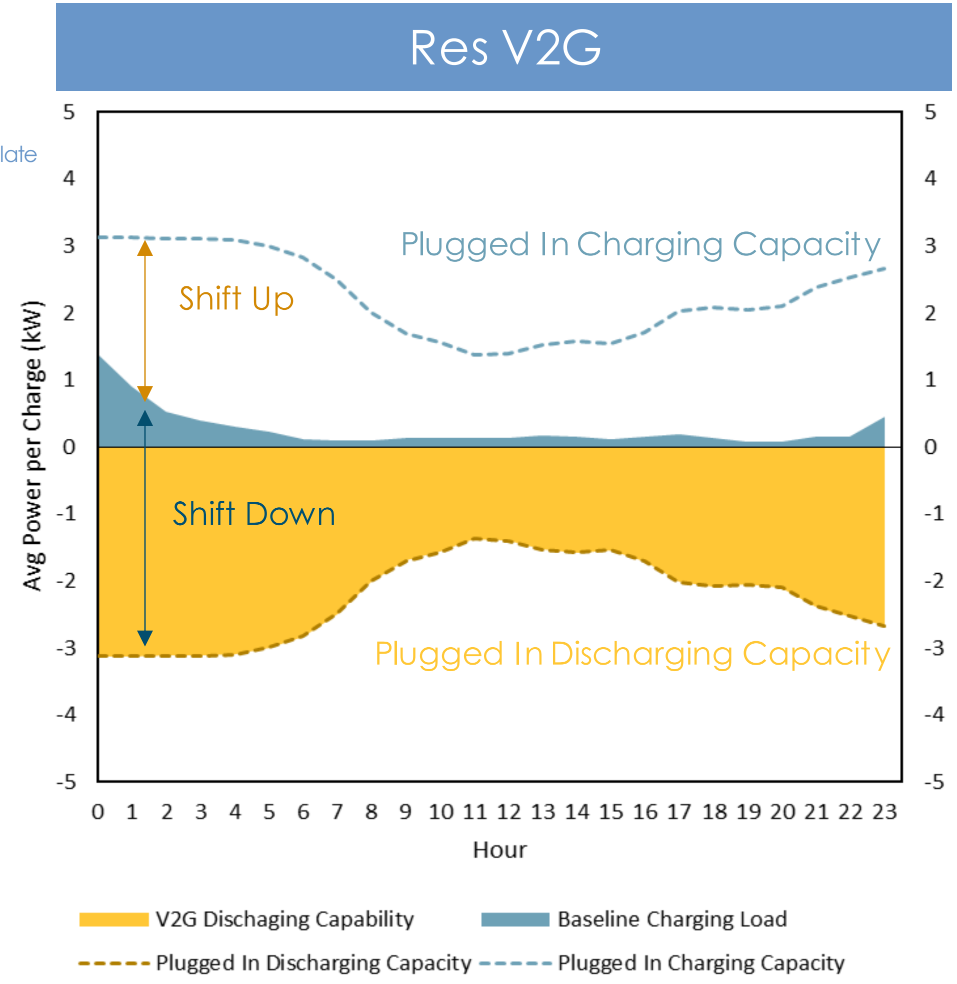
** The equations to calculate these flexibility parameters are in the Appendix E*
RESOLVE assumes daily energy neutrality to ensure the total shift up is balanced with total shift down

Illustrative Example to Calculate Hourly Shift Constraints

- Modeling aggregated, population-level average charging shapes per vehicle to represent VGI resource potential in IRP



Assuming 5kW average nameplate capacity



Supply Curve – VGI Potential

Request to Stakeholders: Please provide better enrollment data available from VGI programs and assumptions on V2G timeline and potential to inform this modeling exercise

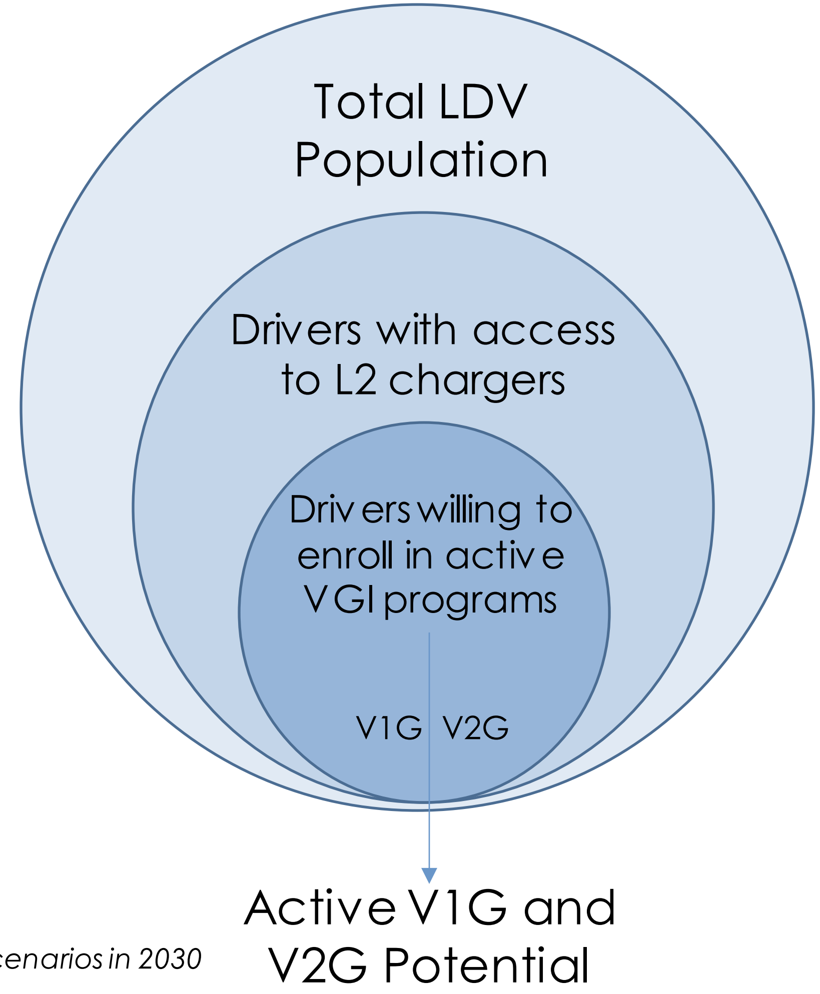
- Assumptions:
  - General Assumptions

	Value
% of vehicles with L2 charger	40%
Res EV/Charger Ratio	1
Com EV/Charger Ratio [1]	25
Weighted Average L2 charging capability (kW) [2]	5

  - V1G potential is estimated using LBNL propensity score based on enrollment data on air conditioning programs (subject to change)

Incentive Tranches	Incentive Tranches ($/kW-yr)	Cumulative Enrollment	Incremental Enrollment
T1	$0	14%	14%
T2	$10	20%	6%
T3	$25	23%	3%
T4	$50	25%	2%

  - V2G potential % will be linearly extrapolated as a function (x%) of V1G potential
    - 0% in 2025 → 50% in 2050



[1] Estimated based on CEC AB2127 report
[2] Estimated assuming 30% PHEV (3kW) and 70% BEVs (6kW) based on the AB2127 report for the EVI-Pro2 Scenarios in 2030

**Illustrative examples of the VGI potential calculation are in the Appendix E*

Supply Curve – VGI Costs

Request to Stakeholders: Welcome feedback and better data to refine cost assumptions

- Active VGI costs assumptions in IRP are to reflect the costs potentially paid by utilities to incentivize participation in active VGI programs.
  - Will *not* include incremental tech costs to enable VGI
  - **And these are *not* CPUC endorsed/approved incentives**

- Costs included:
  - Fixed O&M Costs reflect the cost of incentivizing participation in active VGI programs
    - Administration
    - Marketing
    - Incentives
  - Variable O&M Costs reflect the cycling degradation costs of V2G resources

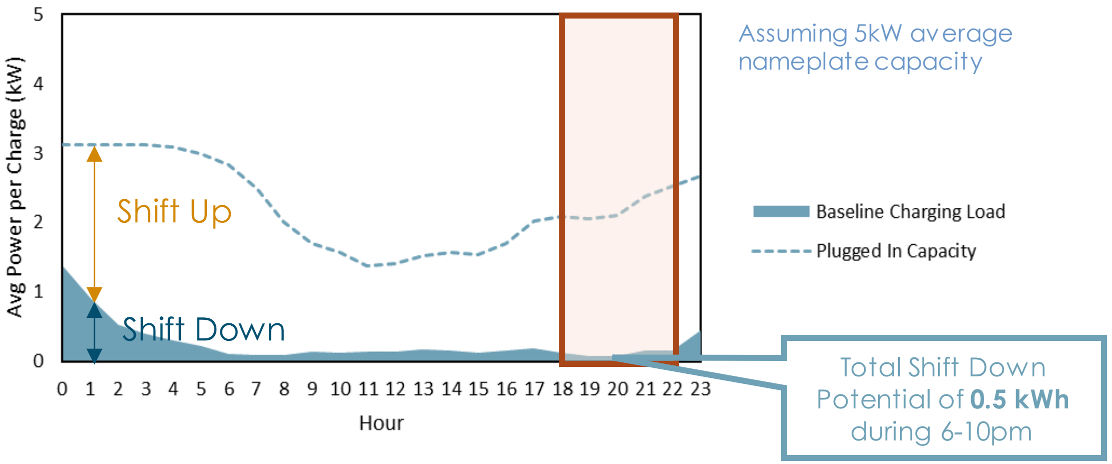
**Details of the cost assumptions and an illustrative example of supply curve are in the Appendix E*

VGI Reliability Contribution

- **VGI will be put on the 4-hr storage dimension of the solar + storage ELCC surface** to account for the interactive effect between grid storage and VGI
- Given that VGI is not as fully available as grid-scale storage to provide power at its nameplate capacity in every single hour, **a scaling factor will be applied to normalize VGI shift down capability relative to its "nameplate capacity"** during the 4-hr evening net peak (e.g., 6-10pm)

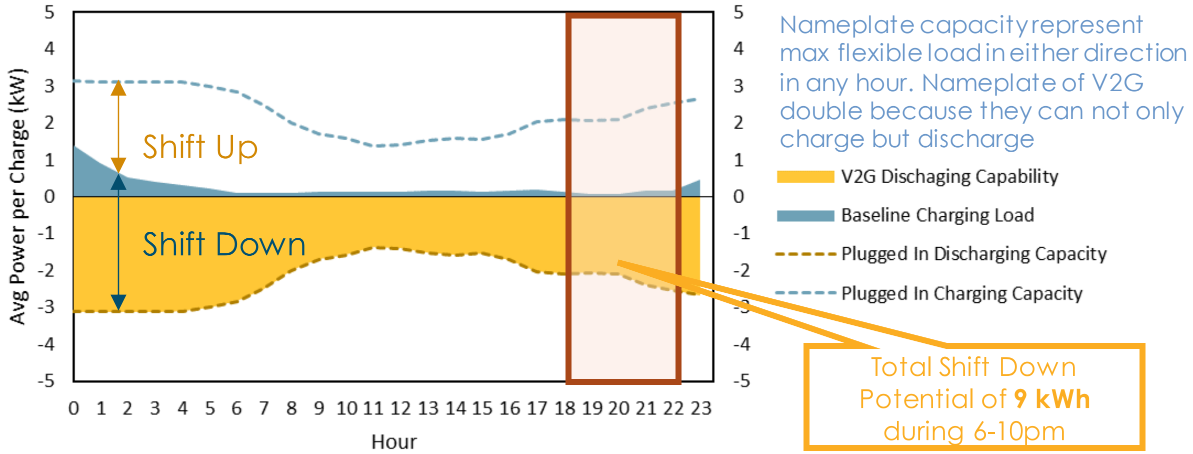
Typical Weekday Profile: Res V1G

$$Res\ V1G\ Scaling\ Factor(\%) = \sum_{1}^{4} \frac{Shift\ Down_h}{Nameplate\ Capacity_h} = \frac{0.5\ kWh}{5kW\ * 4\ hr} \cong\ 2\%$$



Typical Weekday Profile: Res V2G

$$Res\ V2G\ Scaling\ Factor(\%) = \sum_{1}^{4} \frac{Shift\ Down_h}{Nameplate\ Capacity_h} = \frac{9\ kWh}{\mathbf{2} * 5kW\ * 4\ hr} \cong\ 20\%$$



- $Battery\ (4hr)\ Equivalent\ Capacity\ of\ VGI\ (kW) = VGI\ Nameplate\ Capacity\ (kW) * VGI\ Scaling\ Factor\ (\%)$
  - VGI will be put on the storage dimension of the solar + storage ELCC surface, together with storage and shed demand response, to determine its ELCC value

Illustrative examples of the battery equivalent capacity calculation are in the Appendix

Summary of Requested Feedback

- Staff is seeking feedback from stakeholders on the following inputs
  - **Propensity score data available from VGI programs to inform VGI program enrollment potential at different cost levels**
  - **Data to inform the assumptions and projections of costs for active VGI programs**
  - **Assumptions on the timing and scale of VGI (especially V2G)**
  - **Statistics on VGI participation/response during reliability events**

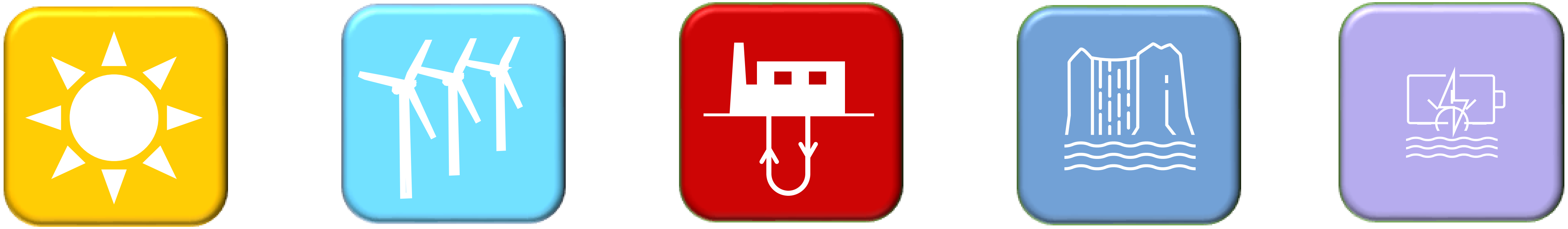
- Staff is seeking feedback from stakeholders on the methodology to
  - **Develop flexibility parameters**
  - **Credit VGI contribution to reliability**

3.5. Renewable Characterization Methodology -Resource Potential and Land-Use Constraints

Contents

Resources with Locational Constraints

- Solar, wind, geothermal, small hydro, and pumped hydro storage have resource potentials limited by location
  - Although this presentation focuses on the solar, wind, and geothermal technologies
  - The other location-constrained technologies will be addressed in the Inputs and Assumptions draft document
- Understanding the resource potential based on where resources can be built is a crucial step in the CPUC IRP Inputs and Assumptions process



Process for Developing Resource Potential

Hypothetical "Unlimited" Potential

Solar based on insolation

Wind based on wind speed

Geothermal from existing studies

Remove Low-Capacity Factor sites

Solar min CF threshold

Wind min CF threshold

Geothermal N/A

Apply Land Screens

Slope of terrain limitations

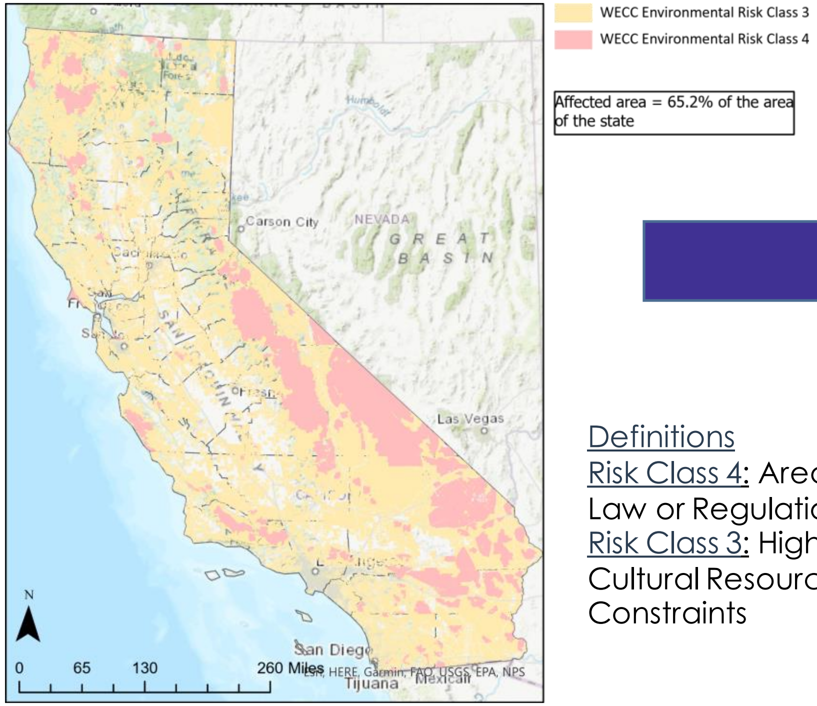
Screen out un-developable areas

- *Private land, sensitive habitats, etc.*

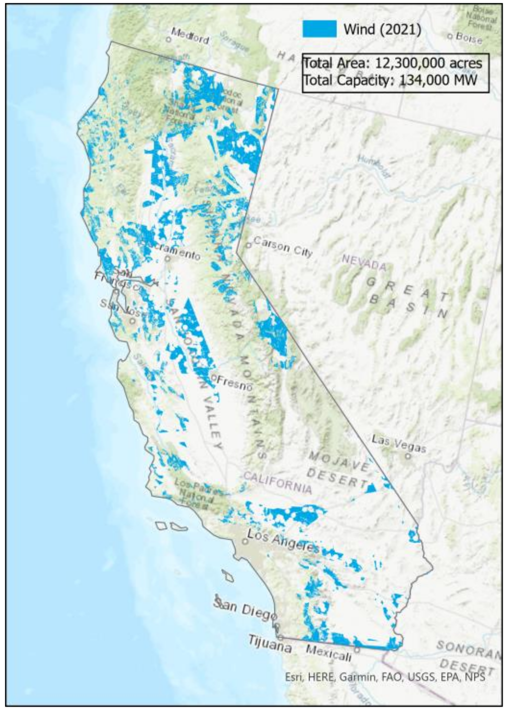
Applying Land Use Screens

- Current use of [Western Electric Coordinating Council's Environmental Risk Class 3 & 4]() will change when aligning with CEC's new screens but expect similarities

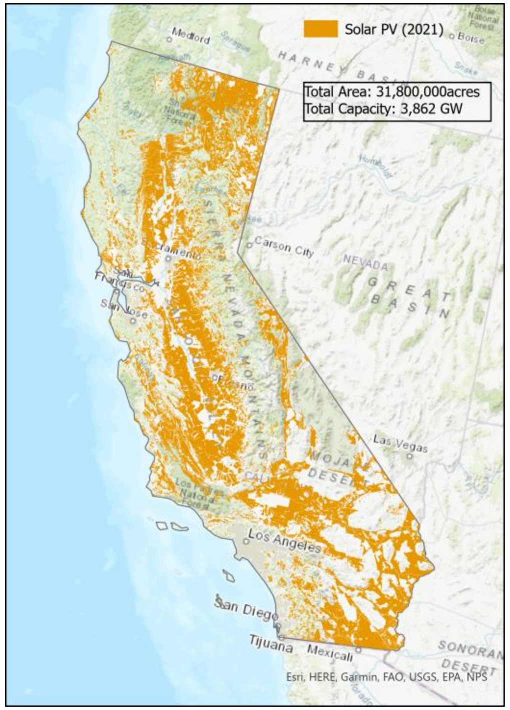
WECC Land Screens



Wind Potential



Solar Potential

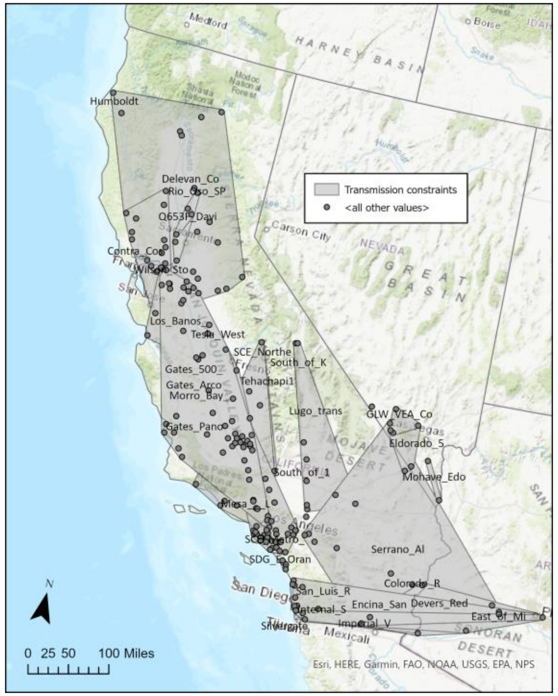


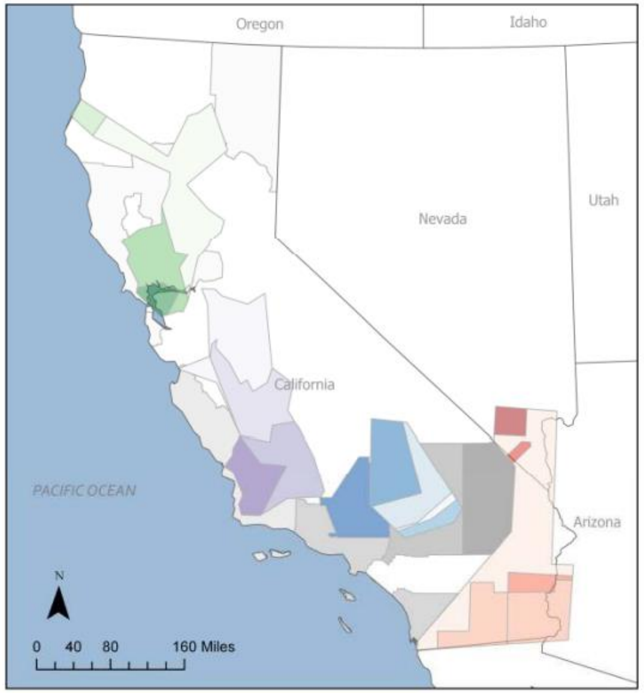
Definitions
Risk Class 4: Areas Presently Precluded by Law or Regulation
Risk Class 3: High Risk of Environmental or Cultural Resource Sensitivities and Constraints

Aggregating Resources for RESOLVE Under Transmission Constraints

- After the application of land-use screens, final resource potentials are then grouped by region
- Current regions are largely based on CAISO transmission constraints defined in its Transmission Planning Process (TPP)
- Renewable energy Candidate Project Areas (CPAs) are assigned to transmission constraints based on pre-selected criteria, including proximity and available transmission capacity

2022 LSE Filing Requirements Vintage Transmission Constraints	2019 RSP Vintage Transmission Constraints





Land Use Screens – Current and Proposed Updates

Current land-use screens: There are three screens in RESOLVE:

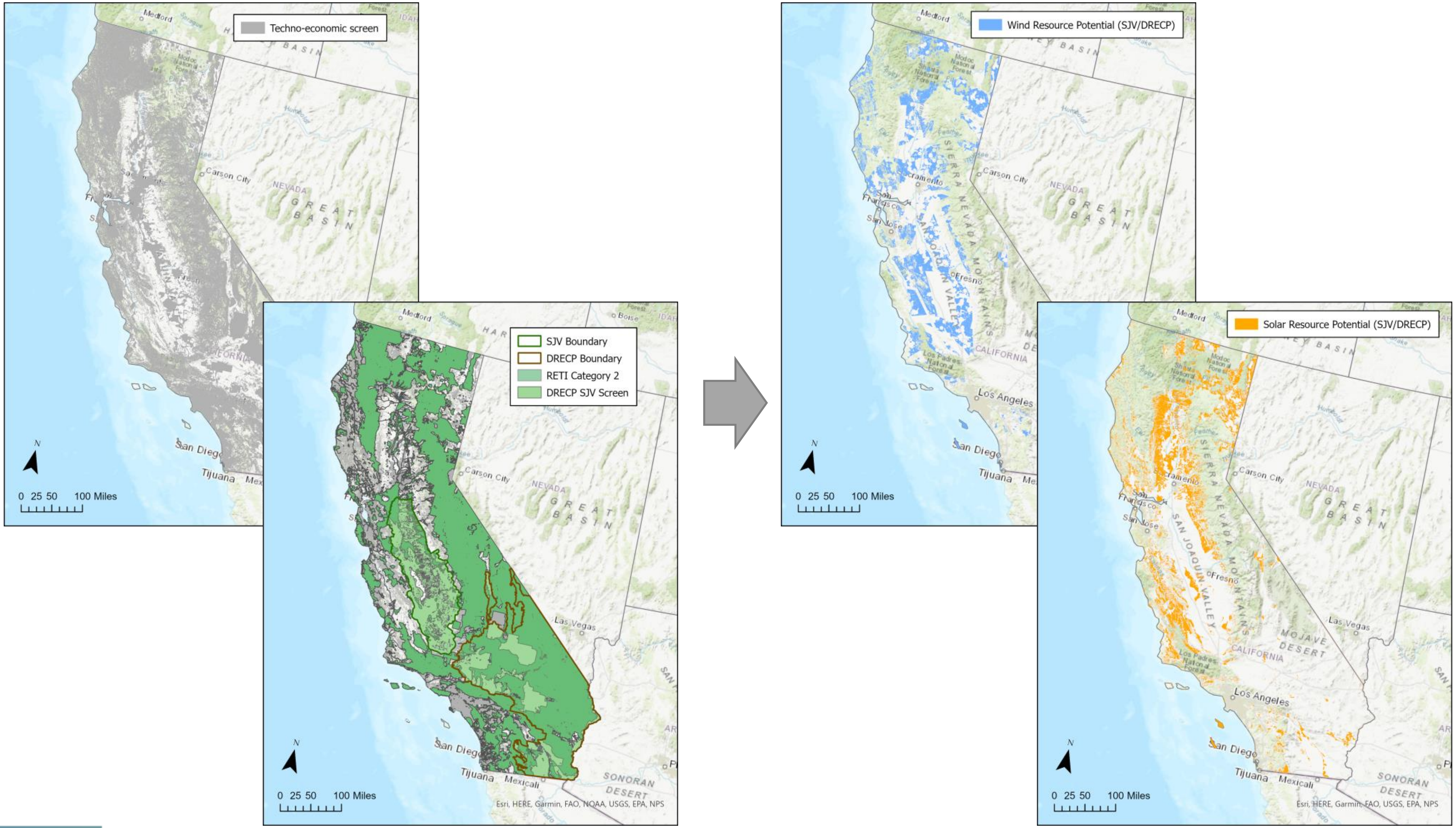
- Renewable Energy Transmission Initiative (RETI) Category 1
  - Excludes techno-economically unsuitable areas and protected areas where development prohibited only
- RETI Category 2
  - Excludes areas listed above AND areas where administrative protections apply (example: threatened and endangered species habitat, wetlands)
- San Joaquin Valley (SJV)/ Desert Renewable Energy Conservation Plan (DRECP) screen (primary screen used in analysis)
  - Designed to test the hypothesis that even if the solar resource were narrowed down to include only the very top high priority lands from a conservation policy perspective, there would still be enough land to meet the state's solar needs. Under this screen, all areas within the DRECP and San Joaquin Valley "Least Conflict Land for Solar" study boundaries were excluded, except those prioritized for solar development (Development Focus Areas and "Least-Conflict" lands).

Proposed Updates: CPUC and CEC staff have collaborated in aligning the underlying datasets and land-use screens used for solar, wind, and geothermal resource potential. There are a few options proposed for the updates to the land-use screens used in RESOLVE

- Within California:
  - Three new land use screens under development by CEC (see forthcoming paper)
- Outside California:
  - WECC Environmental and Cultural Data Inventory

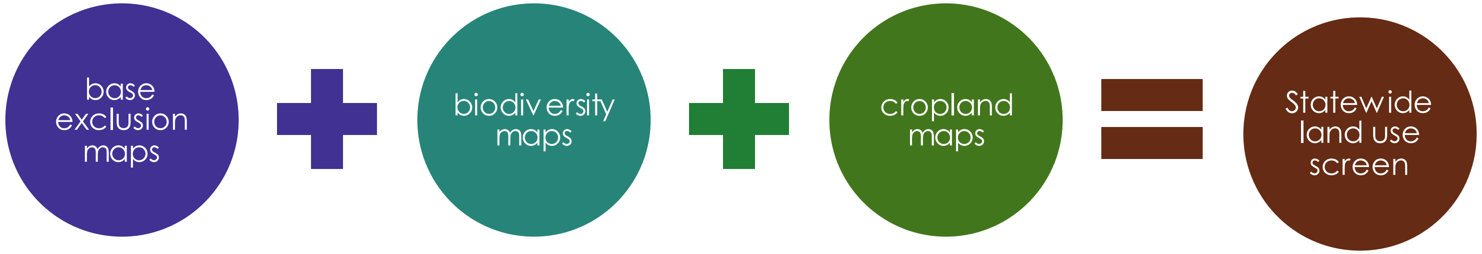
Existing Land Use Screens in RESOLVE

- Current RESOLVE analyses have used the SJV/DRECP land-use screen



There are 3 CEC Land Use Screens Under Consideration for RESOLVE

- In 2022, CEC and CPUC staff collaborated to revise the land use screens for resource planning
- In early October, CEC will release a draft staff report describing the process and methods for updating the land use screens
- On October 10, CEC will host an Integrated Energy Policy Report (IEPR) land use screens workshop
- Each of the three land use screens will contain a combination of information from base exclusion maps, biodiversity maps, and cropland maps



Definition of Proposed Land Use Screens Under Consideration for RESOLVE

- Screen 1 – Includes statewide information representing biodiversity and croplands
- Screen 2 – Includes biodiversity and cropland, plus statewide information about distance from protected areas and landscape intactness (levels of land disturbance)
- Screen 3 – Includes biodiversity and cropland data, plus statewide information about terrestrial climate resilience (lands relatively buffered from the effects of climate change, where conditions will likely remain suitable for plants and wildlife)
- All screens use information that is publicly available.

