Analysis for Centralized Procurement of Specified Long Lead-Time Resources

Energy Division Staff

With Support from Energy and Environmental Economics (E3)

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California Public
Utilities Commission

Outline

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Considering Centralized Procurement for LLT Resources

Key Legislation
Relevant for Specified Long Lead-Time Resources

- **AB 1373** (2023, Garcia et al.) enables CPUC to request DWR to conduct central procurement of "eligible energy resources" until January 1, 2035 and to "*develop and adopt procedures and requirements that govern competitive procurement by, obligations on, and recovery of costs incurred by the department*."
- Further requires the Commission (initially by September 1, 2024, and thereafter in a recurring process) to determine if there is a need for the procurement of eligible energy resources.

Information Used to Inform an AB 1373 Need Determination

- Consistent with AB 1373 requirements, CPUC staff has sought to draw on multiple pieces of information to inform decision-making regarding a need determination for central procurement of eligible resource types.
- This includes consideration of individual LSE plans filed on November 1, 2022; LSE procurement actions as filed in the IRP proceeding; and the planning track of the CPUC's IRP process, particularly the most recently adopted IRP Preferred System Plan.
- The relevant information from each is summarized in the following slides.

Load Serving Entities (LSEs) IRP plans for relevant resource types

- AB 1373 requires the Commission to "*determine if there is a need for the procurement of eligible energy resources based on a review of the integrated resource plans submitted by load-serving entities …*"
- This table shows the aggregate resource builds submitted by CPUC-jurisdictional LSEs in their November 1, 2022 IRP filings for relevant resource types.

2023 LSE Planned LLT Resource Build in GW

Resource	2024	2025	2026	2028	2030	2032	2033	2034	2035
Geothermal	*0.00*	*0.00*	*0.78*	*1.14*	*1.54*	*1.59*	*1.61*	*1.61*	*1.64*
Out-of-State Wind	0.01	0.64	1.67	3.41	*3.41*	*3.41*	*3.41*	*3.41*	*3.41*
Offshore Wind	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*2.74*	*3.33*	*3.86*	*4.53*
Li-ion Battery (8-hr)	*0.01*	*0.01*	*0.42*	*0.95*	*1.23*	*1.35*	*1.35*	*1.71*	*2.83*
Pumped Hydro Storage	*0.00*	*0.00*	*0.00*	*0.48*	*0.48*	*0.48*	*0.48*	*0.48*	*0.48*
Long Duration Storage	*0.00*	*0.00*	*0.11*	*0.31*	*0.31*	*0.36*	*0.41*	*0.46*	*0.51*

Progress to date and forecasted procurement of AB 1373-eligible resource categories

- AB 1373 provides statutory guidance through 454.52 (4)(A) for the Commission to review load serving entities integrated resource plans when developing a need determination for central procurement.
- Regarding related procurement for existing IRP procurement requirements:
  - Geothermal: LSEs have procured 26 MW through 8/1/2023, forecasted to be 26 MW for 6/1/24.
    - 258 MW of additional capacity is forecasted to be online by 6/1/28.
  - OOS Wind: LSEs have procured an expected 318 MW of OOS through 6/1/24.
    - Another 28MW of OOS is expected through 6/1/28.
  - Long Duration Storage: 361 MW of 8-hour LDES is forecasted to be online by 6/1/28.
    - No 8-hour LDES battery storage is expected to be procured through 6/1/24.
  - OSW: LSE IRP procurement filings do not indicate that OSW has been procured yet.

Preferred System Plan LLT Build out for relevant resource types

2023 RESOLVE Build for 25 MMT Core by 2035 in GW

Resource	2024	2025	2026	2028	2030	2032	2033	2034	2035
Geothermal	*0.00*	*0.00*	*0.78*	*1.14*	*1.54*	*1.79*	*1.95*	*1.97*	*1.97*
Out-of-State Wind	*0.01*	*0.64*	*1.67*	*3.41*	*4.52*	*4.52*	*4.52*	*5.33*	*6.33*
Offshore Wind	*0.00*	*0.00*	*0.00*	*0.00*	*0.00*	*2.74*	*3.33*	*3.86*	*4.53*
Li-ion Battery (8-hr)	*0.01*	*0.01*	*0.42*	*0.95*	*1.23*	*1.35*	*1.35*	*1.71*	*2.83*
Pumped Hydro Storage	*0.00*	*0.00*	*0.00*	*0.48*	*0.48*	*0.48*	*0.48*	*0.48*	*0.48*
Long Duration Storage	*0.00*	*0.00*	*0.11*	*0.31*	*0.31*	*0.36*	*0.41*	*0.46*	*0.51*

- The 2023 RESOLVE build was modeled by first "forcing in" LSE IRP planned resources that were submitted through the Nov 2022 filings. IRP staff then used RESOLVE modeling to optimally augment the LSE plans to achieve the buildout necessary to meet the increased GHG reduction target of 25MMT and reliability needs for 2035.
    - Among the resources that were selected in this process were geothermal and out of state wind.

Considering Centralized Procurement for LLT Resources

- Beyond the Commission's most recently adopted Preferred System Plan, additional analysis was conducted on four "eligible energy resource" types (LLTs) that could be eligible for central procurement under AB 1373.
- While some limited sensitivity analysis was conducted for LLT resources (and offshore wind specifically) in the 2023 PSP RESOLVE modeling, a robust risk-based analytical approach was designed for this study.
- This initial analysis focuses largely, but not entirely, on offshore wind, particularly given the unique nature, scale, and uncertainty regarding the resource and some of the assumptions around it. This analysis is reviewed in the following presentation slides.

Centralized procurement of specific resources should be carefully considered

Benefits of centralized procurement

- Addresses procurement challenges for existing technologies
    - Procurement challenges occur when resource procurement has net system benefits, but LSEs are unable to procure that resource on their own
- Supports market transformation for emerging technologies
    - Centralized procurement can support new high-cost technologies with the potential for future cost reductions

Risks of centralized procurement

- May increase ratepayer costs by decreasing procurement competitiveness
    - All source, attribute-based procurement (e.g., X MW ELCC or Y GWh of clean energy instead of resource specific procurement) tends to yield least cost outcomes[1]
    - A single buyer may be subject to seller market power if a prescribed quantity is set with limited sellers
- Decreases ability of LSEs to procure their own resources

[1] "All-Source Competitive Solicitations: State and Electric Utility Practices"

Considerations for Determining Whether Centralized Procurement is Justified

- What conditions demonstrate a significant procurement challenge?
  - If a resource has not yet been procured, that does not on its own constitute a procurement challenge
  - Resource size relative to buyer size could demonstrate a procurement challenge or a technology that appears cost-effective at the system level
    - However, resources can find multiple buyers or multiple buyers can join together to buy a larger resource
    - Is a proven cost-effective resource not being procured by LSEs because of a size mismatch or other procurement challenges?
  - Resource development timelines could be delayed if many LSEs procure instead of a centralized entity
    - Does this represent a need for LSEs to initiate additional procurement or a need for centralized action?
- When does a market transformation opportunity justify centralized procurement?
  - Market transformation should be weighed against the cost to ratepayers
  - Market transformation requires a resource with large potential and without easily available substitutes, that can achieve cost reductions through learning and/or economies of scale

Considering a test for centralized procurement

Category	Test	Offshore Wind	Out-of-state Wind	Geothermal	Pumped Hydro Storage
Procurement Challenges	A) Mismatched size of resource and/or transmission between sellers and buyers				
	B) Cost-effective across broad range of future scenarios, yet not being procured				
Market Transformation	C) Large resource potential				
	D) Serves a key role in future portfolios without readily available substitutes				
	E) Emerging technology with significant likelihood of cost reductions through learning				

- **Questions for stakeholders:**
  - **Are these the right tests?**
  - **Are these the right ratings for each technology?**

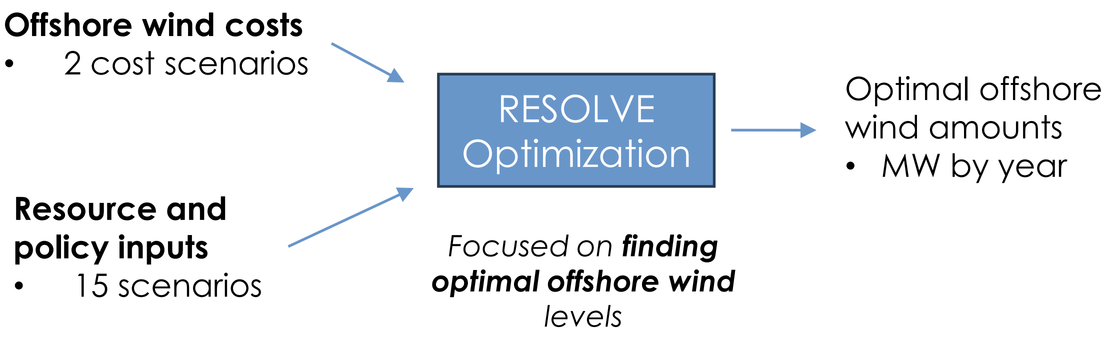
Test ratings explained

Category	Test	Offshore Wind	Out-of-state Wind	Geothermal	LDES
Procurement Challenges	A) Mismatched size of resource and/or transmission between sellers and buyers	Large typical project sizes	Large transmission size, incremental small offtakers may be possible but creates financing challenges	Smaller and modular procurement sizes available but some resource zones require high volumes	Large-scale projects, may be challenging to finance and build without a single contract
	B) Cost-effective across broad range of future scenarios, yet not being procured	Cost-effectiveness depends on scenario analyzed.	Selected across all RESOLVE cases and currently being procured by LSEs	Selected across all RESOLVE cases and currently being procured, at least in small volumes by LSEs	Selected across all RESOLVE cases but may not be cost-effective. Not being procured by LSEs
Market Transformation	C) Large resource potential	Supporting infrastructure enables economies of scale for large resource	Large high quality wind resource available with transmission investment	Large resource potential (with high capacity factor, especially in some resource zones	Project locations are generally limited by unique geographic characteristics, for some technologies
	D) Serves a key role in future portfolios without readily available substitutes	Supports resource diversity. Substitutes exist but may face challenges (e.g., in-state or out-of-state wind)	Supports resource diversity. Substitutes exist but may face challenges (e.g., in-state or offshore wind)	Clean firm resource with high capacity factors emerging (e.g., gas with CCS), but unproven substitutes	LDES selected in future portfolios, but many existing and emerging alternatives exist
	E) Emerging technology with significant likelihood of cost reductions through learning	New technology with low amount of deployment globally	Proven, established technology	Some emerging geothermal technologies benefit from learning; conventional geothermal does not	Emerging technologies benefit from learning; conventional technologies do not

Background on Offshore Wind Cost-Benefit Analysis

RESOLVE's analytical approach was adjusted to focus on offshore wind cost-benefit analysis and ratepayer risk

PSP Modeling Approach



Offshore wind costs
- 2 cost scenarios

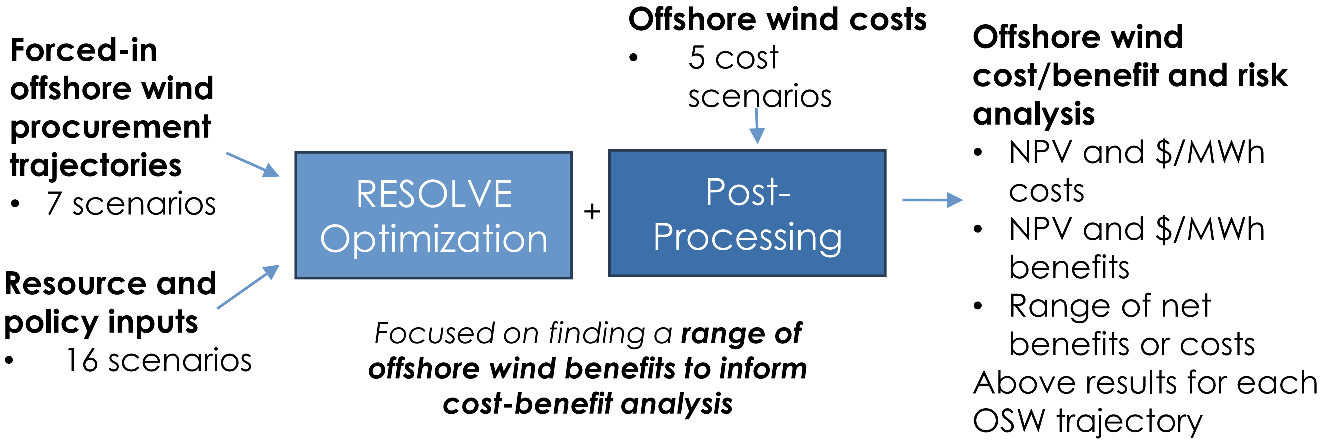
Resource and policy inputs
- 15 scenarios

RESOLVE Optimization

Optimal offshore wind amounts
- MW by year

*Focused on **finding optimal offshore wind** levels*

Cost Risk Modeling Approach (this study)



Forced-in offshore wind procurement trajectories
- 7 scenarios

Resource and policy inputs
- 16 scenarios

Offshore wind costs
- 5 cost scenarios

RESOLVE Optimization + Post-Processing

Offshore wind cost/benefit and risk analysis
- NPV and $/MWh costs
- NPV and $/MWh benefits
- Range of net benefits or costs

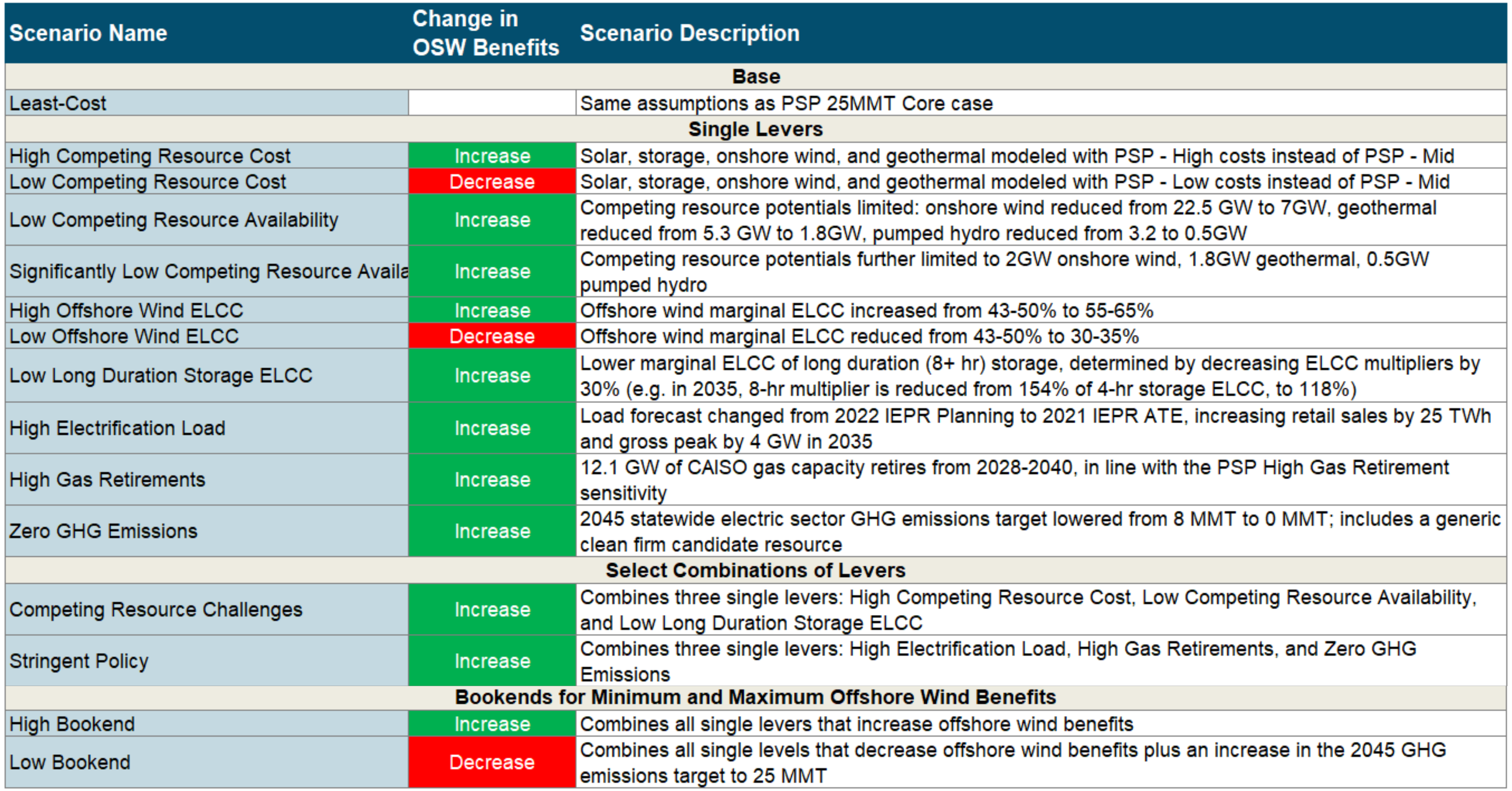
Above results for each OSW trajectory

*Focused on finding a **range of offshore wind benefits to inform cost-benefit analysis***

