2019-20 IRP: Preliminary Results

CPUC Energy Division

October 4, 2019

Purpose of this Presentation

- These results provide IRP stakeholders with information about the resource portfolios California should procure to meet SB 350 goals in 2030: greenhouse gas (GHG) emissions reductions, reliability, and least cost.

The analytical foundation includes:

- Comparison of portfolios under three Greenhouse Gas (GHG) Planning Targets for the electric sector.
- Presentation of sensitivities that explore the impact of certain assumptions changes on the optimal portfolio of resources.
- Explanation of modeling and resource assumptions and updates.
- Exploration of how California can make progress towards deep GHG emissions reductions in the electric sector in 2045.

Contents

Acronyms & Abbreviations

AAEE	Additional Achievable Energy Efficiency
AB	Assembly Bill
BANC	Balancing Area of Northern California
BTM	Behind-the-Meter
Btu	British thermal unit
CAISO	California Independent System Operator
CARB	California Air Resources Board
CCA	Community Choice Aggregator
CCGT	Combined Cycle Gas Turbine
CEC	California Energy Commission
CHP	Combined Heat and Power
CPUC	California Public Utilities Commission
CREZ	Competitive Renewable Energy Zone
CRVM	Common Resource Valuation Methodology
DAC	Disadvantaged Community
DER	Distributed Energy Resources
DR	Demand Response
DRP	Distributed Resources Plan
EE	Energy Efficiency
EV	Electric Vehicle
GHG	Greenhouse Gas
IC	Internal Combustion
IDER	Integrated Distributed Energy Resource
IEPR	Integrated Energy Policy Report
IOU	Investor Owned Utility
IRP	Integrated Resource Plan (or) Planning
IRP 2017-18	The first cycle the CPUC's new IRP process
ITC	Investment Tax Credit
GW	Gigawatt
LBNL	Lawrence Berkeley National Laboratory

LNBA	Locational Net Benefit Analysis
LSE	Load Serving Entity
$MM	Millions of Dollars
MMBtu	Millions of British thermal units
MMT	Million Metric Tons of Carbon Dioxide
MW	Megawatt
MWh	Megawatt hour
NEM	Net Energy Metering
NOx	Nitrogen Oxide
NQC	Net Qualifying Capacity
OOS	Out-of-state
OTC	Once Through Cooling
PCC	Portfolio Content Category
PM 2.5	Particulate Matter, 2.5 microns
POU	Publicly-owned utility
PRM	Planning Reserve Margin
PTC	Production Tax Credit
PV	Photovoltaic
REC	Renewable Energy Credit
RETI	Renewable Energy Transmission Initiative
RPS	Renewables Portfolio Standard
SB	Senate Bill
ST	Steam Turbine
TOU	Time-of-Use
TPP	Transmission Planning Process
TRC	Total Resource Cost
TWh	Terrawatt hours
WECC	Western Electricity Coordinating Council
ZEV	Zero Emissions Vehicle
ZNE	Zero Net Energy

1. BACKGROUND

Integrated Resource Planning (IRP) in California Today

- The value proposition of <u>integrated</u> resource planning is to reduce the cost of achieving GHG reductions and other policy goals by looking across individual LSE boundaries and resource types to identify solutions to reliability, cost, or other concerns that might not otherwise be found.
- Goal of 2019-20 IRP cycle is to ensure that the electric sector is on track to help California reduce economy-wide GHG emissions 40% from 1990 levels by 2030, and to explore how achievement of SB 100 2045 goals could inform IRP resource planning in the 2020 to 2030 timeframe.
- California today is a complex landscape for resource planning:
  - Multiple LSEs including utilities, CCAs, and ESPs.
  - Multiple state agencies (CPUC, CEC, Air Resources Board) and CAISO.
  - Partially deregulated market.

Statutory Basis of IRP

The Commission shall…

PU Code Section 454.51

Identify a diverse and balanced portfolio of resources… that provides optimal integration of renewable energy in a cost-effective manner

PU Code Section 454.52

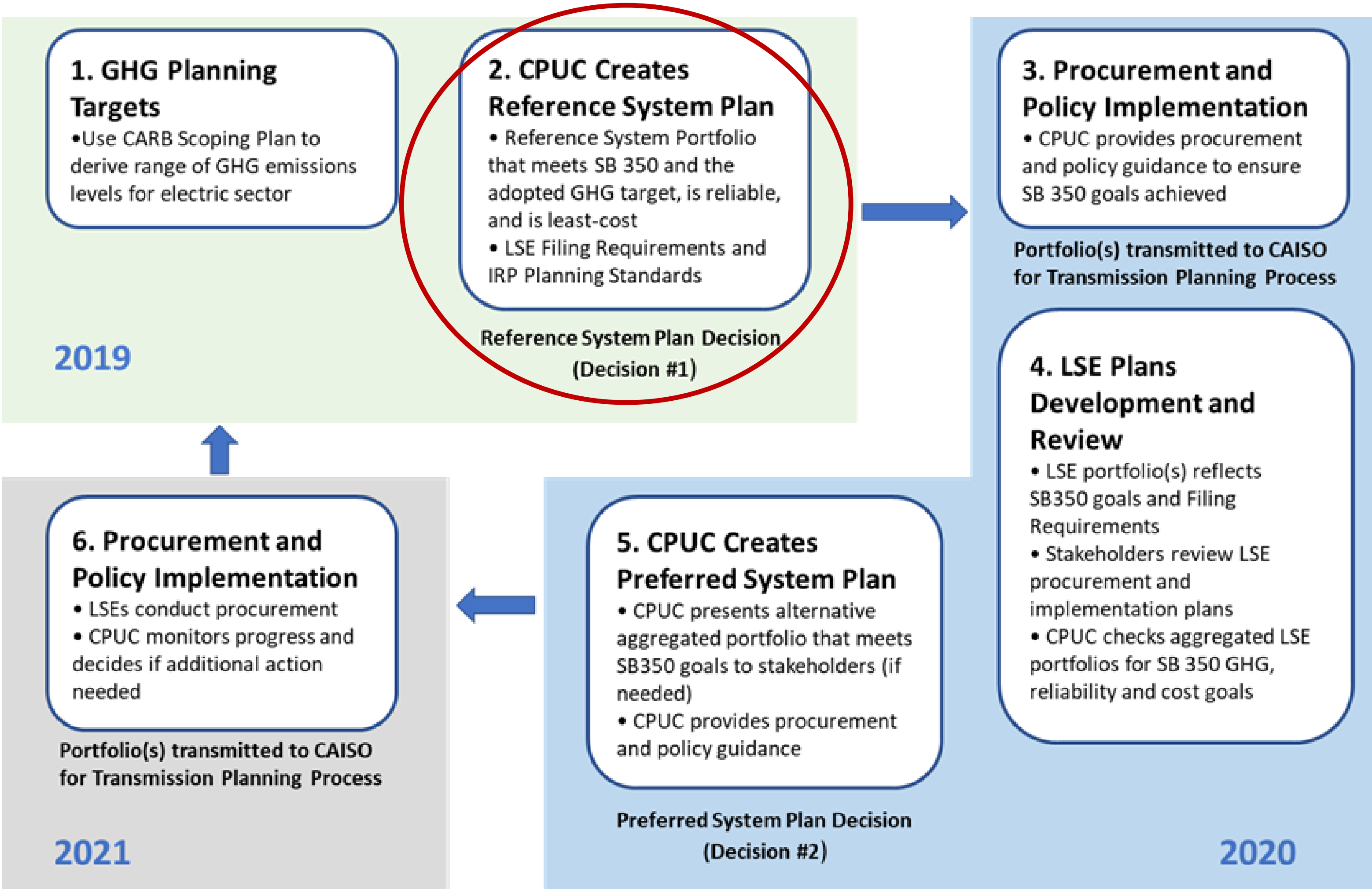
...adopt a process for each load-serving entity…to file an integrated resource plan…to ensure that load-serving entities do the following…

- Meet statewide GHG emission reduction targets
- Comply with state RPS target
- Ensure just and reasonable rates for customers of electrical corporations
- Minimize impacts on ratepayer bills
- Ensure system and local reliability
- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities
- Enhance distribution system and demand-side energy management
- Minimize air pollutants with early priority on disadvantaged communities

Background on the CPUC IRP Process

- Commission Decision (D.18-02-018) established IRP as a two-year planning cycle designed to ensure LSEs are on track to achieve GHG reductions and maintain electric grid reliability at least cost while meeting the state's other policy goals.
- Year One is focused on:
  - Generating and evaluating optimal resource portfolios at the CAISO system-level using a capacity expansion model (RESOLVE) and production cost model (SERVM) in parallel.
  - Adopting one portfolio as the <u>Reference System Portfolio</u> to be used in statewide planning, including the CAISO transmission planning process.
  - Identifying actions needed to implement the selected portfolio, such as new procurement authorization.
  - Developing filing requirements for LSEs to submit individual IRPs.
- Year 2 is focused on:
  - LSE development of individual IRPs.
  - Staff evaluation of LSE IRPs both individually and in aggregate.
  - Commission adoption of a <u>Preferred System Portfolio</u> to be used in statewide planning, as well as actions needed to implement the portfolio (<u>Preferred System Plan</u>).

Overview of the IRP 2019-20 Process



IRP GHG Target Setting

- Reduce statewide GHG emissions 40% below 1990 levels by 2030.
- In 2018, CARB, in coordination with CPUC and CEC, established a GHG planning target range for the electric sector of <u>30 – 53 MMT by 2030*.</u>
- CARB also defined a methodology for setting LSE- and POU-specific GHG planning targets in IRP based on that range.
- CPUC D.18-02-018 adopted an electric sector GHG target of 42 MMT as part of the 2017-18 IRP Reference System Plan.

*For perspective, electric sector emissions were ~62 MMT in 2017 (SOURCE: CARB's GHG emissions inventory)

2019 Core GHG Cases

- **46 MMT* Case (Default)**
  - Achieves the Commission-established electric sector planning target
  - Demand forecast: CEC 2018 IEPR Mid AAEE
  - Baseline resources assumed to be online as defined in Section 2.3 of this presentation
  - Considered "Default" case in 2019 IRP modeling as it most closely resembles adopted policy from the 2018 IRP Preferred System Plan (PSP)
- **38 MMT Case**
  - Represents the midpoint between 46 MMT and the low end of CARB's established range for the electric sector
  - Includes all constraints and assumptions from Default Case
- **30 MMT Case**
  - Represents the low end of CARB's established range
  - Includes all constraints and assumptions from Default Case

*In the IRP 2017-18, emissions from behind the meter CHP facilities were not included as part of the electric sector emissions. To align with CARB's GHG accounting methodology, emissions from behind-the meter CHP, which were estimated as 4 MMT in the last cycle, are now included as electric sector emissions in the 2019/2020 Reference System Plan. Thus, the 46 MMT target in IRP 2019-20 translates to approximately a 42 MMT GHG target in IRP 2017-18.

Translating Statewide GHG Targets to CAISO Targets

- Staff expresses the core modeling cases throughout this analysis in terms of the statewide electric sector GHG targets.
- However, the CPUC's IRP modeling covers only the CAISO balancing authority area; the RESOLVE model allows specification of a GHG planning target in tons of CO2 equivalent to constrain the portfolio at the CAISO system level on an annual basis.
- For IRP modeling, statewide electric sector GHG targets are translated to CAISO targets based on CARB's proposed Cap and Trade allowance allocation methodology for 2021-2030 (~81% in 2030).

2030 Statewide Target	2030 CAISO Target
46.0 MMT	37.3 MMT
38.0 MMT	30.8 MMT
30.0 MMT	24.3 MMT

Preliminary Results: Relationship to 2045 Analysis

- CPUC staff and consultants performed analysis to explore how SB 100's 2045 goal could affect the outlook for electricity sector GHG emissions and resource planning in the 2030 timeframe.
- This analysis is primarily informational and directional, intended to inform Commission decision-making regarding the appropriate 2030 GHG planning target for CPUC-jurisdictional LSEs, the Reference System Portfolio to meet that target, and associated least-regrets investments needed by 2030.

Summary of Documents Released in Conjunction with IRP 2019 Preliminary Results

- IRP 2019 Preliminary Results slide deck
  - Preliminary modeling results associated with 2019 Reference System Portfolio development under multiple potential GHG targets
  - 2045 Framing Study
- Updated IRP 2019-20 Draft Inputs & Assumptions document
  - Resources, transmission, and assumptions used for IRP 2019-20 capacity expansion and production cost modeling
- Updated RESOLVE model and accompanying documentation
  - The RESOLVE model used to generate Preliminary Results is available for use by parties, along with upstream inputs and assumptions spreadsheets and related information
- Updated SERVM model input datasets
  - Incremental to data presented at the 6/17 MAG on baseline model inputs development

Process for 2019 IRP Reference System Portfolio Development

Step #	Activity	Estimated Date
1	Data Development	March-June 2019
2	Informal release: core model inputs + MAG presentation	June 2019
2a	Informal party comment on Step 2 content	July 2019
3	Input validation for RESOLVE & SERVM models	July 2019
4	Develop calibrated modeling results	July-Sept 2019
<u>5</u>	<u>Informal release of complete RESOLVE model and draft results</u>	<u>October 2019</u>
6	Formal release of Proposed 2019 IRP Reference System Plan	November 2019
7	Formal party comment on Proposed 2019 Reference System Plan	November 2019
8	Formal release of 2019 Reference System Plan Proposed Decision	January 2020
9	Formal party comment on 2019 Reference System Plan PD	January 2020
10	Commission Decision on 2019 Reference System Plan	February 2020
11	Transmittal of 2019 IRP portfolios to 2020-21 CAISO TPP	February 2020

2. MODELING APPROACH

2.1. MODELS USED

RESOLVE Model Overview

- RESOLVE is a capacity expansion model designed to inform long-term planning questions around renewables integration.
- RESOLVE co-optimizes investment and dispatch for a selected set of days over a multi-year horizon in order to identify least-cost portfolios for meeting specified GHG targets and other policy goals.
- Scope of RESOLVE optimization in IRP 2019-20:
  - Covers the CAISO balancing area including POU load within the CAISO
  - Optimizes dispatch but not investment outside of the CAISO
    - Resource capacity outside of CAISO cannot be changed by the optimization
- The RESOLVE model used to develop the preliminary Reference System Plan results, along with accompanying documentation of inputs and assumptions, model operation, and results is available for download from the CPUC's website at: https://www.cpuc.ca.gov/General.aspx?id=6442459770

SERVM Model Overview

- The Strategic Energy Risk Valuation Model (SERVM)* is a probabilistic system-reliability planning and production cost model – primary objective is to reduce risk of insufficient generation to an acceptable level (e.g. security-constrained planning)
  - Configured to assess a given portfolio in a target study year under a range of future weather (20 weather years), economic output (5 weighted levels), and unit performance (30+ random outage draws)
  - Hourly economic unit commitment and dispatch
    - Reserve targets to reflect provision of sub-hourly balancing and ancillary services
    - Multiple day look-ahead informs unit commitment
    - Individual generating units and all 8,760 hours of year are simulated
    - Unit operating costs and constraints
  - Pipe and bubble representation of transmission system
    - 8 CA regions, 16 rest-of-WECC regions
    - Includes region to region flow limits and hurdle rates as well as simultaneous flow limits

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

Why Two Models are Used in IRP Analysis

Objective of IRP modeling: To develop an optimal portfolio of new resources to add to the existing fleet in the CAISO area to plan for:

- Achievement of long-term GHG reduction targets and other policy goals
- Maintaining reliability
- Keeping costs reasonable
- Accounting for uncertainty and expected energy market conditions (i.e., "real world" conditions)

- The role of the RESOLVE model in IRP is to select portfolios of new resources that are expected to meet our policy goals at least cost while ensuring reliability.
- The role of the SERVM model in IRP is to validate the reliability, operability, and emissions of resource portfolios generated by RESOLVE.

2.2. OVERVIEW OF MODELING ASSUMPTIONS

General Assumptions Components Used in 2019 IRP Modeling

- IRP seeks to use standardized modeling inputs in both capacity expansion (RESOLVE) and production cost modeling (SERVM).
- Generally, these assumptions pertain to use of demand forecasts and the definition of what baseline resources to consider in both models.
- An overview of core modeling inputs for 2019 modeling is included in this section
  - Descriptions of demand forecast and baseline resource inputs

Core Modeling Input: Demand Forecast

- Per the 2013 joint agency leadership agreement to use a single forecast set*, current IRP modeling uses the Energy Commission's 2018 IEPR Update Forecast as a core input.
- Uncertainty in future electricity demand considered:
  - 1998-2017 weather scenarios and 5 weighted levels of load forecast uncertainty in SERVM
  - Sensitivity and scenario modeling (e.g. high load, high electrification) in RESOLVE
- IEPR forecast annual projections of electricity consumption and demand modifiers are used to scale corresponding hourly shapes in RESOLVE and SERVM
  - See 6/17 MAG presentation for further background on hourly shapes used by RESOLVE and SERVM; both models' shapes have been updated since the previous IRP cycle

* See February 25, 2013 CPUC-CEC-CAISO Letter to Senators Padilla and Fuller and more information available on CPUC's webpage; Also see Final 2018 Integrated Energy Policy Report Update, Volume II- Clean Version

Core Modeling Input: Baseline Resources

- **Baseline resources** are resources that are included in a model run as an assumption rather than being selected by the model as part of an optimal solution.
- Within CAISO, the baseline resources are intended to capture:
  - Existing resources, net of planned retirements (e.g. once-through-cooling plants)
  - "Steel-in-the-ground" new resources that are deemed sufficiently likely to be constructed, usually because of being LSE-owned or contracted, with CPUC and/or LSE governing board approval
    - e.g. CPUC- or LSE governing board-approved renewable power purchase agreements, CPUC-approved gas plants, CPUC storage procurement target (i.e., AB 2514)
  - Projected achievement of demand-side programs under current policy
    - e.g. forecast of EE achievement, BTM PV adoption under NEM tariff

Core Modeling Input: Baseline Resources (continued)

- In external zones (e.g., BANC), where RESOLVE does not optimize the portfolios, the baseline resources are derived from the WECC Anchor Data Set, which includes each external BA's plans to add/retire resources to meet assumed policy and reliability goals
- RESOLVE optimizes the selection of additional resources in the CAISO area needed to meet policy goals, such as RPS, a GHG target, or a planning reserve margin; these resources that are selected by RESOLVE are *not* baseline resources.
- The same baseline resources are assumed in the 46, 38, and 30 MMT Core Policy Cases.
- The baseline developed for 2019 IRP modeling includes data collected up to the spring of 2019 and differs from the baseline used in the IRP's 2018 Preferred System Plan Decision (D.19-04-040).

Baseline Resource Assumptions: Retirements, Repowering, Risk Adjustments

- Retirements
  - Power plants with announced retirements are modeled as retired. Compliance with Once-Thru-Cooled Water Board policy is assumed and Diablo Canyon Power Plant is retired in 2024/2025.
  - Of the remaining existing plants, RESOLVE uses new economic retention functionality to examine what portion of the existing gas-fired generation fleet may need to be retained or allowed to retire within the IRP planning horizon
- Repowering
  - Staff is aware that a significant fraction of California's wind capacity may need to be repowered to remain online through 2030.
  - Further data gathering and RESOLVE development will be needed to explicitly consider repowering in modeling.
  - In the interim Staff will estimate the capacity of wind that would need to be repowered to maintain baseline wind power production through 2030, with reference to stakeholder input already provided in this proceeding.
- Risk Adjustment for LSE-owned or contracted resources not yet online: 5% discount applied to installed capacity

2.3. CANDIDATE RESOURCES IN RESOLVE

Candidate Resource Assumptions

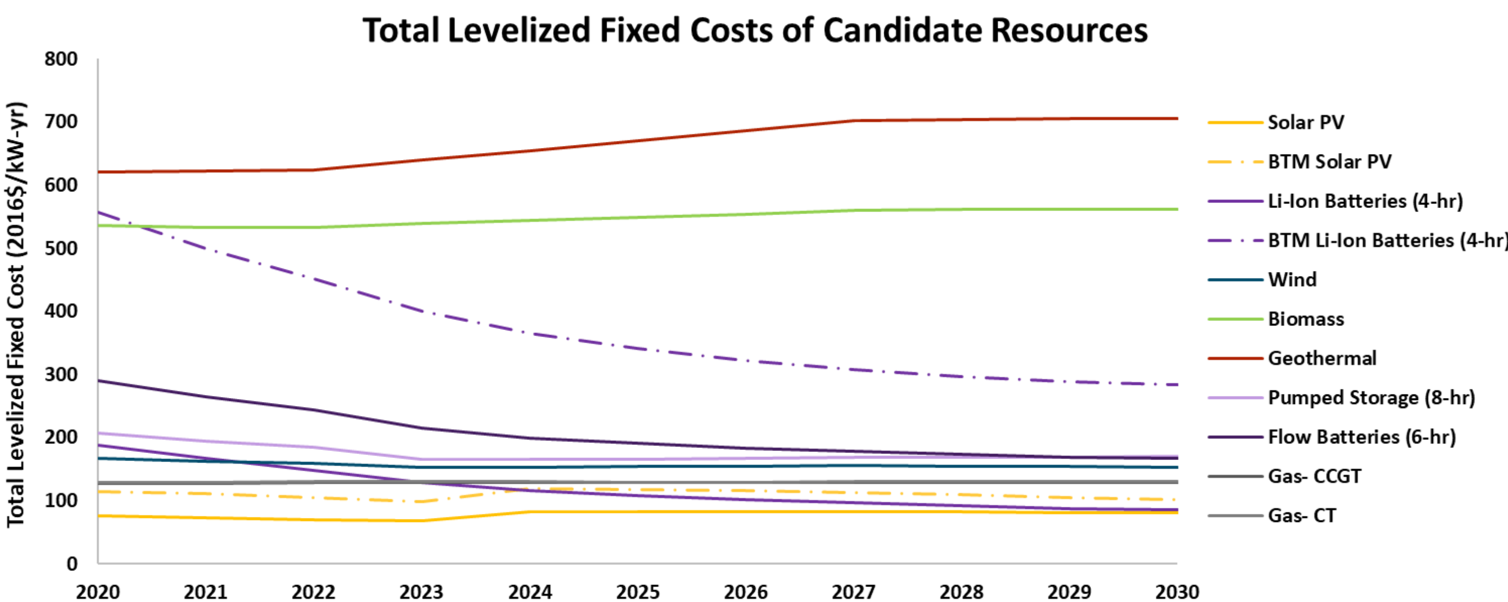
- "Candidate" resources represent the menu of options from which RESOLVE can select to create an optimal portfolio.
- Publicly-available data on cost, potential, and operations are used to the maximum extent possible to develop candidate resource assumptions.
- Both supply and demand-side resources are included as candidate resources.
- Supply-side Candidate Resources:
  - Natural gas: CCGT, CT
  - Renewables: Solar PV, Wind, Geothermal, Biomass
  - Utility-Scale battery storage: Li-ion, Flow
  - Pumped storage
- Demand-side Candidate Resources:
  - Behind-the-meter PV
  - Behind-the-meter Li-ion Storage
  - Shed Demand Response

Portfolio Selection: Costs and Benefits

- The optimal mix of candidate resources in RESOLVE is a function of the costs and characteristics of the candidate resources and the constraints that the portfolio must meet.
- When choosing a resource, RESOLVE weighs:
  - Costs of building and operating each resource
    - Fixed costs: capital, fixed O&M, transmission upgrades
    - Variable costs: fuel, variable O&M, start
  - The system benefits of adding each resource to the portfolio
    - Hourly energy and reserve value
    - Contribution to GHG and RPS policy goals
    - Contribution to system resource adequacy (planning reserve margin)
    - Contribution to local capacity requirements (if any - none modeled in 2019 IRP)
- Capital costs are typically the largest cost category for renewable resources.

Levelized Fixed Resource Costs

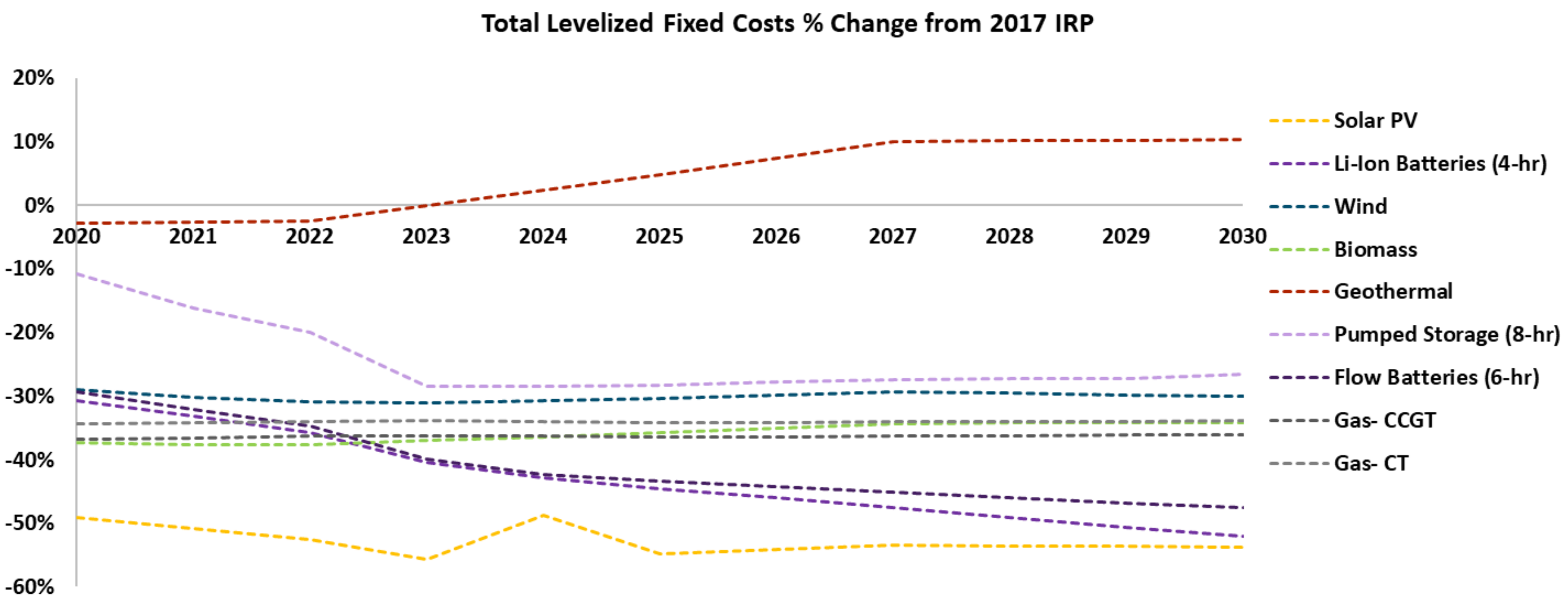
- Renewable resource capital and fixed O&M cost forecasts based on 2018 National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB).
- Storage resource capital and fixed O&M cost forecasts based on Lazard Levelized Cost of Storage 4.0 and NREL Solar + Storage study.
- Financing costs based on NREL ATB.
- Shed DR costs (not shown on plot) are included as a supply curve based on the LBNL California Demand Response Potential Study.



*Costs shown are US-wide and do not include regional multipliers applied to all technologies or project-specific multipliers applied to renewable projects in the supply curve.
**The chart above capture the total fixed costs of resources only. Does not include variable costs (e.g. fuel) which are modeled in RESOLVE.

