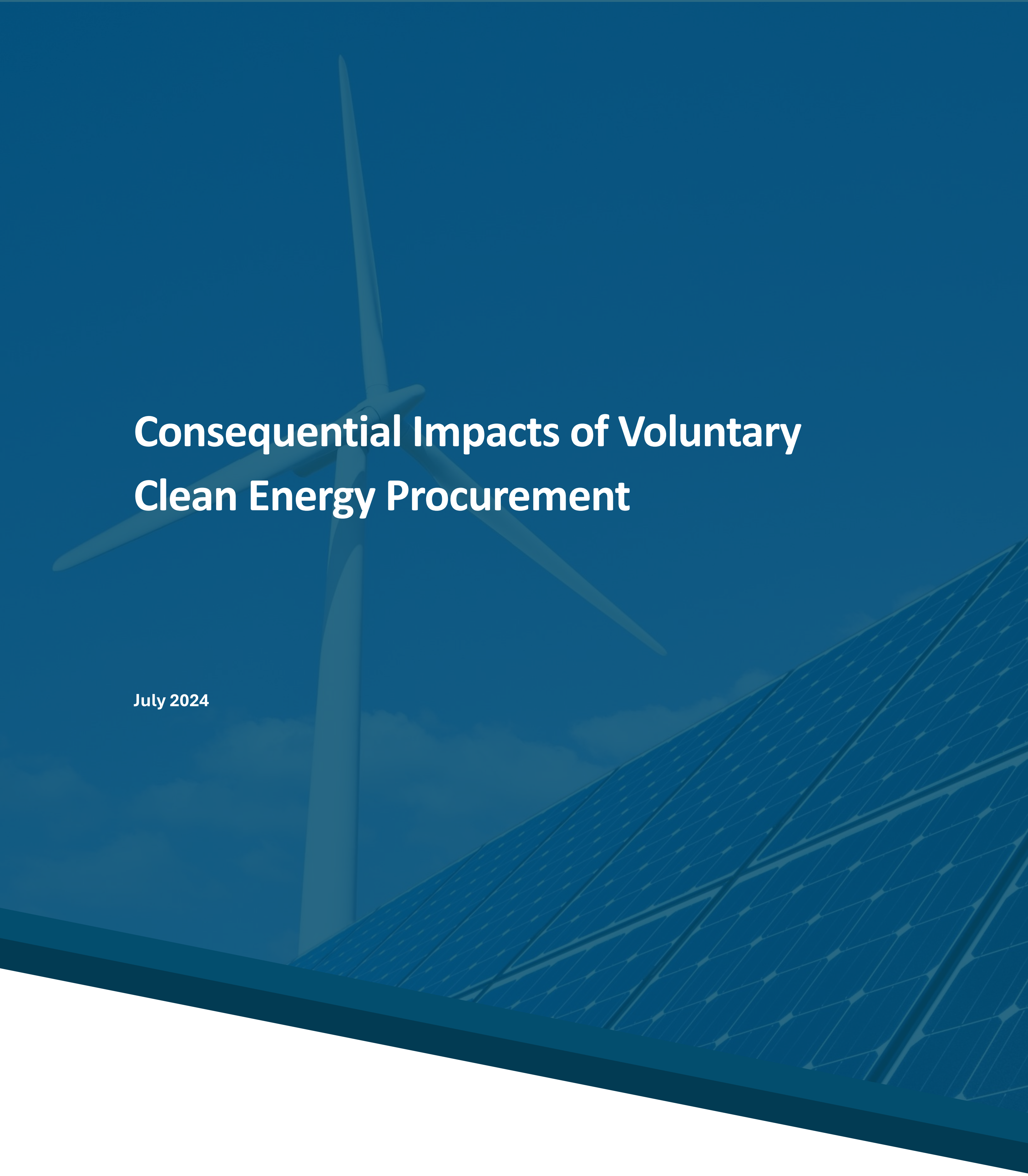

Consequential Impacts of Voluntary Clean Energy Procurement

July 2024

Energy+Environmental Economics

Study in Brief

The growing threat of climate change has prompted a surge of investment in clean electricity generation over the past two decades. While early clean energy market activity primarily took place in "compliance" markets created by state renewable procurement targets for electric utilities, the "voluntary" market has become more prominent in recent years as energy consumers at all levels increasingly seek to procure clean electricity to meet their energy and Environmental, Social and Governance (ESG) goals. Accounting for the clean electricity content in such "specified" purchases is important to ensure that consumers get the clean energy they pay for, and that clean energy "attributes" cannot be claimed by more than one consumer in the United States' multi-jurisdictional electricity system. This was addressed in the early days of clean electricity markets by creating Renewable Energy Certificates (RECs) and entities to track their creation, ownership and retirement. However, interest in the methods of clean energy accounting and the attendant impacts on carbon dioxide emissions has intensified in recent years as the cost of clean generation has declined and the voluntary market has grown substantially. A variety of methods to augment or replace the standard REC accounting have been proposed, including the creation of time-stamped RECs or Energy Attribute Certificates (EACs) and the use of locational marginal emissions factors (LMEs) to track the carbon impact of clean electricity.[1]

This report evaluates the economic and emissions impacts of voluntary clean energy accounting frameworks. It uses long-term capacity expansion (LTCE) modeling to assess dynamic, system-wide impacts of actions by a subset of market participants. It also evaluates the role of long-term offtake contracts on clean energy deployment in practice by analyzing real-world project performance parameters that can significantly affect project financing. The report investigates the following questions:

- What is the **impact of annual and hourly** matching requirements on system-level clean energy generation, emissions, and costs, under different policy assumptions?
- What are the **limitations** of the long-term capacity expansion modeling framework that has been used in the literature to evaluate voluntary corporate procurement frameworks, including the ability of models to capture real-world challenges of **hourly requirements** and the **renewable energy financing requirements and risks**?
- Is there a continued need for **long-term off-take agreements** in a post-IRA world, or will projects be able to obtain sufficient financing based on market revenues alone?

The study generates six key findings:

[1] Temporal matching is one of what have been described in some policy discussions as the "Three Pillars". The other two pillars are "Deliverability" – the source of generation must be located near the electric load, and "Additionality" or "Incrementality" – the generation would not have existed but for the clean energy procurement.

1. **Both annual and hourly matching drive additional clean energy generation** sufficient to meet new clean energy demand and largely eliminate the buyer's carbon emissions under **High Clean Energy Demand** scenarios, such as stringent clean energy policy futures, where demand for clean energy attributes exceeds the quantity that can otherwise be supplied by market forces alone.

2. **Neither annual nor hourly matching drive additional long-run clean energy generation** sufficient to serve the energy requirements of a clean energy purchaser during all hours under most **Low Clean Energy Demand** scenarios, where there is a surplus of available EACs.

3. **Hourly matching requires clean energy purchasers to procure significantly more clean energy than needed to serve their own load** during many hours. This is because the clean energy resources procured to serve load during the worst hours generate a substantial surplus of clean energy during many other hours. This subjects the clean energy buyer to substantial added cost and market risk, discouraging future clean energy investment.

4. **Strict hourly matching is much more difficult to achieve in real life than in LTCE models** for many reasons, including the variability and unpredictability of renewable energy output, transmission congestion, illiquidity in secondary attribute markets, and many other factors. Hourly matching requirements would impose substantial transaction costs and market risks on clean energy purchasers that are not considered in conventional modeling techniques.

5. **Project economics are sensitive to fluctuations in output that may not be captured by system-level capacity expansion modeling.** Real-world risks such as curtailment, equipment failure, and unexpected weather patterns create barriers to financing projects that may not be captured by capacity expansion modeling tools suitable for resource planning analyses.

6. **Long-term offtake contracts will continue to be needed to finance the vast majority of clean energy projects.** As new wind and solar resources come online, the energy and capacity market revenues for other wind and solar resources decline in unpredictable ways, posing risks to the continued and necessary future development of these resources for decarbonization. Long-term contracts for EACs are necessary under most future years and conditions to ensure that projects can meet financial hurdles to move forward to construction. Significant increases in procurement costs associated with hourly matching requirements increase the risk that project-level returns will fail to justify continued investment in clean energy.

Our findings have a range of implications for the design of corporate procurement compliance guidelines, the future of EACs in the energy transition, and the economically optimal path to emissions reduction in the United States electricity sector.

Authors & Acknowledgments

Project Team

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. For over 30 years, E3's analysis has been utilized by the utilities, regulators, developers, and advocates that are writing the script for the clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

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Acronym Definitions

Acronym	Definition
AB	Assembly Bill
ACORE	American Council on Renewable Energy
ADS	Anchor Data Set
AT CF	After Tax Cash Flows
ATB	Annual Technology Baseline (NREL)
BANC	Balancing Authority of Northern California
BESS	Battery Energy Storage System
BTM	Behind The Meter
C&I	Commercial & Industrial
CA	California
CAES	Compressed Air Energy Storage
CAISO	California Independent System Operator
CARB	California Air Resources Board
CEBA	Clean Energy Buyers Association
CEC	California Energy Commission
CES	Clean Energy Standard
CF	Capacity Factor
CHP	Combined Heat and Power
CO_2	Carbon Dioxide
COD	Commercial Operations Date
CONE	Cost Of New Entry
CPUC	California Public Utilities Commission
D/E	Debt-to-Equity
DR	Demand Response
DSCR	Debt Service Coverage Ratio
E3	Energy and Environmental Economics, Inc.
EAC	Energy Attribute Certificate
ELCC	Effective Load Carrying Capability
EPA	Environmental Protection Agency

Acronym	Definition
ESG	Environmental, Sustainability, and Governance
FO&M	Fixed Operating & Maintenance
GHG	Greenhouse Gas
GW	Gigawatt
I&A	Inputs & Assumptions
IEPR	Integrated Energy Policy Report
IID	Imperial Irrigation District
IPP	Independent Power Producer
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
IRR	Internal Rate of Return
ITC	Investment Tax Credit
kW	Kilowatt
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LCOE	Levelized Cost of Energy
LFC	Levelized Fixed Cost
LSE	Load Serving Entity
MMT	Million Metric Tons
MW	Megawatt
MWh	Megawatt-hour
NEM	Net Energy Metering
NOPR	Notice Of Proposed Rulemaking
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
NW	Northwest
O&M	Operating & Maintenance
OEM	Original Equipment Manufacturer
PPA	Power Purchase Agreement
PSP	Preferred System Plan
PTC	Production Tax Credit
PV	Photovoltaic

Acronym	Definition
REC	Renewable Energy Certificate
RPS	Renewable Portfolio Standard
SB	Senate Bill
SW	Southwest
TE	Tax Equity
TWh	Terawatt-hour
U.S.	United States
VO&M	Variable Operating & Maintenance
WECC	Western Electricity Coordinating Council
WRI	World Resources Institute

Disclaimer Required by the California Public Utilities Commission

This report has been prepared by E3 for Meta and public purposes. This report is separate from and unrelated to any work E3 is doing for the California Public Utilities Commission. While E3 performed technical analysis in preparation of this report, E3 does not endorse any specific California policy or regulatory measures as a result of this analysis. The California Public Utilities Commission did not participate in this project and does not endorse the conclusions presented in this report.

E3 utilized the RESOLVE model developed for the CPUC's 2023-2024 Integrated Resource Planning proceeding (R.20-05-003) in preparation of this report. E3 has made specific modifications to the CPUC RESOLVE model for the purpose of conducting the analysis described herein.

Category	Assumption for this Study	Difference from CPUC IRP
Model Topology/ Zonal Representation	A new modeling zone linked to the CAISO zone is added to separately model the participating load for generation matching.	CAISO is modeled with a single zonal representation including all CAISO load.
Loads	Updates are made to the electrification loads to be able to isolate commercial and industrial (C&I) customer sector's load.	CPUC IRP leverages IEPR forecast of CAISO load inclusive of C&I load (but without the ability to easily separate C&I load).
New Gas Capacity	New gas capacity is allowed in all modeled years. New gas resources are available that represent new gas frame technology.	CPUC IRP assumes 2029 is the first year that new gas capacity is available, but gas frame technology in particular is not an available technology in the IRP assumptions.
Candidate Resources	Certain resources are modeled with a constrained resource potential for C&I zone matching. Specifically, geothermal is limited to 150 MW for the C&I zone selection. Geothermal costs were updated to reflect binary technology. Pumped hydro is also limited to 1 GW across C&I and rest of CAISO.	CPUC IRP uses potential from 2023 Inputs and Assumptions document. Flash geothermal technology was represented.
Reliability Targets	Mid-term reliability (MTR) policy targets are removed in this study. Small adjustments were made to gross system peak load to align with load adjustments, impacting total capacity requirement for reliability.	MTR is modeled in all CPUC IRP scenarios. Gross system peak for CAISO reliability is directly sourced from IEPR.
Annual Clean Energy Targets/	For High Clean Energy Demand Scenarios, SB 100 target extension of	Clean energy RPS requirements modeled through 2030, and SB 100 goals are

Carbon Constraints	85% modeled for the year 2030. Low Demand scenarios remove RPS and SB100 requirements. Additional clean energy matching requirements are added for certain participating C&I load procuring matching clean energy demand.	extended from 2031 to 100% by 2045. IRP scenarios also largely include caps on total carbon emissions, which are removed from this study.
Hourly Matching Policy	New code updates implemented to ensure hourly load matching for C&I.	The CPUC IRP model does not have the ability to model hourly load matching.
Carbon Price Policy	For certain scenarios (Low Clean Energy Demand), carbon prices are removed to represent a limited policy case.	In the IRP, CARB carbon floor prices were modeled as a default assumption.

1 Introduction and Key Findings

1.1 Motivation

The growing threat of climate change has prompted a surge of investment in clean electricity generation over the past two decades. The decarbonization imperative, along with improving economics, supportive state policies, and new federal tax incentives, are fueling remarkable growth in renewable energy investments in the United States. In 2022 alone, the Clean Energy Buyers Association (CEBA) recorded 16.9 GW of corporate clean energy procurement deals – greater than all the non-emitting generation brought online in the United States in that year – dramatically accelerating total clean energy deployment.[2] The National Renewable Energy Laboratory estimates voluntary procurement made up 44% of the total U.S. market for clean energy in 2022.[3] While early clean energy market activity primarily took place in "compliance" markets created by state renewable procurement targets for electric utilities, the "voluntary" market has become more prominent in recent years as energy consumers at all levels increasingly seek to procure clean electricity to meet their energy and Environmental, Social and Governance (ESG) goals.

Given the scale of these investments, clean energy buyers understandably want to be sure that their actions are leading to real reductions in greenhouse gas (GHG) emissions. Accounting for the clean electricity content in such "specified" purchases is important to ensure that consumers get the clean energy they pay for, and that clean energy "attributes" cannot be claimed by more than one consumer in the United States' multi-jurisdictional electricity system. This was addressed in the early days of clean electricity markets by creating Renewable Energy Certificates (RECs) and entities to track their creation, ownership and retirement. However, the impact of clean electricity generation on grid carbon emissions can vary by time and location due to differences in the composition of generating resources that would be displaced by clean energy.

Interest in the methods of clean energy accounting and the attendant impacts on carbon dioxide emissions has intensified in recent years as the cost of clean generation has declined and the voluntary market has grown substantially, and some corporations and standard-setting organizations are re-evaluating the way they measure the impact of clean energy purchases on a buyer's overall carbon footprint. The World Resources Institute and the World Business Council for Sustainable Development set voluntary corporate carbon accounting practices, known as the Greenhouse Gas Protocol, for indirect "Scope 2" emissions from electricity generation used to serve electric load as well as any emission reductions from clean energy purchases.[4] Current standards generally allow clean energy purchases to be matched on a MWh-for-MWh basis with electric load

[2] See CEBA Deal Tracker, available at: https://cebuyers.org/deal-tracker/
[3] https://www.nrel.gov/analysis/assets/pdfs/status-and-trends-2022-data.pdf
[4] See: https://ghgprotocol.org/about-wri-wbcsd and https://ghgprotocol.org/scope-2-guidance

during a calendar year.[5] Updates to the protocols and outcomes of the debate on carbon accounting more broadly will have significant consequences for the design of future clean energy markets and the growth of voluntary clean energy demand. New proposals, including the creation of time-stamped RECs or Energy Attribute Certificates (EACs) and the use of locational marginal emissions factors (LMEs) to track the CO_2 impact of clean electricity, would require more granular methods to measure the carbon footprint of corporate electricity generation. Some have advocated for an approach that has been referred to as the "Three Pillars":

1) **Additionality or Incrementality:** specified clean energy must be produced from generation that is new and would not exist but for the clean energy purchase.
2) **Deliverability or Regionality:** specified clean energy must be generated in the same grid or region where the energy is consumed.
3) **Temporal or Hourly Matching:** specified clean energy must be generated during the same time period in which the energy is consumed.

Enforced compliance with the "Three Pillars" approach would eliminate the use of other approaches of demonstrating clean content, including the annual REC approach that has been in use for over 25 years. It would also preclude novel methods such as "emissions-matching" or "carbon matching" – the direct matching of emissions associated with load to the emissions avoided by new clean energy.[6] Some literature has advocated for a focus on this paradigm as an improvement over annual matching because of its improved accuracy in reflecting time- and area-specific marginal carbon emissions rates, and as a better alternative to temporal matching because of the latter's high cost and challenging compliance requirements.[7]

This study uses long-term capacity expansion (LTCE) modeling to dynamically evaluate the impact of these requirements – specifically the hourly matching requirement – on "consequential" carbon emissions, i.e., emissions from the electricity system as a whole. We use the California RESOLVE LTCE model created and maintained by E3 for the California Public Utilities Commission's (CPUC) Integrated Resource Planning (IRP) proceeding. The model optimizes investments for the California Independent System Operator (CAISO) market footprint and operations across the entire Western Interconnection. Unlike many previous studies, this study uses a fully dynamic evaluation approach which measures not just the direct impact of specified clean energy purchases in the year in which they occur but also the response to those investments from the rest of the electricity market both immediately and over time. This approach is the only way to estimate the "additionality" of clean energy investments, i.e., the extent to which a specified clean energy purchase in a given modeling

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[5] Temporal matching is one of what have been described in some policy discussions as the "Three Pillars". The other two pillars are "Deliverability" – the source of generation must be located near the electric load, and "Additionality" or "Incrementality" – the generation would not have existed but for the clean energy procurement.

[6] For example, see: https://cleanpower.org/wp-content/uploads/gateway/2023/06/ACP_GreenHydrogenFramework_OnePager.pdf.

[7] For an example of analysis of emissions matching, referred to as "carbon matching", see: https://tcr-us.com/uploads/3/5/9/1/35917440/paths_to_carbon_neutrality_white_paper_april23.pdf

scenario results in incremental clean energy resource additions, as opposed to claiming clean energy attributes from resources that would otherwise have been built.

To explore these dynamics, the study quantifies clean energy generation, carbon emissions, and cost to match a proportion of commercial and industrial (C&I) load with voluntary clean energy purchases. Four cases are considered:

1. A **Reference Case** without any specified Commercial & Industrial (C&I) clean energy procurement.
2. An **Annual Matching** case, in which participating C&I clean energy demand can be met with clean energy generated at any time during the modeled year.
3. An **Hourly "Island"** case, in which incremental C&I clean energy demand must be met with new clean energy generated during the same hour, but in which the C&I loads are not allowed to buy from *or* sell to the wholesale electricity market.
4. An **Hourly "Market"** case, in which incremental C&I clean energy demand must be met with clean energy generated during the same hour, and C&I loads are allowed to sell excess energy into the wholesale electricity market. In this case, procured hourly-matched supply is required to be equal to demand in each hour, and thus no unspecified market purchases are required or allowed (hourly purchases of specified clean energy from new resources built to serve C&I demand is allowed and implied).

In all cases, the clean generation is required to be "new", meaning selected during the current model "investment period."[8] These cases are evaluated under two scenarios:

1. A **High Clean Energy Demand** Scenario, in which demand for clean energy attributes is assumed to be strong. Demand for clean energy in this scenario is stimulated by assuming compliance with California's SB 100 and SB 1020 clean energy targets, which require 90% of retail electricity sales to be met with non-emitting generation by 2035, 95% by 2040 and 100% by 2045. Additionally, a target of 85% by 2030 is assumed, consistent with the latest CPUC IRP scenarios.
2. A **Low Clean Energy Demand** Scenario, in which there is no demand for clean energy attribute certificates outside of the participating C&I load. This scenario assumes that current California clean energy policies including SB 100, SB 1020, AB 32 (including the cap-and-trade program) and IRP GHG targets do not exist; clean generation accordingly is only selected if it is economic to include in the least-cost supply portfolio.

Several different levels of specified C&I clean energy procurement are evaluated: 10%, 25% and 50% of C&I load within the CAISO footprint are assumed to procure sufficient clean energy to match 100% of their energy requirements. All scenarios include the tax incentives provided by the Inflation Reduction Act, which are expected to significantly reduce the cost of clean energy generation.

[8] Resource additions and operations are simulated in five-year periods, i.e., 2025, 2030, 2035, 2040 and 2045.

Previous work by Xu et al. (2024) and others have concluded that specified clean energy purchases, annually matched, do not lead to consequential carbon emission reductions under the conventional annual matching approach, and that more exacting approaches such as hourly matching are needed to drive consequential carbon reductions.[9] However, these studies' conclusions about hourly matching are based on a relatively narrow, improbable, and unstable set of circumstances in which:

a) Significant quantities of renewable energy enter the market based on price alone, driven in part by the tax incentives in the Inflation Reduction Act,
b) Demand for clean energy attributes is assumed to remain unchanged, despite these very low prices, and
c) New demand for clean energy from the loads in question (e.g., hydrogen or C&I customers) materializes instantly in quantities that are larger than the market would build on its own.

Further, studies that model a single investment period do not consider the impact that these new clean energy resources would have on market investment decisions in subsequent years, namely, by diminishing the economic returns from investment in clean energy resources in those years.

This study considers a range of market conditions including both low and high demand for clean energy, favorable and unfavorable economic conditions for clean energy, and market response both in the current and in subsequent investment periods. We find that annual and hourly approaches perform similarly in terms of incremental clean energy generation and consequential carbon emissions reductions across almost all scenarios. Significant near-term consequential carbon emissions reductions are observed under both annual and hourly matching approaches in scenarios with high clean energy demand, whereas neither annual nor hourly matching approaches are found to result in long-term consequential emission reductions under low clean energy demand scenarios. Significant differences in the performance of hourly matching relative to annual matching are observed only under the specific conditions outlined above.

The study then goes further by analyzing the underlying project financing assumptions assumed within the capacity expansion modeling framework and assessing their feasibility under both 'typical' operating and financing conditions assumed in the capacity expansion model, and under alternative potential real-world conditions. Real world shocks considered in this study include reduced output due to curtailment or equipment failure, constrained availability of tax equity, and variability in debt sizing assumptions. This study relies upon common assumptions for hourly renewable output and resource costs between the capacity expansion modeling and project economic analysis, and the curtailment forecasts produced from the capacity expansion modeling results are applied in the project economic analysis. In this way, the study combines 'top-down' and 'bottom-up' approaches to estimating the impact of different emissions accounting on procurement

[9] For example: Xu, Q., Ricks, W., Manocha, A., Patankar, N., & Jenkins, J. D. (2024). "System-level Impacts of Voluntary Carbon-free Electricity Procurement Strategies". Joule. https://www.cell.com/joule/fulltext/S2542-4351%2823%2900499-3.

dynamics. The study's conclusion is that under many conditions, long-term contracts for clean energy are essential to enabling continued electricity sector emissions reductions.

1.2 Objectives

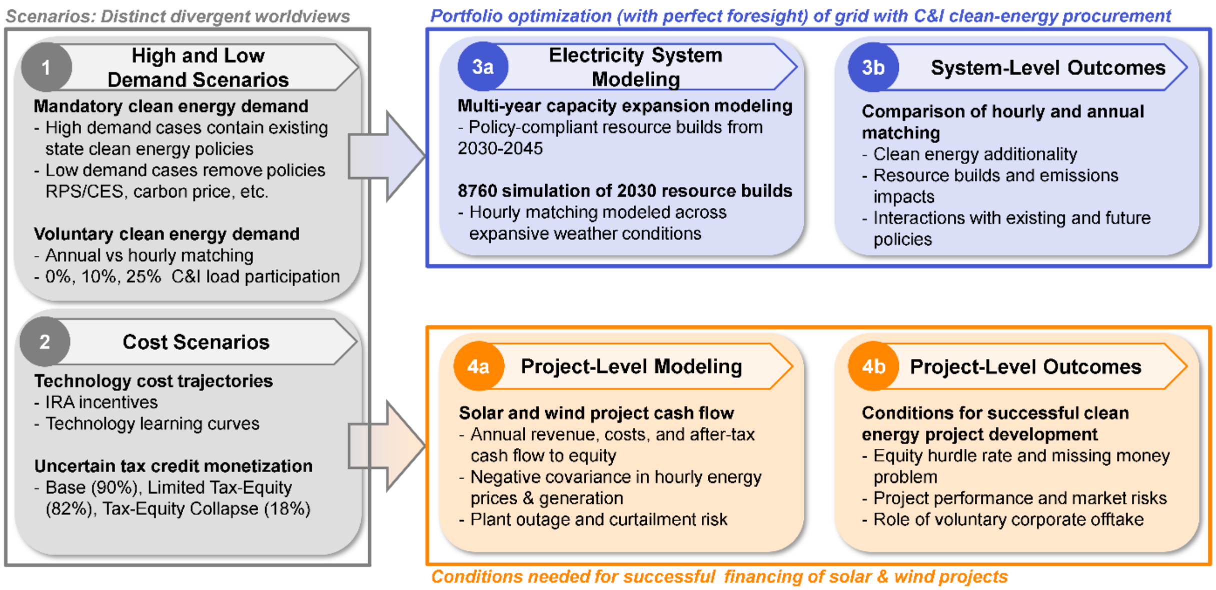
This report evaluates the following questions:

- **What is the impact of hourly and annual matching requirements on system-level clean energy generation, emissions, and costs, under different policy assumptions?** Using the California Independent System Operator as a case study, we evaluate the impact of hourly and annual emissions accounting frameworks for representative corporate loads on CAISO electric system generation, emissions, and costs, using a capacity expansion framework. We focus on California because it is a large market with significant clean energy deployments today and strong renewable resource potential. It also has a publicly-available and thoroughly vetted long-term capacity expansion model that is used in the state's IRP process.
- **What are the limitations of the long-term capacity expansion (LTCE) modeling framework that has been used in the literature to evaluate voluntary corporate procurement frameworks, including the ability of models to capture real-world challenges of hourly requirements and the renewable energy financing requirements and risks?** We extend the capacity expansion modeling through sensitivity analysis, as well as perform production simulation modeling of the LTCE portfolios that evaluates matching on an hourly basis under different weather years. We also test the impact of tax equity financing terms on portfolios.
- **Is there a continued need for long-term off-take agreements in a post-IRA world, or will projects be able to obtain sufficient financing based on market revenues alone?** We evaluate project-specific economics under different scenarios, including but not limited to those covered in the capacity expansion modeling, to estimate the potential project cash flows and conditions that would drive need for policy or corporate support for clean energy through Power Purchase Agreements (PPAs) or alternative contracting mechanisms.

1.3 Approach

To address the above questions, we utilize a multi-step modeling framework as depicted in Figure 1-1 below. First, a Reference Case is modeled which establishes the baseline market conditions against which changes induced by our scenarios are measured. Then a demand "shock" is introduced by assuming a portion of C&I loads procure clean energy equal to 100% of their energy demand in a given time period. The extent to which this shock results in additional clean energy generation and consequential carbon emissions reductions is determined by comparing the energy and emissions quantities with those of the Reference Case. This modeling is performed in a capacity expansion framework, with supplemental hourly production simulation for selected weather years. The outputs of this modeling are then used to inform detailed analysis of the project economics, and the conditions necessary for renewable projects to be built. Section 3 describes the capacity expansion modeling utilized for this work, and Section 4 describes the project economics modeling.

Figure 1-1. Overview of E3 Modeling Approach



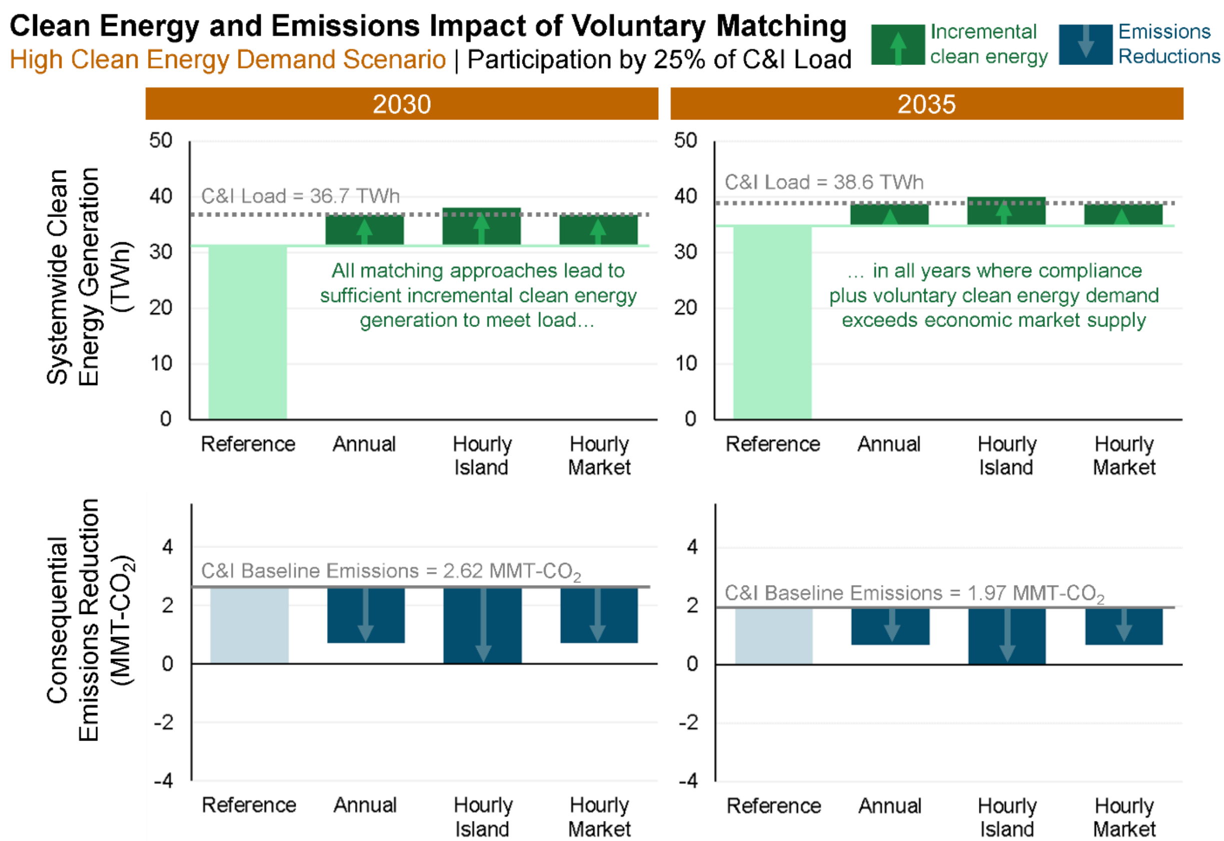
1.4 Key Findings

1. **Both annual and hourly matching drive additional clean energy generation sufficient to meet new clean energy demand and largely eliminate the buyer's carbon emissions under High Clean Energy Demand scenarios, such as stringent clean energy policy futures, where clean energy demand exceeds the quantity otherwise supplied by market forces.**

Under conditions where clean energy demand exceeds supply, incremental voluntary procurement of clean energy drives proportional incremental clean energy generation and emissions reductions in each model year until SB 100 is fully achieved in 2045. Figure 1-2 below compares a Reference Case without any incremental C&I clean energy procurement with the three different C&I procurement scenarios: Annual Matching, the Hourly Island case, and the Hourly Market case. Under this Reference Scenario, the market procures 201 TWh of clean energy in CAISO to meet the assumed 85% clean energy generation target. Meeting 25% of C&I demand with 100% clean energy requires 5.5 TWh of clean energy procurement. The chart demonstrates that clean generation is added to meet this incremental C&I demand on a MWh-for-MWh basis under each of the Annual Matching, Hourly Island and Hourly Market cases, and that this incremental clean energy offsets nearly all of the carbon emissions associated with C&I load. Emissions reductions are slightly smaller in the Annual and Hourly Market cases primarily due to SB100's clean energy accounting definition, which allows storage losses to be met with emitting generation.

Demand for clean energy is high in California due largely to California's clean energy policies, including SB 100 requiring 100% of retail electricity sales to be met with clean generation by 2045 and the greenhouse gas targets adopted by the CPUC in the region's Integrated Resource Planning proceeding, require significant investments in clean energy. Our modeling finds that demand for clean energy in California under SB 100 exceeds the supply that would be provided by the market without the SB 100 requirements today and throughout the modeling period. However, the cause of the clean energy demand is not relevant to the model results;[10] similar results are found in all cases where market demand for EACs exceeds supply.

Figure 1-2. Clean Energy and Emissions Impacts under High Clean Energy Demand



2. **Neither annual nor hourly matching drive additional long-run clean energy generation sufficient to serve the energy requirements of a clean energy purchaser during all hours under most Low Clean Energy Demand scenarios, where there is a surplus of available EACs.**

In cases where the market supply of clean energy exceeds demand, we find that incremental clean energy demand does not necessarily lead to enduring incremental, clean energy generation. The systemwide change in clean energy and emissions for the 25% matching cases are shown in Figure 1-3 below. Additional clean energy generation is observed in all cases in 2030; however, in the

[10] Indeed, voluntary clean energy demand in the broader California market is not considered.

Annual case, a portion of the demand could be met by resources that would otherwise have been developed by the market, i.e., that are built in the Reference Case. The Hourly cases result in a larger quantity of incremental generation, because the model must build clean energy to match incremental demand in the most difficult hours; this results in larger quantities of incremental clean generation during all other hours. In the Hourly Market case, this surplus clean generation is sold into the wholesale market, resulting in consequential emissions reductions that far exceed the participating C&I customers' own carbon emissions. In the Hourly Island case, this surplus clean generation must either be stored or curtailed as the C&I customers are prevented from transacting with the wholesale energy market.