- Focused on optimizing offshore wind within the broader set of long-term system needs
  - Output = optimal offshore wind levels for each scenario

- Focused on building out a robust set of ratepayer cost and risk scenarios
  - Output = range of benefits vs. costs across a broader range of cost + benefit scenarios

Definitions of Levers Used in Benefit Scenarios

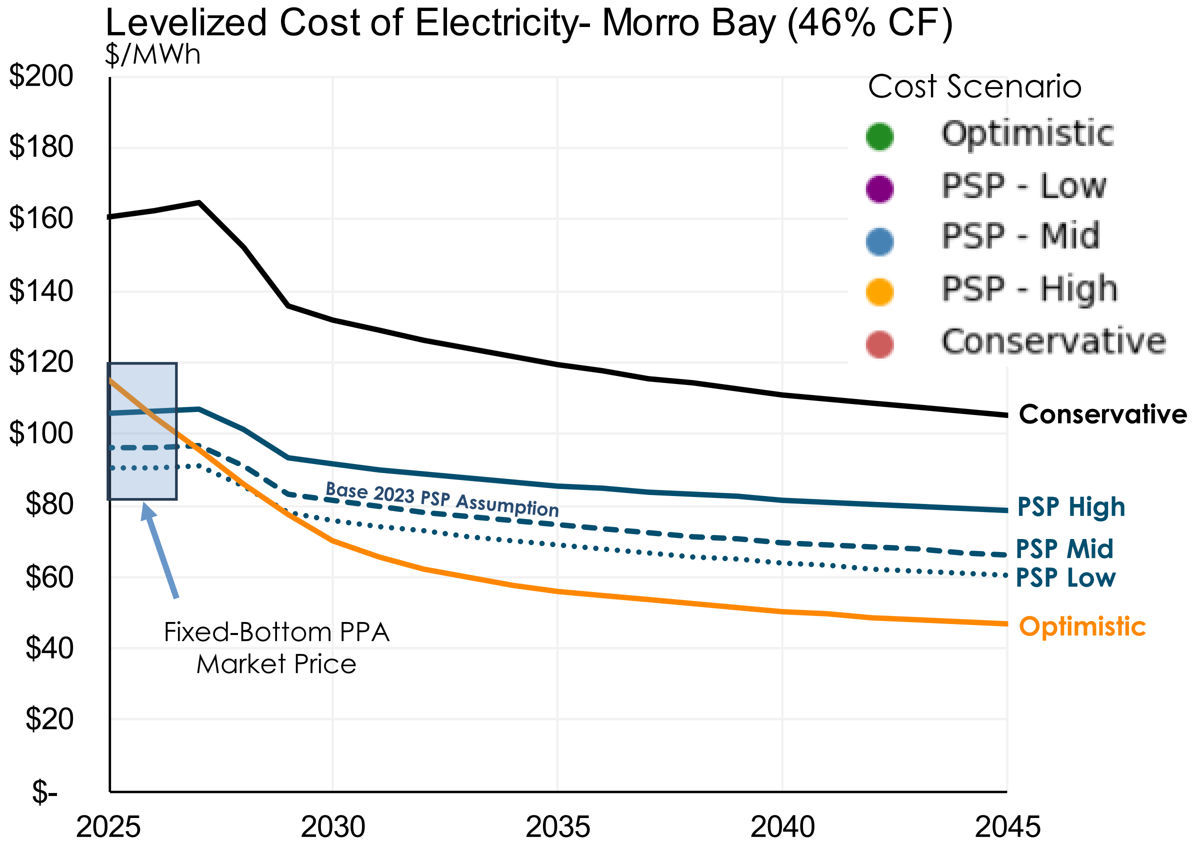


Scenario Name	Change in OSW Benefits	Scenario Description
Base		
Least-Cost		Same assumptions as PSP 25MMT Core case
Single Levers		
High Competing Resource Cost	🟩 Increase	Solar, storage, onshore wind, and geothermal modeled with PSP - High costs instead of PSP - Mid
Low Competing Resource Cost	🟥 Decrease	Solar, storage, onshore wind, and geothermal modeled with PSP - Low costs instead of PSP - Mid
Low Competing Resource Availability	🟩 Increase	Competing resource potentials limited: onshore wind reduced from 22.5 GW to 7GW, geothermal reduced from 5.3 GW to 1.8GW, pumped hydro reduced from 3.2 to 0.5GW
Significantly Low Competing Resource Availa	🟩 Increase	Competing resource potentials further limited to 2GW onshore wind, 1.8GW geothermal, 0.5GW pumped hydro
High Offshore Wind ELCC	🟩 Increase	Offshore wind marginal ELCC increased from 43-50% to 55-65%
Low Offshore Wind ELCC	🟥 Decrease	Offshore wind marginal ELCC reduced from 43-50% to 30-35%
Low Long Duration Storage ELCC	🟩 Increase	Lower marginal ELCC of long duration (8+ hr) storage, determined by decreasing ELCC multipliers by 30% (e.g. in 2035, 8-hr multiplier is reduced from 154% of 4-hr storage ELCC, to 118%)
High Electrification Load	🟩 Increase	Load forecast changed from 2022 IEPR Planning to 2021 IEPR ATE, increasing retail sales by 25 TWh and gross peak by 4 GW in 2035
High Gas Retirements	🟩 Increase	12.1 GW of CAISO gas capacity retires from 2028-2040, in line with the PSP High Gas Retirement sensitivity
Zero GHG Emissions	🟩 Increase	2045 statewide electric sector GHG emissions target lowered from 8 MMT to 0 MMT; includes a generic clean firm candidate resource
Select Combinations of Levers		
Competing Resource Challenges	🟩 Increase	Combines three single levers: High Competing Resource Cost, Low Competing Resource Availability, and Low Long Duration Storage ELCC
Stringent Policy	🟩 Increase	Combines three single levers: High Electrification Load, High Gas Retirements, and Zero GHG Emissions
Bookends for Minimum and Maximum Offshore Wind Benefits		
High Bookend	🟩 Increase	Combines all single levers that increase offshore wind benefits
Low Bookend	🟥 Decrease	Combines all single levels that decrease offshore wind benefits plus an increase in the 2045 GHG emissions target to 25 MMT

Additional detail on inputs and methodology for each lever is provided in Appendix D

California Floating Offshore Wind Resource Cost Scenarios

- Five cost trajectories reflect uncertainty in projected floating offshore wind capital costs
- Conservative costs apply the NREL ATB trajectory to floating offshore wind pilot project costs ($10,000/kW)[1]
- Optimistic costs align with the 2035 DOE Earthshot target[2], applying a high 11.5% learning curve[3] to pilot project costs, assuming 16.5 GW of global procurement by 2030[4]
- Floating offshore wind is an emerging technology that will be more expensive than fixed-bottom projects
  - The magnitude and timing of floating offshore wind cost declines will be dependent on technology advances in floating platforms and a scale-up of California's port and vessel infrastructure



* *Costs shown above do not include system transmission costs.*

* *Assumes cost recovery term and system useful life of 25 years, for consistency with I&A. Longer terms (e.g. 30 years from NREL ATB) can lower costs by 3-5%.*

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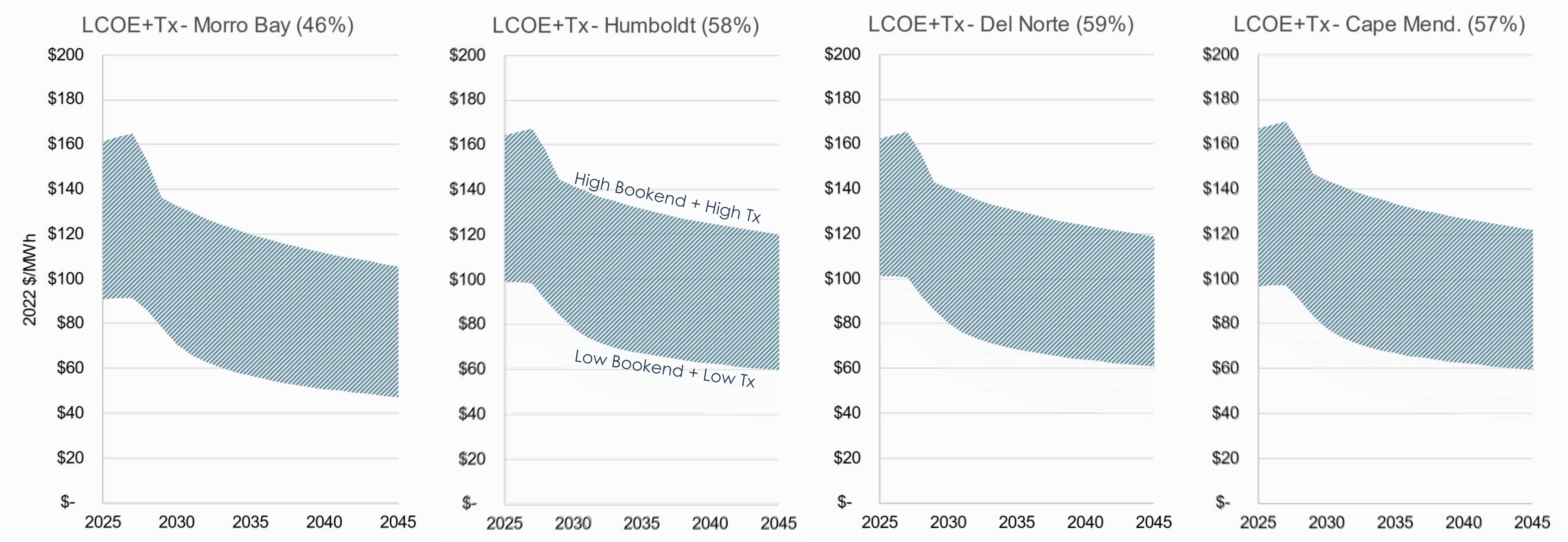
[1] Shields, M., et. al. NREL, 2022. https://www.nrel.gov/docs/fy23osti/81819.pdf

[2] Floating Offshore Wind Shot

[3] Schatz, 2023. http://schatzcenter.org/pubs/2023-OSW-R2.pdf

[4] NREL 2023 ATB. https://atb.nrel.gov/electricity/2023/offshore_wind

Higher Output from North Coast Resources Offsets Higher Transmission Costs



All project sites have comparable LCOE after factoring transmission costs, as higher capacity factors offset the additional costs to deliver North Coast offshore wind

Summary of Offshore Wind Cost-Benefit Analysis

Offshore Wind Cost-Benefit Analysis

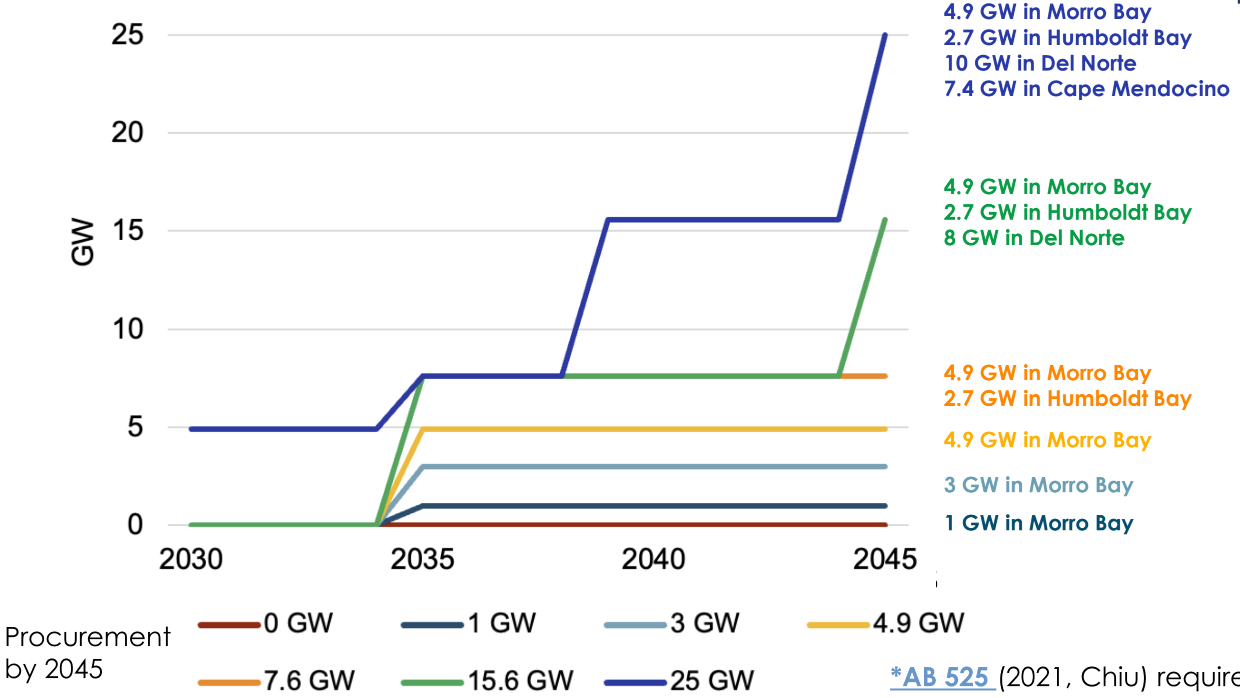
Background and Analytical Approach

- This cost-benefit analysis was conducted to compare the range of potential costs for offshore wind procurement (including transmission) to a range of the potential benefits across a broad range of future scenarios
  - Offshore wind benefits represent avoided investment and operating costs from RESOLVE, calculated through comparison of system costs with and without offshore wind at different procurement amounts
- Results were analyzed using the following key metrics:
  - $/MWh offshore wind net benefits: levelized avoided costs vs. levelized resource + Tx costs
  - $ Net Present Value (NPV) net benefits: net ratepayer impacts across the offshore wind lifetime
  - This analysis provides insights into the electric system value and cost risk of offshore wind procurement, including how those risks change as increasing levels are procured
- Additional analysis was conducted to inform CPUC's AB1373 procurement decision making, including qualitative research on offshore wind procurement outside of CA, research on commercialization of other emerging technologies, academic literature on decision making under uncertainty, and limited analysis of other LLTs

Offshore Wind Procurement Trajectories Studied

- This analysis evaluates in detail procurement amounts of 0 GW, 1 GW, 3 GW, 4.9 GW, and 7.6 GW by 2035
  - Additional limited analysis was performed for higher long-term scenarios that reach 15.6 GW or 25 GW by 2045

Offshore Wind Procurement Trajectories



Probable Development Implications of Build Levels

*25 GW: AB 525 trajectory**

15.6 GW: Intermediate buildout between 7.6 GW and 25 GW

7.6 GW: Full utilization of Morro Bay + Humboldt

4.9 GW: Full utilization of Morro Bay

3 GW: Partial utilization of Morro Bay

1 GW: Estimated minimum viable project size

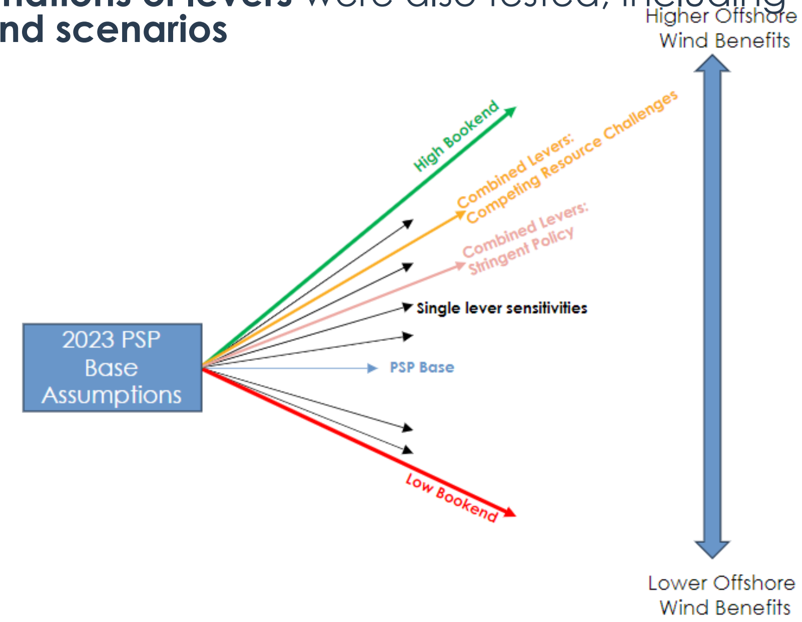
*AB 525 (2021, Chiu) requires the California Energy Commission, in coordination with specified agencies, to develop a strategic plan for offshore wind energy developments installed off the California coast in federal waters. The Draft Assembly Bill 525 Offshore Wind Strategic Plan is posted here. An aspirational goal of 25 GW by 2045 has been set in the CEC's AB 525 process.