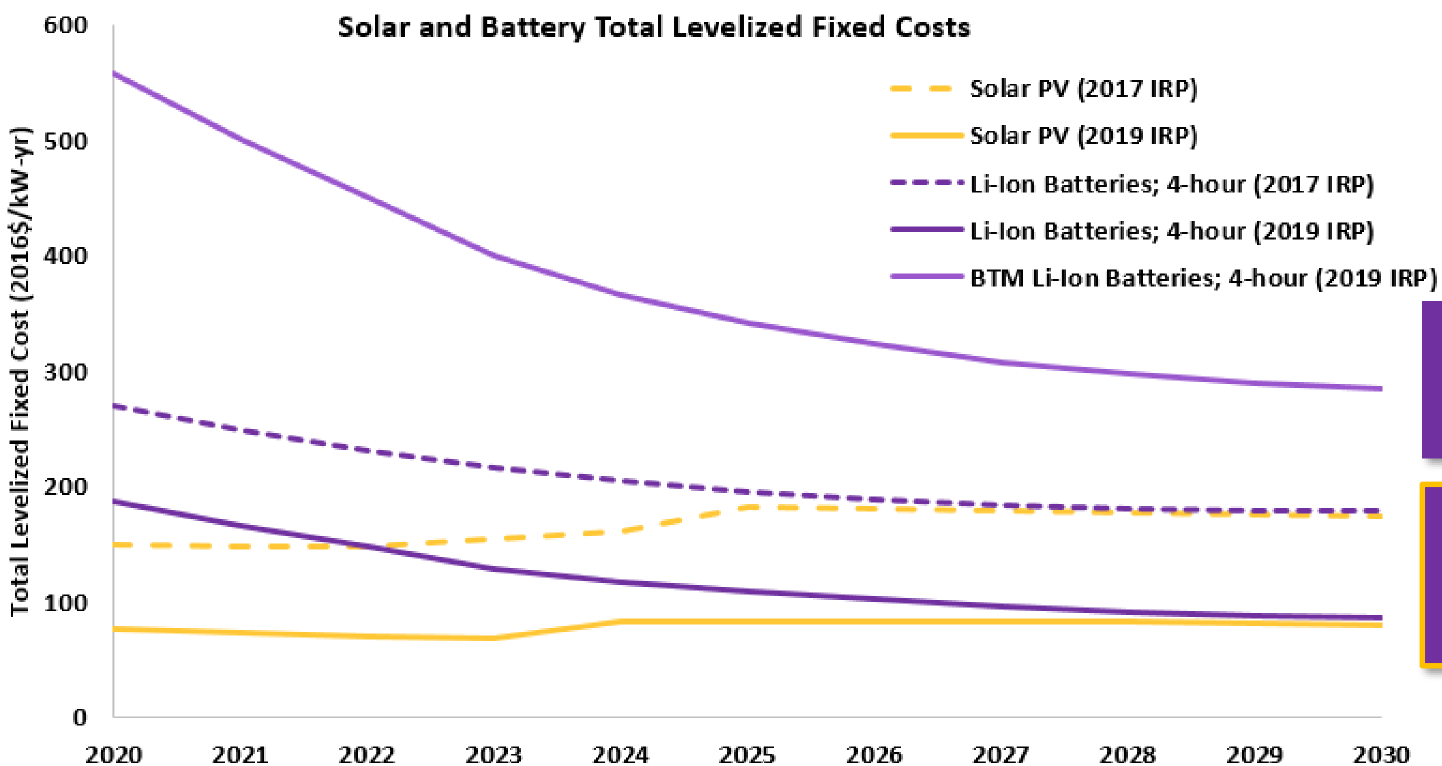
Total Levelized Fixed Cost Comparison: 2017 to 2019 IRP

- Sustained cost declines have outpaced expectations for solar and lithium-ion technologies.
- Continued wind technology innovations (e.g. taller hub heights and longer blades that increase power capacity per turbine) result in lower installed costs per kW than assumed in 2017 IRP.
- Financing (debt/equity ratio) and tax rate updates since last IRP cycle drive changes in levelized costs assumptions for natural gas technologies.



Based on the total levelized fixed costs of technologies before the application of any regional-specific cost multipliers. Does not include variable costs (e.g. fuel) which are modeled in RESOLVE.

Solar PV and Li-Ion Batteries
Total Fixed Cost Comparison: 2017 to 2019



BTM Li-Ion fixed costs significantly higher than utility-scale

By 2030, 2019 IRP fixed cost projections for utility scale PV and Li-Ion are roughly half of 2017 IRP values

Costs shown are US-wide and do not include regional multipliers applied to all technologies or project-specific multipliers applied to renewable projects in the supply curve.

Supply Curve Validation: Cost & Potential

- Updated RESOLVE "supply curve" of candidate resources based on stakeholder feedback on supply curve used for 2017-18 IRP.
- Northern California geothermal: cost increased to reflect interconnection gentie length.
- Wind resource potential updated to reflect contracting activity, land use changes and technology development since supply curve was refreshed by Black & Veatch in 2016; considered wind industry's feedback, including reference to commercial interest as indicated by interconnection queues.
  - Greater Carrizo: reduced potential due to interconnection and land use challenges
  - Northern California: renewable potential for Northern California wind was set to zero across all screens in 2017 IRP due to both the unproven nature of the resource and expected obstacles in resource permitting. For 2019 cycle, ~900 MW of Northern California wind resource potential was re-instated based on stakeholder input and interconnection queue review that commercial activity has increased.
- In 2017 IRP, candidate solar capacity as calculated from Black and Veatch geospatial analysis was discounted by 95% to reflect land use constraints and preference for geographic diversity. Value updated to 80% in 2019 IRP; geographic diversity largely enforced by transmission limits.

First Available Online Date

- "First Available Year" of some resource types updated to reflect feasible timeline to bring resources online, considering current interconnection queues and typical development processes

Resource Type	First Available Year
Solar PV	2020
Wind (CA onshore)	2022-2023*
Wind (OOS onshore)	2026
Geothermal	2022-2026*
Biomass	2020
Pumped Storage	2026
Battery Storage	2020

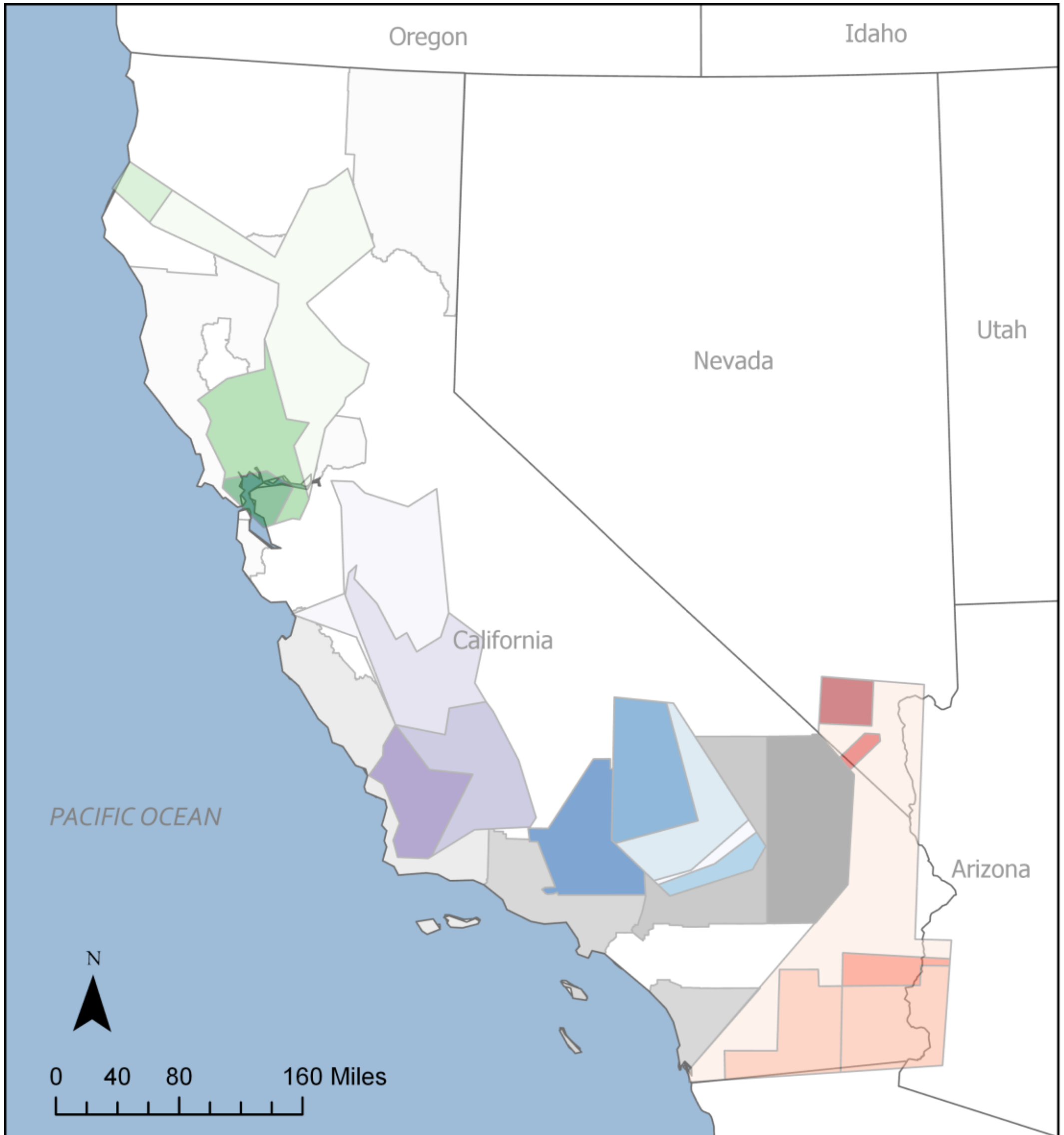
*First Available Year is an assumption applied on a resource-by-resource basis in RESOLVE; accordingly range of years applies when summarizing by resource type

Transmission Cost & Availability

- The CAISO published its latest capability estimates for each transmission zone, as well as cost estimates for upgrades to increase capability, in its May 20, 2019 white paper
- RESOLVE has been updated per "Option 2A" described in the June 17, 2019 Modeling Advisory Group (MAG) presentation*:
  - Assigned candidate resources to updated transmission zone definitions
  - Where candidate resources do not fall within any transmission zone, these were assigned to adjacent zones where possible, or to new zones for which capability limits were assumed to equal the capacity in the interconnection queue
  - Identified delivery points to CAISO zones for out-of-state and offshore resources
  - Capability and upgrade cost values per the CAISO's estimates, with deductions to capability to allow for baseline resources with online dates of 2019 or later
  - Transmission capability divided between subzones such that both subzone and outer zone transmission limits are not exceeded
- Further RESOLVE development is in progress to reflect the "nested" nature of zone capability limits ("Option 1" described in the June 17, 2019 MAG presentation*)

*See MAG slides 82-92 available at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_MAG_20190617_CoreInputs.pdf

2019 Transmission Zones



- Norcal_Z3_SacramentoRiver
- Norcal_Z2_Humboldt
- Norcal_Z4_Solano
- Norcal_Z4_Solano_subzone
- SPGE_Z4_CentralValleyAndLosBanos
- SPGE_Z1_Westlands
- SPGE_Z2_KernAndGreaterCarrizo
- SPGE_Z3_Carrizo
- GK_Z1_GreaterKramer
- GK_Z3_NorthOfVictor
- GK_Z4_Pisgah
- GK_Z2_InyokernAndNorthOfKramer
- SCADSNV_Z5_SCADSNV
- SCADSNV_Z3_GreaterImperial
- SCADSNV_Z4_RiversideAndPalmSprings
- SCADSNV_Z1_EldoradoAndMtnPass
- SCADSNV_Z2_GLW_VEA
- Tehachapi
- NorCalOutsideTxConstraintZones
- WestlandsOutsideTxConstraintZones
- GreaterImpOutsideTxConstraintZones
- TehachapiOutsideTxConstraintZones
- KramerInyoOutsideTxConstraintZones
- SCADOutsideTxConstraintZones
- <all other values>

2.4. CORE IRP MODELING FUNCTIONALITY AND ASSUMPTIONS UPDATES

New RESOLVE Functionality: Economic Retention of Existing Thermal Generation

- In the 2017 IRP, existing thermal resources were assumed to be available indefinitely unless retirement had been announced.
- In the 2019 IRP, the RESOLVE model has been updated to determine the level of dispatchable gas resources that should be retained by CAISO ratepayers to minimize overall CAISO system costs.
  - Retention decisions are made for CCGTs, Peakers, and Reciprocating Engines.
  - Combined heat and power (CHP) facilities are retained indefinitely due to the presence of a thermal host.
  - OTC plants are already scheduled for retirement and are retired on schedule (retention decisions not made by RESOLVE).
  - Note: RESOLVE's economic thermal retention functionality assesses whether it is economic to retain gas capacity for CAISO ratepayers, but does <u>not</u> assess whether gas capacity should retire. Other offtakers may contract with gas plants balanced by CAISO, even if CAISO ratepayers do not. In addition, gas plant operators may choose to keep plants online without a long-term contract.
- To retain existing gas assets in RESOLVE, CAISO ratepayers must pay a fixed O&M cost to maintain the resource.
  - CCGT: $11/kW-yr; Peaker and Reciprocating Engines: $14/kW-yr ($2016)

Retention when needed for Local Capacity Requirements (LCR)

- Gas plants located in LCR zones are retained indefinitely.
  - Only the retention of dispatchable gas resources *outside of* LCR zones is decided by RESOLVE.
  - Further study necessary to determine replacement resources that meet local reliability requirements.

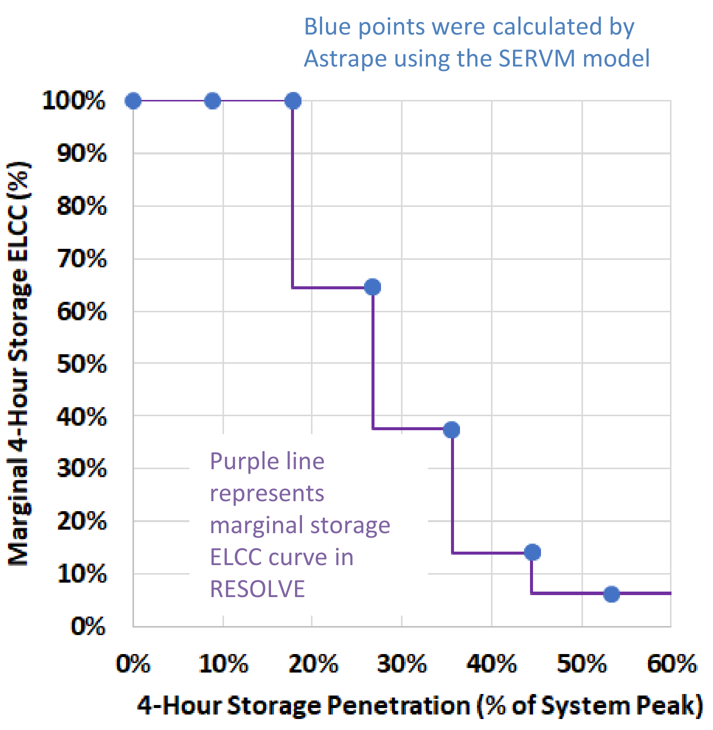
RESOLVE Resource	2030 Baseline Capacity (MW)	LCR capacity - retained indefinitely (MW)	Retention decided by RESOLVE (MW)
CAISO_CCGT1	13,333	8,412	4,921
CAISO_CCGT2	2,928	1,885	1,043
Peaker1	4,914	3,163	1,751
Peaker2	3,683	1,309	2,374
CAISO_Reciprocating_Engine	255	184	71

Battery Storage Capacity Value

- Battery storage provides resource adequacy value.
  - Current CPUC RA rules count a battery with 4 hours of duration as having 100% ELCC.
- In the 2017 IRP, battery storage capacity value was a function of the duration of the battery, with batteries reaching full capacity value at 4 hours of duration.
  - Capacity value = Power Capacity * Min(1, Duration/4)
- In the 2019 IRP, the battery storage capacity value has been modified to decline with storage penetration.
  - 2017 IRP power-duration relationship retained.

Battery Storage ELCC Curve

- Battery storage does not provide equivalent capacity to dispatchable thermal resources at higher battery storage penetrations because:
  - Storage flattens the net peak, requiring longer duration and/or higher stored energy volumes.
  - Increasing penetrations face the challenge of having enough energy to charge to support peak demand
- Astrape Consulting used the SERVM model and the CPUC's SERVM database populated with a preliminary RESOLVE 46 MMT portfolio to calculate the capacity contribution of storage in 2030 across a wide range of storage capacities
  - Case includes significant BTM and utility-scale solar capacity that can be used to charge batteries
- RESOLVE includes a declining storage ELCC curve for utility-scale Li-Ion and Flow batteries



ELCC curve was developed for a 2030 system with high levels of solar generation and may overstate battery capacity value in the early 2020s when solar capacity is lower

2.5. CASES MODELED

Types of Cases Modeled

- **Core Policy Cases**: Three cases that reflect different potential GHG trajectories for the electric sector.
  - Purpose: Compare the impacts of different GHG goals on portfolio composition, costs, and emissions.
- **Core Policy Sensitivities:** Variations on the core policy cases that reflect changes to one or more of the default assumptions about the future (e.g., load, resource costs).
  - Purpose: Determine how different future conditions could affect portfolio composition, costs, and emissions.
- **SB100 2045 Framing Study:** Three cases that reflect different potential GHG and load trajectories for the electric sector based on different economy-wide decarbonization pathways.
  - Purpose: Explore how 2045 goal under SB100 and economy-wide decarbonization targets could affect outlook for electricity sector GHG emissions and resource planning in 2030 timeframe.

List of Sensitivities

Cases that reflect variations in assumptions about the future against which the core policy cases were tested.

2030 Cases	2045 Framing Studies
Reference	High Electrification
New OOS Transmission	High Electrification with New OOS Transmission
Low Cost OOS Transmission	High Electrification with Offshore Wind Available
High Cost OOS Transmission	High Hydrogen
High Solar PV Cost	High Biofuels
ITC Extension	
High Battery Cost	
Paired Battery Cost	
Low RA Imports	
High RA Imports	
2045 End Year	
High Load	

2.6. PORTFOLIO METRICS

Metrics Used to Characterize Modeling Results

- **Selected Resources**, in MW: new resources that the model selects as part of the optimal, least-cost portfolio
  - Selected resources are incremental to any resources included in the baseline
- **Gas Capacity not Retained**, in MW: capacity of existing gas power plants that the model did not retain as a part of the optimal, least cost portfolio.
  - Values do not include planned retirements of OTC gas power plants.
- **Costs**
  - <u>Incremental Total Resource Cost</u>: fixed and operating costs, including program costs and customer costs; calculated as difference from Default Case
  - <u>Revenue Requirements</u>: fixed and operating costs, including program costs, but not customer costs
  - <u>Average Rate</u>: revenue requirements divided by retail sales

Incremental Total Resource Cost Metric

- The **"incremental total resource cost"** (or incremental TRC) for each scenario is calculated relative to the 46 MMT Reference Case.
  - Represents an **annualized incremental cost ($MM/yr)** expressed in 2016 dollars over the course of the analysis (2020-2030).
- "Incremental TRC" metric captures the sum of costs directly considered in development of Reference System Portfolio:
  - RESOLVE objective function
    - Fixed costs of new electric sector investments (generation & transmission)
    - CAISO portion of WECC operating costs (including net purchases & sales)
  - Other costs modeled externally to RESOLVE associated with assumptions
    - Utility & customer demand-side program costs
- "Incremental TRC" does not reflect previously authorized costs; e.g., distribution infrastructure replacement.

Sources for Calculating Revenue Requirements

- Revenue requirements calculated based on
  - RESOLVE outputs
  - IOU IEPR filings: forecasts of annual IOU revenue requirement (2017-2030) submitted to CEC IEPR docket
  - IOU AB67 filings: historical revenue requirement data (2003-2017) submitted by IOUs to CPUC
  - Padilla report: report published by CPUC summarizing cost of renewable procurement for 2018
  - Data from demand-side programs: assumed program costs provided by EE, DR groups in Energy Division (from 2017 IRP)

Revenue Requirement Components

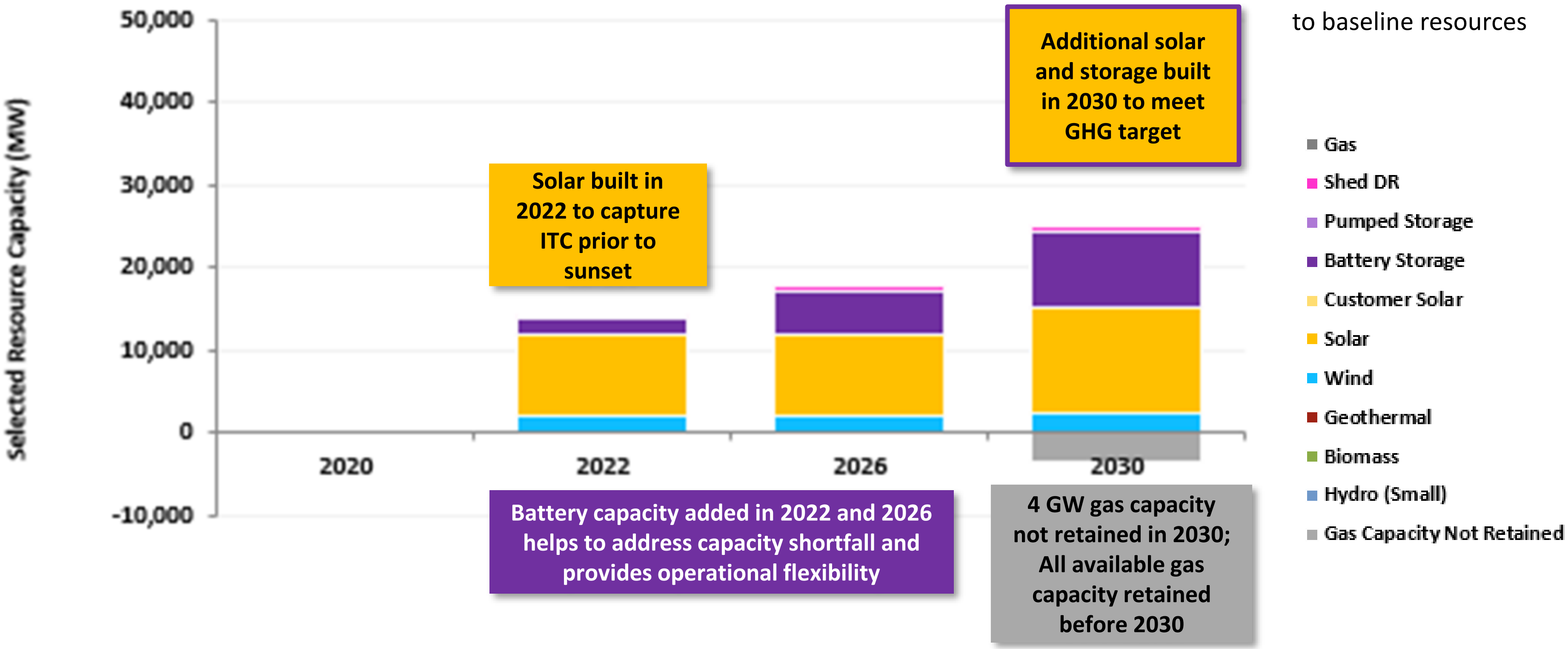
Category	Component	Source
Distribution	Existing Distribution Revenue Requirement (RR)	IEPR
Transmission	Existing Transmission RR	IEPR
	New Renewables-Driven Transmission	RESOLVE
Generation	Existing Utility Owned Generation (UOG) RR	IEPR
	Existing Bilateral Contracts	AB67
	Existing Renewables Contract Cost	Padilla
	New Renewables Contract Cost	RESOLVE
	New Storage Cost	RESOLVE
	Variable Generation Costs	RESOLVE
	Allowance Allocation Revenue	RESOLVE
Demand-Side Programs	Energy Efficiency Program Costs	Other
	Existing DR Program Costs	Other
	New DR Program Costs	RESOLVE
Other	DWR Bond Charges	IEPR
	Nuclear Decommissioning Cost	IEPR
	Public Purpose *(excluding energy efficiency)*	IEPR
	Other Misc	IEPR

3. MODELING RESULTS

3.1. SELECTED RESOURCES IN THE CORE POLICY CASES

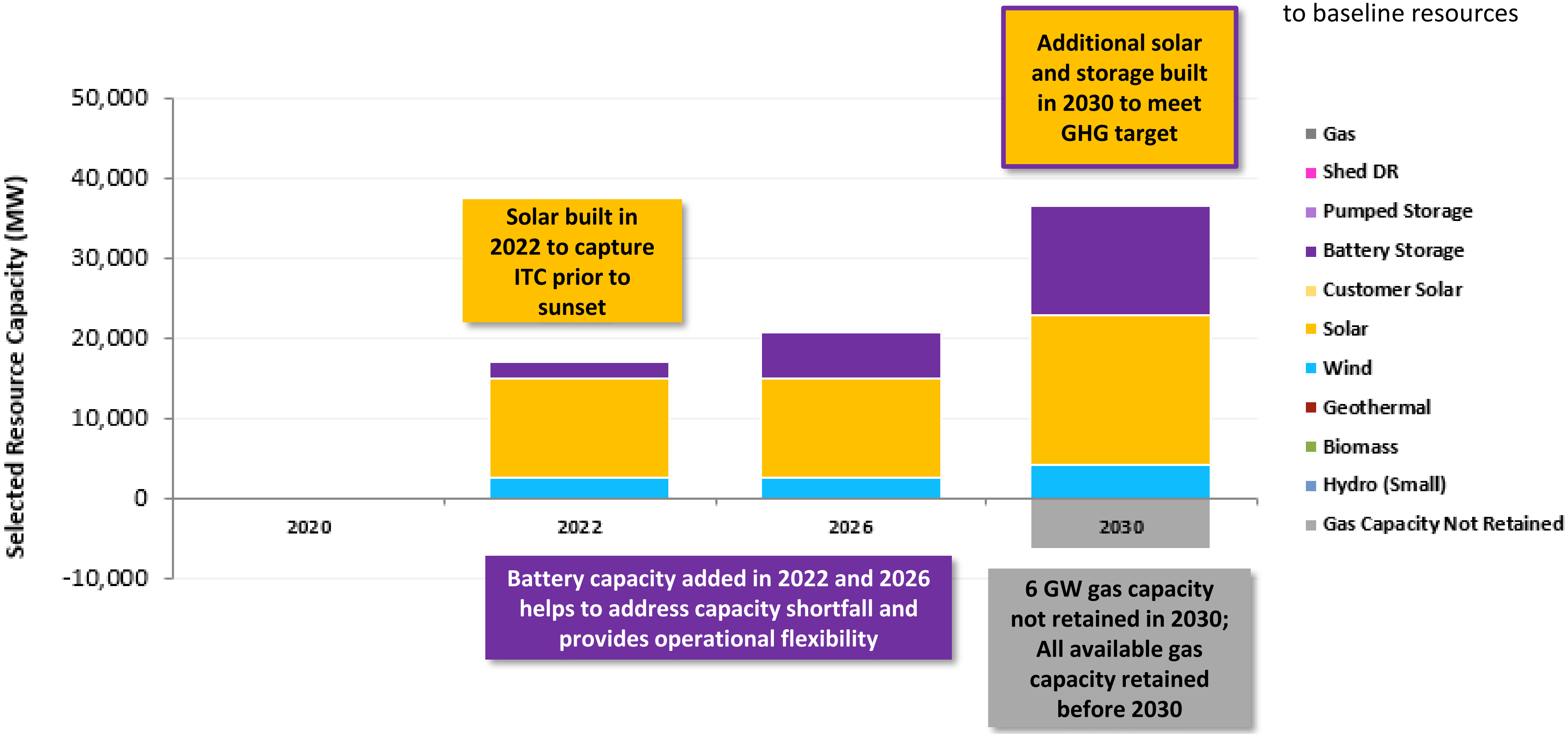
RESOLVE Output: Resources Selected in 46 MMT Case

Note: all resources shown in this chart are selected by RESOLVE and are in addition to baseline resources