However, the additional clean energy generation is temporary; almost no incremental clean energy generation is observed in the following modeling period, after the market has had time to adjust. By 2035, the market would have built enough clean generation on its own to meet both annual and hourly-matched demand. The incremental clean generation in 2030 was caused by a sudden, large increase in clean energy demand, an increase that is larger than the market would otherwise build in the same period. It is doubtful that such a large proportion of the C&I load would seek to procure clean energy all at once; it is far more likely that participating C&I load would grow gradually over time at a rate that is less than the organic growth in clean generation.

Moreover, the extent to which incremental clean generation is observed also depends on the size of the demand shock. The impacts of both the scale and timing of the demand shock in a low clean energy demand future are summarized in Figure 1-4. The impact of the 2030 demand shock dissipates by 2035 in all cases for both the 10% and 25% C&I demand levels. Under the 50% C&I case, both Annual and Hourly approaches lead to significant incremental clean generation in 2030, however here the demand shock is large enough that the effect does not entirely dissipate until 2040 in the Annual case and beyond in the Hourly cases.

Consequential carbon emissions reductions under low clean energy demand conditions are the result of a temporary and unstable market disequilibrium that results from this sudden demand shock, without time for the market to adjust and reach a new equilibrium. Unless similar quantities of new demand are continually introduced, the market will adjust over time and eventually return to the same equilibrium that existed in the absence of the new clean energy demand. In our study, a complete adjustment occurs in the next planning period in most cases (i.e., 2035). The important conclusion is that any benefits of hourly matching relative to annual matching in a low clean energy demand scenario are transitory; neither annual nor hourly matching frameworks are likely to result in lasting consequential carbon emissions reductions in a Low Clean Energy Demand scenario.

Figure 1-5 summarizes the conditions under which hourly matching results in meaningfully different outcomes than annual matching. First, the supply of clean energy attributes that is developed through market forces alone must exceed the demand for *annual* EACs, otherwise new demand leads to additional clean energy supplies under both annual and hourly matching approaches. Second, the new clean energy demand for *hourly* EACs must be greater than the quantity the market would build on its own in the contemporaneous build period, otherwise new demand could be met with non-additional supplies. Finally, incremental demand must continue to grow at a rate that is faster than the growth of market-driven clean energy supplies, otherwise the effect of the demand shock will dissipate over time and new demand would be met with non-additional supplies under both the annual and hourly matching approaches.

Figure 1-3. Clean Energy and Emissions Impacts under Low Clean Energy Demand

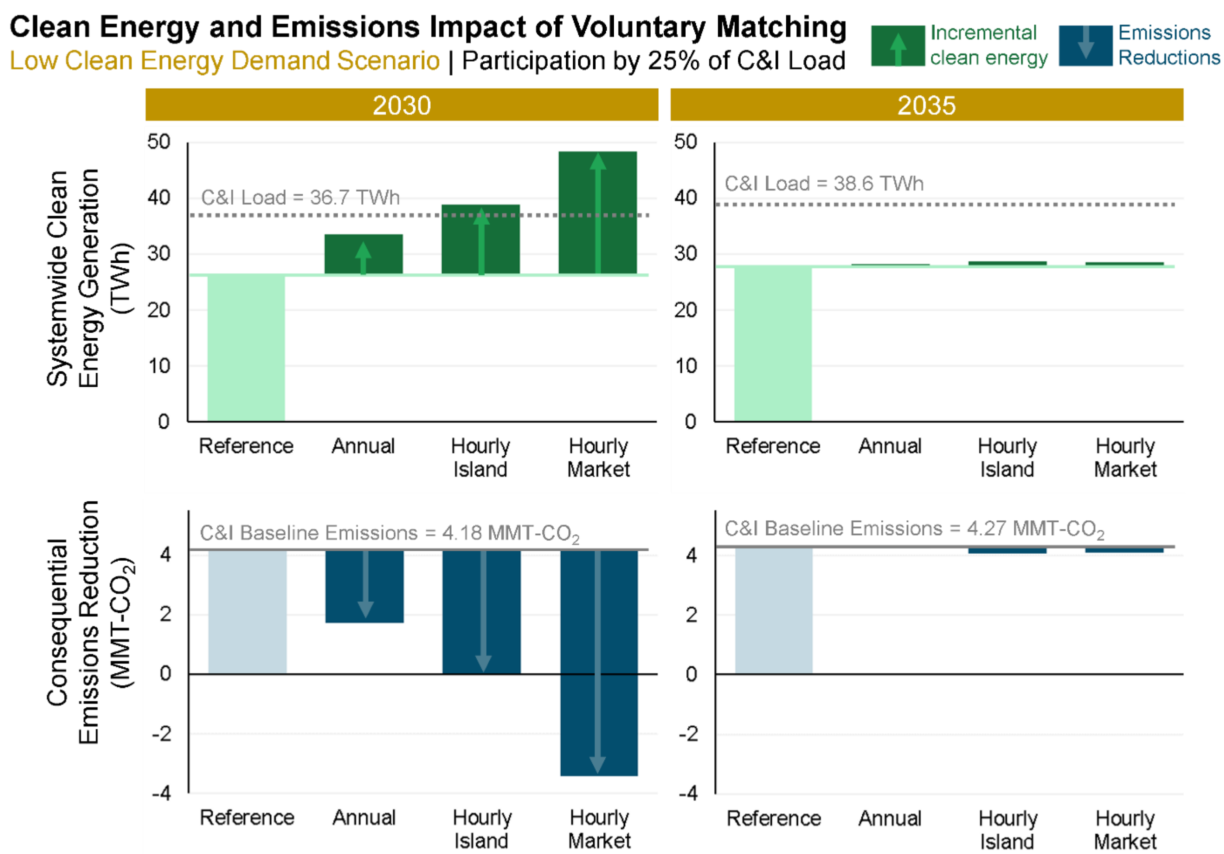
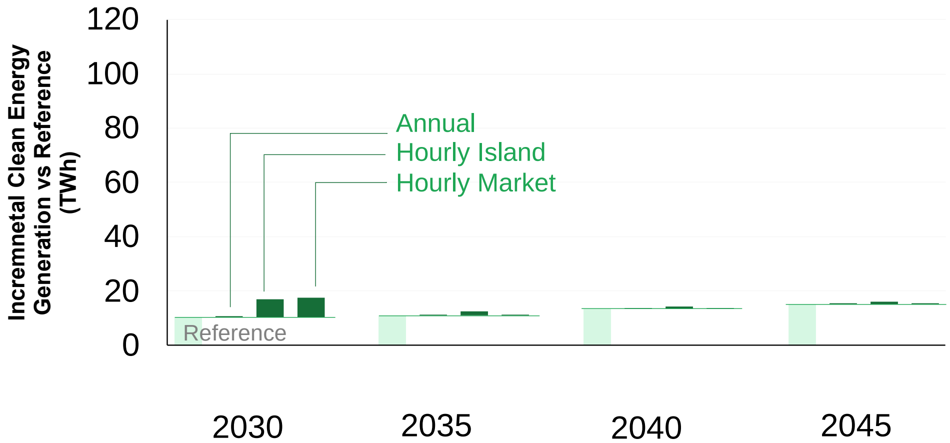
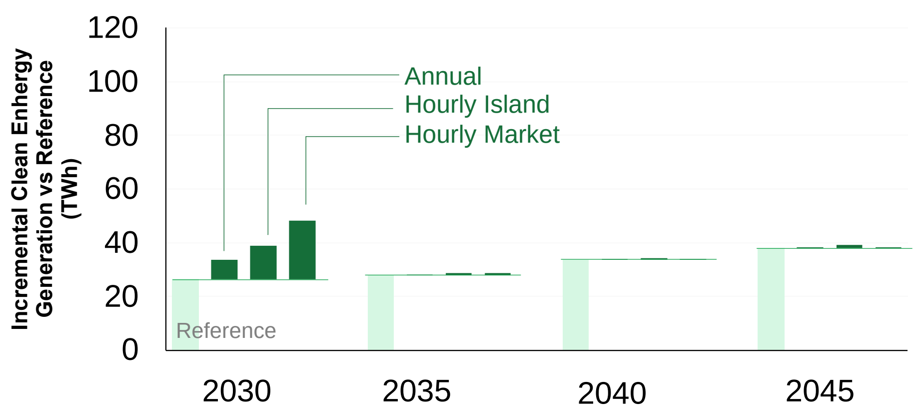


Figure 1-4. Incremental Clean Energy Generation in 10%, 25% and 50% C&I Matching for Low Demand Scenarios

10% C&I Participating Load



25% C&I Participating Load



50% C&I Participating Load

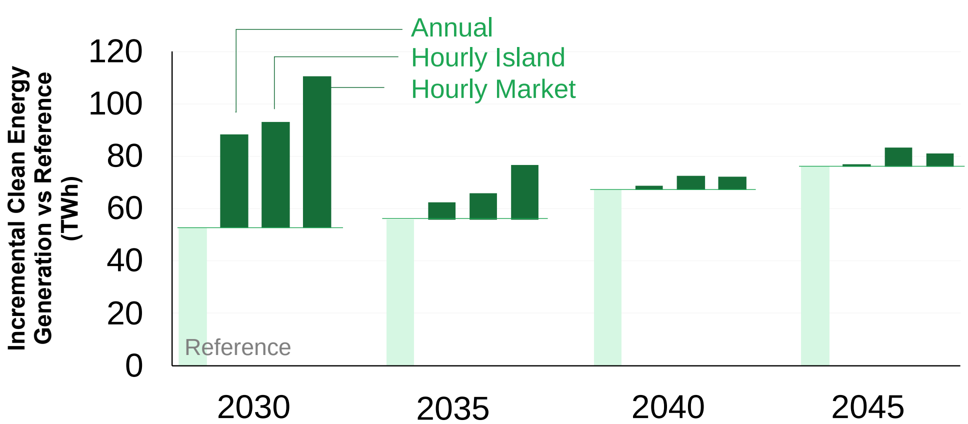


Figure 1-5. Three Conditions Must be True for Incremental Clean Generation to be Different under Hourly Matching vs. Annual Matching

<table>
<tr><th>Condition 1</th><th></th><th>Condition 2</th><th></th><th>Condition 3</th><th></th><th>Result</th></tr>
<tr><td rowspan="4">Condition 1. Is the market demand for Annual EACs less than what the market could supply on its own?</td><td>No</td><td colspan="5">Both Annual and Hourly Matched new EAC demand results in new incremental clean energy supply</td></tr>
<tr><td rowspan="3">Yes</td><td rowspan="3">Condition 2. Is the demand for Hourly EACs in Year 1 greater than new market supply in Year 1?</td><td>No</td><td>New EAC demand does not result in new incremental clean energy supply in Year 1</td><td></td><td rowspan="2">New EAC demand does not result in durable new incremental clean energy supply</td></tr>
<tr><td rowspan="2">Yes</td><td rowspan="2">Condition 3. Is the growth in Hourly EAC demand in Year n greater than the growth in market supply?</td><td>No</td></tr>
<tr><td>Yes</td><td>Some Hourly EAC demand results in new supply</td></tr>
</table>

3. Hourly matching requires clean energy purchasers to procure significantly more clean energy than needed to serve their own load during many hours. This subjects the buyer to significant added cost and market risk, discouraging future clean energy investment.

Under annual matching, purchasers can procure and bank RECs generated during hours in which specified clean energy supply exceeds consumption to cover hours when clean energy supply is less than consumption. Any surplus or deficit that remains on an annual basis can be transacted in a relatively liquid secondary market for clean energy attributes. This enables buyers to manage market risk associated with clean energy purchases in much the same way that buyers of conventional energy supplies manage market risk; sophisticated buyers seldom hedge 100% of their risk with physical positions, rather, they manage their market exposure considering the net effects of short and long positions that occur at different times throughout the year.

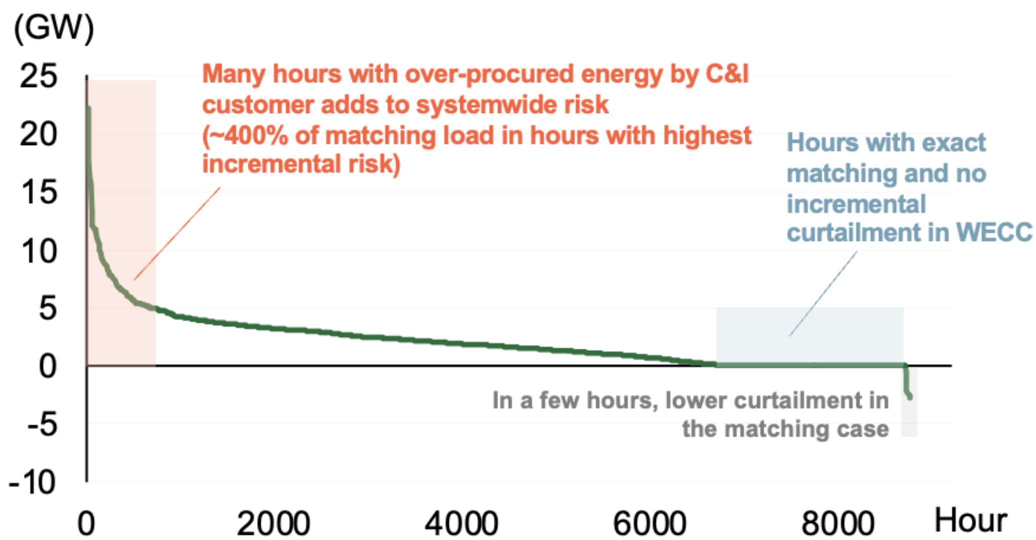
In contrast, hourly matching requires purchasers to procure excess quantities of clean energy over the course of the year; we find that participating customers are forced to procure clean energy about 300% to 400% of the C&I load in the Low Demand Hourly matching cases. Under the High Demand scenario, the excess clean energy available in the Hourly Market case is used by the market to meet binding clean energy demand. This means that the sale of excess clean energy would likely include a premium for the clean energy attribute, improving the return to the C&I customer. However, it also means that this excess clean energy does not result in consequential carbon emissions reductions, since this quantity of clean energy is needed by the market even without the participating C&I load. Thus, we see that all three frameworks result in carbon emissions reductions approximately equal to the carbon emissions from the C&I load.

Under the Low Demand scenario, the clean energy attributes are not valued by the market. This means lower revenues to the participating C&I customers, but higher consequential carbon emissions reductions; carbon emissions reductions are twice as large as the carbon emissions that would have been attributed to the participating C&I load. In effect, **hourly matching requires the participating C&I customers to reduce carbon emissions from non-participating customers**, at a significant cost.

Further, this overbuild is understated due to the limited granularity that can be incorporated into LTCE modeling. Much of this energy is curtailed in the Hourly Island case, despite the presence of large quantities of energy storage markedly increasing costs. In the Hourly Market case, this energy is exported to the rest of the interconnection. While this helps reduce cost, it exposes the consumer to substantial market risk if the expected revenues fall short of assumptions made during project development and financing. In Figure 1-6 below, we illustrate this risk explicitly.

Finally, the financial risk of this over procurement is not considered in conventional LTCE modeling, which matches C&I load to hourly energy supplies *in aggregate*. This implicitly assumes perfectly liquid markets for hourly EAC products with no transaction costs. However, a market for 8,760 different hourly EAC products is likely to be highly *illiquid*, since both the demand and supply can only be known after the fact, resulting in highly uncertain revenue and high transaction costs for surplus EAC sales. This challenge is described in more detail in Finding 4.

Figure 1-6. Over-Procured Clean Energy by C&I Load by Hour, Hourly Matching Market Case in Low Demand Scenario, 2030



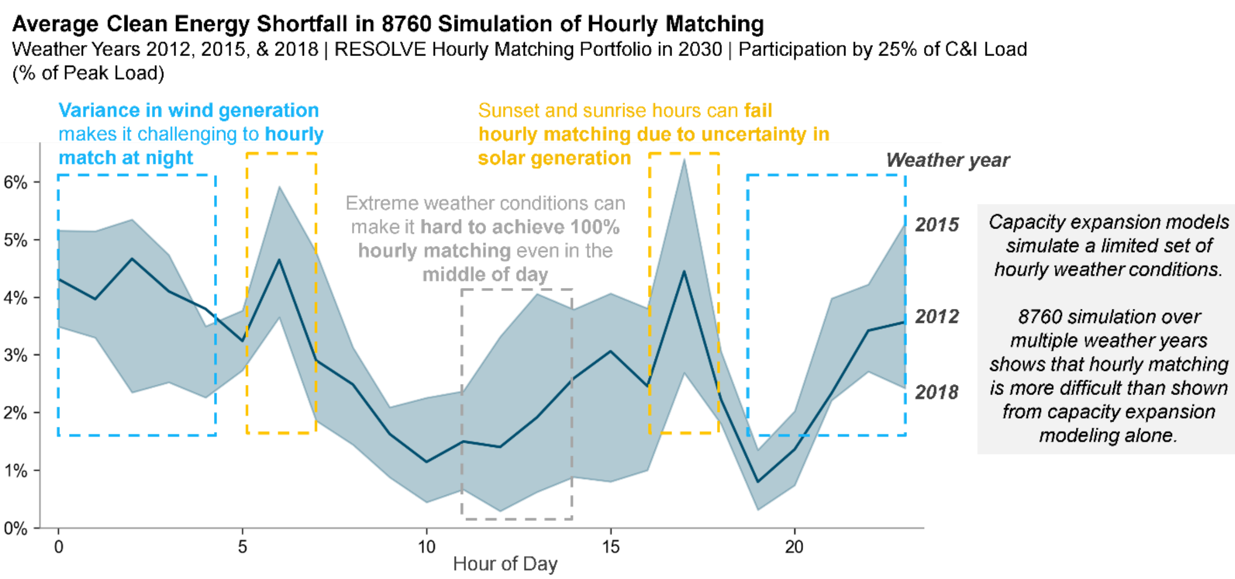
Notes: Graph includes the sum of exports from excess clean energy from C&I procured resources to the rest of the system (i.e., market sales), as well as WECC-wide incremental curtailment in that hour (if any) in the hourly matched scenario, relative to the reference.

4. Strict hourly matching is much more difficult to achieve in real life than in capacity expansion modeling.

Wind and solar generation vary from hour to hour, from day to day and even from year to year, often in unpredictable ways. Transmission congestion and generation flexibility constraints can also limit the power system's ability to absorb variable renewable generation, leading to unexpected curtailment of renewable energy output. Hourly matching requirements therefore would impose substantial market risks on clean energy purchasers that are not considered in conventional modeling techniques. These renewable performance risks further increase the challenge of hourly matching compared to LTCE modeling results shown in this study, which rely on a limited number of representative days from historical weather years that are known with perfect foresight.

While the LTCE modeling provides an indication that hourly matching can be met under most conditions experienced over the course of the year, supplemental 8760-hour production simulation performed for selected historical weather year conditions reveals that the optimal matching portfolios could fail to meet load in many hours of the year. For example, Figure 1-7 below shows that in the weather year 2015, characterized as a relatively low renewable output year, there is less clean energy generation than the ostensibly 100%-hourly-matched load in roughly 5% of the hours in the year. The results also suggest that the depth of the clean energy shortfall could be too large for high load factor customers (e.g., commercial and industrial customers) to respond with load curtailment or clean energy demand reduction.

Figure 1-7. Average Clean Energy Shortfall in Hourly (8760 hours) Simulation of Hourly Matching



Notes: Hourly simulation of capacity expansion portfolios under different weather year conditions.

System level capacity expansion modeling also fails to capture the project-level costs associated with more illiquid market design concepts. As noted above, markets for annual RECs are relatively liquid, providing a stable, long-term investment signal by serving as a forecastable revenue source for the clean energy "missing money;" in other words, the premium above conventional energy prices needed for clean energy projects to be economic. However, hourly REC markets are likely to be *unworkably illiquid*. Hourly demand for and supply of RECs can only be known after the fact, and both supply and demand are perfectly inelastic in *ex-post* markets. This means that the hourly REC market would oscillate between one of two states: either the market would be over-supplied, and prices would be at or near zero, or it would be under-supplied and prices would rise to a level approaching consumers' cost of non-compliance. In either case, such a market would not provide a useful or workable forum for transacting individual short or long positions.

5. **Project economics are sensitive to fluctuations in output that may not be captured by system-level capacity expansion modeling. These real-world risks create barriers to financing new clean energy projects.**

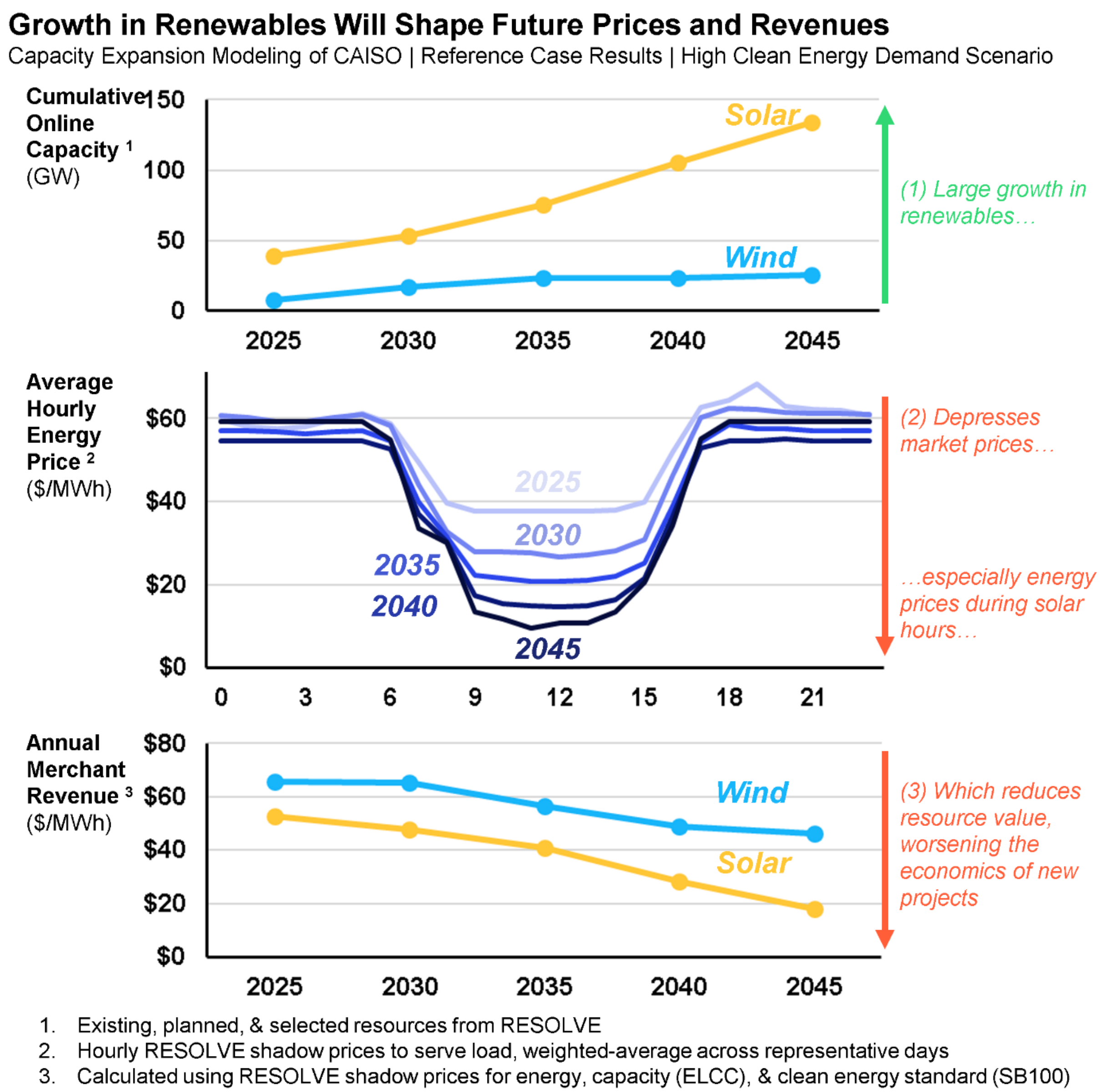
Returns from renewable projects are sensitive to system-level or nodal curtailment, idiosyncratic shocks from equipment failure, or unexpected weather patterns, such as those illustrated above. Real-life risks like these, as well as uncertainty related to policy, technology costs, and evolution in market structure, are not fully captured in system-level modeling, which assumes perfect foresight, generation profiles based on a range of historical but not extreme weather conditions, and unplanned outage rates aligned with historical averages. Furthermore, these risks must be taken into account by lenders and potential contracting counterparties. Where project cash flows, driven by market revenues and operating costs, do not justify leverage (i.e., debt) sufficient for equity investors to expect returns to clear their hurdle rates (i.e., the minimum expected return investors require to consider capitalizing a project), projects will not be developed. If and when this becomes a widespread trend, it poses real risks to financing for new additional clean energy projects.

6. **Long-term offtake contracts will continue to be needed to finance most new clean energy projects.**

As renewable penetration increases, the need for offtake contracts increases as well. The modeling for California, like other jurisdictions, illustrates the impact of increasing renewable energy capacity on merchant (non-contracted) revenue. Specifically, significant "negative covariance" is observed: increasing wind and solar penetration depresses energy prices during those hours when the sun shines and, to a lesser extent, when the wind blows, as shown in Figure 1-8 below. The result is that the market revenues earned by solar and wind assets on a fully merchant basis are expected to decline, even under optimistic capacity factor (output) assumptions. While resource cost declines, driven in large part by Inflation Reduction Act incentives, improve the economics of new solar and wind generators, there continues to be a critical need for projects to fill in the "missing money" gap between resource revenues and costs in the coming decades. This "missing money" must be supplied via third party contract between project developers and buyers such as load-serving entities or corporations.

Offtake and project financing are deeply connected. Riskier contract structures (e.g., hourly matching) may exacerbate this need without providing commensurate returns to investors. When expected economics for clean energy resources deteriorate, the pool of potential off-takers shrinks as the risk of returns falling below required hurdle rates increases. All else being equal, a reduction in the capital available to finance new renewable resource investments will dim the prospects of building sufficient capacity to meet decarbonization targets.

Figure 1-8. Growth in Renewables Will Shape Future Prices and Revenues



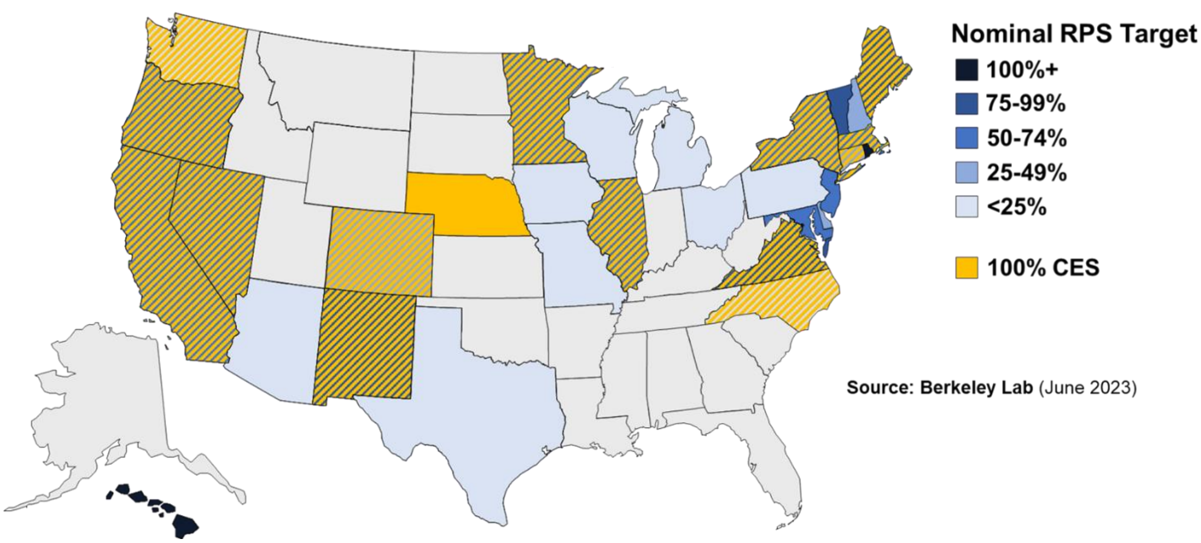
2 Context: Growing Voluntary Corporate Clean Energy Procurement

Renewable generation across North America has grown dramatically over the last twenty years, driven by growing recognition of climate change, advancements in renewable technology performance and cost, and the proliferation of federal and state policies to accelerate deployment. This section first discusses clean energy policy and its role in creating markets for clean energy. It then describes the role of tax credits in facilitating clean energy generation, and the importance of tax equity to utilizing tax credits. Finally, this section summarizes trends in voluntary clean energy procurement and debates surrounding frameworks for measuring the clean energy content of voluntary actions taken by corporations.

2.1 State Clean Energy Policy and the Role of RECs

To achieve high levels of renewable deployment, U.S. states have implemented Renewable Portfolio Standards (RPS), which require electricity providers to meet a minimum percent of load with qualifying renewable resources. California enacted the United States' first RPS in 2002, heralding a new era in which states drive industry growth by creating demand through procurement mandates. Today, 31 states have RPS mandates or targets (Figure 2-1).

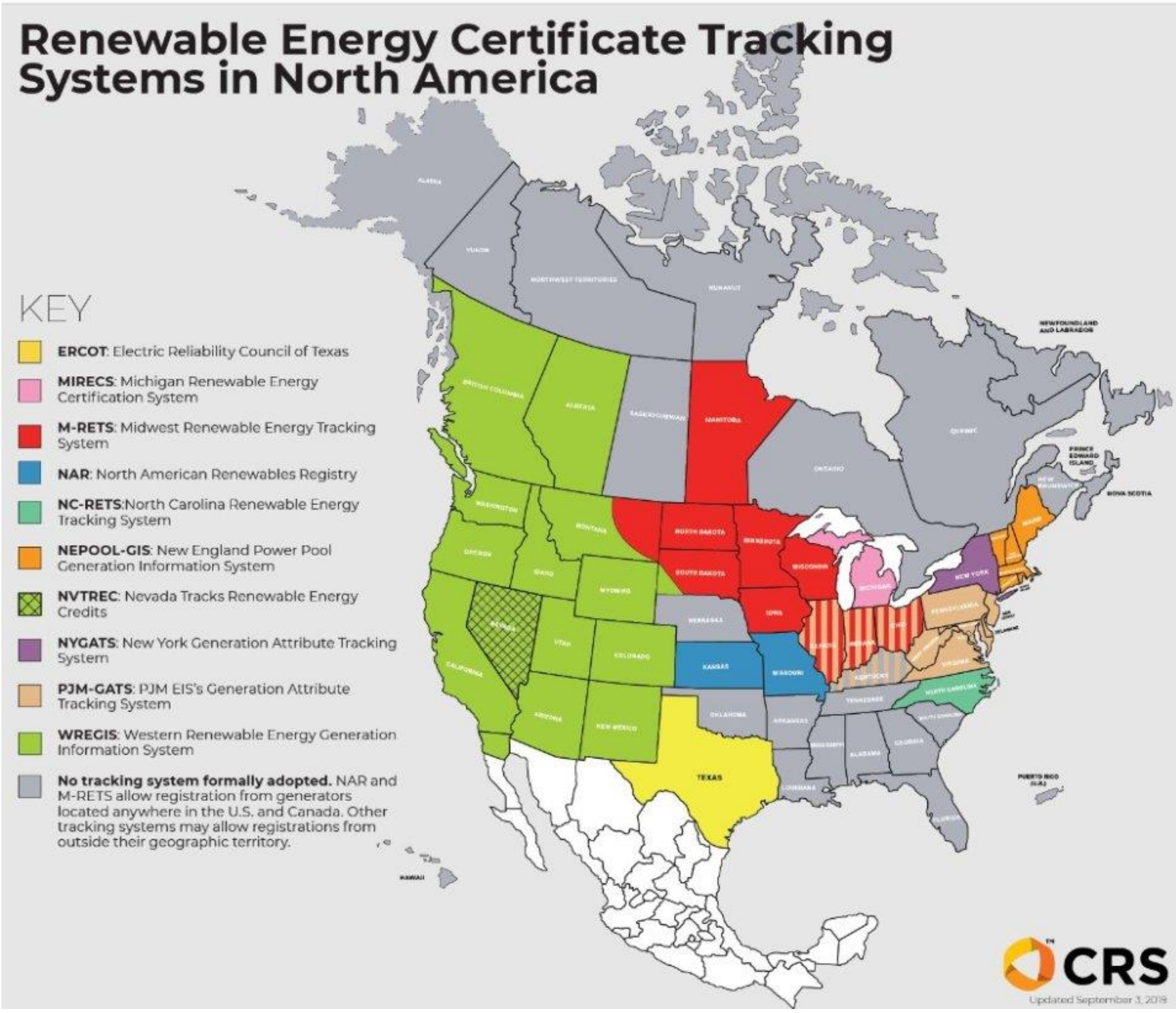
Figure 2-1. RPS Policies in the United States as of 2023



Note: Target percentages represent the total of all RPS resource tiers where applicable. These targets are distinct from any voluntary renewable energy goals. Source: Lawrence Berkeley National Laboratory, June 2023.[11]

[11] https://emp.lbl.gov/projects/renewables-portfolio

Figure 2-2. REC Tracking Systems in North America



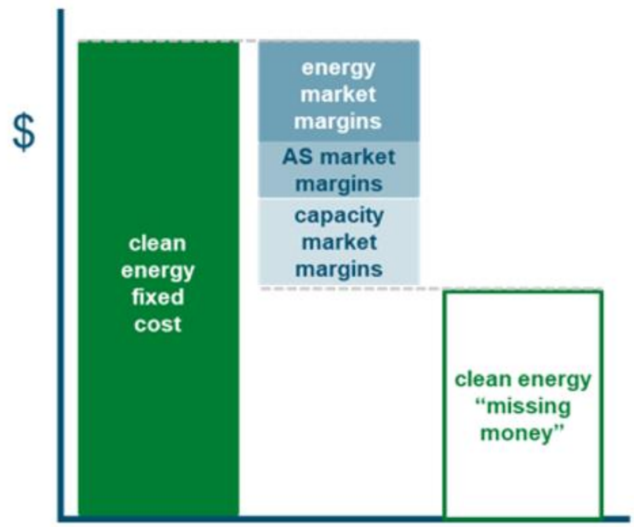
Source: https://resource-solutions.org/wp-content/uploads/2018/02/Tracking-System-Map.png

These "demand-pull" policies create demand and a market for the renewable energy attributes associated with clean energy. Given that clean energy has historically been more expensive than conventional energy, these policies helped to create a market for clean energy by providing a means for projects that would otherwise be uneconomic to enter the market. Renewable energy certificates, or RECs, serve two purposes in this framework. First, because power delivered over a networked electricity system cannot physically be tracked, RECs are the only method for buyers to demonstrate renewable energy content in power purchases. A REC represents the renewable energy attributes of one megawatt-hour (MWh) of renewable electricity generated and delivered to the electricity grid and is created when a qualifying renewable resource delivers energy to the grid. RECs are created when an eligible generator delivers electricity to the grid, and are tracked from creation to retirement by one of ten regional tracking systems active in North America, shown in Figure 2-2.