Benefit − **Cost** = **Net Benefits**

Offshore Wind Cost-Benefit Analysis

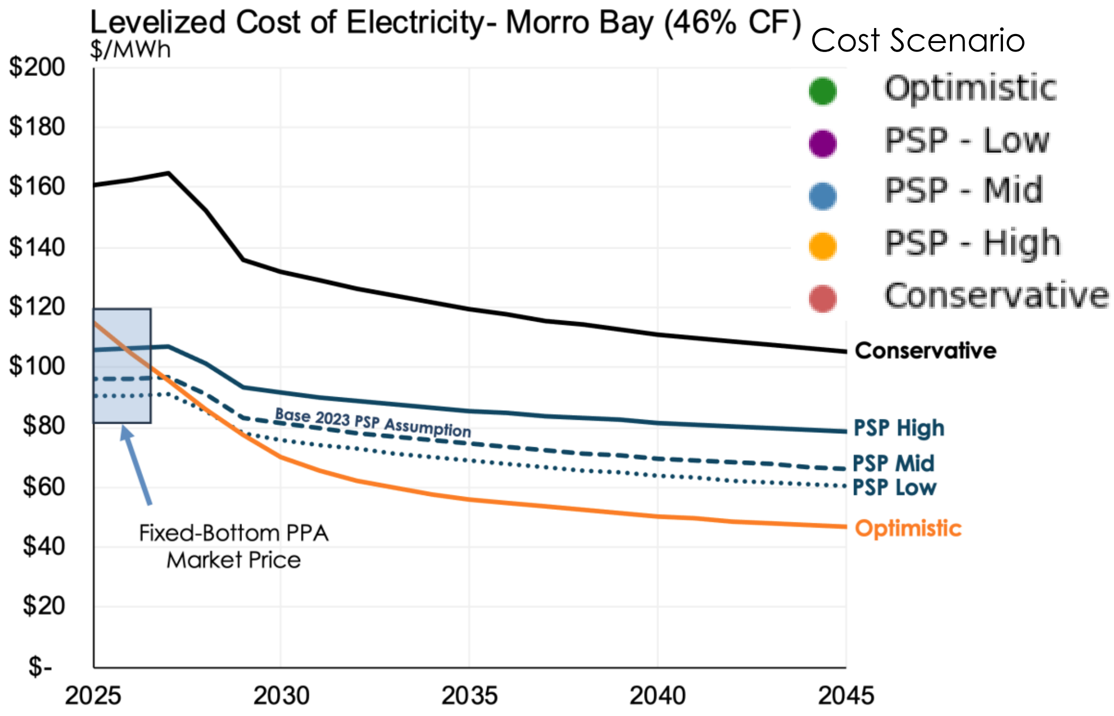
Benefit Scenarios

- Benefits calculated as avoided investment and operating costs when OSW is forced into RESOLVE
- Scenarios were developed for resource costs, resource availability, resource capacity contribution, gas retirements, load growth, and state GHG policy
  - **PSP base** uses 2023 PSP I&A (without LSE plans)
  - **Individual adjustments** to cost, availability, etc. are **"levers"**
  - **Combinations of levers** were also tested, including **bookend scenarios**



Cost Scenarios

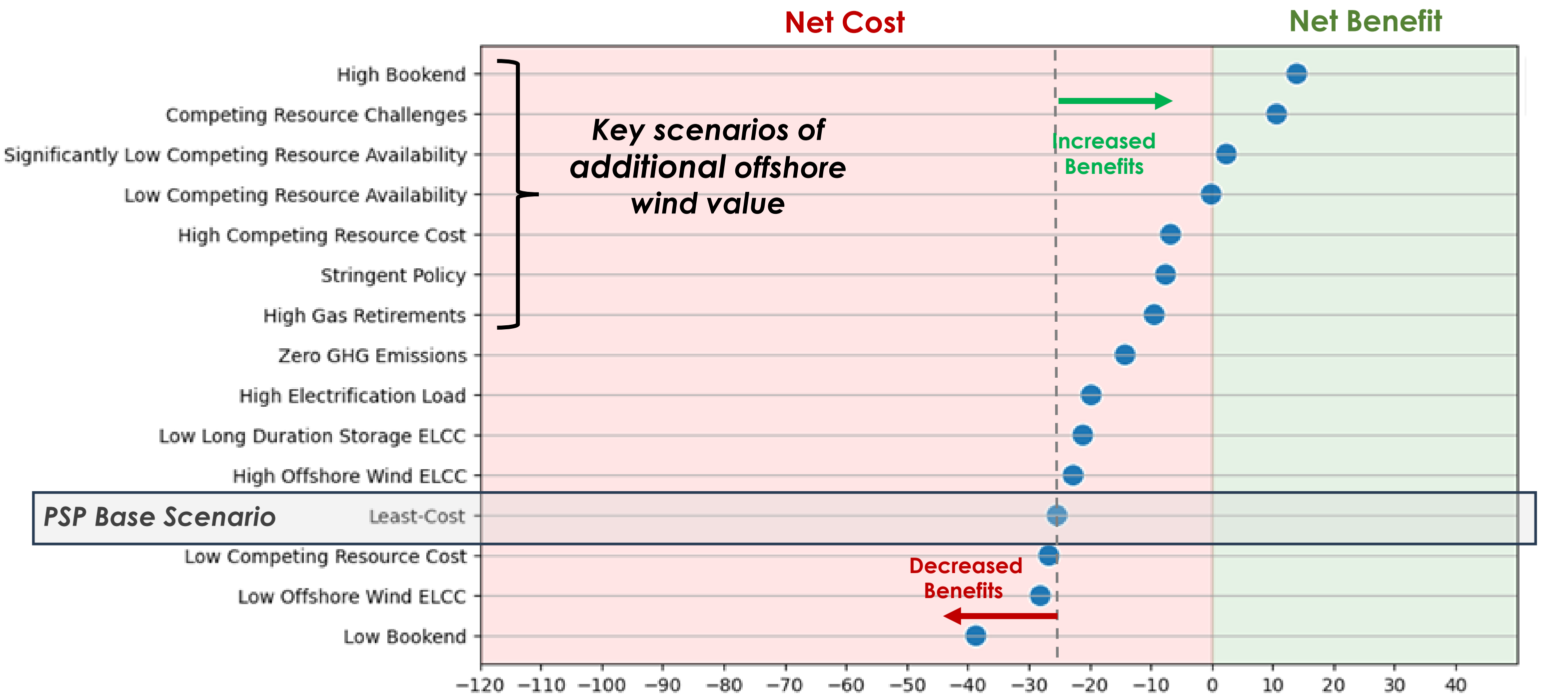
- There is high uncertainty in floating offshore wind costs
  - The five trajectories evaluated represent a large distribution of projected offshore wind capital costs
  - Scenarios beyond the PSP low/mid/high were considered



Additional offshore wind value driven by competing resource availability/cost, gas retirements, and lower 2045 GHG targets

- Offshore wind is not cost-effective under the base 2023 Preferred System Plan (PSP) assumptions
- Key drivers of additional offshore wind value are:
  - Competing resource availability or cost
  - Gas retirements
  - Lower GHG emissions in 2045
- Drivers of offshore wind value are similar across offshore wind procurement amounts
  - The $/MWh impact of each lever, however, generally declines at higher amounts of offshore wind procurement
- Benefit scenarios with multiple levers applied* tend to compound effects of individual levers

Offshore Wind Net Benefits (Benefits minus Costs)
3 GW Morro Bay in 2035 (PSP Mid Cost Scenario)



Y-axis = Scenario

X-axis = Levelized $/MWh

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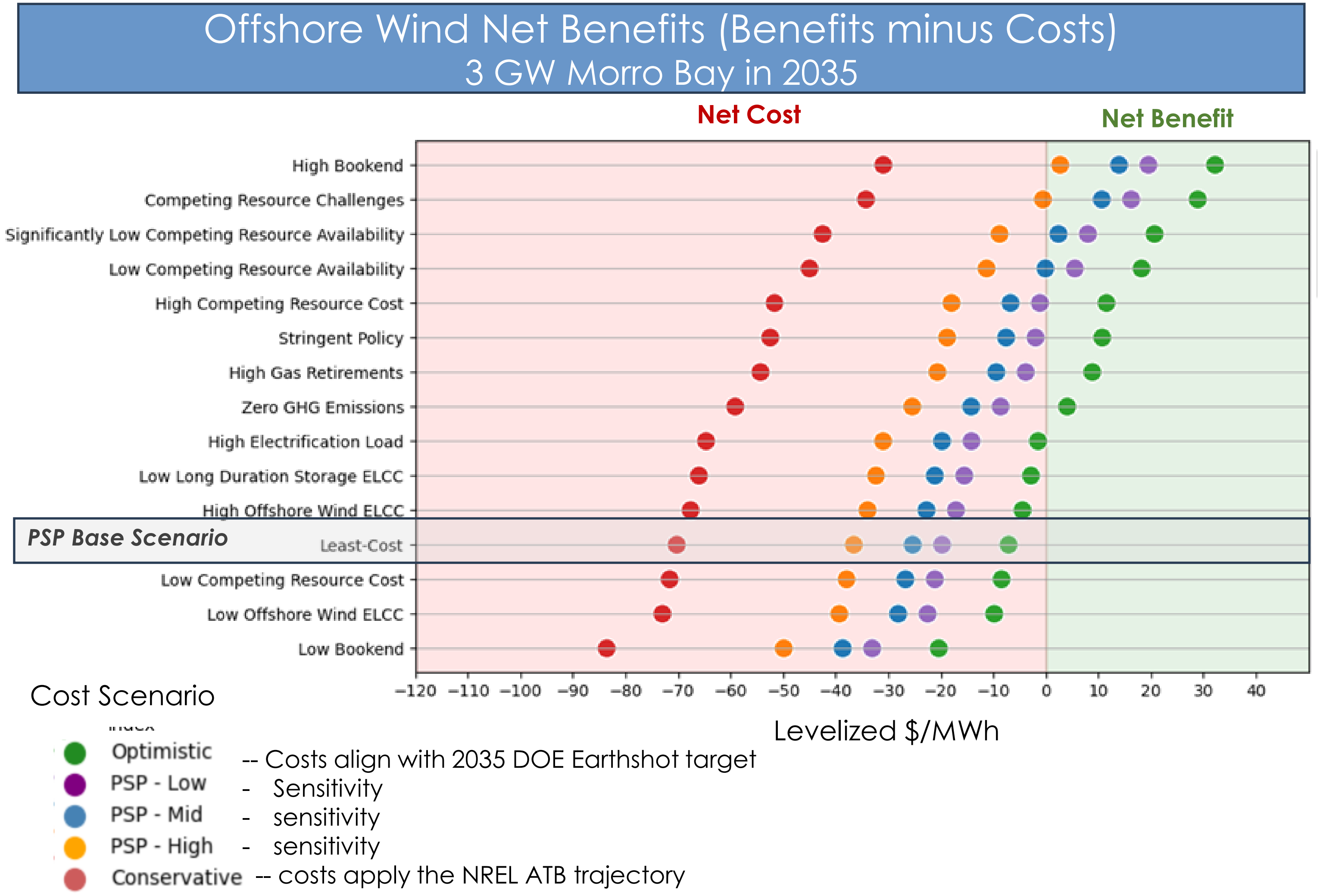
* "Stringent policy" assumes 0 MMT carbon emissions grid by 2045, additional gas plant retirements, and even higher electrification loads
"Competing resource challenges" assumes high competing resource costs, low competing resource availability, and low LDES ELCC

Scenarios tend to show net costs for procuring 3 GW offshore wind, except in some scenarios of higher benefits and/or low costs

- Most scenarios yield negative net benefits (i.e., net costs) for 3 GW of offshore wind
- Under the highest offshore wind cost assumptions (~$120/MWh), offshore wind always has negative net benefits
- Under the lowest offshore wind cost assumptions (~$60/MWh), offshore wind may have net benefits
- Key drivers for positive net benefits are:
  - Competing resources challenges (limited availability and/or high cost)
  - Low offshore wind cost
- Stringent policies* with mid to low offshore wind costs (~$70-75/MWh) are within ~$10/MWh of being cost-effective

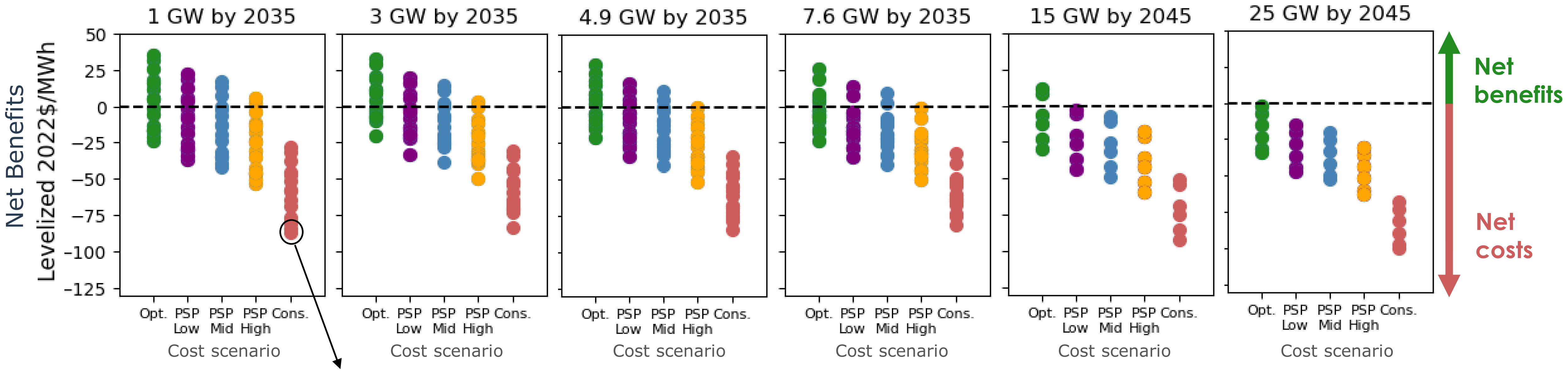


-- Costs align with 2035 DOE Earthshot target
- Sensitivity
- sensitivity
- sensitivity
-- costs apply the NREL ATB trajectory

* Assumes 0 MMT carbon emissions grid by 2045, additional gas plant retirements, and even higher electrification loads

Summary of Offshore Wind Cost-Benefit Analysis

Range of Offshore Wind Net Benefits (= Benefits - Costs)



Each datapoint represents net benefits for a given combination of

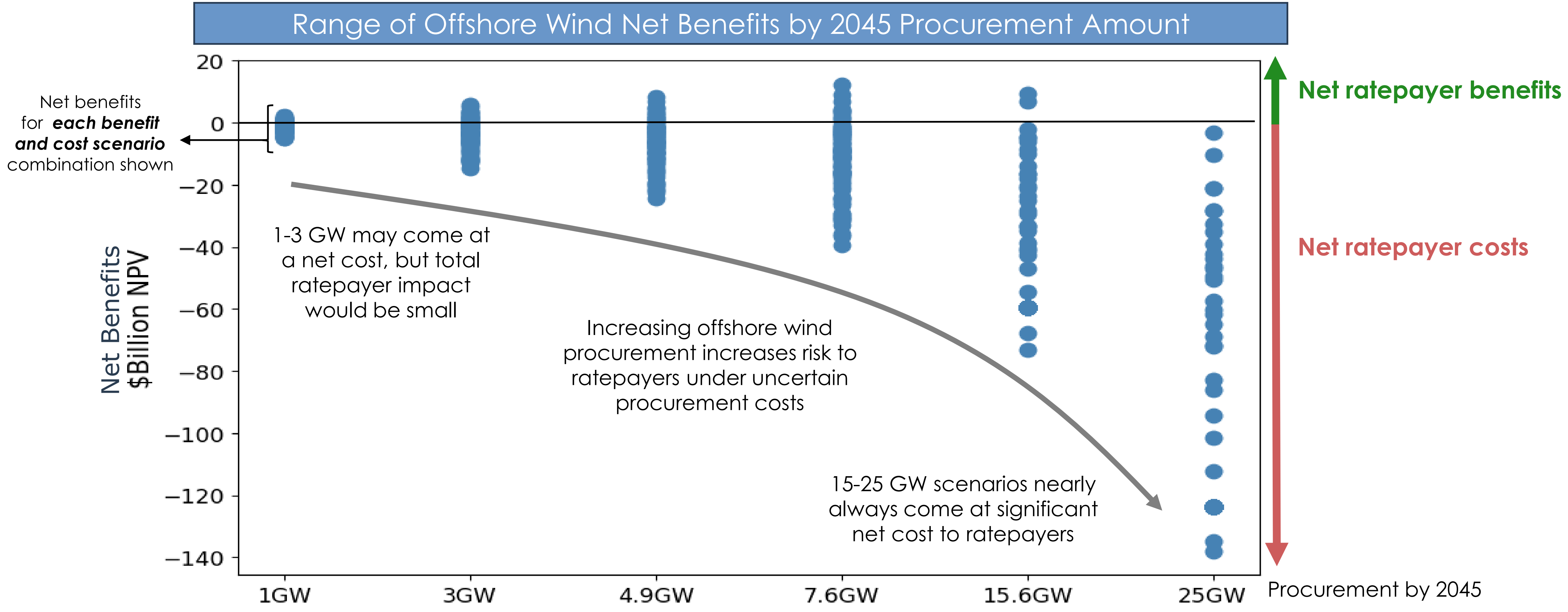
- ***Benefit scenario*** (representing ***avoided CAISO operating & investment costs***)
- ***Cost scenario*** (representing ***OSW costs***, including transmission)