Offshore Wind Resource Potential

- The offshore wind resource potential is currently based on the 2019 UC Berkeley study on offshore wind resource assessment in California
  - This study includes three BOEM call areas/energy areas and two additional areas of interest
- A new 2022 study of two of the five areas in the 2020 study, Morro Bay and Humboldt Bay, has presented potential updates to the resource potential assumptions
  - This is based on additional analyses of the potential outputs of new turbine configurations
- Stakeholder feedback requested on which of these inputs should be assumed for modeling these offshore wind resources in the 2022 Inputs and Assumptions
  - Staff is working with CEC to assess the potential for additional sea space as part of the CEC's development of the AB 525 Offshore Wind Strategic Plan.
  - The full range of resource potential assumptions for offshore wind will be presented in the Inputs and Assumptions draft document

	Resource Potential	
Resource	**2020 NREL Study**	**2022 NREL Study***
Morro Bay	2.4 GW	5.4 GW
Humboldt Bay	1.6 GW	3.0 GW
Cape Mendocino	6.2 GW	N/A
Del Norte	6.6 GW	N/A
Diablo Canyon	4.3 GW	N/A

These potential values are based on the 4 rotor diameters by 10 rotor diameters (4D x 10D) turbine spacing configuration

California Offshore Wind: Workforce Impacts and Grid Integration. Collier et al. 2019, UC Berkeley. Study link

Assessment of Offshore Wind Energy Leasing Areas for Humboldt and Morro Bay Wind Energy Areas, California. Cooperman et al. 2022. NREL. Study link

Annual Build Out Limits

- In previous RESOLVE analyses additional near-term annual build-out limits have been applied to solar resources to constrain the model from overbuilding solar resources to capture the expiring ITC.
  - Cumulative annual build limits of 11 GW through 2025 were assumed in the 2021 PSP and the 2022 LSE Filing Requirements RESOLVE analyses
- The annual build limits were determined based on consideration of different parameters including
  - LSE in-development and planned resources amounts
  - CAISO Interconnection Queue amounts
  - Historical annual new resource operation amounts
- With the extension of the ITC due to the Inflation Reduction Act (IRA), this approach will need to be updated
  - Unlikely to see a rush to build solar resources in the near-term
  - Annual build limits should better reflect feasible annual development

2022 LSE Filing Requirements Assumptions

Year	Annual Build Limit (MW)
2022	3,094
2023	3,455
2024	1,201
2025	3,250

Category	Max Annual Amount (MW)
LSE Planned	3,480
CAISO Int. Queue	20,985*
Historical Annual	2,600

*represents the maximum amount proposed to come online in a single year in the CAISO Interconnection Queue.

First Available Online Year

- In addition to the resource potential and resource costs, another key assumption for new candidate resources is the first available online year
- This is of particular interest for long-lead time resources like offshore wind, out-of-state wind, geothermal, and pumped hydro storage resources
- These assumptions are based on the development time of the resource and the development time for transmission associated with some of the technology types
- The emerging tech review has introduced additional technologies that will also require assumptions for their first available year.

2022 LSE FR Assumptions

Technology	Resource	First Available Online Year
Pumped Hydro Storage	Tehachapi	2026
	Riverside East	2027
	Riverside West	2029
	San Diego	2030
Geothermal	Greater Imperial	2026
	Inyokern North Kramer	2026
	Northern California	2026
	Pacific Northwest	2028
	Riverside Palm Springs	2026
	Solano	2026
	Southern Nevada	2026
Offshore Wind	Humboldt Bay	2030
	Morro Bay	2030
Out-of-State Wind	Wyoming	2026
	New Mexico	2026

Conclusion

- We will be updating the solar, wind, and geothermal resource potential with updated land-use screens
- We welcome stakeholder input on updated data for resource potential for pumped hydro storage resources as well
- In addition to these established resources, CPUC will also introduce emerging technologies in the available candidate resources
- Staff seeks stakeholder feedback on the first available year assumptions for all candidate resources

4. Operating Assumptions

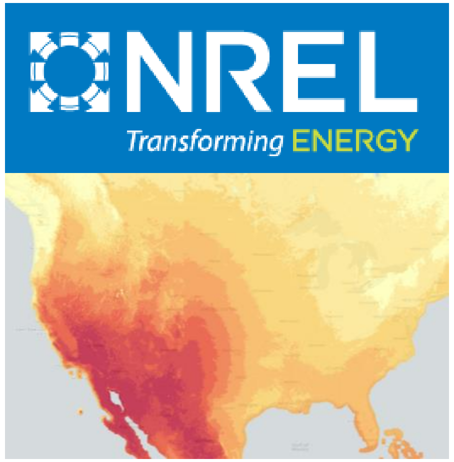
4.1. Renewable Characterization Methodology - Generation Profile Creation

California Public
Utilities Commission

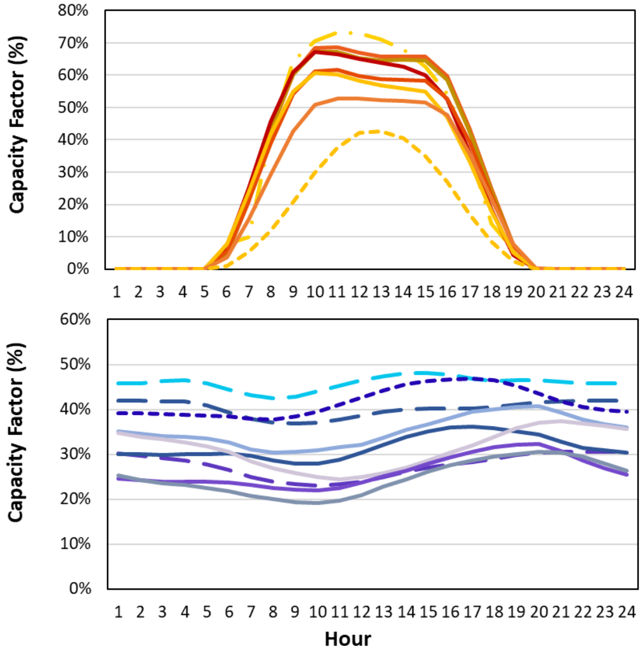
Contents

Developing Generation Profiles – Process Overview

Resource Potential Shapefiles → Scatter Points in Region → Sample NREL data at Points → Aggregate & Normalize Profiles



Solar: NSRDB
Wind: WTK

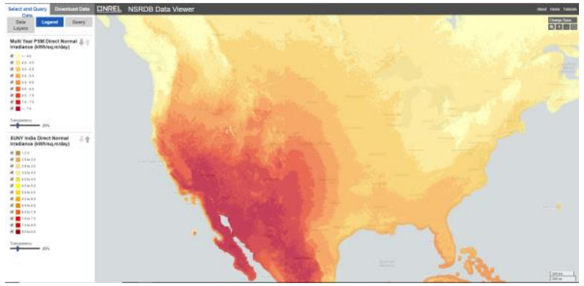


Wind and Solar Profiles Simulated from NREL Resources

- E3 creates location-specific hourly profiles for wind and solar resources using NREL's publicly available datasets
  - other location-specific generation resources are dispatched by the RESOLVE optimization rather than using a fixed hourly profile

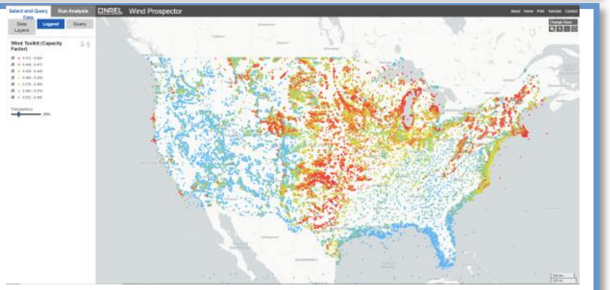
National Solar Radiation Database (NSRDB)

- **4 x 4 km** grid spatial representation
- **30-min** temporal resolution
- **1998-2017** historical period
- Available through Solar Prospector



Wind Integration National Dataset (WIND Toolkit)

- **126,000 sites** across continental US
- **5-min** temporal resolution
- **2007-2013** historical period
- Available through Wind Prospector



Solar Generation Profiles

Overview of Current Simulation Methodology

- Solar profiles for utility-scale resources simulated using NREL System Advisor Model (SAM) and the National Solar Radiation Database (NSRDB)
- Hourly generation profiles are based on location and weather data from 2007-2009 historical years in Pacific Standard Time (PST)
- Individual resource generation profiles simulated based on plant-specific characteristics where possible (for existing resources)
  - Supplemented with generic location and technology assumptions where data was not available (for existing and new candidate resources)

Tracking Type	Category	Inverter Loading Ratio (ILR)
Fixed-tilt	Existing Only	1.3
Single-axis Tracking	Existing and New	1.3

Collected data for solar resources	Units
Installed capacity	MW
Latitude/longitude	degrees
Online date	date
Planned retirement date	date
Forced outage rate	%
Mean time to repair	hours
Inverter loading ratio	%
Tracking/fixed tilt	text
Azimuth angle	degrees
Tilt angle	degrees
Ownership/contractual shares	%

Overview of Current Simulation Methodology

- Hourly wind profiles from 2007 – 2009 simulated based on NREL's WIND Toolkit
- Simulations based on plant-specific hub heights and power curves data collected in the Generator list
  - Choose **best-match models** for existing wind plants w/o power curve data
  - Assume NREL generic curves for planned turbines (NREL 2) based on **local wind speed level**

Collected Wind Turbine Model List	Models used in WIND Toolkit simulation
Vestas V80-1.8	*Leitwind LTW80 1.8 MW (MT)*
Mitsubishi MWT-1000A	*VergnetGEVHP(104.4dba)_62m_1000kw(MT)*
GE 1.5-77	GE 1.5SLE 77m 1.5 MW (MG)
GE 1.5 SLE	GE 1.5SLE 77m 1.5 MW (MG)
Clipper Liberty C96	ClipperLibertyC96_96m_2500 kW(MG)
Vestas V100-1.8	Vestas V100 1.8 MW
Vestas V17-75	*Wind Energy Solutions18_18m_80kw(MT)*
GE 1.5 S	GE 1.5SLE 77m 1.5 MW (MG)
GE 1.6 XLE	GE 1.5XLE 82.5m 1.5 MW (MG)
GE 1.6 XLE	GE 1.5SLE 77m 1.5 MW (MG)
NREL 2	NREL Generic Curve 2 MW

Offshore Wind Resource Generation Profiles

- The offshore wind resource generation profiles are derived from NREL's 2020 study on offshore wind resource assessment in California
  - These profiles were based on assumptions that are still considered state of the art, including as-yet to be commercially available 15 MW turbines
- Since the release of that study NREL has updated some of the underlying assumptions used in creating the generation profile, leading to improvements to the hourly generation profiles
  - These updates improve assumptions around losses that impact the hourly generation, that could potentially be included in RESOLVE
- Staff is currently discussing with NREL how to achieve consistency between the underlying climate data for land-based wind and offshore wind generation profiles
  - Particularly relevant to the connection of generation profiles between the CPUC's RESOLVE and SERVM models
- Staff will present the proposed updated generation profiles in the Inputs and Assumptions draft document later this Fall

Recommended Updates

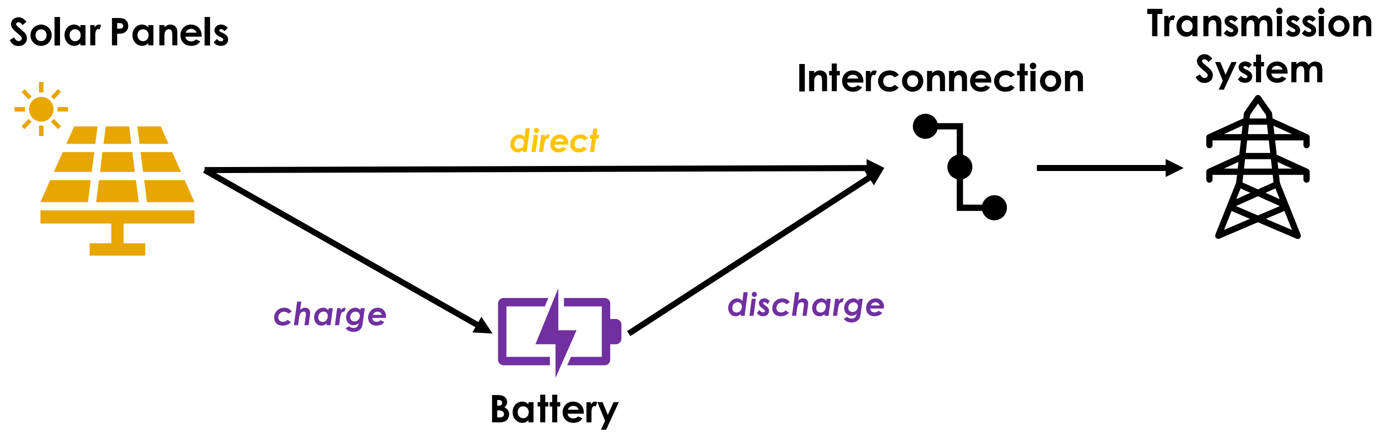
- A refresh of the new candidate resource generation profiles
  - This will allow us to incorporate improvements to land-based wind turbine technology, improved hourly generation profiles for offshore wind, and improved climate modeling for wind speed and insolation
- An expansion of the time horizon of the historical generation data to reflect more recent weather conditions
  - Current RESOLVE generation profiles are based on 2007 – 2009 historical years
- Improved data consistency between RESOLVE and SERVM models
  - To further consolidate the interconnectedness of the inputs and results of the analyses of these models

4.2. Hybrid/Paired Solar-Storage Modeling

Introduction

- The pairing or hybridization of generation and storage resources is becoming increasingly frequent
- "**Paired**" refers to generation and storage resources that share the same grid interconnection
- "**Hybrid**" resources are paired resources with constraints that require storage charging to occur using the paired generation resource rather than the grid

This presentation focuses specifically on combinations of **solar and storage** because of strong commercial interest in solar-storage combinations



Motivation

- To date, RESOLVE capacity expansion modeling for the CPUC IRP has not represented hybrid or paired resources, though RESOLVE can build solar and storage (and other resources) independently
- Post-processing of RESOLVE results into SERVM model inputs has resulted in some hybrid and paired resources being represented in SERVM production cost modeling. SERVM also includes some existing or planned hybrid and paired resources.
- Hybrid and paired resources are important to model in RESOLVE because:
  - Hybrid and paired resources are expected to make up a significant fraction of resource additions in the upcoming years
  - The economics and operations of hybrid and paired resources are different than standalone resources
  - There may be different transmission capacity requirements for hybrid and paired resources relative to standalone solar and storage, which could result in different recommendations to CAISO's transmission planning process (TPP)

IRP modeling balances complexity across many types of inputs

- IRP modeling must balance complexity across resource types, years, geographic areas, policy goals, etc.
- IRP capacity expansion modeling produces future portfolios that inform future policy direction but…
  - Further downstream studies are required for more detailed analysis such as CAISO's transmission planning process, loss of load modeling, production cost modeling etc.
- Hybrid and paired resource modeling in IRP, especially in capacity expansion, must be simplified to a limited design space
  - *Likely only a single hybrid or paired configuration is possible for capacity expansion modeling for the current IRP cycle*
    - Staff requests feedback on the ideal configuration (or configurations) to model in IRP capacity expansion modeling

Hybrid or Paired Design Parameters (1)

Design Parameter	Description
Duration of storage	Hours of sustained discharge for a given power capacity.
Solar to Storage ratio	Ratio of solar capacity to battery power capacity, for example 2 MW solar for every MW of battery discharge capacity.
DC- or AC-coupled	DC-coupled systems typically have one inverter and energy from the solar field can be directly sent to the battery without having to first go through an inverter. AC-coupled systems have two inverters behind a shared interconnection.
Solar inverter loading ratio	Ratio of solar panel rated MW to inverter MW. DC-coupled systems usually have higher inverter loading ratios than AC-coupled.
Interconnection sizing	Combined limit on solar and storage output.
Representation in CAISO transmission deliverability constraints	Transmission capacity needed for hybrid or paired resource may or may not be materially different from an equivalent standalone solar and battery. Highest Peak (HSN), Secondary Peak (SSN), and Off-Peak periods should be considered.
Resource adequacy contribution	The resource adequacy contribution of hybrid and paired resources could be similar to or lower than equivalent standalone resources.

Hybrid or Paired Design Parameters (2)

Design Parameter	Description
Co-control or independent control?	Are the renewable and storage portions of the resource dispatched together or independently?
Storage charging from the grid	The extent to which storage can charge from the grid or is restricted to charge from on-site solar.
REC treatment of renewable energy generated and subsequently stored	Storage losses from the hybrid or paired facility may or may not deduct from Renewable Energy Certificates (RECs) generated by the resource.
Operational reserves	• Should the storage part of the resource be modeled as providing operational reserves (such as regulation, spinning reserve, etc.)? • Should the solar part of the resource be modeled as providing reserves? If so which reserves?
Cost of hybrid or paired resource relative to standalone equivalent	In most cases a hybrid or paired resource is expected to be less expensive than an equivalent standalone solar and battery due to shared infrastructure, permitting, etc. Tax credits will play a role in whether the cost difference is small or large.

Stakeholder input: recommended hybrid or paired configuration for capacity expansion

- Given that the number of configurations of hybrid or paired resources will be limited in the current IRP cycle, staff is seeking stakeholder feedback on the <u>single most</u> important configuration that IRP should model in capacity expansion
  - Stakeholders are free to suggest more than one configuration with the knowledge that IRP capacity expansion will be limited in the number of configurations that can be modeled

A "**configuration**" is a complete set of values for the "Design Parameter" rows in the previous slides

Stakeholders should support their choices with data and/or explanations

Design Parameter	EXAMPLE value – stakeholders can/should suggest others	Explanation of choice
Duration of storage	4 hours	Frequently seen in recent RFPs
Solar to Storage ratio	2 MW solar for every MW of battery discharge capacity	…
DC- or AC-coupled	AC-coupled	…
Solar inverter loading ratio	1.4 MW of solar panels per MW of solar inverter capacity	…
Interconnection sizing	Equal to solar inverter size	…
… Continue with all design parameters on the previous slides …		

4.3 Transmission Constraint Implementation

Contents

- Background
- Updates since 2019 Inputs and Assumptions document
- Additional Updates since 2021 PSP Workshop

Background - Transmission Constraint Modeling in RESOLVE

- The modeling of transmission constraints in RESOLVE is tied to the CAISO's representation of the transmission system in its Transmission Planning Process modeling and the associated Transmission Deliverability Whitepaper
- Prior to 2021, CAISO represented transmission deliverability in Renewable Transmission Zones with technology-agnostic available capacity in full-capacity deliverable status (FCDS) and energy-only (EO) amounts.
- In 2021 the methodology and representation of the transmission regions were updated by the CAISO and implemented in RESOLVE

Transmission Updates Since 2019 Inputs and Assumptions: Limits and Constraints

- CAISO updated on-peak and off-peak transmission capability and included technology-specific transmission information
  - CAISO released a white paper in July 2021 entitled "Transmission Capability Estimates for use in the CPUC's Resource Planning Process" which documents the updated capability estimates
    - Available at: http://www.caiso.com/Documents/WhitePaper-2021TransmissionCapabilityEstimates-CPUCResourcePlanningProcess.pdf
  - New transmission constraint limits generally increase the amount of available capacity on the transmission system relative to the 2019 CAISO white paper values, though this is not true for every constraint
    - The new limits also include geographic areas that were not covered in the 2019 white paper
      - 2019 CAISO white paper available at: https://www.caiso.com/Documents/WhitePaper-TransmissionCapabilityEstimates-InputtoCPUCIntegratedResourcePlanPortfolioDevelopment.pdf

Transmission Updates Since 2019 Inputs and Assumptions: Storage + Solar

- Previous RESOLVE modeling did not consider interactions between storage and transmission constraints
  - Instead, interactions were addressed downstream in the bus-bar mapping process
- RESOLVE has been updated to:
  - Account for the fact that storage capacity selected requires transmission availability to receive full deliverability
    - Lithium-ion battery and pumped storage resources were previous modeled as a single CAISO-wide resource; multiple resources are now modeled such that transmission limits in different areas of the CAISO grid can be considered
  - Model the interaction between storage charging and off-peak transmission limits by expanding off-peak transmission limits when storage is built
    - Storage consumes on-peak transmission capability
    - Storage creates off-peak transmission capability
  - Solar and battery locations aligned as a step towards modeling co-located and hybrid resources
    - Full hybrid modeling out of scope
      - No interactions are modeled between solar and storage in hourly dispatch
      - Cost reductions from shared infrastructure are not modeled

Additional Updates since September 2021 PSP Workshop

- The September 2021 CPUC IRP Proposed PSP workshop contains further details about the RESOLVE model updates carried out since the 2019 Inputs and Assumptions.
- However, after the release of the 2021-2022 TPP Analysis results in Q1 2022, further updates were made to the transmission constraint modeling
  - CAISO presented additional updates to the transmission constraint representation that build on the information contained in the 2021 CAISO transmission deliverability whitepaper
- This updated information includes:
  - Adjustments to available capacity for a few transmission constraints
  - Adjustments to RESOLVE resource mappings to specific transmission constraints
  - Adjustments to transmission utilization factors for battery storage and out-of-state wind resources
- The upcoming 2023-2024 TPP portfolio development will provide stakeholders with further details on the specifics of these adjustments and their potential impacts.

4.4. Fuel Price Update

Summary of fuel price update

Recommendation: Perform test model runs to decide: (a) keep LSE Filing Requirements / 2021 PSP natural gas price inputs or (b) use 2021 IEPR High natural gas prices

- **Natural gas**
  - CEC 2021 IEPR price forecasts **$0.5-1.5/MMBtu lower** than LSE Filing Requirements / 2021 PSP inputs (from June 2020)
  - This difference is primarily a result of low commodity prices at the time of CEC modeling[1]
  - The low gas price forecasts contradict the high fuel prices observed recently

- **Coal and uranium**
  - Coal and uranium prices have not been updated – typically less volatile
  - Coal and nuclear plants are not candidate resources in California RESOLVE, thus fuel prices do not impact resource build results
  - Nuclear plants are currently modeled as must-run in RESOLVE[2], thus fuel prices do not impact nuclear dispatch results

[1] *For details, see: IEPR Commissioner Workshop on Natural Gas Market and Demand Forecasts. August 30, 2021.* https://www.energy.ca.gov/event/workshop/2021-08/iepr-commissioner-workshop-natural-gas-market-and-demand-forecasts. [2] *Nuclear power plants are characterized by high capital costs relative to fuel costs and are therefore economically incentivized to run at high capacity factors.*

Background on natural gas price in RESOLVE

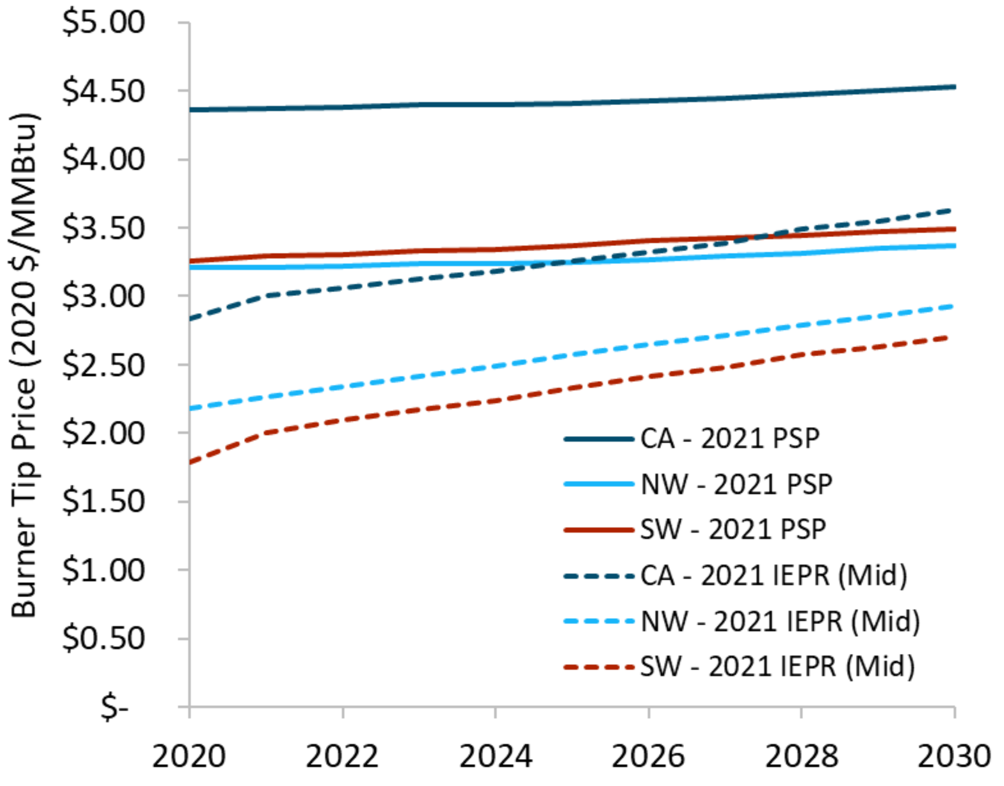
- Gas price inputs in RESOLVE are based on WECC burner tip price estimates from the CEC's North American Market Gas-trade (NAMGas) model runs
- Current gas price inputs (used for 2021 PSP and LSE Filing Requirements) are from a NAMGas model run posted in June 2020 using the Mid Demand Prices scenario
- Latest NAMGas model run was posted in September 2021 as part of 2021 IEPR[1]
  - Forecasts available through 2030

[1] *Natural Gas Burner Tip Prices for California and the Western United States.* https://www.energy.ca.gov/programs-and-topics/topics/energy-assessment/natural-gas-burner-tip-prices-california-and-western.

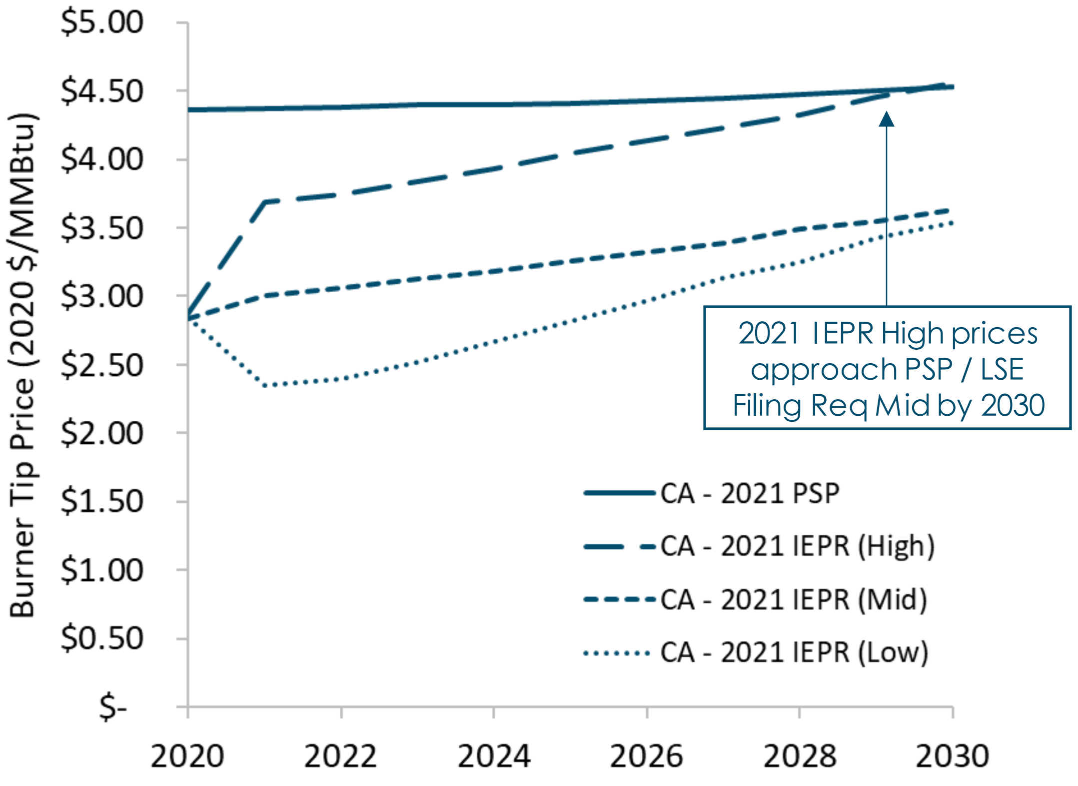
Fuel price comparison

2021 IEPR vs. 2021 PSP / 2022 LSE Filing Requirements

“Mid” Burner Tip Price (2021 IEPR vs. PSP / LSE Filing Req)



CA Burner Tip Price Sensitivities (2021 IEPR Low/Mid/High vs. PSP / LSE Filing Req)



Note: 2021 IEPR gas price forecasts are available through 2030. Model inputs beyond 2030 will be extrapolated.