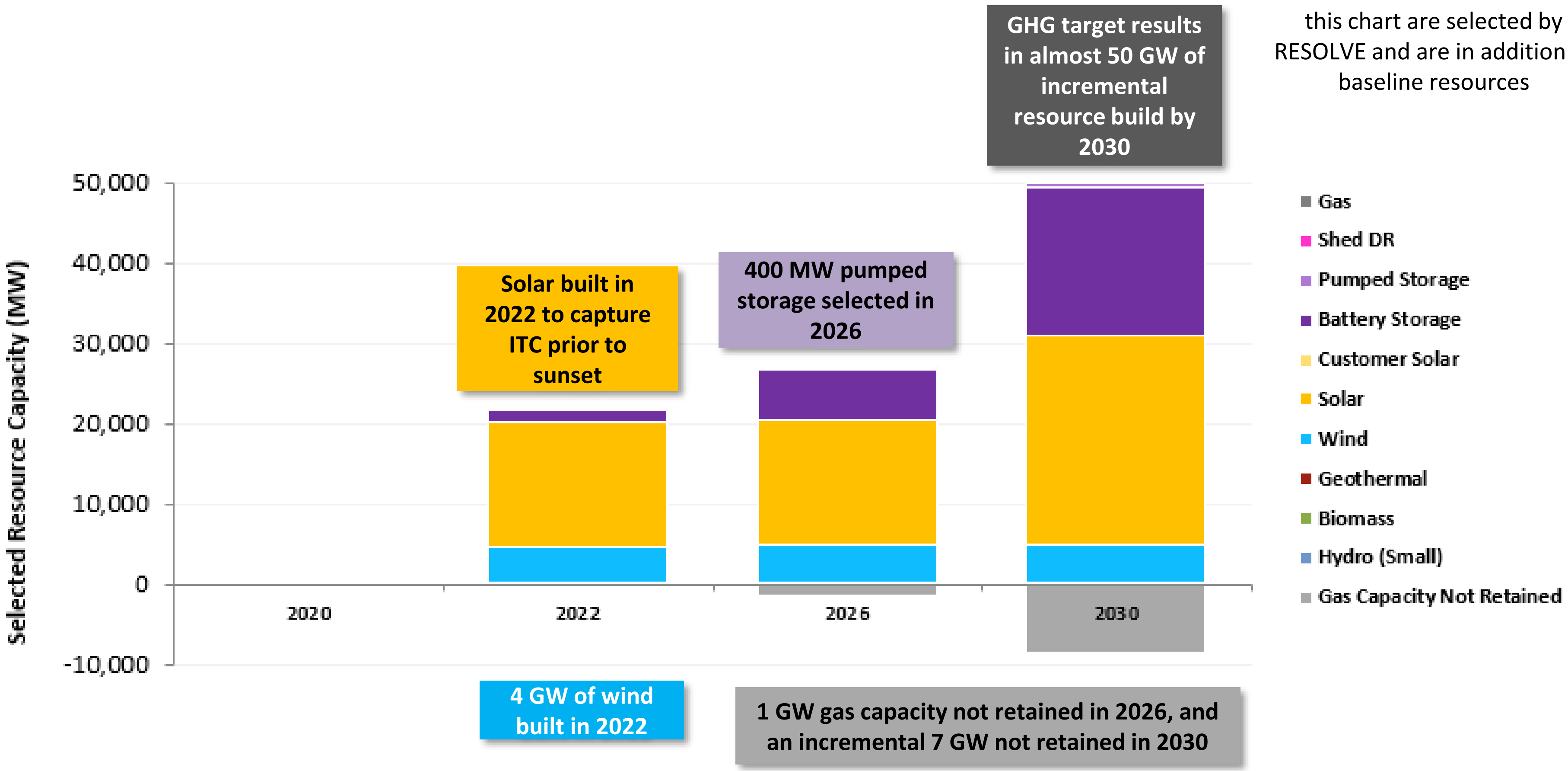
RESOLVE Output: Resources Selected in 38 MMT Case

Note: all resources shown in this chart are selected by RESOLVE and are in addition to baseline resources



RESOLVE Output: Resources Selected in 30 MMT Case

Note: all resources shown in this chart are selected by RESOLVE and are in addition to baseline resources



Observations Regarding Selected Resources in Core Policy Cases

- Core policy case observations:
  - New resources are first selected in 2022.
    - RESOLVE investment decisions reflect <u>online</u> date for resources – significant lead-time required for contracting, permitting, and construction.
  - 2022 buildout of utility-scale solar PV capacity reflects ITC cost reductions available in the near-term.
  - Utility-scale solar PV, battery storage, and wind dominate the selected resources through 2030.
  - Pumped storage (400 MW) built in 2026 under most stringent GHG target.
  - New gas generation is not part of the least-cost solution.
  - Gas capacity retention:
    - Reflecting a near-term capacity shortfall, all existing gas capacity (except for planned OTC retirements) retained until 2030 in the 46 MMT and 38 MMT cases.
    - The 30 MMT case does not retain a small fraction of the gas fleet in 2026 (~1 GW).
    - Range of gas capacity not retained in 2030 is 4 GW (46 MMT) to 8 GW (30 MMT).

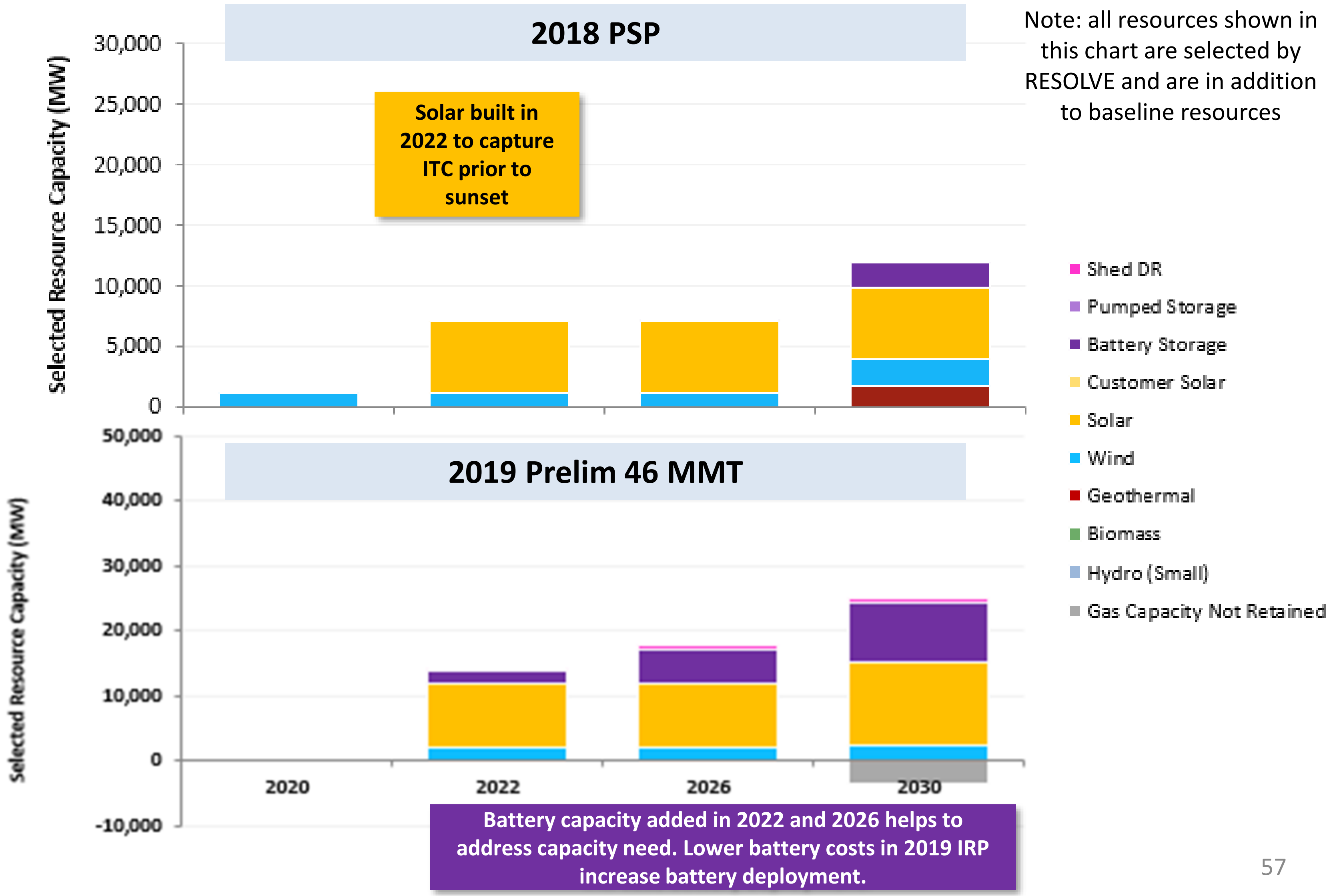
Core Policy Case Results in 2045 Context

- The Core Policy Cases show portfolio results with a planning horizon of 2030.
- The 2045 Framing Study reflects analysis performed on different decarbonization strategies in the CEC Deep Decarbonization report* and focuses on three potential pathways: High Electrification, High Biofuels, and High Hydrogen.
- The 2045 studies generally retain more gas capacity than in the 2030 Core Policy Cases, particularly the 38 and 30 MMT cases.
- An additional sensitivity (slide 102) demonstrates more gas capacity retained in each of the 2030 Core Policy Cases if a 2045 planning year is added to the analysis.
- This suggests that context outside of the 2030 Core Planning Cases should be used to inform any decisionmaking regarding the optimal portfolio of resources for 2030.

*Deep Decarbonization in a High Renewables Future. Available at: https://ww2.energy.ca.gov/2018publications/CEC-500-2018-012/CEC-500-2018-012.pdf

Comparison of 2019 Preliminary 46 MMT to 2018 PSP: Resource Build

Note: all resources shown in this chart are selected by RESOLVE and are in addition to baseline resources

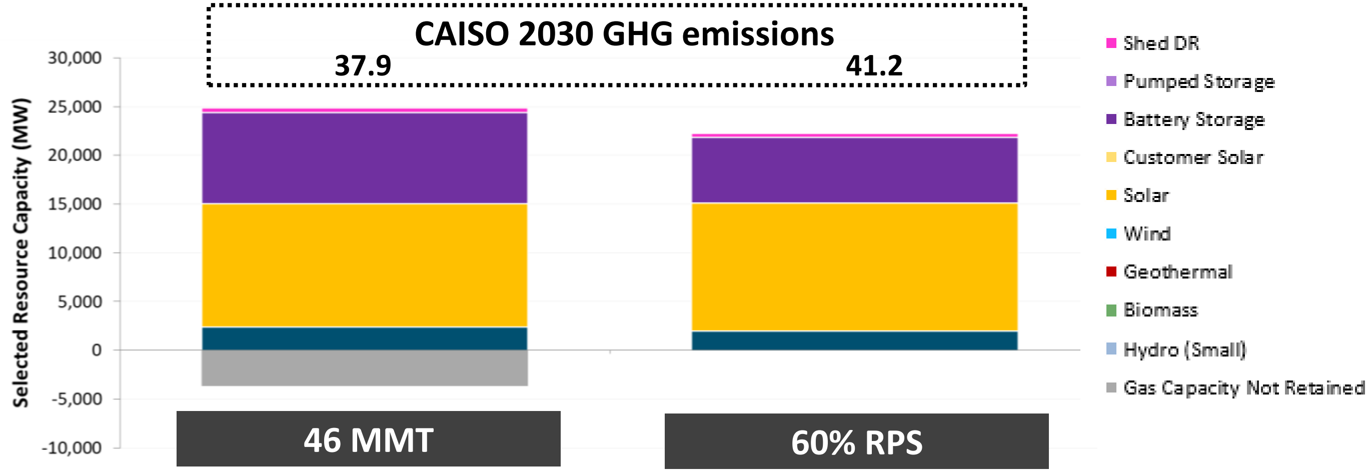


Observations Regarding Comparison of 2019 Preliminary 46 MMT and 2018 PSP

- Similarities:
  - Utility-scale solar PV, battery storage, and wind dominate the selected resources through 2030.
  - Solar PV selected in 2022 to capture value of ITC.
  - New gas plants not part of the least-cost solution.
- Differences:
  - Economic thermal retention functionality has been implemented, with approximately 4 GW of gas capacity not retained in 2030.
  - Some resources, particularly battery storage, are built in 2022 to meet capacity shortfall in 2019 Preliminary 46 MMT, as further described on slide 74.
  - No geothermal resources selected in 2019 Preliminary 46 MMT.
  - Increase in total nameplate capacity is selected by 2030, likely driven by decreased battery and solar PV costs in 2019 modeling.
  - Wind potential updated to reflect feasible timeline to bring resources online, given current interconnection queue and typical development processes.

60% RPS vs 46 MMT Comparison

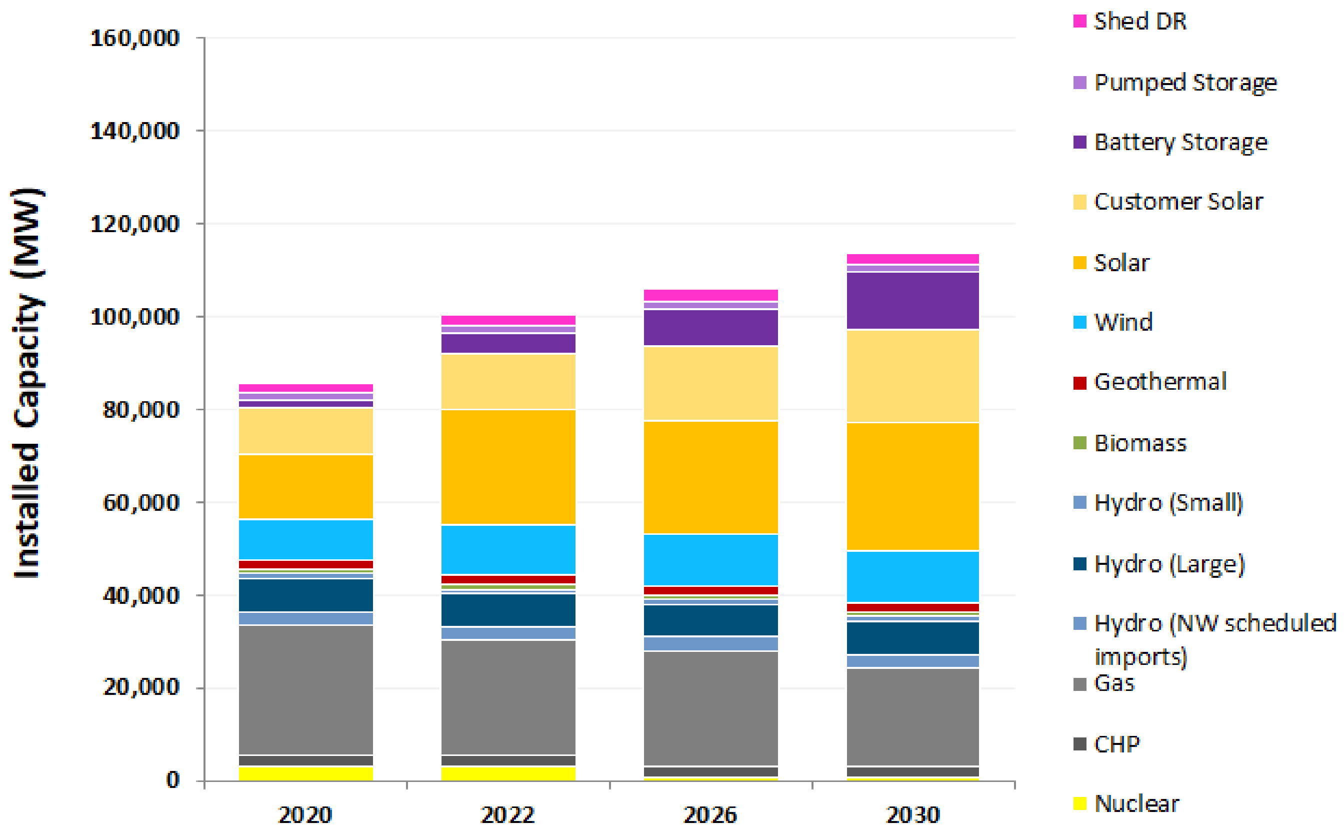
- To explore an RPS-driven portfolio, a case was run without a GHG target. In this case, the 60% RPS requirement by 2030 is a major driver of investments.
- While not identical, the 46 MMT case and the 60% RPS case produce similar portfolios in 2030 (shown below).
- The 46 MMT portfolio results in 3 MMT/yr lower emissions than the 60% RPS portfolio.
- An additional ~3 GW of additional storage build in 46 MMT is accompanied by an additional ~3 GW of gas capacity that is not retained.



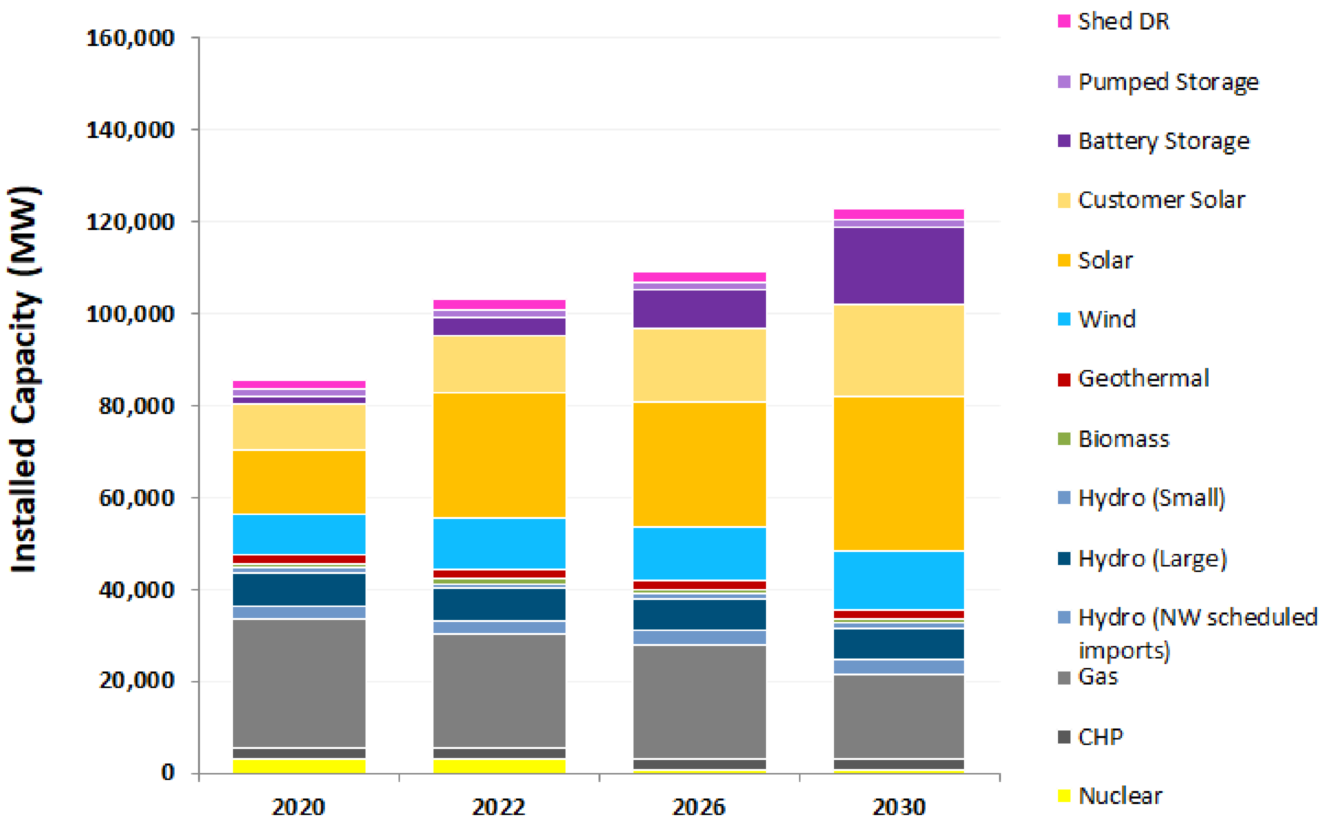
Total Resource Stack Plots

- The previous slides focused on the resource capacity selected by the RESOLVE optimization
- The subsequent slides add baseline resource capacity to the selected capacity to show the total CAISO resource portfolio

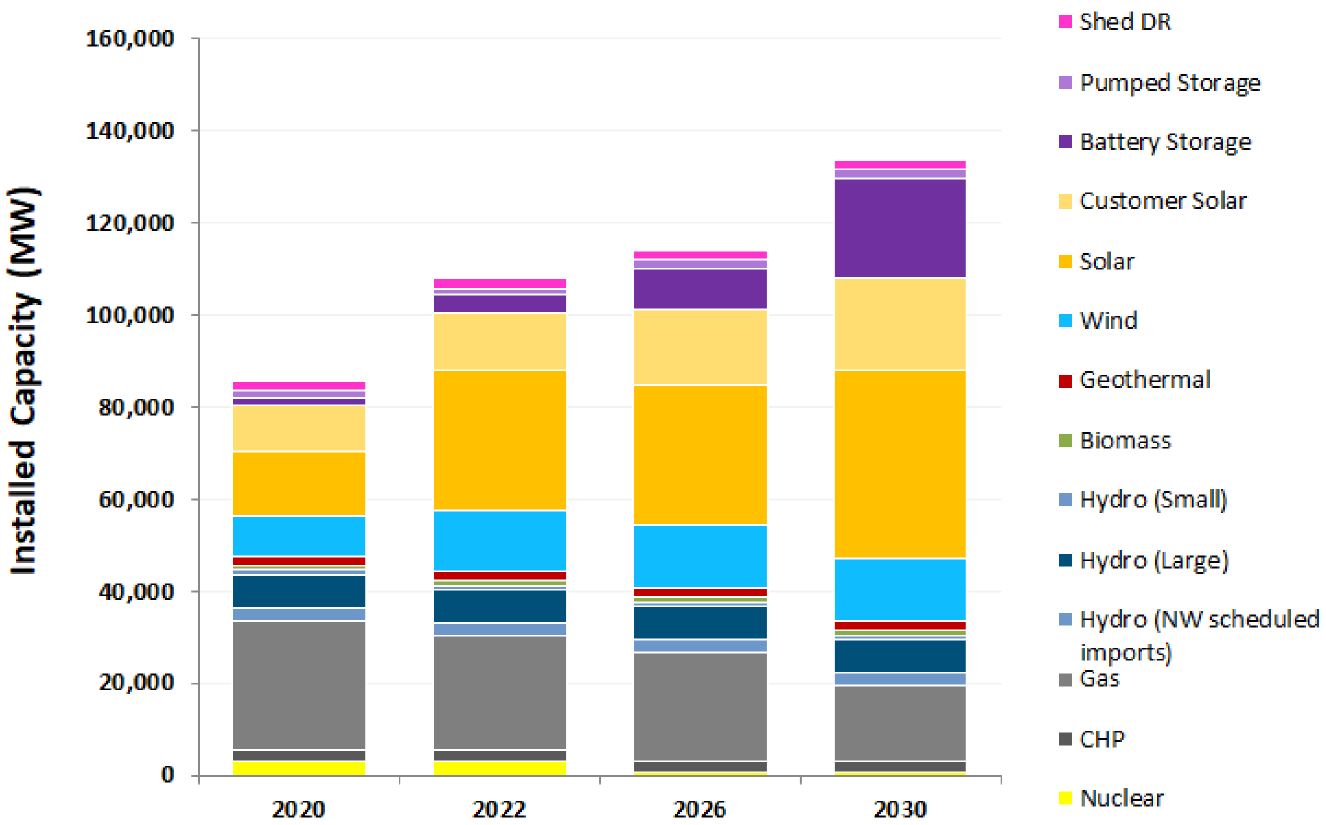
Total Resource Stack: 46 MMT Case



Total Resource Stack: 38 MMT Case



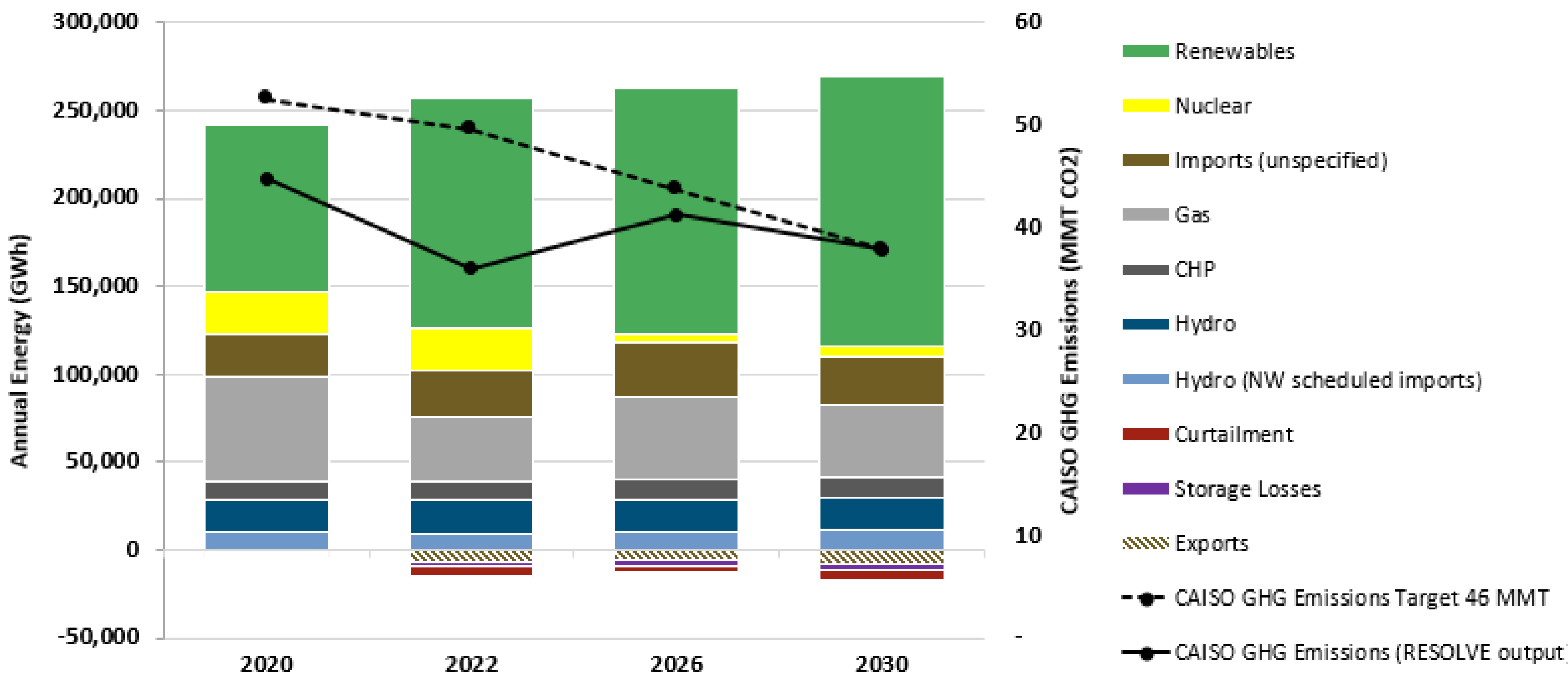
Total Resource Stack: 30 MMT Case



Total Resource Stack in Core Policy Cases

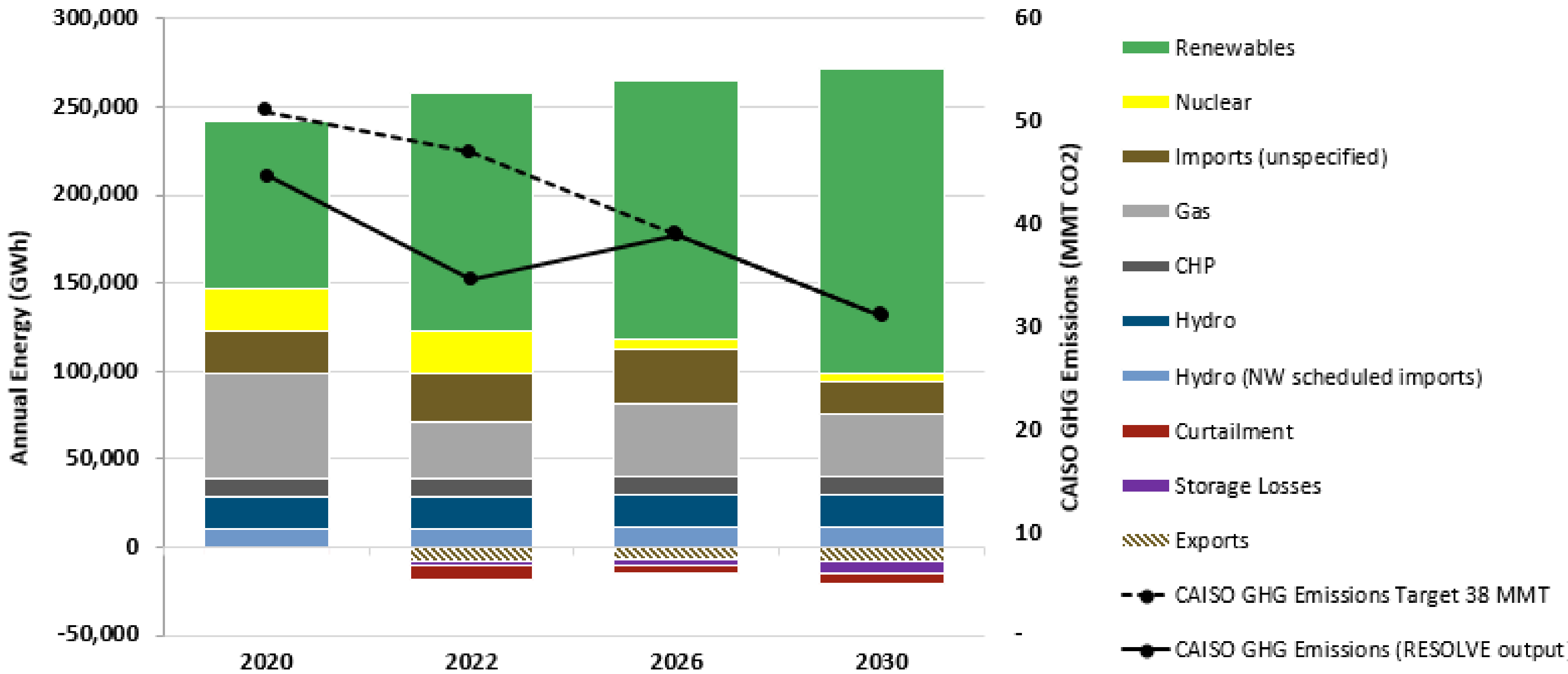
- The previous slides showed installed capacity of both baseline resources and resources selected by RESOLVE.
- RESOLVE's dispatch module uses resource performance information to develop hourly dispatch schedules, resulting in energy production from each resource.
- The following slides show how annual average energy production from different resources to serve CAISO load for the three core policy constraints.
- The GHG target (a RESOLVE *input*), and portfolio GHG emissions (a RESOLVE *output*) are shown for reference.