*There are **some scenarios** with **positive net benefits** for 1-7.6 GW, but none in the highest cost scenario*

*15.6 GW and 25 GW have **few scenarios** with **positive net benefits***

- There are fewer combinations of costs and benefit scenarios that achieve net benefits than those that achieve net costs
  - Higher costs (due to more expensive transmission upgrades) and declining marginal benefits lead to lower net benefits at higher levels of offshore wind, especially at levels above 7.6 GW

Across all scenarios studied, 1-3 GW of offshore wind minimizes total ratepayer cost and risk



Net benefits for **_each benefit and cost scenario_** combination shown

1-3 GW may come at a net cost, but total ratepayer impact would be small

Increasing offshore wind procurement increases risk to ratepayers under uncertain procurement costs

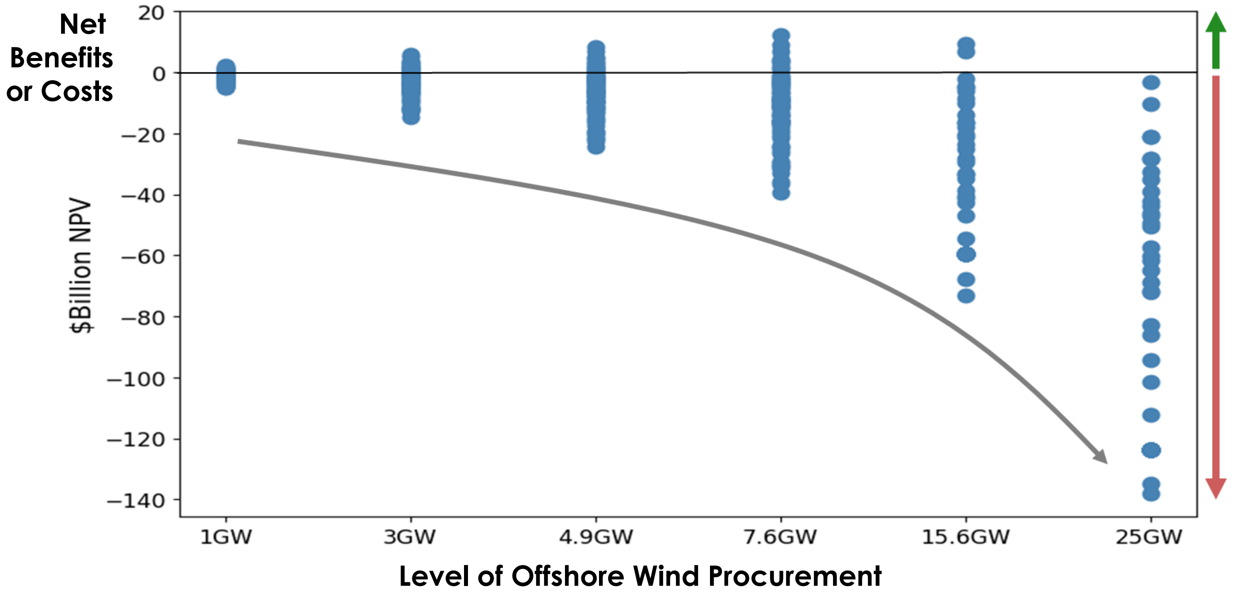
15-25 GW scenarios nearly always come at significant net cost to ratepayers

Initial OSW procurement can support market transformation with limited ratepayer risk	Successful delivery at reasonable cost of initial tranches should inform potential expansion	Very high offshore wind procurement creates a significant cost risk

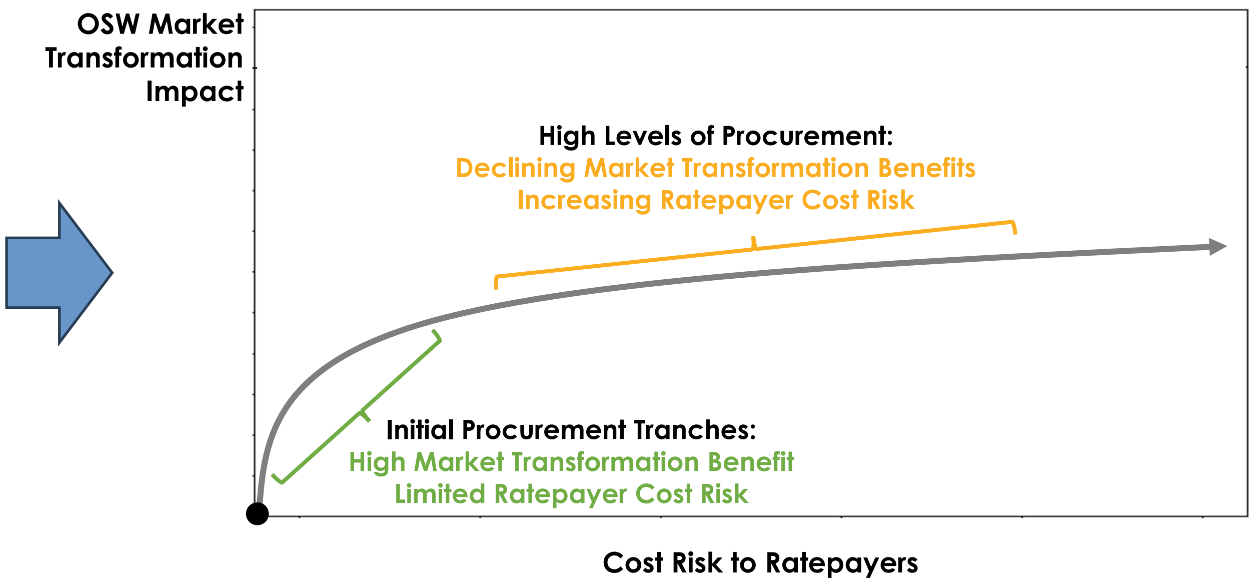
NPV $Billion calculated in 2022 $, with NPV discounted to 2035, when offshore wind procurement costs are assumed to commence

Seeking to balancing the benefits of developing the CA offshore wind industry against the cost risk to ratepayers

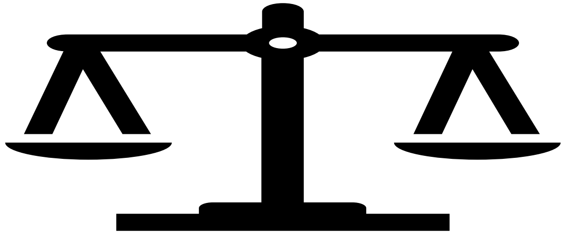
RESOLVE cost-benefit analysis



Offshore wind procurement



Cost Risk to Ratepayers
Quantitative analysis shows offshore wind may have net cost to ratepayers, a risk that may increase with high levels of procurement



Offshore Wind Market Transformation
Initiating procurement of offshore wind can support technology advancement, infrastructure development, and potentially future cost reductions

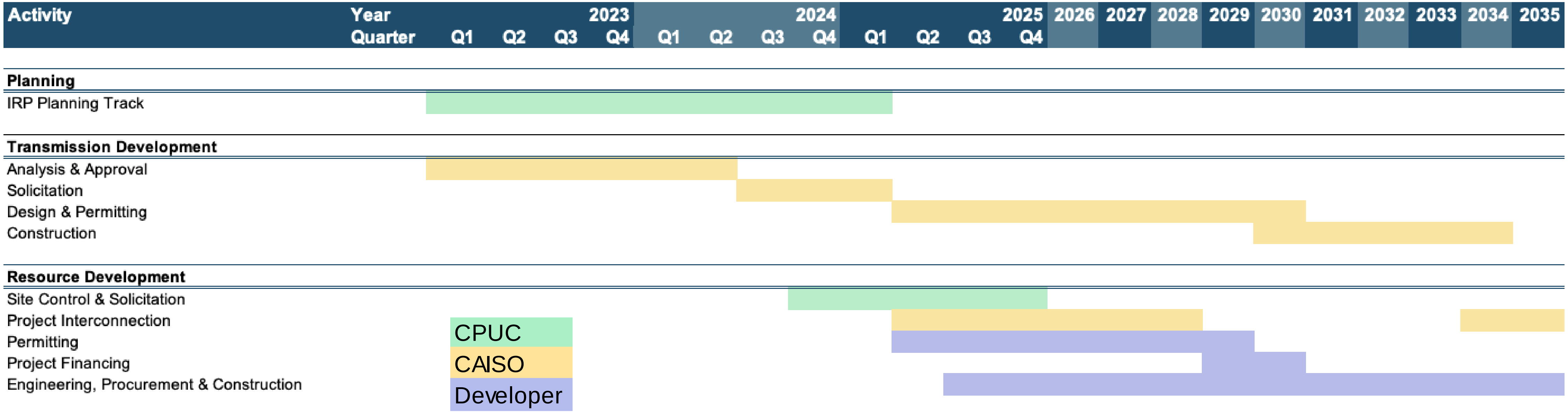
Procurement location could be informed by results of an all-source offshore wind solicitation

If central procurement is authorized, these locational attributes warrant consideration

- For an initial limited tranche of offshore wind procurement, the location must also be decided
- Multiple options for resource area exist and a decision must weigh the pros of ***Morro Bay vs. Humboldt*** as well as the pros of buildout in a ***single vs. multiple locations***
- "All-source" offshore wind solicitation (Option 2) that solicits bids from both Morro Bay and Humboldt with procurement decisions based on bid prices could be optimal
- Humboldt transmission bids to CAISO can also inform the combined resource + transmission cost between the two existing lease areas
  - Humboldt bids relative to the established price cap can inform Humboldt transmission development to mitigate stranded investment risk

Location	Strategy	Pros	Cons
Morro Bay	Initial procurement in Morro Bay	• Leverages a single set of enabling infrastructure (port development, workforce, etc.)	• Does not allow market cost data development for Humboldt
Morro Bay OR Humboldt **"All-source offshore wind"**	Both Morro Bay and Humboldt, subject to bid prices (including transmission)	• Supports market cost data development for both existing lease areas • Increases resource options, potentially enabling lower costs from higher quality Humboldt resource	• Humboldt development requires longer build timelines and risk of transmission delays/costs • Splitting build may require inefficient building two sets of infrastructure simultaneously
Morro Bay AND Humboldt	Both Morro Bay and Humboldt (e.g. 1 GW in each zone)	• Commits to building out both key CA offshore wind resource zones	• May increase ratepayer cost risk if Humboldt resource + transmission costs higher than expected • Splitting build will require inefficient building two sets of infrastructure simultaneously

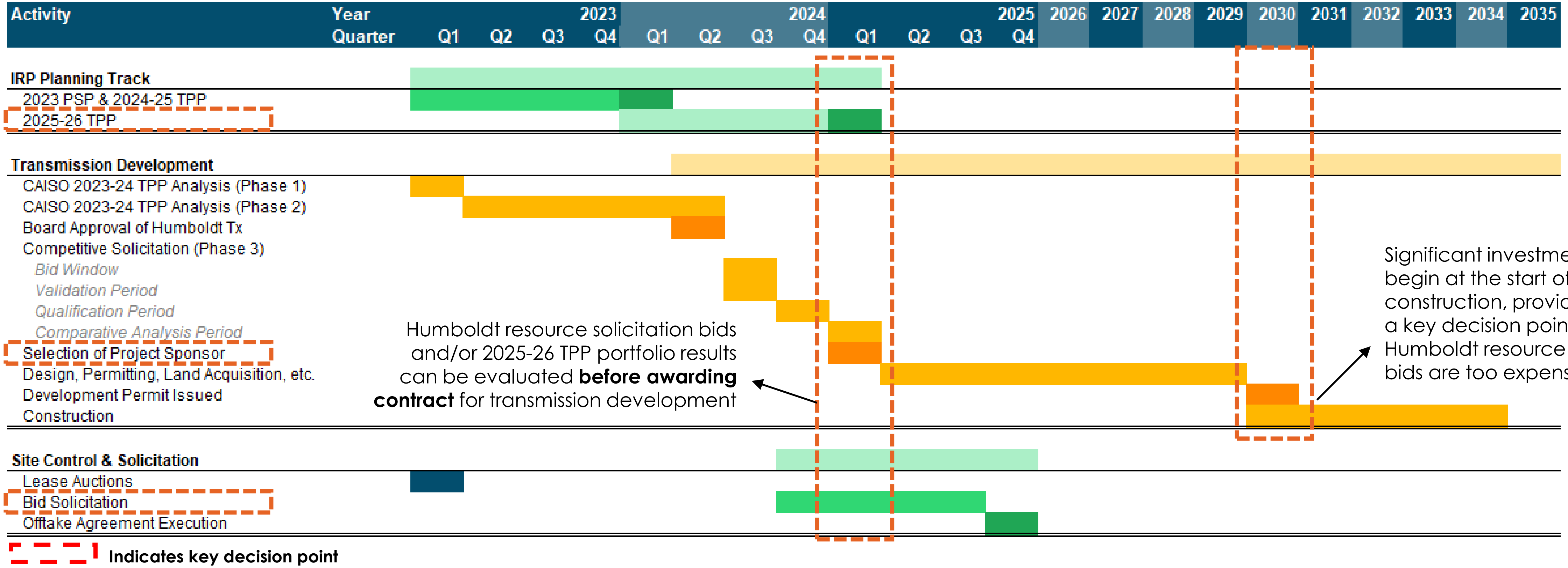
Humboldt Project Development Timeline Estimate



- Humboldt transmission is included in CAISO's Draft 2023-2024 Transmission Plan and may be approved by CAISO Board in May 2024, which would trigger the transmission development process
- Humboldt resource and transmission development is estimated to take **~10 years** ([2022-23 I&A]())
- **Significant investments for resource and transmission development are not needed until construction,** which is estimated to begin ~2030
- Morro Bay transmission development, if approved by CAISO, would have an accelerated timeline due to simpler transmission upgrade needs and fewer land acquisition and permitting requirements

References: IRP Offshore Wind Roadmap (2021), revised to reflect ITC extension and latest estimation of development timeline
Transmission Development in California (2023)