Load-serving entities demonstrate compliance with both voluntary and mandatory clean energy goals by "retiring" RECs.[12]

Second, the value of a REC in economic terms represents "missing money" or "green premium" that clean energy projects need to compete with conventional energy. The ability to transact RECs in markets not only provides important flexibility in RPS policies, ensuring that LSEs can balance their demand for and supply of RECs given uncertainty about load and clean energy generation, but it also provides an important source of revenue for clean energy projects.

Figure 2-3. Clean Energy Missing Money



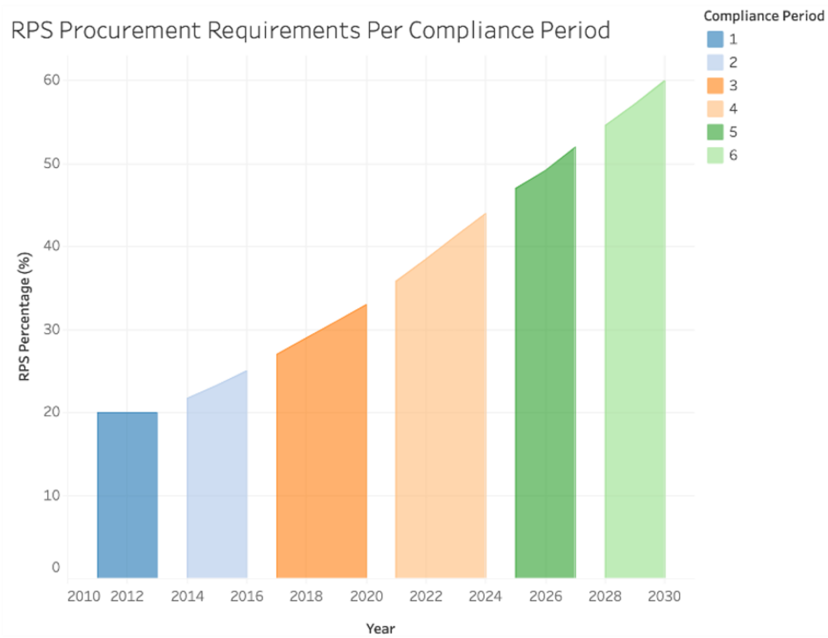
RECs may be 'unbundled' and transacted separately from the underlying electricity supply, in contrast to a 'bundled' REC where the electricity and REC from a renewable generation resource are transacted together. It is therefore possible and commonplace for a consumer to purchase RECs in a transaction that is separate from their purchase of the electricity commodity. REC creation and transfer is documented by the regional electronic REC tracking systems shown above, which register basic information about each megawatt-hour (MWh) of renewable generation in that region and issue RECs to the generator, signifying that a MWh of renewable electricity has been delivered to the grid. RECs generally include certificate data, tracking identification numbers, fuel type, facility location, capacity, project name, build date, utility interconnection, emissions rate, and other information for tracking purposes. Each REC has a unique ID and can only be owned by one account holder at a time, avoiding ownership disputes and preventing double counting.[13]

RPS requirements also contain other important flexibility features, given the fundamental uncertainty in load growth, renewable output, and the timing of when new clean energy projects come online. A key feature of nearly all RPS policies is multi-year compliance programs, which allow

[12] For an overview of REC lifecycle considerations, see: https://resource-solutions.org/learn/recs/.
[13] For more details, see CRS: https://resource-solutions.org/wp-content/uploads/2018/02/Tracking-System-Map.png

LSEs to meet their requirements over a span of years, rather than one year. Many RPS programs in the US have compliance periods of two or more years; an example of this is shown in Figure 2-4, which shows RPS periods for California's program. A related flexibility feature, "banking," allows LSEs to hold excess RECs generated in one compliance period to meet requirements in future periods. These features lower the costs of achieving RPS targets, help LSEs plan for uncertain load growth *and* renewable output, and provide opportunities for larger, more strategic investments in renewable energy.

Figure 2-4. Multi-Year Compliance Periods in the California RPS Program



Source: California Public Utilities Commission[14]

2.2 Federal Policy and the Role of Tax Credits

2.2.1 Federal Tax Credits

In addition to state RPS policies, the Inflation Reduction Act, signed by President Biden in August 2022, includes a range of clean energy and climate provisions that deliver funding through a mix of tax incentives, grants, and loan guarantees.[15] An estimated $216 billion of energy and climate funding is in the form of tax credits, which is intended to promote private investment in clean energy,

[14] 60% RPS Procurement Rules (ca.gov)

[15] For additional details, see:

McKinsey & Company, "The Inflation Reduction Act: Here's what's in it", October 24, 2022. https://www.mckinsey.com/industries/public-and-social-sector/our-insights/the-inflation-reduction-act-heres-whats-in-it

Congressional Research Service, "Tax Provisions in the Inflation Reduction Act of 2022 (H.R. 5376)", August 10, 2022. https://crsreports.congress.gov/product/pdf/R/R47202 transportation, and manufacturing. The IRA allocates over $45 billion for environmental justice priorities[16] and stipulates equity impacts be demonstrated for many funding opportunities.[17]

Critically, the IRA extends the Production Tax Credits (PTCs) and Investment Tax Credits (ITC) available to clean energy resources until the later of 2032 and the year when the IRA target of reducing GHG emissions from the power sector to 75% below 2022 levels is met, as determined by the U.S. Treasury. In addition, the IRA also introduces the 45V PTC for clean hydrogen, which has led to recent discussions and analyses regarding similar principles of temporal matching, additionality, and deliverability in the context of system-level and project-level economic outcomes.[18]

2.2.2 Tax Equity Markets

In the United States, the evolution of tax equity markets will influence deployment of clean energy. Currently, tax equity investments from financial institutions represent roughly $20 billion annually in capital committed to new clean energy generation assets. Incremental to this investment, new IRA allowances for tax credit transfers via sale have supplemented direct tax equity investments. While final data for 2023 was not available at the time this report was written, initial indications suggest that tax credit transfer sales represented between $4 billion and $9 billion in incremental capital in 2023.[19] E3 estimates that monetization of the Production Tax Credit can decrease LCOE by up to 51% for onshore wind resources and 77% for PV-based solar resources; monetization of the Investment Tax Credit can decrease LFC by up to 26% for lithium-ion battery storage resources, assuming the assets qualify for the prevailing wage and apprenticeship multiplier under IRA regulations. This is a direct result of the large share of the project capital structure that tax equity can represent: recent market surveys have estimated that 37% of project financing for solar projects claiming the ITC is from tax equity investors, while up to 35% - 51% of the capital stack is tax equity investment for solar or wind projects claiming the PTC.[20]

Annual fluctuations in the terms sought by tax equity investors can result in material changes to the financing costs for new projects. A recent study by the American Council On Renewable Energy (ACORE) found that actual after-tax returns for tax equity investments exited since 2018 range from

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[16] Environmental justice priorities include investments that can benefit disadvantaged communities across one or more of the following seven areas: climate change, clean energy and energy efficiency, clean transit, affordable and sustainable housing, training and workforce development, remediation and reduction of legacy pollution, and the development of critical clean water and wastewater infrastructure. www.whitehouse.gov/environmentaljustice/justice40.

[17] "Advancing Environmental Justice." EPA.

[18] For prior E3 analysis of this topic, see: https://acore.org/wp-content/uploads/2023/04/ACORE-E3-Analysis-of-Hourly-and-Annual-GHG-Emissions-Accounting-for-Hydrogen-Production.pdf

[19] Norton Rose Fulbright. "Cost of Capital: 2024 Outlook." Webinar. February 19, 2024. https://www.projectfinance.law/publications/2024/february/cost-of-capital-2024-outlook/. For more details, see: https://www.cruxclimate.com/2023-market-report.

[20] Carbon Reduction Capital. "Market Cost of Energy Analysis: H2 2023." January 2024. https://crc-ib.com/analysis-solar-wind-market-cost-of-energy-mcoe-h2-2023/

(0.2)% to 17.7% for PTC investments, and from 8.0% to 24.3% for ITC investments.[21] These ranges imply a 'monetization rate' (i.e., the rate at which the project developer can monetize each dollar of tax credit value) of 82% to 91% for the PTC, and 73% to 80% for the ITC. As a go-forward assumption, E3's Base resource costs assume 90% monetization of tax credits in general, based on available historical data which E3 reviews and updates regularly.

Separate from potential disruptions to the existing tax equity market, it is worth noting that optimistic assumptions for renewable energy resources costs rely on an expectation that the total amount of available tax equity financing will grow, which is not guaranteed. In 2015, lenders estimated that roughly $11.5 billion in tax equity financing was committed to roughly 5.7 GW of new wind and solar capacity.[22] This implies that every incremental kilowatt of clean energy generation capacity required roughly $2,000 in tax equity financing (ratio of $1:2000kW). Between 2015 and 2023, the total amount of mandated tax equity increased to roughly $21 billion, enough to support over 10 GW of new renewable energy capacity by the same metric.[23] Even after accounting for technology cost declines over the same period, which could significantly extend the ability of tax equity to finance additional capacity (closer to $1:1000kW), this investment need still lags well behind actual capacity additions of wind and solar in 2023, which totaled roughly 25 GW.[24] More important, estimates of incremental clean energy needs under current policies have suggested that 83 GW to 94 GW of combined wind and solar capacity may need to be added *every year* in the coming decade.[25] To support this rate of capacity additions, even under aggressive leverage-to-capacity assumptions, the size of the tax equity market would need to quadruple within the next decade. Given current capital requirements and the potential capital requirement constraints discussed, the tax equity market will require lenders to increase the allocation of capital to renewable energy investments relative to other available opportunities. While tax credit transferability does appear to be spurring growth in tax equity financing, the pace of growth and limits of this new market have yet to be realized or tested.[26]

2.3 California Policy Context

California has passed two clean energy and carbon reduction policies with significant relevance to this analysis:

1) **Senate Bill (SB) 100**: Increases the Renewable Portfolio Standard (RPS) for California to 60% of generation by 2030 and requires 100% GHG-free energy generation by 2045.

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[21] https://acore.org/wp-content/uploads/2023/12/ACORE-The-Risk-Profile-of-Renewable-Energy-Tax-Equity-Investments.pdf

[22] https://www.projectfinance.law/publications/2016/february/cost-of-capital-2016-outlook/

[23] https://www.projectfinance.law/publications/2024/february/cost-of-capital-2024-outlook/

[24] EIA 860M data (january_generator2024.xlsx) available at: https://www.eia.gov/electricity/data/eia860m/.

[25] Reflects average annual capacity additions of onshore wind and solar PV, 2023 – 2030, from Princeton Zero Lab: https://repeatproject.org/docs/REPEAT_Climate_Progress_and_the_117th_Congress.pdf.

[26] For a summary of recent tax credit transferability trends, see: https://www.cruxclimate.com/2023-market-report.

a. Subsequently, SB 1020 codified interim targets of 90% clean electricity by 2035 and 95% by 2040, while also stipulating that state agencies must meet a target of 100% clean electricity by 2035.

2) **Assembly Bill (AB) 32**: Sets economy-wide GHG emissions reduction target of 40% below 1990 levels by 2030, and 80% below 1990 levels by 2050.

Figure 2-5. California Electricity Governance Overview

	State Government	California Energy Commission (CEC)	California Public Utilities Commission (CPUC)	Independent System Operator (CAISO)	Load Serving Entities (LSEs) (Retail Utilities)
indicates lead role					
Policy	Designs + issues energy policies	Tracks policy compliance	Directs and enforces policy compliance for regulated entities (IOUs)		
Resource Planning		Forecasts loads by utility service territory for IRP	Runs statewide Integrated Resource Planning (IRP); sets targets for LSEs and approves LSE plans		Prepare and implement procurement plans according to IRP and customer demand
Resource Adequacy			Determines and enforces RA requirements; regulates cost recovery of RA resources in retail rates	Dispatches RA resources as part of system operations (includes Reliability Unit Commitment, RUC)	Procure RA resources
System Operations				Operates transmission system and dispatches generators for ~80% of CA state load	Some LSEs are also Balancing Authorities outside of CAISO network (SMUD, LADWP, IID, NVE, BPA, PacifiCorp)
Wholesale Market				Operates wholesale market for energy and AS	
Retail Service			Regulates retail tariffs		IOUs (PG&E, SCE, SDG&E): Operate & maintain distribution networks; provide retail service CCAs: retail service only

There are three characteristics of the California market most important for this study. First, California has a wholesale market for energy, which allows for procurement to occur in a transparent and liquid market. This is not the case in regulated utility markets, where vertically integrated utilities can monopolize the supply of electricity and constrain retail choice. Therefore, this study is analyzing a market with structures in place that are more conducive to hourly energy tracking and procurement than much of the United States.

Second, California's RPS program stipulates three categories of RECs that can each be traded:

1) **Category 1**: Bundled RECs generated within California;
2) **Category 2**: Bundled RECs generated within the Western Electricity Coordinating Council (WECC) region; and
3) **Category 3**: Unbundled RECs obtained within WECC, for which only the environmental attribute of the REC may be counted towards policy compliance.

The ability to distinguish among these categories of RECs is supported by the Western Renewable Energy Generation Information System (WREGIS), one of ten systems currently in operation in the

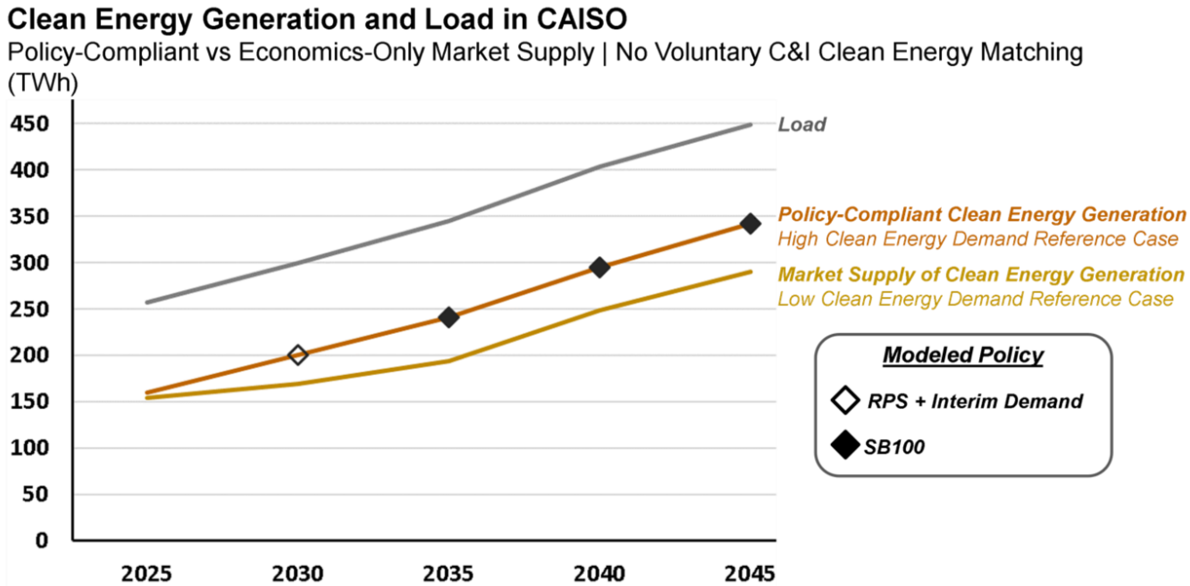
United States. This level of granularity in tradable REC market instruments also does not exist on a consistent basis across the United States, especially in the Southeastern U.S.[27]

Finally, California has a cap-and-trade program for carbon, enforced by the California Air Resources Board and which is intended to support the state's emissions reductions goals as set forth by AB 32.[28] An estimated carbon price associated with the cap-and-trade program is modeled as part of the High Demand scenario.

2.4 Demand for Clean Energy in California

California's clean energy and GHG emissions reduction policies mandate large quantities of annually-matched clean energy procurement. In addition, voluntary decarbonization commitments increase demand for clean energy above and beyond mandated levels in critical near-term years. This includes almost 40 TWh in clean energy demands by 2030.[29] For this study's High Demand scenarios, E3 modeled a clean energy target of 85% of retail sales by 2030, consistent with the latest CPUC IRP scenarios. This target is assumed to be inclusive of existing voluntary procurement commitments.

Figure 2-6. Annual Clean Energy Generation and Load Forecast in CAISO



Notes: Based on forecasted CAISO load used for this study. Generation excludes BTM PV generation which is very large and reduces the expected retail sales required to be met with SB100 eligible generation. This is generator-level (i.e., before T&D losses).

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[27] For more details, see: https://www.epa.gov/green-power-markets/renewable-energy-tracking-systems

[28] For more details on the California program and other analogous programs, see: https://www.c2es.org/content/cap-and-trade-basics/

[29] Aggregated clean energy electricity targets announced by LSEs in California, as aggregated by E3.

2.5 Voluntary Clean Energy Procurement, GHG Protocols, and the "Three Pillars" Debate

Corporations and other large-energy users are increasingly setting emissions reduction targets aligned with Environmental, Sustainability, and Governance (ESG) goals, and are voluntarily procuring RECs to comply with third party standards for GHG accounting such as the World Resources Institute's Greenhouse Gas Protocols, discussed below.[30]

The Clean Energy Buyers Association estimates that roughly 17 GW of voluntary clean energy was contracted through power purchase agreements, green tariffs, tax equity investments, and direct project ownership in 2022. This represents roughly 10 times the amount contracted in 2016. Voluntary demand is expected to continue increasing significantly over the next decade.[31] Voluntary demand for RECs supplements this compliance-driven demand. In sum, renewable energy demand is expected to grow by nearly 400 TWh between 2024 and 2030 just to meet clean energy goals that have already been announced.[32]

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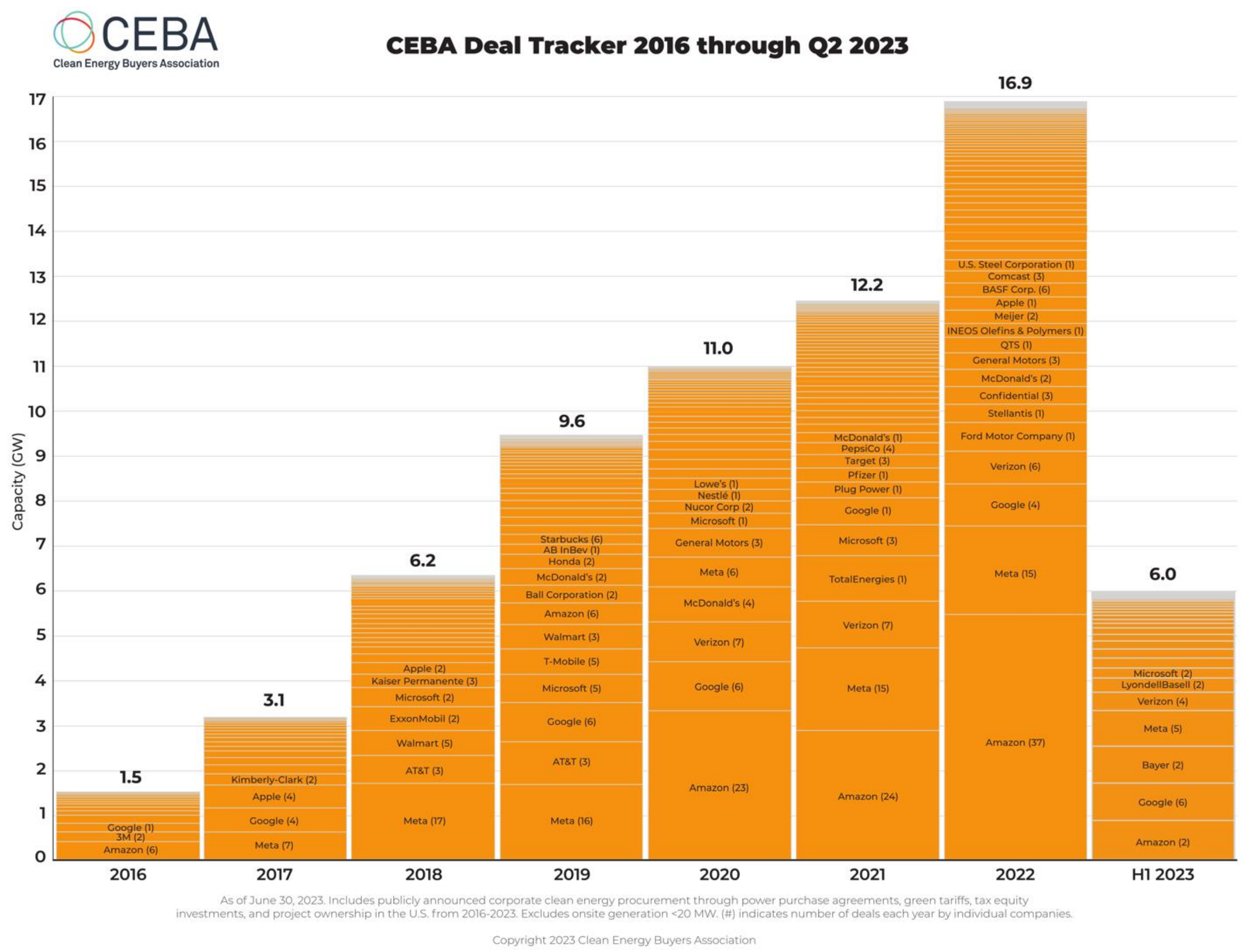
[30] For more details, see: https://www.wri.org/initiatives/greenhouse-gas-protocol.

[31] See:

- Clean Energy Buyers Association: https://cebuyers.org/deal-tracker/
- NREL (2021): https://www.nrel.gov/docs/fy22osti/81141.pdf
- 2022 Corporate Renewables Update. S&P Capital IQ (2022). https://www.capitaliq.spglobal.com/web/client?auth=inherit#news/article?KeyProductLinkType=2&id=69190458

[32] Source: https://emp.lbl.gov/publications/us-state-renewables-portfolio-clean

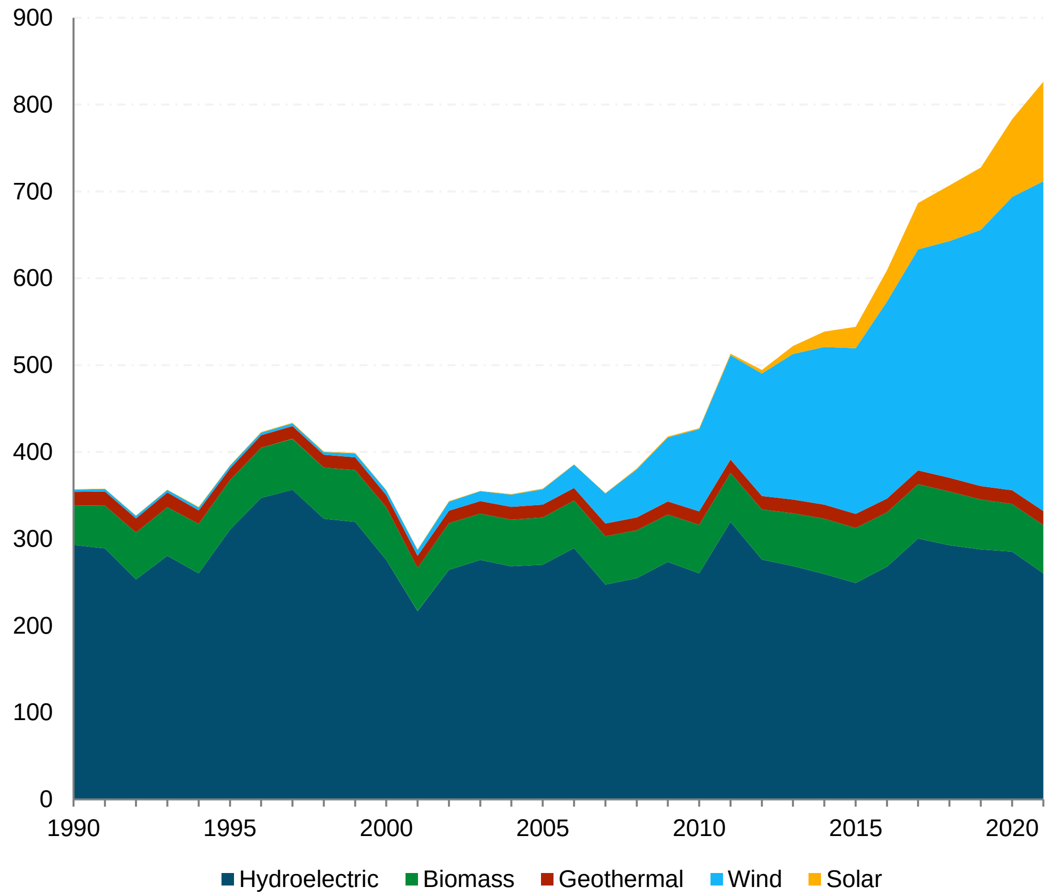
Figure 2-7. Corporate Clean Energy Contracts, 2016 – 2022 (GW)



This system of creating demand for clean electricity through demand-pull state and local policies in combination with voluntary purchases has been very successful in driving clean energy penetration. Figure 2-8 shows the growth in clean energy production over the past three decades. The voluntary market has played a significant role in this growth; NREL estimates that the voluntary market now accounts for 44% of clean energy procurement.[33]

[33] Source: https://www.nrel.gov/docs/fy23osti/86162.pdf

Figure 2-8. Renewable Production in the United States, 1990-2021 (TWh)



Source: Energy Information Administration[34]

2.6 Greenhouse Gas Accounting Protocols

Greenhouse Gas (GHG) accounting protocols are standards for GHG emissions accounting and reporting for corporations and other businesses. The GHG Protocol was created by the World Resources Institute (WRI) in 1998 and outlines internationally accepted standards, which are used by companies to quantify a GHG emissions inventory, including all emissions that are a direct or indirect result of their operations. Companies can also use the GHG Protocol to track emissions reductions achieved by specific company projects or policies.

GHG emissions that can be attributed to a company's operations are typically categorized into Scope 1, 2, and 3, as defined by the Protocol:

[34] Electricity in the U.S. - U.S. Energy Information Administration (EIA)

+ **Scope 1** emissions are direct emissions, originating from sources that the company owns or controls. For example, if a company burns a natural gas boiler it owns to produce electricity or heat, the emissions from the boiler would be Scope 1.
+ **Scope 2** emissions are indirect emissions created to produce energy the company purchases and consumes, including electricity, steam, heating, and cooling. For example, if a company purchases electricity from the grid to power the lighting and air conditioning for its office, the emissions from the generator(s) that produce the electricity would be Scope 2.
+ **Scope 3** emissions are the remaining indirect emissions not included within Scope 2. Scope 3 emissions occur upstream or downstream in the company's value chain. For example, emissions resulting from the production and transportation of a product the company buys would be Scope 3. Additionally, emissions incurred through the production and processing of fuels used for electricity generation (e.g. oil and gas refining) are also Scope 3, and distinct from fuel consumed for the Scope 1 and 2 emissions examples above.

This study evaluates circumstances in which corporations choose to voluntarily match their electricity demand with clean energy (Scope 2 emissions). Scope 2 emissions tied to electricity consumption are difficult to account for because the actual energy flowing from the generator to the purchasing company is not traceable on the bulk grid, i.e. the company's emissions cannot be attributed to a specific generator. To track these emissions, companies currently use either a location-based or market-based approach:

- **Location-Based**: Scope 2 emissions are based on the average emission factor of the grid from which electricity is purchased and consumed.
- **Market-Based**: Scope 2 emissions are based on the emissions of specific generators that are contracted to sell the company electricity. This method uses renewable energy certificates (RECs) to account for non-emitting energy purchased by the company.

This study uses the market-based approach. This approach is necessary for companies to reduce their Scope 2 emissions to zero (i.e. 100% clean electricity), as the alternative would be to wait for the bulk grid to achieve zero emissions, reducing the average emission factor to zero, on a timetable outside of the company's control.

In recent years, advocates have argued for a "three pillars" framework for evaluating the emissions impacts of new loads, or three requirements:[35]

1) **Additionality or Incrementality:** specified clean energy must be produced from generation that is new and would not exist but for the clean energy purchase.
2) **Deliverability or Regionality:** specified clean energy must be generated in the same grid or region where the energy is consumed.
3) **Temporal or Hourly Matching:** specified clean energy must be generated during the same time period in which the energy is consumed.

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[35] For a more detailed summary, see https://cleanpower.org/wp-content/uploads/2023/06/ACP_GreenHydrogenFramework_Explanation.pdf.

The proposed "Three Pillars" approach would eliminate the use of other approaches of demonstrating clean content, including the annual REC approach that has been in use for over 25 years. This would also preclude novel methods such as "emissions-matching" or "carbon matching" – the direct matching of emissions associated with load to the emissions avoided by new clean energy.[36] Advocates have focused on this approach as an improvement over annual matching because of its improved accuracy in reflecting time- and area-specific marginal carbon emissions rates, and as a better alternative to temporal matching because of the latter's high cost and challenging compliance requirements.[37]

[36] For example, see: https://cleanpower.org/wp-content/uploads/gateway/2023/06/ACP_GreenHydrogenFramework_OnePager.pdf.

[37] For an example of analysis of emissions matching, referred to as "carbon matching", see: https://tcr-us.com/uploads/3/5/9/1/35917440/paths_to_carbon_neutrality_white_paper_april23.pdf

3 System-Level Clean Energy Procurement Modeling and Scenario Design

3.1 Capacity Expansion Modeling Scenarios

We evaluate the impacts of C&I load voluntarily choosing to procure clean energy to meet their demand under different matching requirements. Specifically, the study evaluates annual matching requirements in which the total contracted clean energy generation must match the total participating C&I load over the course of the year, and hourly requirements in which contracted clean energy generation must match participating C&I load in every hour. Scenarios also evaluate the implications of allowing excess generation from contracted resources to be sold in markets for the rest of CAISO.

To explore these dynamics, the study quantifies clean energy generation, carbon emissions and costs for four cases:

1. A **Reference Case** without any incremental C&I clean energy procurement.
2. An **Annual Matching** case, in which incremental C&I clean energy demand can be met with new clean energy generation at any time during the modeled year.
3. An **Hourly "Island"** case, in which incremental C&I clean energy demand must be met with new clean energy generated during the same hour, but in which the C&I loads are not allowed to buy from *or* sell into the wholesale electricity market.
4. An **Hourly "Market"** case, in which incremental C&I clean energy demand must be met with new clean energy generated during the same hour, and C&I loads are allowed to sell excess energy into the wholesale electricity market. In this case, procured hourly matched supply is required to be equal to demand in each hour, and thus no additional market purchases are required or allowed.

These cases are evaluated under two primary scenarios for clean energy demand:

1. A **High Clean Energy Demand** Scenario, in which demand for clean energy attributes is assumed to be strong. Demand for clean energy in this scenario is stimulated by assuming compliance with California's SB 100 and SB 1020 clean energy targets, which require 90% of retail electricity sales to be met with non-emitting generation by 2035, 95% by 2040 and 100% by 2045. Additionally, a target of 85% by 2030 is assumed, consistent with the latest CPUC IRP scenarios.
2. A **Low Clean Energy Demand** Scenario, in which there is no demand for clean energy attribute certificates outside of the participating C&I load. This scenario assumes that current California clean energy policies including SB 100, SB 1020, AB 32 (including the cap-and-trade program) and IRP GHG targets do not exist; clean generation accordingly is only selected if it is economic to include in the least-cost supply portfolio.

In each case, a Reference Case is first modeled which establishes the baseline market conditions against which changes induced by our scenarios are measured. Then a demand "shock" is introduced by assuming a portion of C&I loads procure clean energy equal to 100% of their energy demand in a given time period. The extent to which this shock results in additional clean energy generation and consequential carbon emissions reductions is determined by comparing the energy and emissions quantities with those of the Reference Case.

As described in Table 3-1, E3 also modeled a range of tax equity (TE) specifications as sensitivities, which specify how much of the Investment Tax Credit (ITC) or Production Tax Credit (PTC) eligible projects can monetize.

Table 3-1. Scenarios Modeled

Case Set	California Carbon & Clean Energy Policy	Tax Equity Monetization Rate	Matching Framework	Participating C&I Load (%)
High Clean Energy Demand	SB 100, SB 1020, CARB Carbon Price	90% PTC monetization	Reference, Annual, Hourly Market, Hourly Island	0%, 25%
Low Clean Energy Demand	None	90% PTC monetization	Reference, Annual, Hourly Market, Hourly Island	0%, 10%, 25%, 50%
Low EAC Demand + Limited Tax Equity*	None	82% PTC monetization	Reference, Annual, Hourly Market, Hourly Island	0%, 25%
Low EAC Demand + Tax Equity Collapse*	None	18% PTC monetization	Reference, Annual, Hourly Market, Hourly Island	0%, 25%

Notes: * Summary impacts provided in the appendix and additional results available upon request. High EAC Demand + Limited Tax Equity case sets were also explored but the results are excluded due to similarity of incremental clean energy generation outcomes to the default High Clean Energy Demand set.