5. Reliability Modeling in RESOLVE and SERVM

5.1. Approach and Inputs

Use Cases for Reliability Modeling in 2022-23 IRP Cycle

- A broad set of reliability updates are being conducted this IRP cycle, for use as follows:
- **Near-term use case (in progress)**: **LSE plan filing requirements**[1] released in June and July, 2022
  - Reliability planning requirement, including the planning reserve margin
  - Final Resource Data Template (RDT) with resource accreditation metrics, including effective load carrying capabilities (ELCC), by resource type
- **Upcoming use cases**:
  - Updates to RESOLVE and SERVM, and IRP planning track more broadly, including for 2023 Preferred System Plan (PSP) development
  - Mid-to long-term procurement program, including reliability procurement need determination for 2025 and beyond
- **Approach**
  - Where possible, use consistent methodologies and inputs across all use cases

1. Filing requirements plus related material from April and July 2022 MAG webinars are available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials

Opportunities to Improve IRP Reliability Planning

- **2017-18 IRP Cycle**
  - Optimistic import assumptions meant reliability planning was secondary
- **2019-21 IRP Cycle**
  - Changing assumptions led to two large procurement orders for new resources
    - Orders were not directly tied to loss of load probability (LOLP) modeling of reliability need
  - PRM assumed in RESOLVE to reflect Mid-Term Reliability (MTR) High Need scenario has led to portfolio that exceeds the reliability standard, per 2021 Preferred System Plan (PSP) analysis
- **2022-23 IRP Cycle**
  - I&A and LSE plan filing requirements present opportunity to refresh reliability planning inputs
  - Planning track PRM update for IRP modeling broadly
  - PRM for mid-to long-term procurement program

Topic	Past IRP Method	Improvement
PRM	Shifting PRMs not tied to LOLP fundamentals → RESOLVE outputs not always matched to reliability results from loss of load modeling	SERVM-based PRM to meet reliability standard
Thermal resource accounting	NQC-based (installed capacity) → can tip the scales in favor of gas plants vs. clean energy	ELCC-based to create a level playing field
ELCCs for RESOLVE	Solar + wind surface (RECAP) Storage ELCC curve (SERVM)	Solar + storage surface (SERVM) Wind ELCC curves (SERVM)
ELCCs for LSE Plans	Interpolation from RESOLVE outputs	SERVM-based ELCC forecast

Summary of 2022 Approach

- **Reliability Modeling Approach**
  - Use the CPUC's SERVM model, with any appropriate updates, as the basis for need determination and resource accreditation
- **Need Determination**
  - Calculate total system need via a perfect capacity (PCAP) based total reliability need MW (TRN), then translate into a PCAP planning reserve margin (PRM) above median gross peak
  - A PCAP-based approach means removing from the reserve margin an allowance for forced outages of firm resources, and accrediting all resource types at their respective ELCC i.e., their perfect capacity equivalent, based on simulations that consider their risk of outages, resource availability, and their interaction with load and other resource types
  - Calculate marginal reliability need (MRN) relative to total reliability need (TRN) using a marginal ELCC study
  - Base LSE-specific need on share of marginal reliability need using new multi-year CEC LSE-specific managed peak share forecast
- **LSE Plan Resource Accreditation**
  - All resources will use marginal ELCCs
- **RESOLVE Updates**
  - Align PRM and ELCCs with LSE plan inputs (i.e. use same PCAP PRM and ELCCs from same SERVM model)
  - Change solar + wind ELCC surface to a solar + storage ELCC surface, include demand response (DR) on the storage dimension
  - Develop separate wind ELCC curves
  - All other resources will also use ELCC (firm resources, hydro, etc.)

Key SERVM Modeling Updates

The following key updates were completed in May 2022[1] and applied in the June 2022 PRM study[2] as part of comprehensive model updates scoped for the 2022-2023 IRP cycle. Recent studies for the 2021 IRP PSP and the RA proceeding Feb 2022 LOLE/PRM study used assumptions from the prior IRP cycle.

- Performed extensive updates to the Baseline in SERVM. Added new resources online from CAISO Master Generating Capability List as well as new Development resources from the LSE IRP Plans
- Weather Years now span 1998-2020 and determine the distribution of load, wind, solar, and hydro hourly shapes
- Demand forecast updated to CEC's 2021 IEPR mid-mid and Additional Transportation Electrification (ATE) case
- Updated Preferred System Plan portfolio from RESOLVE using 2021 IEPR and updated resource costs and transmission zone limits
- PG&E Bay and Valley regions collapsed into one PGE region
- Only CAISO (PGE, SCE, SDGE regions) units explicitly modeled – transfers with neighbors modeled as fixed import shapes
- Updated forced outage rates
- Relaxed Path 26 transmission limits (to ensure congestion from unbalanced retirements or additions in N vs. S does not increase system reliability need)
- Ratio of fixed to tracking solar capacity aligned with RESOLVE assumptions
- BTM battery storage treated as a load modifier using 2021 IEPR shapes

1. Staff's input data for reliability modeling is available at https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/long-term-procurement-planning/2022-irp-cycle-events-and-materials/unified-ra-and-irp-modeling-datasets-2022

2. Available at https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2022-irp-cycle-events-and-materials/20220616-irp-lse-plan-prm-study-results.pdf

Energy Division's Reliability Modeling Strategy

Energy Division is using the LOLE reliability modeling framework in a variety of Commission proceedings in addition to IRP.

- Energy Division completed LOLE and ELCC studies in 2022 for the Resource Adequacy (RA) proceeding to inform the determination of wind, solar and storage resource ELCCs as well as the PRM for the 2023 and 2024 RA compliance years.
- Energy Division is using the LOLE framework with the "NoNewDER" portfolio for the Avoided Cost Calculator in the Integrated Demand Energy Resource proceeding to establish avoided costs.
- Energy Division is also proposing to perform LOLE modeling to support the Slide of Day framework in the RA proceeding

These diverse applications of LOLE modeling all rely on the same IRP baseline dataset.

- Baseline dataset includes electric demand, baseline resources, generation profiles for non-firm resources, fuel prices, etc.
- Maintaining consistency and stability in datasets is critical for enabling modeling work across these proceedings to be relatable and consistent with each other.
- Modeling data is posted to the CPUC website (Unified RA+IRP Dataset page) for parties to review and comment
- Parties can provide feedback during the regular IRP Inputs/Assumptions development process and periodic MAG meetings

Next Steps

- Consider RESOLVE reliability updates (next section)
- Staff expects there to be more process around adoption of reliability inputs and approaches later this cycle, for IRP planning track and mid- to long-term procurement program, including reliability procurement need determination for 2025 and beyond

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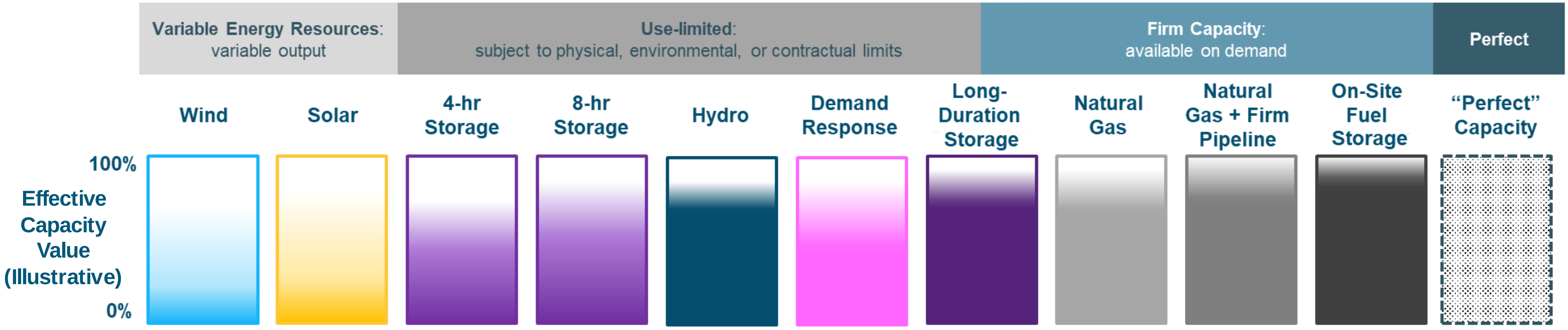
5.2. RESOLVE Reliability Updates

Overview of Reliability Updates in RESOLVE

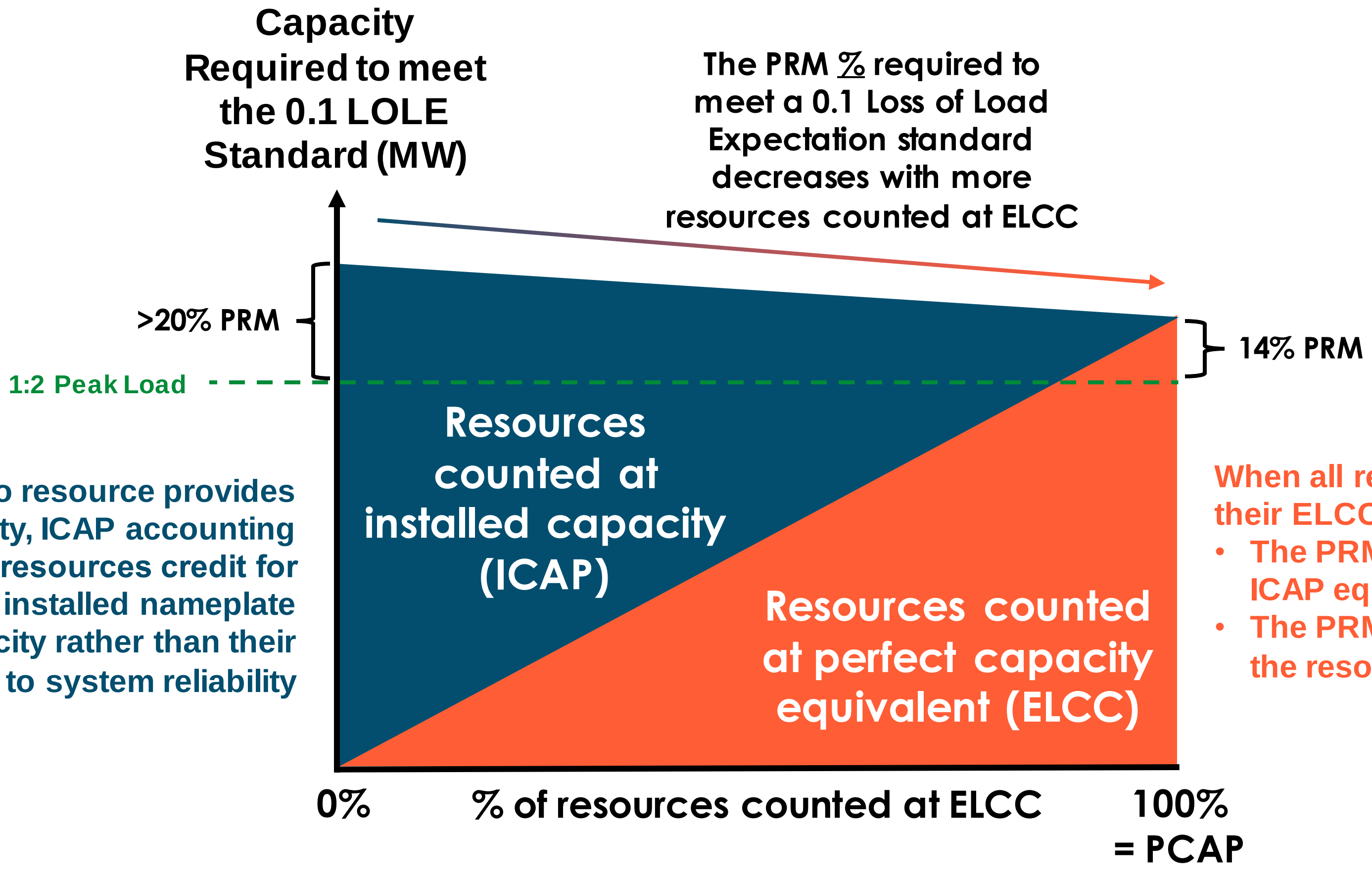
1. **Updating RESOLVE's total reliability need (Planning Reserve Margin, PRM)**
   - Switch from ICAP (Installed capacity) to PCAP (Perfect capacity) PRM
   - Update PRM based on SERVM analysis
   - Switch basis of PRM percentage from managed peak to gross peak
2. **Updating resource contributions to resource adequacy in RESOLVE**
   - Count all resources at their perfect capacity equivalent (Effective Load Carrying Capability, or ELCC) to be consistent with the PCAP PRM
   - Update resource ELCCs based on SERVM analysis
   - Move to a solar + storage ELCC surface to capture strong diversity benefits

These updates better align RESOLVE + SERVM
to better ensure RESOLVE develops sufficiently reliable portfolios

No Resource Provides Perfect Capacity



PCAP PRM provides a more durable definition of total reliability need



Even though no resource provides perfect capacity, ICAP accounting gives "firm" resources credit for their full installed nameplate capacity rather than their contribution to system reliability

When all resources are counted at their ELCC value:

- The PRM % is lower than its ICAP equivalent
- The PRM % does not change as the resource portfolio evolves*

* Since the PCAP PRM % is a function of operating reserves, and load variability, the % may change over time if these inputs change but the percentage won't be dependent on the resource portfolio.

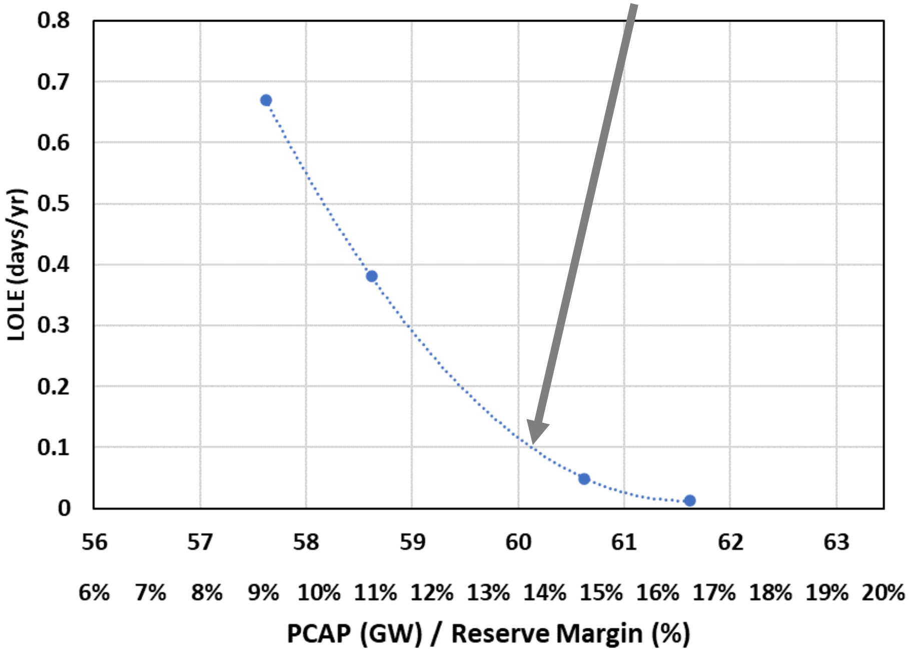
PCAP PRM Results
(from July Filing Requirements MAG)

- A Perfect Capacity (PCAP) PRM analysis varies PCAP MW until 0.1 LOLE is achieved
- PCAP PRM is driven by
    A. Inter-annual load variability in historical weather dataset
    B. SERVM's load forecast error
    C. 6% operating reserves
- PCAP PRM was calculated for 2024, 2026, 2030, and 2035
- PRM is measured relative to median gross peak (i.e. BTM PV counted as a supply-side resource at ELCC)

Staff propose RESOLVE to use a 14% PCAP PRM applied to the IEPR gross peak

SERVM's CAISO PCAP PRM Simulations (2024)

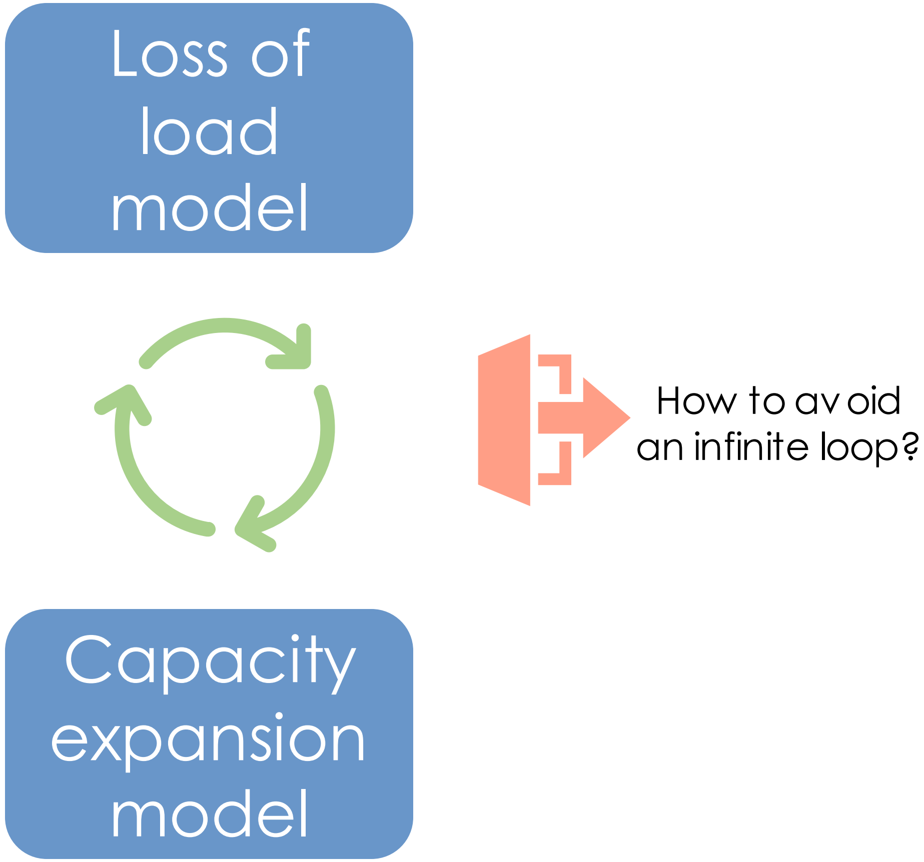
*LOLP simulations indicate an **13.8%** reserve margin needed to meet 0.1 days/year LOLE*



- *PCAP PRM simulations for years 2024, 2026, 2030 and 2035 ranged between ~13.5-14.0%*
- *Equivalent 2030 ICAP PRM over gross peak is ~18-21.5%, depending on the share of resources counted at ELCC vs. installed capacity*
- *All PRMs calculated relative to CAISO median gross peak*

Planning models need estimates of resource adequacy contributions

- Capacity expansion models enforce resource adequacy constraints (e.g. PRM)
- To ensure reliability at minimum cost, the marginal *and* total resource adequacy contribution of energy-limited resources needs to be accurately reflected
  - But declining marginal capacity values and interactive effects between resources require <u>constant re-calibration</u> of energy-limited resource adequacy contributions
- It's not feasible to embed a detailed loss-of-load model within a capacity expansion model

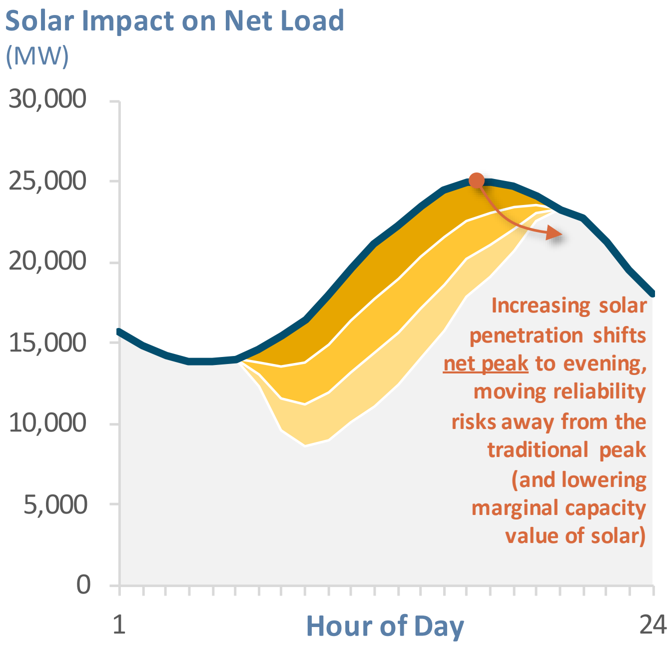


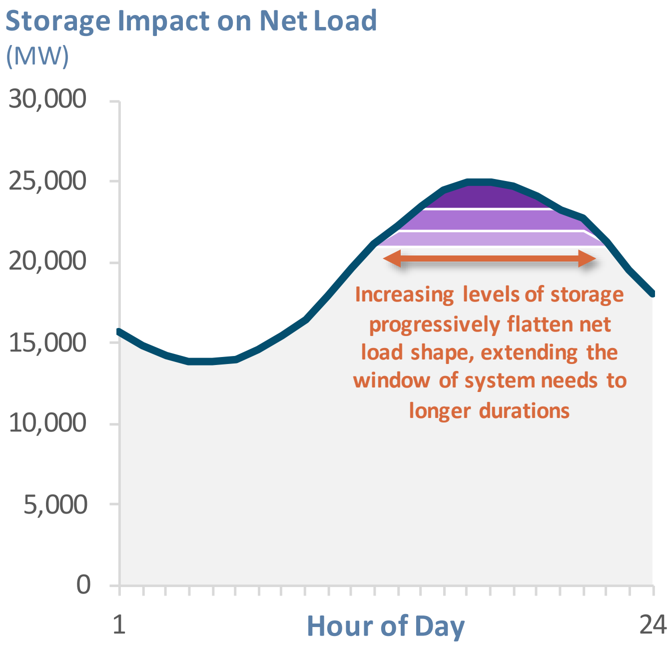
ELCC captures complex dynamics resulting from increasing penetrations of variable & energy limited resources

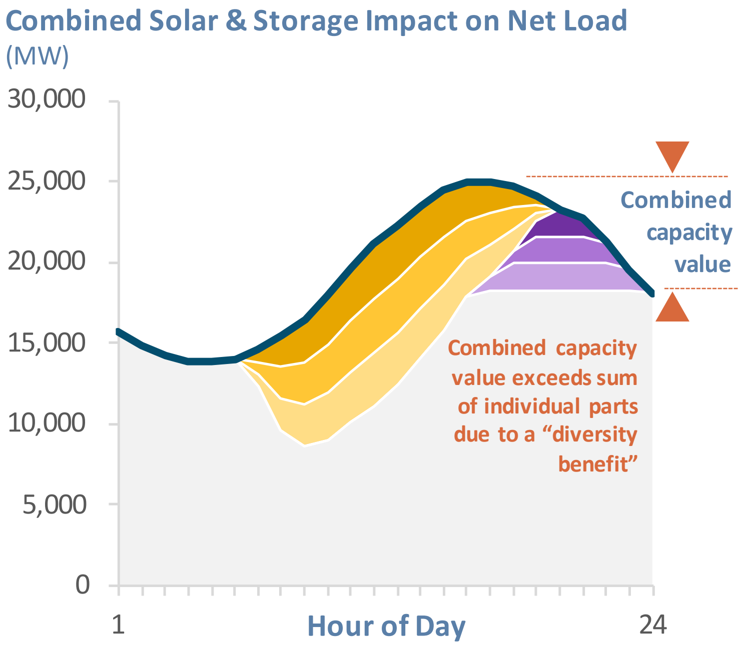
“**Variable**” resources shift reliability risks to different times of day

“**Energy-limited**” resources spread reliability risks across longer periods

A **portfolio** of resources exhibit complex interactive effects, where the whole may exceed the sum of its parts







The ELCC approach inherently captures both **capacity** & **energy** adequacy

Proposed RESOLVE Approach

	Prior Approach: 2021 Preferred System Plan (PSP)	Proposed Approach: 2022 IRP Cycle and beyond
Planning Reserve Margin	**22.5% installed capacity based (ICAP)** PRM above managed peak	**14% perfect capacity based (PCAP)** PRM above gross peak
Wind	ELCC (solar/wind ELCC surface)	ELCC (in-state, OOS, offshore wind curves)
Solar PV		ELCC (solar/storage surface)
BTM PV	ELCC (solar/wind ELCC surface), after increasing need by IEPR peak shift	
Battery Storage	ELCC curve (Battery only)	
Demand Response (Load Shed)	DR program capacity (NQC) for new + existing	ELCC (model new DR on storage dimension of solar/storage surface)
Pumped Storage	Installed capacity (NQC)	ELCC
Hydro		
Bio/Geo/Nuclear		
Fossil (CT/peaker, CCGT, CHP, coal)		
BTM Storage	Load modifier via IEPR assumptions	Load modifier via IEPR assumptions

RESOLVE will now rely on SERVM runs to represent ELCCs for all resources, driving further consistency between the two models

- ELCC calculations in SERVM use 2030 loads from the 2021 IEPR and the 2030 38MMT portfolio from the LSE filing requirement runs.
- To avoid double counting interactive effects, ELCC calculations in SERVM were sequenced: firm resources first, hydro second, existing pumped storage third, existing demand response fourth, then candidate resource options.