IRP Planning & Transmission Solicitation Timelines



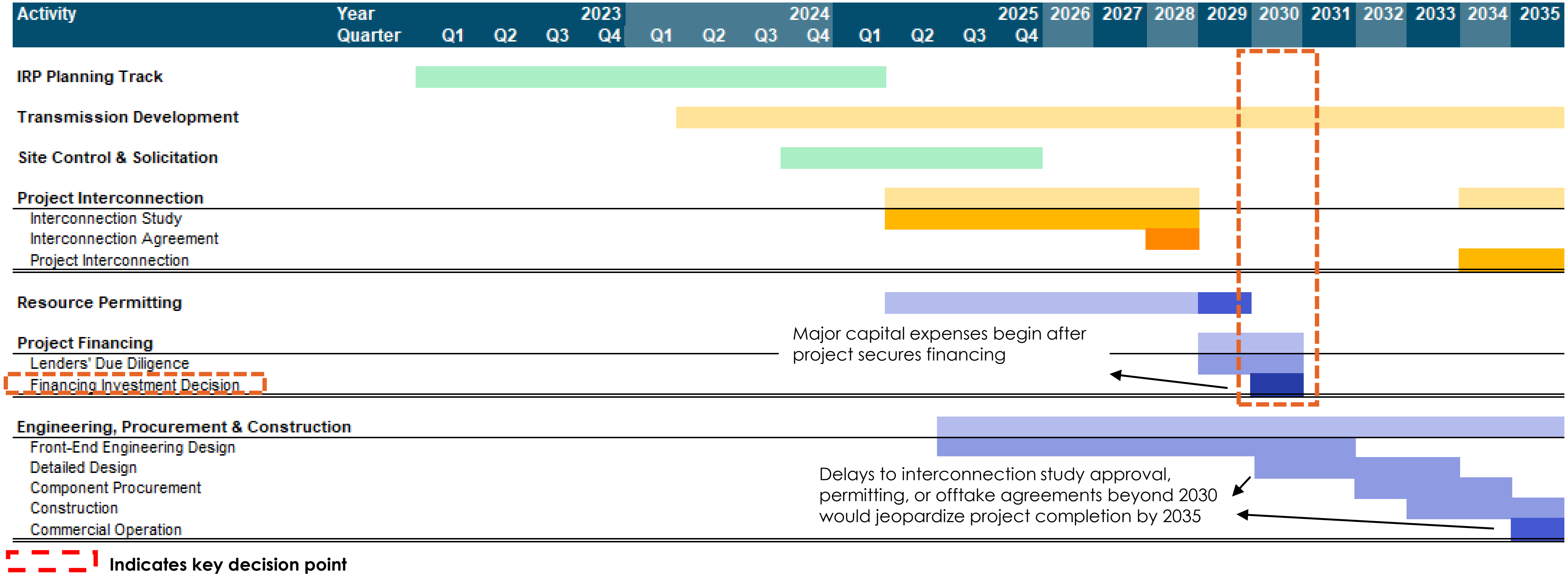
Humboldt resource solicitation bids and/or 2025-26 TPP portfolio results can be evaluated **before awarding contract** for transmission development

Significant investments begin at the start of construction, providing a key decision point if Humboldt resource bids are too expensive

- 2025-26 TPP Portfolio results could help inform CAISO Board decision to award contract to Project Sponsor for Humboldt transmission development
- Project bid prices in an accelerated bid process (submittals by Q1 2025) could also inform project viability and influence CAISO selection process

References: IRP Offshore Wind Roadmap (2021), revised to reflect ITC extension and latest estimation of development timeline
Transmission Development in California (2023)

Resource Development Timeline



Major capital expenses begin after project secures financing

Delays to interconnection study approval, permitting, or offtake agreements beyond 2030 would jeopardize project completion by 2035

Indicates key decision point

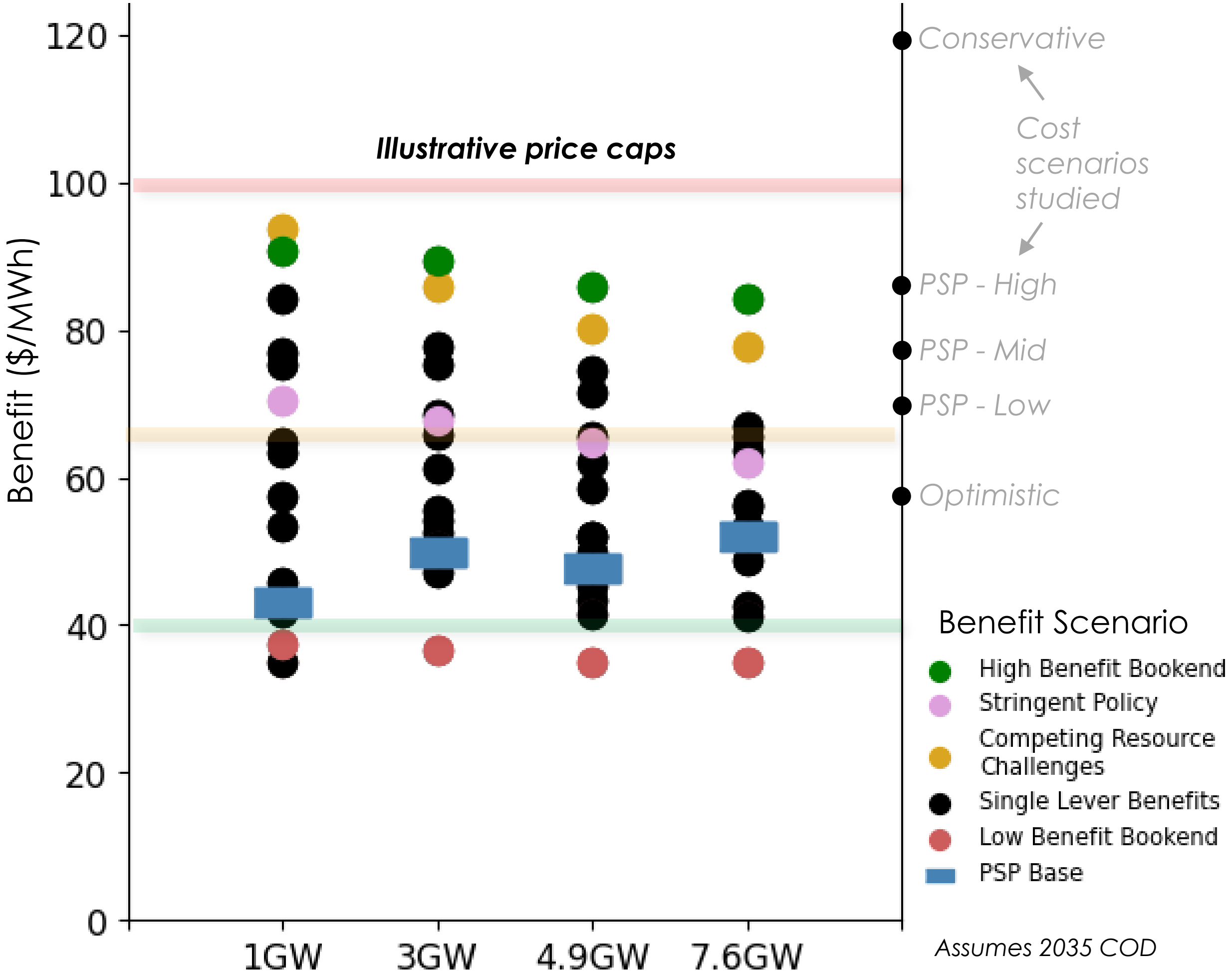
- Financial closing requires site control, permitting, interconnection, and offtake agreements, and construction contracts
- Project financing must be in place by 2030 to avoid risk of delays in project operation beyond 2035

References: IRP Offshore Wind Roadmap (2021), revised to reflect ITC extension and latest estimation of development timeline
Transmission Development in California (2023)

Cost-benefit analysis can inform a price cap

***Benefits** of offshore wind from avoided resource costs provide breakeven points for OSW that **can help inform price caps** on power purchase agreement (PPA) prices*

Range of Offshore Wind Benefits



Assumes 2035 COD

Ratepayer Cost Risk

High Risk
Price Cap >$90/MWh
Very likely ratepayer costs… but may support initial deployments

Medium Risk
Price Cap ~$50-90/MWh
Less certain ratepayer impacts… balances ratepayer risk

Low Risk
Price Cap <$50/MWh
Very likely ratepayer benefits… but unrealistic near-term prices for floating OSW

- *If benefits < PPA price, OSW will increase ratepayers costs*
- *If benefits > PPA price, OSW will decrease ratepayer benefits*
- ***Price cap for initial amount (e.g., 1 GW) could be set higher*** if market transformation benefits are seen outweighing ratepayer costs
- ***After that, a declining price cap could be instituted*** for additional procurement to A) limit ratepayer impacts amidst declining marginal benefits, and B) encourage cost reductions to justify continued centralized procurement
  - This ***could limit procurement in the first round of AB1373 procurement*** to enable time for the industry to demonstrate further cost reduction

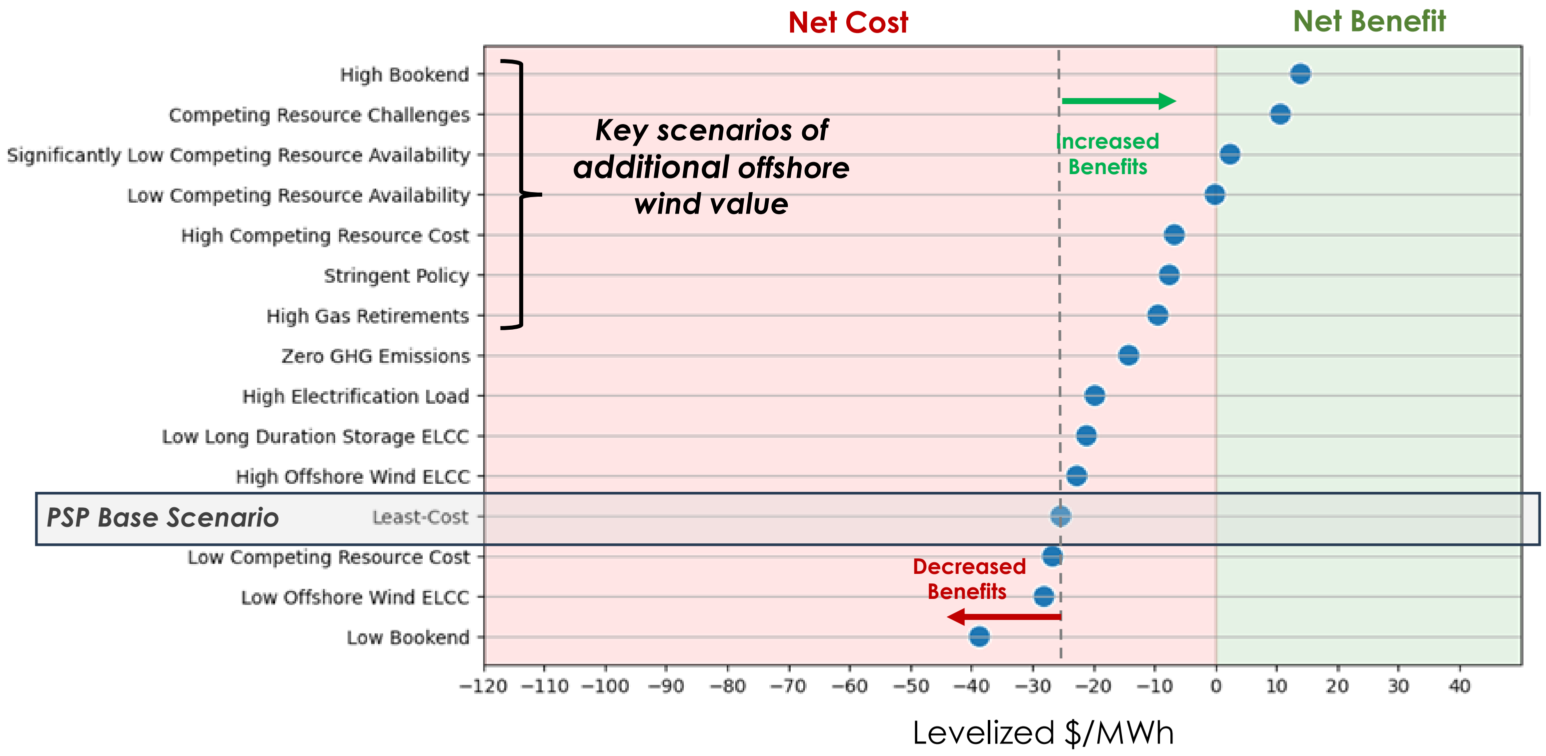
Values shown here are in real 2022$ and should be adjusted for inflation as needed to align with OSW bids

Offshore Wind Cost-Benefit Analysis Results

Additional offshore wind value driven by competing resource availability/cost, gas retirements, and lower 2045 GHG targets

- Offshore wind is not cost-effective under the base ("least-cost") 2023 Preferred System Plan (PSP) assumptions
- Key drivers of additional offshore wind value are:
  - Competing resource availability or cost
  - Gas retirements
  - Lower GHG emissions in 2045
- Drivers of offshore wind value are similar across offshore wind procurement amounts
  - The $/MWh impact of each lever, however, generally declines at higher amounts of offshore wind procurement
- Benefit scenarios with multiple levers applied* tend to compound effects of individual levers

Offshore Wind Net Benefits (Benefits minus Costs)
3 GW Morro Bay in 2035 (PSP Mid Cost Scenario)

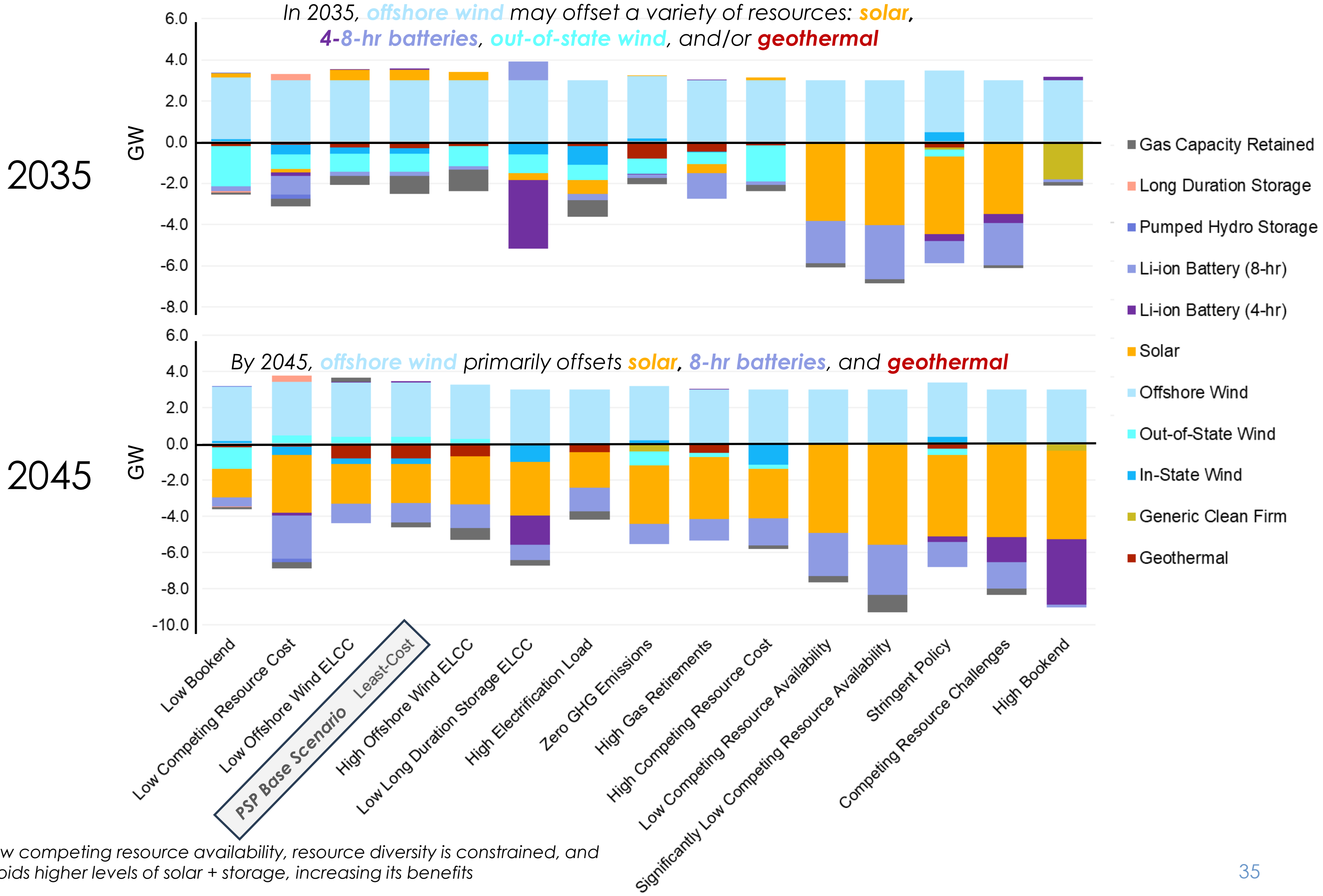


* "Stringent policy" assumes 0 MMT carbon emissions grid by 2045, additional gas plant retirements, and even higher electrification loads
"Competing resource challenges" assumes high competing resource costs, low competing resource availability, and low LDES ELCC

3 GW Morro Bay Scenario

Avoided alternative resource buildout drives OSW system benefits

- Offshore wind's long-run value (by 2045) is to **provide additional resource diversity** by **replacing solar + storage**
- **Offshore wind development may also defer* or avoid a small amount of other diverse resources** (geothermal, in-state or out-of-state wind, clean firm capacity)
- A **small amount of additional gas retirements (up to 1 GW)** may also be facilitated



*In 2035, offshore wind may offset a variety of resources: **solar**, **4-8-hr batteries**, **out-of-state wind**, and/or **geothermal***