CAISO Energy Balance
46 MMT Statewide Target



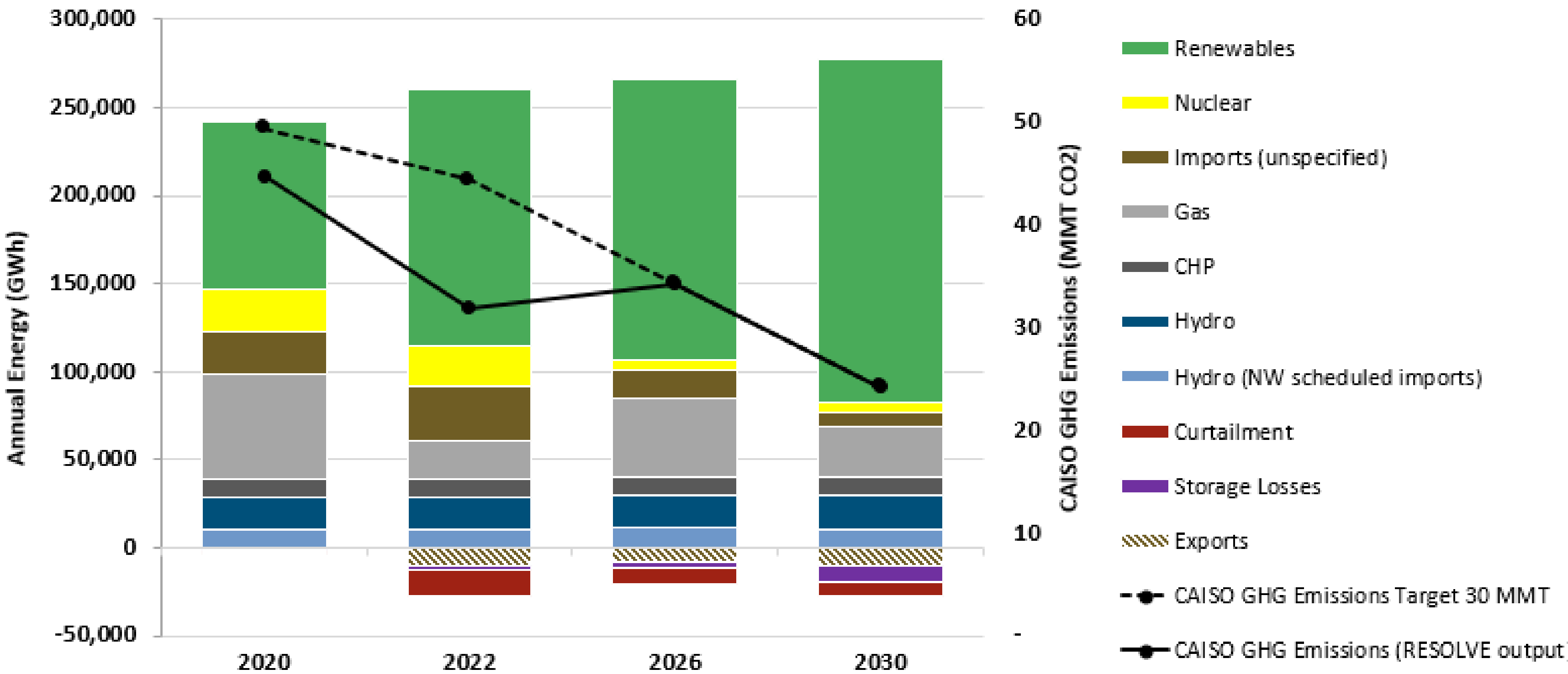
Renewable generation shown on the graph is net of curtailment. Curtailment is also shown separately on the graph to demonstrate its magnitude.

CAISO Energy Balance
38 MMT Statewide Target



Renewable generation shown on the graph is net of curtailment. Curtailment is also shown separately on the graph to demonstrate its magnitude.

CAISO Energy Balance
30 MMT Statewide Target



Renewable generation shown on the graph is net of curtailment. Curtailment is also shown separately on the graph to demonstrate its magnitude.

Energy Balance Observations

- In 2020 and 2022, emissions are lower than the GHG target in all three cases (46, 38, and 30 MMT)
  - Baseline resources in 2020 are sufficient to reduce emissions below the 2020 target
  - Resource additions in 2022, especially solar PV, reduce emissions below 2020 levels, and significantly below the 2022 GHG target
- GHG emissions are higher in 2026 relative to 2022, in large part due to the retirement of Diablo Canyon Power Plant (DCPP)
  - Solar deployment in 2022 increases GHG-free energy available to the system <u>before</u> DCPP retirement, largely due to other factors such as capturing the value of expiring ITC for those solar resources*
- More stringent GHG targets in 2030 (relative to 2026) drive investment in zero-GHG generation and storage, reducing energy production from in-CAISO gas resources and the level of unspecified imports

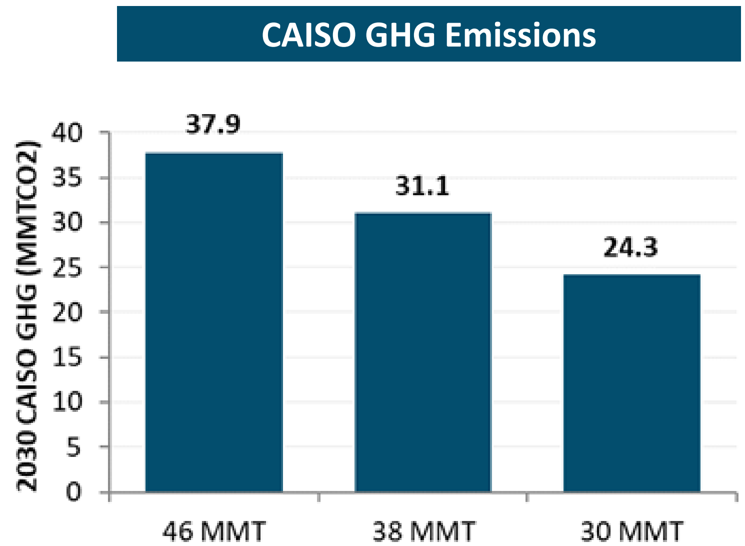
*CPUC Decision (D.)19-04-040, Section 6.3, addresses this topic and the relationship between IRP modeling results, Diablo Canyon retirement, and the adopted 2018 Preferred System Plan in more detail: http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M287/K437/287437887.PDF

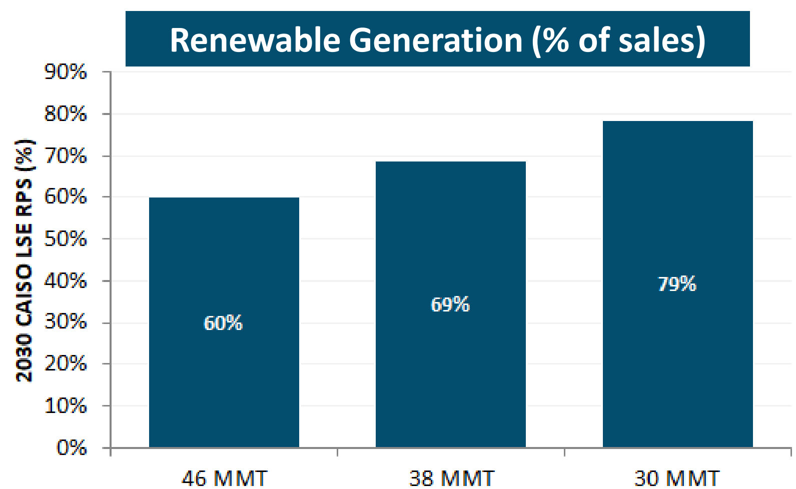
GHG Goals Are Expected to Lead to Reduced Utilization of Fossil Plants

- Expansion of renewable and storage resources in response to GHG planning targets results in lower energy production on a fleet-wide basis from dispatchable gas resources.
- Total gas plant capacity is relatively independent from gas plant usage.
- Dispatchable gas plants can provide power during times when energy-limited resources (solar and storage for example) are not able to produce.
- Under more stringent GHG targets, gas plants are increasingly retained for capacity rather than energy and are dispatched less frequently. Related content in other portions of this presentation:
  - Slide 38, explanation of economic retention functionality in RESOLVE
  - Slide 56, discussion of context of Core Policy Case gas retention in broader context, including 2045
  - Slide 76, description of existing gas generation in the context of 2022 capacity shortfall and increased battery storage penetration

2030 CAISO Renewables & Emissions

- GHG target assumptions are one of the largest drivers of RESOLVE investments.
- All three core GHG cases (46, 38, and 30 MMT) also include a 60% RPS constraint in 2030 and interim RPS targets, per SB100.
  - Each core policy case meets SB100 RPS target.
- The 46 MMT case results in 60% RPS energy, but the RPS target is very close to binding.
- In the 38 and 30 MMT cases, the GHG target drives resource portfolio selection – more than 60% renewables are selected in 2030 as a result of the GHG target.
  - For example, an RPS of ~69% is a byproduct of achieving the 38 MMT carbon goal.





3.2. RELATIONSHIP TO CAPACITY NEEDS

RESOLVE Planning Reserve Margin Constraint

- In each year modeled, RESOLVE imposes a Planning Reserve Margin (PRM) constraint on the total CAISO generation fleet
- Contribution of each resource to the PRM requirement depends on the capabilities of the resource

PRM Requirement
1-in-2 peak x 115%

≤

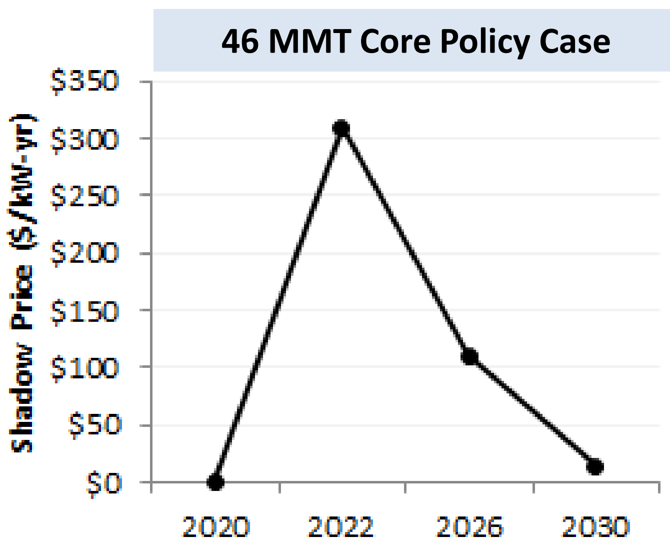
Available Capacity

PRM constraint designed to ensure that sufficient generation capability is available to meet load during system peak conditions

Resource	Basis
Thermal NQC	Based on NQC List
Hydro NQC	Based on NQC List
Solar + Wind ELCC	Calculated in RESOLVE via ELCC surface
Imports	Planning Assumption
Demand Response	Forecast 1:2 peak load impact
Storage	Function of capacity, duration, and penetration

Capacity Need and Price

- RESOLVE's Planning Reserve Margin (PRM) constraint ensures that system resource adequacy needs are met in each period
- If the baseline resource capacity does not meet the 15% PRM target, RESOLVE will build additional resources until the target is met
- The marginal cost of meeting the PRM constraint (the "shadow price") reflects the difficulty of meeting the constraint

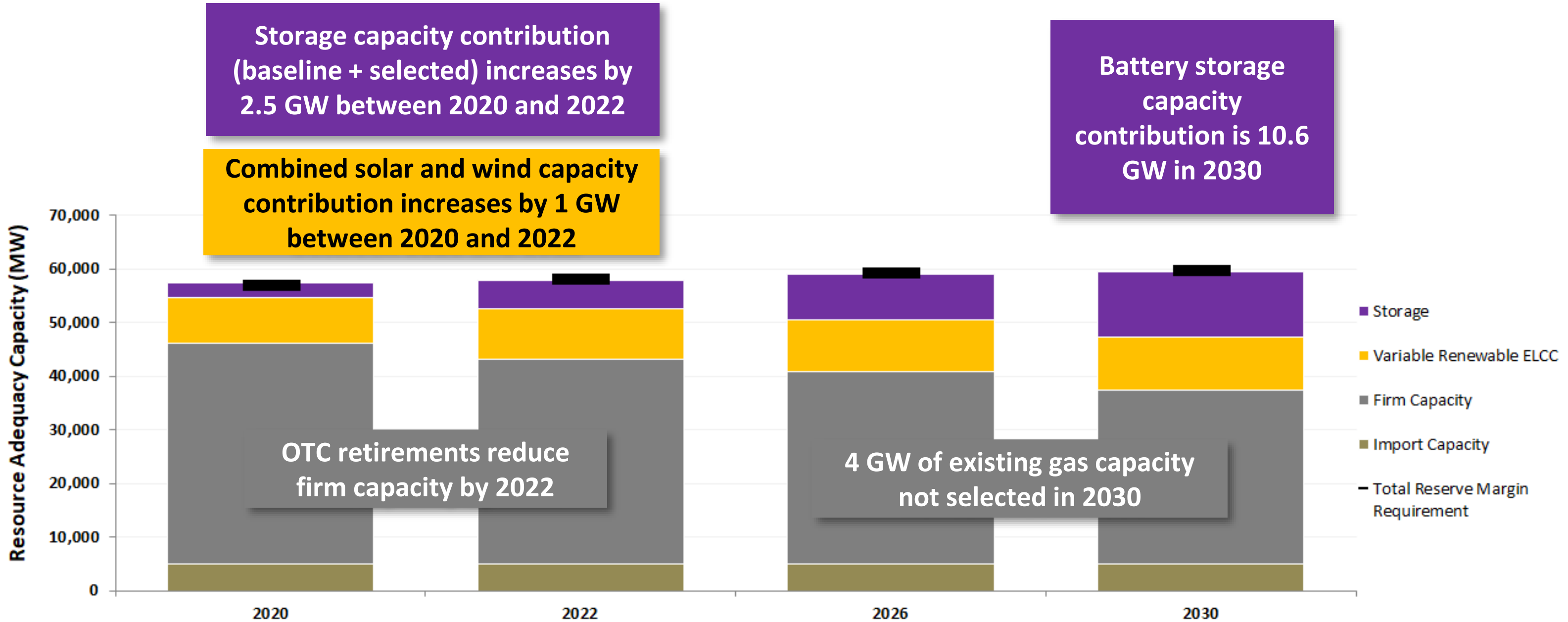


Capacity need in 2022 and 2026 results in high PRM prices that reflect the net capacity cost of building new infrastructure

Lower prices in 2020 and 2030 reflect cost of retaining existing gas resources

Resources to Address Capacity Shortfall: 46 MMT Case

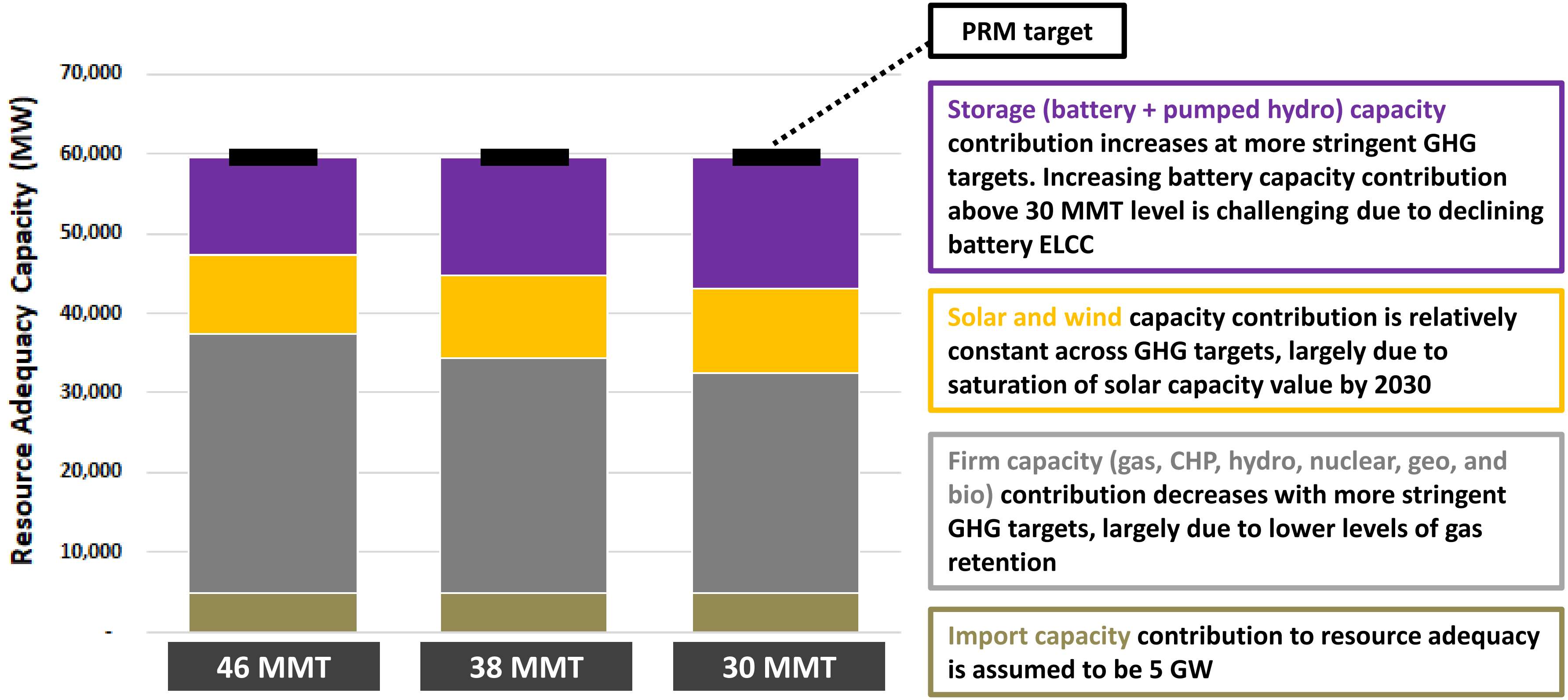
- 2022 capacity shortfall met with predominantly new battery storage and solar resources
- After 2022, marginal solar capacity value is minimal due to resource saturation
- Battery capacity represents large source of new capacity by 2030, with 12.5 GW of batteries (both baseline and selected) providing 10.6 GW of RA capacity
  - Marginal ELCC of 4-hour Li-Ion batteries in 2030 is 65%



Firm Capacity = Gas, CHP, Hydro, Nuclear, Geo, and Bio

Resource Types That Fill 2030 Core Policy Case Resource Adequacy Requirements

- Plot depicts the resource adequacy capacity value of various resource types in 2030. The planning reserve margin target is shown for reference.



Existing Gas Not Selected

- In all core policy cases, the capacity shortfall in 2022 results in <u>all available</u> gas power plants being retained for CAISO ratepayers.
  - OTC plants are retired on current retirement schedule and retention decisions for these plants are not made in RESOLVE.
- In the 46 and 38 MMT cases, all available gas plants are also retained in 2026, in part due to the retirement of 2 GW of capacity from Diablo Canyon Power Plant.
  - The 30 MMT case does not retain ~1 GW of gas in 2026.
- By 2030, RESOLVE selects ~9 – 19 GW of battery storage for the main purpose of shifting solar generation into the nighttime, and the total (baseline + selected) battery storage RA capacity contribution is ~11 – 14 GW.
  - 4 - 8 GW of gas is surplus to CAISO ratepayers as a result.
  - Gas generation dispatch decreases from 2026 to 2030.
  - Level of gas retention is dependent on the capacity value of battery storage in a grid with relatively abundant solar generation.
    - Batteries + solar is an untested reliability paradigm and the combined capacity contribution of these resources has significant uncertainty.
- RESOLVE does not select new gas in core policy cases.

3.3. SUMMARY OF CORE POLICY CASE METRICS

RESOLVE Output: Incremental Total Resource Cost (TRC) to Meet GHG Targets

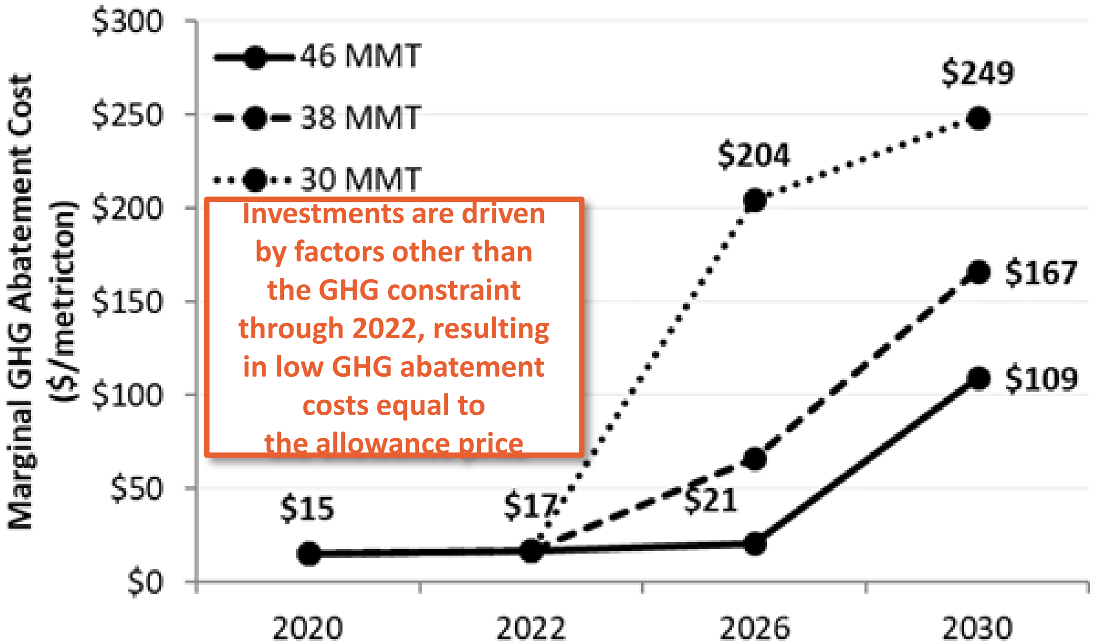
- Relative to the 46 MMT case, incremental cost of the 38 MMT and 30 MMT GHG target is **$0.6 to $1.6 billion per year** respectively
- Primary driver of incremental costs is **new investment in renewables and storage** which displace emissions from thermal generation and unspecified imports

		Incremental TRC ($MM/yr)		
		38 MMT	30 MMT	
Incremental Fixed Costs	*Renewables*	+540	+1,252	Increased investments in zero-carbon renewables and storage are primary driver of incremental costs
	Storage	+404	+959	
	Thermal	-18	-35	No additional thermal resources added to meet GHG goals (retirement amounts vary)
	DR	-28	-30	Lower GHG targets build less Shed DR
	CAISO Transmission	+9	+131	Little new transmission construction
Incremental Variable Costs		-319	-656	Addition of renewables displaces generation from thermal resources, reducing operating costs
Incremental DSM Program Costs		—	—	Because demand-side assumptions are constant between scenarios, incremental costs are zero
Incremental Customer Costs		—	—	
Incremental Total Resource Cost		**+589**	**+1,621**	

GHG Planning Price

- Staff defines the "GHG Planning Price" as the system-wide marginal GHG abatement cost associated with achieving the electric sector GHG emissions targets.
- To determine the GHG Planning Price, Staff relies on the "shadow price" of the GHG constraint in RESOLVE.
  - Within optimization modeling, the "shadow price" of a constraint is the change in the objective function if that constraint is relaxed by one unit and is frequently interpreted as the marginal cost to meet that constraint.
- Because RESOLVE captures the financial cost of allowances under the cap & trade in its objective function, the shadow price alone does not reflect the full marginal cost of GHG abatement.
  - The assumed allowance cost increases the cost to combust fossil fuels, reducing the apparent cost premium of carbon-free resources (and, by extension, the shadow price).
- Therefore, Staff calculates the GHG Planning Price as the sum of RESOLVE's GHG shadow price and the assumed cost of allowances under cap & trade.
- In 2017-18 IRP, the GHG Adder adopted in D.18-02-18 and currently used in the IDER proceeding was derived partially from the GHG Planning Price.

RESOLVE Output: Marginal GHG Abatement Cost in Core Policy Cases



In <u>38 MMT</u> and <u>30 MMT</u> case, the GHG constraint first becomes a main driver of new investments in 2026, and marginal cost of carbon abatement increases quickly thereafter as marginal GHG reductions become more expensive

In <u>46 MMT</u> case, the GHG abatement cost only becomes large in 2030

- GHG abatement cost curves reflect the selection of increasingly higher-cost resources to reduce increasingly more GHG emissions.
- The total marginal cost of GHG abatement (or "GHG Planning Price") is estimated by adding the assumed allowance cost to the GHG shadow price.
  - 2030 marginal abatement cost in 30 MMT scenario: $223 +$25 = **<u>$249/metric ton</u>** (rounded up)
  - 2030 marginal abatement cost in 46 MMT scenario: $84 + $25 = **<u>$109/metric ton</u>**

Summary Metrics for 46 MMT, 38 MMT and 30 MMT Portfolios in 2030

Metric	46 MMT Case	38 MMT Case	30 MMT Case
CAISO GHGs	**37.9**	**31.1**	**24.3**
Selected Resources (by 2030)	• 2.4 GW wind • 12.6 GW solar PV • 9.3 GW battery storage • 440 MW shed DR	• 4.2 GW wind • 18.6 GW solar PV • 13.9 GW battery storage • 40 MW shed DR	• 230 MW geothermal • 4.7 GW wind • 26 GW solar PV • 18.6 GW battery storage • 370 MW pumped storage
Gas Capacity Not Retained	**3.6 GW**	**6.4 GW**	**8.6 GW**
Selected Renewables *(on existing Tx)*	**15 GW**	**22.7 GW**	**30.9 GW**
Levelized Total Resource Cost (TRC)	**$46.3 billion/yr**	**$46.9 billion/yr**	**$47.9 billion/yr**
Incremental TRC *(relative to 46 MMT Case)**	-	***$589 million/yr****	***$1.6 billion/year****
Marginal GHG Abatement Cost	**$109/metric ton**	**$166/metric ton**	**$248/metric ton**
System Planning Reserve Margin	**15%**	**15%**	**15%**

*The incremental TRC results are calculated relative to the Default Case. All other results are total, not incremental.