ELCC curves and surfaces address challenging issues for capacity expansion models

- Saturation impacts are addressed because marginal ELCC declines endogenously with resource penetration
- Creating ELCC curve equations using the results of a LOLE model implicitly includes energy limitations on different timescales
  - For wind and solar, production profiles across many years in the LOLE model allows for consideration of low renewable output periods
  - For storage, ELCC simulations have charging and discharging constraints
    - Portfolio ELCC captures charging energy sufficiency and flattening of the net peak via the LOLE model
- ELCC curve with a single resource class does *not* include synergistic or antagonistic impacts with other resource classes
  - ELCC "surface" with two resource classes can include interdependent effects between two resource classes

Workflow for using ELCC curve or surface in planning

1. **LOLE model** (SERVM)

   Calculate ELCC of combinations of energy-limited resources over a wide range of installed capacities

2. **Linear equations**

   Convert portfolio ELCC values at a range of penetrations into linear equations for marginal and total ELCC

3. **Capacity Expansion**

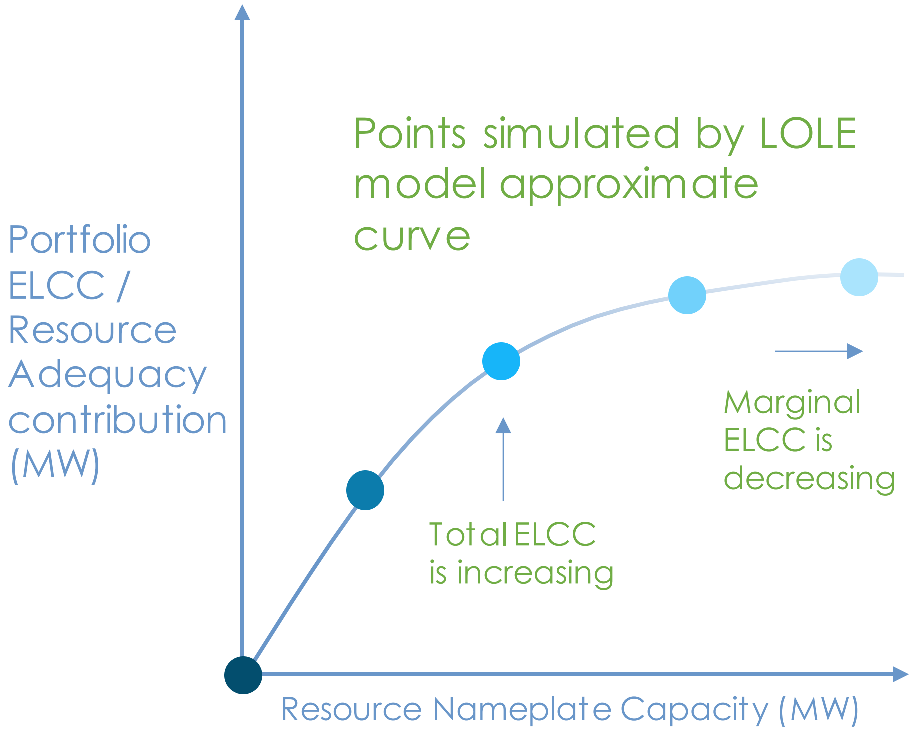
   Implement curve or surface equations in capacity expansion model, create least-cost portfolios

4. **Reliability Check**

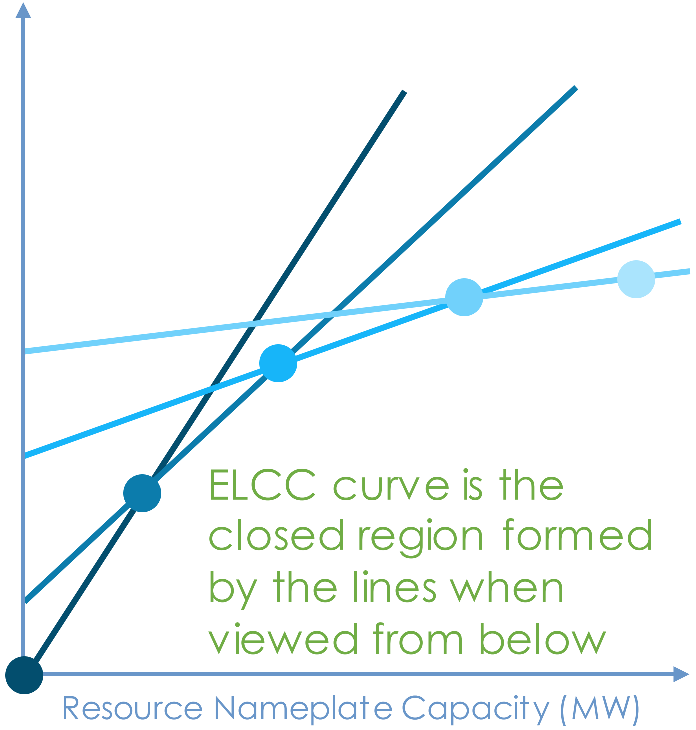
   Check reliability using LOLE model, adjusting if any issues are found

Building an ELCC curve in one dimension

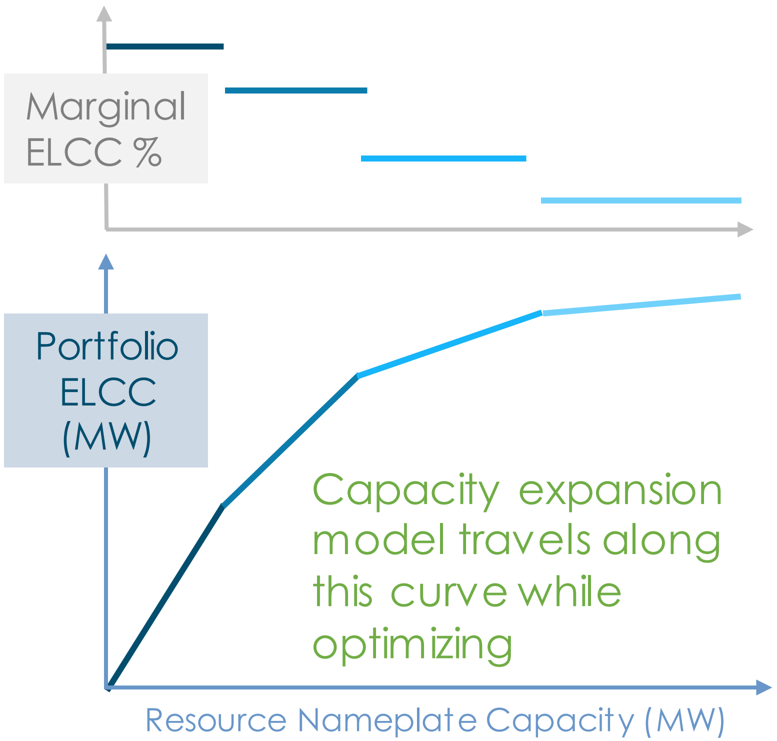
1 **Calculate ELCC at Different Levels of Penetration**



2 **Linear equations approximate "true" ELCC curve**

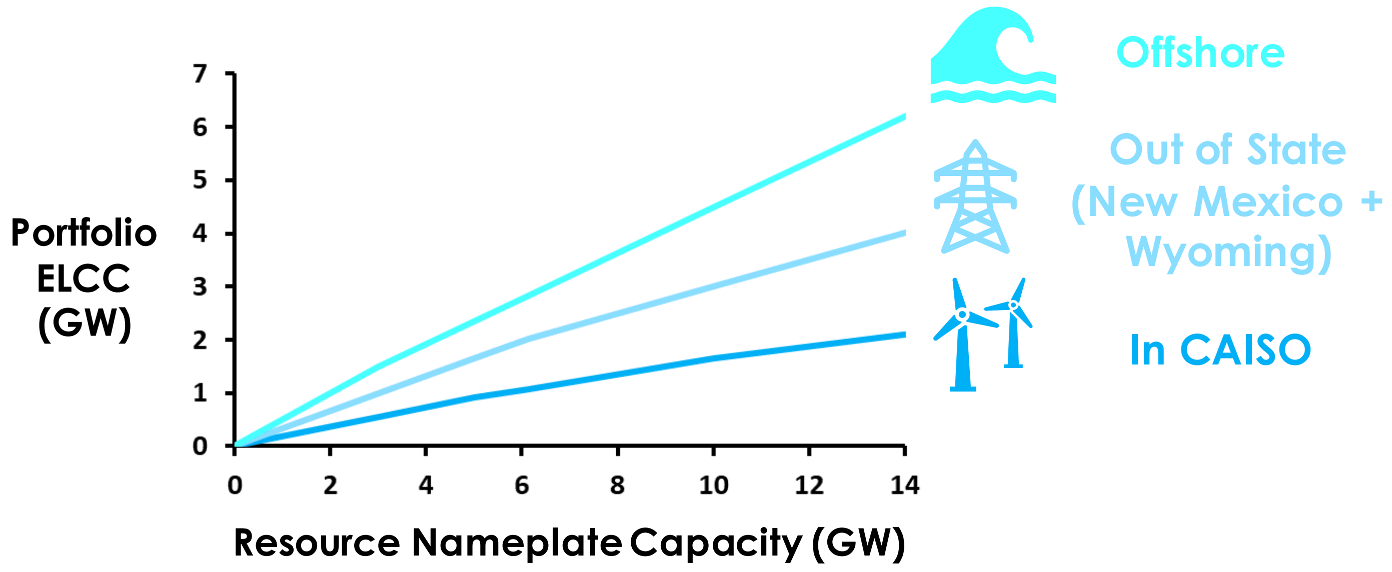


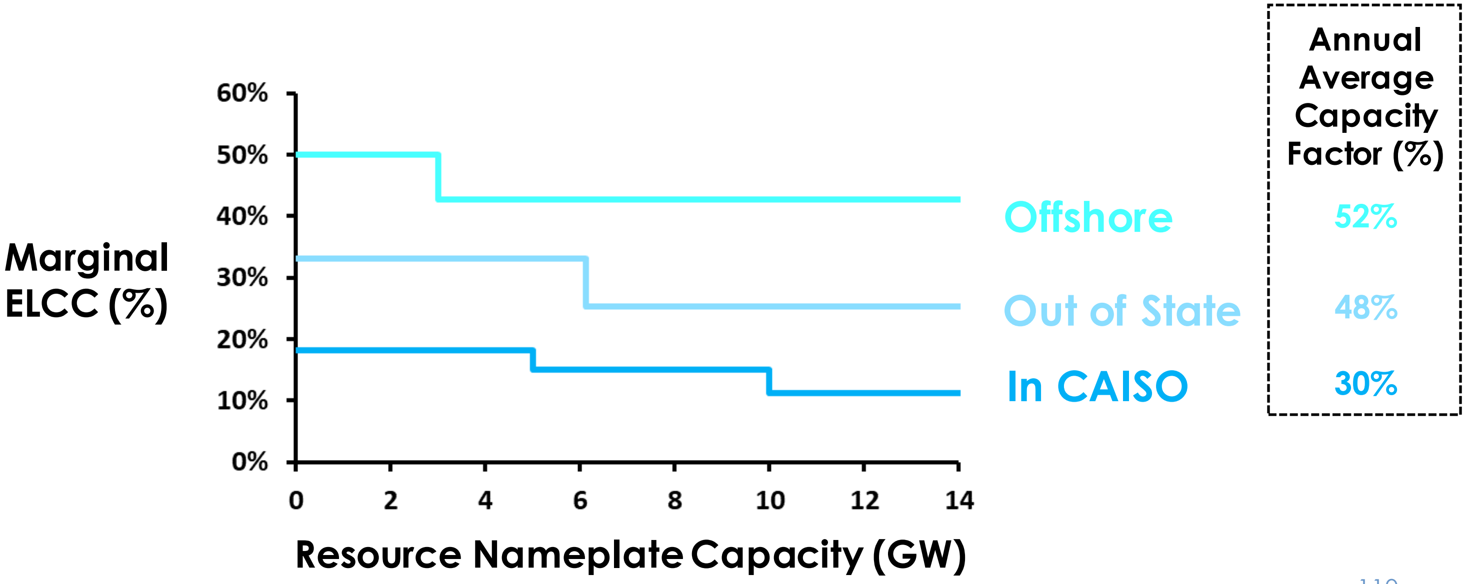
3 **Implement in capacity expansion model**



Wind ELCC Curves

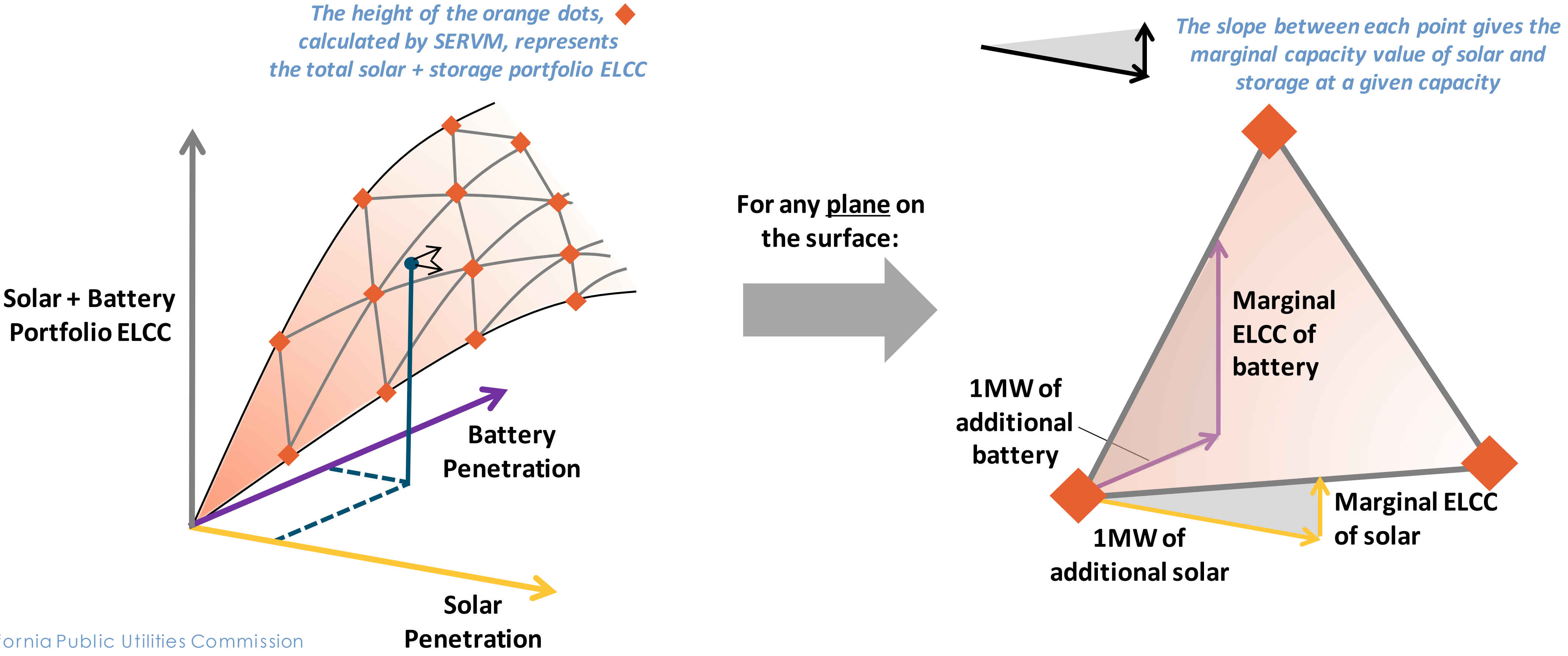
- Proposed update is to model three wind types (in-CAISO, out of state, and offshore) on separate ELCC curves
  - SERVM runs with different combinations of the three wind types demonstrated that separate ELCC curves are more accurate than combining into a single wind ELCC curve
- Marginal ELCC is relatively stable over range of wind capacity and is largely proportional to annual average capacity factor





Now add a dimension….

- An ELCC surface with two resource classes can capture both diminishing returns and diversity benefits between resources



Solar + Battery Surface Marginal ELCCs

At lower levels of battery capacity, battery marginal ELCC is supported by solar because A) solar can charge batteries, and B) solar production can delay battery discharge

Marginal Battery ELCC (%)

Battery marginal ELCC increases for a given battery penetration as solar is added

Solar Nameplate Capacity (GW)

4-Hour Battery Nameplate Capacity (GW)	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
0							98%								
5							94%								
10							94%								
15							87%								
20	11%	24%	24%	36%	36%	47%	51%	55%	55%	55%	55%	55%	59%	59%	59%
25							26%								
30							15%								
35							15%								
40							9%								
45							6%								
50							6%								

Battery marginal ELCC saturates without supporting solar capacity

Marginal Solar ELCC (%)

Solar marginal ELCC increases for a given solar penetration as batteries are added

Solar Nameplate Capacity (GW)

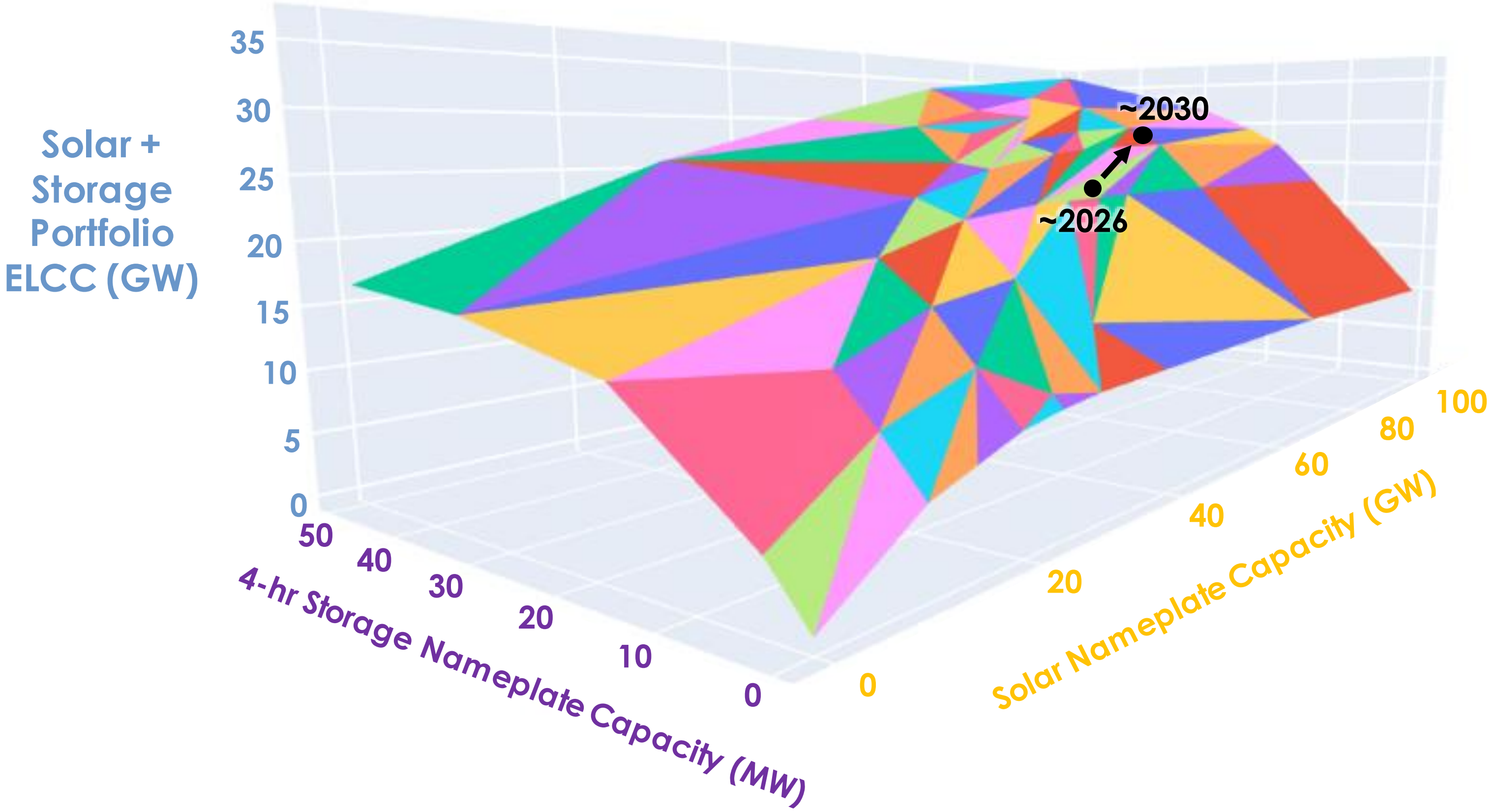
4-Hour Battery Nameplate Capacity (GW)	30	35	40	45	50	55	60	65	70	75	80	85	90	95	100
0							2%								
5							2%								
10							1%								
15							2%								
20	29%	27%	21%	18%	13%	12%	4%	4%	3%	1%	1%	1%	0%	0%	0%
25							12%								
30							18%								
35							18%								
40							18%								
45							20%								
50							20%								

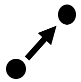
Solar marginal ELCCs saturate without supporting storage capacity

Batteries support solar marginal ELCC by shifting solar generation to hours when it is needed most

Solar + storage surface in 3D

Each colored area represents a different combination of marginal solar and marginal storage ELCC

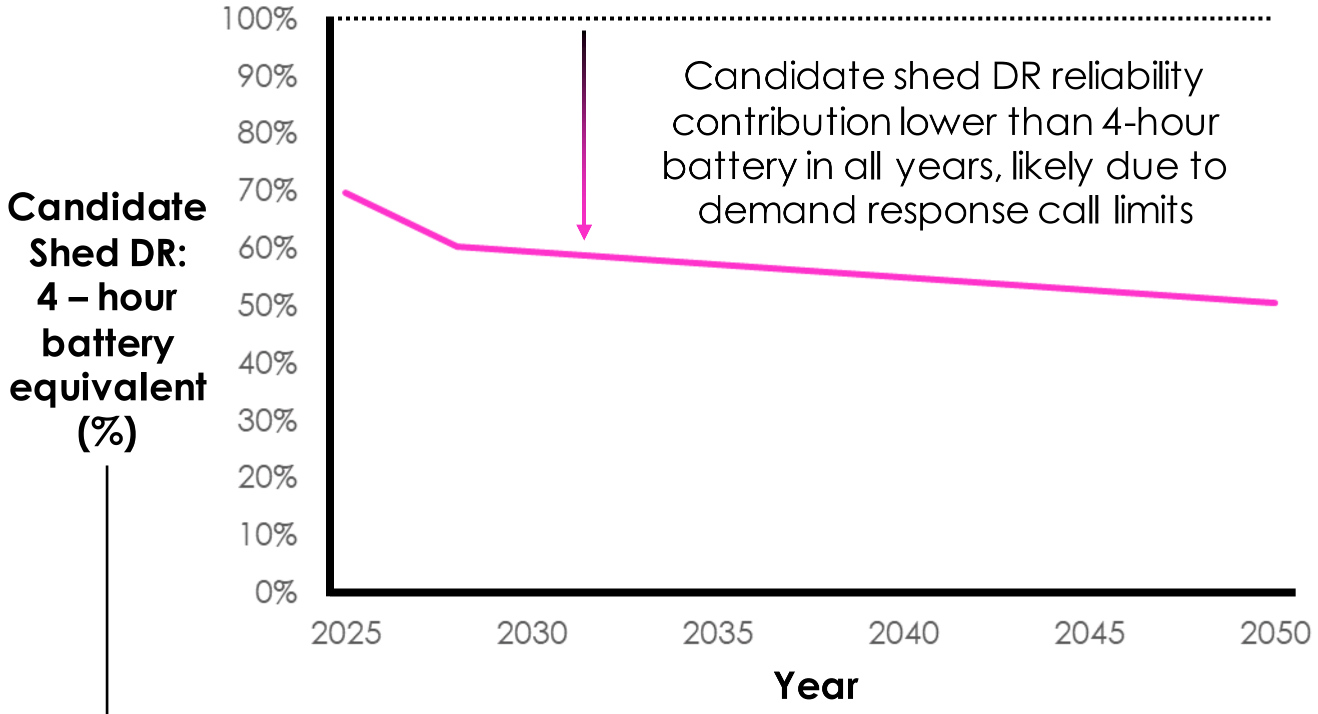




As RESOLVE adds solar and storage resources:
(1) the portfolio ELCC increases and (2) the marginal solar and storage values may change if enough capacity is added to move to a different plane (each colored area is a plane)

Shed Demand Response (DR)

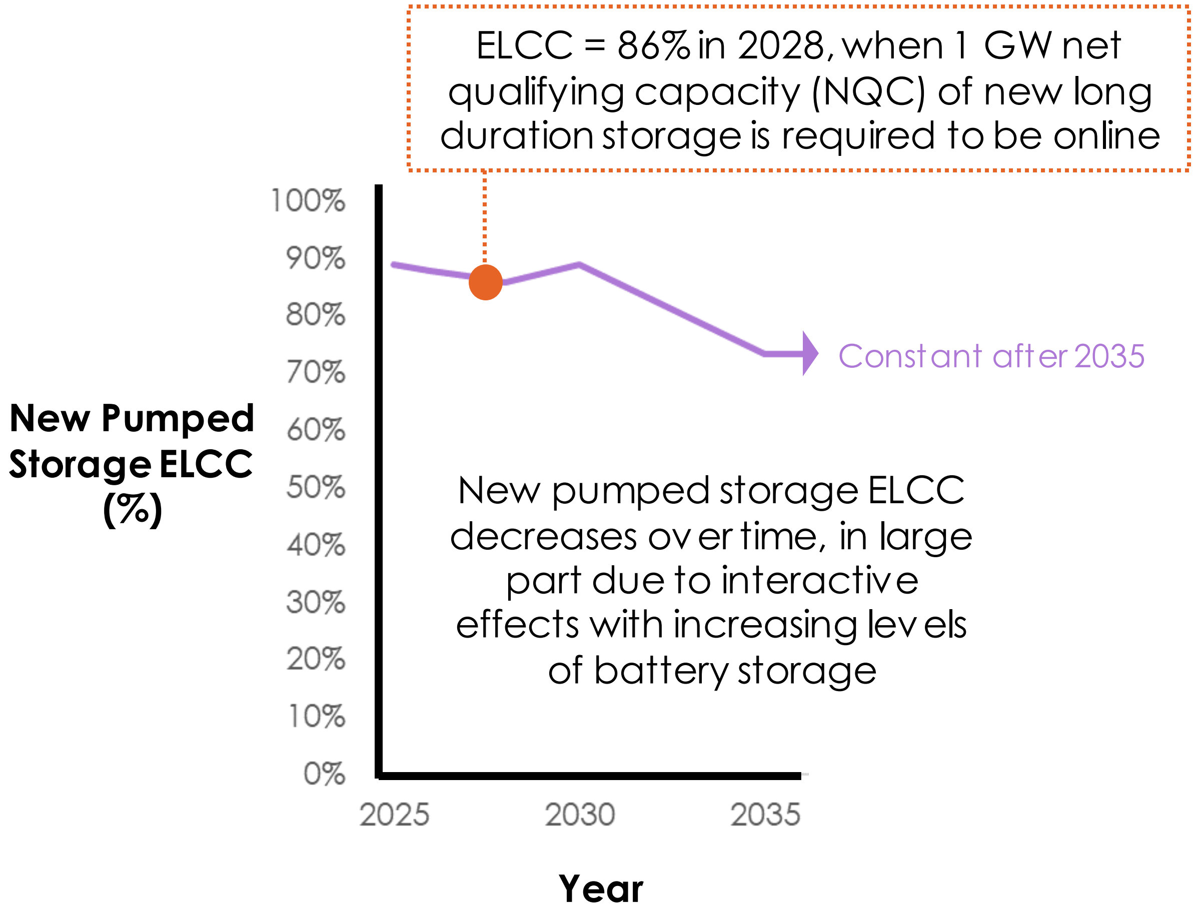
- 2021 PSP approach: Shed DR program capacity (NQC) for existing and candidate
- 2022 proposed approach:
  - Existing: constant SERVM-calculated ELCC of 96% in all years
  - Candidate: Modeled on the storage dimension of solar + storage ELCC surface with multiplier that represents the 4-hour storage equivalent for DR in each future year
    - Multiplier calculated via pairs of SERVM runs in which additional batteries are compared to additional shed DR



Y-axis represents candidate shed DR reliablity contribution *relative to a 4-hour battery*. 4-hour battery ELCC declines with increasing penetration via ELCC surface so candidate shed DR ELCC will also decline in the same manner

Pumped Storage

- 2021 PSP approach: 100 % NQC for existing and candidate
- 2022 proposed approach:
  - Existing: constant 95% ELCC calculated by SERVM
  - Candidate: New pumped storage is given a constant ELCC in each year
    - ELCC doesn't depend on the capacity of other resources on the system
    - However, ELCC decreases as a function of year



ELCC values from 2022 LSE plan filing requirements (38 MMT scenario) are used to define ELCC trajectory over time for new pumped storage

Long-duration Storage ELCCs

More analysis will be explored in this IRP cycle to refine modeling of long-duration storage ELCCs in RESOLVE

- Long-duration storage ELCCs are higher than short-duration storage… but how much higher may change dramatically across the solar-storage surface

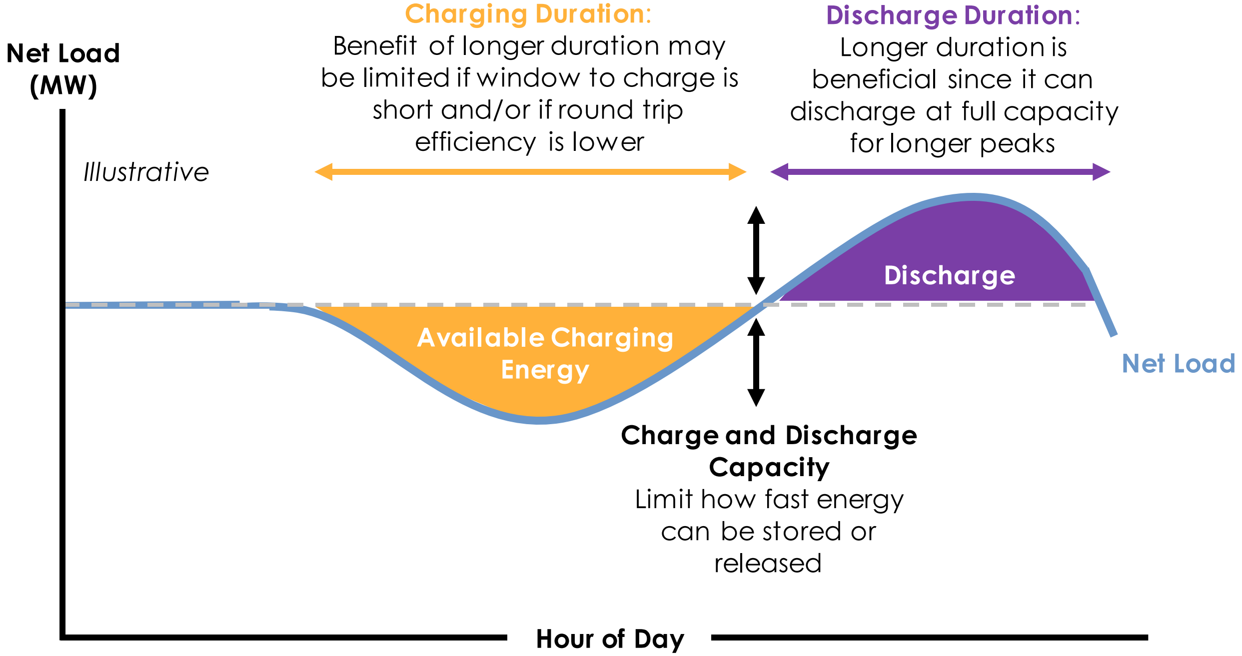
LSE Filing Requirements Marginal ELCC (38MMT scenario)												
Resource Class	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**
4-hr Battery Storage	89%	90%	92%	85%	77%	76%	75%	68%	61%	54%	47%	40%
8-hr Battery Storage	89%	91%	93%	90%	87%	86%	85%	82%	79%	76%	73%	70%

Minimal ELCC increase for longer duration

Longer duration results in large ELCC increase

Factors to consider:

- Storage duration
- Storage round trip efficiency (incl. parasitic / idle losses)
- Charging energy availability
- Duration of charging energy availability
- Portfolio of longer and shorter duration storage already on the system
- Persistence of extreme weather events
- LOLP modeled operations (including foresight to pre-charge long duration storage)



Hydro ELCC

- 2021 PSP approach: Non-pumped hydroelectric facilities counted at their (Sept) NQC value from the CAISO NQC list
- 2022 proposed approach:
  - ELCC of the hydro portfolio (both small and large) calculated by SERVM
    - Portfolio ELCC = 4,970 MW
    - Portfolio ELCC distributed between small and large hydro based on their capacity-weighted NQC
  - Resultant values to be used in RESOLVE:
    - Large hydro = 60% ELCC, or 4,692 MW ELCC (includes Hoover dam imports)
    - Small hydro = 43% ELCC, or 278 MW ELCC

Firm Resource ELCCs

1 Portfolio ELCC of all "firm" resources was calculated in SERVM

2 Firm resource portfolio ELCC allocated between resource classes using capacity-weighted forced outage rate (EFORd from SERVM analysis)

> Due to portfolio interactive effects, especially the dynamic that loss of load events happen more frequently during simultaneous outages, this results in a lower ELCC than the Unforced (UCAP) %

Resource Class	1-EFORd: Equivalent Forced Outage Rate demand (%)	UCAP =1-EFORd (% of nameplate)	>	ELCC for RESOLVE (% of nameplate)
Combined Cycle	5.5%	94.5%		88.3%
Combustion Turbine	6.2%	93.8%		87.0%
Reciprocating Engine	4.2%	95.8%		91.2%
Steam	7.2%	92.8%		84.8%
Combined Heat and Power (CHP)	3.1%	96.9%		93.5%
Nuclear	2.0%	98%		95.9%
Biomass and Biogas	5.7% (biomass) 7.6% (biogas)	94.3% (biomass) 92.4% (biogas)		86.7%
Geothermal	2.6%	97.4%		94.5%

Note: In SERVM, biomass and biogas are modeled as separate categories, while they are modeled together in RESOLVE

6. Next steps

California Public Utilities Commission

Next Steps

- Stakeholders are invited to submit their informal comments to staff on the topics covered in this webinar by October 6, 2022.
  - Submit your comments to IRPDataRequest@cpuc.ca.gov and use "2022 I&A" in the subject line
    - Stakeholders are encouraged to include the IRP service list as well.
  - Please categorize your comments based on the sections in this webinar and submit one single pdf document
  - Stakeholders should support their input with data and/or explanations. If referring to specific data, please provide the link(s) to those data
- Staff will review and incorporate input in the draft I&A document
- Staff expects to release the draft I&A document in November for stakeholders' review
  - Staff will hold a webinar to present the draft I&A document
- Stakeholders will have two weeks after the draft I&A release to submit their informal comments to staff.
- Staff expects to finalize the 2022 I&A document, including the stakeholder process, by late Q4 2022

Appendix

California Public
Utilities Commission

Appendix A
Additional Resource Cost Comparison

Note: Results shown in this section do <u>not</u> reflect impacts of the Inflation Reduction Act (IRA). Impacts of the IRA are shown on slides 21-23 and in Appendix B.