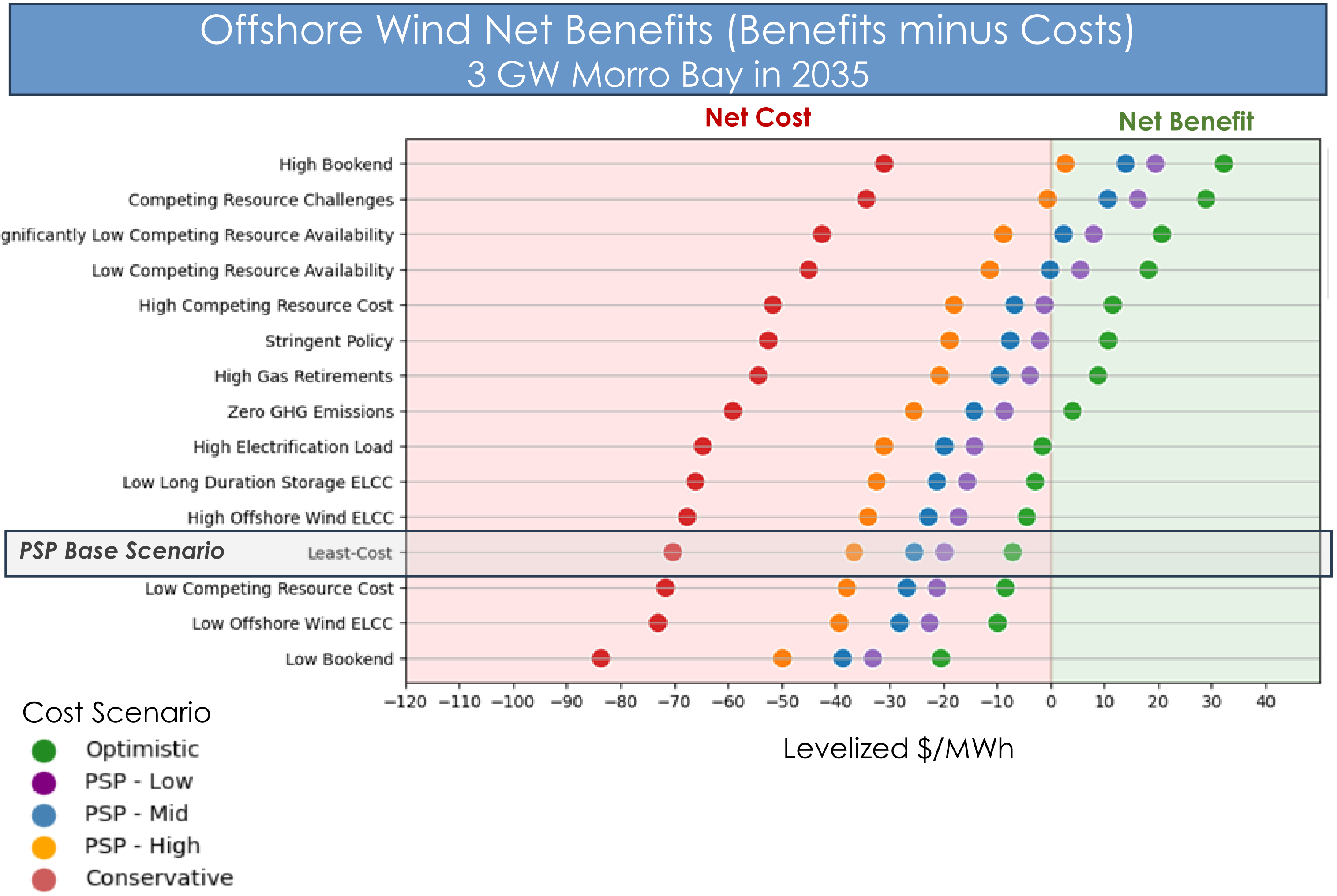
*By 2045, offshore wind primarily offsets **solar**, **8-hr batteries**, and **geothermal***

Under low competing resource availability, resource diversity is constrained, and OSW avoids higher levels of solar + storage, increasing its benefits

**Avoided resources in the 2035 chart that go away by 2045 (such as out-of-state wind in many cases) indicate a delayed build (instead of avoided build)*

Scenarios tend to show net costs for procuring 3 GW offshore wind, except in some scenarios of higher benefits and/or low costs

- Most scenarios yield negative net benefits (i.e., net costs) for 3 GW of offshore wind
- Under the highest offshore wind cost assumptions (~$120/MWh), offshore wind always has negative net benefits
- Under the lowest offshore wind cost assumptions (~$60/MWh), offshore wind may have net benefits
- Key drivers for positive net benefits are:
  - Competing resources challenges (limited availability and/or high cost)
  - Low offshore wind cost
- Stringent policies* with mid to low offshore wind costs (~$70-75/MWh) are within ~$10/MWh of being cost-effective



Offshore Wind Net Benefits (Benefits minus Costs)
3 GW Morro Bay in 2035

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* Assumes 0 MMT carbon emissions grid by 2045, additional gas plant retirements, and even higher electrification loads

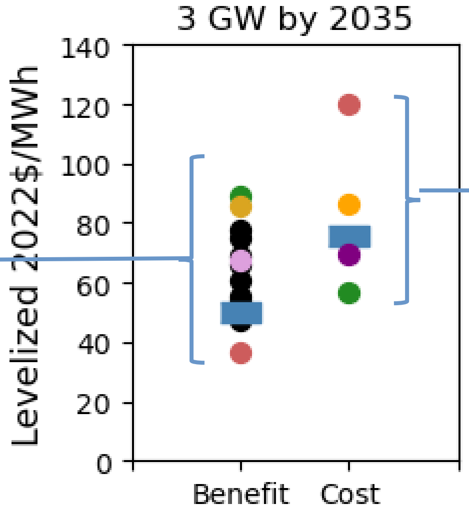
Orientation to results structure

Cost-Benefit Analysis Summary

Benefit Scenarios

- ● High Benefit Bookend
- ● Stringent Policy
- ● Competing Resource Challenges
- ● Single Lever Benefits
- ● Low Benefit Bookend
- 🟦 PSP Base

Each **benefit** datapoint represents ***avoided*** operating & investment ***costs*** from RESOLVE runs with a single lever or a combination of levers applied

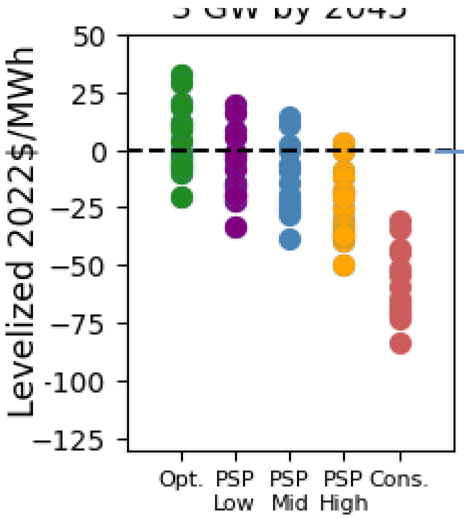


Each ***cost*** datapoint represents an estimate of ***offshore wind costs*** (including transmission)

Cost Scenario

- ● Optimistic
- ● PSP - Low
- ● PSP - Mid
- ● PSP - High
- ● Conservative

$$\text{\$/MWh benefits, costs, and net benefits} = \frac{\text{NPV of benefits, costs, or net benefits}}{\text{NPV of offshore wind generation potential*}}$$



Net Benefit = Benefit – Cost, categorized by cost scenario and calculated for each benefit scenario

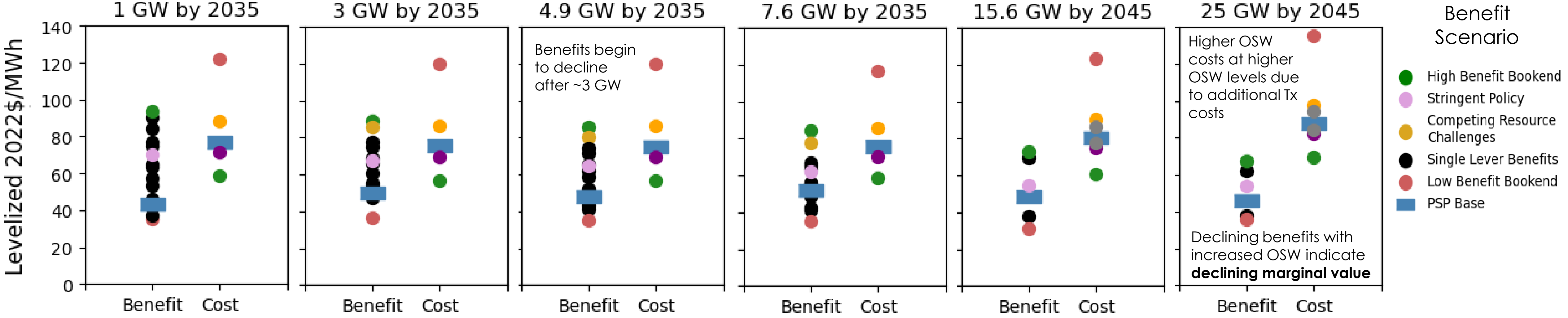
Cost Scenario

- ● Optimistic
- ● PSP - Low
- ● PSP - Mid
- ● PSP - High
- ● Conservative

*Generation potential includes total potential generation (not reduced by any curtailment)

Summary of Offshore Wind Cost-Benefit Analysis

Range of Costs and Benefits

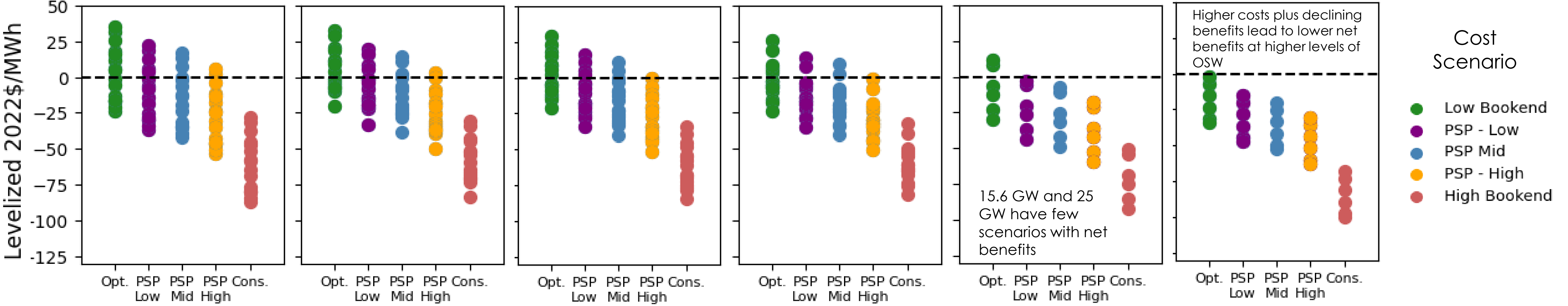


Benefits begin to decline after ~3 GW

Higher OSW costs at higher OSW levels due to additional Tx costs

Declining benefits with increased OSW indicate **declining marginal value**

Range of Net Benefits (Benefits – Costs)

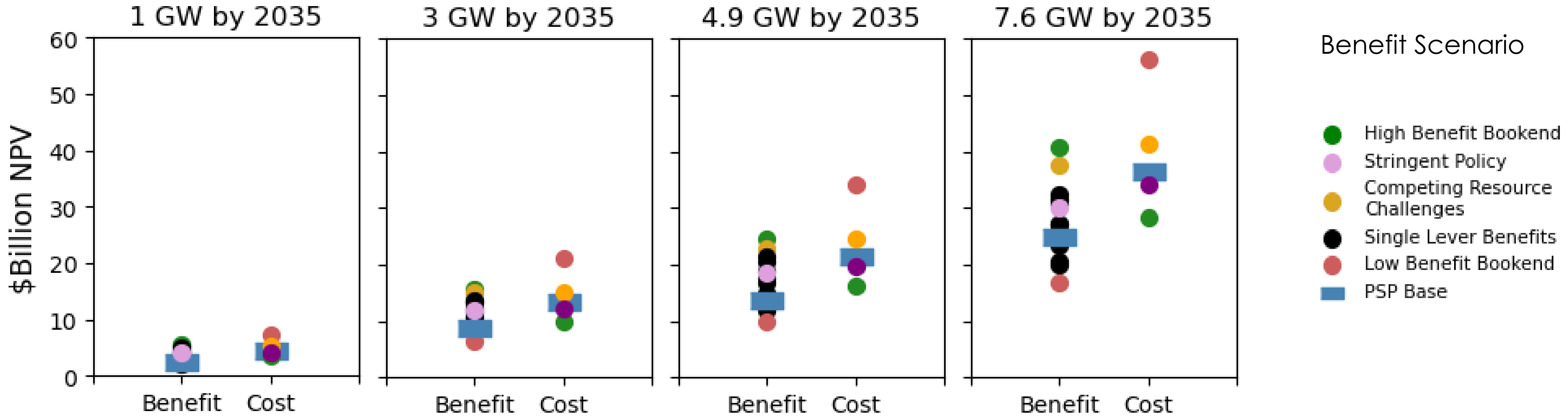


15.6 GW and 25 GW have few scenarios with net benefits

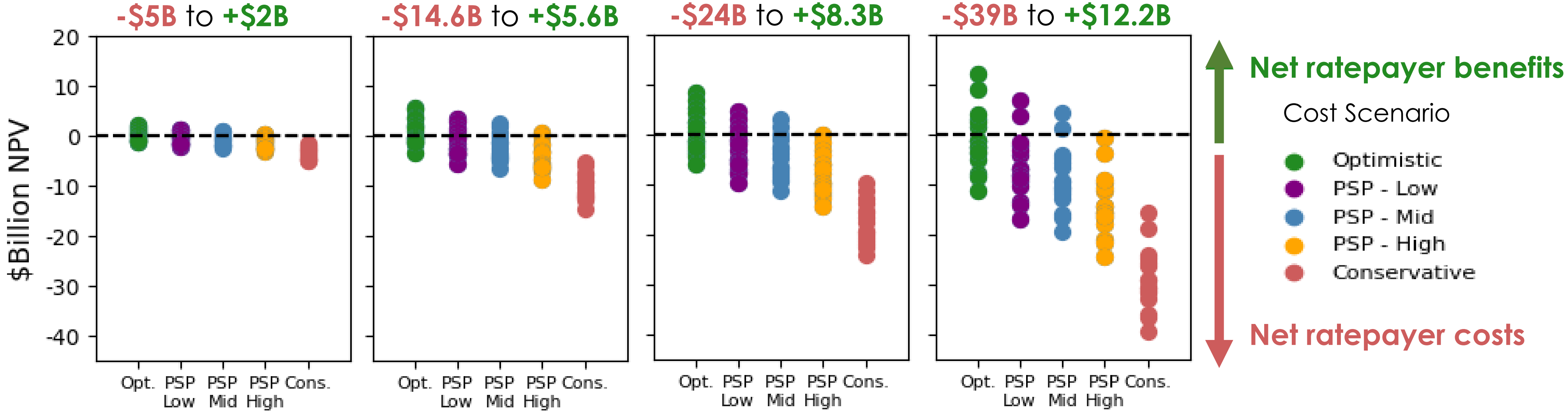
Higher costs plus declining benefits lead to lower net benefits at higher levels of OSW

Ratepayer Impact Summary ($Billion NPV)

Range of Costs and Benefits

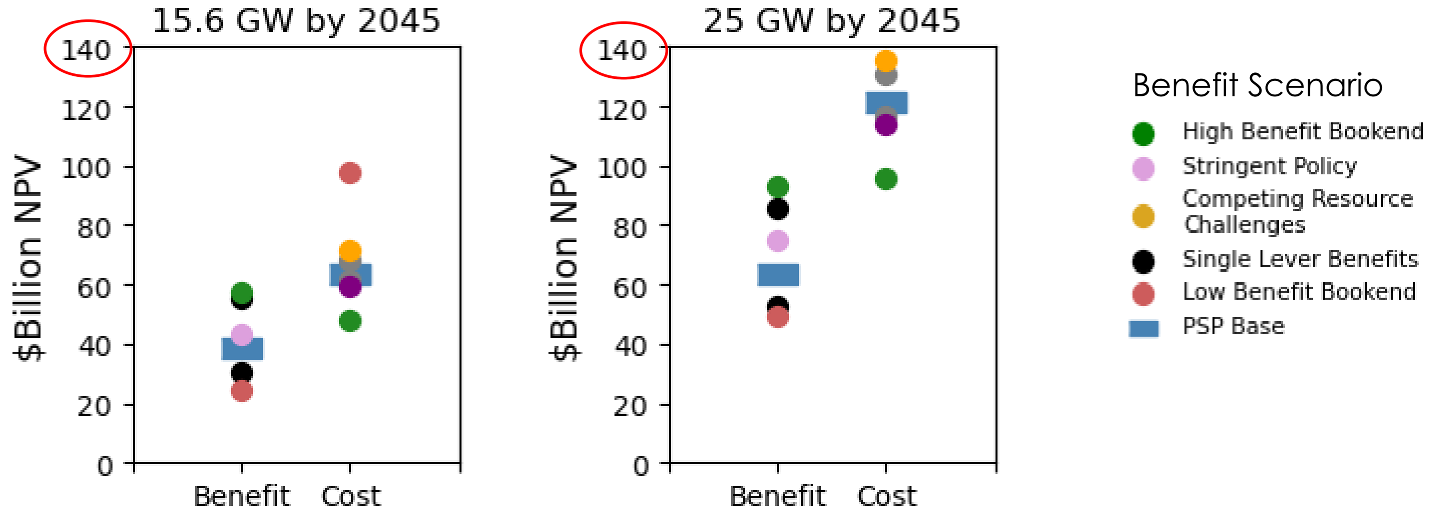


Range of Net Benefits (Benefits – Costs)