Comparison of 2019 Preliminary 46 MMT to 2018 PSP: Summary Metrics

Metric	2018 Preferred System Plan	2019 Preliminary 46 MMT Case
CAISO GHGs (BTM CHP GHGs excluded)	**34 MMT**	**32.4 MMT**
Selected Resources (by 2030)	• **2.2 GW wind** • **5.9 GW solar PV** • **2.1 GW battery storage** • **1.7 GW geothermal**	• **2.4 GW wind** • **12.6 GW solar PV** • **9.3 GW battery storage** • **440 MW shed DR**
Selected Renewables *(on existing Tx)*	**9.8 GW**	**15 GW**
Levelized Total Resource Cost (TRC)	**$44.5 billion/yr**	**$46.3 billion/yr**
Marginal GHG Abatement Cost	**$219/metric ton**	**$109/metric ton**
System Planning Reserve Margin (resulting from addition of new resources)	**22%**	**15%**

- 2018 PSP assumed ~2x the RA import capacity of the 2019 Preliminary RSP and did not include economic gas retention (retained all available gas through 2030)
- Cost projections of solar PV and batteries are roughly half of 2017 IRP assumptions
- There are different underlying load and baseline assumptions between the two cases
- Updated BTM CHP assumptions result in a slightly more stringent GHG target

3.4. SENSITIVITY CASE RESULTS

Sensitivity Definitions

Sensitivity	Description
Reference	Core Policy Case
New OOS Tx	Out-of-state resources on new transmission available
Low OOS Tx Cost	Out-of-state resources on new transmission available with 25% lower out of state transmission costs than default
High OOS Tx Cost	Out-of-state resources on new transmission available with 25% higher out of state transmission costs than default
High Solar PV Cost	Higher projections of future solar PV cost
PV ITC Extension	30% Investment Tax Credit (ITC) for solar PV is maintained indefinitely
High Battery Cost	Higher projections of future battery cost
Paired Battery Cost	Li-Ion battery costs are reduced due to ITC benefits and shared infrastructure from co-locating
Low RA Imports	2 GW of RA import capacity assumed
High RA Imports	Maximum (10.2 GW) RA import capacity assumed
2045 End Year	Core Policy Cases are run with 2045 as end year
High Load	High IEPR baseline load trajectory assumed

RESOLVE Output:
Impact of Sensitivities on Incremental Cost

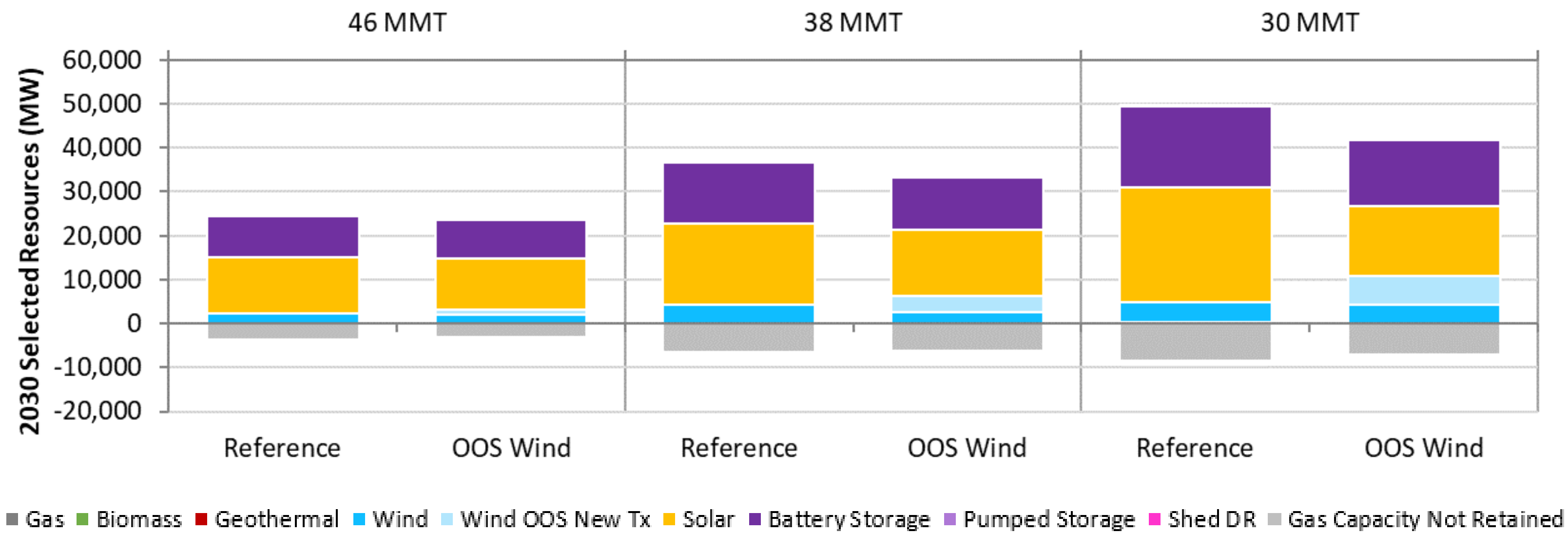
"Incremental TRC" calculated relative to 46MMT Reference case (highlighted in orange)

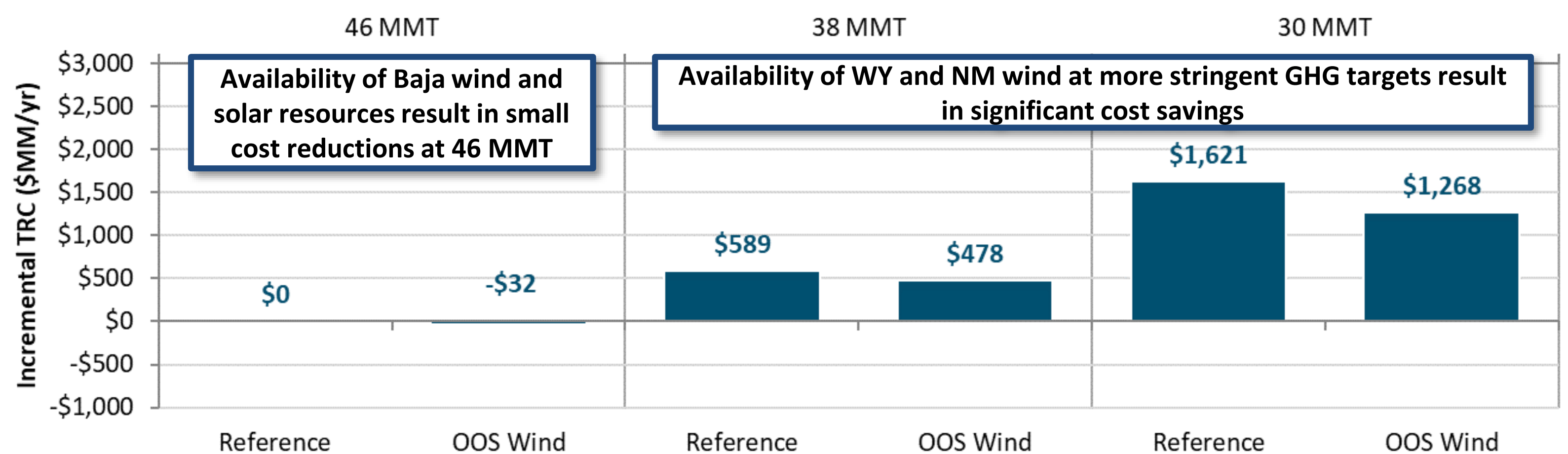
"Change from Reference" calculated relative to corresponding "Reference" case

	Incremental Cost ($MM/yr)			Change from Reference ($MM/yr)		
Sensitivity	**46 MMT**	**38 MMT**	**30 MMT**	**46 MMT**	**38 MMT**	**30 MMT**
Reference	**$0**	**$589**	**$1,621**			
Low RA Imports	$294	$840	$1,833	**+$294**	**+$252**	**+$212**
High RA Imports	-$141	$563	$1,579	**-$141**	**-$26**	**-$42**
Paired Battery Cost	-$461	$88	$1,008	**-$461**	**-$501**	**-$613**
High Battery Cost	$602	$1,451	$2,634	**+$602**	**+$862**	**+$1,013**
PV ITC Extension	-$330	$297	$1,152	**-$330**	**-$292**	**-$469**
High PV Cost	$614	$1,351	$2,441	**+$614**	**+$762**	**+$819**
Low OOS Tx Cost	-$37	$362	$1,125	**-$37**	**-$227**	**-$496**
New OOS Tx	-$32	$478	$1,268	**-$32**	**-$111**	**-$353**
High OOS Tx Cost	-$30	$513	$1,412	**-$30**	**-$76**	**-$209**
High Load	$793	$1,533	$2,608	**+$793**	**+$944**	**+$987**

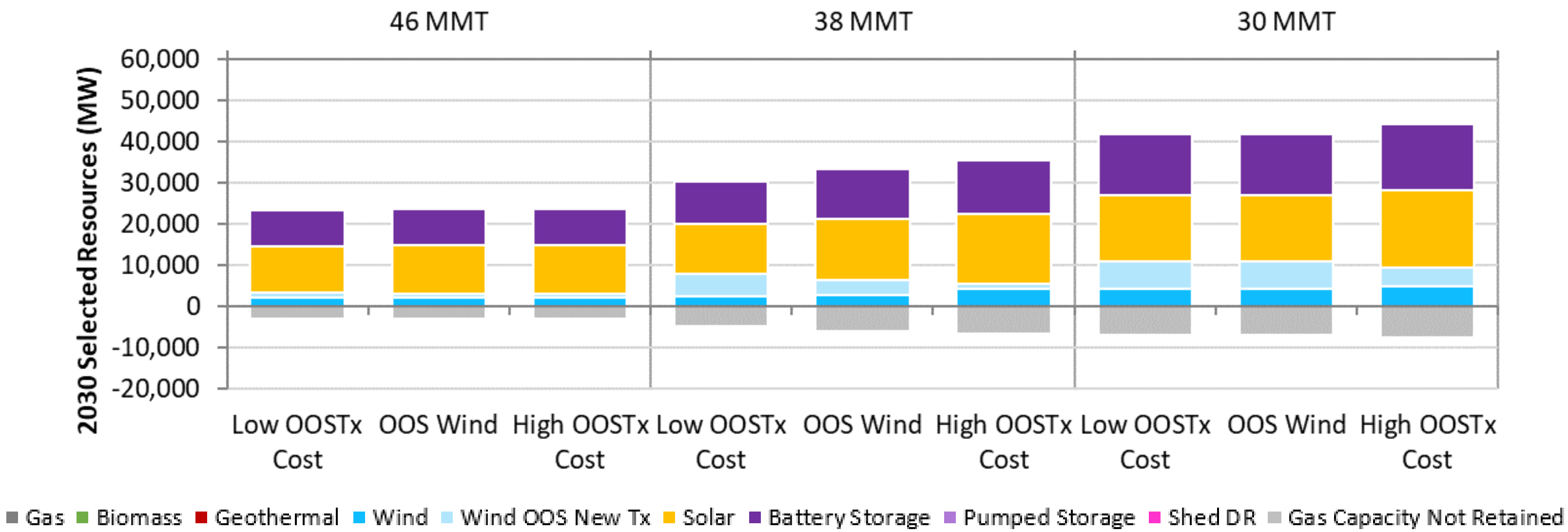
3.5. TRANSMISSION SENSITIVITIES

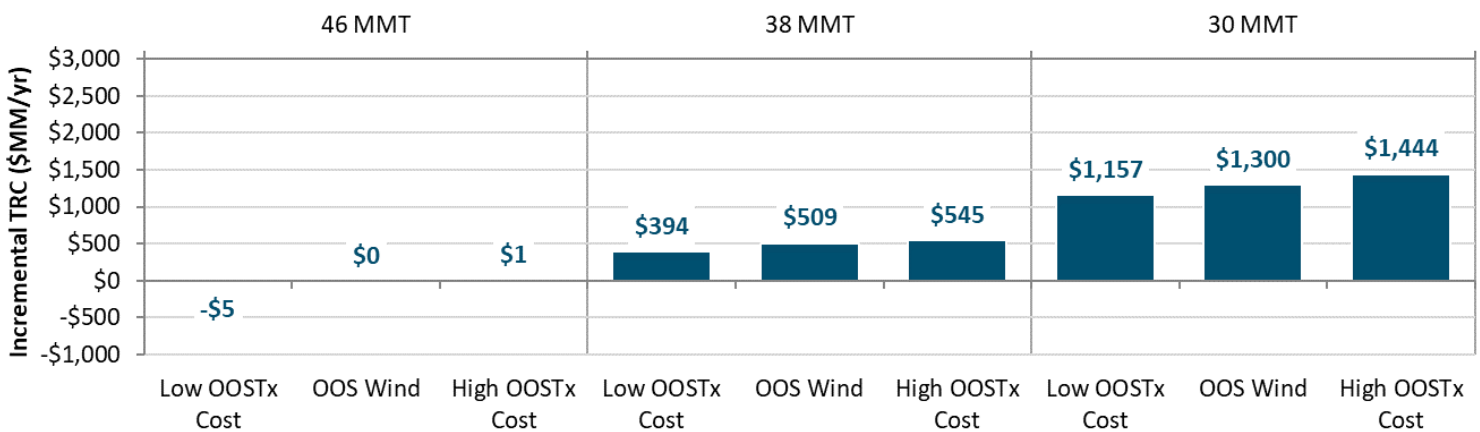
New Out of State Transmission Sensitivity





New Out of State Transmission Cost Sensitivities





New Out of State Transmission Conclusions

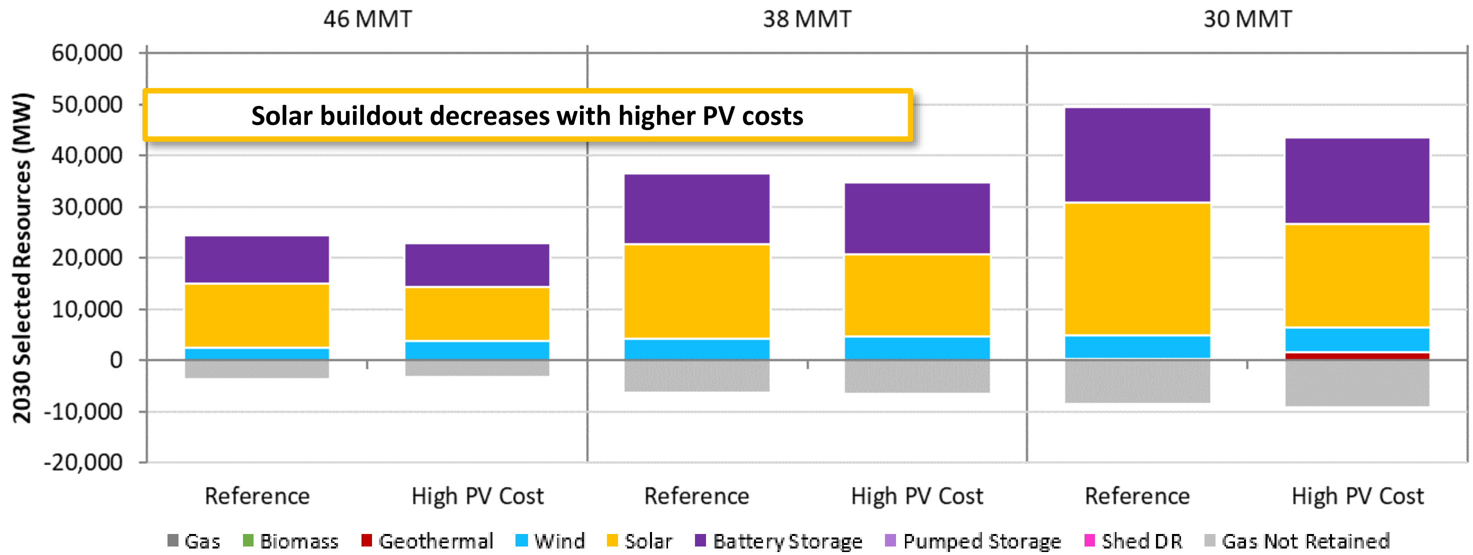
- Out of state resources on new transmission, if available as candidate resources, are selected at all GHG targets. Most resources selected are wind, but Baja solar is also selected.
  - Baja wind and solar are selected under the 46 MMT target, resulting in modest cost savings.
  - 38 MMT target selects 2.4 GW of New Mexico wind in addition to Baja resources.
  - 30 MMT target selects substantial capacity of New Mexico (3.1 GW) and Wyoming (2.4 GW) wind, as well as 1.1 GW of Baja wind, totaling ~7 GW of OOS wind on new transmission.
- The capacity of OOS wind on new transmission selected is sensitive to transmission cost assumptions, especially at the intermediate GHG target of 38 MMT.
- Under a 30 MMT target, 5 GW of OOS wind is selected by 2030 even if transmission costs are higher than expected.
- Further updates to the transmission zone representation in RESOLVE may change which OOS resources are selected.

3.6. COST SENSITIVITIES

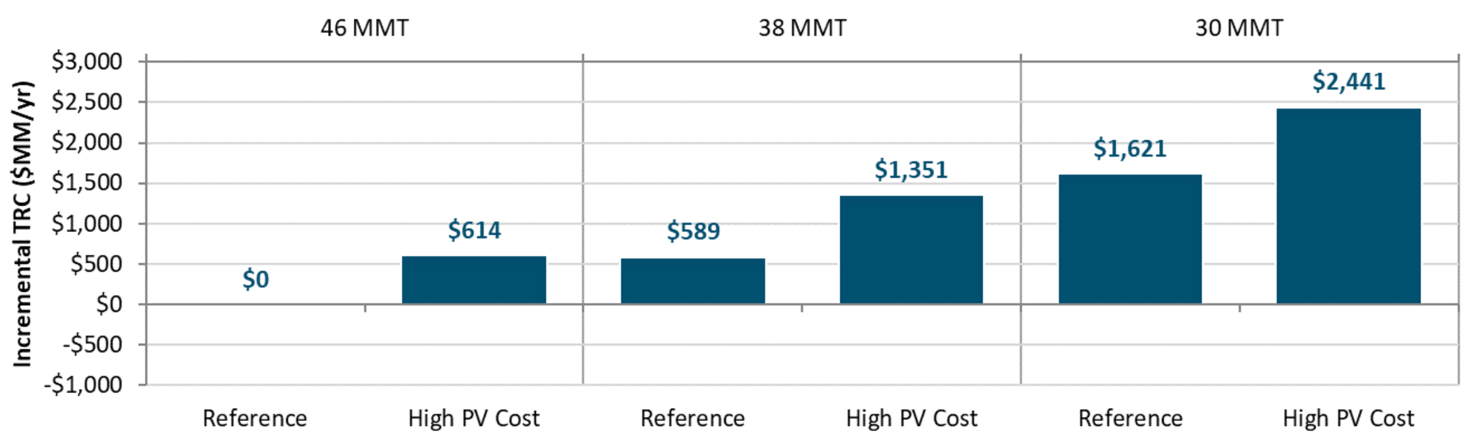
Cost Sensitivities

- Solar cost sensitivities:
  - **High PV Cost**: NREL ATB high solar PV costs are used in place of NREL ATB mid costs
  - **ITC Extension**: 30% Investment Tax Credit (ITC) for solar PV is maintained indefinitely
    - By default, Solar ITC drops from 30% to 10% for utility scale PV in the early 2020s
- Battery cost sensitivities:
  - **High Cost:** High costs from Lazard 4.0 and NREL Solar + Storage Study for both Li-Ion and Flow batteries
  - **Paired Battery Costs:** Li-Ion battery costs are reduced due to shared infrastructure from co-locating with other resources (likely solar) and are eligible for the solar ITC tax credit through the early 2020s (e.g., “hybrid” battery resources).
    - Note: additional operational constraints are not imposed on battery charging and discharging in this sensitivity. ITC charging requirements and operational constraints resulting from pairing would reduce the value of pairing relative to what is depicted herein.

Solar Cost Sensitivities: High PV Cost

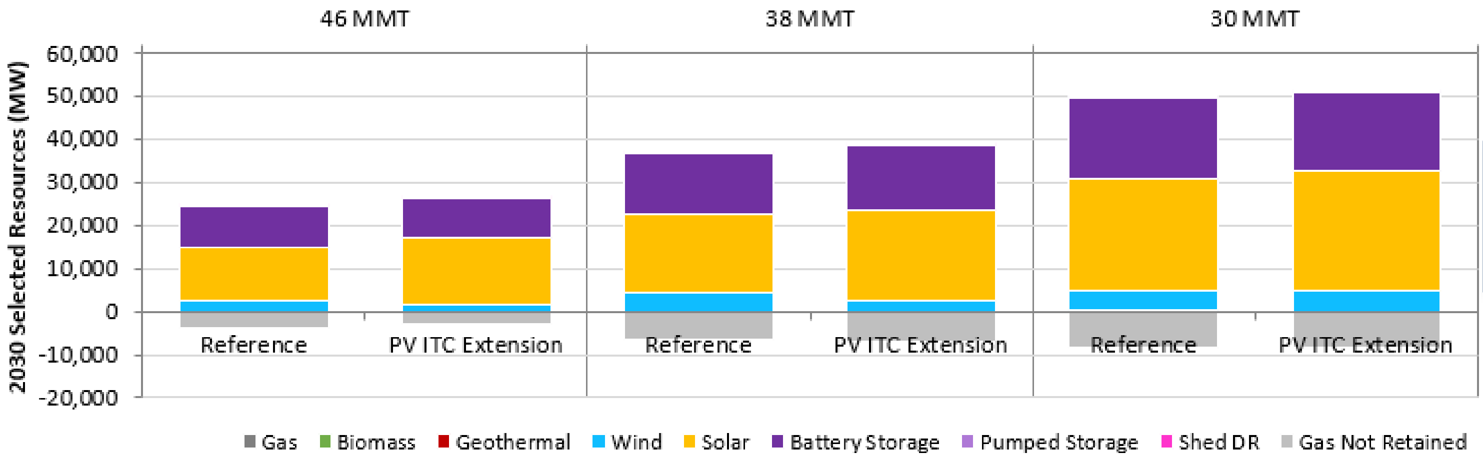


Geothermal (1.7 GW) included in portfolio if solar costs are higher than reference

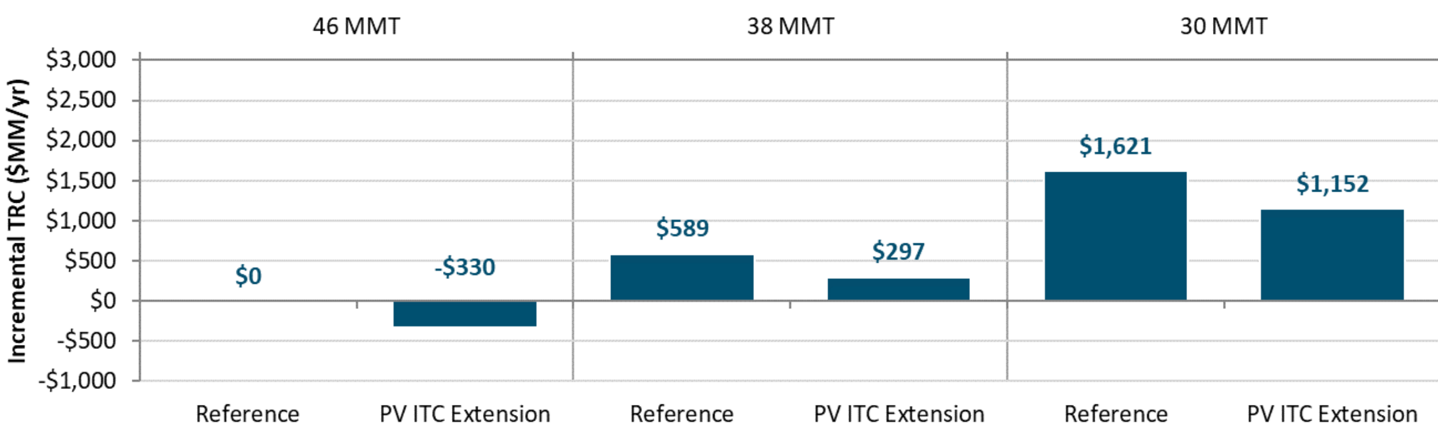


Solar resources are more expensive, resulting in cost increases relative to Reference

Solar Cost Sensitivities: PV ITC Extension

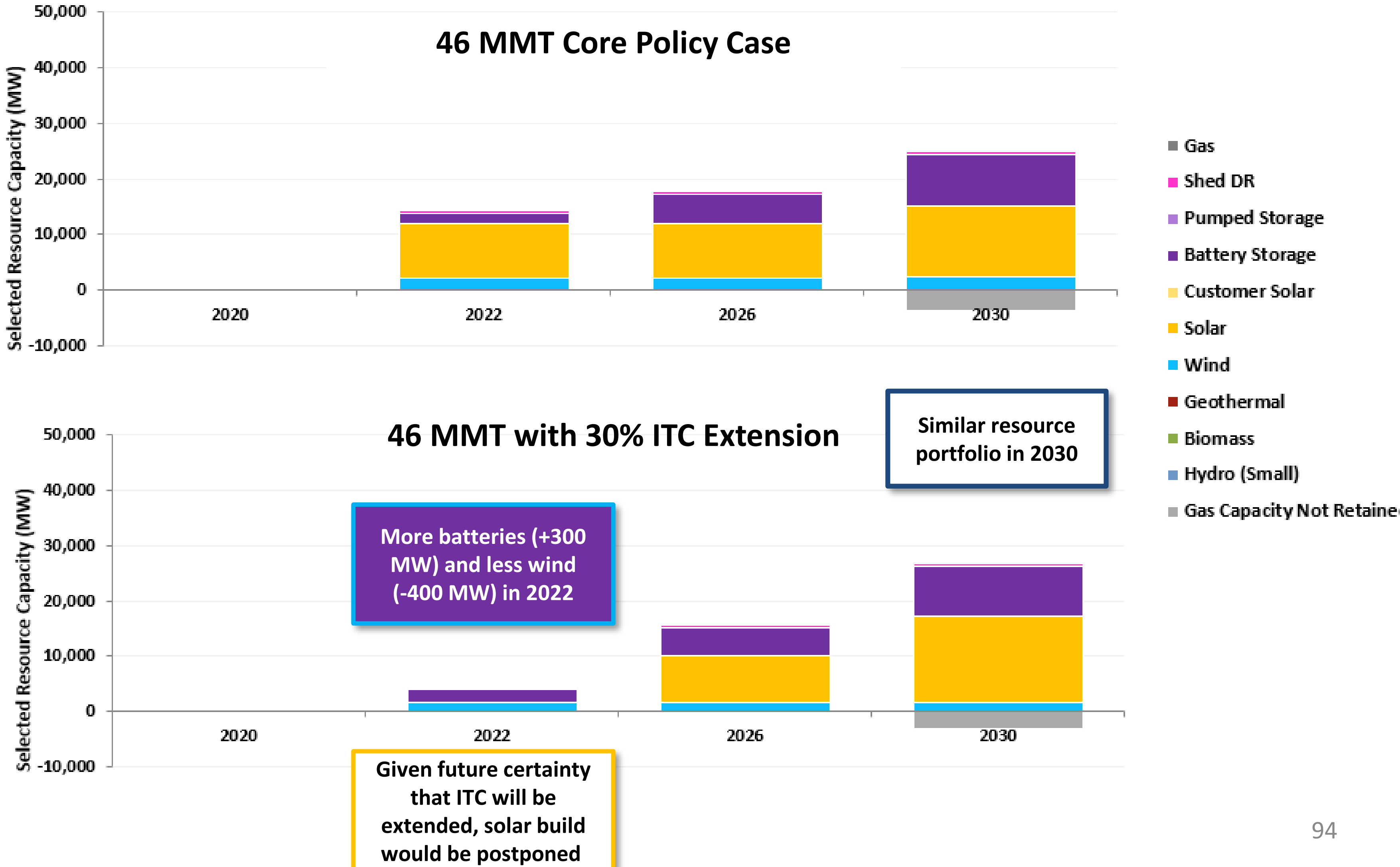


2030 Resources portfolios similar with and without ITC extension



Costs decrease with ITC extension because lower cost solar is available through 2030