In this study, the following definitions are adopted:

+ **Incremental clean energy demand** is the amount of clean energy demanded by C&I customers relative to the Reference Case without the demand shock.
+ **Incremental clean energy generation** measures the additional clean energy generation across the CAISO in relation to the Reference Case without the demand shock.
+ **Eligible new clean energy resources** are similar for both annual and hourly matching. Since storage is strictly charged with clean energy in the hourly matching, discharged energy from storage are considered clean and eligible to match the hourly C&I load.
+ **Excess clean energy** refers to the amount of clean energy procured by C&I participating loads in excess of their energy needs on an hourly basis.
+ **Consequential GHG emission reductions** for each case are quantified as the CAISO-wide GHG emissions changes relative to the Reference Case.

- **Incremental costs** are presented as the changes in total WECC-wide net present value costs as of 2024, over the entire planning horizon with 20 years of end-year effects (2025-2064) levelized over incremental C&I clean energy generation.
- **Incremental carbon abatement costs** are defined as the average incremental costs associated with achieving greenhouse gas emissions reductions across cases, calculated by taking the change in cost NPV between the Matching Case and the Reference Case, divided by systemwide change in emissions NPV (also Matching relative to the Reference Case). This $/ton is based on discounting to 2024.[38]

3.2 Overview of the CAISO RESOLVE Model

RESOLVE is an electricity system capacity expansion model that identifies optimal long-term generation and transmission investments needed to meet demand over time, subject to reliability, technical, and policy constraints. This model is used to inform resource planning and investment decisions in jurisdictions across North America, including in New York, Hawaii, and California.[39] RESOLVE considers both the fixed and operational costs of resource portfolios over the lifetime of the resources and is specifically designed to simulate power systems operating under high penetrations of renewable energy and electric energy storage. By co-optimizing investment and operations decisions in one stage, the model directly captures dynamic trade-offs between them, such as energy storage investments versus renewable curtailment/overbuild. The model uses weather-matched load, renewable, and hydro data and simulates interconnection-wide operations over a representative set of sample days in each year. The model captures the dynamic contribution of renewable and energy storage resources to the system that vary as a function of their penetration, specifically in terms of capacity requirements toward the planning reserve margin. The objective function minimizes net present value (NPV) of electricity system costs, which is the sum of fixed investment costs and variable plus fixed operating costs, subject to various constraints. Figure 3-1 provides an overview of the model.

The CAISO RESOLVE model utilized in this study is continuously updated and used in multiple ongoing California studies. This model has been used for purposes such as the CPUC Integrated Resource Plan's Load Serving Entities (LSE) Filing Requirements, and at the state level, for California's Air Resources Board's (CARB) Scoping Plan's electric system modeling for decarbonization. The version modified for this analysis was based on the publicly available model recently used for the CPUC Integrated Resource Plan (IRP), including the 2023 Preferred System Plan and 2024-25 Transmission Planning Process. Other modeling details as well as the data sources are provided in Appendix A.

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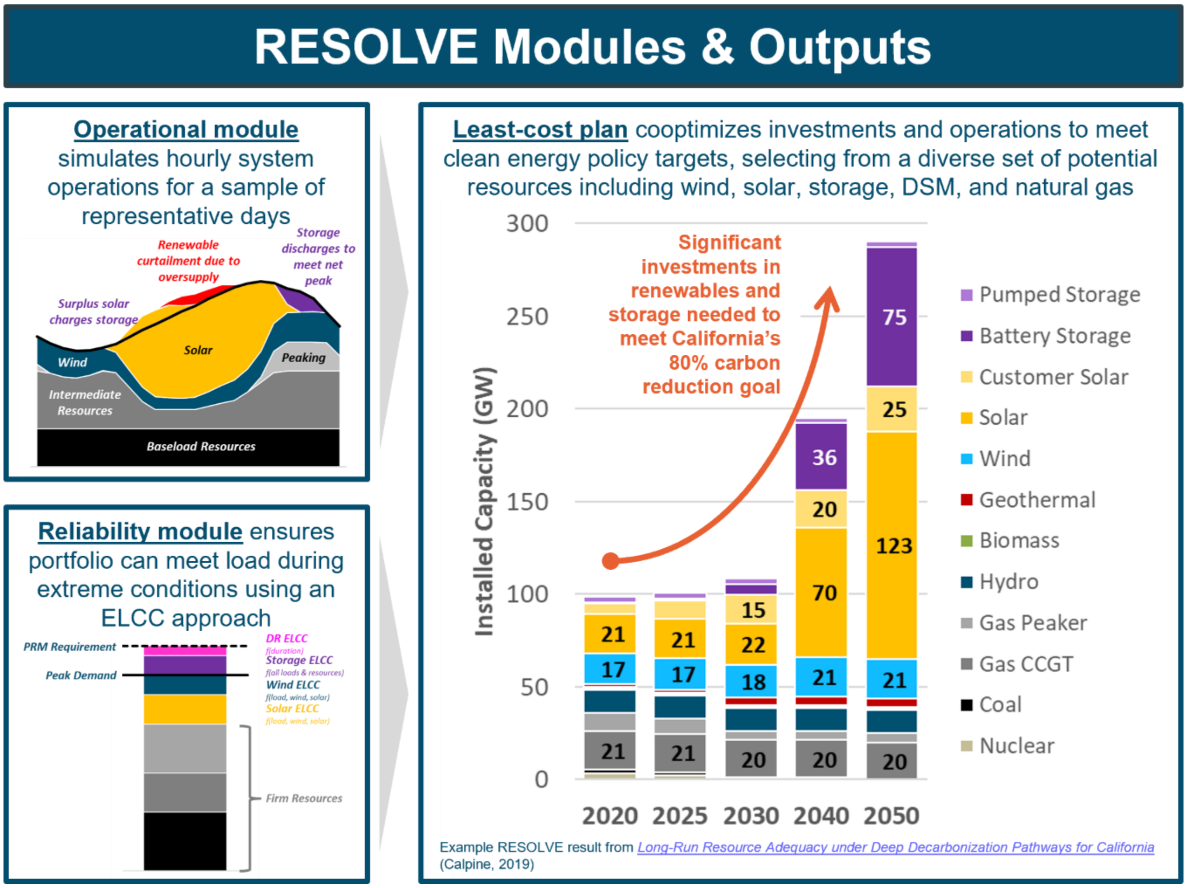
[38] Because RESOLVE performs its optimization at the WECC level, costs are reported at the WECC level.
[39] For more information, see overview and recent studies on E3's website here: [RESOLVE - E3 (ethree.com)](https://www.ethree.com)

Figure 3-1. Overview of the RESOLVE Model

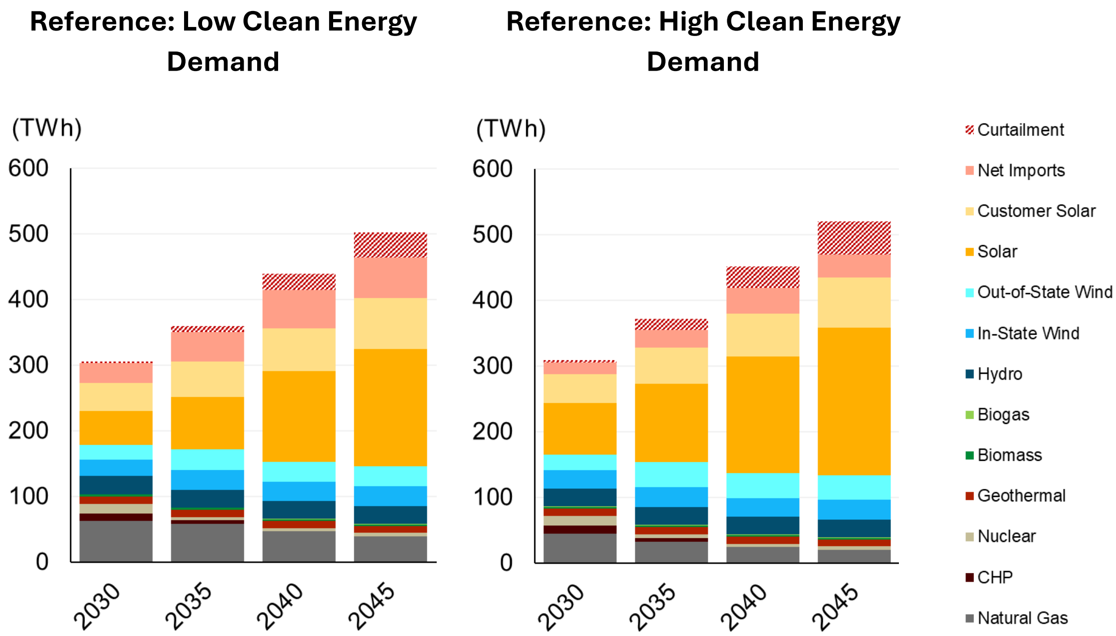


3.3 CAISO Resource Portfolios

Figure 3-2 summarizes the Reference scenario generation mix in both the Low and High Clean Energy Demand scenarios. The model selects a mix of solar, onshore wind, out-of-state wind, geothermal energy, and battery storage, along with planned behind-the-meter solar adoption driven by California's NEM program.

In the Low Demand scenario, which removes state clean energy policy and carbon pricing, the generation mix still shifts towards cleaner generation such that CAISO's electricity demand is served by about 70% clean energy, including hydro and nuclear power, in 2030 and 80% in 2040. In the High Demand scenario, which includes California's carbon price and SB 100 and SB 1020 policy compliance requirements, larger amounts of renewable energy and a more diverse set of resources are procured. Clean energy generation achieves 85% of retail sales by 2030 and 95% by 2040, aligned with 2030 IRP planning targets and the 2040 SB 100 requirements.

Figure 3-2. CAISO Generation under Low and High Demand Scenarios – Reference Cases



The summary of the Reference cases for Low and High Demand Scenarios are presented in Tables 3-2 to 3-5. Unless specified, the results section focuses on 25% of C&I load choosing to clean energy match. The tables below also include the incremental clean energy generation, emissions reductions and cost increases for annual and hourly matching for 25% participating C&I load.

Table 3-2. Summary Energy and Emissions Metrics: 25% C&I Matching Cases Compared to Reference in High Demand Scenario

		2030				2035			
			Changes vs. Reference				Changes vs Reference		
	Unit	Reference	Annual	Hourly Island	Hourly Market	Reference	Annual	Hourly Island	Hourly Market
C&I Participating Load	TWh	-	36.7	36.7	36.7	-	38.6	38.6	38.6
Incremental C&I Gross EAC Demand	TWh	31.2	+ 5.5	+ 5.5	+ 5.5	34.7	+ 3.9	+ 3.9	+ 3.9
Incremental EAC Supply from C&I	TWh	31.2	+ 5.5	+ 6.9	+ 14.2	34.7	+ 3.9	+ 5.2	+ 11.2
Changes in Rest of CAISO Clean Energy Supply	TWh	-	0	0	-8.7	-	0	0	-7.3
Systemwide Incremental Clean Energy Supply	TWh	-	+ 5.5	+ 6.9	+ 5.5	-	+3.9	+5.2	+3.9
Incremental Emissions	MMT	2.6	-1.9	-2.6	-1.9	2.0	-1.3	-2.0	-1.3

Notes: Reference reports results in the Reference Case, and the subsequent columns are changes relative to that Reference. Incremental Gross EAC demand refers to how much incremental EAC demand C&I load is requiring relative to reference clean energy demand, on an accounting basis. Incremental EAC supply from C&I is a function of what is built by C&I customer compared to the Reference case. C&I procured clean energy can impact clean energy generation in the rest of CAISO in the matching cases which is reported as changes in rest of CAISO. Emissions report average emissions for matched C&I load and incremental change in total systemwide emissions within CAISO. Numbers are rounded to nearest tenth.

Table 3-3. Summary Cost Metrics: 25% C&I Matching Cases Compared to Reference in High Demand Scenario

		High Demand Modeled System Costs, 2025-2064			
			Changes vs Reference		
	Unit	Reference	Annual	Hourly Island	Hourly Market
NPV WECC Modeled (Partial) System Costs	Billion $	$333	+0.1	+6.9	+0.1
Ref. Cost and Modeled Cost of Incremental Clean Generation	$/MWh	$24.6	+2.9	+186.6	+3.9

Notes: NPV reported in 2024 dollar-years, as of January 1, 2024, with costs over the period of 2025-2064. The modeling is performed from 2025 through 2045, with results interpolated for non-modeled years, and end effects added as weights for 2046-2064. The modeled costs include the sum of optimized new CAISO transmission and generation-related fixed costs and WECC-wide system operating costs. The Reference cost per C&I is simply the average modeled system cost. The change in cost assumes that the increase in total system cost is borne by the incremental clean matched C&I load above the Reference, so represents the change in system cost over the same period, divided by the amount of incremental clean energy, discounted to 2024.

Table 3-4. Summary Energy and Emissions Metrics: 25% C&I Matching Cases compared to Reference in 2030 and 2035 in the Low Demand Scenario

		2030				2035			
			Changes vs. Reference				*Changes vs Reference*		
	Unit	Reference	Annual	Hourly Island	Hourly Market	Reference	Annual	Hourly Island	Hourly Market
C&I Participating Load	TWh	-	36.7	36.7	36.7	-	38.6	38.6	38.6
Incremental C&I Gross EAC Demand	TWh	26.2	+ 10.4	+ 10.4	+ 10.4	27.9	+ 10.7	+ 10.7	+ 10.7
Incremental EAC Supply from C&I	TWh	26.2	+ 10.4	+ 12.0	+ 26.2	27.9	+10.7	+12.2	+34.2
Changes in Rest of CAISO Clean Energy Supply	TWh	-	- 3.1	+ 0.6	- 4.1	-	- 10.5	- 11.4	- 33.5
Systemwide Incremental Clean Energy Supply	TWh	-	+ 7.3	+ 12.6	+ 22.1	-	+0.2	+0.8	+0.6
Incremental Emissions	MMT	4.2	-2.5	-4.2	-7.6	4.3	-0.0	-0.2	-0.2

Notes: Reference reports results in the Reference Case, and the subsequent columns are changes relative to that Reference. Incremental Gross EAC demand refers to how much incremental EAC demand C&I load is requiring relative to reference clean energy demand, on an accounting basis. Incremental EAC supply from C&I is a function of what is actually built by C&I customer compared to the Reference case. C&I procured clean energy can impact clean energy generation in the rest of CAISO in the matching cases which is reported as changes in rest of CAISO. Emissions report average emissions for matched C&I load and incremental change in total systemwide emissions within CAISO. Numbers are rounded to nearest tenth.

Table 3-5. Summary Cost Metrics: 25% C&I Matching Cases Compared to Reference in Low Demand Scenario

		Low Demand System Costs, 2025-2064			
			Changes vs Reference		
	Unit	Reference	Annual	Hourly Island	Hourly Market
NPV WECC Modeled (Partial) System Costs	Billion $	$305	+0.02	+6.6	+0.5
Ref. Cost and Modeled Cost of Incremental Clean Generation	$/MWh	$22.6	+0.2	+51.4	+4.1

Notes: NPV reported in 2024 dollar-years, as of January 1, 2024, with costs over the period of 2025-2064. The modeling is performed from 2025 through 2045, with results interpolated for non-modeled years, and end effects added as weights for 2046-2064. The modeled costs include new the sum of optimized new transmission and generation-related fixed costs and system operating costs. The Reference cost per C&I is simply the average modeled system cost. The change in cost assumes that the increase in total system cost is borne by the incremental clean matched C&I load above the Reference, so represents the change in system cost over the same period, divided by the amount of incremental clean energy, discounted to 2024.

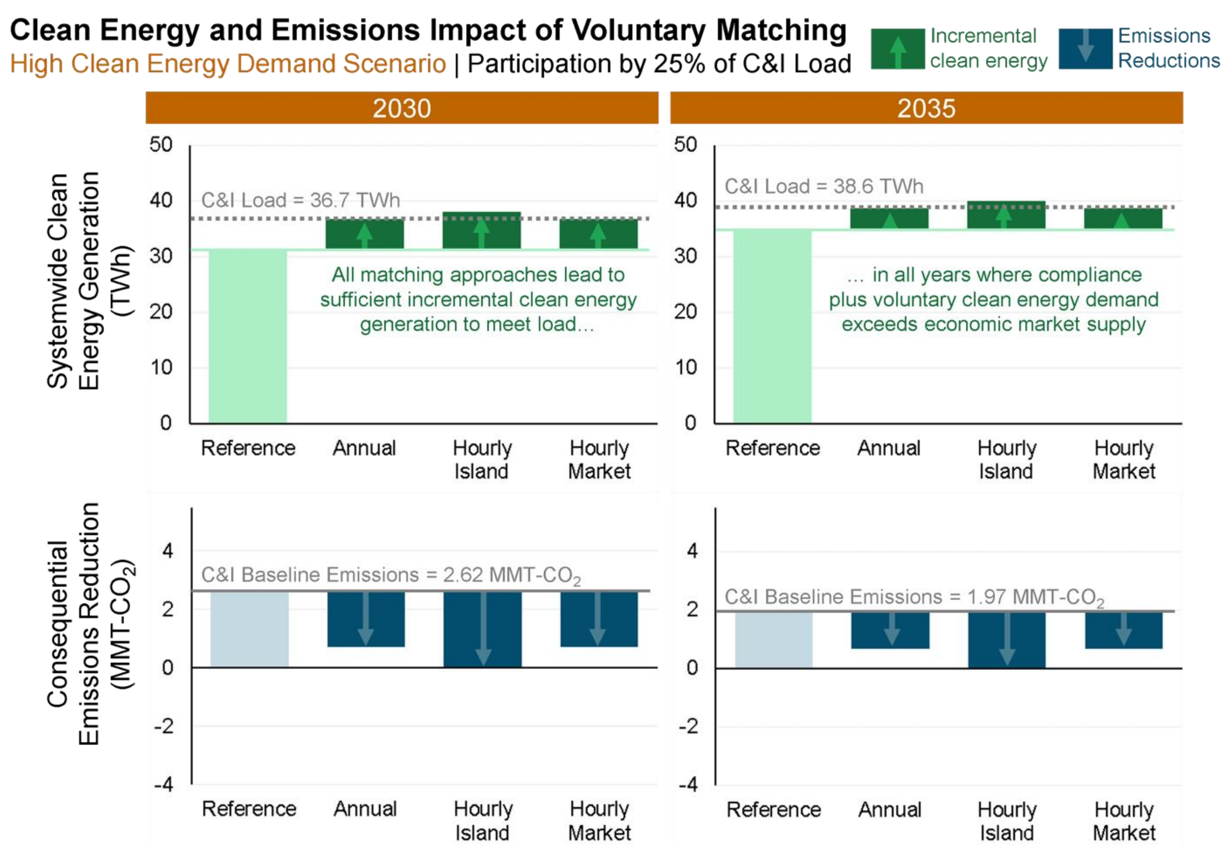
3.4 High Clean Energy Demand Scenarios: Annual and Hourly Matching Cases Result in Similar Emissions Reductions

In the voluntary procurement cases, participating C&I loads contract for EACs equal to 100% of their electricity consumption. When clean energy demand is high, there are not enough EACs available in the market and new clean energy generation must be deployed to meet the increased demand from incremental clean energy demand to ensure that existing demand continues to be satisfied. For markets like California, which has a 100% clean energy retail sales requirement by 2045, the incremental clean energy procured by voluntary matching can accelerate clean energy deployment and GHG reductions until LSEs reach the 100% requirement in 2045.

The upper left quadrant of Figure 3-3 reports the average clean energy generation serving participating C&I load in the Reference case and the incremental system-level clean energy generated under different matching requirements. Given California's planning target of 85% of retail sales in 2030, demand is served by high levels of clean energy even in the Reference case. In this scenario, clean energy demand is binding, and thus annual or hourly matching requirements drive new clean energy on a systemwide basis. This new clean energy ensures that nearly all emissions associated with the clean energy buyers are eliminated. We note that some emissions remain under both annual and hourly market cases, which is largely a function of the SB 100 policy design and because scenarios charge slightly more storage in their matching portfolios.[40] More details related to the replacement generation are provided in the appendix, with all matching scenarios adding incremental solar in the system, plus small amounts of incremental wind and geothermal in the hourly island case.[41]

This same pattern occurs in 2035, although now SB 100 requires 90% clean energy to serve retail sales, which increases the amount of clean energy in the Reference case. In this period, all matching frameworks generate incremental clean energy to serve their load and reduce most of the emissions associated with that load. The remaining small differences relate to the same factors noted above.

Figure 3-3. Incremental Clean Energy Generation and Emissions Reductions from Serving 25% of C&I Load with 100% Clean Energy under High Demand Scenarios



The need for participating C&I customers to invest in new renewable energy sources drives costs above what they would pay for energy under the Reference Case. Intuitively, hourly matching results in higher costs than annual matching across all cases, reflecting the additional resource builds

[40] Specifically, these cases use slightly more storage duration, which increases the total generation to charge storage. Because the SB 100 requirement is an exogenous input in our study and only a function of retail sales to LSE consumers and not to charge storage, higher amounts of storage allow for slightly higher gas generation.

[41] Note that the resource mix in all cases, including the Reference, includes significant growing BTM PV consistent with the state's IRP planning assumptions.

necessary. Costs decrease if market integration is allowed under hourly matching (i.e. excess clean energy can be exported to the market) but are still higher than annual matching across all cases.

Matching costs can also be measured in terms of a carbon abatement cost, or the money spent for each unit of CO_2 reduction. Annual matching results in a modest *average* abatement cost, estimated at $6/ton CO_2 in cases with 25% C&I matching for emissions reductions relative to the Reference case. Hourly matching increases the average carbon abatement costs, but the magnitude of this increase depends on whether the matching load is integrated with the market, in which case it can support compliance with SB 100. Under hourly matching without market integration, excess energy must be curtailed and the abatement cost rises to nearly $300/ton. In contrast, under market integration, the abatement cost is significantly lower, as the ability to export excess energy to the grid reduces the net cost of the incremental procurement.

Table 3-6. Average Carbon Abatement Cost Under Different Matching Frameworks, High Demand, 2025-2064

	High Demand Scenario 25% Matching	
Matching Assumption	**Cumulative CAISO-Wide GHG Reduction (MMT)**	**Cost ($2024/ton CO_2)**
Annual	39.7	$6
Hourly Island	56.0	$272
Hourly Market	39.7	$8

Notes: Undiscounted cumulative emissions reduction is reported for 2025-2064 by assuming linear trajectory across modeled years. The cost per ton is based on the NPV (as of January 1, 2024, for costs from 2025-2064) of total incremental system costs divided by the NPV of total incremental emissions reductions.

3.5 Low Clean Energy Demand Scenarios: Neither Annual nor Hourly Matching Drives Consequential Long-Term Emissions Reductions

Voluntary procurement of EACs for 100% of consumption has distinct impacts in scenarios with low clean energy demand. In these scenarios, we assume there is no demand for EACs other than what is specified for the participating C&I customers. This means that the level of clean energy in the Reference case represents what would be driven by market forces alone (although it does include the effect of the federal tax policies such as the IRA).

In Figure 3-4, we report the Reference clean energy mix serving C&I load, and the system-wide incremental clean energy across the annual, hourly island and hourly market cases, both in 2030 and 2035. In 2030, we see that all cases result in additional clean energy. However, in the annual scenario, the net incremental clean energy generated is somewhat less than the total C&I load. This is because some of the clean energy that serves this load was also built in the Reference case, and thus in the matching scenario, there is a smaller net change in clean energy. To emphasize this point, Figure 3-5 illustrates the two component parts of the impact. This figure illustrates that while the C&I load does procure the full amount to meet its load (hashed green), there is a reduction in clean energy generation outside the C&I load (hashed pink). In 2030, the hourly cases generate larger amounts of incremental clean energy, because the model must build large quantities of clean energy to match incremental demand in the most difficult hours. This creates excess clean generation in certain hours of the year, as we illustrate in more detail further below.

Despite this shock to the system in 2030, both figures illustrate that by 2035, the system has fully adjusted to the same level of clean energy generation in both Reference and Matching cases. In other words, the additional clean energy generation is temporary; almost no incremental clean energy generation is observed in the following modeling period (i.e., 2035), after the market has had time to adjust. This implies that by 2035, the market would have built enough clean generation on its own to meet both annual and hourly-matched demand.

Figure 3-4. System Impacts of Clean Energy Procurement in 2030 and 2035 from Serving 25% of C&I Load with 100% Clean Energy under the Low Demand Scenario

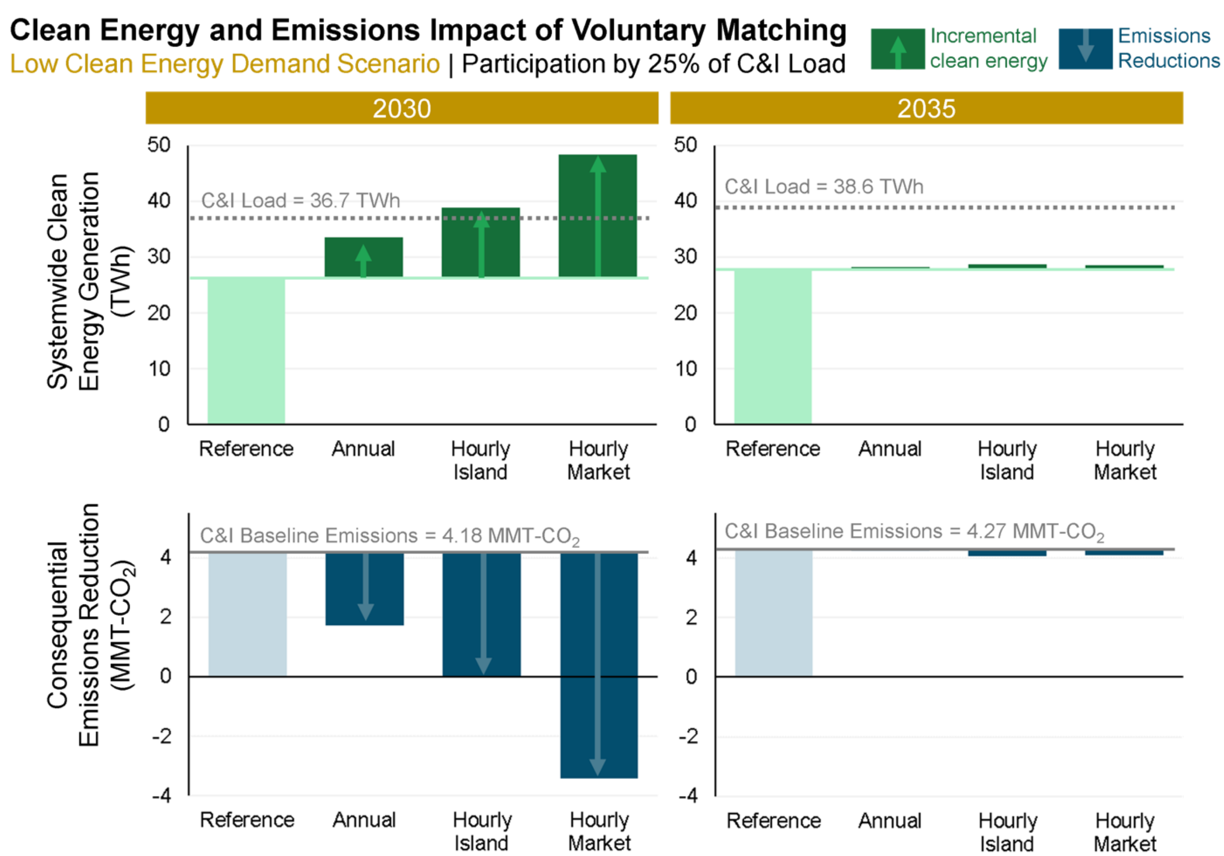
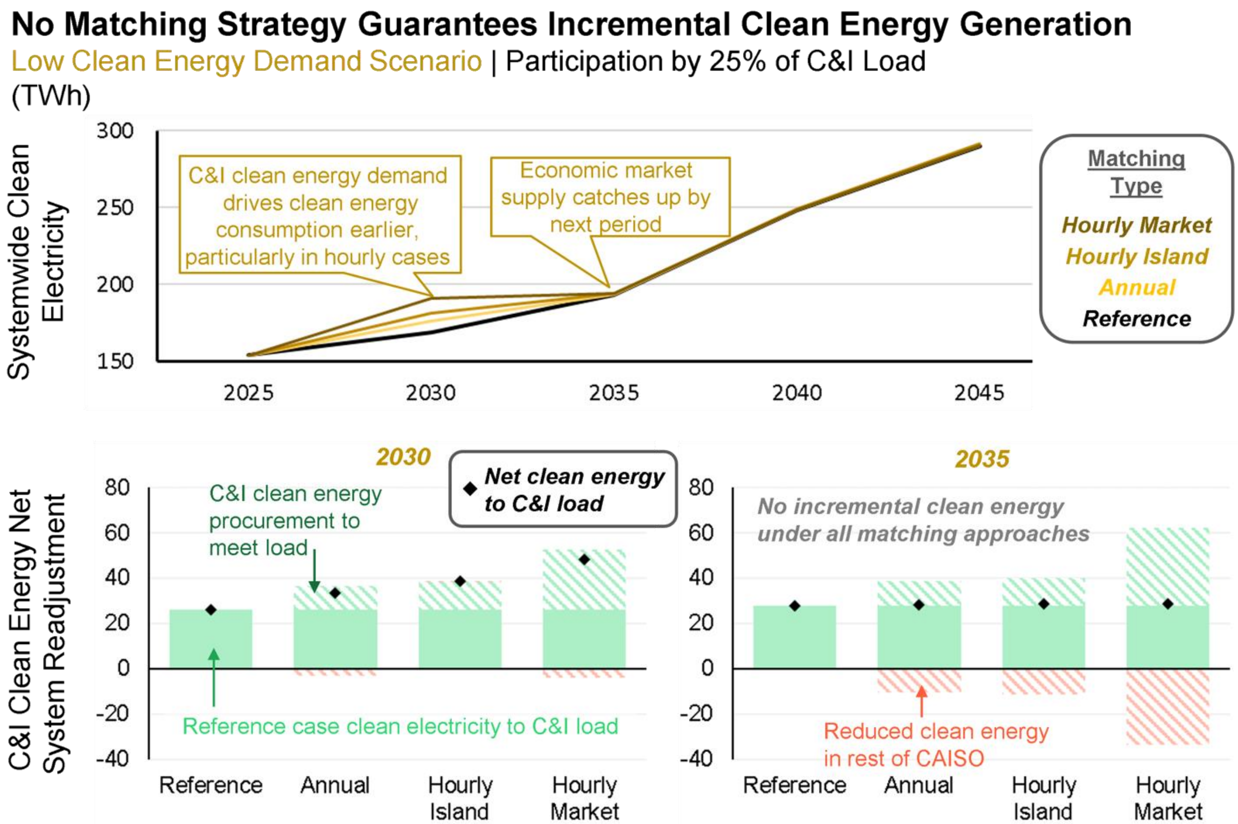


Figure 3-5. Systemwide Clean Energy Procurement under Low Clean Energy Demand



Consistent with above, we report an average carbon abatement cost for the low clean energy demand scenarios. Again, this represents the net present value of the total stream of incremental system costs, divided by total emissions reductions. Given the market adjusts in the subsequent model period, cumulative emissions reductions are smaller, and the abatement cost is therefore lower, though the same pattern holds with hourly matching scenarios, particularly hourly scenarios without the ability to export, being much more expensive on average.

Table 3-7. Average Carbon Abatement Cost Under Different Matching Frameworks, Low Demand, 2025-2064

	Low Demand Scenario 25% Matching	
Matching Assumption	**Cumulative CAISO-Wide GHG Reduction (MMT)**	**Cost ($2022/ton CO_2)**
Annual	11.7	$2
Hourly Island	33.6	$334
Hourly Market	38.0	$18

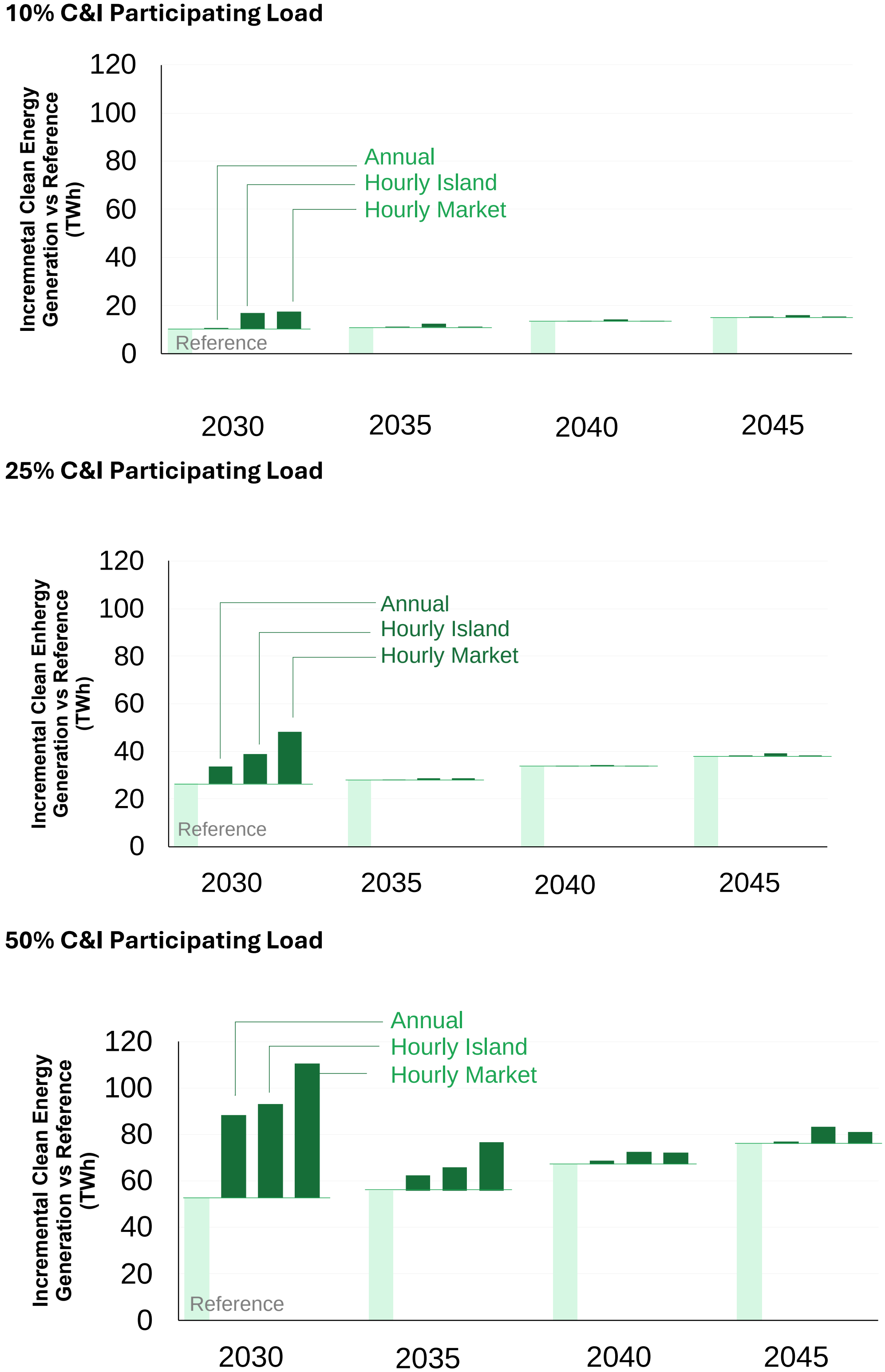
Notes: Undiscounted cumulative emissions reduction is reported for 2025-2064 by assuming linear trajectory across modeled years. Based on the NPV (as of January 1, 2022, for costs from 2025-2064) of total incremental system costs divided by the NPV of total incremental emissions reduction.