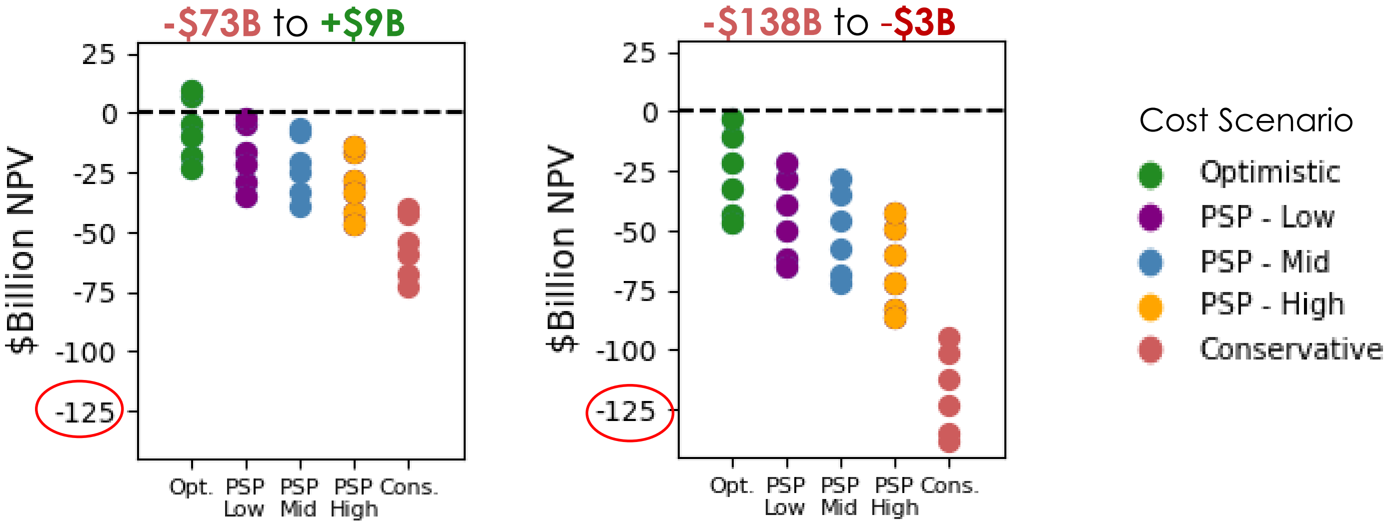


Ratepayer Impact Summary ($Billion NPV), 15-25 GW

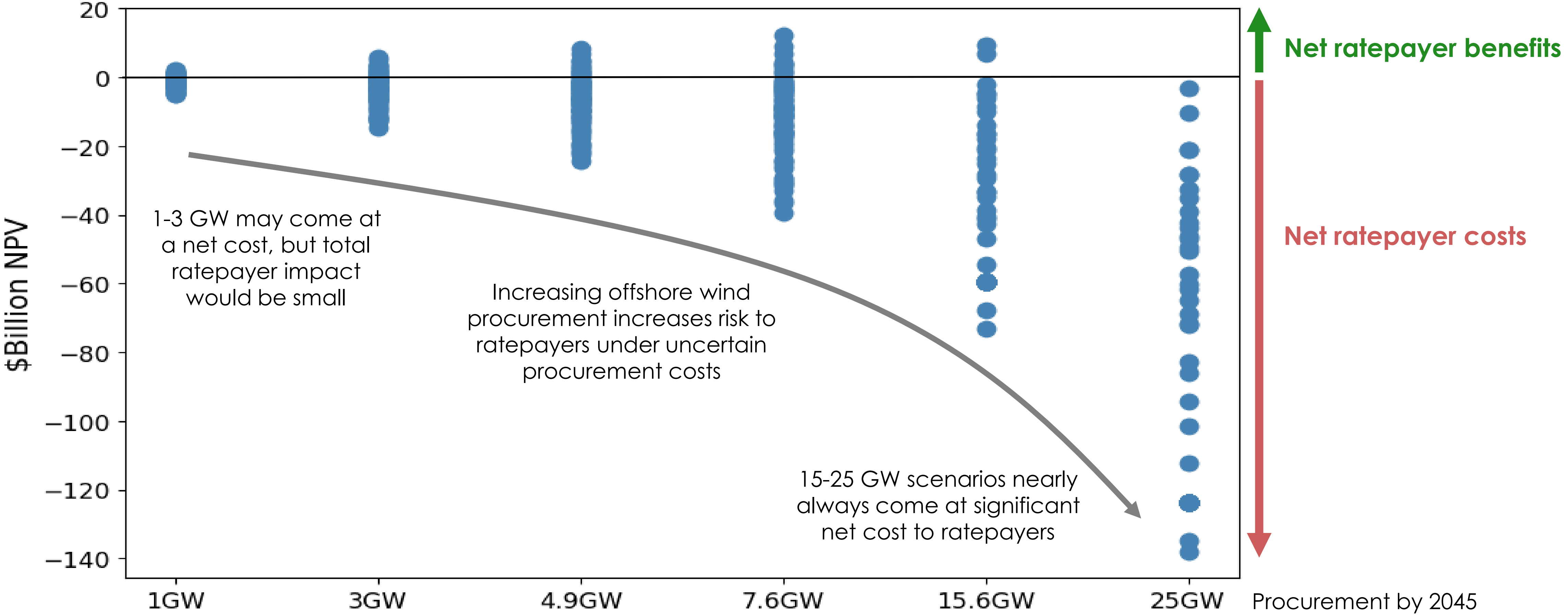
Range of Costs and Benefits



Range of Net Benefits (Benefits – Costs)



Results for scenarios studied, with lower amounts of offshore wind generally minimizing total ratepayer cost and risk



1-3 GW may come at a net cost, but total ratepayer impact would be small

Increasing offshore wind procurement increases risk to ratepayers under uncertain procurement costs

15-25 GW scenarios nearly always come at significant net cost to ratepayers

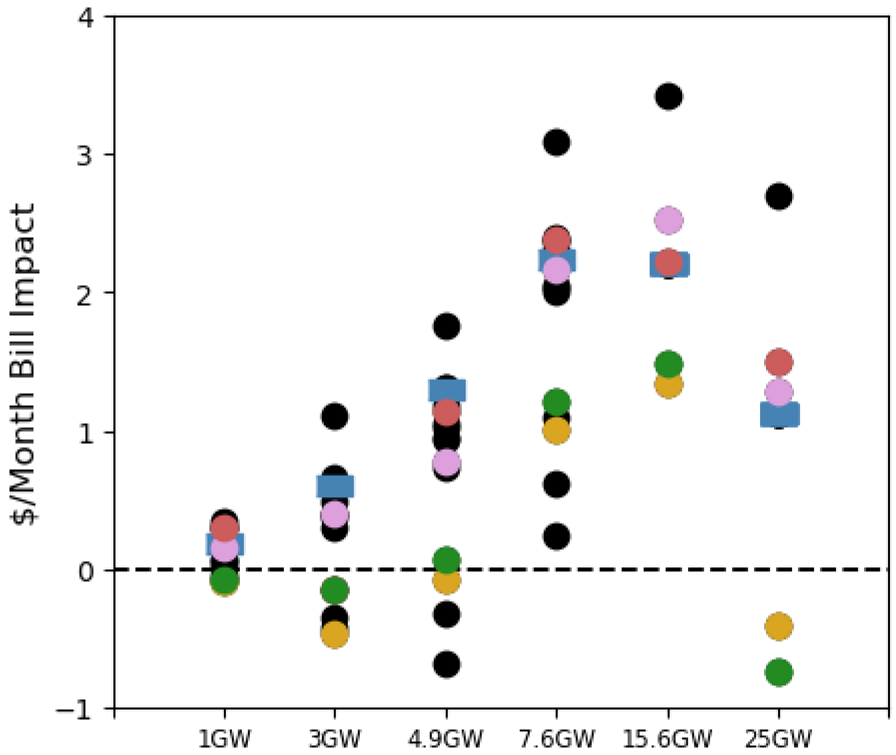
Initial OSW procurement can support market transformation with limited ratepayer risk	Successful delivery at reasonable cost of initial tranches should inform potential expansion	Very high offshore wind procurement creates a significant cost risk

Results shown for all benefit and cost scenarios considered
NPV $Billion calculated in 2022 $, with NPV discounted to 2035, when offshore wind procurement costs are assumed to commence

Impact of Offshore Wind to Ratepayers in 2035 and 2045

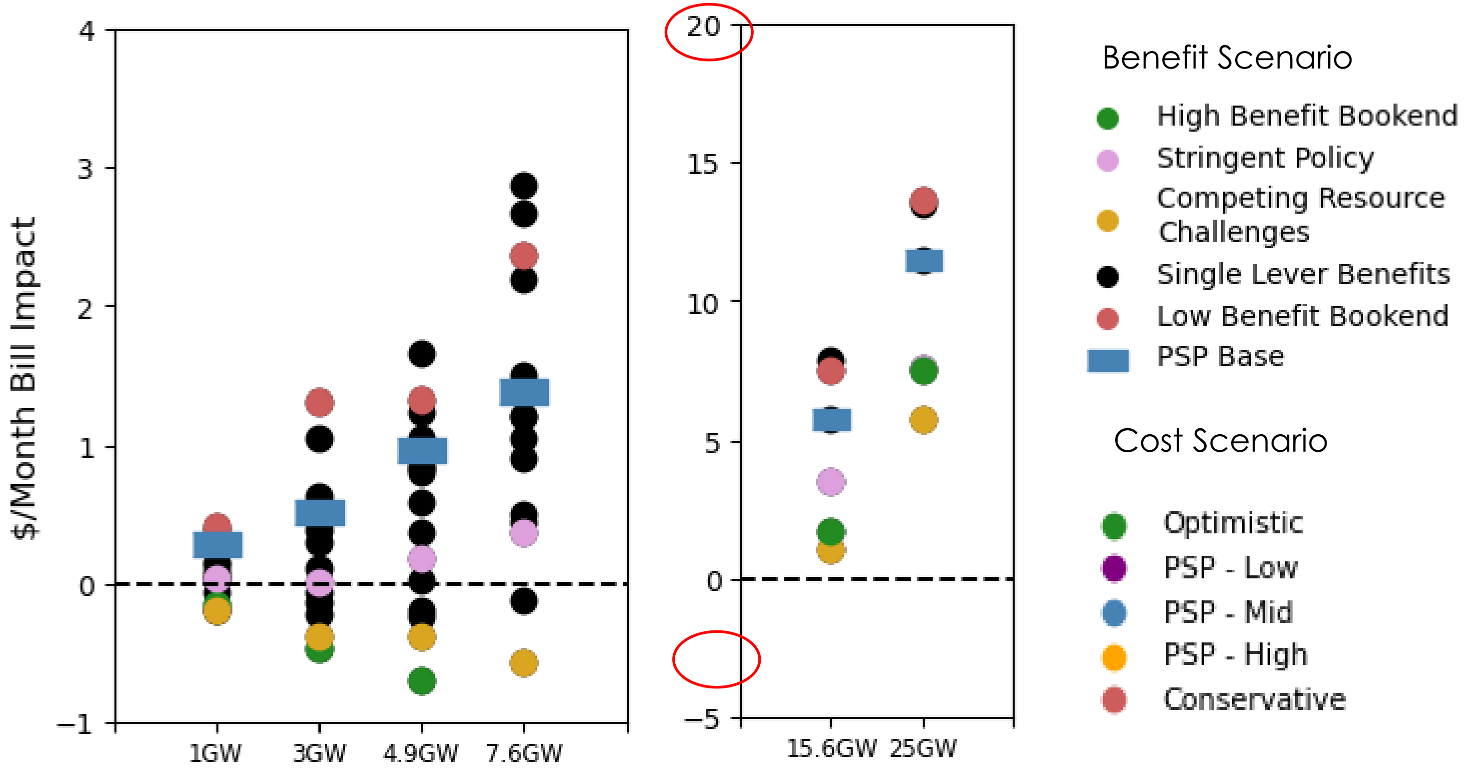
(Rate Impact compared to the 2023 PSP base case)

2035 Ratepayer Impact



Modest bill impacts up to 7.6 GW, (0.1%-2.4% bill increase) given the substantial system revenue requirement relative to offshore wind costs

2045 Ratepayer Impact



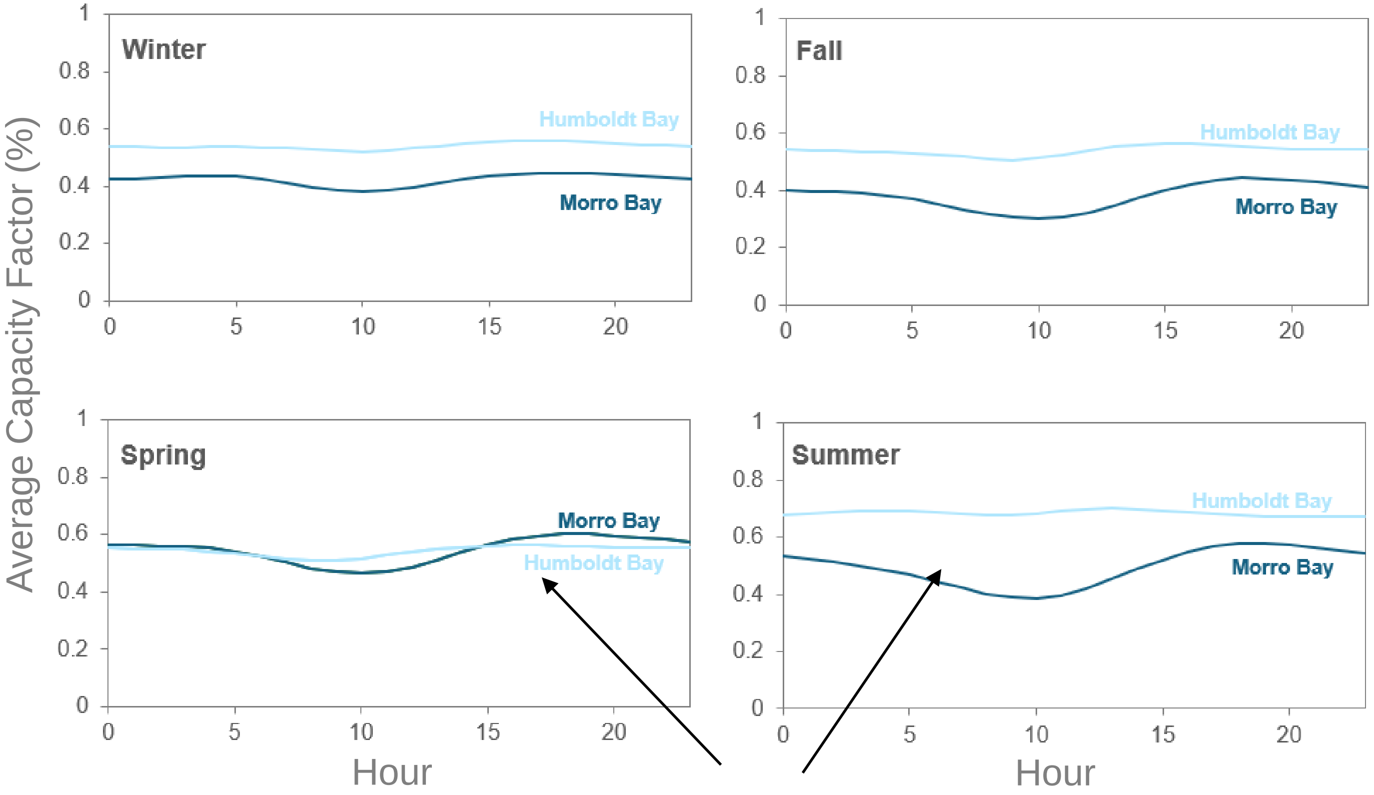
By 2045, procurement **above 7.6 GW leads to significant potential bill impacts** (up to 11% bill increase)