Summary of Data Sources
2022 I&A vs. 2022 LSE Filing Requirements

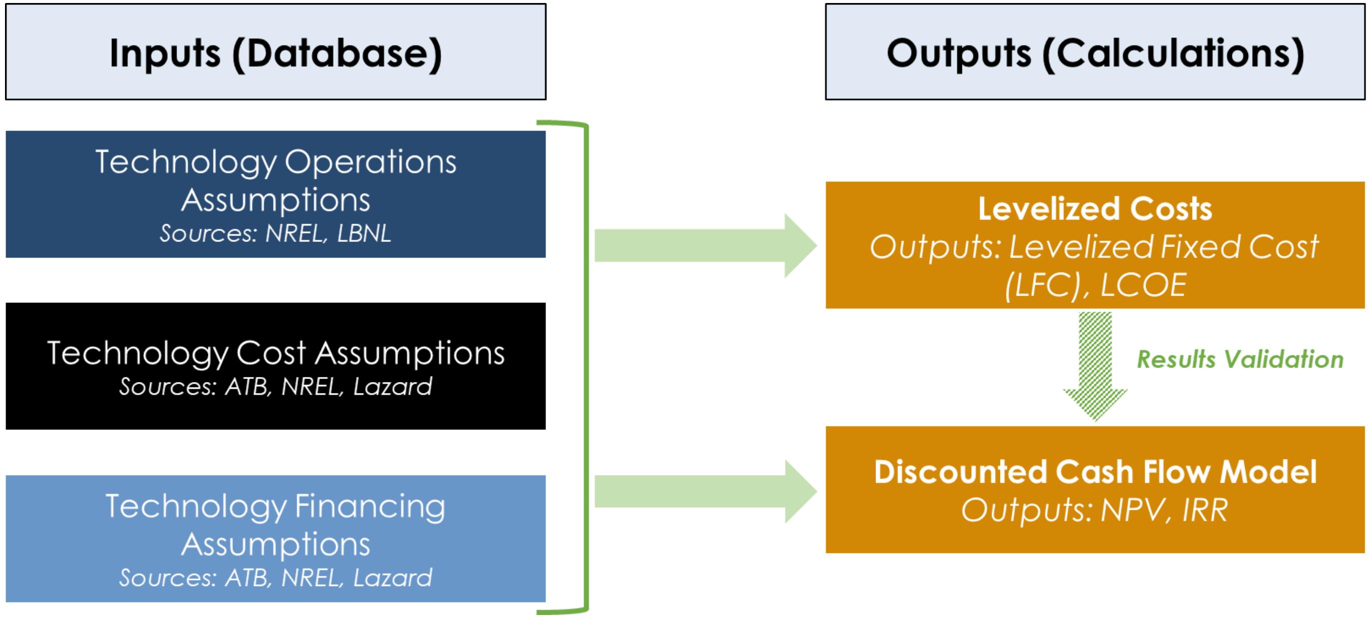
Technology	Data Source – 2022 LSE Filing Requirements[1]	Data Source – 2022 I&A
Solar PV (utility-scale, distributed)	NREL 2021 Annual Technology Baseline (ATB)	NREL **2022** ATB
Land-Based (Onshore) Wind	NREL 2021 ATB	NREL **2022** ATB
Offshore Wind	NREL OCS Study BOEM 2020-048 (+ financing assumptions from NREL 2021 ATB)	NREL OCS Study BOEM 2020-048 (+ financing assumptions from NREL **2022** ATB)
Geothermal	NREL 2021 ATB	NREL **2022** ATB
Small Hydro	NREL 2021 ATB	NREL **2022** ATB
Biomass	NREL 2021 ATB	NREL **2022** ATB
Gas (combined cycle, combustion turbine)	NREL 2021 ATB	NREL **2022** ATB
Li-ion Battery	Lazard Levelized Cost of Storage v7.0 (LCOS 7.0) (+ cost trajectories from NREL battery study)	Will be updated to Lazard LCOS 8.0 when available[2]
Flow Battery	Lazard LCOS 4.0	No update (not available in later LCOS)
Pumped Hydro Storage	Lazard LCOS 2.0	NREL **2022** ATB

[1] "2022 LSE Filing Requirements" denotes cost inputs used in the RESOLVE analysis for the 2022 LSE Filing Requirements. [2] Lazard LCOS v8.0 expected to be released in November. E3 incorporated property taxes for battery costs in the 2022 I&A update. Property taxes are included in NREL 2022 ATB technology costs.

Resource Cost Methodology

- Levelized fixed costs (RESOLVE inputs) are calculated in E3's pro forma financial model
  - E3's pro forma calculates levelized costs of energy ($/MWh) or capacity ($/kW-yr) under typical project financing structures, and validates these results using discounted cash flow analysis
- The pro forma model with California-specific assumptions is incorporated into the Resource Costs & Build workbook, which is published as part of the RESOLVE package
- The model and methodology are consistent with previous IRP analyses

E3's Pro Forma Model



**Note: Levelized costs for emerging technologies can be generated using the same pro forma model, with cost and performance data coming from various sources (combination of E3 analysis, and scientific and manufacturer literature, as documented in the Zero-Carbon Technology Assessment Report).*

More details: Inputs & Assumptions: 2019-2020 Integrated Resource Planning. February 27, 2020.

Terminology

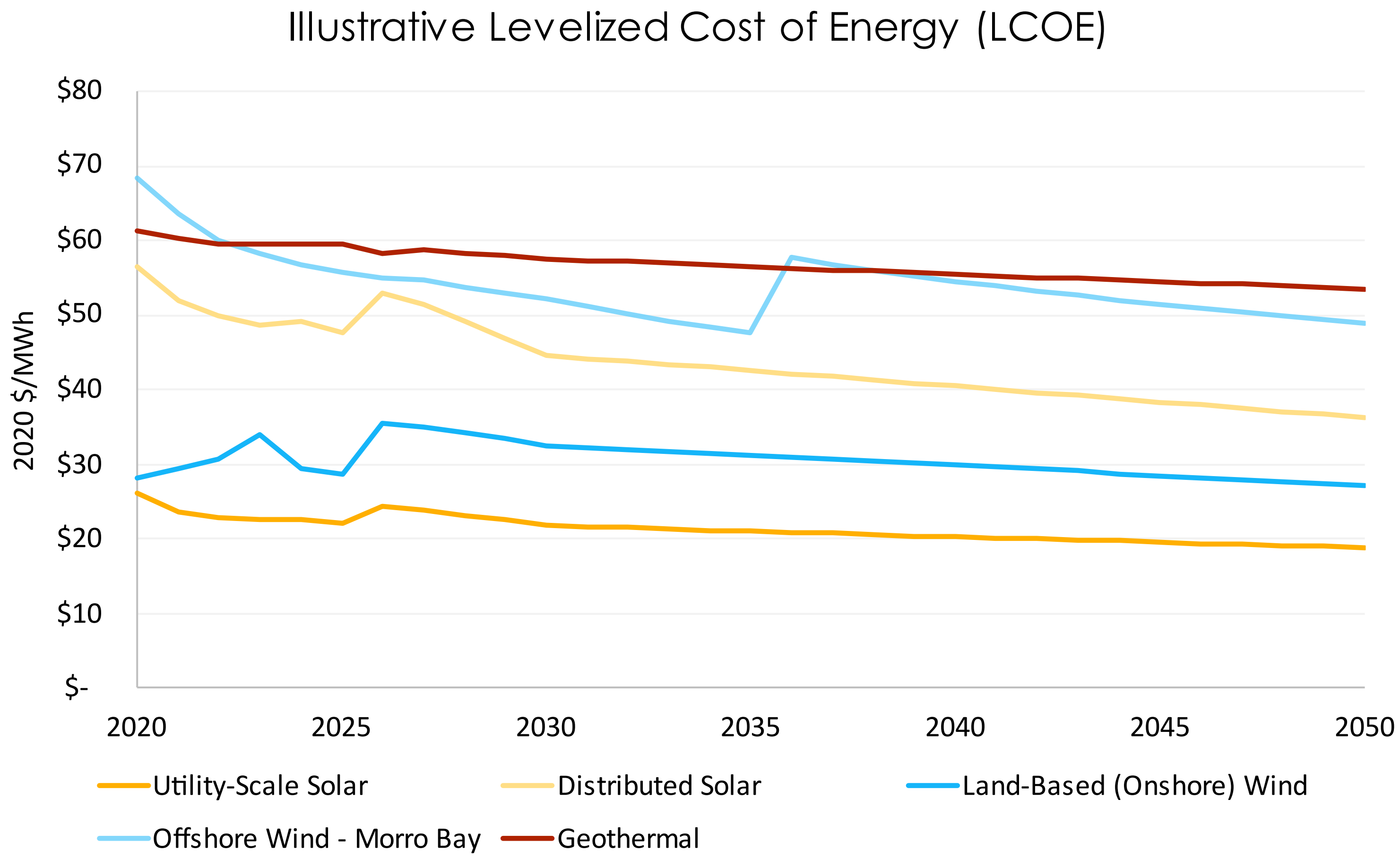
- **Total ("all-in") levelized fixed costs**
  - Include overnight capital cost, construction financing costs, fixed O&M costs, and any capital-based tax credits[1]
  - Total levelized fixed costs are <u>cost inputs into RESOLVE</u> for candidate resources and impact resource build decisions
- **Levelized cost of energy (LCOE)**
  - LCOE is <u>not</u> a RESOLVE input or output but can be inferred from dispatch results
  - The LCOEs shown in this presentation are <u>illustrative</u> and are for generic <u>technologies</u>
    - The LCOE of individual <u>resources</u> may vary by factors such as resource location and resource availability (e.g., capacity factor)
    - The LCOE is calculated using the pre-curtailment potential production; RESOLVE can curtail wind and solar resources, potentially resulting in lower levels of renewable production than are reflected in the LCOE values[1]

[1] *[Inputs & Assumptions: 2019-2020 Integrated Resource Planning](). February 27, 2020.*

Summary of Levelized Cost of Energy (LCOE)

2022 I&A

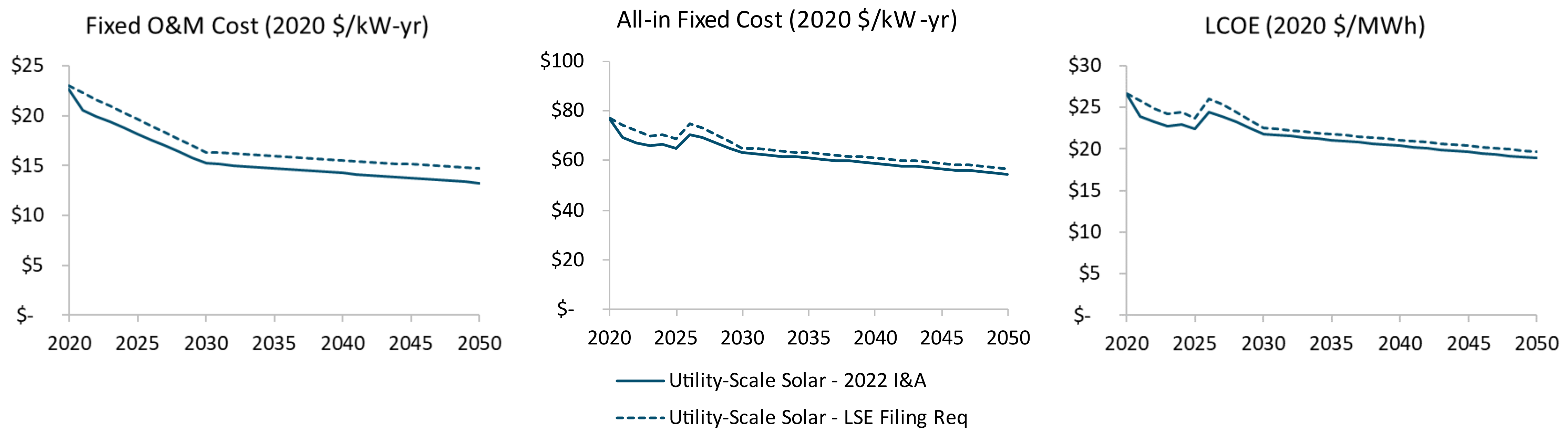
- The LCOEs shown here are illustrative
  - The LCOE of individual resources may vary by factors such as resource location and resource availability
- LCOE is not a RESOLVE input or output but can be inferred from dispatch results



Note: (a) Levelized cost estimates shown here do not reflect IRA. Impacts of IRA are shown in Appendix B. (b) LCOEs are estimated for the following capacity factors utility-scale solar 33%, distributed solar 20%, land-based (onshore) wind 36%, offshore wind 49%, geothermal 90%.

Utility-Scale Solar PV
2022 I&A vs. 2022 LSE Filing Requirements

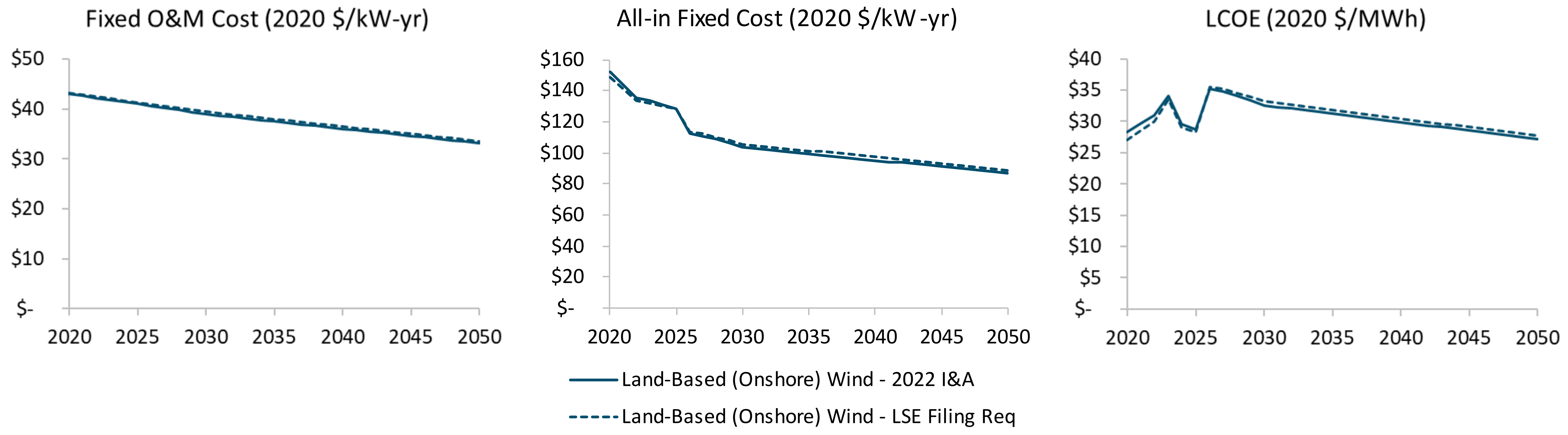
- Decreases in total fixed costs and LCOE are driven by continued declines in solar PV capex and O&M costs, tracking annual reports of utility-scale project costs



Land-Based (Onshore) Wind

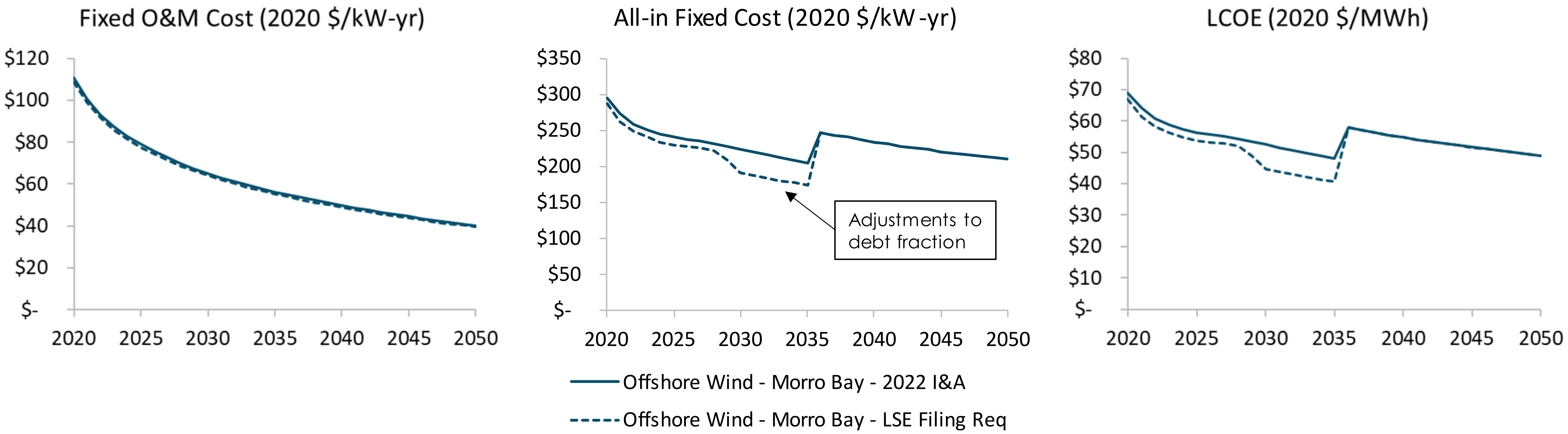
2022 I&A vs. 2022 LSE Filing Requirements

- Adjustments to capex trajectory result in slight changes to levelized fixed cost and LCOE



Floating Offshore Wind
2022 I&A vs. 2022 LSE Filing Requirements

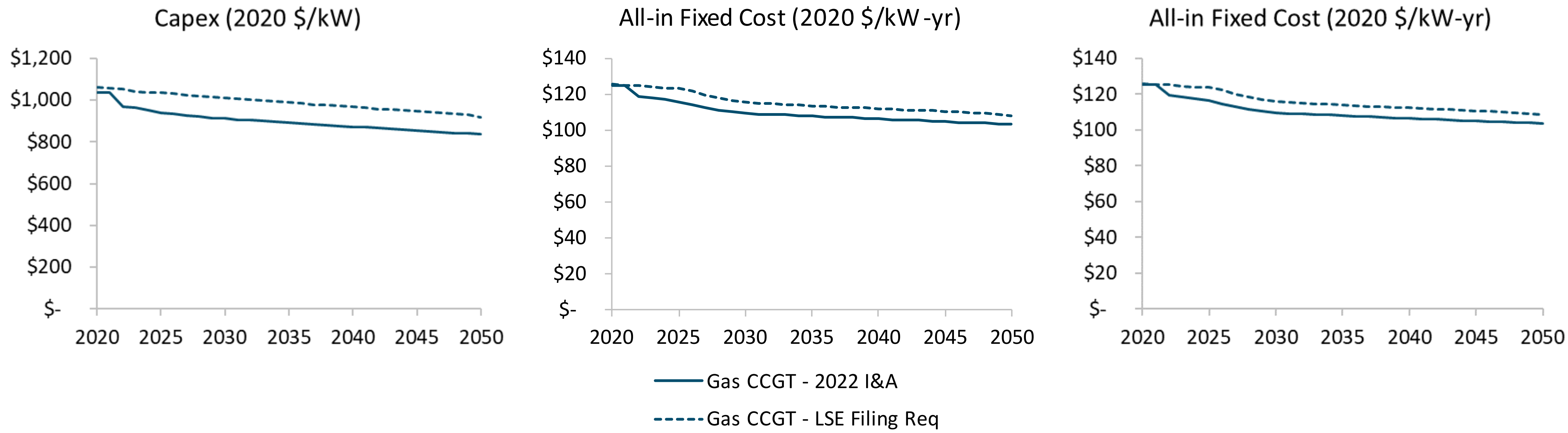
- 2022 I&A cost update uses the same inputs (capex, fixed O&M, etc.) as LSE Filing Requirements, both from NREL [OCS Study BOEM 2020-048]
- Differences in levelized fixed costs due to NREL 2021 vs. 2022 ATB financing assumptions



Note: Offshore wind costs in both 2022 I&A and LSE Filing Requirements assume ITC benefits are accessed for all projects coming online through 2035 via the safe harbor exemption. This assumes the developer would start construction or spend at least 5% of total capital expenditure of a project prior to end 2025.

Natural Gas Combined Cycle (CCGT)
2022 I&A vs. 2022 LSE Filing Requirements

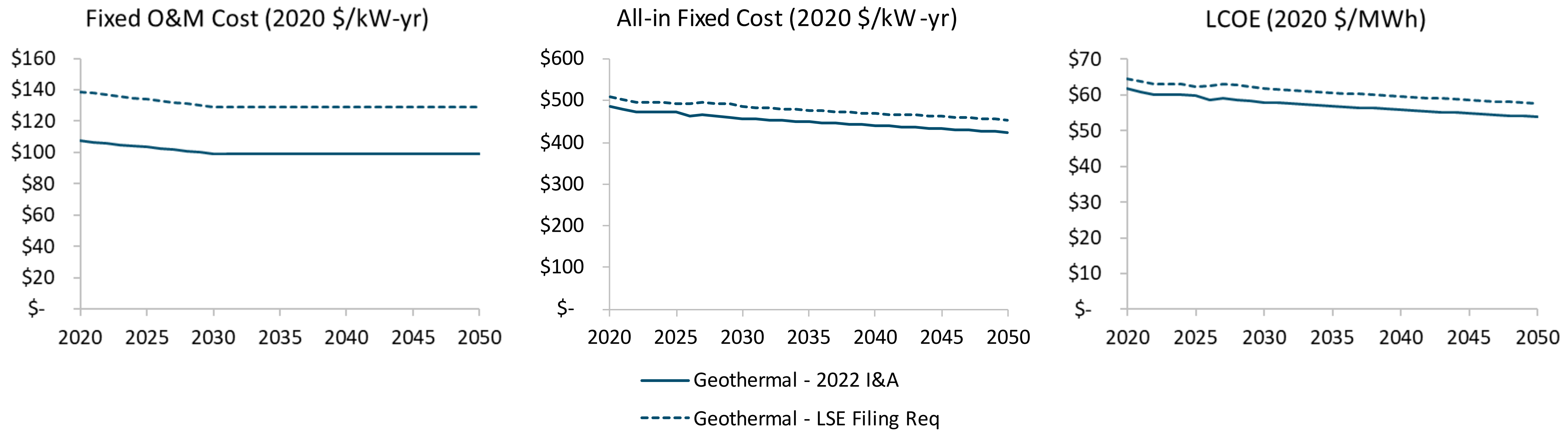
- Reduction to capex results in lower levelized fixed cost



Geothermal

2022 I&A vs. 2022 LSE Filing Requirements

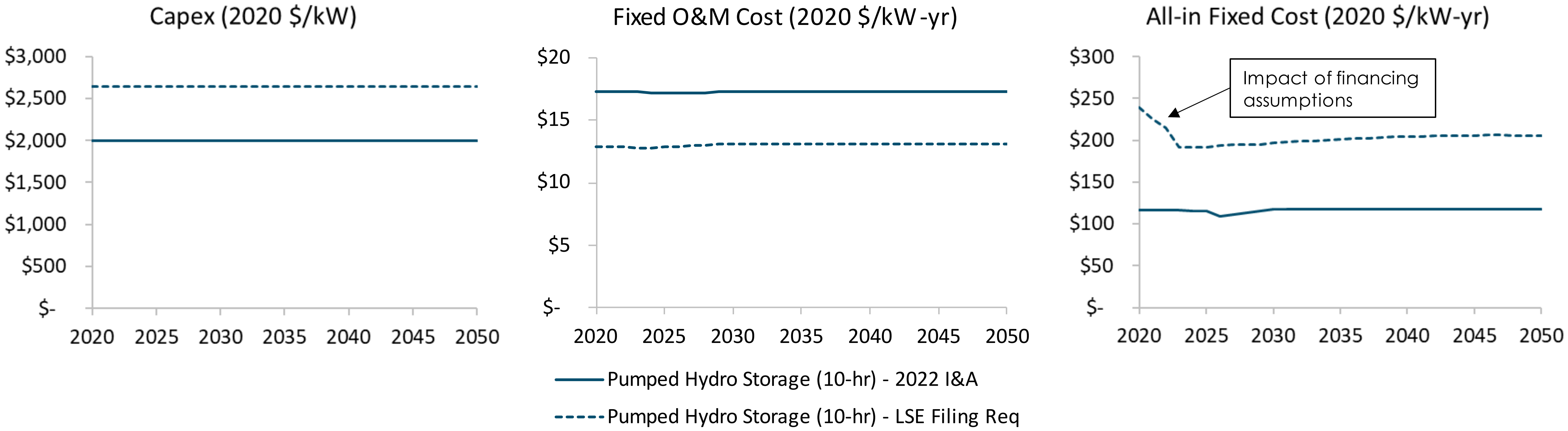
- For NREL 2022 ATB, base year fixed O&M costs are decreased by 23% relative to 2021
  - This adjustment is due to proprietary geothermal industry data acquired by NREL
- NREL ATB modifications to financing assumptions result in deviations between 2025-2027



Pumped Hydro Storage (PHS)

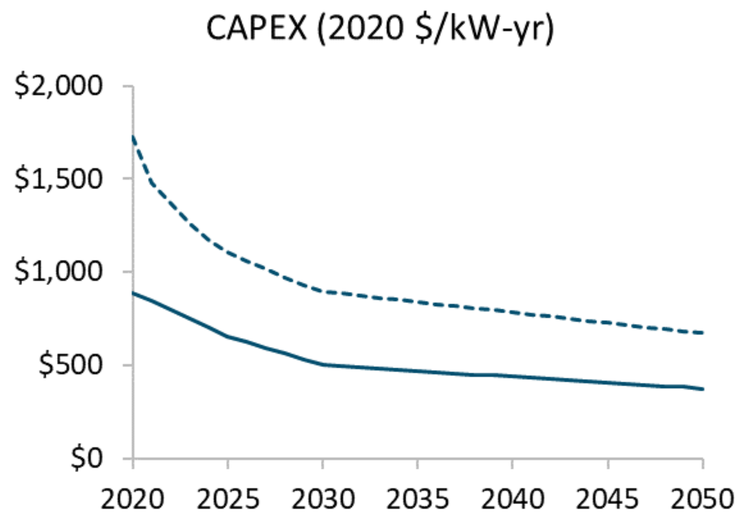
2022 I&A vs. 2022 LSE Filing Requirements