3.6 The Persistence of the Shock Depends on the Scale of Matching Clean Energy Demand

Of course, the magnitude of C&I load participating in matching influences the amount of clean energy deployment. Figure 3-6 shows incremental clean energy generation under 10%, 25% and 50% voluntary matching under Low Demand Scenario assumptions, and highlights three conditions:

- **When clean energy supply exceeds clean energy demand:** In a low C&I participation rate (i.e., 10% in this study), annual matching results in no incremental clean energy generation because economics alone add enough clean energy to meet all C&I incremental demand in 2030. Conversely, hourly matching results in incremental clean energy generation even in the 10% participation because over-procured clean energy needed for hourly matching accelerates builds that are not yet economic, providing incremental clean energy. However, the growth in clean energy demand is slower than the growth in market-driven clean energy supply, and thus by the subsequent model period, we find supplies are non-additional under both annual and hourly matching approaches.
- **When clean energy demand exceeds economic clean energy supply:** At higher C&I participation rates (i.e., 25% and 50% in this study), economic clean energy additions are not enough to meet the increased clean energy demand from voluntary procurement in 2030; thus, both annual and hourly matching result in incremental clean energy generation in that year. However, the growth in clean energy demand is slower than the growth in market-driven clean energy supply, and thus by the subsequent model period, we find supplies are non-additional under both annual and hourly matching approaches.
- **When the clean energy demand significantly exceeds clean energy supply:** In the highest C&I participation rate studied (i.e., 50%), the demand is high enough to drive otherwise uneconomic clean energy projects online through the last modeled year (i.e., 2045), sustaining amounts of additional clean energy compared to the Reference.

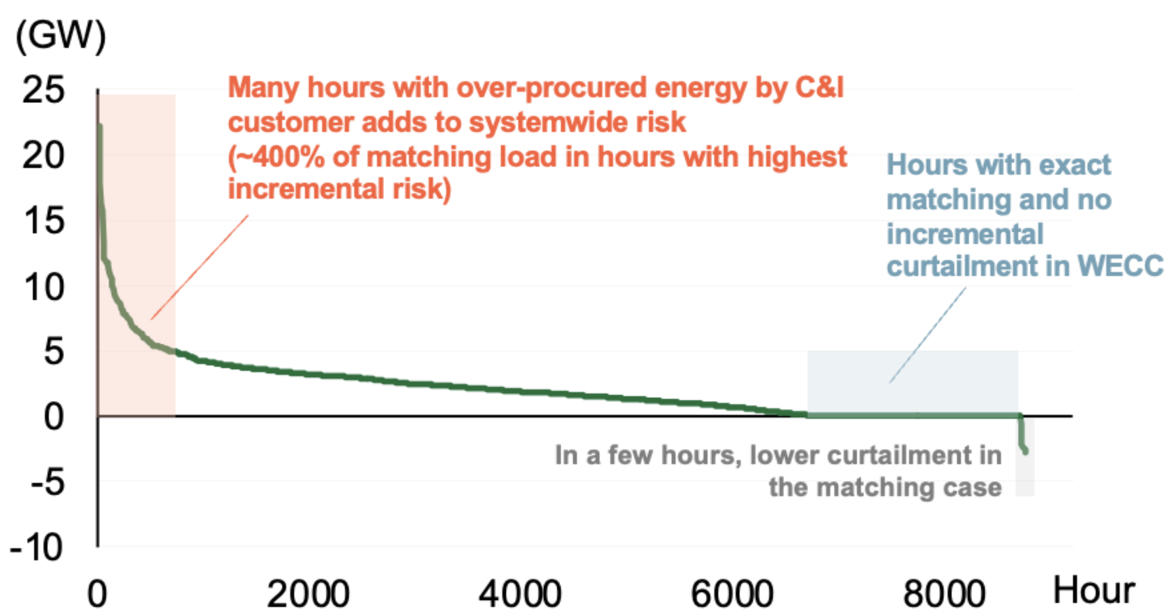
Figure 3-6. Incremental Clean Energy Generation in 10%, 25% and 50% C&I Matching Cases for Low Demand Scenario



3.7 Hourly Matching Requires Clean Energy Purchasers to Procure Significantly More Clean Energy than Needed to Serve their Own Load

Hourly matching cases require that the participating C&I load procure significant quantities of excess clean energy generation to ensure that they have enough clean energy on the most challenging days (i.e., low renewable output days, particularly long stretches when battery generation depleted). When the system is built to meet demand on the most challenging days, this means that on all other days, the C&I load will have excess generation that must either be exported to the rest of the grid (if possible) or curtailed. Figure 3-6 below reports excess clean energy, representing the sum of clean energy exports and incremental curtailment, under an hourly matched market scenario. This combined sum represents the amount of energy that participating C&I customers must procure above and beyond the energy that is directly serving their load. In fact, participating customers must procure clean energy equivalent to about 400% of their C&I load in the hours with the most excess energy. In the hours with no excess clean energy for exports, storage charging is absorbing additional available clean energy from C&I procurement, or those are hours when C&I procured clean energy exactly matches the C&I load. In just a handful of hours, there is lower curtailment in the hourly matching case compared to the Reference case, due to changes in the overall portfolio. In the market cases, much of this excess energy must be sold to the rest of the grid, while in the island scenarios, participating customers must simply curtail this excess energy. This structure creates significant market risk to voluntary clean energy matching C&I customers.

Figure 3-7. Excess Clean Energy Procurement by C&I Load by Hour, Hourly Matching Market Case in Low Demand Scenario, 2030



Notes: Graph includes the sum of exports from excess clean energy from C&I procured resources to the rest of the system (i.e., market sales), and WECC-wide incremental curtailment in that hour (if any) in the hourly matched scenario, relative to the reference.

3.8 Hourly Load Matching is Much More Challenging Under Extreme Weather Conditions

Capacity expansion models, including this study, optimize portfolio buildouts based on representative days from historical weather years. While sample day selection methods ensure a wide range of historical conditions are represented among the sample days, more extreme events (e.g., 1-day-in-10-year conditions) are typically not represented and increase the risk of missing hours for 100% compliance.

Figure 3-8 and Figure 3-9 show observed generation uncertainty for wind and solar resources. In Figure 3-8, the variability in wind output is shown for a wind site in California. This figure illustrates that the average annual capacity factor for wind can vary by over 20 percent. Similarly, Figure 3-9 illustrates the differences in hourly generation in summer days across historical weather conditions between 1998 to 2022 for a Tehachapi Solar project located in California. Notably, the range of solar performance varies substantially across extreme and warm climates even during the middle of the day. Such variation in renewable power is well-understood and incorporated in RESOLVE's representative day modeling derived from historical weather conditions. However, given the increased frequency of severe weather events, the real-word performance risks of renewable power can be underrepresented in the reduced dataset. Because of that, an optimized renewable and storage portfolio that can achieve hourly clean energy matching in an ordinary weather year may not be workable in severe weather conditions. In the case when corporate loads are not flexible enough to modulate operations based on the vagaries of the weather, even if they contract large capacities of resources, they are at the risk of occasional non-compliance from their own procured resources and must turn to other alternatives such as purchasing clean energy attributes from other entities.

Figure 3-8. Annual Capacity Factor at Selected Wind Sites Across Weather Years

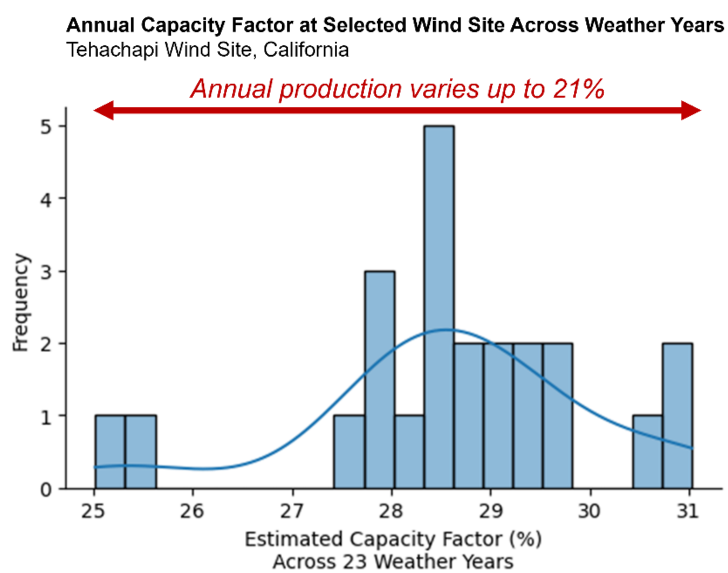
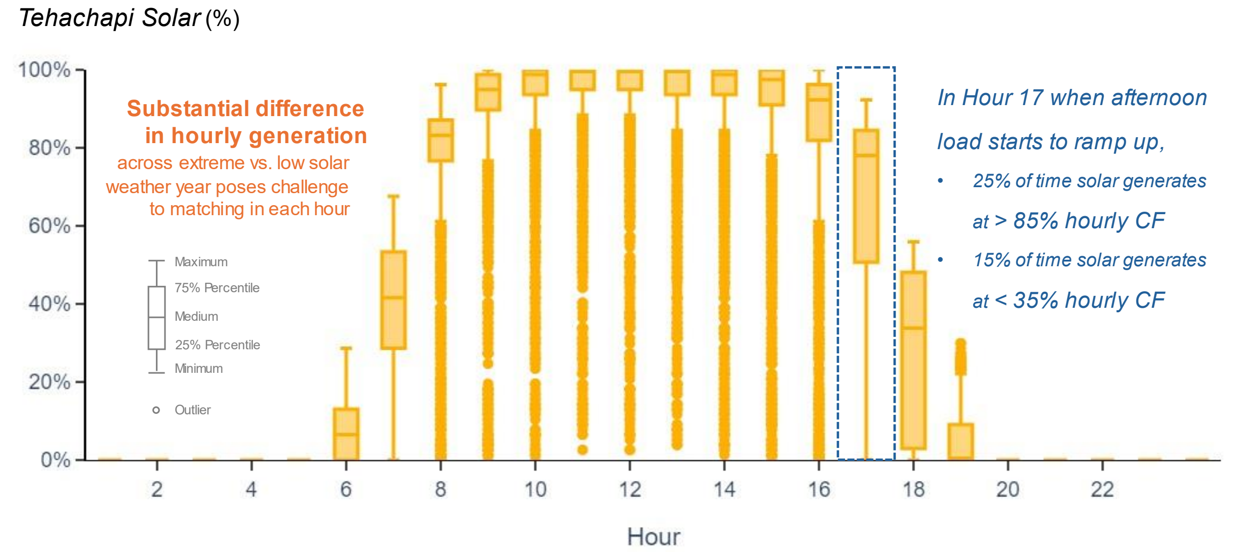
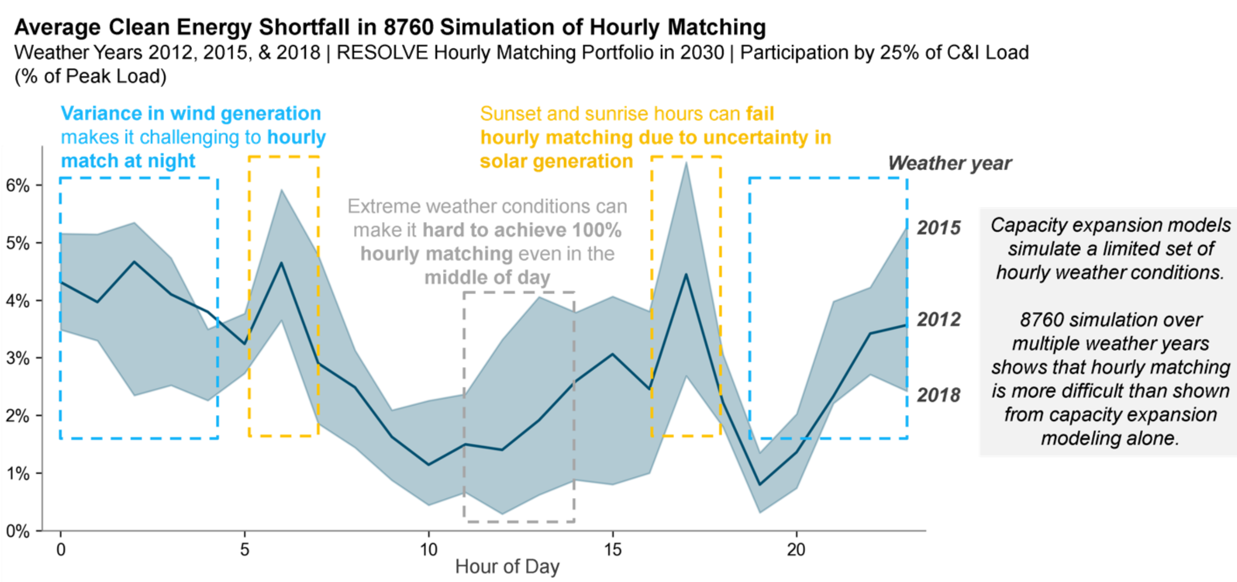


Figure 3-9. Range of Hourly Generation Across Weather Years at Select Solar Site, 1998 – 2022, Summer



The optimized portfolios from the RESOLVE capacity expansion modeling were tested under different weather conditions using hourly production simulation modeling, in which dispatch of the RESOLVE portfolio to meet load occurs over 8,760 hours of the year. The results for the 2030 portfolio for 25% C&I hourly load matching indicate that there is insufficient clean energy to serve hourly load in roughly 5% of the hours under the 2015 weather year, a low renewable output year. Taking a closer look at the challenging hours where insufficient supply risks are observed, around 30% of C&I load during the challenging hour may not be matched to equivalent amount of clean energy generation. With a higher than 25% participation rate, the insufficient supply risks across the full year as well as differences between weather years would be expected to become more prominent.

Figure 3-10. Average Clean Energy Shortfall in 8760 Simulation of Hourly Matching

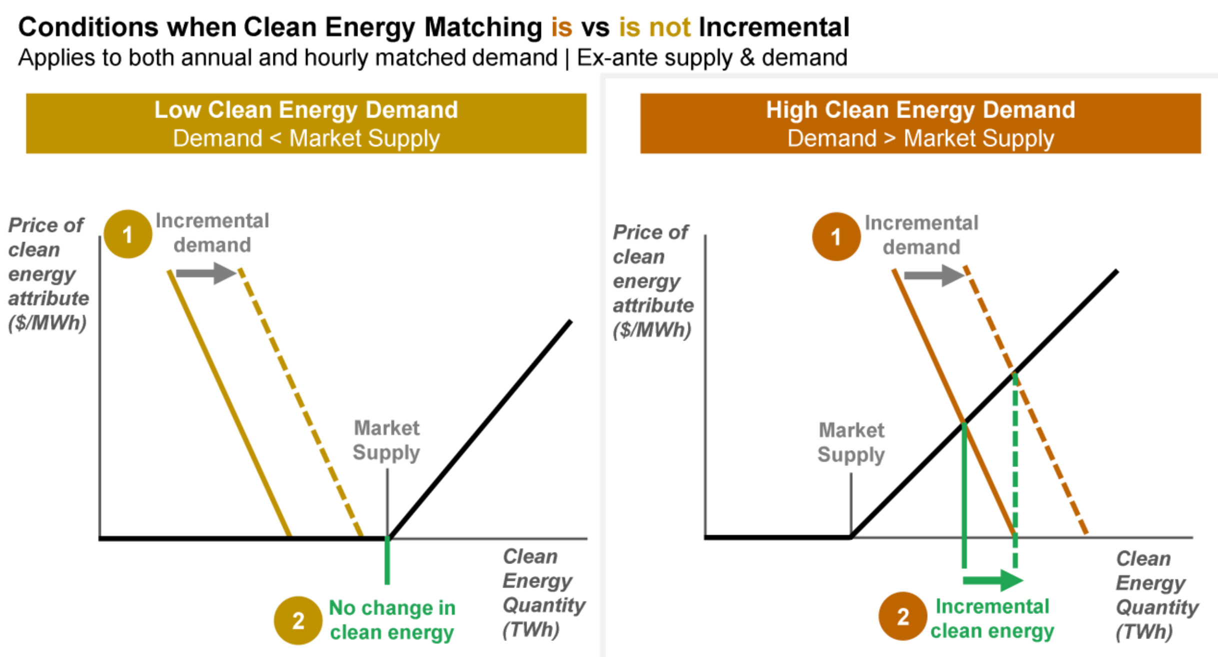


3.9 Implications of LTCE Results

3.9.1 The Impact of Voluntary Corporate Procurement depends on Supply and Demand for Clean Energy

Whether voluntary corporate procurement under either annual or hourly matching generate incremental clean energy depends on the amount of clean energy supply relative to clean energy demand (e.g., demand through a state RPS or an energy policy that requires a specific amount of clean energy attributes). When demand for clean energy exceeds the supply that would be provided by market forces alone, for example under an RPS policy in which clean energy generation is exactly meeting that requirement (i.e., a "binding" policy), any new voluntary corporate demand will create incremental new supply to ensure that binding policy requirements are met. An illustration of this is shown in Figure 3-11 below.

Figure 3-11. Illustration of Conditions in which Clean Energy Matching is Incremental



This must also be true dynamically. As shown in Figure 3-12 below, the new clean energy demand must be greater than the quantity the market would build on its own in the build period, otherwise new demand could be met with non-additional supplies under both the annual and hourly matching approaches. Moreover, for hourly matching to result in *different and greater* clean energy generation than annual matching, it must be that annual matching can be met with non-additional supplies while hourly matching requires additional supplies. Finally, for this impact to be durable, incremental demand must continue to grow faster than the growth in market-driven clean energy supply. Otherwise, over time the system will catch up and ultimately new demand will be met with non-additional supplies under either matching approach.

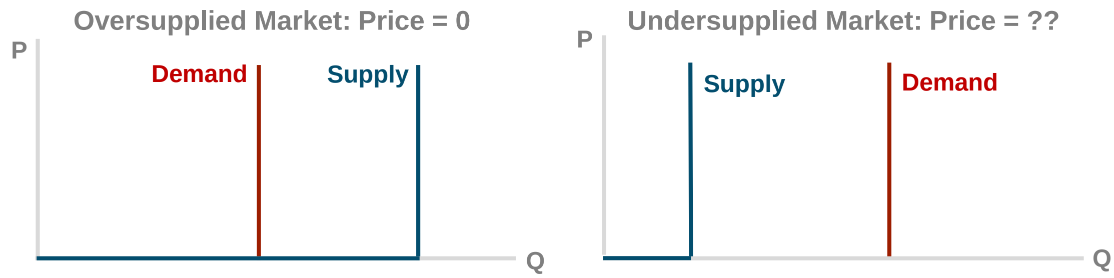
Figure 3-12. Three Conditions Must be True for Incremental Clean Generation to be Different under Hourly Matching vs. Annual Matching

<table>
<tr><th>Condition 1</th><th></th><th>Condition 2</th><th></th><th>Condition 3</th><th></th><th>Result</th></tr>
<tr><td rowspan="4">Condition 1. Is the market demand for Annual EACs less than what the market could supply on its own?</td><td>No</td><td colspan="5">Both Annual and Hourly Matched new EAC demand results in new incremental clean energy supply</td></tr>
<tr><td rowspan="3">Yes</td><td rowspan="3">Condition 2. Is the demand for Hourly EACs in Year 1 greater than new market supply in Year 1?</td><td>No</td><td>New EAC demand does not result in new incremental clean energy supply in Year 1</td><td></td><td rowspan="2">New EAC demand does not result in durable new incremental clean energy supply</td></tr>
<tr><td rowspan="2">Yes</td><td rowspan="2">Condition 3. Is the growth in Hourly EAC demand in Year n greater than the growth in market supply?</td><td>No</td></tr>
<tr><td>Yes</td><td>Some Hourly EAC demand results in new supply</td></tr>
</table>

3.9.2 Voluntary Corporate Procurement Introduces Market Risks

Markets for annual RECs provide stable, long-term investment signal by serving as a forecastable revenue source for the clean energy “missing money” – the premium above conventional energy prices needed for clean energy projects to be economic. In contrast to this, hourly REC markets are likely to be *unworkably illiquid*. Hourly demand for and supply of RECs can only be known after the fact, and both supply and demand are perfectly inelastic in *ex-post* markets. This means that the hourly REC market would oscillate between one of two states: either the market would be over-supplied, and prices would be at or near zero, or it would be under-supplied and prices would rise to a level approaching consumers’ cost of non-compliance. In either case, such a market would not provide a useful or workable forum for transacting individual short or long positions. This means that in practice, the performance of the hourly matching case is likely to be closer to the Hourly Island case modeled in this study than to the Hourly Market case, which assumes that clean energy buyers can sell their sizable quantities of surplus energy and EACs into a perfectly liquid secondary EAC market with no transaction costs.

Figure 3-13. Conceptual Illustration of the Two Possible Market States for Ex-Post Hourly REC Markets



3.9.3 Voluntary Demand for Clean Energy is Elastic, and Unnecessary Increases in Procurement Costs Will Reduce Participation

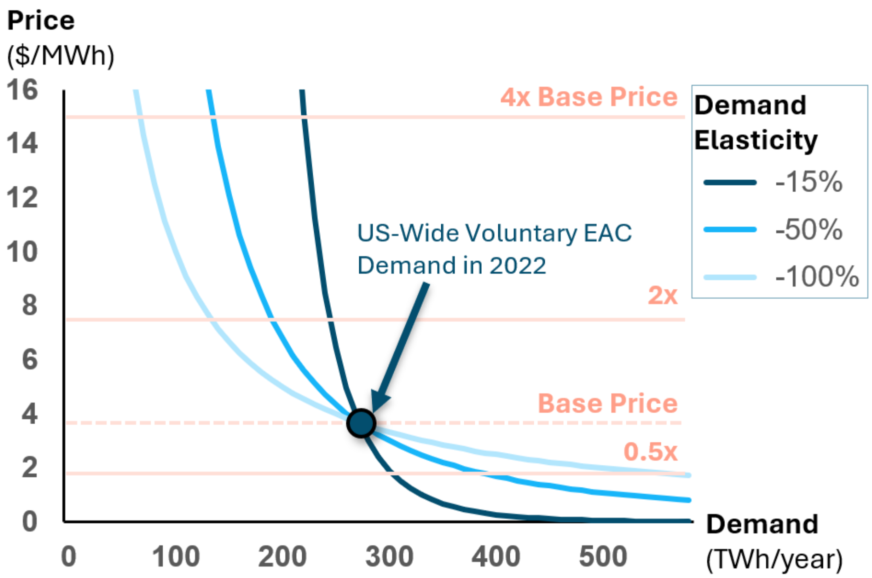
Demand elasticity captures the percentage change in quantity demanded of a good in response to a percentage change in the price of the same good. When demand is inelastic, the quantity demanded will not change regardless of changes in price. When demand is highly elastic, the quantity demanded will change significantly in response to a change in price. In the context of this study, demand elasticity is a helpful concept for understanding the potential impact of changes to EAC procurement costs on the quantity of clean energy demanded from sources of voluntary demand, for example from corporate buyers.

Recent evidence suggests that low and positive EAC prices can help accelerate the adoption of clean energy policies (e.g., state RPS) that increase demand for clean energy and help drive emissions reductions. From an empirical perspective, E3 reviewed studies of demand elasticity for voluntary EACs (i.e., voluntary RECs) across different U.S. markets. Across studies reviewed by E3, voluntary demand for EACs is elastic, meaning demand was sensitive to changes in EAC prices. Estimates of demand elasticity range between sources; we analyze a potential range of demand outcomes in response to changes in price, as well as the emissions impacts associated with these changes in price. Under some simplifying assumptions for the purpose of a national estimate, the results of this analysis are shown below. The conclusion from this review is that **increases in EAC prices may reduce the voluntary demand for clean energy generation.** This point is important because more illiquid hourly markets increase costs of clean energy procurement, particularly in certain hours, and risk reducing adoption of clean energy policies.

Table 3-8. Summary of E3 Demand Elasticity Research and Calculations

Demand Elasticity	4x Base Price	2x Base Price	Base Price (2022 Reference[42])	0.5x Base Price
EAC Price				
	$14.72/MWh	$7.36/MWh	$3.68/MWh	$1.84/MWh
EAC Demand Outcome				
-15% [43]	221 TWh	245 TWh	272 TWh	302 TWh
-100% [44]	68 TWh	136 TWh	272 TWh	544 TWh
CO_2 Emissions Impact (Relative to Base) [45]				
-15%	+26 MMT	+13 MMT	-	-15 MMT
-100%	+102 MMT	+68 MMT	-	-136 MMT

Figure 3-14. Summary of Demand for Wind Generation at Constant Elasticity Levels[46]



[42] 2022 average voluntary REC price for wind https://emp.lbl.gov/publications/land-based-wind-market-report-2022.

[43] Minimum elasticity based on PJM EAC demand curve: https://www.pjm.com/-/media/committees-groups/task-forces/capstf/2022/20220728/item-06---rmi-scaling-clean-report.ashx

[44] Maximum elasticity based on 2011 econometric study: https://www.sciencedirect.com/science/article/abs/pii/S0301421510007639

[45] Assumes marginal emissions rate of 500 kg-CO_2/MWh: https://www.epa.gov/system/files/documents/2023-05/Simple%20Cycle%20Stationary%20Combustion%20Turbine%20EGUs%20TSD.pdf

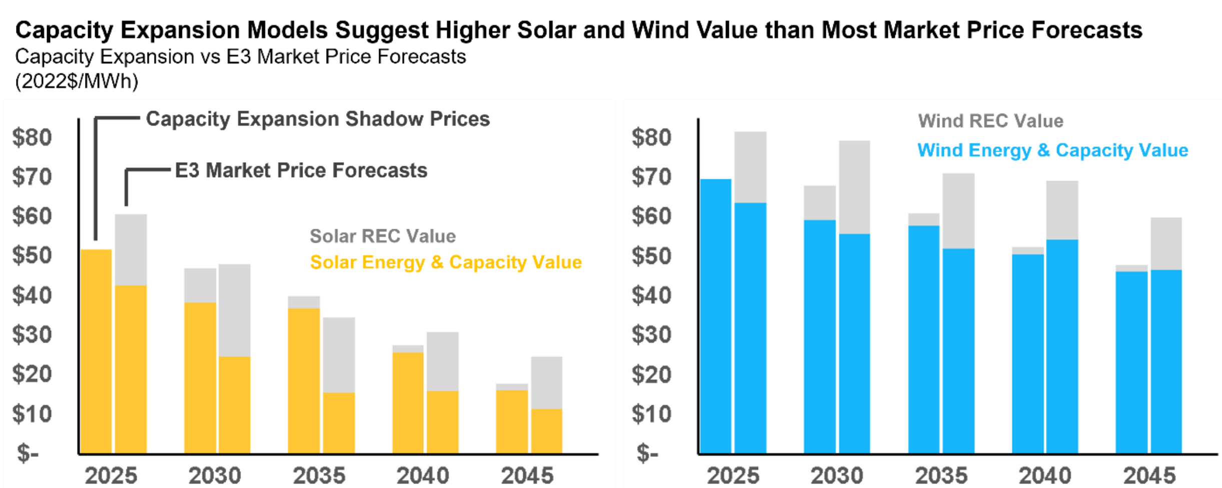
[46] Shape of each elasticity curve defined by input from previous Table. National voluntary EAC demand in 2022 from NREL: https://www.nrel.gov/analysis/green-power.html

3.9.4 LTCE Models are Limited in their Ability to Represent Markets

Capacity expansion models capture the fundamental supply-demand dynamics that influence decisions to build renewable resources: as electricity demand grows, the model chooses to build the optimal least-cost set of resources that can meet the energy and capacity needs of the system, subject to constraints such as clean energy policy requirements, and taking into account factors such as the existing system configuration, candidate resource generation profiles, technology costs over time, and fuel prices. To ensure modeling is computationally feasible, all capacity expansion models make simplifying assumptions about project economics. RESOLVE selects project resource types, build years, and build locations with perfect foresight at the system level. RESOLVE assumes future resource revenues are known with certainty (i.e., future revenues are entirely riskless), and then supplements these revenues with required incremental above-market financing. RESOLVE does not capture fluctuations in the year-on-year ability of a project to service its debt, or the impact of idiosyncratic shocks to output on the internal rate of return (IRR) for equity investors. LTCE models like RESOLVE also do not capture the inefficiencies created by participants navigating disjointed markets for energy, capacity, and RECs, and the presence of out-of-market transactions.

While this simplified view focused on market fundamentals is the appropriate perspective for resource planners, LTCE models like RESOLVE produce shadow prices that are different from market price forecasts reflecting market inefficiencies and other deviations from "optimal" behavior. These differences may be particularly apparent in systems undergoing rapid transitions. The modeling for California, like other jurisdictions, illustrates the impact of increasing renewable energy capacity on merchant (non-contracted) revenue. As shown in Figure 3-15 below, E3's capacity expansion modeling illustrates that market revenues earned by solar and wind assets on a fully merchant basis are expected to decline as more of each resource comes online. That said, compared to E3's market price forecasts, RESOLVE finds higher energy and capacity value for solar and wind in California. REC values, which represent the missing money for clean energy projects, are correspondingly lower in RESOLVE than price forecasts.

Figure 3-15. Differences between LTCE and Market Price Forecasting Expected Market-Clearing Merchant Revenues



4 Project-Level Economic Analysis

4.1 Motivation

Achieving the levels of clean electricity generation selected by least-cost capacity expansion models requires new clean energy projects to be successfully financed and built. While capacity expansion models are an appropriate tool for understanding the system-level implications of different clean energy matching strategies under different policy and market scenarios, capacity expansion models make simplifying assumptions about the markets in which clean energy project developers operate. This section describes the project-level economic analysis, which was performed in alignment with capacity expansion modeling in RESOLVE. This analysis complements the RESOLVE modeling results by quantitatively and qualitatively examining the role of voluntary clean energy procurement at the project level, with an emphasis on energy and capacity market revenue dynamics, tax credit monetization after the passage of the federal Inflation Reduction Act (IRA), and project risk.

In particular, while capacity expansion modeling captures the system-level dynamics under most conditions, the resource costs represented in capacity expansion modeling assume financing based on a long-term Power Purchase Agreement (PPA), consistent with how the industry has operated historically. This means that the financing assumptions used for resource cost forecasts applied to capacity expansion modeling assume a project's revenues are sufficient to cover its costs, and that project returns are de-risked by an offtake contract for which cash flows are certain during the contract term.

In the real world, changes in the risk profile of new resources can impact the ability of planned projects to attract the capital necessary to be built in the first place. Therefore, E3 has conducted project-specific economic analysis to isolate project-level impacts of annual variation in output and financing costs in a price-taker context. This analysis is intended to inform E3's conclusions regarding the need for corporate offtake (contracting) for new renewable energy resources, under Power Purchase Agreement (PPA) or alternative contracting structures. Ultimately, project-level cash flow analysis is better-suited for capturing the perspective of investors who must evaluate the impact of uncertainty on the returns associated with financing the energy transition.