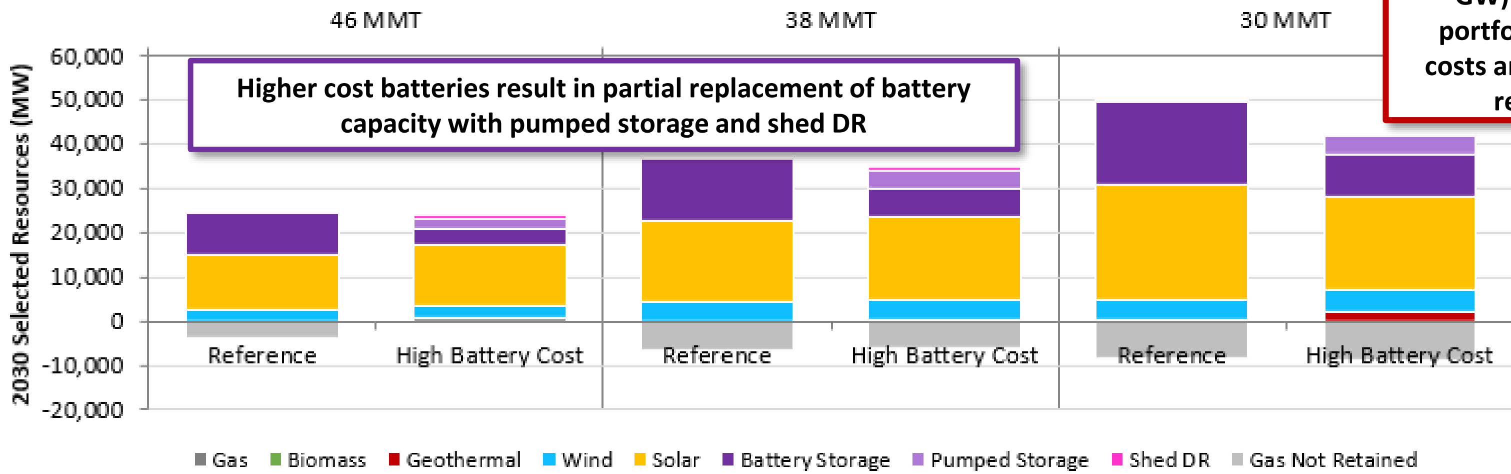
Solar Cost Sensitivities: PV ITC Extension, Comparison with 46 MMT Core Policy Case

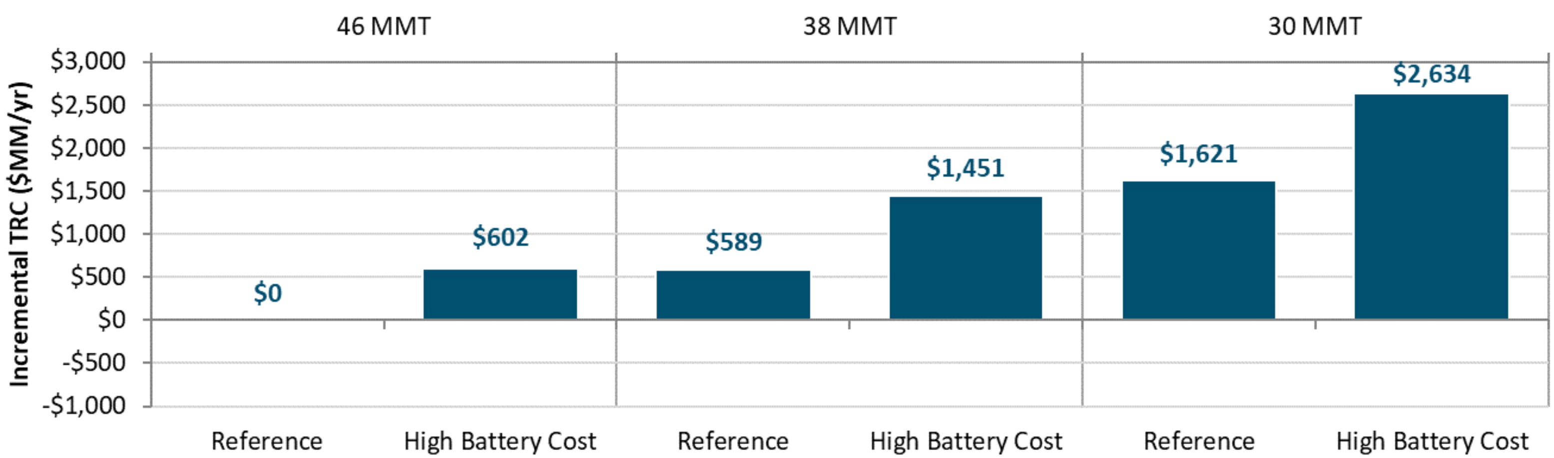


Battery Cost Sensitivities: High Cost

Geothermal (2.2 GW) included in portfolio if battery costs are higher than reference

Higher cost batteries result in partial replacement of battery capacity with pumped storage and shed DR

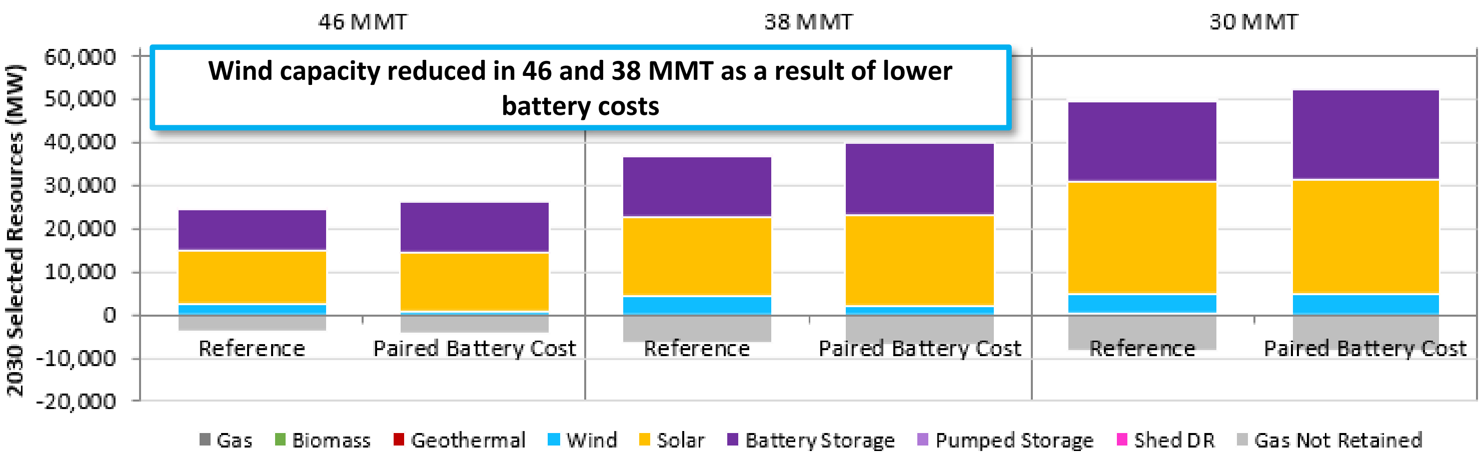


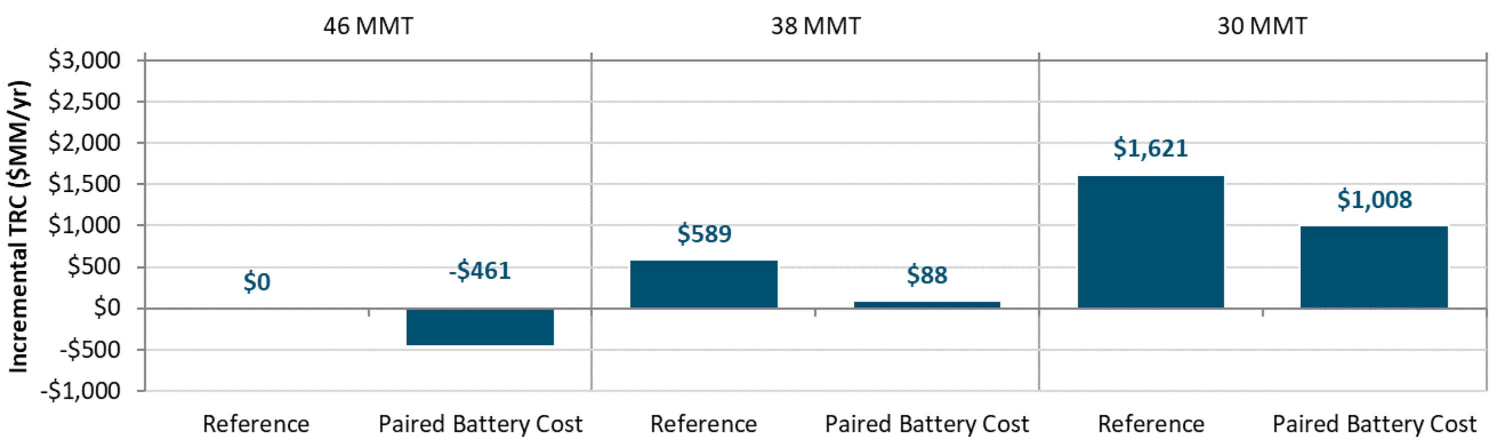


More expensive batteries result in higher system costs

Battery Cost Sensitivities: Paired Battery Costs

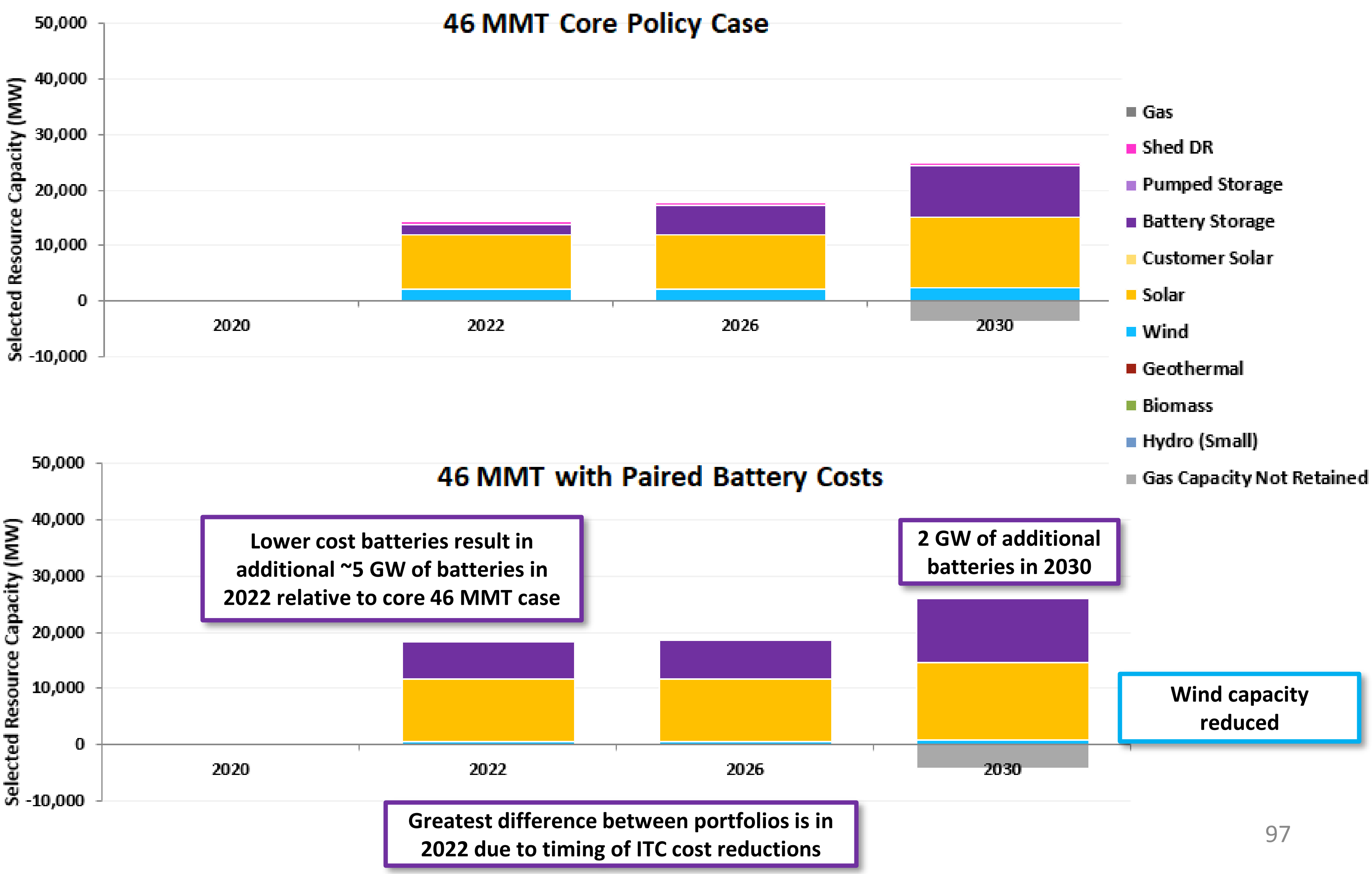
Reduced battery costs from pairing results in modest increases in 2030 battery capacity





Costs decrease with paired battery costs, especially for near-term battery installations.
As shown on next slide, near-term ITC cost reductions drive earlier installation of batteries.
ITC-driven cost reductions are an upper bound due to the lack of charging constraints.

Battery Cost Sensitivities: Paired Battery Costs, Comparison with 46 MMT Core Policy Case



Cost Sensitivities Conclusions

- Under more ambitious GHG targets, higher solar or battery costs result in a more diverse portfolio of resources
  - Geothermal is included in the 30 MMT portfolio if either solar or battery costs are higher than expected
  - Higher cost batteries result in partial replacement of battery capacity with pumped storage and shed DR
- Extension of the Investment Tax Credit delays solar build relative to Reference case, but results in similar 2030 portfolios
- Lower battery costs result in higher near-term buildout of batteries to capture ITC savings from pairing

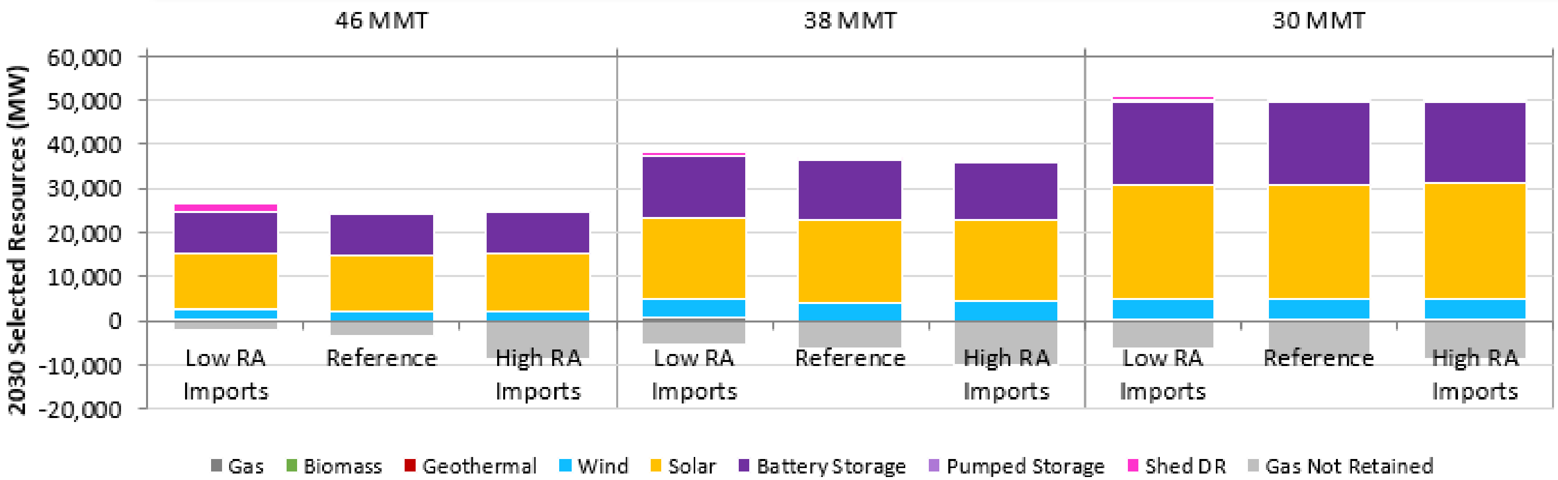
3.7. RESOURCE ADEQUACY AND LOAD SENSITIVITIES

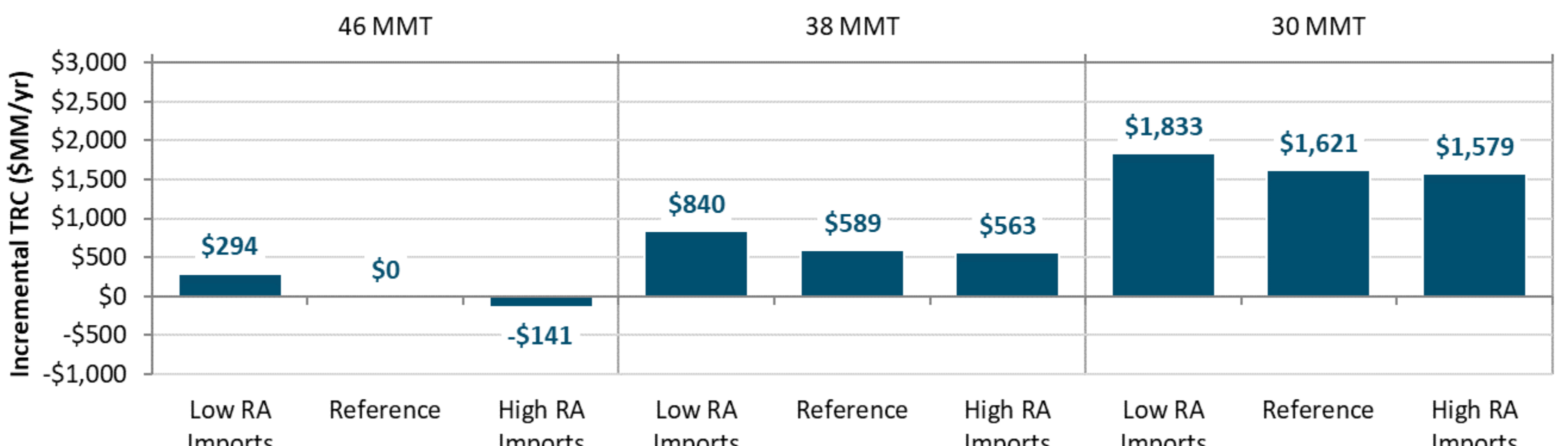
Resource Adequacy and Load Sensitivities

- Sensitivities in this section are grouped together due to their potential impact on the planning reserve margin
- RA Imports Sensitivities:
  - Resource adequacy contribution of imports is assumed to be 5 GW by default but the changing load and resource balance outside CAISO make this value uncertain
  - In sensitivities, import RA contribution is increased or decreased across the entire modeling horizon (2020 – 2030) to:
    - Low RA import – 2 GW
    - High RA import - 10.2 GW
- 2045 End Year Sensitivity:
  - Cases run through 2030 – but not further – may result in sub-optimal resource portfolios if the magnitude and timing of electricity demand changes drastically after 2030
  - The 2045 end year sensitivity adds a single 2045 period onto the core policy cases. Electricity demand and GHG targets in 2045 are consistent with the CEC Deep Decarbonization High Biofuels case
- High Load
  - Core policy cases use the IEPR Mid load forecast. Faster economic and/or demographic growth may result in higher baseline load than is found in the IEPR Mid forecast
  - The High Load sensitivity use the IEPR High baseline load forecast through 2030, but does not vary other components of the load forecast (energy efficiency, electric vehicles, etc.)

Imports Sensitivities

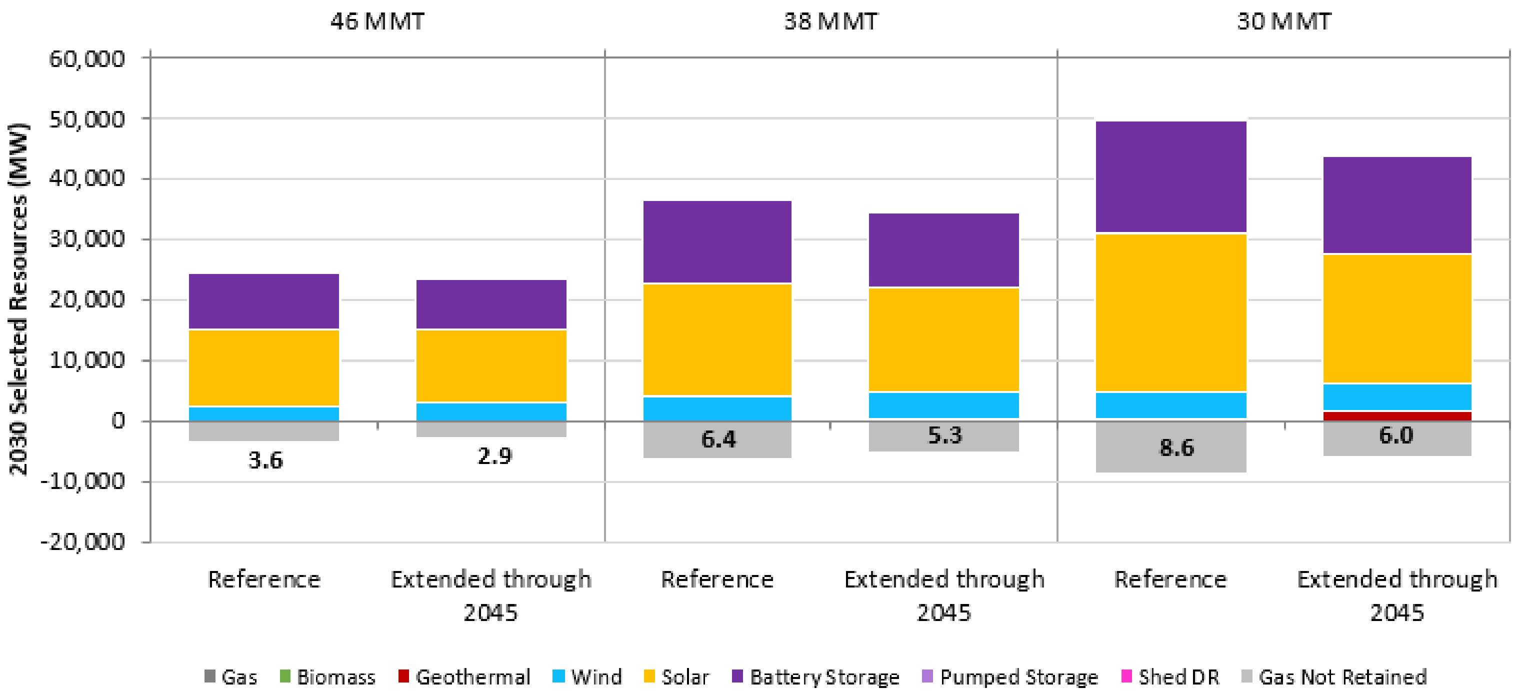
Lower available RA import capacity results in higher levels of gas retention





Lower levels of available RA import capacity can result in selection of additional and/or more expensive resources to meet resource adequacy requirements, potentially increasing costs to CAISO ratepayers.
Note: cost of contracting with OOS resources for resource adequacy not included in optimization. As a result, the cost differences shown here represent an upper bound.

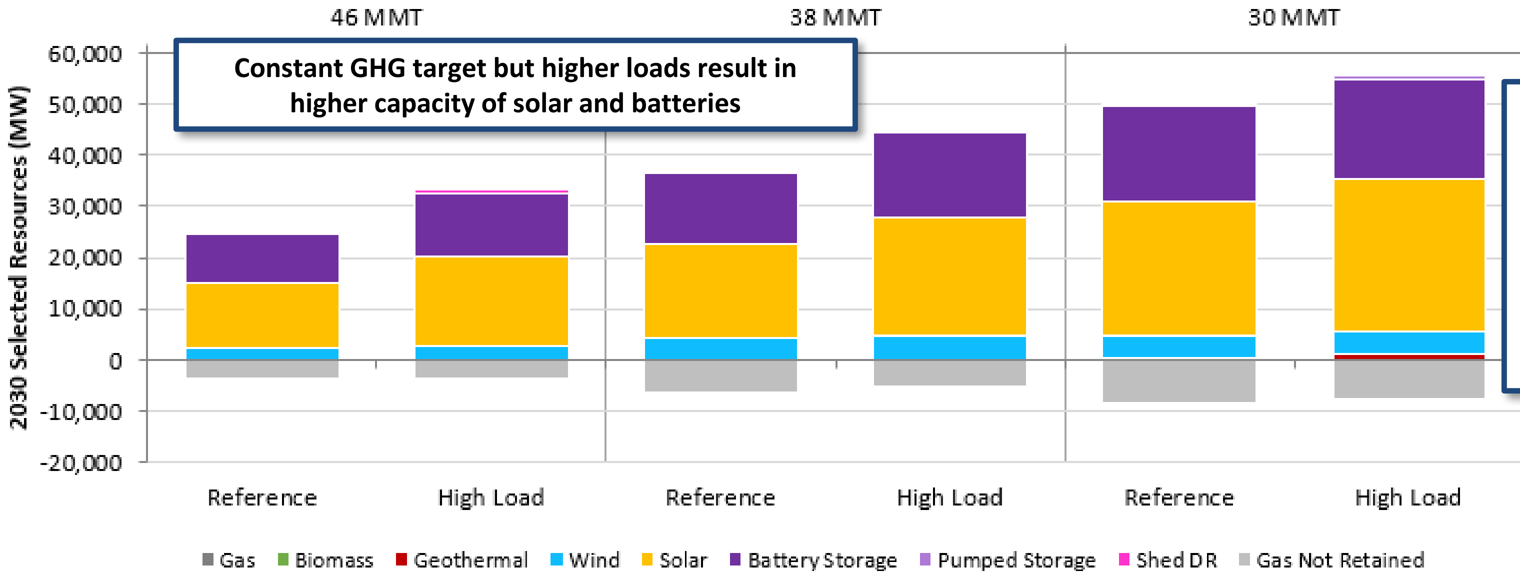
2045 End Year Sensitivity



An additional ~1 - 2.5 GW of gas retained if case is extended through 2045

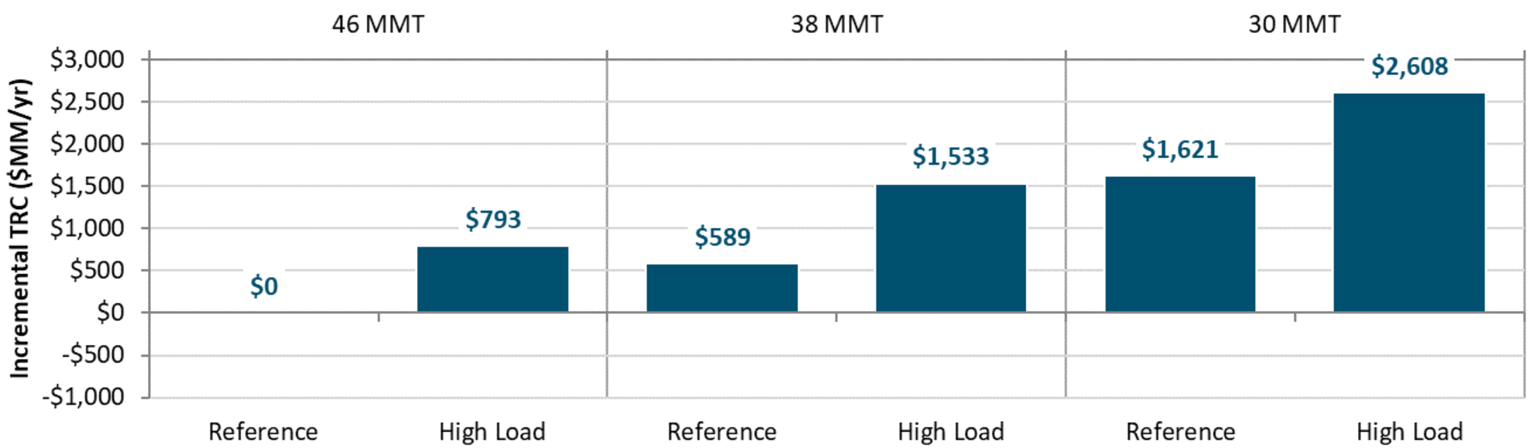
Post-2030 load and GHG targets can significantly impact 2030 portfolio. Gas retention in 2030 is higher across all 2030 GHG targets if 2045 is considered.
The 2045 End Year Sensitivity includes loads that are broadly consistent with the 2045 High Biofuels Framing Study. Loads in the High Biofuels scenario are lower than the other two framing study scenarios. Is likely that more gas capacity would be retained under higher load levels, which would increase the difference in gas retention between the 2030 core policy cases and cases that include a 2045 end year.