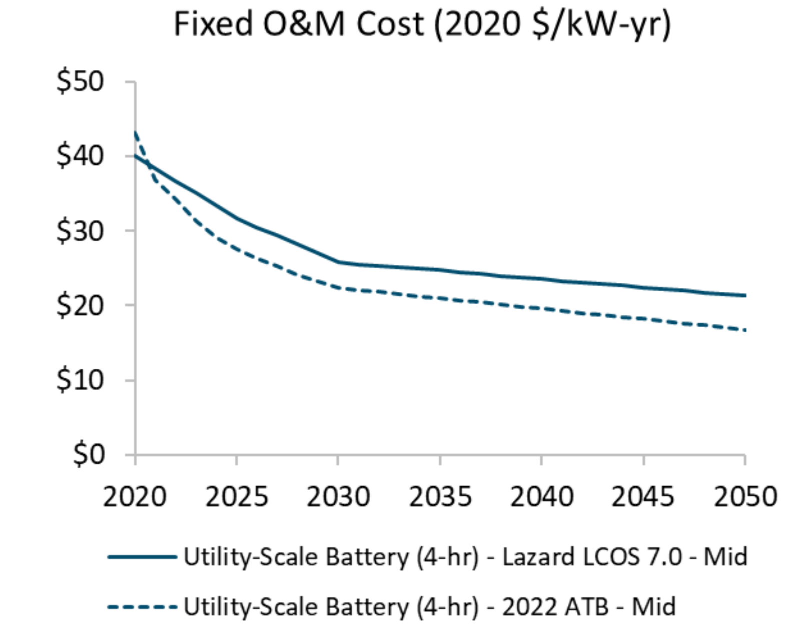
- Costs updated from Lazard LCOS v2.0 (2016) to NREL 2022 ATB
- NREL 2022 ATB includes 15 Classes of pumped hydro
  - Class 1 (500+ MW) represents large-scale installations and is most aligned with new capacity additions in California
  - NREL 2022 ATB assumes 10-hour storage duration



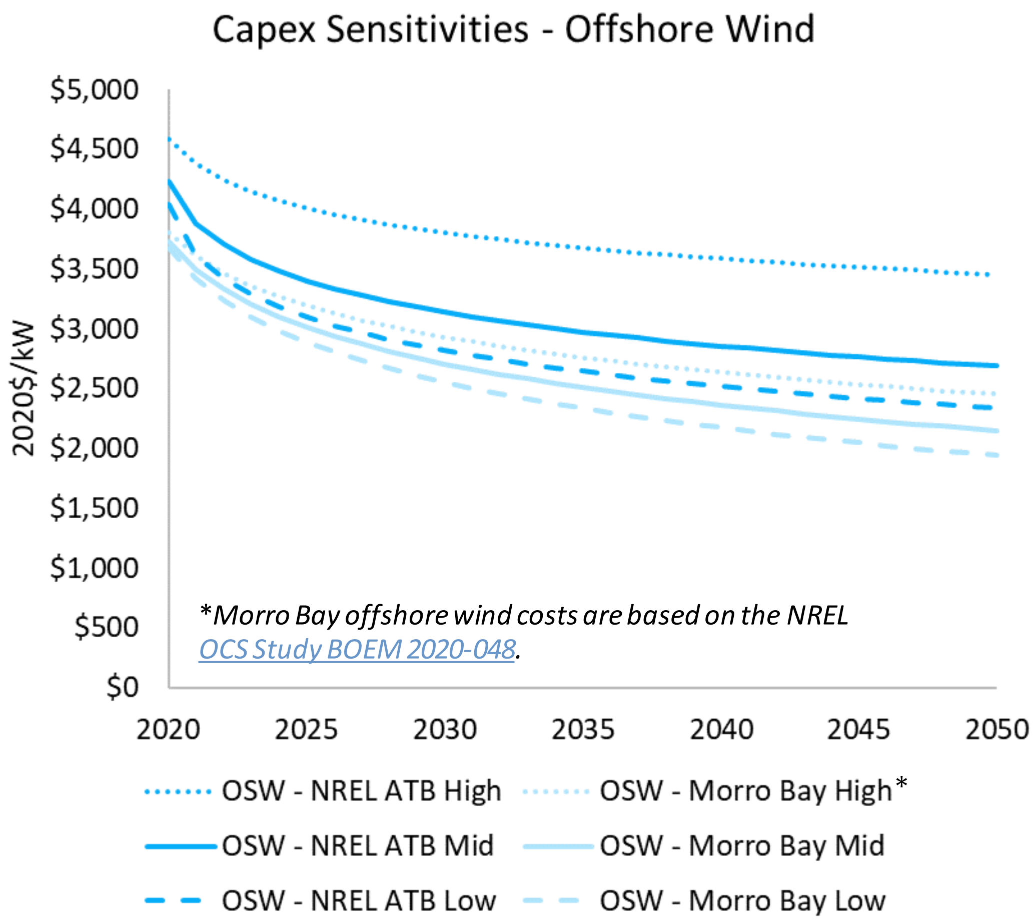
Utility-Scale Lithium-ion Battery
NREL 2022 ATB vs. Lazard LCOS 7.0

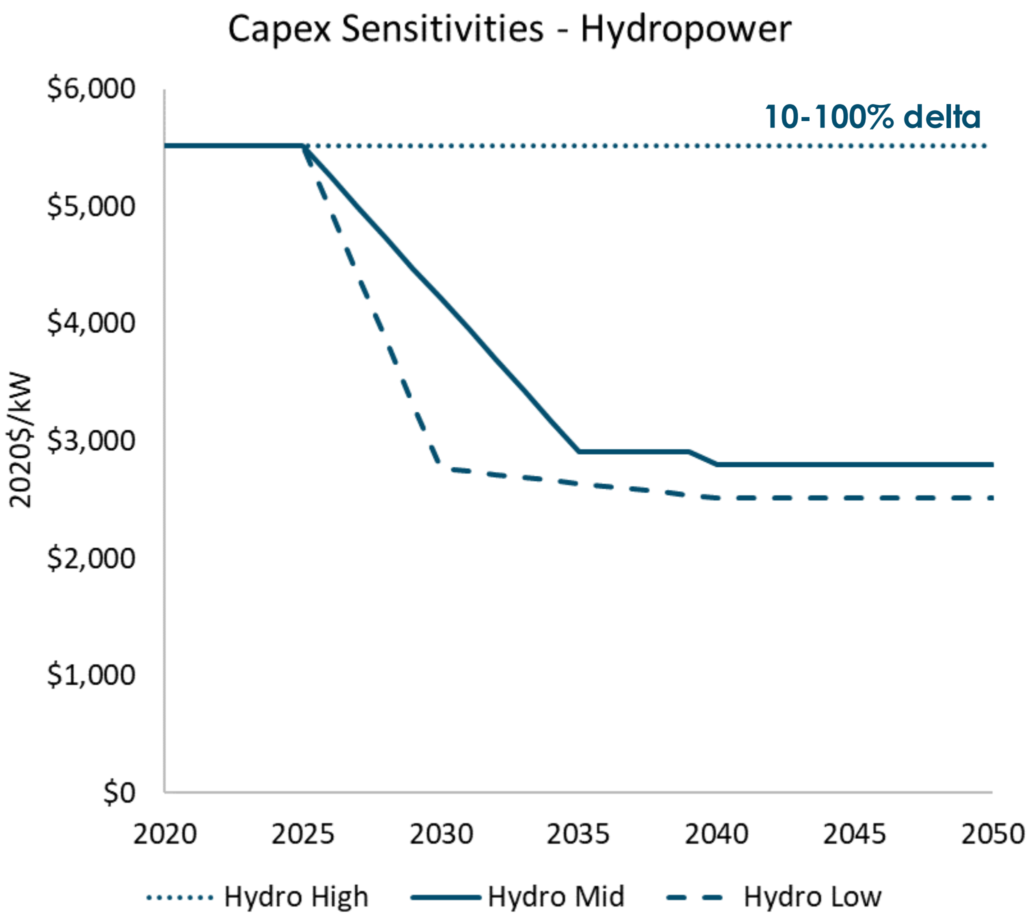
- NREL representation of battery costs continues to improve, but Lazard is still the preferred data source
  - NREL 2022 ATB still lacks financing assumptions and other key inputs for battery storage levelized costs; currently relying on Lazard for these inputs – there may be more refined financing assumptions for storage in future ATB publications
- NREL ATB storage costs have been on the high side compared to E3's experience of market prices before, but with recent supply chain constraints, this gap is narrowing and has likely flipped
- Lazard assumptions tend to be more optimistic on upfront capital costs, but this is partially compensated by higher fixed O&M costs
  - Higher fixed O&M due to warranty extension, augmentation, and periodic replacement





Additional Cost Sensitivities





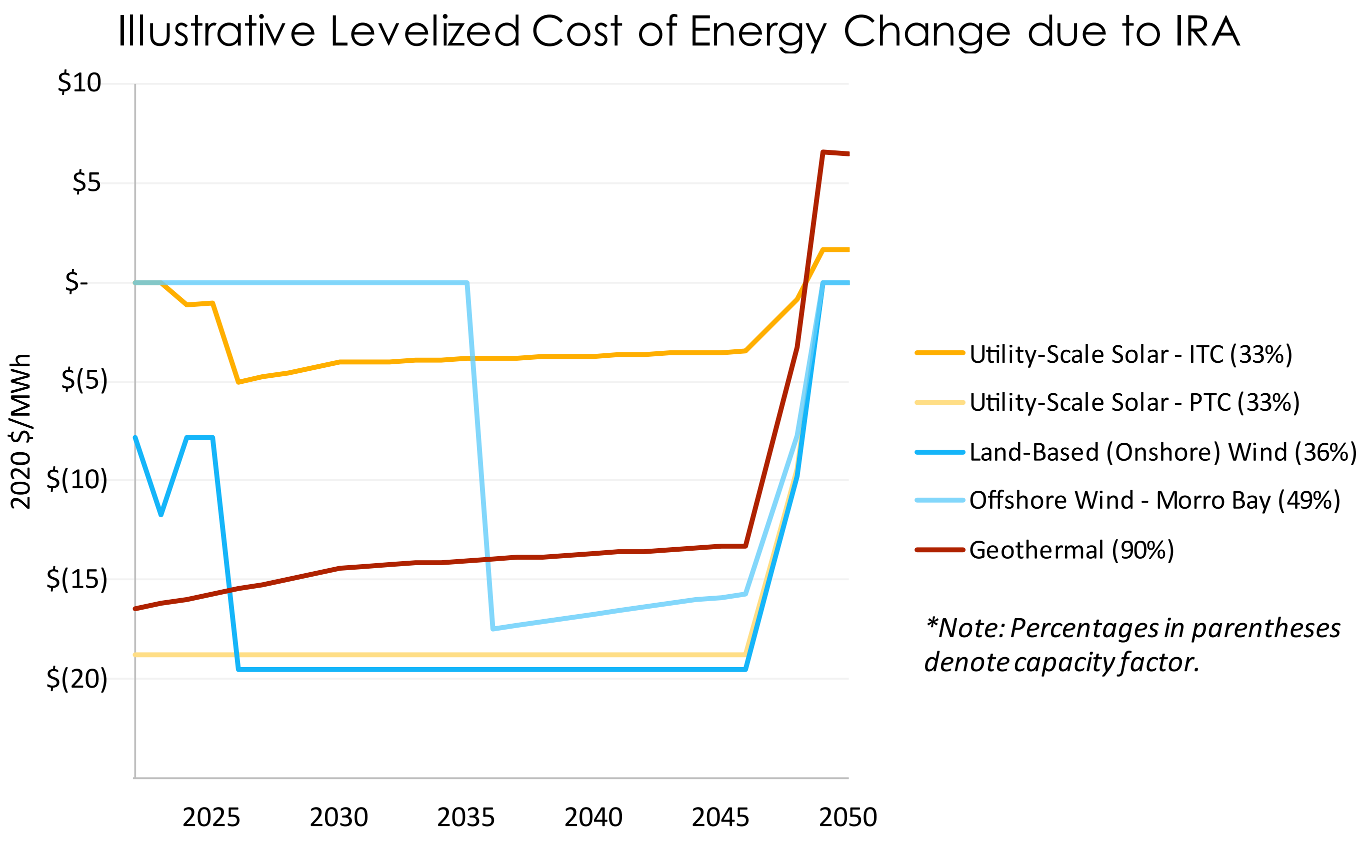
Note: Biomass has the same cost trajectory for Low, Mid, and High scenarios.

Appendix B
Additional Inflation Reduction Act (IRA) Results

Inflation Reduction Act Impacts on Levelized Cost of Electricity (LCOE)

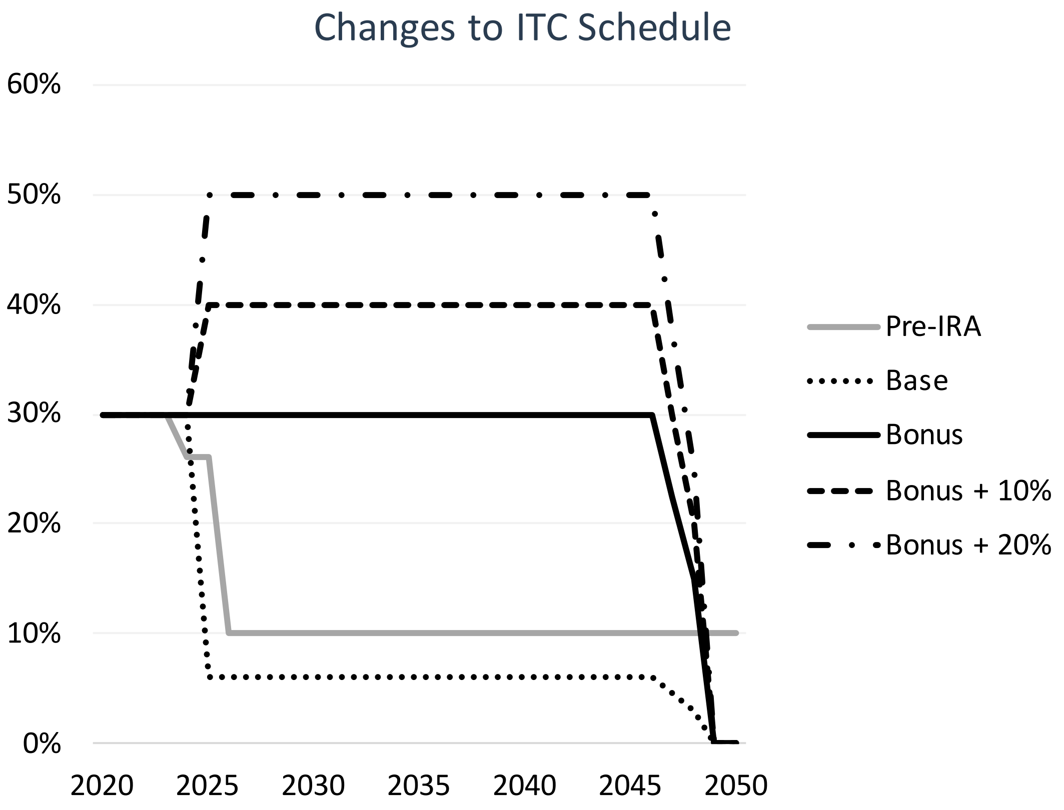
- Relative ($/MWh) impact on LCOE due to the IRA
- Assumes "**Bonus**" incentive level for meeting prevailing wage and apprenticeship rules
- IRA tax credits end date is subject to **assumption** of IRA emissions reduction target year

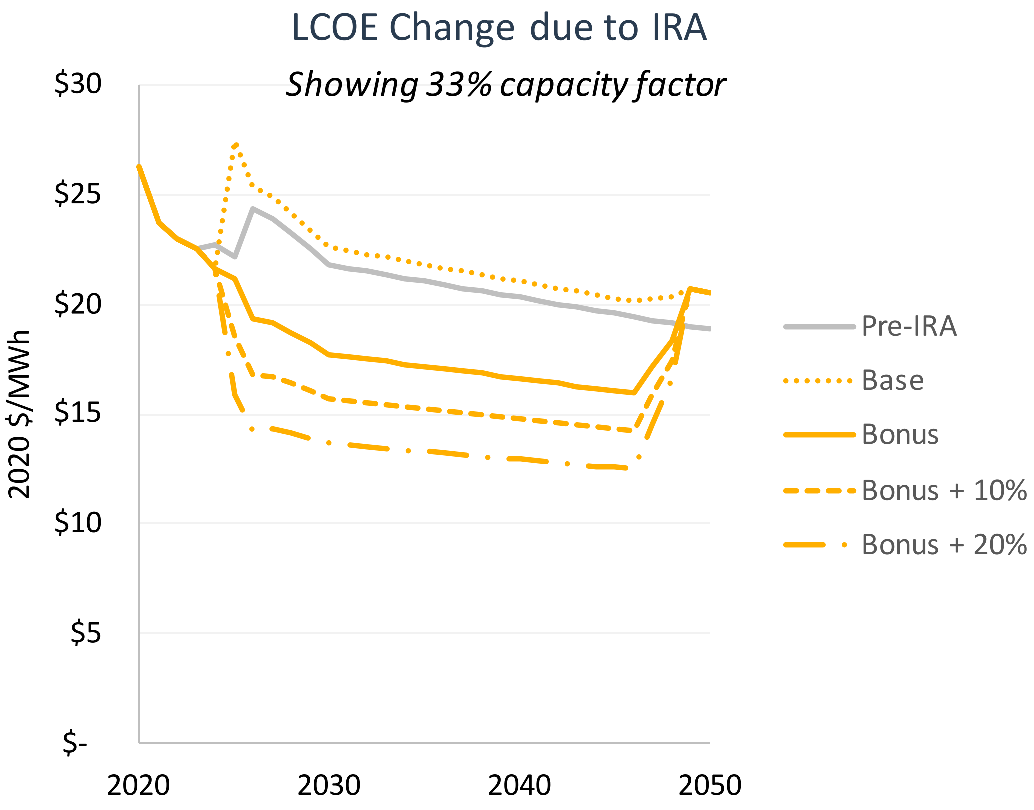
*Note: Assumes carbon emissions reduction targets are met in **2045** (75% reduction below 2022 levels for power sector per IRA), followed by a 3-year incentive step-down.*



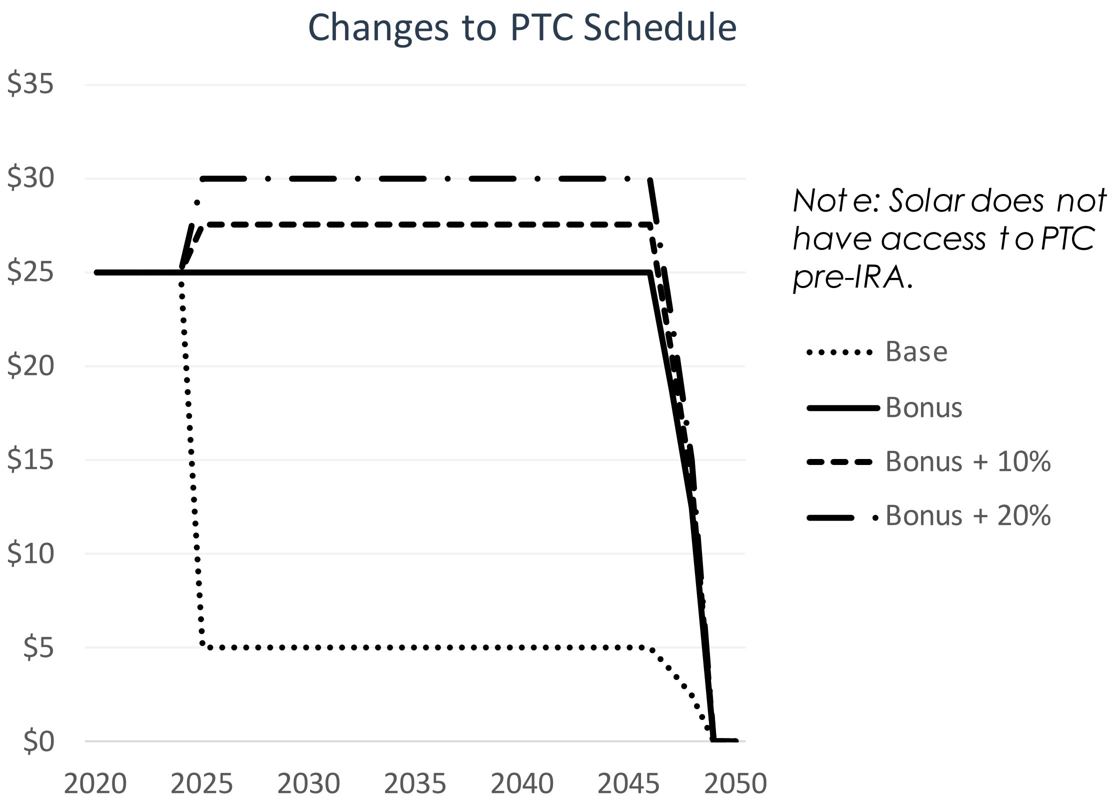
**Note: Percentages in parentheses denote capacity factor.*

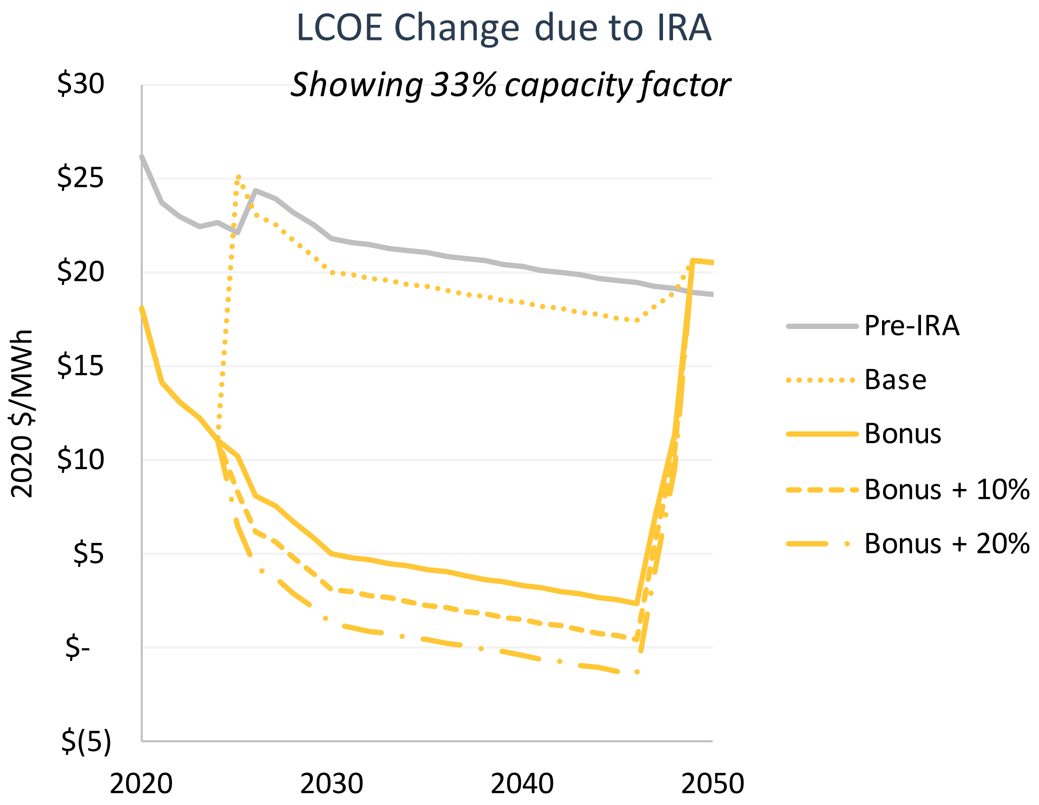
IRA Impact on LCOE – Solar ITC





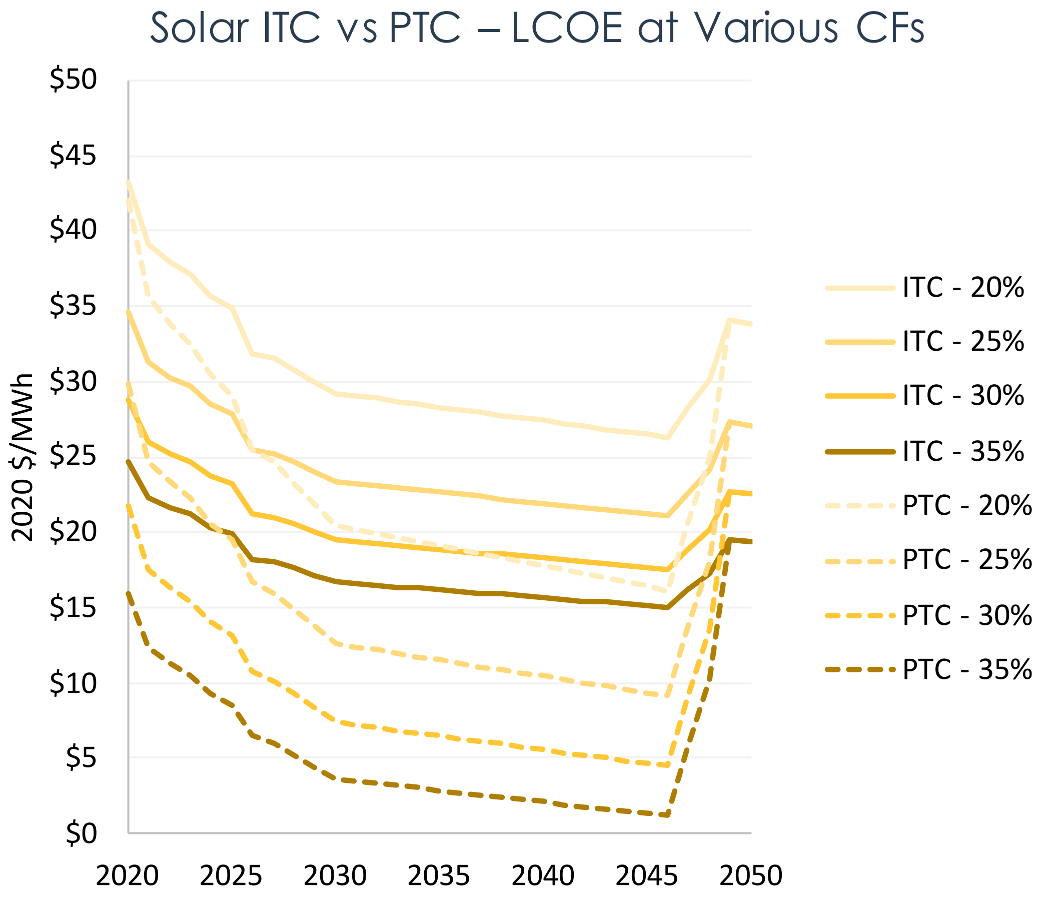
IRA Impact on LCOE – Solar PTC



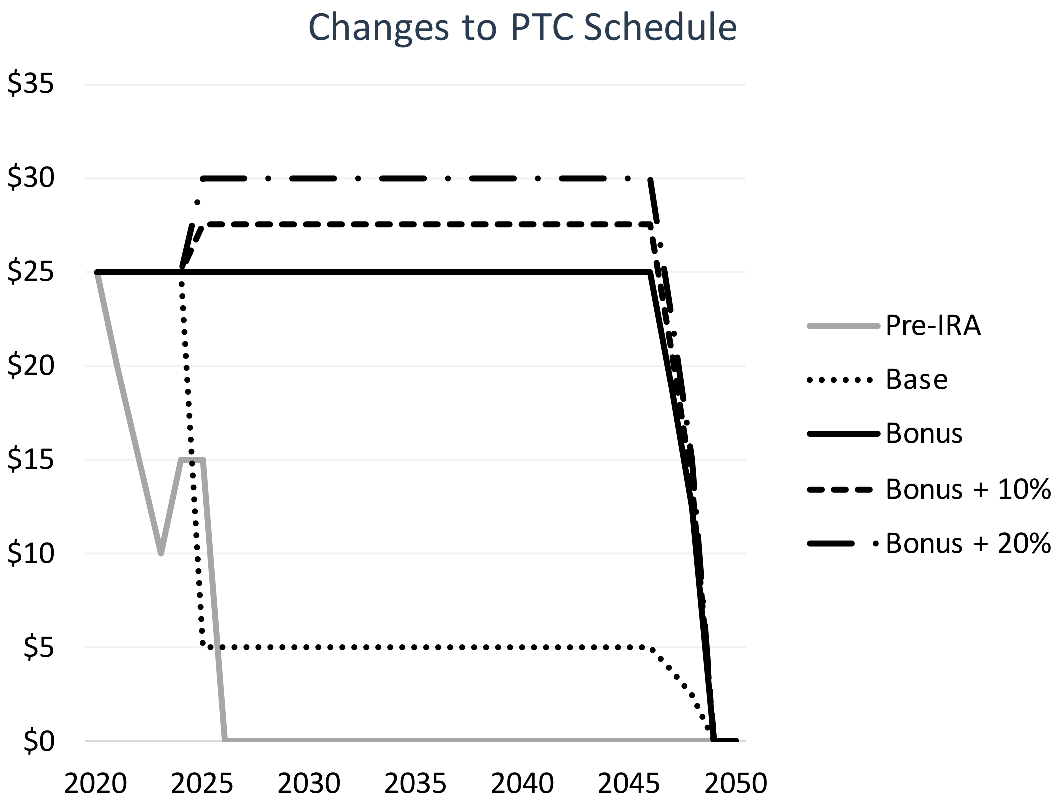


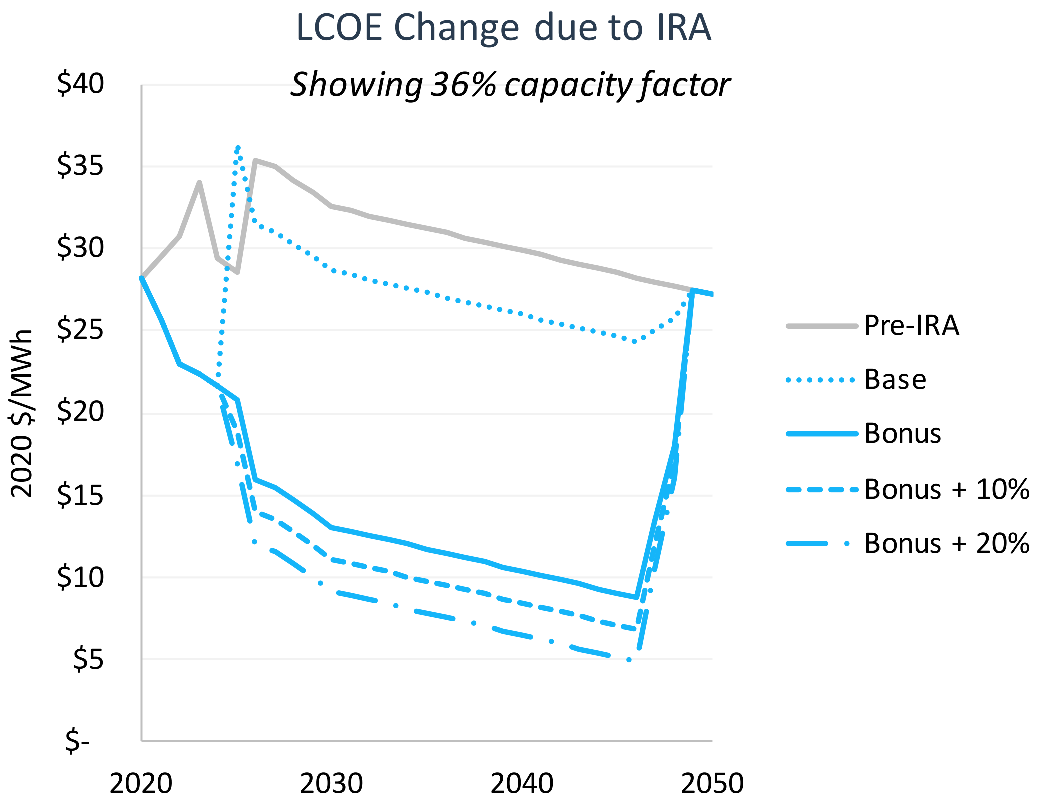
IRA Impact on LCOE – Solar ITC vs PTC

- Under the IRA, solar has the option to select either investment tax credits (ITC) or production tax credits (PTC)
- The decision to choose ITC vs PTC is primarily a function of vintage year, capacity factor (CF), and Capex
- Using NREL 2022 ATB Capex assumptions, PTC is found to outperform ITC across a wide range of CFs