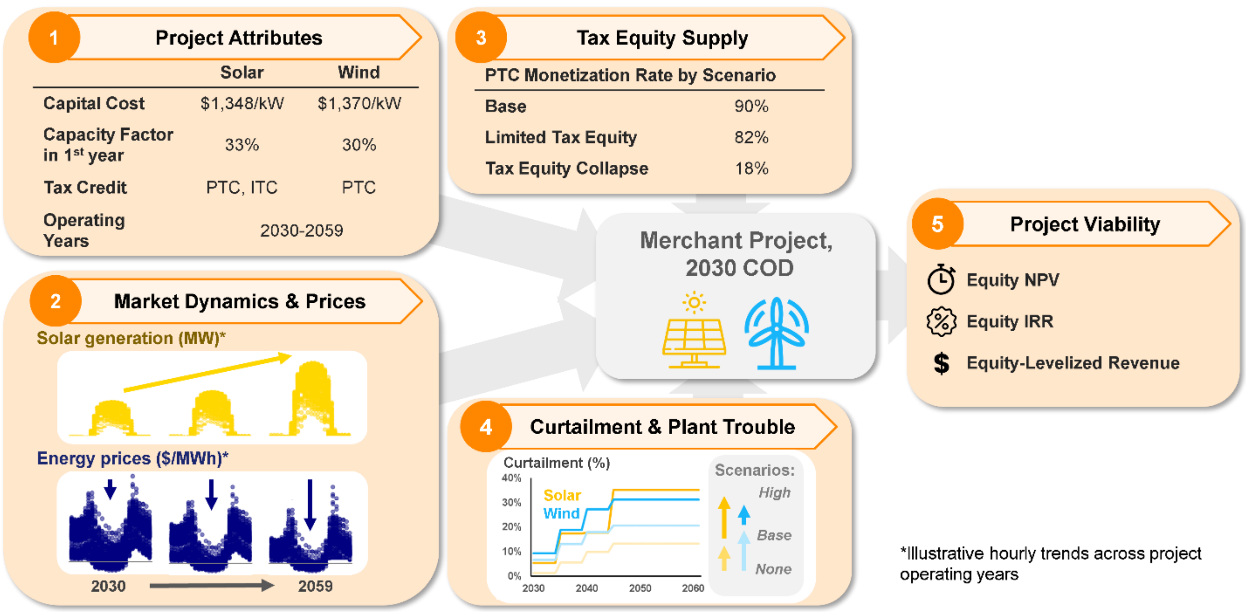
The project-level economic analysis addresses the third question from the overall project study:

+ **Is there a continued need for long-term off-take agreements in a post-IRA world, or will projects be able to obtain sufficient financing based on market revenues alone?** We evaluate project-specific economics under different scenarios, including but not limited to those covered in the capacity expansion modeling, to estimate the potential project cash flows and conditions that would drive need for policy or corporate support for clean energy through Power Purchase Agreements (PPAs) or alternative contracting mechanisms.

To assess this question, this section performs project-level economic analysis to evaluate costs and revenues in greater detail, highlighting the challenges and requirements to determine if new clean energy projects can be built. It then summarizes recommendations on the role of voluntary clean energy procurement in getting projects built.

4.2 Modeling Approach

Figure 4-1. Summary of E3 Methodology: Project Economic Analysis



This analysis examined the economics of a solar project and an onshore wind project developed independently in California with commercial operations starting in 2030. Assuming the perspective of an independent power producer (IPP), E3 forecasts annual after-tax cash flows to equity investors for each project by modeling project revenues, tax credit monetization, debt service, and other costs. Revenue modeling includes hourly (8760) wholesale energy market price dynamics in CAISO for all project operating years.

Key challenges and risks faced by new clean energy projects are examined in scenarios which vary the tax equity monetization rate, plant curtailment, plant outages, and several sensitivities. Project viability is assessed by comparing equity internal rate of return (IRR) against benchmark equity hurdle rates over scenarios and sensitivities. Risks beyond this study's scope include unexpected changes in natural gas prices, unexpected changes in resource costs due to supply chain factors, and project construction delays. Figure 4-1 summarizes the project-level economic analysis.

4.2.1 Clean Energy Project Attributes

For this analysis, E3 considered a new utility-scale solar project and a new onshore wind project which come online in 2030. These two resources are the most common and mature technologies being deployed in the energy transition in California and across the United States. The 2030 commercial operation date was chosen since this is a critical period in electric sector decarbonization where system dynamics are changing rapidly. Successful financing of new clean energy generation projects in those years will be challenged by uncertainty and risk at the time when rapid deployment is needed at a large scale. Additionally, modeling the project operating years of 2030-2059 provides an opportunity to discuss system dynamics and needs relevant to today's policy decisions as well as voluntary clean energy procurement decisions happening now and in the near future.

Resource costs, attributes, and hourly (8760) generation profiles for both resources are aligned with the input data and assumptions in the RESOLVE capacity expansion modeling in this report and the CPUC IRP. Key resource attributes are shown in Figure 1-1 in the Introduction and Key Findings section and Figure 4-2 below.

4.2.2 Market Dynamics & Prices

E3 estimated the market value of each project using our energy, capacity, and REC market price forecast for the CAISO. Wholesale energy prices are hourly (8760) for NP15 whereas capacity and REC prices are annual and for all of CAISO. E3's market price forecasts are directionally aligned with the energy and capacity shadow prices from the RESOLVE capacity expansion modeling in this study. However, raw shadow prices from optimization models are sensitive to binding periods. This was the case with the annual capacity shadow prices from RESOLVE in this study. Additionally, RESOLVE's shadow prices are only for representative days and model years spaced at 5-year intervals from 2025-2045. Results using E3's market price forecasts are shown in this analysis because of their greater granularity and realism. The core cases were tested using RESOLVE shadow prices which produced aligned results. See the appendix for more details on the CAISO market price forecast.

4.2.3 Scenarios and Sensitivities

4.2.3.1 Project Cost Scenarios

Figure 4-2. Costs Inputs to Project Economic Analysis, by Resource

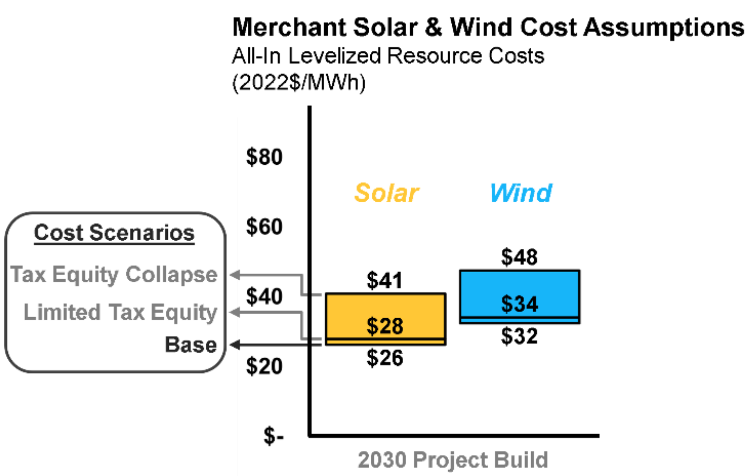
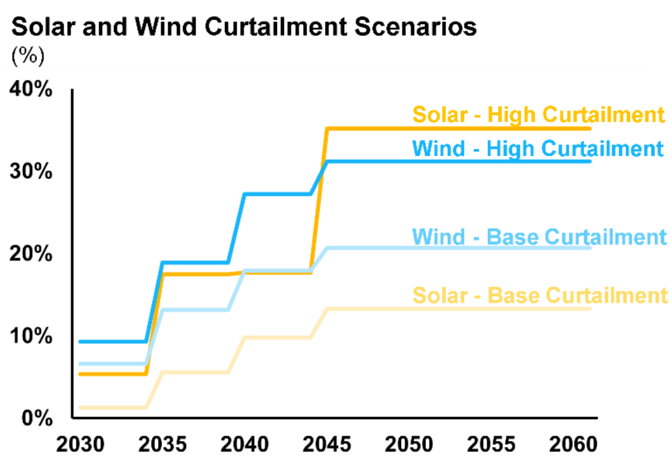


Figure 4-2 shows the project cost assumptions across the three cost scenarios as levelized cost of energy (LCOE). LCOE show the total fixed capital costs of the project minus the federal production tax credit (PTC), levelized over each MWh of energy generation potential. Whereas levelized costs are reported here, this analysis modeled project capital, operating & maintenance (O&M), and tax credit benefits with additional granularity in a cash flow analysis. The underlying calculations used to forecast cash flows are the same as those used to estimate the levelized resource costs used as RESOLVE inputs for this study and the CPUC IRP.

For a post-IRA analysis, the dynamics that drive resource costs have become more complicated as subsidies have expanded and changed. Firstly, solar and wind projects in high capacity-factor regions are expected to elect the production tax credit (PTC) which exposes project returns to higher curtailment risk. This contrasts with the investment tax credit (ITC) which utility-scale solar generally depended on before the IRA. As the quantity of clean energy projects relying on tax equity financing increases, scarcity of tax equity investors may become a significant challenge. This will translate to tax equity investors capturing larger fractions of IRA tax credits, requiring higher equity returns, having lower risk tolerance, or all of the above. We directly model these challenges by reducing the tax equity monetization rate from 90% in the Base scenario, to 82% in the Limited Tax Equity scenario, and 18% in the Tax Equity Collapse scenario. Figure 4-2 shows how reduced tax equity monetization rates increase resource costs.

4.2.3.2 Curtailment Scenarios

Figure 4-3. Curtailment Assumptions in Project Economic Analysis



Reductions in energy delivered by the project plant can have significant implications for the project's economic viability by reducing energy revenues, Production Tax Credits received, and clean energy attributes earned (RECs or other EACs). All three revenue sources require electricity from the project to be physically delivered to the grid. Undelivered energy due to curtailment, plant outage, or any other delivery challenge prevents the project from earning energy, PTC, and EAC revenue. To assess the impact of changes in output on project economics, E3 modeled several curtailment and "Plant Trouble" scenarios.

Curtailment may be technical (driven by physical constraints on the electricity grid) or economic (when an asset bids into the energy market but is not selected because it is outbid by other assets). In the near term, local curtailment at congested nodes is the primary threat to project economics. As renewable penetration increases later in the projects' operating life, curtailment due to systemwide overgeneration will be an additional risk. Project-level curtailment can be forecasted but is inherently uncertain, which is a significant risk challenge for new clean energy projects seeking capital.

E3 designed curtailment scenarios using the average and maximum locational solar and wind curtailment results from the RESOLVE modeling. RESOLVE curtailment is driven by both CAISO-wide overgeneration and deliverability constraints. However, RESOLVE lacks granular deliverability constraints which could lead to greater curtailment. Figure 4-3 shows curtailment in the Base and High Curtailment scenarios modeled in addition to the No Curtailment scenario.

4.2.3.3 "Plant Trouble" Scenarios

In addition to curtailment, plant output may be significantly reduced due to unexpected temporary reductions in production which E3 modeled in the "plant trouble" scenarios. Factors within the operator's control (e.g., equipment failure) and outside of the operator's control (e.g., natural disasters) can have a material impact on project-level cash flows that is not captured by technology-level cost estimates from sources like NREL's Annual Technology Baseline. While the project may be insulated to some degree from the impact of these risks by contracts with Original Equipment Manufacturers (OEMs) for maintenance and routine service, these agreements may not cover all equipment and may not extend throughout the project's useful life. Similarly, while offtake contracts may contain "force majeure" clauses that mitigate the potential impact of natural disasters, this is not the case for fully merchant generators. Therefore, while it is unlikely that all projects will experience some form of "plant trouble" that significantly reduces output across consecutive months, it is highly likely that this will be true for some projects. In other words, time-limited but significant downward shocks to plant generation output are idiosyncratic but real considerations for developers and investors, and are therefore worth analysis.

To demonstrate the impact of this class of risks on project-level returns, E3 has modeled "plant trouble" as a 50% decrease in plant output before the shock occurred, limited to two consecutive years. E3 has estimated the impact of shifting this two-year window of decreased output across the entire project operating life. This shock is assumed to be incremental to any curtailment impacting the project, because curtailment reflects system-level renewable build trends that are distinct from this project-level shock.

4.2.3.4 Financing Sensitivities: Dynamic Debt Sizing & ITC

This analysis assumes the solar and wind projects receive the federal Production Tax Credit (PTC) instead of the Investment Tax Credit (ITC) due to its higher value to projects, even under high curtailment and plant trouble scenarios. This was verified by conducting ITC sensitivities which are shown in the appendix.

This analysis also uses a static debt fraction across the core scenarios modeled. Consistent with the assumptions used in RESOLVE, utility-scale solar receives a 45% debt fraction and onshore wind receives a 33% debt fraction. Sensitivities where the debt-equity ratio was dynamically optimized based on project cash flows did not change the findings of the analysis. The results of these sensitivities are shown in the appendix.

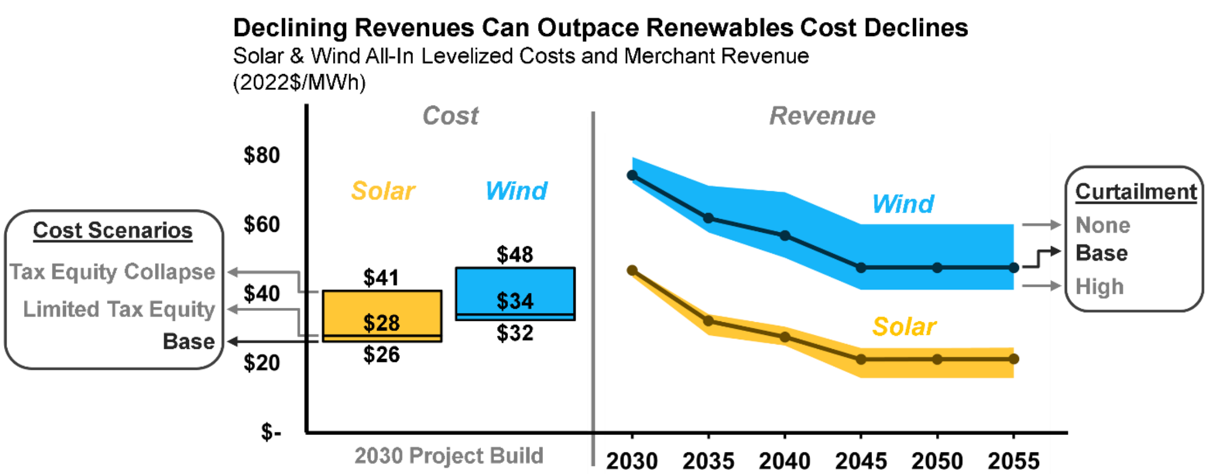
4.3 Results and Findings

The project-level economic analysis shows a continued need for long-term offtake contracts to mitigate risk and enable financing for most new clean energy projects. If capital available to finance new renewable resource investments were to dry up, project level returns and incentives for future deployment will suffer. On its own, this does not mean that voluntary procurement will guarantee incremental clean energy generation, but in our capacity expansion modeling summarized above, neither annual nor hourly matching guarantees incremental clean energy generation when clean energy demand is less than economic market supply. Ultimately, strict incrementality is difficult or impossible to determine without a reliable counterfactual.

The Negative Covariance section below summarizes the project-level impacts of system-level increases in solar and, to a lesser extent, wind generation in California. The Project Equity Returns and Hurdle Rates sections describe the missing money and risk challenges in more detail.

4.3.1 Negative Covariance

Figure 4-4. Negative Covariance Relative to Resource Costs for Solar and Wind Generation



Project revenue analysis using E3's market price forecasts and RESOLVE shadow prices lead to the same conclusion: merchant solar and merchant wind projects realize less market revenue over time in California. All else being equal, an increase in the deployment of wind or solar capacity in a market will lead to increasing saturation of energy prices during the hours when the wind is blowing and the sun is shining. This may be offset to some extent by electricity demand growth, if it is time-coincident with the renewable output. Additionally, capacity revenues decline due to the diminishing marginal

Effective Load Carrying Capability (ELCC) for these resources. In general, the pace of growth of renewable generation will exceed the growth in demand for electricity in hours when renewable output occurs.[47] This is sometimes referred to as negative covariance or market cannibalization.

Figure 4-4 shows the solar and wind project costs under the range of tax-equity monetization rate scenarios and annual revenues under the range of curtailment scenarios. Figure 1-8 in the Introduction and Key Findings section of this report shows the same conclusion using RESOLVE shadow prices instead of E3's market price forecast to calculate solar and wind revenues.

Negative covariance is a well understood electricity market dynamic. In some cases, as this analysis found with the 2030 utility-scale solar project in California, projects face a predictable and chronic missing money problem due to a declining revenue outlook. For other clean energy projects seeking financing, there remains a risk that negative covariance will drive revenues down faster than expected in upfront modeling. This could be due to unexpected changes on the system or price node where the project will be sited. Examples include faster than expected deployment of competing projects, slower than expected transmission buildout, and slower than expected load growth. Negative covariance between the deployment of clean energy projects and the revenues they earn creates a risk problem for the clean energy projects needed to achieve decarbonization goals.

The capacity expansion modeling conducted for this study showed that the quantity of clean energy generation built on market economics alone (Low Clean Energy Demand Scenario) is significantly less than the quantity of clean energy generation built when California's existing annual matching, clean energy standards are enforced (High Clean Energy Demand Scenario), as shown in Figure 2-6. As modeled in RESOLVE, all projects which bridge the gap between the Low and High Clean Energy Demand Scenarios face a missing money problem primarily driven by negative covariance.

[47] Variations in demand and supply at the nodal level may differ from system-level outcomes, but this logic is intended to reflect grid- or system-level dynamics that will reflect outcomes for a 'typical' or illustrative project.

4.3.2 Project Equity Returns and Hurdle Rates

Figure 4-5. Solar and Wind Project Cash Flows, Base Case and Other Scenarios

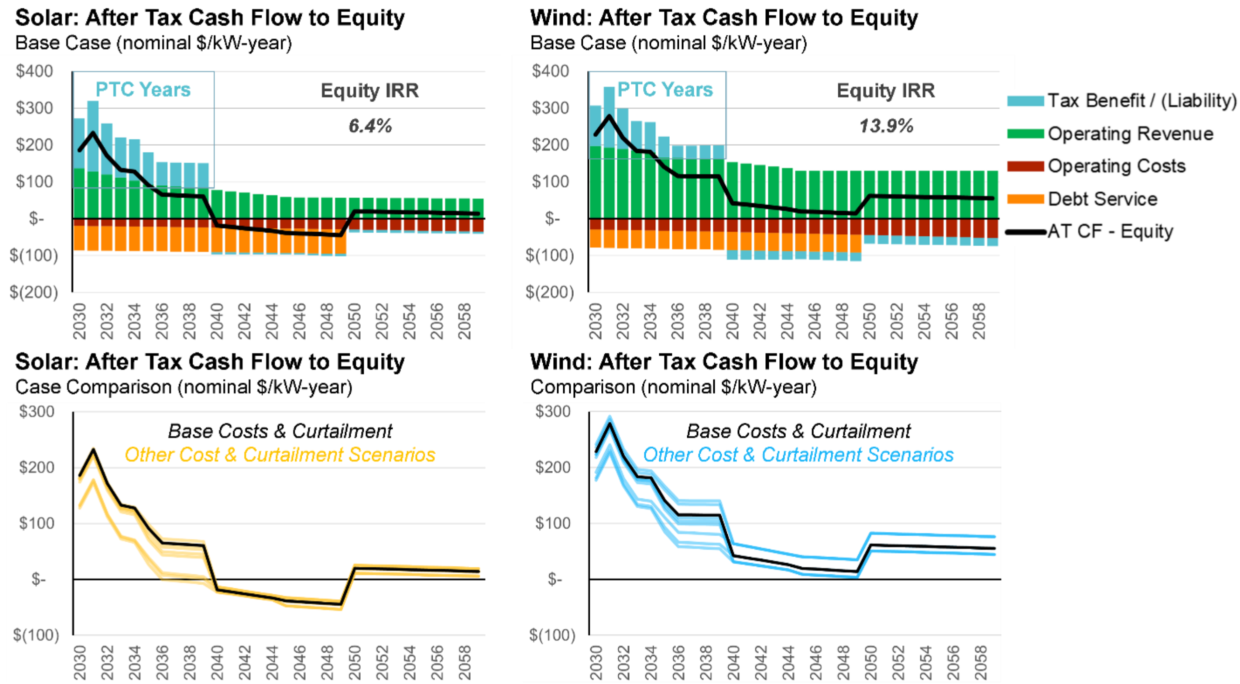


Figure 4-5 shows the components of annual after-tax cash flows (AT CF) to equity investors under Base Cost and Curtailment assumptions in the top row; net AT CF is then compared across scenarios in the bottom row. Under Base assumptions, the solar project achieves a 6.4% internal rate of return (IRR) to equity investors. This fails to meet the 8.8% equity hurdle rate assumed by E3 for utility-scale solar in California. This is despite the near-term value of the PTC from the IRA, shown in turquoise. In contrast, the wind project achieves a 13.9% equity IRR under Base assumptions, exceeding the 10.0% equity hurdle rate for onshore wind. Despite different equity IRR outcomes, AT CF to equity from both solar and wind projects experience negative covariance highlighted in the prior section. Under Base assumptions, utility-scale solar fails to meet equity investor hurdle rates and hence faces a missing money problem, while onshore wind does not face a missing money problem but still faces risk discussed further below.

Figure 4-6. Equity IRR Relative to Assumed Hurdle Rate, by Technology and Scenario

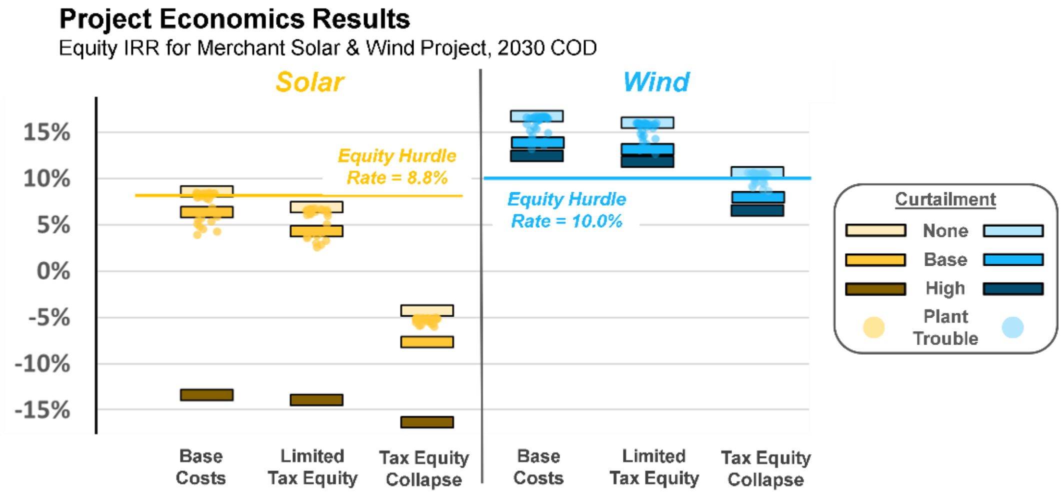


Figure 4-6 shows equity IRR for each cost-curtailment scenario pair as a rectangular bar. Equity IRR for each starting year of "Plant Trouble" tested is shown as a scatter point. The merchant solar project is unable to meet the equity hurdle rate under most scenarios. Under these assumptions, solar projects will at least require a missing money injection, risk absorption, or a long-term offtake contract to be financed and built. The merchant wind project exceeds its equity hurdle rate under most scenarios. Under these assumptions, wind projects can be financed without a missing money injection, however, wind project economics are dependent on high-quality sites which are limited in California and susceptible to negative covariance due to local transmission congestion.

While the Base results described above are helpful reference points, it is critical to note that curtailment, idiosyncratic plant issues, and constraints on available financing can all drive a materially different result for any new wind or solar generator. We find that solar generators without an offtake contract will not clear equity hurdle rates required for investors to commit capital without accepting reduced leverage. Wind generator outcomes may clear investor hurdle rates but are not guaranteed to do so. This is especially true in High Curtailment scenarios and Plant Trouble sensitivities, which created some of the largest divergences in equity IRR results.

4.3.3 Implications for Clean Energy Deployment

The project-level economic analysis shows a continued need for long-term offtake contracts to mitigate risk and enable financing for most new clean energy projects. A drying-up of capital available to finance new renewable resource investments would dim the prospects of building sufficient capacity to meet decarbonization targets. The capacity expansion modeling in this report shows that neither annual nor hourly matching guarantees incremental clean energy generation when clean energy demand is less than economic market supply. Ultimately, strict incrementality is difficult or impossible to determine without a reliable counterfactual. However, providing critical project finance support to new clean energy projects via long-term offtake contracts is an effective way for entities to directly support the deployment of clean energy projects needed to achieve societal decarbonization goals.

Appendix A. Additional Modeling Details and Results

A.1. Additional Capacity Expansion Methodology

The CAISO RESOLVE model used in this study contains the most up-to-date information presented in the CPUC's 2023 Inputs and Assumptions document,[48] vetted through feedback via extensive stakeholder engagement workshops and comments to ensure that the model contains the latest publicly available data sources, integrates data from other major California agencies, and has transparent methodologies to examine long-term planning questions. The current model includes the latest resource potential and loads from California Energy Commission,[49] transmission deliverability information from 2023 CAISO Whitepaper,[50] resource costs reflecting IRA incentives, and ELCC-based system reliability accounting. In the sections below, key assumptions are presented and specific changes that were made for this study to the public version of RESOLVE are described.

Table A-1. Key Technical Assumptions in this Study

Category	Sub-Category	Description/Source
Area	Geographical Scope	California, Arizona, Nevada, Oregon, Washington
	Topology	California Independent System Operator (CAISO), with a separate "C&I Load Zone" within CAISO representing C&I matching load; external zones representing California POUs (BANC, IID, LADWP) and neighboring areas (NW, SW)
Load	CAISO and CA zones	CEC Integrated Energy Policy Report (2022 IEPR vintage)

[48] California Public Utilities Commission, "Inputs & Assumptions: 2022-2023 Integrated Resource Planning (IRP)." https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf

[49] California Energy Commission, "Land-Use Screens for Electric System Planning: Using Geographic Information Systems to Model Opportunities and Constraints for Renewable Resource Technical Potential in California." https://www.energy.ca.gov/publications/2022/land-use-screens-electric-system-planning-using-geographic-information-systems

[50] California Independent System Operator, "Transmission Capability Estimates for use in the CPUC's Resource Planning Process." http://www.caiso.com/Documents/White-Paper-2023-Transmission-Capability-Estimates-for-use-in-the-CPUCs-Resrouce-Planning-Process.pdf

	Commercial & Industrial	Estimated from 2022 California Air Resources Board's Scoping Plan
	External Zones	WECC 2032 ADS 2.0 dataset
Resource Cost	Base Costs by Resource Type	"PSP-Mid" costs as defined in the CPUC IRP I&A, derived from NREL 2023 Annual Technology Baseline
	Sensitivity Costs	Applies different IRA tax monetization rate assumptions on Base Costs
	Regional Cost Multipliers	CPUC IRP I&A, using Bureau of Labor Statistics
Fuel Costs	Natural Gas	CEC's North American Market Gas-trade (2023 IEPR vintage)
	Coal and Uranium	Regional prices from 2023 Annual Energy Outlook
Resource Potential	Solar & Wind	CPUC IRP I&A, using CEC Land Use Screening
	Geothermal	Maximum 1,000 MW, from which up to 150 MW is eligible for C&I load matching
	Pumped Storage	Maximum 1,000 MW, all eligible for clean energy matching
	Other Storage	No limits, except for CAES that is limited to 500 MW
	Gas	No limits
Baseline Resources	CAISO	CAISO Master File, CAISO Master Generating Capability List, CAISO Mothball/Retirement List
	External Zones	WECC 2032 ADS 2.0 dataset
	Diablo Canyon Nuclear	Fully retires by the end of 2030
Carbon Pricing	Cap-and-Trade	California Greenhouse Gas Allowance price projections (2022 vintage)
Transmission	Upgrade Costs	2023 CAISO Transmission Deliverability Estimates Whitepaper
	Utilization Constraints	
	Hurdle Rates	CPUC IRP I&A
Reliability	Planning Reserve Margin Target	CPUC IRP I&A
	Resource ELCCs	
Operational Characteristics	Solar & Wind Generation Profiles	CPUC IRP I&A
	Maintenance Schedules	
	Operating Reserves	

i) Zonal Representation and Candidate Resources

For this study, E3 modified the RESOLVE model to incorporate a new load and resource zone within CAISO, inclusive of the commercial and industrial loads required to be met with 100% clean energy, while offering the same supply options as the main CAISO zone. The C&I Load Zone can import and export energy to CAISO without limit in annual matching cases, while in hourly matching cases, imports are not allowed, and unrestricted exports are allowed in the "market" scenarios. Only energy produced by *new* clean projects may count toward volunteer clean energy targets for both annual and hourly matching. It is assumed that existing renewables will continue serve CAISO load throughout all modeled years and repowering these projects will not be counted as additional clean generation. The combined resources of the CAISO and C&I Load Zones are used to satisfy the system-level reliability needs for planning reserve margin (PRM). We do not model existing resources as eligible resources for annual or hourly matching. For the state policies (RPS and SB 100) clean energy generation from all resources including existing is assumed to qualify. The list of all candidate resources to serve load is provided in Table A-2.

Table A-2. Candidate Resources in this Study

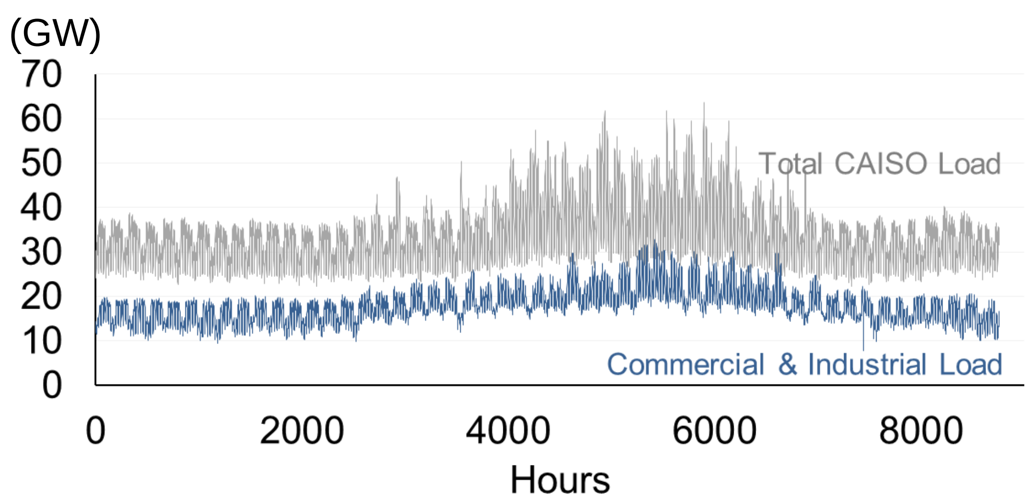
Candidate Resource Type	Available Options	Functionality
Renewables	Solar	Variable resource, generating as available, and can be curtailed at no cost
	In-State Wind	Variable resource, generating as available, and can be curtailed at no cost; "In-State" signifies onshore wind in or near California that can interconnect to the California ISO (CAISO) transmission system
	Out-of-State Wind	Variable resource, generating as available, and can be curtailed at no cost; "Out-of-State" signifies onshore wind in other states that require new transmission to deliver energy to CAISO, with the new transmission included in the resource cost
	Offshore Wind	Variable resource, generating as available, and can be curtailed at no cost
	Geothermal	Clean, dispatchable resource running economically based on operating costs, typically as a baseload resource, subject to ramping and on/off time limitations
Storage	Li-ion Battery	Shifts energy from one part of the day to another by charging in hours with excess energy and discharging in hours where additional energy is needed to serve load, subject to a limited duration for charging and discharging (in our model, 4 or 8 hours at maximum capacity)
	Pumped Hydro Storage	Operates similarly to Li-ion Battery, but can charge and discharge over a longer duration (in our model, 12 hours at maximum capacity)
	Long Duration Energy Storage	Compressed air energy storage (CAES) with a 24-hour duration
Natural Gas	Combustion Turbines (Peakers)	Dispatches economically based on operating & fuel costs, subject to ramping and on/off time limitations
	Reciprocating Engines (Peakers)	Dispatches economically based on operating & fuel costs, subject to ramping and on/off time limitations

ii) Loads

The CPUC IRP model includes load profiles derived from the California Energy Commission (CEC) load forecast in the 2022 Integrated Energy Policy Report (IEPR). In the study, additional data was required to estimate C&I annual demand, since IEPR does not directly provide the breakdown of energy forecast by economic sectors, and small modifications result in the overall load forecast relative to the IRP. Specifically, annual C&I load is estimated from the 2022 California Air Resource's Borad (CARB) Scoping Plan annual load forecast for industrial and commercial sectors, downscaled using the CAISO historical load share (i.e., CAISO being 82% of CA load). C&I retail sales demand is estimated to be 147 TWh in 2030 and 180 TWh in 2045, with about 1.4% compound annual load growth rate. Additional modifications are made to CAISO baseline and additional achievable fuel substitution and energy efficiency load components to avoid double counting of commercial load growth that was estimated independent from IEPR forecasts. As a result, CAISO retail sales are estimated to be about 236 TWh in 2030 and 342 TWh in 2045 (excluding BTM generation and T&D losses), reflecting significant load growth, largely associated with transportation electrification.

For hourly load profiles, C&I load profiles are taken from NREL's Mid Electrification and Moderate Technology Advancement scenario. For all other load categories, IEPR load profiles are used.[51] In the model, load must be reflected at the generator level, thus retail sales are scaled assuming about 8% for transmission and distribution losses.

Figure A-1. Modeled Hourly Loads in 2030



iii) Resource Costs

Since 2010, E3 has regularly created and released formal public databases and calculations of levelized resource costs for clients, including for the WECC Transmission Expansion Planning and Policy Committee, as well as the CPUC. This analysis is conducted through E3's in-house analytical

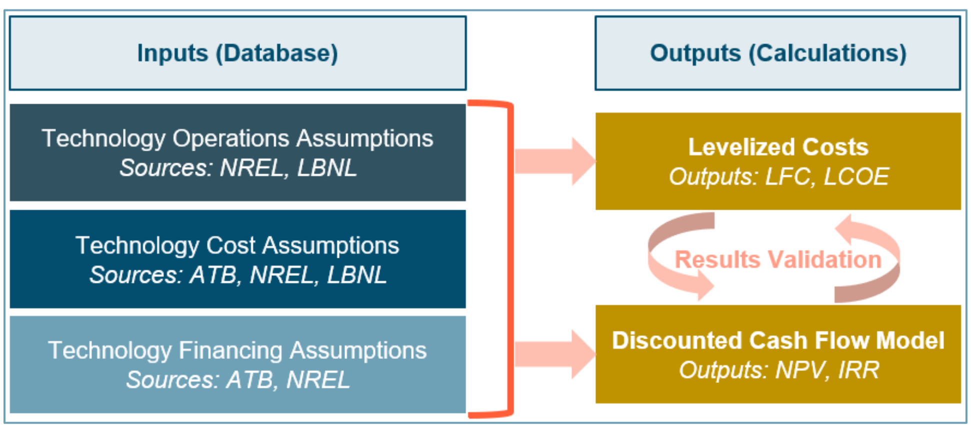
[51] Mai, Trieu, Paige Jadun, Jeffrey Logan, Colin McMillan, Matteo Muratori, Daniel Steinberg, Laura Vimmerstedt, Ryan Jones, Ben Haley, Brent Nelson, Caitlin Murphy, and Yinong Sun. 2020. "Electrification Futures Study Load Profiles." NREL Data Catalog. Golden, CO: National Renewable Energy Laboratory. Last updated: September 16, 2022. DOI: 10.7799/1593122.

tool, known as the "Pro Forma" in the CPUC Integrated Resource Planning process, and referred to as RECOST hereafter.