High Load



Constant GHG target but higher loads result in higher capacity of solar and batteries

Geothermal and pumped storage selected under higher load projections and a 30 MMT target



Higher load projections result in higher total resource cost because more load must be served while meeting the same GHG target.

Resource Adequacy and Load Sensitivities Conclusions

- Lower available RA import capacity results in higher levels of gas retention and selection of additional and/or more expensive resources to meet reliability requirements
- Higher demand results in more solar and battery capacity under the 46 MMT and 38 MMT GHG targets
- Under more ambitious GHG targets, higher demand results in a more diverse portfolio of resources
- Higher load projections result in higher total resource cost because more load must be served while meeting the same GHG target
- Extending the analysis timeframe past 2030 results in higher levels of gas plant retention

4. 2045 FRAMING STUDY

Purpose of SB100 2045 Framing Study

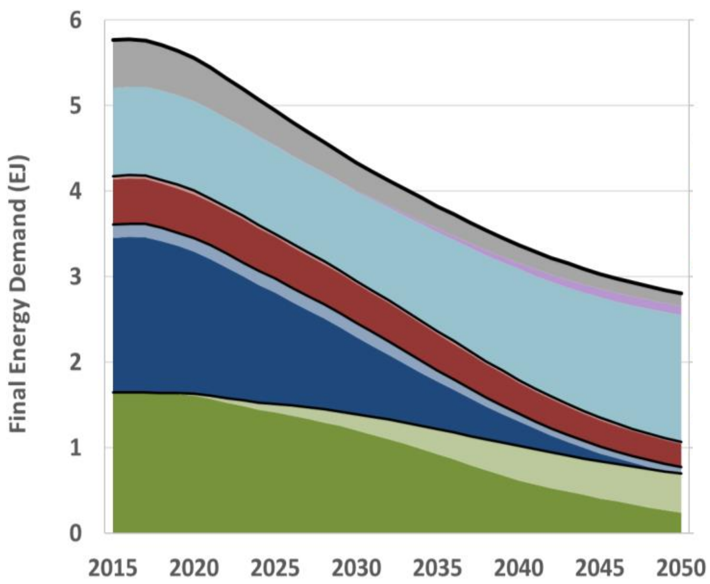
- Explore how 2045 goal under SB100 could affect the outlook for electricity sector GHG emissions and resource planning in the 2030 timeframe.
- Provide analysis that includes context from other sectors.
- Inform Commission decision-making around the appropriate 2030 GHG planning target for CPUC-jurisdictional LSEs, as the Reference System Portfolio to meet that target.
- Primarily <u>informational</u> and <u>directional</u> regarding least-regrets investments needed by 2030.

SB100 2045 Framing Study Scenarios

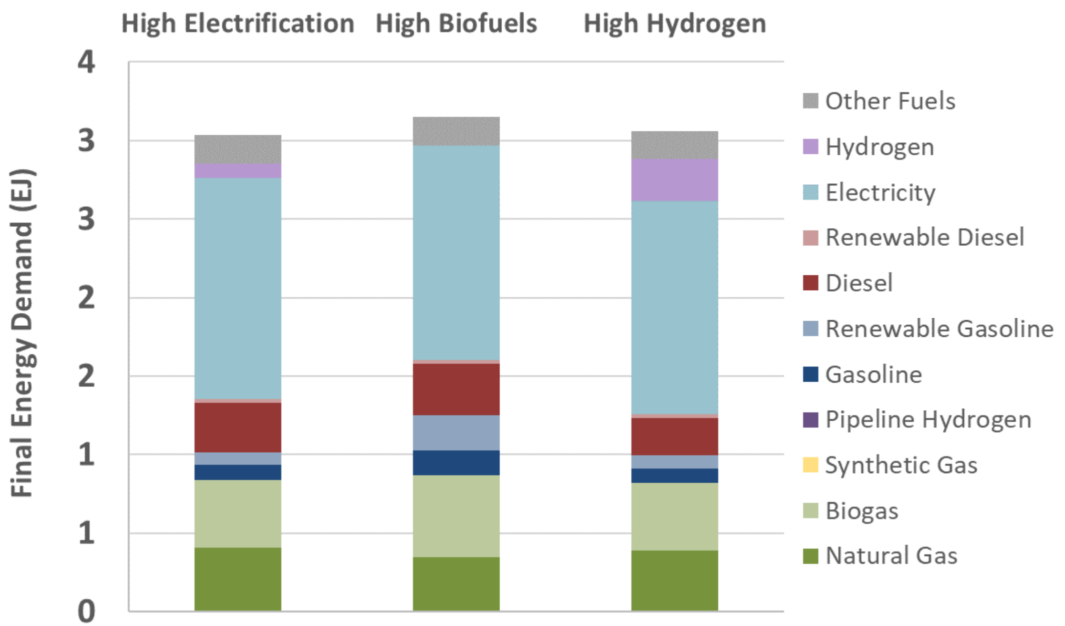
- While the CPUC IRP focuses on infrastructure decisions between present day and 2030, some near-term decisions may depend on changes to the electricity sector that result from post-2030 economy-wide decarbonization.
- Three scenarios are explored in the 2045 Framing Studies that reflect different decarbonization strategies in the CEC Deep Decarbonization report:
  - High Electrification
  - High Biofuels
  - High Hydrogen
- The three scenarios have the same economy-wide GHG constraint of 86 MMT by 2050 (80% below 1990).
- The electric sector GHG emissions target and electricity loads vary by scenario and are a product of complex cross-sectoral interactions within each scenario. Electricity-sector GHG emissions and electric loads by sector are outputs of the PATHWAYS model.

Final Energy Demand by Fuel, Statewide

High Electrification



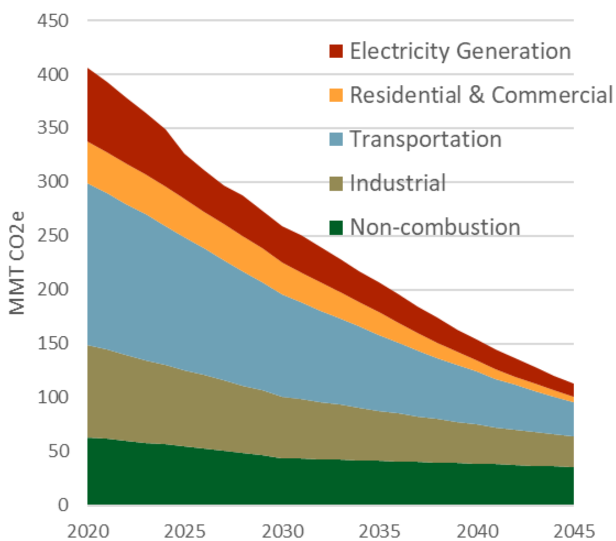
2045 – Comparison Between Scenarios



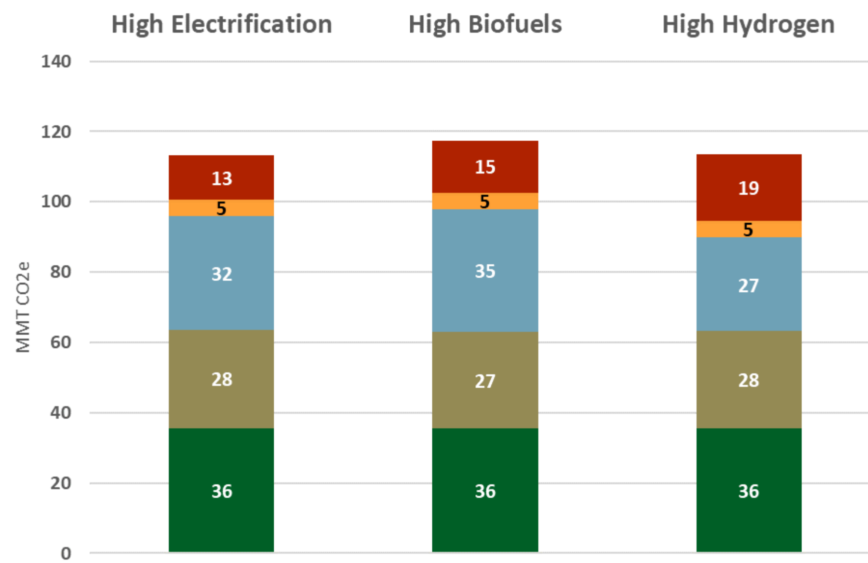
- Demand for electricity, hydrogen and biofuels varies by scenario

GHG Emissions by Sector, Statewide

High Electrification



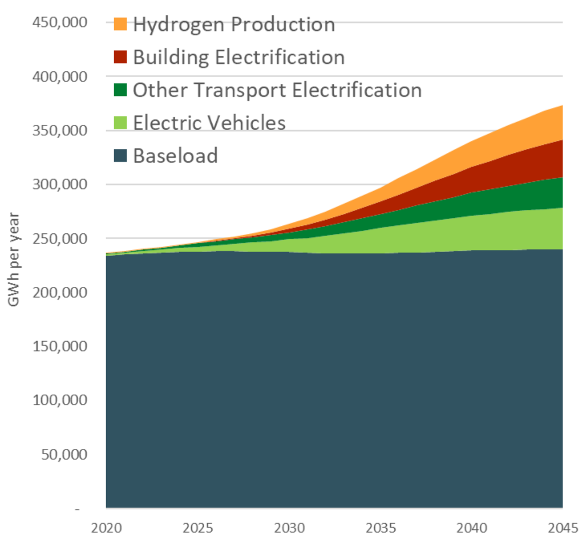
2045 – Comparison Between Scenarios



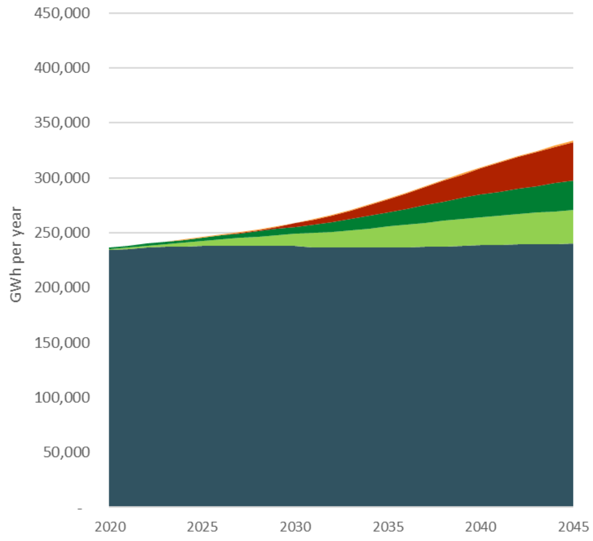
- All scenarios meet the same economy-wide 2050 GHG target, but result in different energy systems

CAISO Electricity Loads

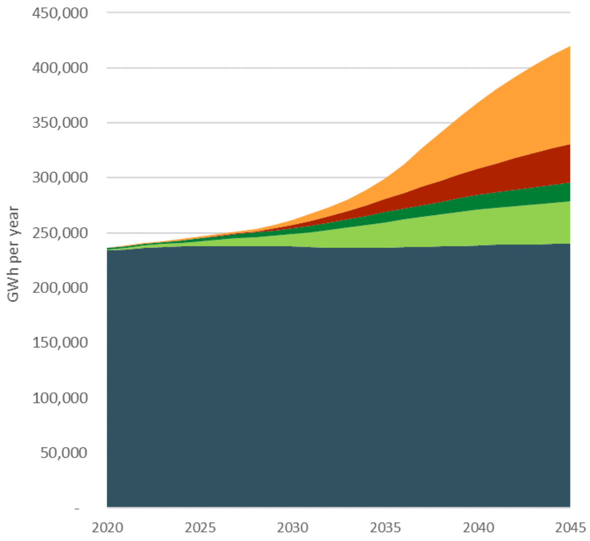
High Electrification



High Biofuels



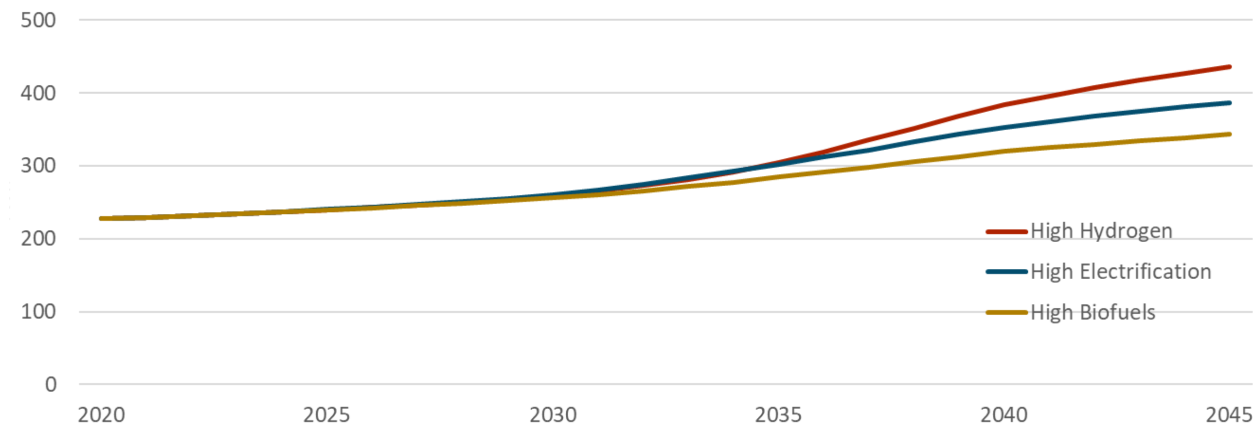
High Hydrogen



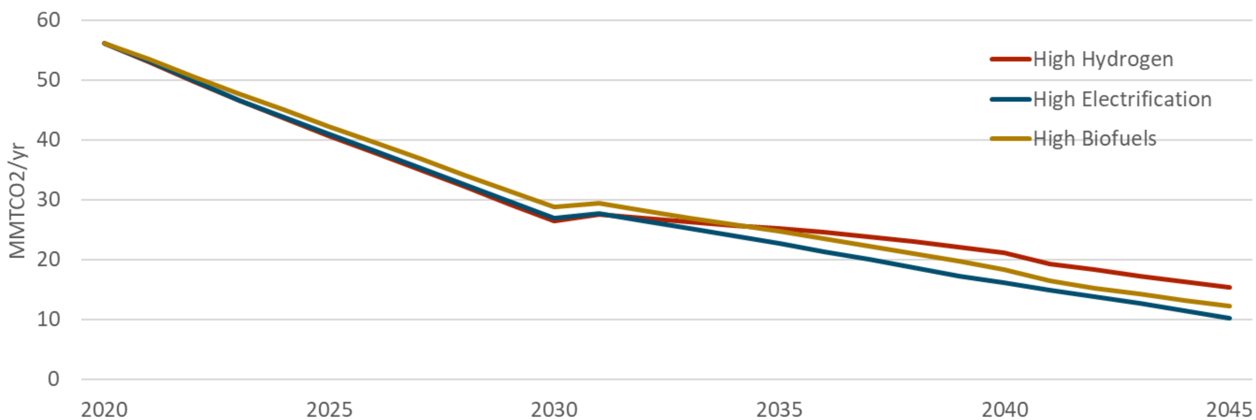
- Electricity loads vary by scenario and are a product of complex cross-sectoral interactions within each scenario
- Electrifying buildings, transportation and industry, and hydrogen electrolysis are key drivers of higher electric sector loads

Pathways Inputs into RESOLVE

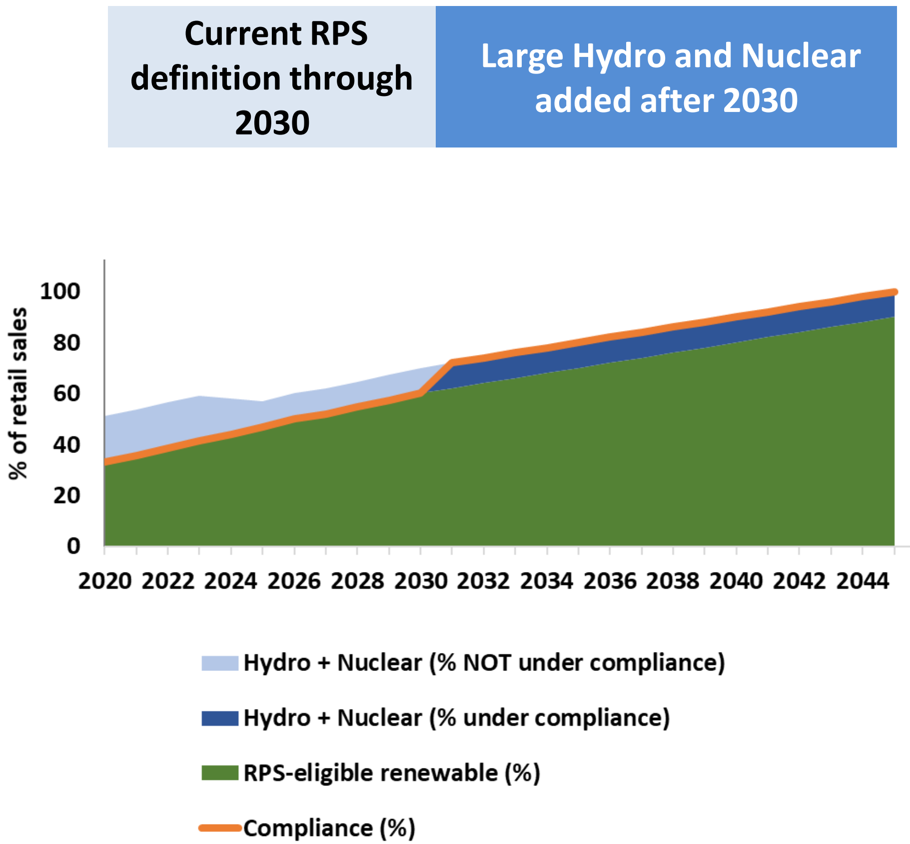
CAISO Electricity Demand (TWh)



CAISO Electricity GHG Target ($MMTCO_2$/yr)



Modeling SB 100 in RESOLVE

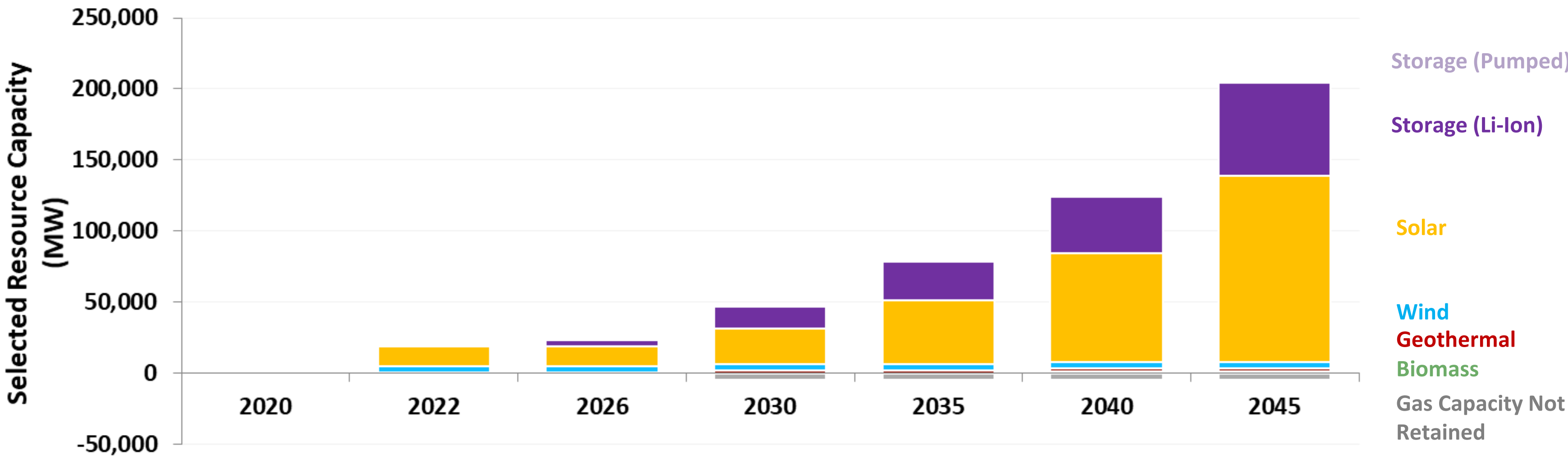


*Total retail sales includes pumping loads after 2030 (not shown)

- Will inform SB100 joint agency report process
- SB100 does not define "zero carbon resources"
  - Renewables, nuclear and hydro are assumed to be eligible resources under SB100 post-2030
- SB100 interpreted as a percent of retail sales
  - Through 2030: current RPS definition retained
  - After 2030: nuclear and large hydro are added to eligible resources
- SB100 requires GHG-free generation to equal electricity retail sales in 2045 and, as modeled in RESOLVE, gas generation is not prohibited for the following reasons:
  - Exported GHG-free power counts towards the SB100 requirement, leaving room for some internal load to be met with GHG-emitting resources
  - Transmission and distribution losses (~8% of demand) are not counted as retail sales, and may be met with GHG-emitting resources
- All of the 2045 framing studies include some natural gas power plants
  - The model makes economic decisions on how much existing gas capacity to retain, but must retain some gas plants for local reliability
  - All natural gas combined heat and power capacity is ramped down between 2030 and 2040

Resource Build: High Electrification

- Resources in chart are selected by RESOLVE and are in addition to baseline resources
- RESOLVE does not retain some thermal resources beginning in 2030



- Solar and batteries dominate
  - Li-Ion batteries have 6-8 hours of duration from 2030 on (thorough 2045)
- Around 450 MW of long duration (12-hr) pumped storage is selected in 2026
- Wind:
  - Maximum resource potential built for onshore wind. Only in-state wind allowed in base case.
  - The option to build offshore wind is allowed in a 2045 sensitivity.
- Biomass and geothermal provide resource diversity and firm capacity, but are a small portion of the portfolio

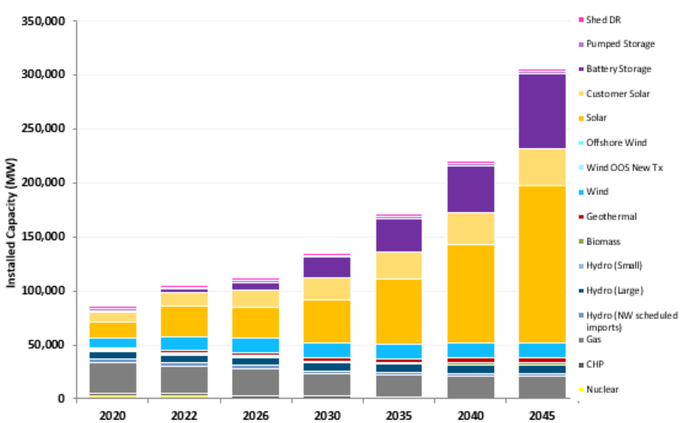
Comparison to Previous Studies

- Resource mix in the High Electrification scenario predominantly consists of solar, wind, and battery storage after 2030 through 2045. Wind resource potential limited to in-state onshore, but sensitivities increase wind generation options.
- Results are broadly consistent with recent studies examining long-term electric sector decarbonization portfolios.