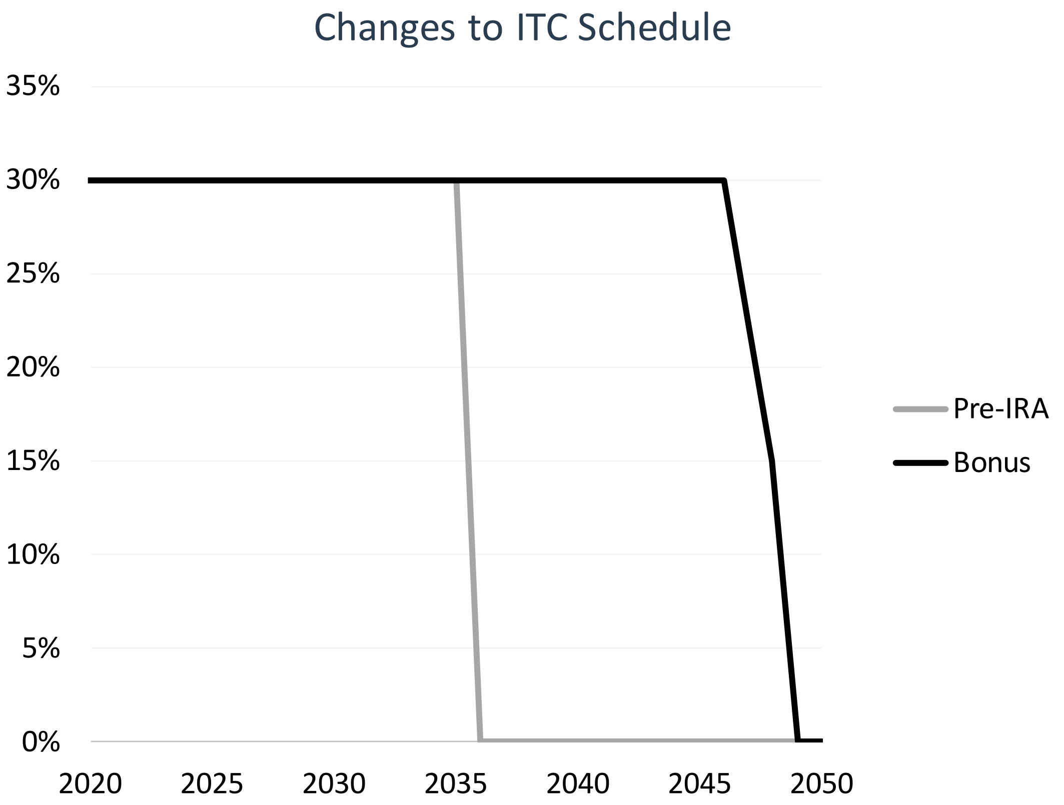


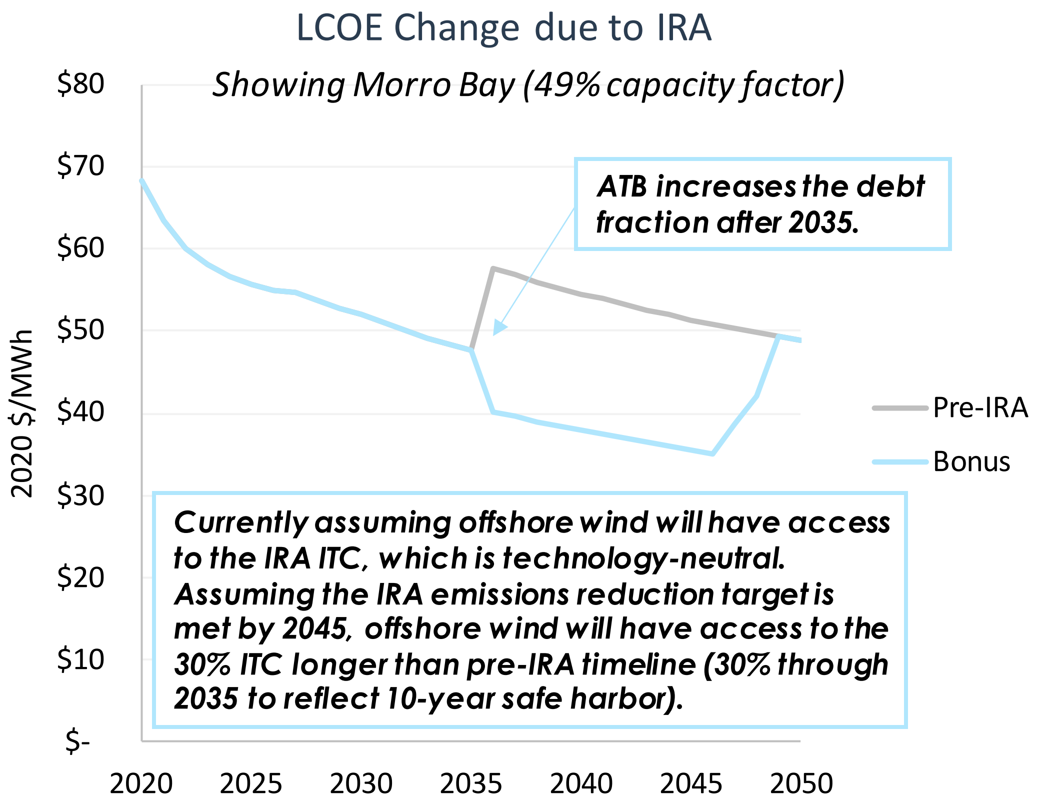
IRA Impact on LCOE – Onshore Wind





IRA Impact on LCOE – Offshore Wind





Appendix C
Additional Information on Emerging Technologies

Summary of Operational Parameters

- CCGTs + >99% CCS are found to have slightly lower efficiency than Allam Cycle + CCS
- Round-trip efficiency of storage technologies tends to decline with the duration of storage

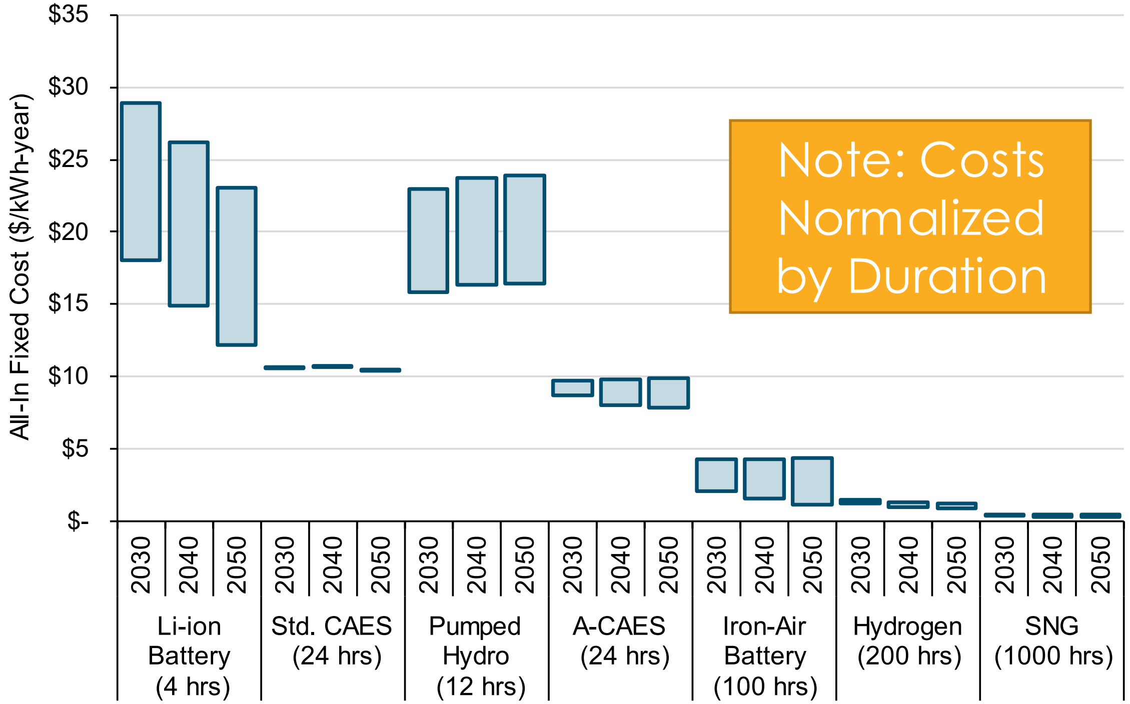
Category	Tech.	Efficiency (One-Way or RTE, HHV)	Ramp Rate Limit	Operational Lifetime
Generation	CCGT + >99% CCS	~ 30% - 45% (One-way)	Modeling suggests CCS has minimal impact on ramping	Equivalent to plant without CCS
	Allam Cycle CCS	~40-50% (One-way)	Unknown	30 years
	SMR	30% (One-way)	Unknown	30-80 years
	EGS	10-22% (One-way)	Unknown	30-80 years
Storage	Hydrogen	H_2: 70-80% (One-way), 25-45% (RTE in CT/ CCGT)	Electrolyzer: 100%/Min.	20 years for electrolyzer
	SNG	SNG: 40-50% (One-way), 15-25% (RTE in CT/CCGT)	Electrolyzer: 100%/Minute. DAC and Sabatier reaction flexibility unknown	20 years for electrolyzer; 20-40 years for DAC and Sabatier reactor
	A-CAES	60% (RTE)	Unknown	30-50 years
	Iron Air Battery	45-50% (RTE)	Unknown	Unknown

RTE = round-trip efficiency; HHV = higher heating value

Cost Comparison – Storage Technologies, Normalized for Duration

- Energy Costs for Li-Ion and PSH are very high relative to other technologies
- CAES also has fairly high prices
- SNG, Hydrogen and iron-air batteries are very cheap from a capital cost of energy duration perspective
- Storage durations are chosen for comparison purposes only
  - CPUC RESOLVE model would be able to pick lowest-cost combination of resources and their durations
- Cost data do *not* show effects from Federal IRA
  - This will be included in the draft I&A document to be released Q4 2022

Levelized Fixed Cost of Technologies Normalized for Duration (2022$/kWh-yr)



Note: Li-ion battery costs are from Lazard LCOS 6.0, pumped hydro costs are from Lazard LCOS 2.0, and both are shown for comparison purposes only. These costs are updated for 2022 I&A per earlier slides.

Appendix D
Shift DR and Shed DR

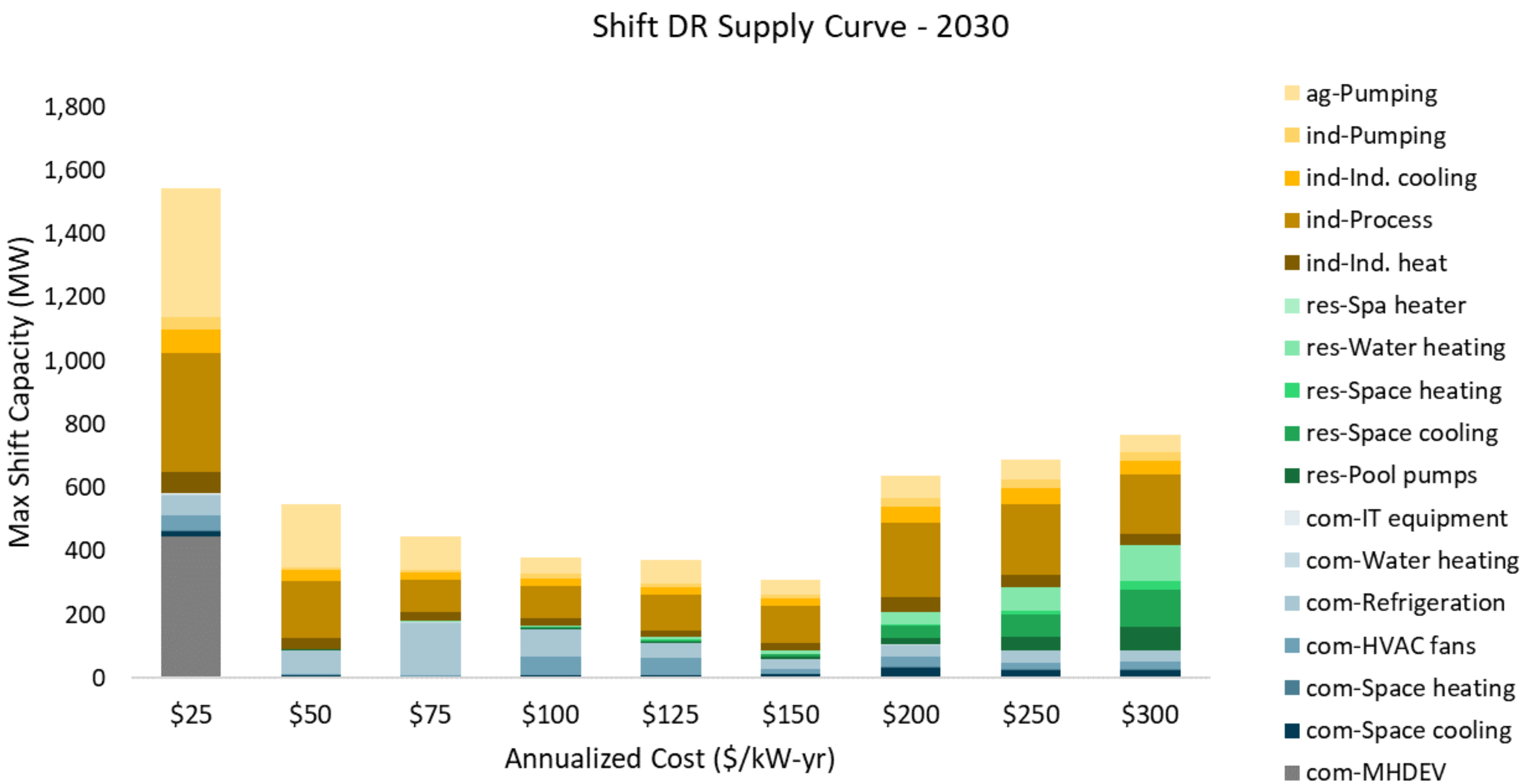
Technologies Included in Shed DR and Shift DR Supply Curves

- LBNL's Shed DR supply curve and Shift DR supply curve represent potential from each of these sectors and technologies
- Light Duty EV potential is removed from the Shed and Shift DR resources and included in the VGI workstream

Commercial	Residential	Industrial
Medium/Heavy Duty EV	Light Duty EV	Industrial heat
Light Duty EV	Pool pumps	Process
Space cooling	Space cooling	Industrial cooling
Space heating	Space heating	Industrial Pumping
HVAC fans	Appliances	Agricultural Pumping
Water heating	Water heating	
Refrigeration	Refrigeration	
Lighting	Lighting	
IT equipment	Electronics	
Office Equipment	Spa heater	

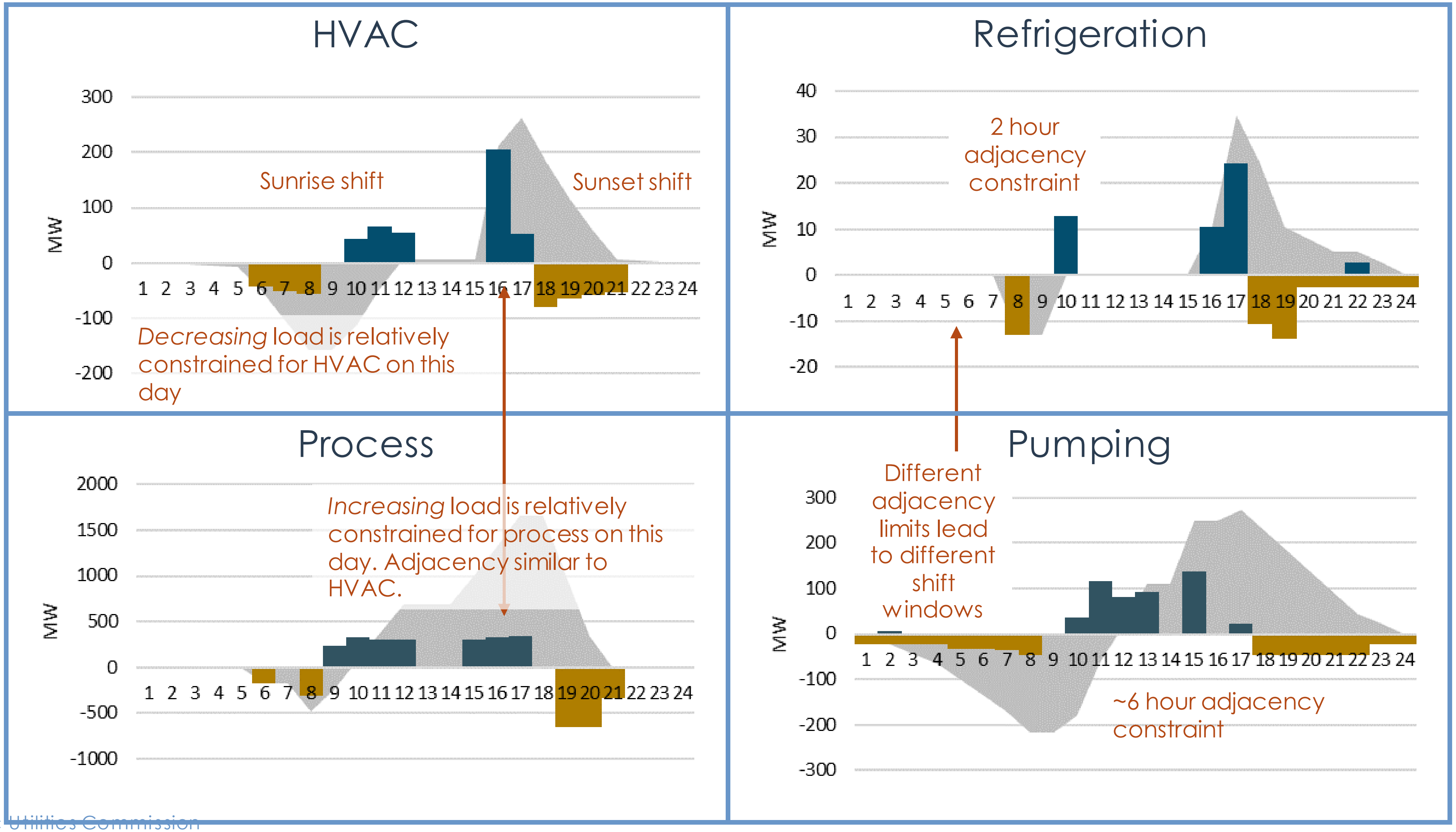
Shift DR Supply Curve – Disaggregated View

- Each cost tranche is the incremental supply available at that cost



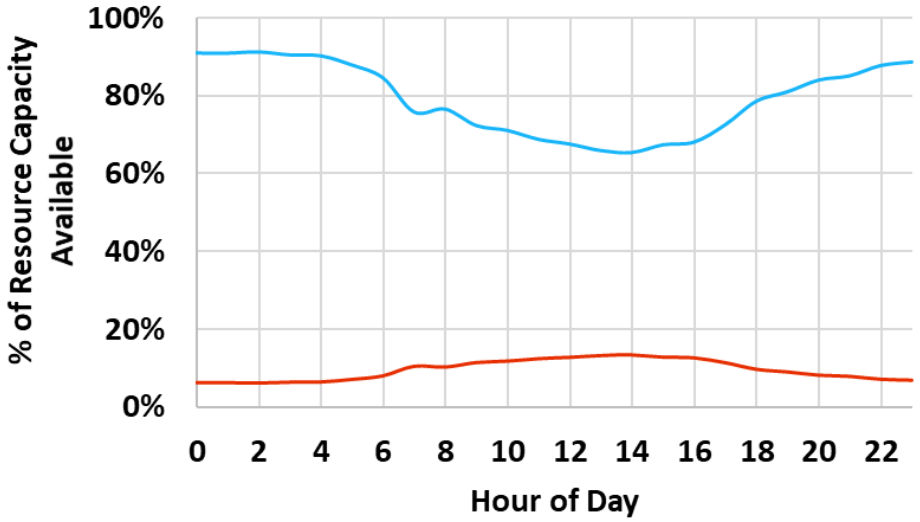
Example Shift Hourly Results

Legend:	DECREASE Load	INCREASE Load	Energy "Stored" (Running Tally)



Hourly Shift Up and Down limits

- Unique limit on each hour of each RESOLVE dispatch day
- Shift Up limits represent maximum "headroom" on loads, for example the number of "plugged in" devices minus the (unshifted) reference load of those devices
- Shift Down limits represent the portion of the (unshifted) reference load that could be reduced in an hour while still maintaining an acceptable amount of "service" (cool houses, pumped water, etc)



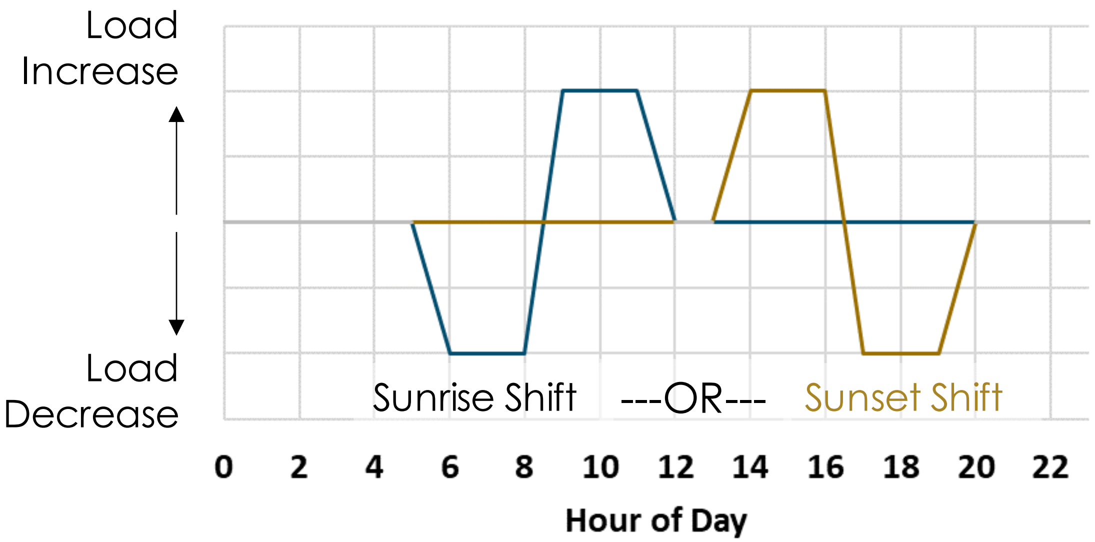
Shift Up less constrained than Shift Down

Shift Down opportunities limited

Example day for HVAC resource

Daily Mileage

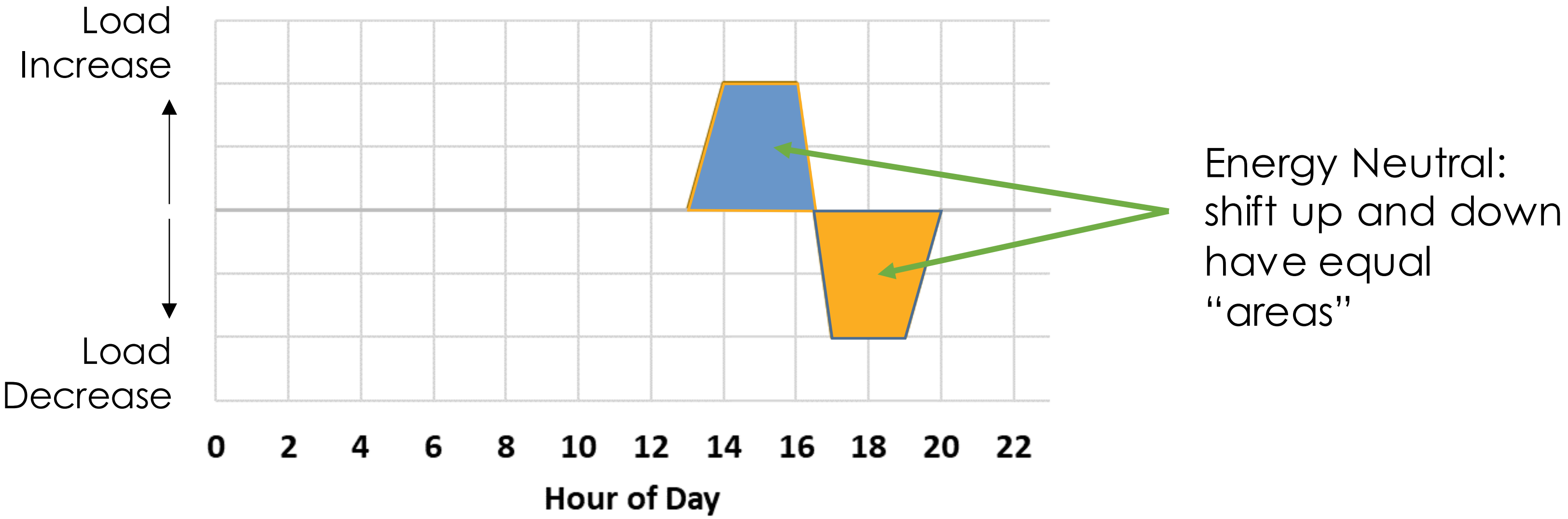
- For many loads there is significant potential to shift loads up or down each hour
- But, it's not acceptable to the end-user for the load to be increasing and decreasing frequently
- LBNL provided daily limits on the MWh of shiftable load, per MW of shiftable load capacity – these limits are enforced in RESOLVE



Example: Without mileage constraint, model would want to do both sunrise and sunset shifts. Mileage constraint forces it to pick only one.