RECOST calculates levelized fixed costs (LFC, in $/kW-yr) and the levelized cost of electricity (LCOE, in $/MWh) for a range of resources, including but not limited to utility-scale solar (PV), onshore wind, offshore wind, standalone and hybrid utility-scale battery storage (lithium-ion), Behind-The-Meter (BTM) battery storage (lithium-ion), pumped hydropower storage, geothermal, biomass, natural gas (CCGT, CCGT + Carbon Capture and Storage, and CT), and nuclear (Small Modular Reactor and Light Water Reactor).

LFC and LCOE are calculated by initial commercial operations date (COD), from 2024 through 2050. RECOST estimates are calculated using the latest inputs from various sources (see below). In addition to the estimation of levelized costs, RECOST also includes a Discounted Cash Flow (DCF) model to represent the asset's expected cash flows under a given set of operating, cost, and financing assumptions.

Figure A-2. Summary of E3 RECOST Inputs and Outputs



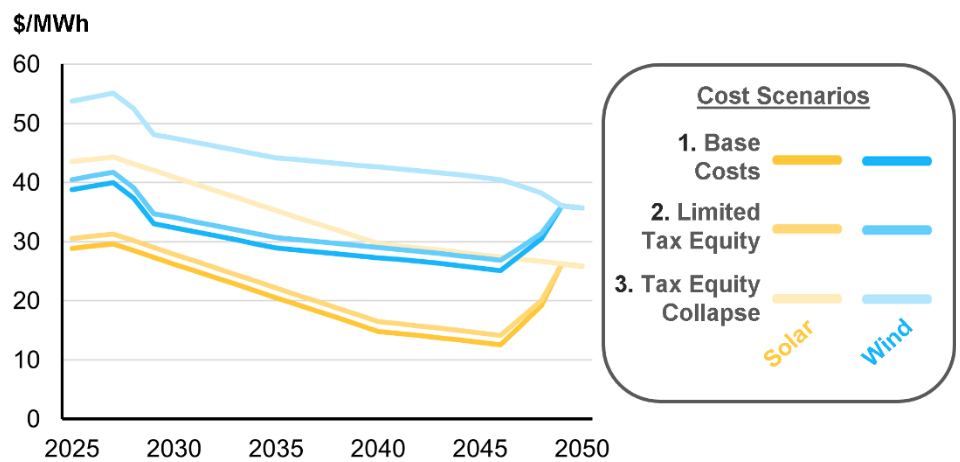
Technology operating assumptions include capacity factors, degradation rates, heat rates, and useful life. Technology cost assumptions include upfront capital expenditures (sometimes referred to as "overnight capital cost"), fixed operating and maintenance (FO&M) and variable O&M costs, interconnection costs and property taxes. Financing assumptions include debt term, debt costs, the cost of equity, and tax credit monetization rates.

RECOST also reflects the recently enacted Inflation Reduction Act ("IRA"). The IRA includes various provisions intended to accelerate the deployment of resources in support of the energy transition, among which one of the most significant is the extension of the Investment Tax Credit ("ITC") and Production Tax Credit ("PTC"). E3 assumes that the United States will reach the IRA target of reducing GHG emissions from the power sector to 75% below 2022 levels in 2045, after which the 3-year phase-out period for tax credits begins as specified in the legislation.

For specific technologies and to reflect specific market factors, E3 has adjusted inputs from third-party sources (e.g., NREL ATB) to reflect current market conditions and feedback from current market participants. E3 continuously validates these results with clients and other stakeholders in the electricity sector over time. E3 also updates RECOST to reflect the latest available data on resource performance, costs, and financing.

This study begins by using the same resource cost expectations used in the CPUC's most recent IRP process.[52] These forecasts assume financing is provided by an Independent Power Producer (IPP) in line with third-party development models in California. In general, E3 uses NREL ATB (2023) data as the starting point for the CPUC IRP forecast. To reflect the state-specific context for development of renewable resources, E3 modifies these location-agnostic sources by applying a labor cost multiplier to the share of resource capital costs attributable to labor.[53] In addition, E3 modifies the forecasts for specific resources based on our own research to best reflect actual current market conditions. This is the case for lithium-ion battery energy storage system (BESS), offshore wind, utility-scale solar, and onshore wind resources, which have been disproportionately affected by shocks from commodity prices, supply chain disruptions, and policy measures. LCOE for onshore wind and utility-scale solar (PV) are shown in the chart below.

Figure A-3. Levelized Cost of Energy (LCOE) for Selected Resources Used in This Study



Notes: Resource costs are from the CPUC IRP. Solar and wind resource costs are sensitized in cost scenarios by adjusting the weighted average cost of capital (WACC).

[52] For more details on these cost forecasts, see the final Inputs & Assumptions document for the most recent IRP proceedings (Section 4): https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/2023-irp-cycle-events-and-materials/inputs-assumptions-2022-2023_final_document_10052023.pdf

[53] Labor cost multipliers calculated using median rages by region for Construction Laborers relative to median national wage, from U.S. Bureau of Labor Statistics data, available here: https://www.bls.gov/oes/current/oes472061.htm. Resource capital costs attributable to labor are sourced from the 2019 WECC Cost Calculator, available here: https://www.wecc.org/Administrative/E3_WECC_Cost_Calculator_2019-07-02_FINAL.xlsm.

iv) Tax Equity Considerations

To reflect potential disruptions in, or limitations on, tax equity financing and their associated impacts on system- and project-level outcomes, E3 created additional sensitivities to the Base resource costs which reflect variation in the availability of tax equity. These sensitivities reflect two possible downside scenarios: the cost of tax equity financing increases but remains within recent historical ranges as demand continues to outpace supply ("Limited TE"), or tax equity financing becomes severely constrained or inaccessible to certain projects, or spikes upward due to a specific shock such as the implementation of current Basel III standards for regulatory capital requirements ("TE Collapse"). The objective of estimating "Limited TE" costs is to demonstrate the impact of likely fluctuations in financing costs on project economics, while the objective of estimating "TE Collapse" costs is to provide a lower end that captures the importance of this source of financing.

Table A-3. Tax Equity Monetization Rate Assumptions, by Scenario

Scenario	PTC Resources	ITC Resources	Source
Base	90%	90%	CPUC IRP and E3 Research
Limited Tax Equity	82%	73%	ACORE 2023[54]
Tax Equity Collapse	18%	18%	ACORE 2023[55]

As noted earlier, this study relies on key assumptions developed as part of the 2023 CPUC IRP, however, certain additional model updates were made for this analysis. For example, the "C&I Load Zone" was added within CAISO to represent matching corporate loads. Thus, in C&I matching cases, RESOLVE makes investment decisions for both the C&I zone and the CAISO zones (which includes all CAISO loads minus C&I matching load). Additionally, new clean energy policies are added to reflect the clean energy demand for CAISO and for the annual and hourly matching corporate loads. In this study, hourly matching for C&I load is defined as 100% clean energy generation requirement to match metered load in every hour. In hourly matching cases, no imports from CAISO are allowed; thus, the entire matching load and storage charging is entirely served by new clean resources. Exports from hourly matching cases are allowed only in the "Market" cases. When allowed, imports and exports between C&I and CAISO are unconstrained to allow full market integration. Similarly, in annual matching cases, C&I load is only allowed to be met by new clean projects built in 2030 and beyond. In annual matching cases, charging storage resources from clean energy is not enforced; thus, the total clean energy demand for annual matching is set for the matching C&I load. This approach is consistent with the modeling of SB 100 and SB 1020 policy in California that also requires annual clean energy generation based on retail sales. Some other adjustments were made

[54] https://acore.org/wp-content/uploads/2023/12/ACORE-The-Risk-Profile-of-Renewable-Energy-Tax-Equity-Investments.pdf

[55] https://acore.org/wp-content/uploads/2023/08/ACORE-Letter-on-the-Impact-of-Proposed-Bank-Regulatory-Capital-Requirements-on-Tax-Equity-Investment-in-Clean-Energy.pdf. E3 has calculated the implied monetization rate on the basis of the potential shock to tax equity market size of (80%) to (90%) identified here.

to resource potential for most constrained resources such as geothermal and pumped hydro storage as explained in the table below.

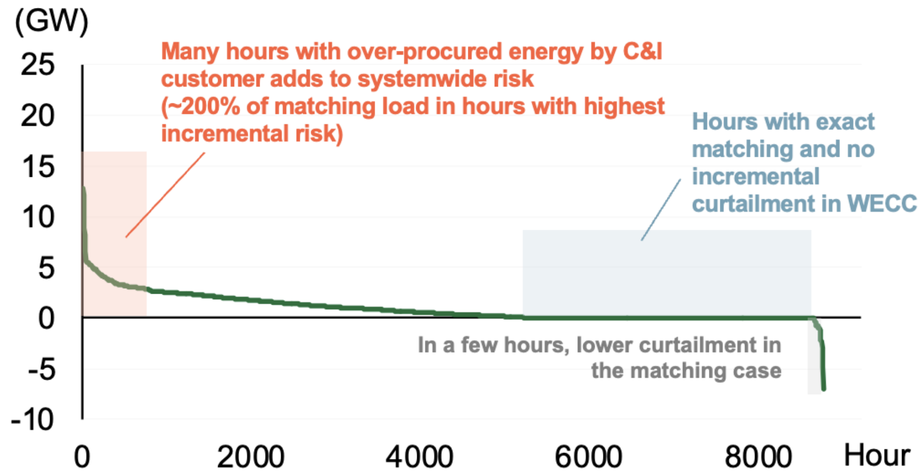
v) Weather Years

E3's RESOLVE model of CAISO relies on hourly load, wind and solar generation profiles covering a range of weather years. Specifically, to reduce model runtime, the capacity expansion modeling includes 36 representative days, sampled from load, hydro and renewable generation profile data for 23 weather year conditions (1998-2020). The weights for these representative days are estimated such that on average, a reasonably diverse set of days are selected representing a sufficient range of "challenging" conditions (i.e., high load and low renewable output.) Overall, RESOLVE's optimal capacity selections and operations, presented in the results section, are based on average multi-weather variations. No changes were made from the public version of RESOLVE.

In addition to the RESOLVE capacity expansion, E3 also ran the RESOLVE 8760-hour dispatch module, which simulates demand and dispatch of a given resource portfolio over all 8760 chronological hours of the year, preserving systemwide policy targets. The 8760-hour dispatch analysis, as mentioned in the results section, was used to assess the hourly matching challenges of selected resources in meeting the matching requirements during a broader set of conditions, representing more challenging days and hours. That said, "extreme" conditions (e.g., 1-day-in-10-year events) were not modeled for this study in the hourly production simulation (though are still parametrized via the PRM and ELCCs when developing the portfolios in capacity expansion), and it would be valuable future work.

A.2. Additional Capacity Expansion Results

Figure A-4. Over-Procured Clean Energy by C&I Load by Hour, Hourly Matching Market Case in High Demand Scenario, 2030



Notes: Graph includes the sum of exports from excess clean energy from C&I procured resources to the rest of the system (i.e., market sales), as well as WECC-wide incremental curtailment in that hour (if any) in the hourly matched scenario, relative to the reference.

Figure A-5. CAISO-wide Generation Changes in Annual and Hourly Matching in 2030 and 2040 for 25% C&I Matching under Low Demand and High Demand Scenarios

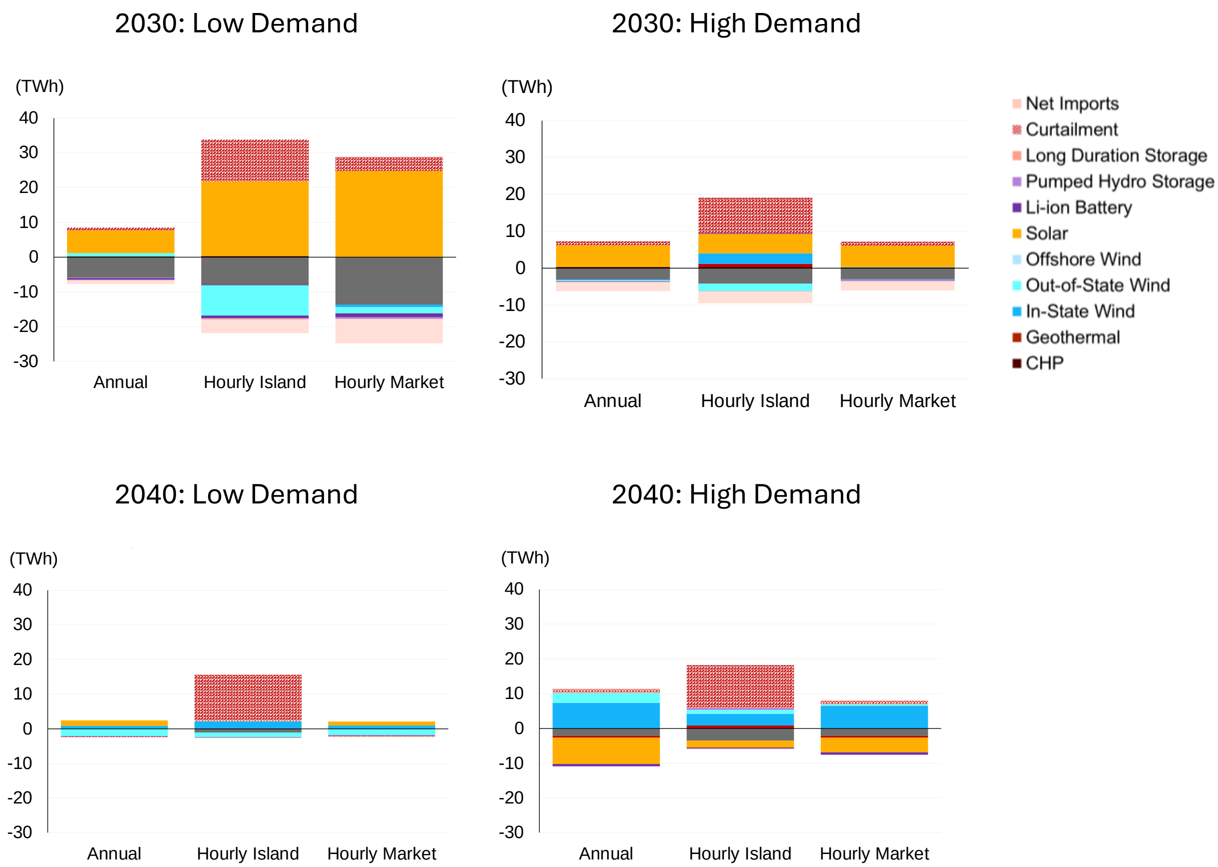


Figure A-6. CAISO-wide Changes in Capacity for Annual and Hourly Matching in 2030 and 2040 for 25% C&I Matching under Low Demand and High Demand Scenarios

Figure A-7. Energy Mix Serving 25% C&I Load in Matching Frameworks under Low Demand and High Demand Scenarios, in 2030 and 2040 (Accounting Basis)

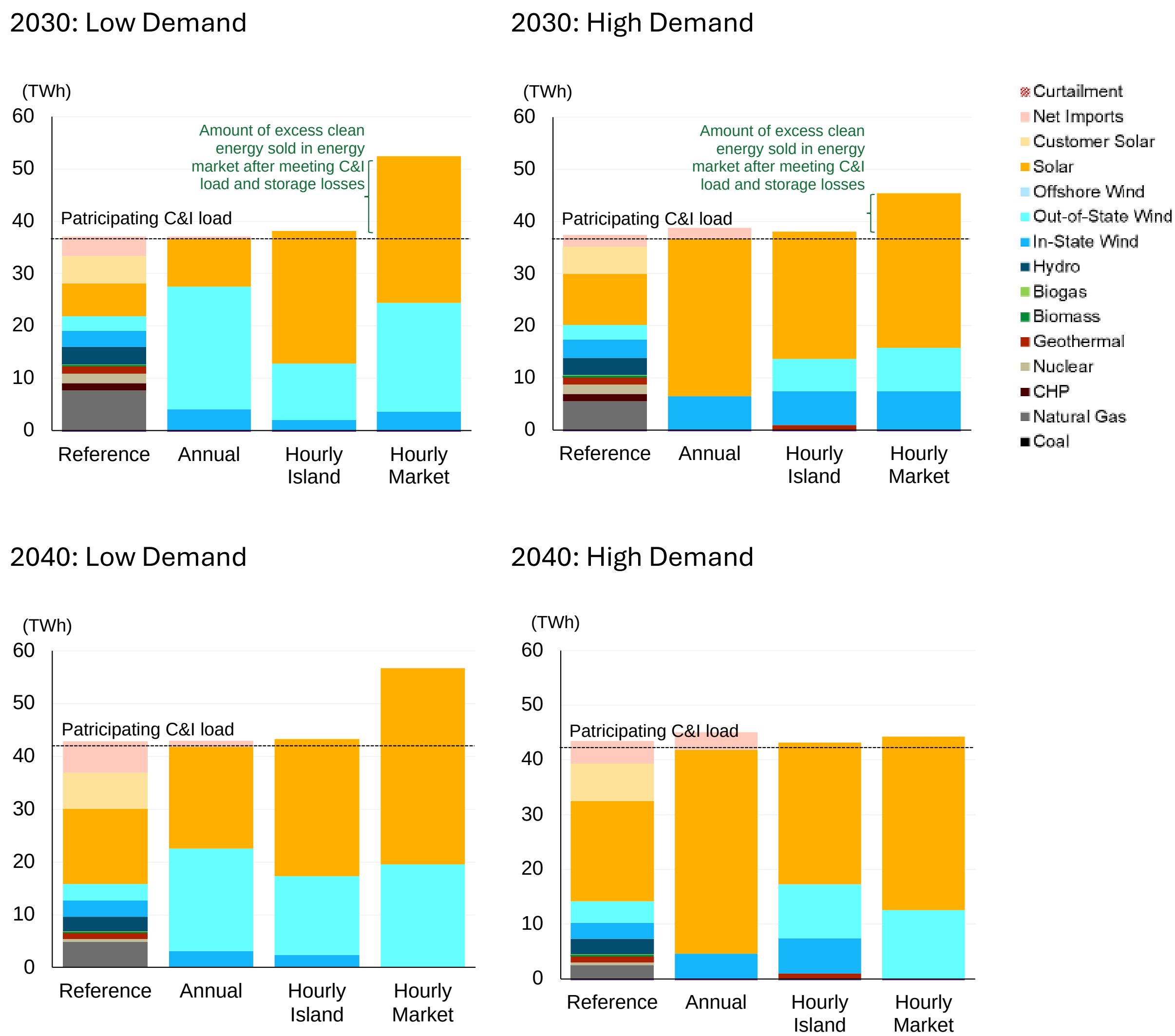
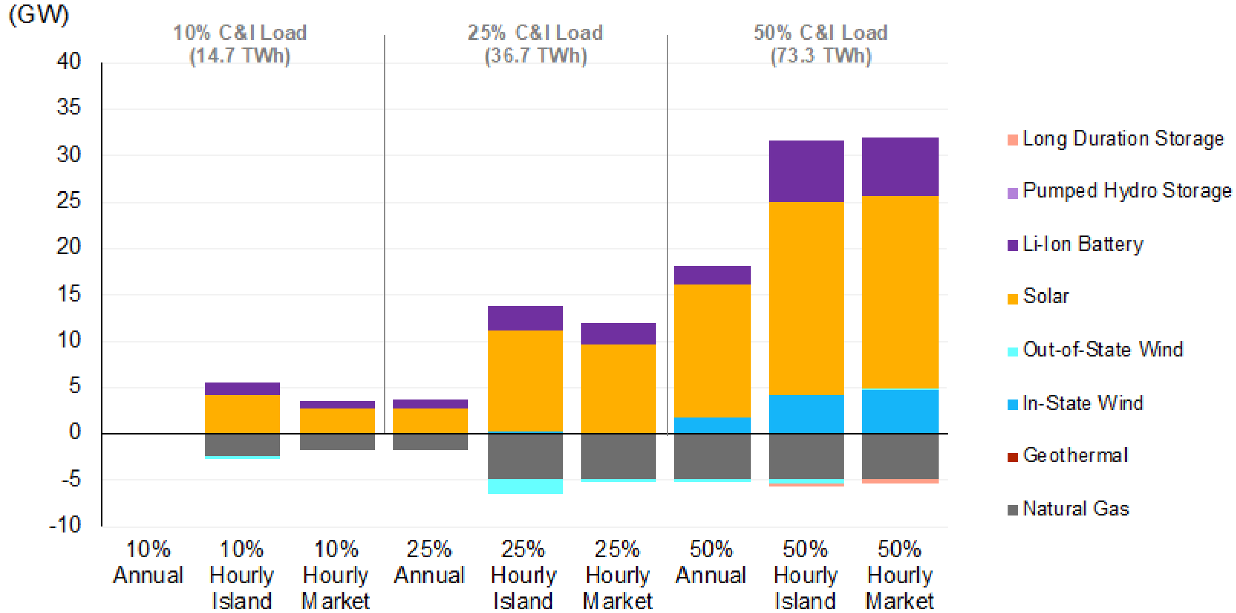


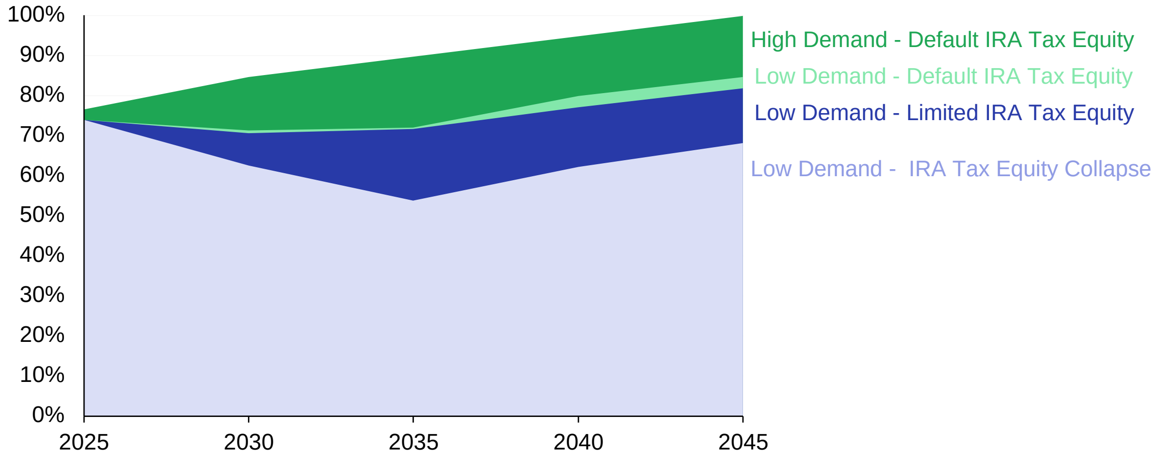
Figure A-8. Comparison of CAISO-wide Incremental New Resource Additions, Compared to Reference, at 10%, 25% and 50% C&I Load Matching in 2030, for Low Demand Scenario



A.3. Clean Energy Builds for Lower IRA Tax Monetization Rate

Additional Low Demand Scenarios were modeled using lower tax equity assumptions noted below as “Limited TE” and “TE Collapse” to explore the impact of conditions where access to full IRA tax incentives is limited. This impact on clean energy generation in Reference (no matching) cases are shown for in Figure A-9.[56]

Figure A-9. CAISO Clean Energy Generation as Percentage of Retail Sales Under Range of Hypothetical California State Policy and IRA Tax Incentive Monetization Rate Assumptions



Note: Note that the “Low Demand” Scenarios reflect low clean energy demand, which is not consistent with current California policy, and thus not an expected real-world outcome. Rather, this scenario was used to illustrate outcomes under conditions with low clean energy demand.

A.4. Selected Resource Dispatch Charts for Low and High Demand Scenarios

The figures below provide examples of dispatch from average and challenging load days. We note that in annual matching cases, particularly during challenging conditions, the load is not necessarily met with all clean energy on that day, given that RECs can be provided by clean energy consumption on other days.

[56] Additional results from these cases are available upon request.

Figure A-10. Illustrative Hourly Dispatch for <u>Average Load Days</u> in 2030 for 25% C&I Matching Load under Low Demand Scenario, 2030

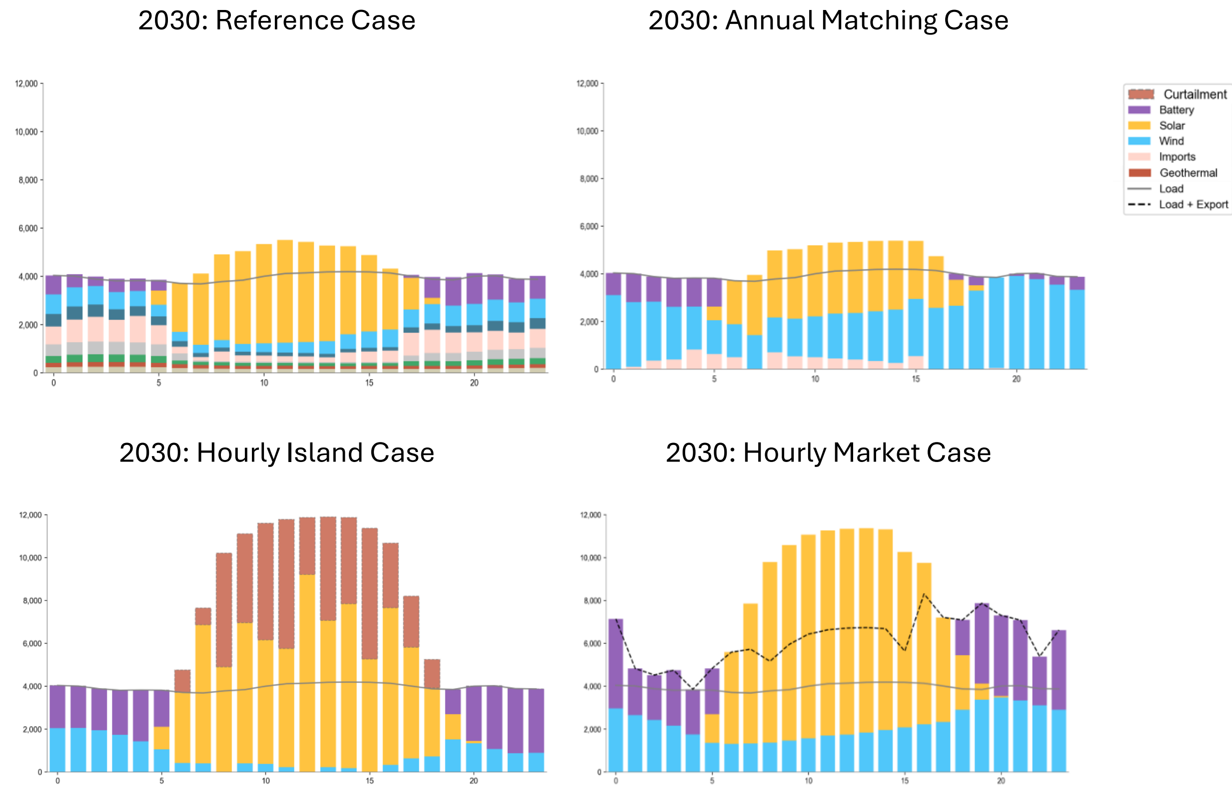


Figure A-11. Illustrative Hourly Dispatch for <u>Challenging Days</u> in 2030 for 25% C&I Matching Load under High Demand Scenario

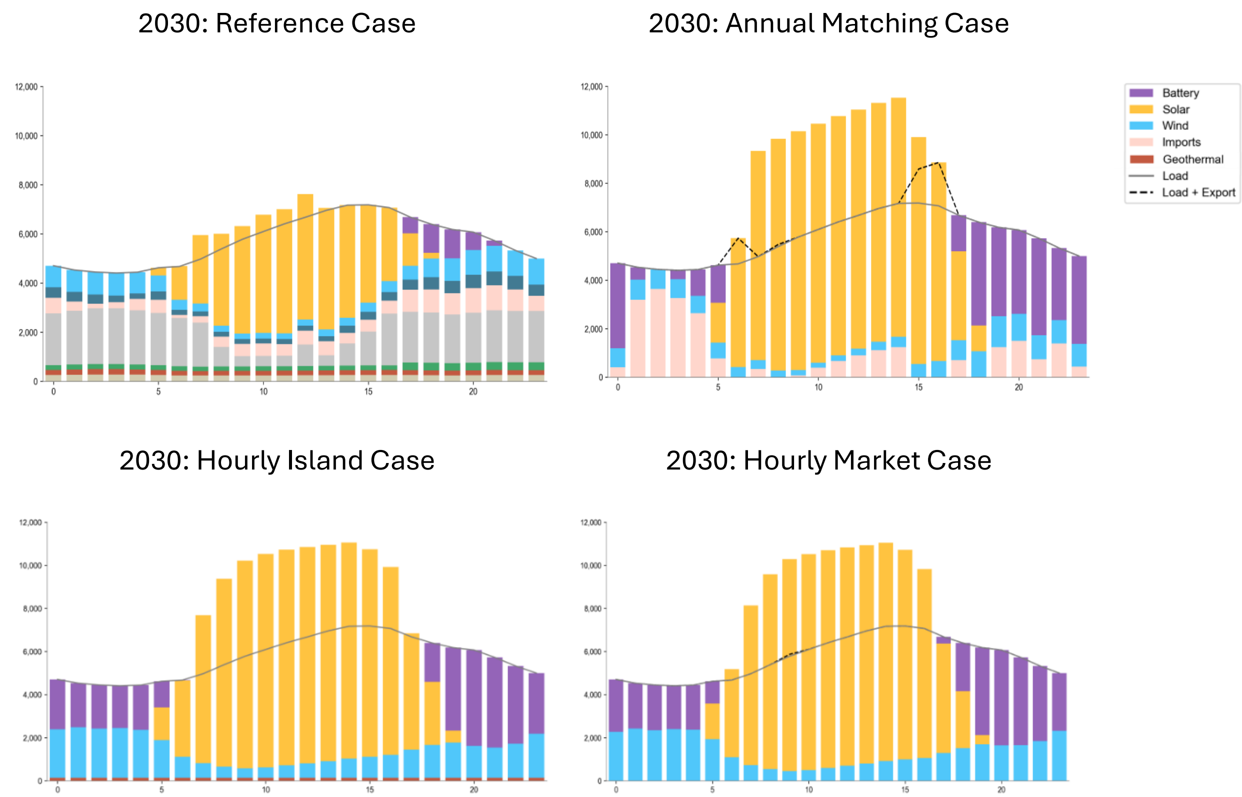
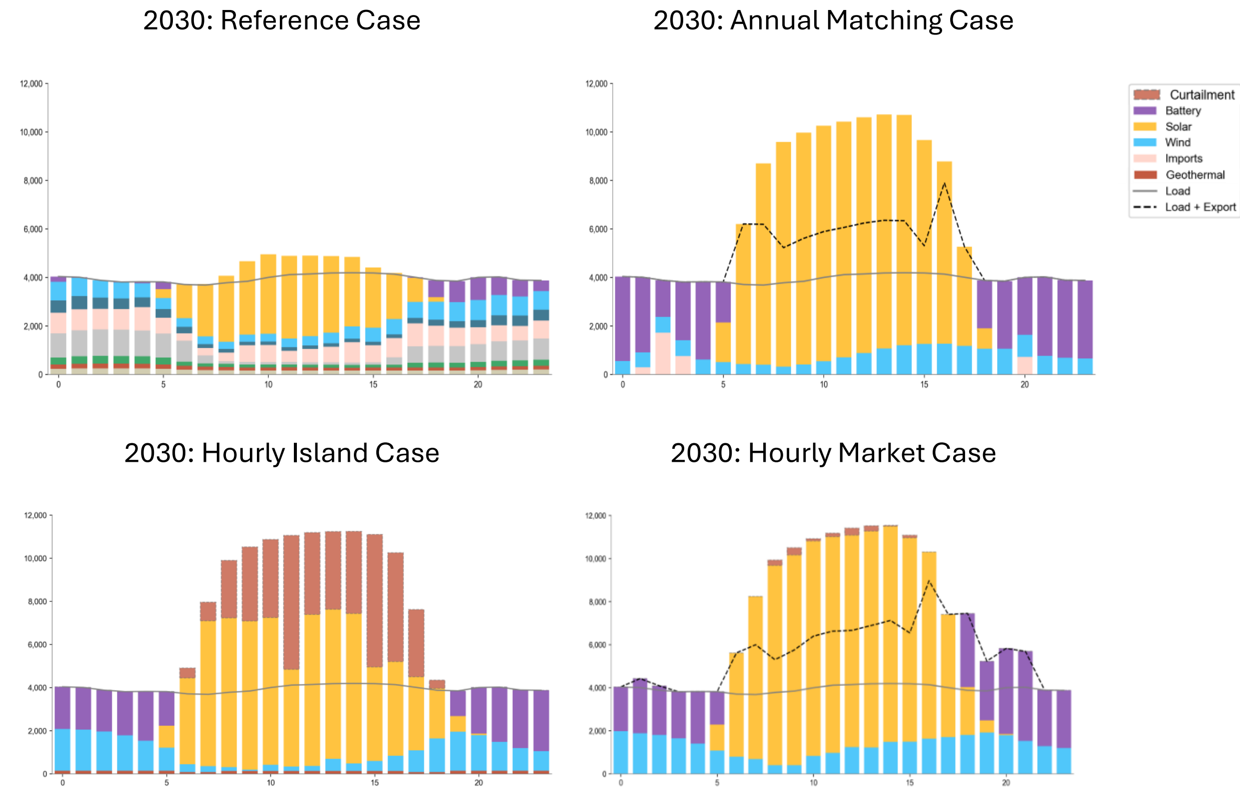
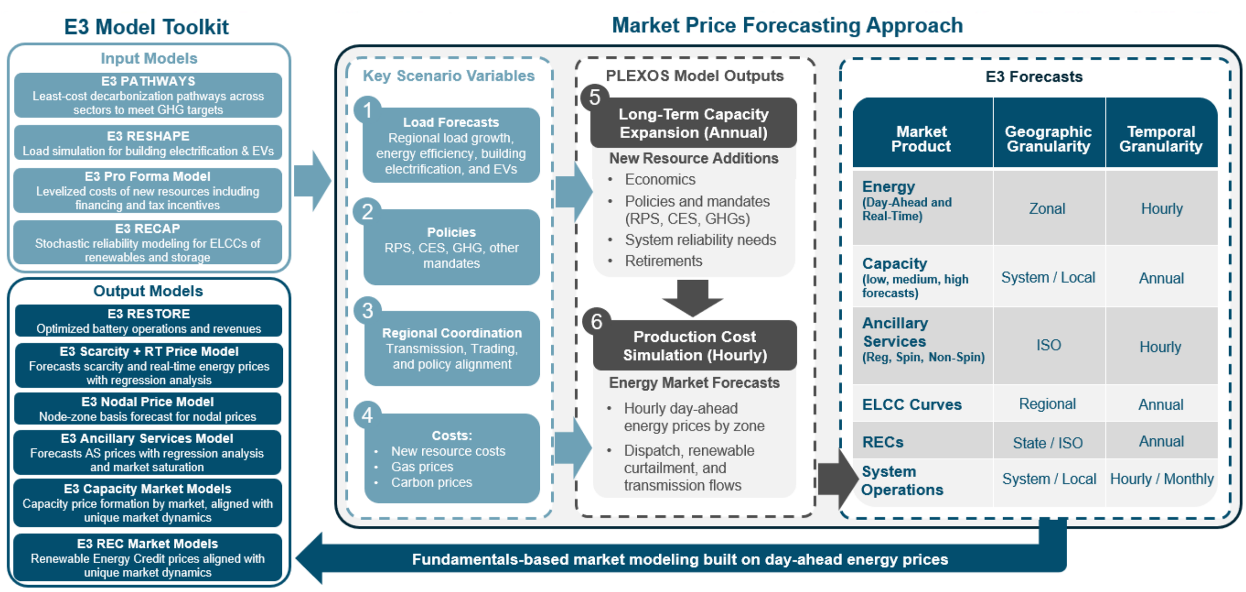