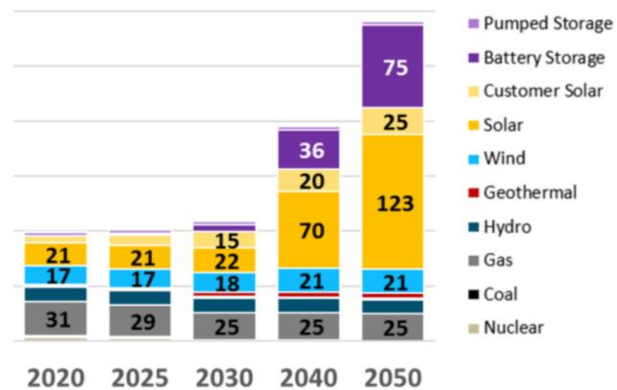
CAISO-only

California Statewide

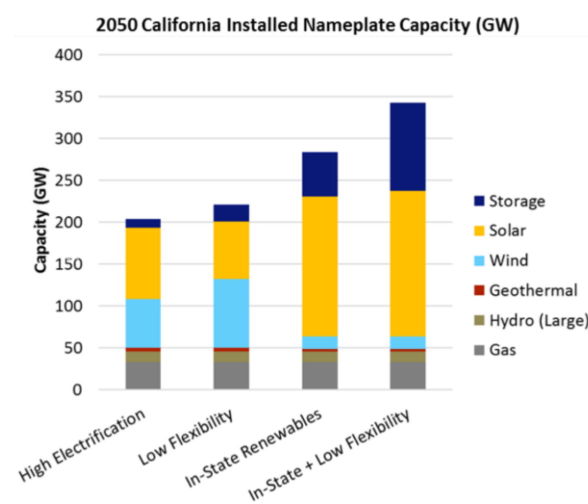
2019 IRP High Electrification



Long-Run Resource Adequacy (a): High Electrification



CEC Deep Decarbonization (b)



"Flexibility" = demand flexibility

(a) https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf, Figure 10
(b) https://www.ethree.com/wp-content/uploads/2019/06/E3_Long_Run_Resource_Adequacy_CA_Deep-Decarbonization_Final.pdf, Figure 16

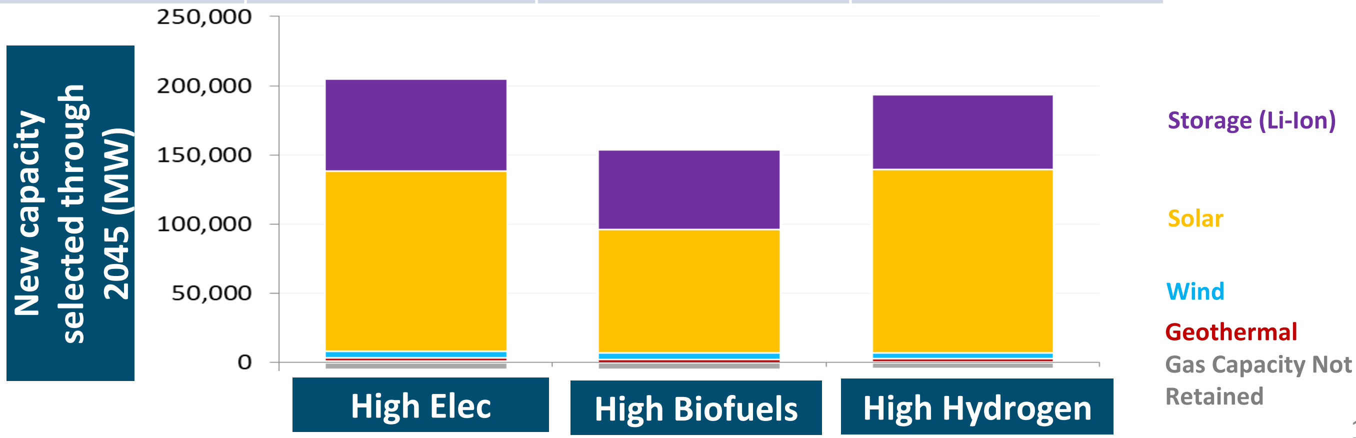
Key Scenario Metrics in 2045

Metric	High Electrification	High Biofuels	High Hydrogen
CAISO load in 2045	425 TWh	383 TWh	459 TWh
CAISO GHG Target in 2045	10.3 $MMTCO_2$/yr	12.3 $MMTCO_2$/yr	15.5 $MMTCO_2$/yr
Marginal GHG Abatement Cost	\$555/tCO_2	\$493/tCO_2	\$480/tCO_2
Effective SB100 % Note: 100% CES target enforced	109%	107%	105%
Gas capacity not retained Note: Does not include OTC retirements	4.9 GW	4.6 GW	4.1 GW
Reserve Margin	72 GW	70 GW	70 GW
Curtailment + storage losses	23%	21%	18%
Levelized Total Resource Cost (TRC) Note: Electrolysis capital cost not included	\$57.2 bn/yr	\$55.1 bn/yr	\$56.9 bn/yr
Incremental TRC *(relative to High Electrification)*	-	(\$2.1 bn/yr)	(\$0.3 bn/yr)

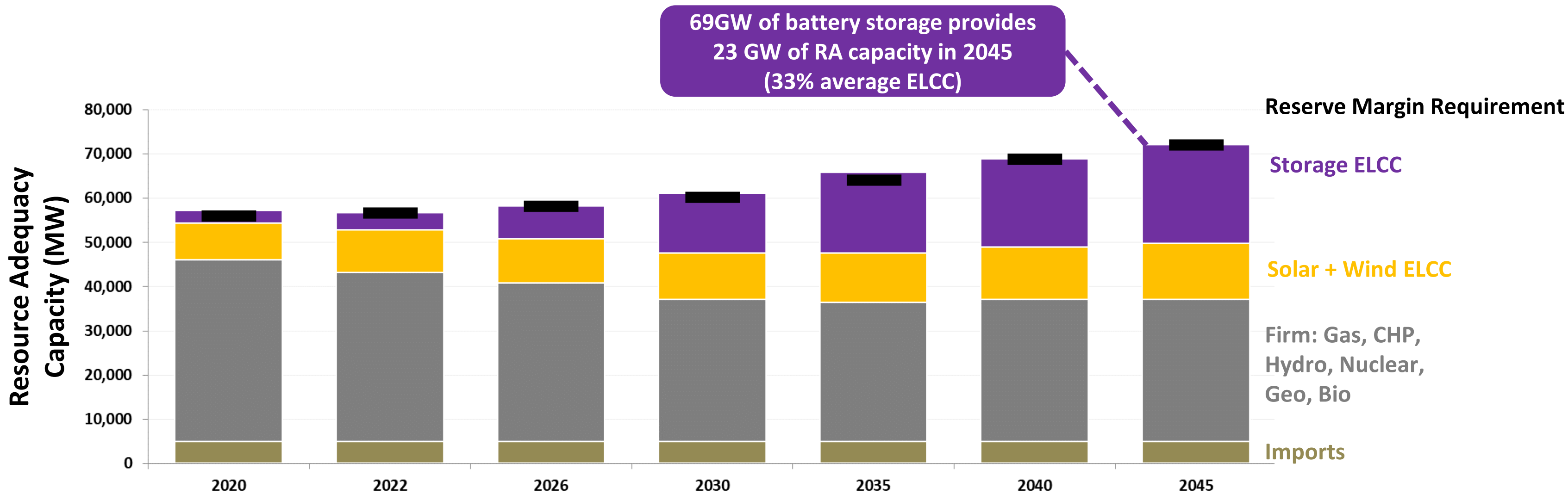
More zero-GHG generation is procured to meet GHG targets than is required to meet the RESOLVE SB100 constraint, resulting in > 100%

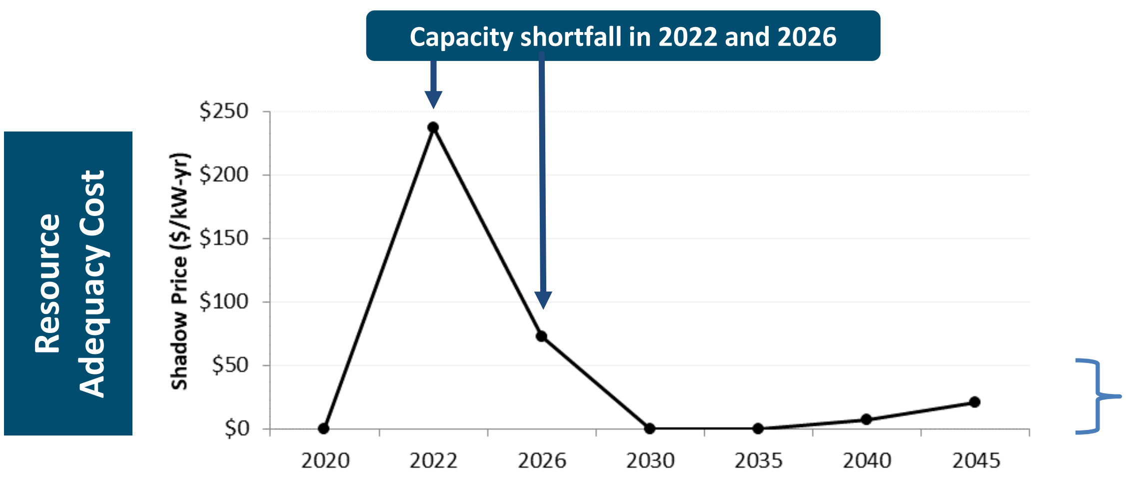
Almost all gas capacity retained due to high peak demand post-2030

Hydrogen load flexibility substitutes for storage and reduces curtailment relative to high electrification, but would require significant electrolyzer investment



Capacity Contribution: High Electrification

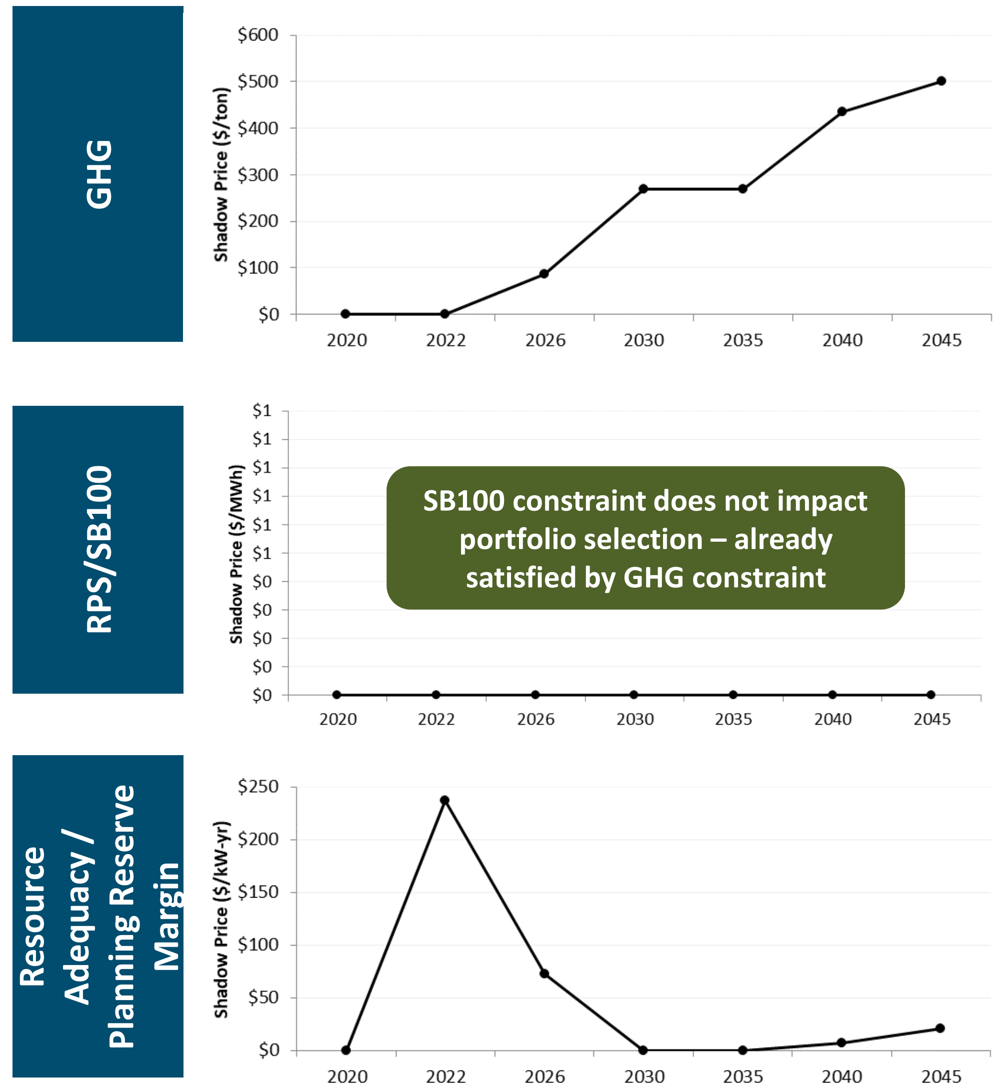




Policy targets drive capacity installation in most years. Moderate cost of retaining existing gas likely explains low but non-zero capacity cost in 2040-5

Multiple Constraints: High Electrification

- RESOLVE portfolios are the least cost solution to meet many different requirements (“constraints”)
- Three important constraints may drive portfolio selection: GHG, RPS/SB100, and Planning Reserve Margin
- In any modeled year, one or many of the constraints could drive portfolio selection.
- Constraints that drive selection have a high “shadow price,” – a high cost to meet the constraint.
- A shadow price of zero indicates that the constraint is not impacting the solution.
  - The constraint could be removed and the optimal portfolio would not change.

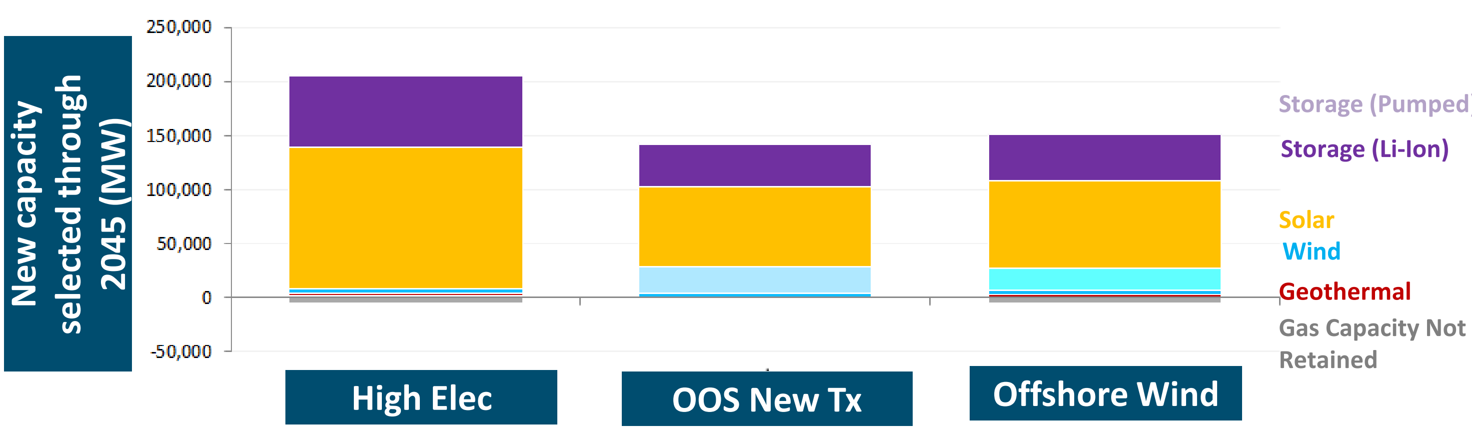


High Electrification: Wind and Tx Sensitivities

Metric	High Electrification (Base)	OOS New Transmission (mostly wind)	Offshore Wind available
CAISO load in 2045 (TWh)	425	425	425
CAISO GHG Target in 2045	10.3 $MMTCO_2$/yr	10.3 $MMTCO_2$/yr	10.3 $MMTCO_2$/yr
Marginal GHG Abatement Cost	\$554/tCO_2	\$410/tCO_2	\$520/tCO_2
Effective SB100 % Note: 100% CES target enforced	109%	107%	108%
Gas capacity not retained (GW) Note: Does not include OTC retirements.	4.9 GW	0.5 GW	5.2 GW
Achieved RA Reserve Margin (target = 15%)	15%	15%	16%
Curtailment + storage losses (%)	23%	15%	19%
Levelized Total Resource Cost (TRC)	\$57.2 bn/yr	\$56.1 bn/yr	\$56.0 bn/yr
Incremental TRC *(relative to High Electrification)*	-	(\$1.1 bn/yr)	(\$1.1 bn/yr)

Gas capacity necessary to maintain reliability, even with significant buildout of OOS or offshore resources

Availability of additional wind resources reduces curtailment and costs

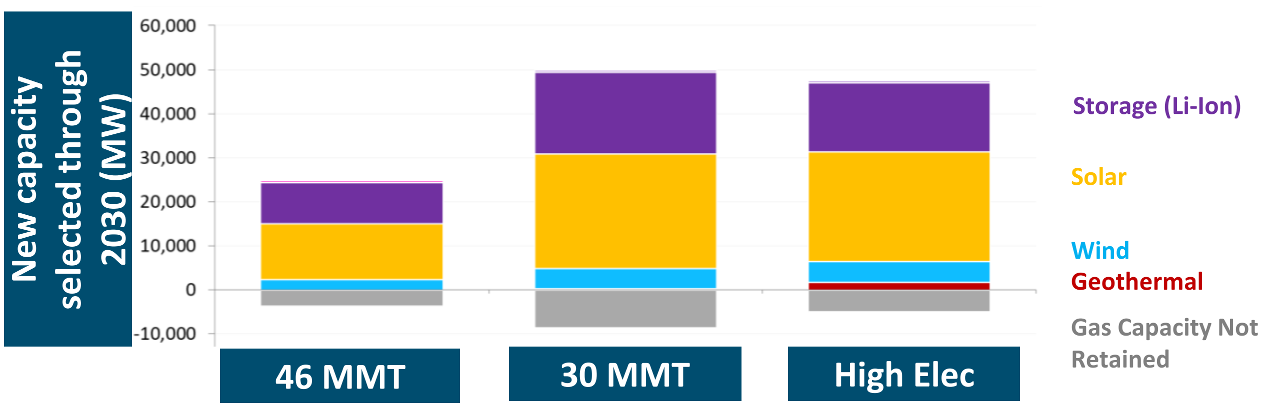


Looking Beyond 2030 Highlights Potential Path dependencies for 2030 Portfolios

Metric in 2030	46MMT in 2030	30MMT in 2030	High Electrification in 2030 (ends in 2045)
CAISO load in 2030 (TWh)	**257**	**257**	**275**
CAISO GHG Target in 2030	**37.9**	**24.3**	**26.9**
Marginal GHG Abatement Cost	**$109/tCO_2$**	**$248/tCO_2$**	**$293/tCO_2$**
Effective RPS % Note: 60% target enforced	**60%**	**79%**	**77%**
Gas capacity not retained in 2030 (GW) Note: Does not include OTC retirements.	**3.6 GW**	**8.6 GW**	**4.9 GW**
Achieved RA Reserve Margin (target = 15%)	**15%**	**15%**	**17%**

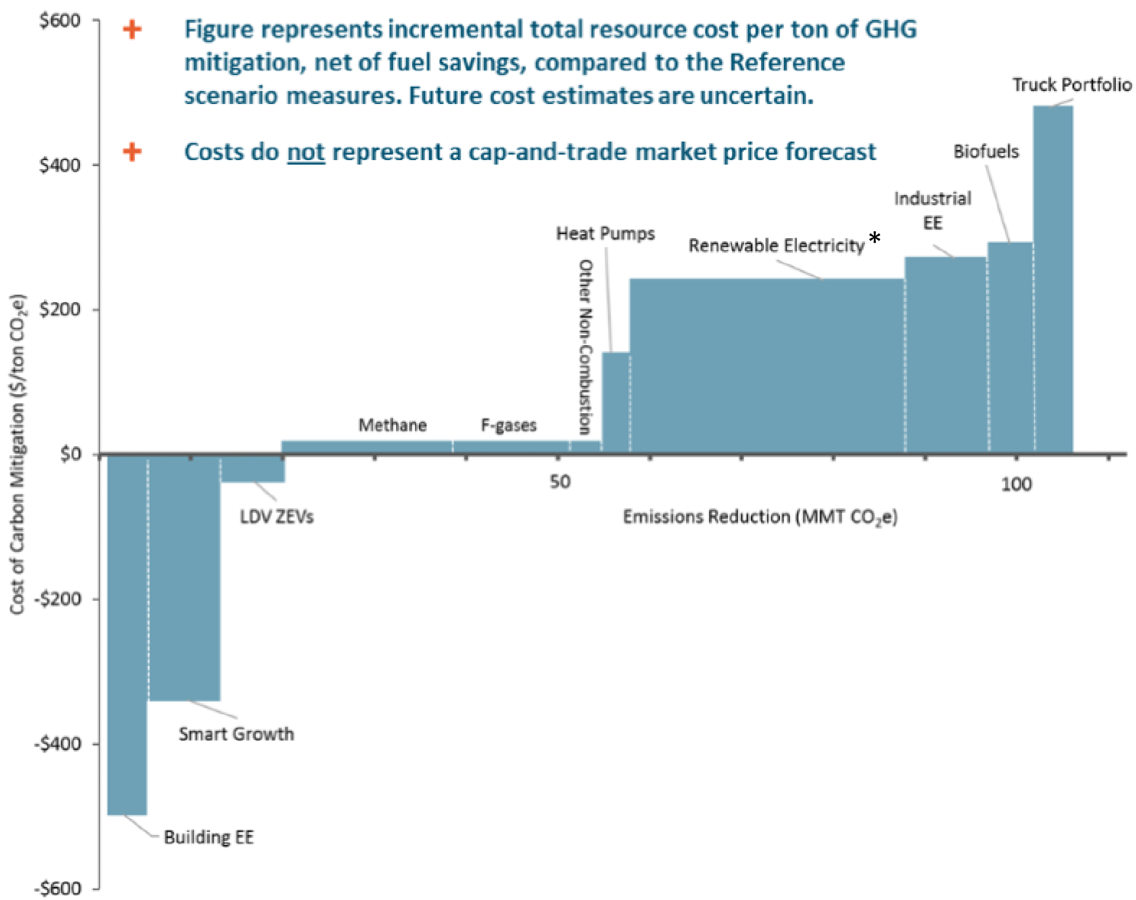
30 MMT and High Electrification runs similar in 2030

Comparing the 30 MMT and High Electrification scenarios, an increase in electrification loads post-2030 results in more gas retention in 2030



Abatement Opportunities are Available Across Sectors, but have Greater Implementation Uncertainty

Figure 25. 2030 Incremental Carbon Abatement Cost Curve (Total Resource Cost per Ton of GHG Reduction Measures, Net of Fuel Savings), in the High Electrification Scenario



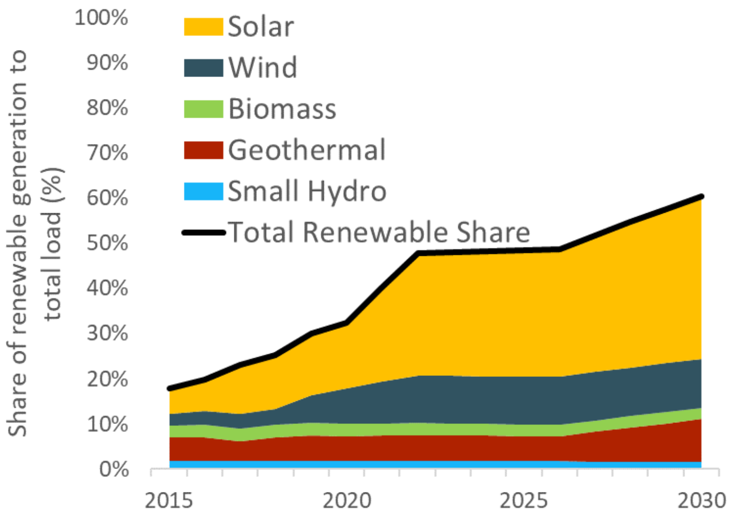
- Mitigation measures from other sectors may have lower estimated GHG abatement cost in 2030:
  - e.g., EE and VMT reduction, EVs, building electrification
- However, successful implementation of these measures is still uncertain
- The PATHWAYS electricity GHGs assume success in all other sectors, but if any of these fall short, greater reductions in electricity may be needed as a backstop

* **Illustrative results from E3 2018 report CEC-500-2018-012**. The cost of carbon mitigation for the Renewable Electricity represents the average incremental cost of mitigating electricity emissions by 30 MMT by 2030. This is different than the marginal costs shown previous slides, which represent the cost of mitigating the last ton of carbon to reach the electricity sector GHG target. The average incremental cost of renewable electricity is higher in the E3 2018 report due to the significantly higher cost assumptions for solar and storage than those used in this analysis.

PATHWAYS Electricity GHG Targets Assume Maximum Level of Effort in Other Sectors

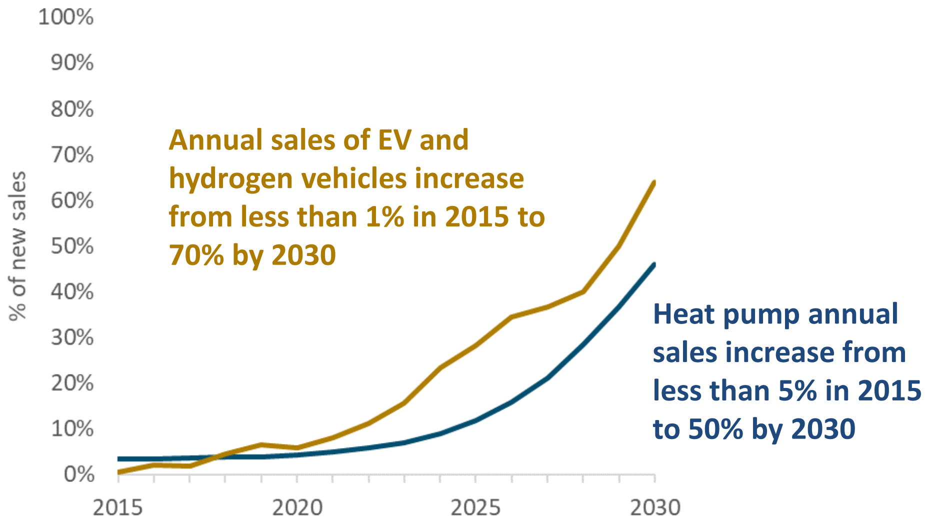
- Meeting the 2030 target requires accelerated progress in all other sectors with aggressive effort compared to the historical trajectory.

Renewable generation share increases steadily from 18% in 2015 to 60% by 2030



Source: E3 RESOLVE High Electrification scenario

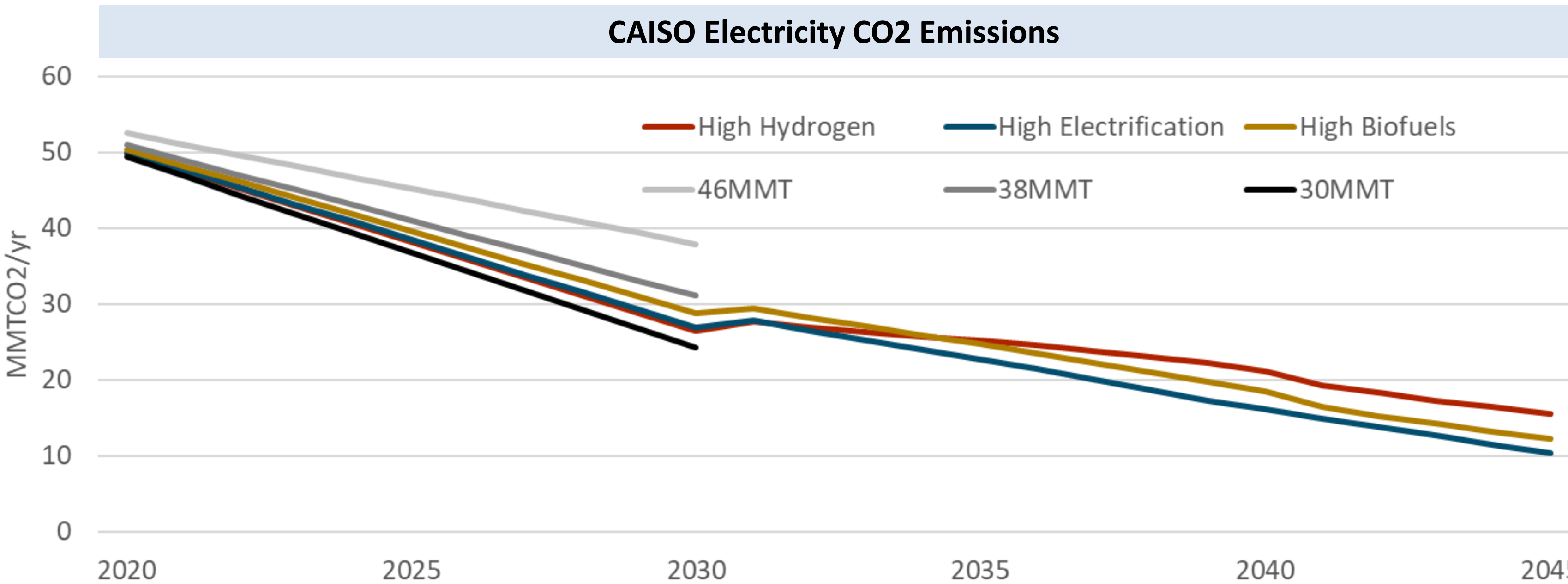
The sales share of electric heat pumps and ZEVs need to ramp up rapidly from single digits to more than 50% by 2030



Source: E3 2018 report CEC-500-2018-012, High Electrification Scenario

- Recent trends suggest challenges in achieving intended progress
  - Increased LDV GHG emissions in year 2017 inventory
  - Uncertainty over implementation of fuel economy standards
- How should the costs and risks of achieving GHG mitigation in the electricity sector be compared to the other sectors?

GHG Target Comparison Shows Deeper Reductions in 2030 Under 2045 Framing Studies than 46 MMT Scenario



•46MMT scenario includes ~60% RPS in 2030, roughly consistent 2030 requirements under SB100

•The High Hydrogen, High Electrification, and High Biofuels scenarios all <u>exceed</u> a 60% RPS in 2030, and have lower GHG emissions in 2030 than the 46MMT scenario. These scenarios are consistent with the statewide PATHWAYS scenarios (CEC 2018) that achieve a 40% reduction in economy-wide GHG emissions by 2030, relative to 1990 levels

•In the PATHWAYS (CEC 2018) scenarios, the electricity sector reduces GHG emissions more than other sectors, and exceeds the minimum regulatory requirements under SB100, due to lower GHG abatement costs in the electricity sector relative to other sectors, and due to the implementation challenges of achieving a 40% reduction in GHG emissions from some of the other sectors by 2030

Key Takeaways from 2045 Framing Study

- Looking beyond 2030 helps to inform near-term thermal retention decisions.
- Resource build under a more ambitious 2030 target (30 MMT) is more in line with 2045 scenarios.
- All three 2045 Framing scenarios rely heavily on solar and batteries to meet load and GHG policy requirements.
- Availability of out of state or offshore wind displaces in-state solar and batteries and lowers costs. Resource diversity lowers the cost of meeting long-run GHG goals.
- PATHWAYS electricity GHG targets assume maximum level of achievement in other sectors but it isn't clear to what extent other sectors will achieve reductions.