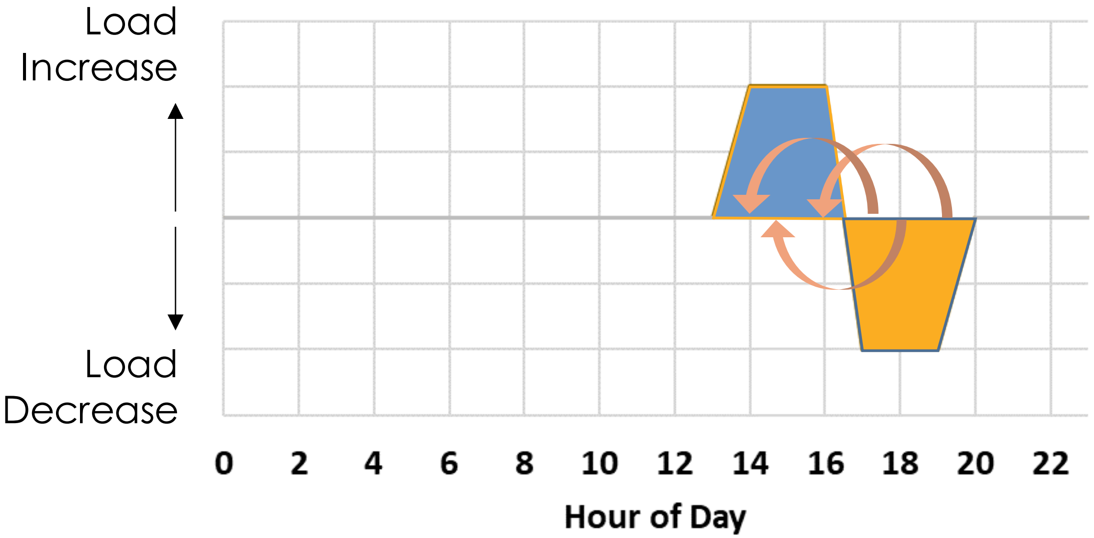
Daily Energy Neutrality

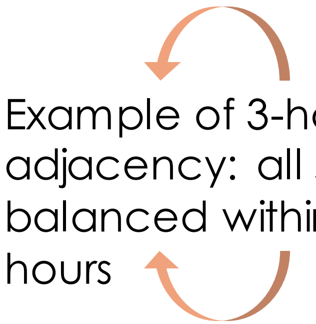
- Shift resources are assumed to be energy neutral across each day
- This is a simplification because pre-heating, pre-cooling, etc. can result in some efficiency loss (or gain)



Shift Hour Adjacency

- Shifting down and shifting up must be relatively close to each other
  - Consumers can't wait for most of a day to cool buildings, heat water, etc.
- Adjacency constraints ensure that if load is shifted down in one hour, an equivalent amount of load is shifted up at most X hours away
  - X depends on the type of load and is provided by LBNL.
  - Opposite limit is also enforced (if load is shifted *Up* in an hour, *Down* is X hours away)





Appendix E
Vehicle-Grid Integration Analysis

Formula for Flexibility Parameters

Request to Stakeholders: Welcome feedback on the methodology to calculate flexibility parameters

<table>
<tr><th></th><th>V1G</th><th>V2G</th></tr>
<tr><td>Shift Window</td><td colspan="2">Shift window is calculated as the average flexible window for all charging sessions (e.g. a car is parked plugged in for 8 hours, and spends 2 hours charging, flex window = 6 hours):

$$flex\_window_s = plugin\_period_s - \frac{SOC\_kWh\_end_s - SOC\_kWh\_start_s}{charge\_power_s}$$

$$shift\_window = \frac{\sum_s^n flex\_window_s}{n}$$

plugin_period = time the EV is parked at a location with charging
SOC_kWh_start/end = state of charge of battery in kWh at the start/end of the session
charge_power = max available charging power for the session</td></tr>
<tr><td>Hourly Shift</td><td>Baseline shapes determines the hourly shift potential

$$Shift\ Down_h = Baseline\ Charging\ Load_h$$

$$Shift\ Up_h = Plugged\ in\ Capacity_h - Baseline\ Charging\ Load_h$$</td><td>IEPR shapes assume no baseline discharging load so greyed out

$$Shift\ Down_h = Plugged\ in\ Capacity_h + Baseline\ Charging\ Load_h - Baseline\ Discharging\ Load_h$$

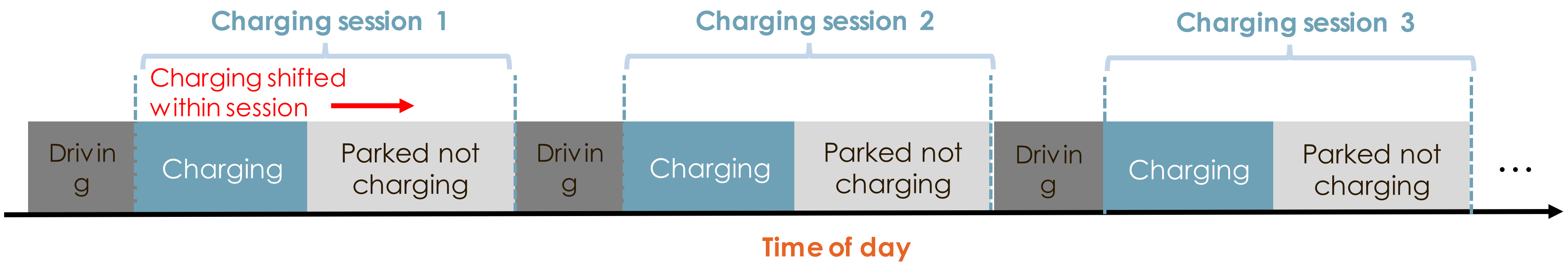
$$Shift\ Up_h = Plugged\ in\ Capacity_h - Baseline\ Charging\ Load_h + Baseline\ Discharging\ Load_h$$</td></tr>
<tr><td>Daily Energy</td><td>Daily energy is calculated as a minimum of the total shift up and shift down potential within a day:

$$Daily\_energy = \min\left\{\sum_0^{23} Shift\ Down_h, \sum_0^{23} Shift\ Up_h\right\}$$</td><td>V2G daily energy is not constrained by the total energy charged during the session, but only by total plugged in capacity. Multiplying it by ½ because V2G can technically charge during half of a day and discharge during another half:

$$Daily\_energy = \left(\sum_0^{23} Plugged\ in\ Capacity_h\right) * \frac{1}{2}$$</td></tr>
</table>

Illustrative Example to Calculate Shift Window

- Shift window is the average window when the vehicle is plugged in and able to change its charging behaviors



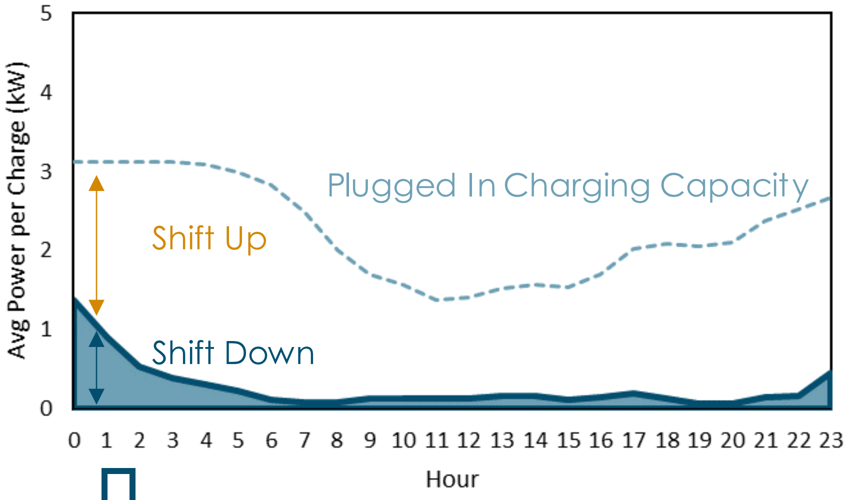
- $$\text{Shift window (h)} = \frac{\text{Parked not charging 1} + \text{Parked not charging 2} + \text{Parked not charging 3} + \dots + \text{Parked not charging n}}{\text{N, Total Number of Charging Sessions}}$$

* Modeling currently assumes intra-session charge management, which means that charging can only be shifted within each session, not between sessions

Illustrative Example to Calculate Daily Energy

- Aggregated, population-level average charging shapes per vehicle

Res V1G

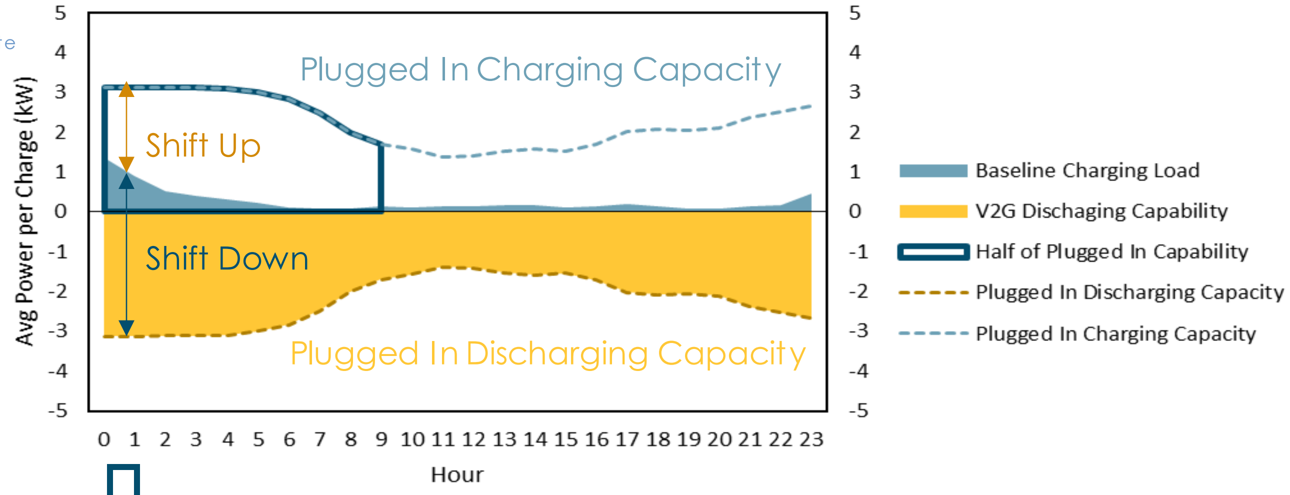


Assuming 5kW average nameplate capacity

V1G Daily Energy (kWh) =
Total shaded blue area of shift down potential

The daily baseline charging load determines the max amount of energy that an EV can shift in a day. It can't reduce more load than its baseline charging amount.

Res V2G



V2G Daily Energy (kWh) =
Half of Total Plugged In Charging (or Discharging) Capability

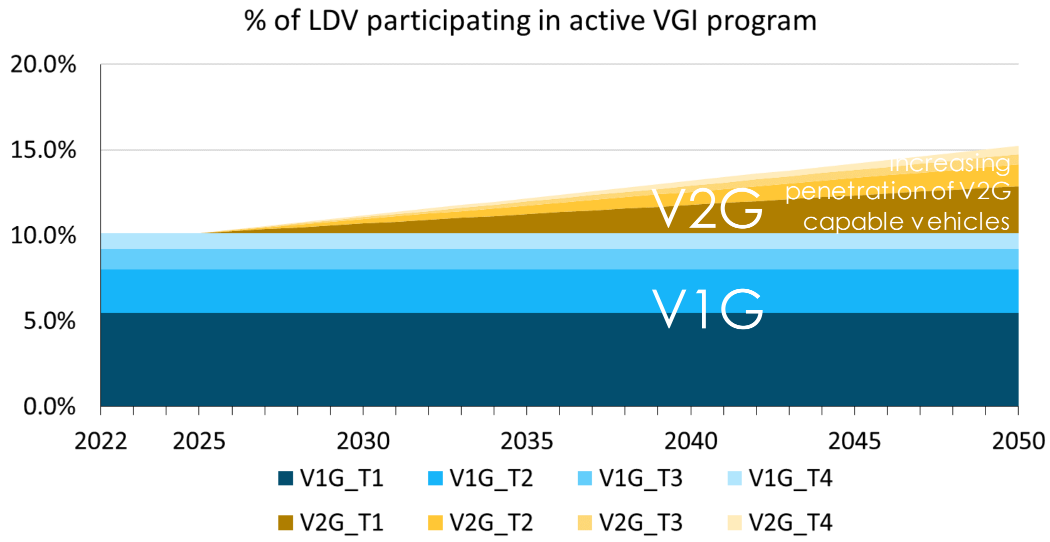
V2G daily energy is not constrained by the total energy charged during the session, but only by total plugged in capacity. It can technically charge half of a day and discharge another half of a day assuming the vehicle is plugged in the whole day

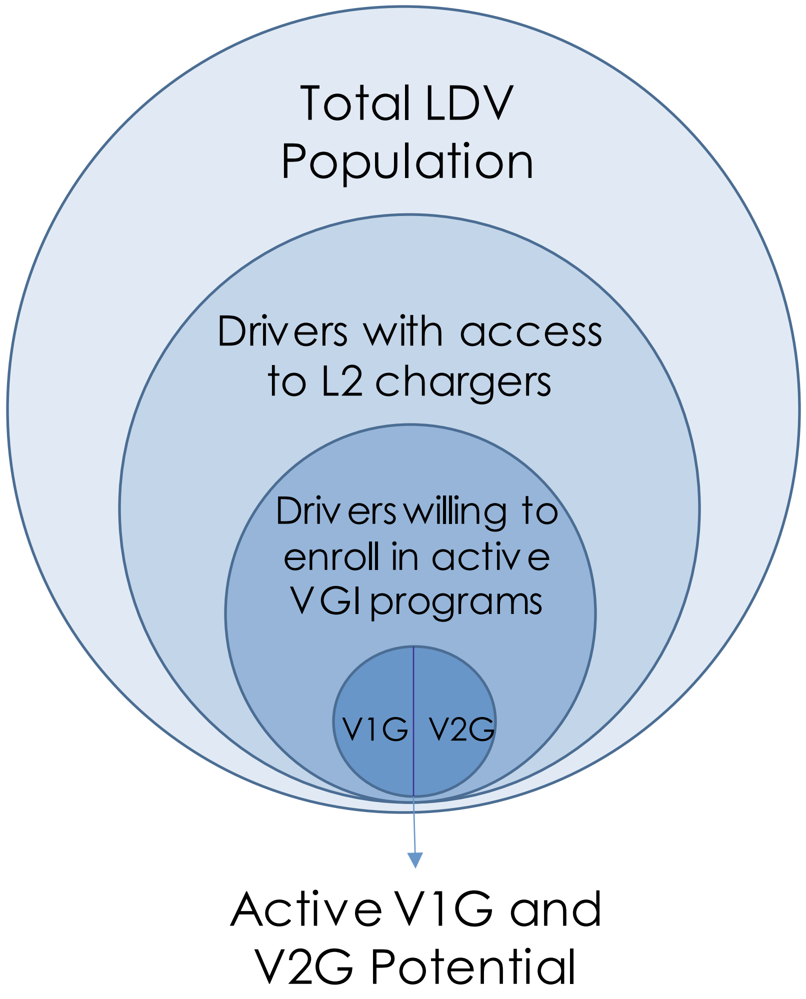
Example of VGI Participation Potential (%) Calculation

Request to Stakeholders: Please provide better enrollment data available from VGI programs and assumptions on V2G timeline and potential to inform this modeling exercise

- VGI Potential (%)
  - $\%\ Driver\ with\ VGI\ Potential = \%\ Access\ to\ L2\ charger * \%\ Enrollment\ by\ tranches\ * \%\ V2G\ potential\ as\ of\ V1G$

Example in 2030	V1G	V2G
Total LDV Population	100%	100%
% Access to VGI (L2) enabled chargers	40%	40%
% Willingness to participate at cost tranche 1	14%	14%
% V2G potential as of V1G in 2030	-	10%
T1 Potential as of LDV population in 2030	**5%**	**0.5%**





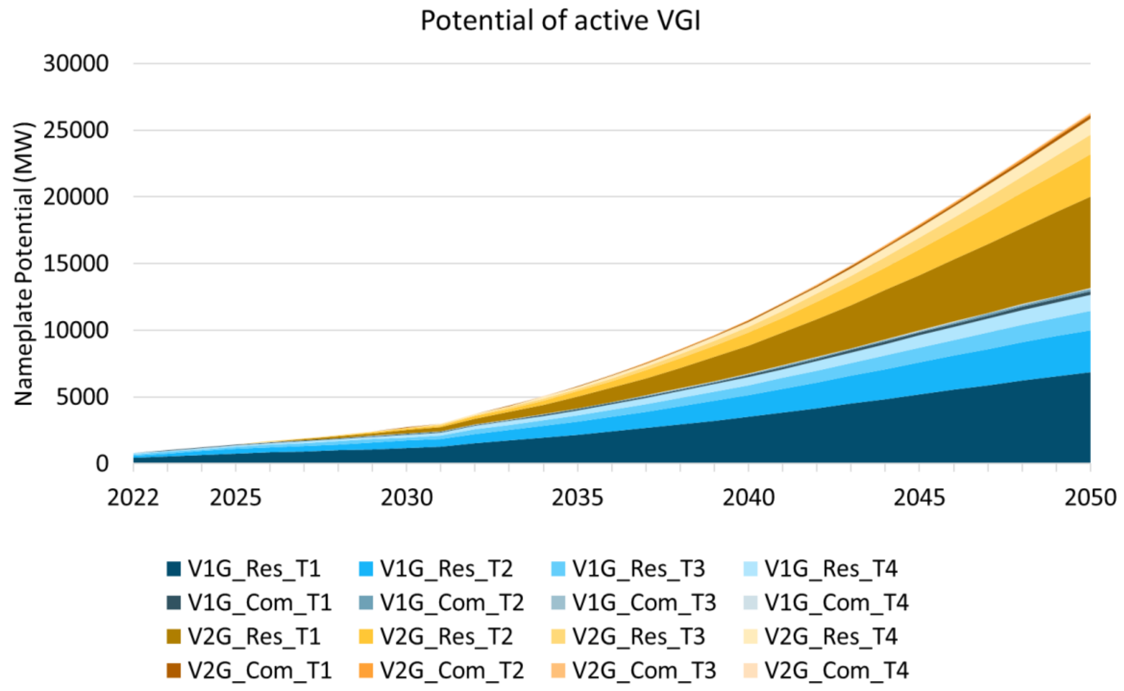
Example of VGI Potential (MW) Calculation
- Based on 2020 IEPR EV High + PATHWAYS Forecast

- VGI potential (MW)
  - $V1G\ Potential\ = \%\ Access\ to\ L2\ charger * \%\ Enrollment\ by\ tranches\ * \boldsymbol{LDV\ stock} * \frac{\boldsymbol{Charger}}{\boldsymbol{EV}} \boldsymbol{ratio} * \boldsymbol{charger\ capacity}$
  - $V2G\ Potential\ = \%\ Access\ to\ L2\ charger * \%\ Enrollment\ by\ tranches\ * V2G\ potential\ \%\ as\ of\ V1G * \boldsymbol{LDV\ stock} * \frac{\boldsymbol{Charger}}{\boldsymbol{EV}} \boldsymbol{ratio} * \boldsymbol{charger\ capacity}\ * \boldsymbol{2}$
    - V2G potential needs to be multiplied by two because it can not only charge but discharge

Res Example in 2030	V1G	V2G
T1 Potential as of LDV population in 2030	**5%**	**0.5%**
LDV population in 2030	4 million	4 million
Charger/EV ratio at Res	1	1
Charger capacity (kW)	5	10
Res_T1 Potential in 2030 (MW)	**1000**	**200**

Com Example in 2030	V1G	V2G
T1 Potential as of LDV population in 2030	**5%**	**0.5%**
LDV population in 2030	4 million	4 million
Charger/EV ratio at Com	1/25	1/25
Charger capacity (kW)	5	10
Com_T1 Potential in 2030 (MW)	**40**	**8**

* The Final LDV population in 2022-2023 PSP will be based on the latest IEPR forecast



Supply Curve – VGI Costs

Request to Stakeholders: Welcome feedback and better data to refine the assumptions and projections of costs

- Costs included:
  - Fixed O&M Costs reflect the cost of incentivizing participation in active VGI programs

Category	Fixed O&M Costs ($/kW-yr) [1]
Administration Costs	$20/yr for each enrolled customer (~$3/kW-yr)
Marketing Costs	$15/yr for each enrolled customer (~$2.5/kW-yr)
Incentive Costs	$0/kW-yr ~ $50/kW-yr, varying by incentive tranches

  - Variable O&M Costs reflect the cycling degradation costs of V2G resources

	2022	2030	2040	2050
EV Pack & Cell Price ($2018/kWh) [2]	134	85	74	64
Cycles [3]	3500	3500	3500	3500
Cost per cycle ($2018/kWh)	0.04	0.02	0.02	0.02

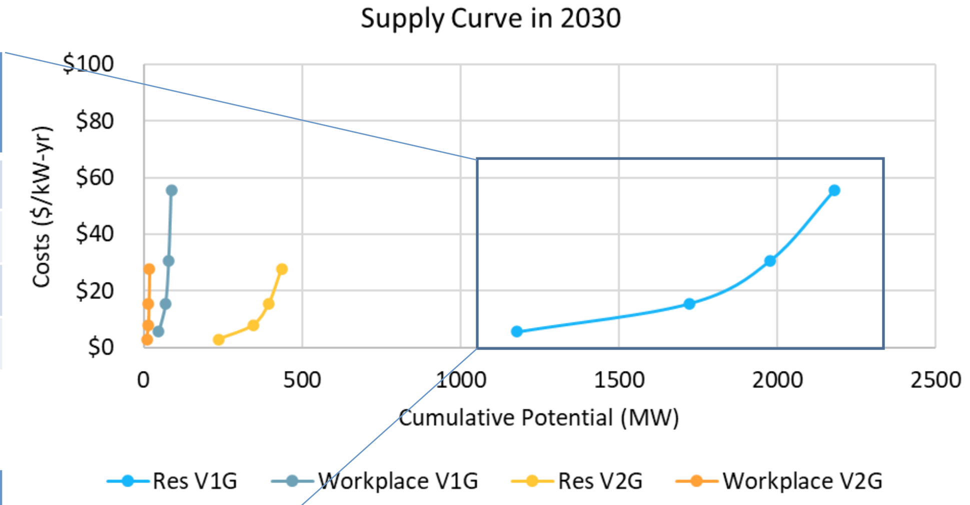
[1] Cost information is obtained from LBNL's DR-path model. Fixed O&M costs are tentatively assumed to be constant in real terms through the study horizon
[2] EV pack and cell price forecasts in 2021 and 2030 is obtained from the BNEF report and it's extrapolated to 2050 using 2021 PSP storage cost trajectory. The exact values can be subjected to change with updated storage cost trajectory for the 2022-2023 PSP
[3] The degradation cost is estimated using stationary storage cycle limit, assuming the impact of using EV as a stationary storage resource will have less degradation impact on EVs compared to driving the vehicles. A typical EV warranty cycles nowadays is around 100,000 miles, around 500 cycles

Example of VGI Supply Curve Results
- Based on 2020 IEPR EV + PATHWAYS Forecast

- Supply curve is a function of cost and potential

Res V1G Example in 2030	Access to L2 Charger (%)	Willingness to Participate (%)	LDV Population	Charger/EV ratio at Res	Charger Capacity (kW)	Potential (MW)	Cumulative Potential (MW)
V1G_Res_T1	40%	14%	4 million	1	5	1200	**1200**
V1G_Res_T2	40%	6%	4 million	1	5	500	**1700**
V1G_Res_T3	40%	3%	4 million	1	5	250	**1950**
V1G_Res_T4	40%	2%	4 million	1	5	200	**2150**

Res V1G Example in 2030	Administration ($/kW-yr)	Marketing ($/kW-yr)	Incentives ($/kW-yr)	Total Costs ($/kW-yr)
V1G_Res_T1	3	2.5	0	**5.5**
V1G_Res_T2	3	2.5	10	**15.5**
V1G_Res_T3	3	2.5	25	**30.5**
V1G_Res_T4	3	2.5	50	**55.5**



Due to the low charger to EV ratio at workplace, the magnitude of the workplace VGI potential is much smaller than residential VGI

V2G cost per kW of capacity is ½ of V1G because of its doubling capacity modeled in RESOLVE

Example of VGI Reliability Contribution Calculation

Request to Stakeholders: Welcome feedback on the methodology to calculate reliability contribution and data to validate VGI contribution during reliability events

- Given that VGI is not as fully available as grid-scale storage to provide power at its nameplate in every single hour, a scaling factor will be applied to normalize VGI shift down capability relative to its "nameplate capacity" during the 4-hr evening net peak (e.g., 6-10pm)
- Equation
  - $VGI\ Scaling\ Factor(\%) = \sum_1^4 \frac{Shift\ Down_h}{Nameplate\ Capacity_h} = \frac{Population\ Average\ Shift\ Down\ Potential\ \ During\ Peak\ Period\,(kWh)}{Total\ Nameplate\ Potential\ During\ Peak\ Period\ (kWh)}$

Res Example in 2030	V1G	V2G
Population average shift down potential per charger from 6-10pm (kWh)	0.5	9
VGI nameplate capacity per charger (kW)	5	10
Peak window duration (hr)	4	4
Total nameplate potential per charger from 6-10pm (kWh)	20	40
Res VGI Scaling Factor (%) *	**2%**	**20%**

  - $Battery\ (4hr)\ Equivalent\ Capacity\ of\ VGI(kW) = VGI\ Nameplate\ Capacity\ (kW) * VGI\ Scaling\ Factor\ (\%)$

Res Example in 2030	V1G	V2G
VGI nameplate capacity per charger (kW)	**5**	**10**
VGI Scaling Factor (%)	2%	20%
Battery (4hr) Equivalent Capacity (kW)	**0.1**	**2**

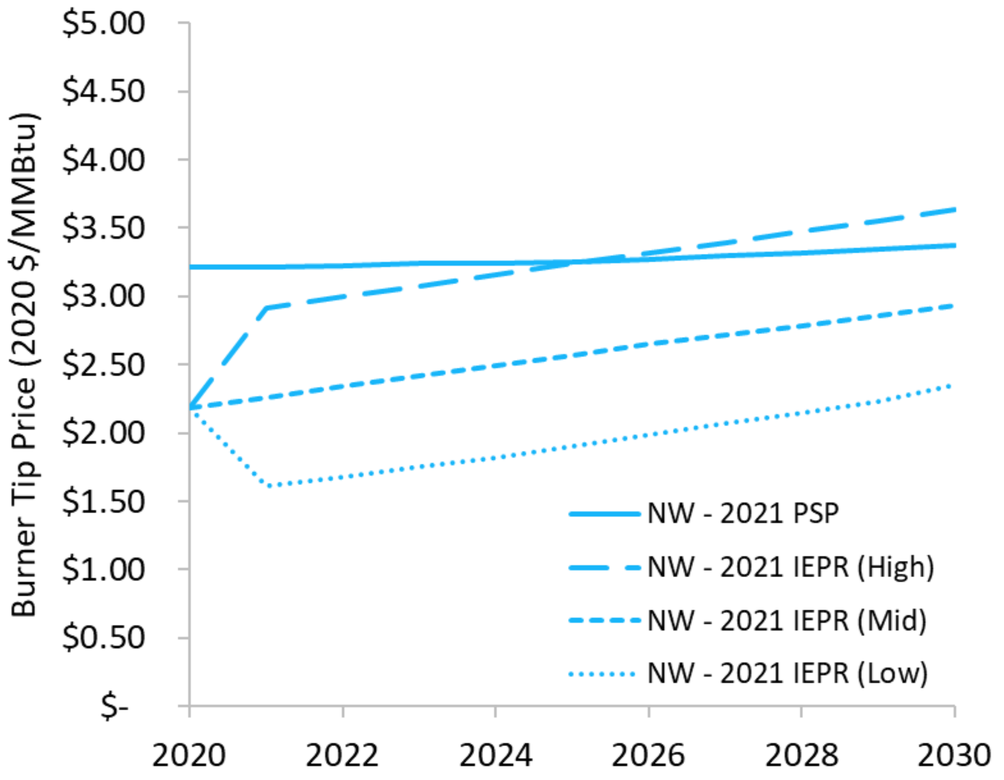
* VGI scaling factor is highly dependent on the underlying load shapes and charger utilization. Workplace scaling factor is much higher than residential scaling factor due to the higher utilization of charger

Appendix F
Additional Information on Fuel Prices

Fuel price comparison

2021 IEPR vs. 2021 PSP / 2022 LSE Filing Requirements, NW + SW

NW Burner Tip Price Sensitivities (2021 IEPR Low/Mid/High vs. PSP / LSE Filing Req)



SW Burner Tip Price Sensitivities (2021 IEPR Low/Mid/High vs. PSP / LSE Filing Req)