Figure A-12. Illustrative Hourly Dispatch for Average Load Days in 2030 for 25% C&I Matching Load under High Demand Scenario, 2030



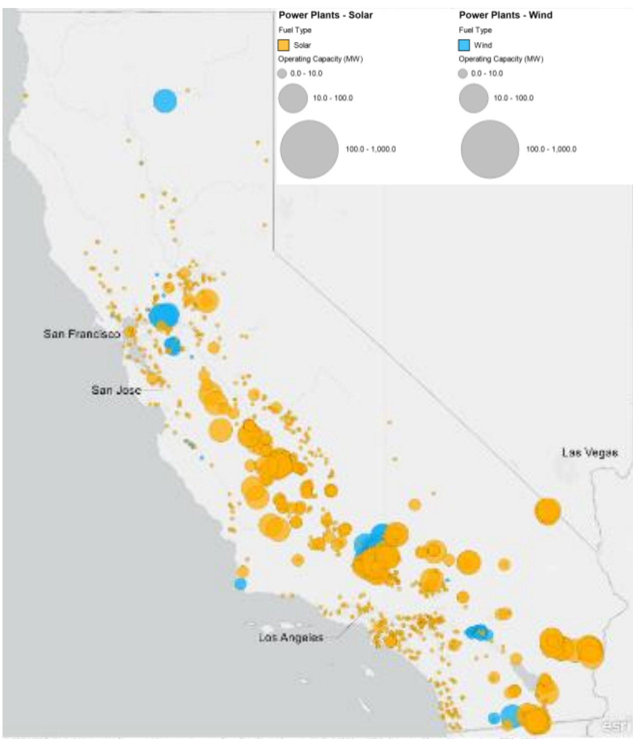
A.5. Additional Project Economics Methodology

Figure A-13. E3's Market Price Forecast Modeling Approach



E3 estimated the market value of utility-scale solar and onshore wind in California using our latest market price forecasts for the CAISO. Our price forecasts are built around a "Core Case" for each market which encompasses E3's expectation for how policies, regulations, technologies, economics, and customer demand will evolve to drive new resource additions, retirements, and market prices from today through 2050+. In markets with strong decarbonization policies such as California and the Pacific Northwest, our Core Case presents our view of the most reasonable, reliable, and low-cost way to achieve existing policy targets through current market structures and available technologies. Our market price modeling approach relies upon E3's customized PLEXOS[57] production cost simulation model. This commercially available software has been heavily modified and customized by E3 to reflect actual system operations as well as the capabilities of new resources like energy storage.

Figure A-14. Operating Solar and Wind Capacity in California, 2024



The model outputs day-ahead zonal ("hub-level") energy price forecasts, on the basis of which E3 derives real-time prices and ancillary services prices (i.e., regulation, spinning, and non-spinning reserves) to ensure alignment with system fundamentals. We also tailor our price outlook to account for specific market rules and procurement methods (i.e., state-administered resource adequacy programs vs. organized capacity markets). E3's capacity or resource adequacy price forecasts incorporate day-ahead energy prices in the calculation of net Costs of New Entry for marginal new capacity resources. Our capacity price forecasts account for going-forward costs of existing resources, availability of new resources, and forecasted planning reserves. Our Renewable Energy

[57] https://www.energyexemplar.com/plexos

Certificate (REC) price forecast for the CAISO represents the additional revenue needed beyond the energy market to cover levelized costs for new solar resources. For this analysis, where zonal (hub-level) granularity was needed, E3 used NP-15 market prices, reflecting conditions in Northern California.

Figure A-15. Illustration of Resource Supply Curve for New Solar Resource in California

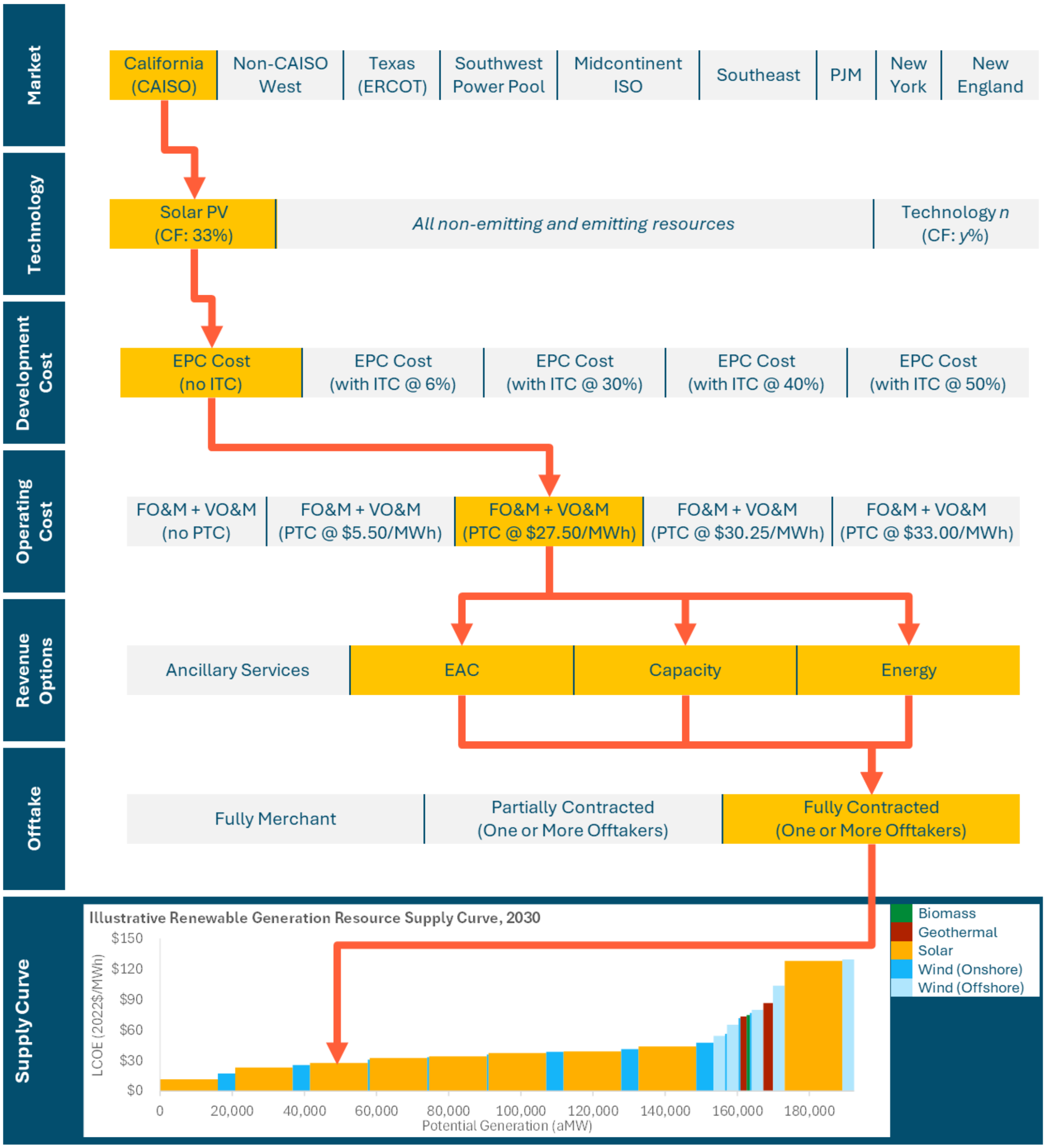
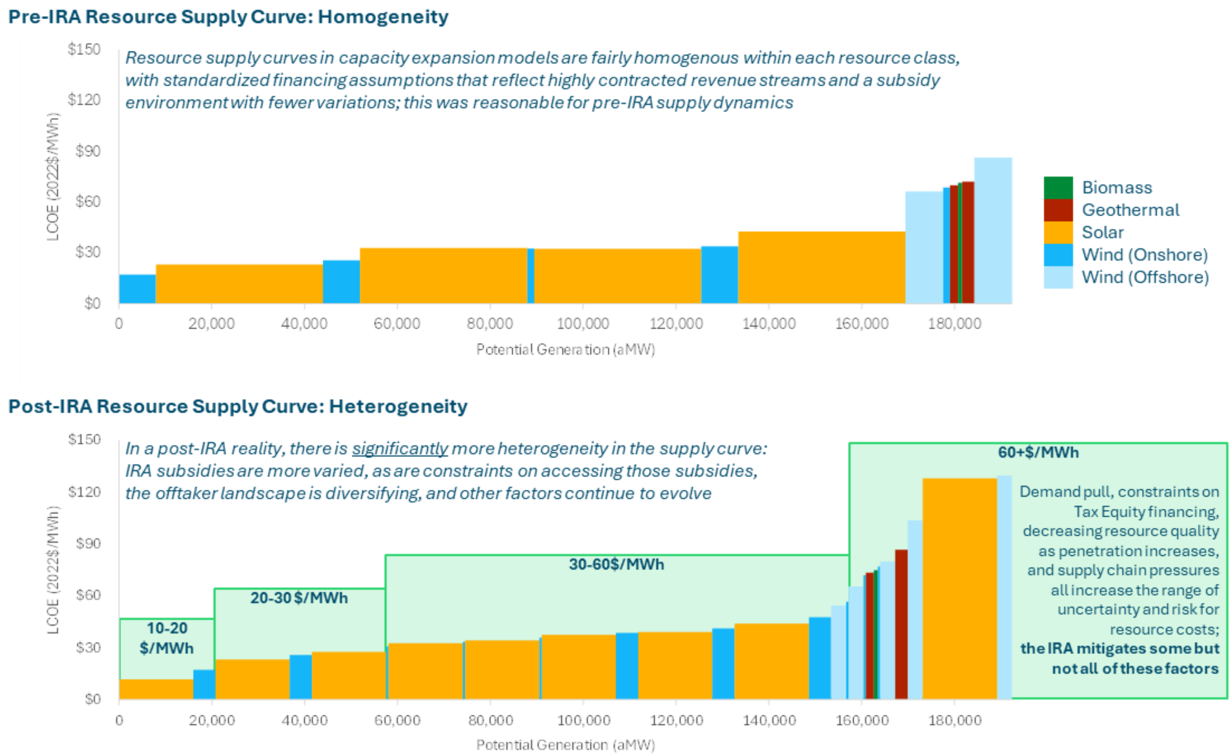


Figure A-16. Illustration of Renewable Energy Supply Diversity



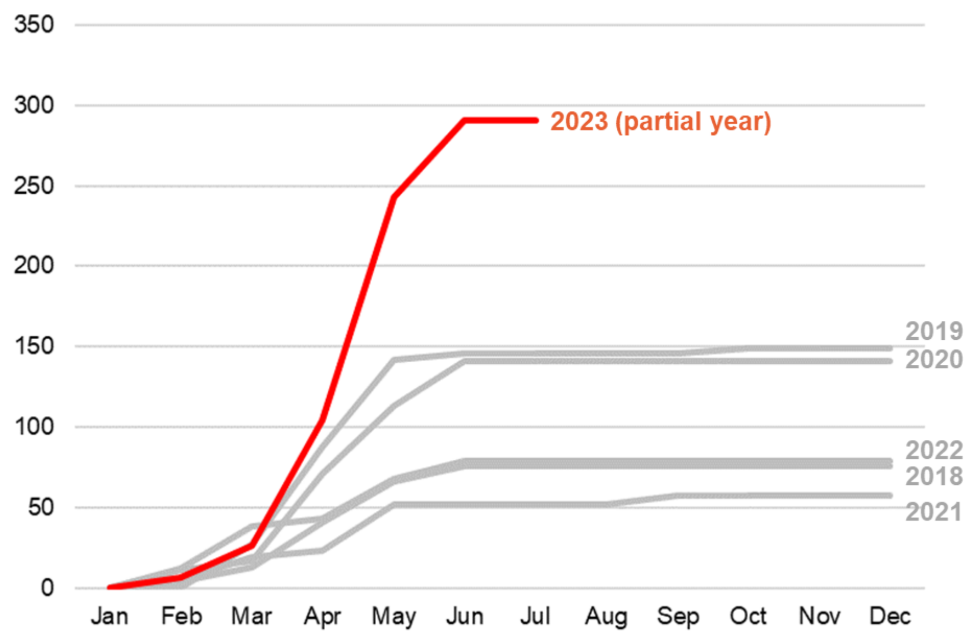
There are three options for **curtailment** across scenarios:

- **No Curtailment**:
  - Output is not reduced from the initial capacity factor at project COD, except to reflect plant equipment degradation as reflected in NREL ATB resource cost forecasts. Delivered solar generation declines from a 33% capacity factor at COD to 29% by the end of its operating life due to degradation of 0.5% per annum.
- **Base Curtailment**:
  - Solar: RESOLVE forecast of CAISO-wide average curtailment expected across all operating solar generation facilities.
  - Wind: RESOLVE forecast of CAISO-wide average curtailment expected across all operating wind generation facilities.
- **High Curtailment**:
  - Solar: RESOLVE forecast of curtailment expected across all operating solar generation facilities in the Greater Kramer region of California (San Bernardino County), which experiences the highest curtailment levels in RESOLVE modeling.
  - Wind: RESOLVE forecast of curtailment expected for a generic operating wind generation facility in the CAISO, where “generic” means that RESOLVE has the option to select a specific resource with characteristics assumed to reflect statewide

potential. This is the wind resource available to RESOLVE that experiences the highest levels of curtailment in E3 modeling.

While E3 did not explicitly model different potential negative pricing outcomes, increasing negative pricing is an important related risk to curtailment. To avoid economic curtailment, a clean energy generation resource may bid a negative price as low as the negative value of the EAC the asset would expect to earn if it is successful. For example, an onshore wind facility may bid as low as ($15/MWh) if it expects to receive revenue from EACs equivalent to $15/MWh if successful. However, this is not the lowest possible bid in a deeply decarbonized system: assets claiming the Production Tax Credit are incentivized to bid as low as the combined negative value of the EAC and PTC the asset would claim if it is successful. To continue the previous example, an onshore wind facility claiming the PTC (i.e., during its first ten years of operations) may bid as low as ($15/MWh + $27.50/MWh), or ($42.50/MWh), if it expects to receive revenue (or avoid non performance penalties) equivalent to $42.50/MWh if successful. This can create a meaningfully different risk profile to that of physical curtailment: instead of seeking to avoid the relatively shallow and less-persistent periods of negative pricing due to technical curtailment, an asset must compete against resources willing to bid consistent and deeply negative prices while they are eligible for PTCs. Negative pricing is not a hypothetical issue. In California, negative pricing in the southern zone (SP15) has increased considerably over time, and in 2023 was well above historical levels.

Figure A-17. Incidence of Hours with Negative Pricing in DA Energy Market, SP15 (CAISO)



Source: CAISO and E3 analysis.

In markets where renewable penetration increases, there tends to be an increase in system-level curtailment – this could result from a relative scarcity of energy storage available to charge from excess renewable generation, a nodal- or project-specific constraint in the transmission system, a buildout of renewable capacity at a faster rate than the growth of demand, or other factors. With the passage of the IRA, solar resources are more likely to claim the Production Tax Credit instead of the Investment Tax Credit, as the PTC tends to be economically preferable at capacity factors common in the California market. While this represents an improvement in project economics for solar generators relative to the pre-IRA policy environment, it also increases the risks associated with curtailment. When a renewable generator is curtailed, it misses out on energy revenue, revenue from RECs, and the value of the PTC, because each of these value streams require that energy is injected into the grid.

Solar and onshore wind project economics are sensitized against curtailment scenarios informed by RESOLVE curtailment outcomes and E3's market price forecasts for the CAISO. E3 confirmed as part of our analysis that new resource build assumptions are broadly aligned between RESOLVE modeling and our market price forecast assumptions. RESOLVE curtailment is driven by CAISO-wide overgeneration and deliverability constraints at the system level, and results in delivered solar generation falling from a 33% capacity factor at COD to 21-27% CF by the end of the project's useful life. E3 assumes a 2030 COD for all projects in this analysis. Separate from the curtailment assumptions, E3 assumes 0.5% annual solar module degradation based on NREL ATB inputs.

Economics for solar generation projects claiming the Investment Tax Credit (ITC) are worse than for projects claiming the PTC. While this should lead more solar projects to claim the PTC moving forward, there are multiple reasons why it is important to consider both ITC and PTC results in this analysis. Most notably, PTC claims represent a riskier potential value for offtakers and tax equity investors, since the PTC must be claimed in each of the 10 years for which the project is eligible, while the ITC need only be successfully claimed in the first year of the project's operations (subject to some recapture risk that is still shorter-term than the full PTC period). In addition, the rationality of the PTC from the project perspective does not necessarily mean that all projects will be able to claim the PTC from a financing perspective. Therefore, it is worth considering as well the economics of those projects for which the ITC is the only practically viable option.

Table A-4. DSCR Assumptions by Technology

Technology	Offtake	Output	"Market" DSCR[58]	NREL ATB DSCR[59]
Wind	Contracted	P50	1.30x	1.40x
Wind	Merchant	P50	1.80x	–
Solar	Contracted	P50	1.25x	1.30x
Solar	Merchant	P50	1.75x	–

[58] https://www.projectfinance.law/publications/2024/february/cost-of-capital-2024-outlook/
[59] https://atb.nrel.gov/electricity/2023/financial_cases_&_methods#dscr

The capital structure assumptions reflected in the resource costs used in E3's RESOLVE modeling are based on NREL Annual Technology Baseline expectations for resource-specific trends in debt and equity financing. These, in turn, are based in part on an assumption of the Debt Service Coverage Ratio (DSCR) applicable to each technology. DSCR measures the ability of any entity (corporate or project) to meet its debt obligations, and is widely used to determine how much debt an entity can raise. In general, DSCR is calculated as follows:

$$DSCR = \frac{CFADS}{Principal\ Payments + Interest\ Payments}$$

Where:

CFADS = Revenue – Operating Expenses – Capex – Taxes Paid

Debt Service = Interest Payments + Principal Payments

Lenders typically assume a minimum DSCR for a project based on the safety of the cash flows, which then determines the amount of debt that can be raised to finance the project. Offtake contracts like PPAs are generally perceived to be "safer" than merchant revenues, and therefore lenders can apply a lower DSCR if they have signed a PPA than if they are depending on merchant revenues.

NREL Annual Technology Baseline (ATB) inputs assume some form of offtake contract, specified as a PPA in NREL documentation.[60] However, projects may still seek financing even on a fully-merchant basis (i.e., without a contract), where the implicit 'penalty' for not having an offtake contract is an elevated DSCR. To assess the impact of a higher DSCR assumption on project economics, E3 has supplemented NREL ATB assumptions with more current DSCRs that include a range sufficient to encompass fully merchant plants, based on available information from a recent Norton Rose Fulbright webinar.[61] Based on conversations with market participants, E3 has concluded that these represent reasonable proxy inputs to reflect current market conditions, albeit slightly optimistic (e.g., it would not be unreasonable to assume that both wind and solar receive a DSCR of 2.0x if they are fully merchant).

After tax cash flows to equity capture the full impact of tax credit for project development, while CFADS complements this perspective by capturing the value of cash flows for the most senior elements of the project capital stack.

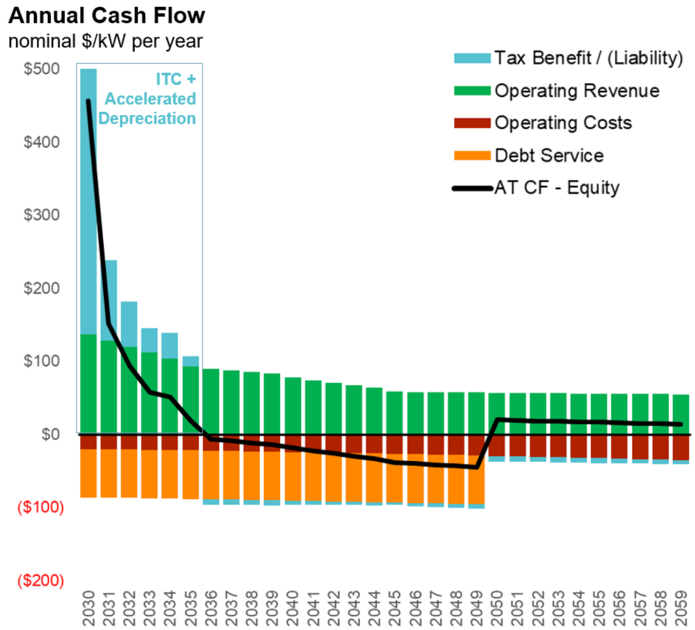
[60] https://atb.nrel.gov/electricity/2023/financial_cases_&_methods#dscr
[61] https://www.projectfinance.law/publications/2024/february/cost-of-capital-2024-outlook/

A.6. Additional Project Economics Results

Project Economics Results					
Resource	Cost Scenario	Curtailment Scenario	Equity IRR	Capacity Factor, 2030	Capacity Factor, 2059
Solar	Base Costs	No Curtailment	8.6%	33.0%	28.5%
Solar	Base Costs	Base Curtailment	6.4%	33.0%	24.7%
Solar	Base Costs	High Curtailment	(13.4%)	33.0%	18.5%
Solar	Limited Tax Equity	No Curtailment	6.9%	33.0%	28.5%
Solar	Limited Tax Equity	Base Curtailment	4.3%	33.0%	24.7%
Solar	Limited Tax Equity	High Curtailment	(14.0%)	33.0%	18.5%
Solar	Tax Equity Collapse	No Curtailment	(4.3%)	33.0%	28.5%
Solar	Tax Equity Collapse	Base Curtailment	(7.6%)	33.0%	24.7%
Solar	Tax Equity Collapse	High Curtailment	(16.4%)	33.0%	18.5%
Wind	Base Costs	No Curtailment	16.7%	30.0%	30.0%
Wind	Base Costs	Base Curtailment	13.9%	30.0%	23.8%
Wind	Base Costs	High Curtailment	12.4%	30.0%	20.6%
Wind	Limited Tax Equity	No Curtailment	16.0%	30.0%	30.0%
Wind	Limited Tax Equity	Base Curtailment	13.2%	30.0%	23.8%
Wind	Limited Tax Equity	High Curtailment	11.8%	30.0%	20.6%
Wind	Tax Equity Collapse	No Curtailment	10.7%	30.0%	30.0%
Wind	Tax Equity Collapse	Base Curtailment	8.0%	30.0%	23.8%
Wind	Tax Equity Collapse	High Curtailment	6.5%	30.0%	20.6%

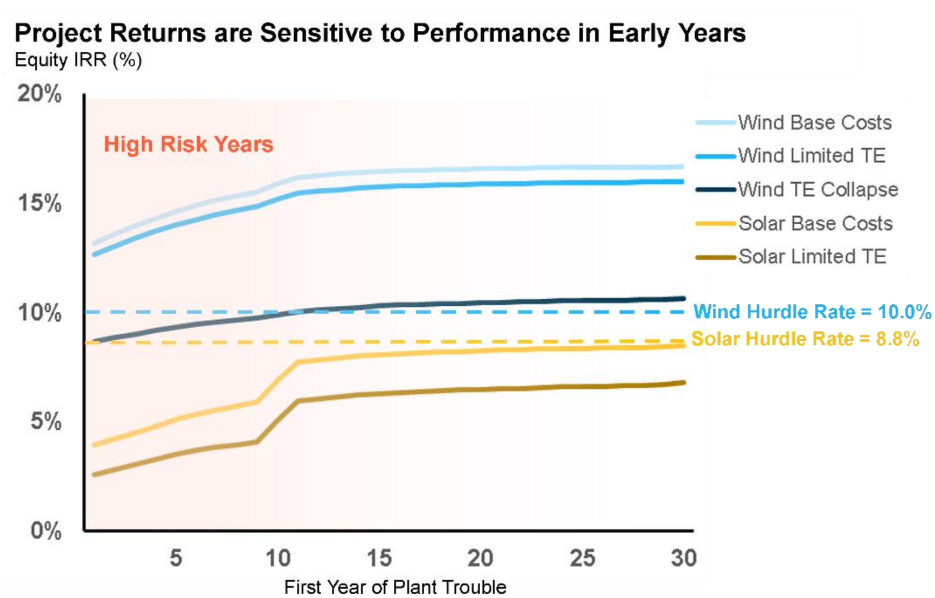
Figure A-18. Solar Project Cash Flows, Base Assumptions, ITC

Scenario Assumptions	
Revenue Forecast	NP15 E3 Market Prices
Tax Equity Monetization Rate	Base (90%)
Curtailment	Base
Project Details	
Project Type	Solar ITC
Capital Cost, 2030 COD	$1,348/kW-ac
Site Capacity Factor, COD	33%
Site Capacity Factor, 2059	25%
Operating Years	2030-2059
Scenario Results	
Equity IRR	(6.9%)



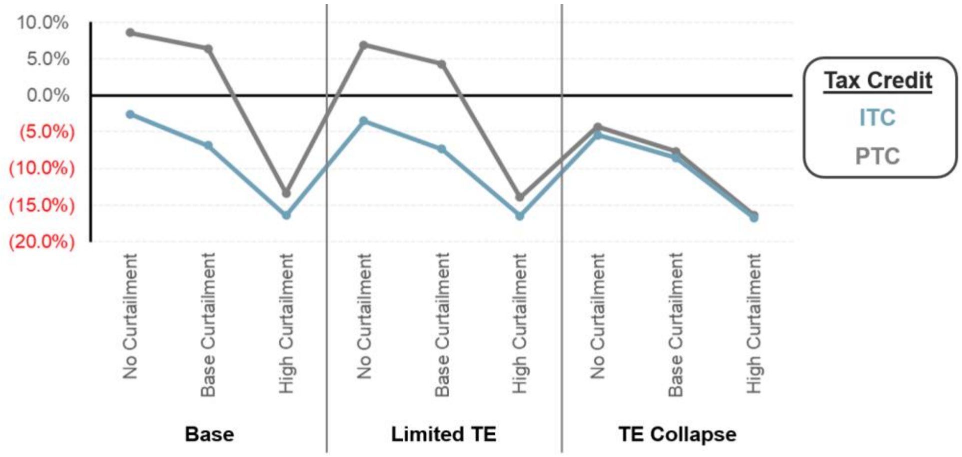
The metrics presented in the project economics analysis were selected to capture the project-level perspective on both equity and debt financing. Merchant revenues are used to support debt service commensurate with NREL ATB assumptions for capital structure. Annual after-tax cash flows to equity are the key output variable through which project economics are assessed. Project economic viability is quantitatively assessed by comparing the equity internal rate of return (IRR) against benchmark equity hurdle rates required to incent equity investment. IRR below the hurdle rate indicates the clean energy project faces a missing money problem.

Figure A-19. Equity IRR Sensitivity: Timing of 2-year Plant Trouble Period



In addition to the simulations of solar project economics under an assumption that the project will claim the PTC, E3 also assessed equity IRR results for solar projects claiming the ITC relative to the PTC. As noted earlier, solar generation economics under the ITC are generally worse than they are for projects claiming PTC, and this result is robust across tax equity financing assumptions.

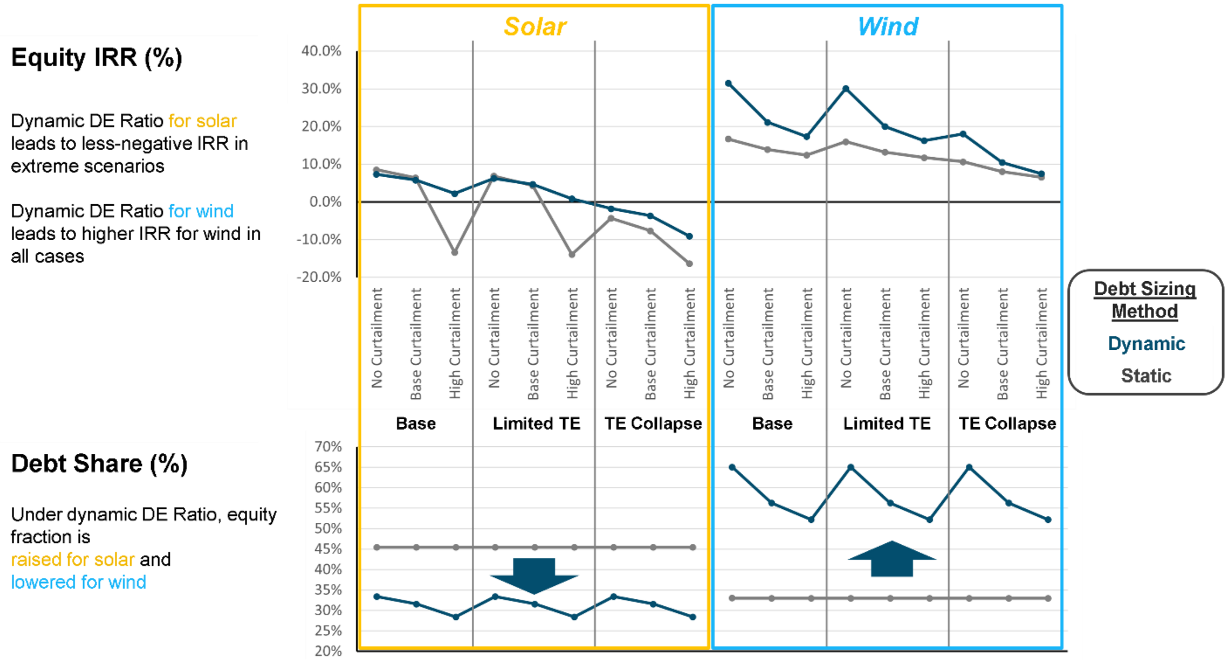
Figure A-20. Equity IRR Sensitivity: Solar PTC vs ITC



In conversations with market participants, E3 finds that the assumed levered after-tax equity hurdle rates (8.8% for solar, 10.0% for onshore wind) are meaningfully lower than the typical project being financed today. If we assume an additional 150 – 200 basis points (bps) in required equity return, this would result in all solar scenarios failing to 'pencil' (i.e., represent a sufficient return to attract the necessary capital) and would push two of the wind scenarios shown above below the necessary hurdle rate.

E3 also tested the ability of each solar and wind asset to raise debt financing under merchant DSCR assumptions instead of contracted DSCR assumptions. In this analysis, the worst equity IRR results are avoided for solar generators but this comes at the expense of reducing the share of debt financing for the project, requiring additional equity commitment and therefore reducing the ability of capital providers to support further industry expansion. More importantly, even under flexible debt financing assumptions, all solar projects modeled by E3 failed to clear the reference (conservative) equity hurdle rate of 8.8%. For wind, results are more positive: higher equity IRRs are supported by increasing the share of debt across scenarios. This supports the earlier conclusion that outcomes for solar generators are generally worse for investors than for wind generators. While this may lead some to infer that this simply requires a realignment of capital from solar investments to wind investments, this will not be feasible given total technical resource potential limits and transmission constraints in the California market.

Figure A-21. Equity IRR Sensitivity: Static vs Dynamic Debt Sizing



Note: Base curtailment is consistent with RESOLVE scenarios and grows from near-zero to over 10% (system-wide) by 2045. High curtailment assumes curtailment grows from 5% to over 30%. Tax equity collapse assumes that tax equity market contracts to 18% of the full value of the PTC.