High Bookend & stringent policy cases have higher loads than most single lever cases, spreading the costs or benefits over more MWh

Morro Bay vs Humboldt Offshore Wind Resource

- Morro Bay and Humboldt Wind Energy Areas are the only resource areas currently recognized by the Bureau of Ocean Energy Management (BOEM), making these the most likely resource areas for near-term solicitations
- Morro Bay resources have ability to interconnect at the Diablo Canyon substation
- Humboldt requires more transmission buildout but has a higher average capacity factor (57%) compared to Morro Bay (46%)
    - Humboldt's higher output in peak summer and winter hours could unlock higher GHG reduction value per MWh (given the increased ability to displace gas on the margin)

Comparison of Generation Profiles

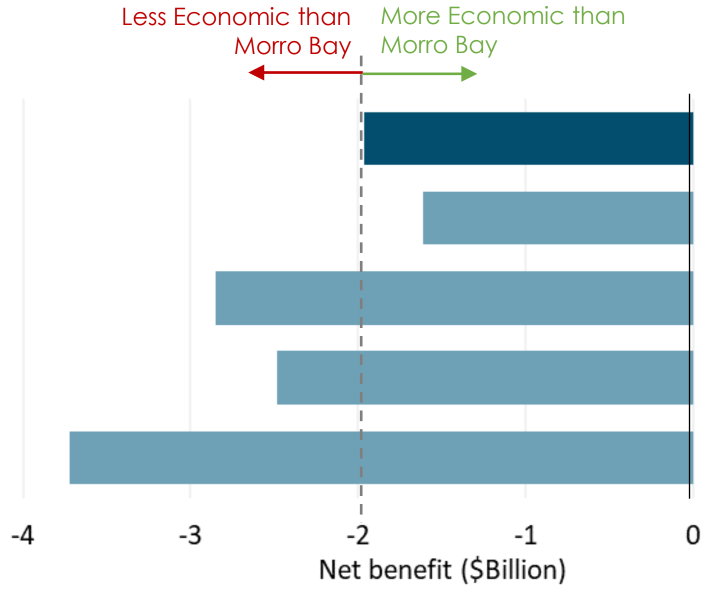


On average, Humboldt has a flatter generation profile that is almost always higher than Morro Bay across all seasons and hours of day

Cost competitiveness of Humboldt is highly dependent on transmission cost and capacity factor assumptions

- Relative economics of Humboldt and Morro Bay are dependent on Humboldt transmission and capacity factor (CF) assumptions:
  - Under **low transmission cost** and **high CF**, Humboldt has ***higher net benefits*** than Morro Bay
  - Under **high transmission cost** and/or **low CF**, Humboldt has ***lower net benefits*** than Morro Bay
- New information on Humboldt resource potential and transmission upgrades have informed cost updates:
  - CAISO 21-22 Transmission Plan: Least-cost option estimated $2.6 billion (2022 $) for 1.6 GW of resource potential(1)
  - 2023 I&A: Updated area density factor(2) informed transmission cost adjustment to $4.3 billion
  - CAISO 23-24 TPP: Clarification that the ~$4.2 billion investment include 3,500 MVA line ratings, which could likely accommodate 2.7 GW of resource potential without adjustment(3)
- Uncertainty in the Humboldt capacity factor
  - 2023 PSP assumes a 57% CF based on CPUC wind profiles, but the 2022 NREL assessment of California WEAs(4) has indicated that the CF may be closer to 49%

Net Benefits of 2.7 GW Offshore Wind in 2035



Location	Tx Cost	CF
Morro Bay	$110 Million	46%
Humboldt	$2.6 billion	57%
Humboldt	$4.3 billion	57%
Humboldt	$2.6 billion	49%
Humboldt	$4.3 billion	49%

Results shown use PSP Mid resource costs

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(1) CAISO 2021-22 Transmission Plan used a 3 MW/km^2 area density factor (1.6 GW) for Humbolt.

(2) 2023 I&A uses a 5 MW/km^2 area density factor (2.7 GW) for Humbolt, informing a linear scaling of transmission costs to $4.3 billion for the 2023 PSP.

(3) CAISO 2023-24 TPP Stakeholder Meeting (11/16/23)

(4) Assessment of Offshore Wind Energy Leasing Areas for Humboldt and Morro Bay Wind Energy Areas, California (nrel.gov)

Key Conclusions for OSW: Quantitative Analysis

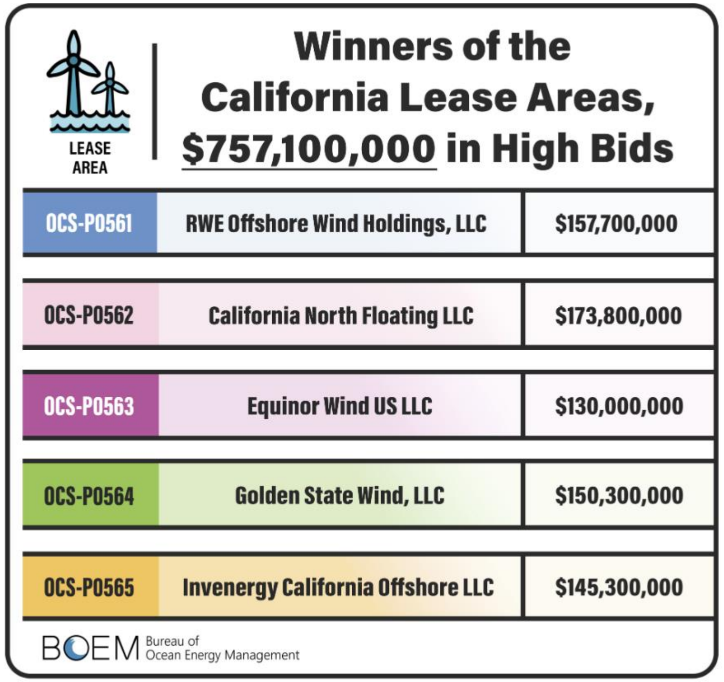
- Offshore wind's long-run system value in this analysis is primarily to provide additional resource diversity
- The PSP Least-Cost scenario contained zero MWs of OSW, even with low offshore wind resource or transmission cost assumptions. This could be interpreted as the costs of OSW outweighing the benefits in that scenario.
  - This is consistent with PSP Least-Cost RESOLVE runs, where no offshore wind was selected
- Net benefits are highly sensitive to offshore wind costs
  - Offshore wind is never cost effective at costs over $100/MWh, but may be cost effective at lower costs (~$60-80/MWh)
- Under certain scenarios, 1 – 7.6 GW of offshore wind in 2035 may be cost-effective given the assumptions in this study
  - Key drivers of these scenarios are competing resource challenges (limited availability and/or high cost), high gas retirements, lower 2045 GHG emissions targets, and low offshore wind cost
    - At PSP Mid Cost assumptions, limited resource availability becomes a more important driver
  - Declining marginal value plus larger transmission costs at higher levels of procurement (15-25 GW) lead to few scenarios at higher levels of procurement with net system benefits in this analysis.

* Lowest costs for 25 GW assumes ~$60/MWh for all 25 GW, meaning if initial procurement tranches are higher than $60/MWh, then future tranches would have to be lower than $60/MWh for all 25 GW to be procured at ~$60/MWh

Key Learnings from Qualitative Research

Overview of Offshore Wind Development in CA

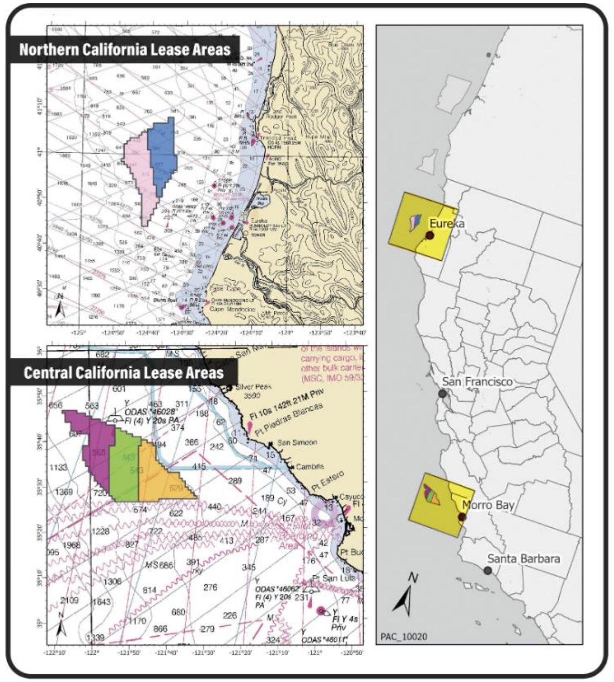
- The Bureau of Ocean Energy Management (BOEM) held an auction for 5 lease sites in CA (3 in Morro Bay, 2 in Humboldt) in December 2022
- Winners of the CA lease areas are currently preparing Site Assessment Plans (due June 1, 2024)
- Although there are only 5 eligible bidders for near-term solicitations, there are likely to be enough bidders to maintain competitiveness



Winners of the California Lease Areas, $757,100,000 in High Bids

LEASE AREA		
OCS-P0561	RWE Offshore Wind Holdings, LLC	$157,700,000
OCS-P0562	California North Floating LLC	$173,800,000
OCS-P0563	Equinor Wind US LLC	$130,000,000
OCS-P0564	Golden State Wind, LLC	$150,300,000
OCS-P0565	Invenergy California Offshore LLC	$145,300,000

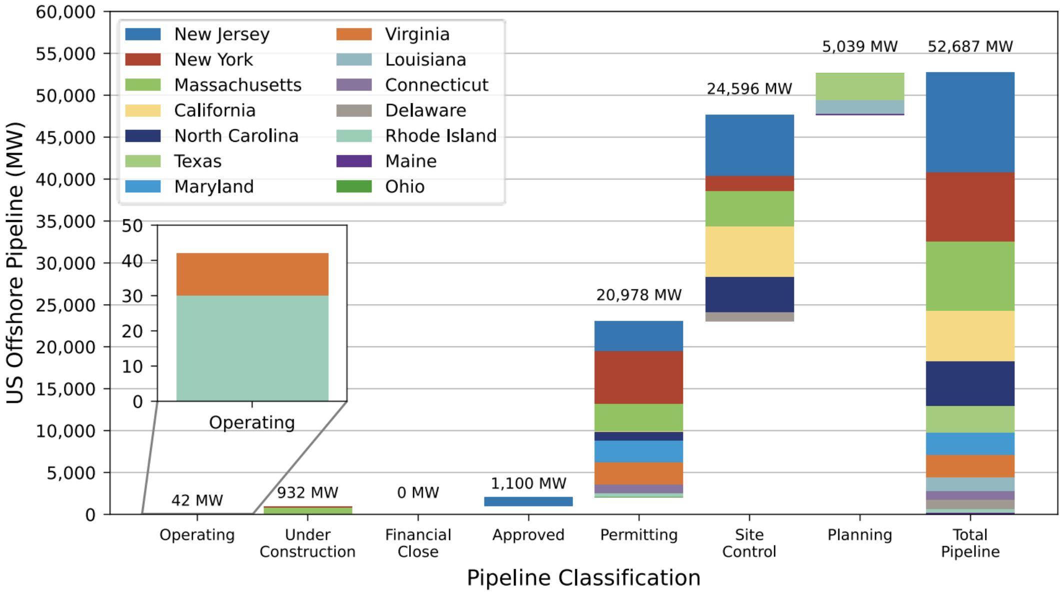
BOEM Bureau of Ocean Energy Management



Overview of Offshore Wind Development Outside CA

- Nearly all offshore wind installed in the U.S. and globally to date has been fixed-bottom projects
- A number of offshore wind projects in the U.S. (as well as globally) have been cancelled over the past 1-2 years, primarily due to cost increases and supply chain challenges
    - Many developers are no longer able to build projects at costs originally bid in RFPs. State procurement agencies have been largely unwilling to renegotiate existing contracts and have instead directed projects to bid in future solicitations
- The timeline for east coast offshore wind projects between an RFP and COD has been ~8-10 years

U.S. Offshore Wind Development

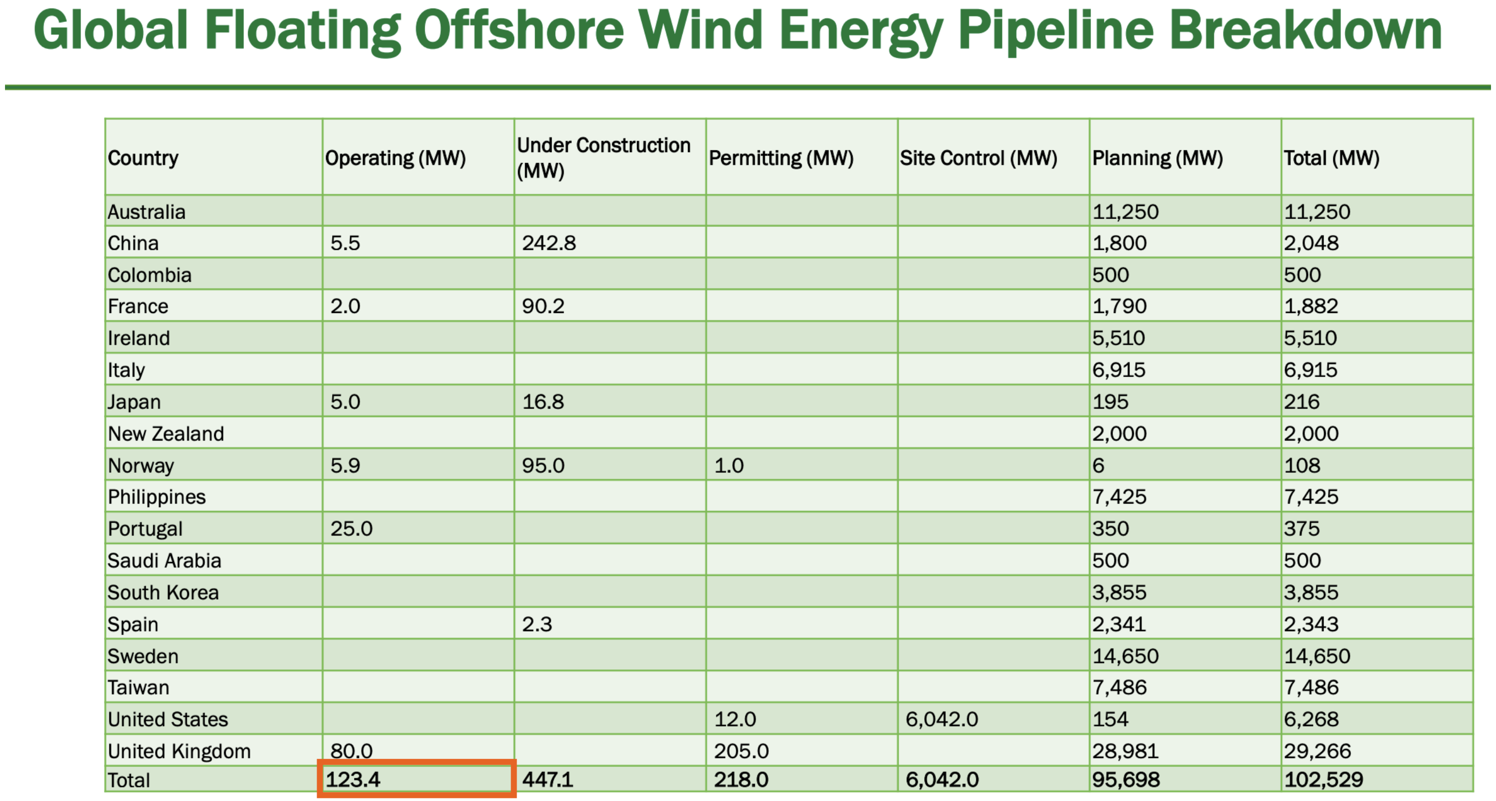


U.S. project pipeline classification by status.

Note: The approval of Ocean Wind occurred on July 5, 2023, after the stated cutoff date of May 31, 2023.

Overview of Floating Offshore Wind

- Floating offshore wind projects deployed globally to date have been pilot or small-scale projects (most under 30 MW)
- There are 2 floating offshore wind pilots in the U.S. currently planned – an 11 MW project in Maine starting construction in 2024 and the 60 MW CADEMO project in California with a targeted 2026/2027 COD



Global Floating Offshore Wind Energy Pipeline Breakdown

Country	Operating (MW)	Under Construction (MW)	Permitting (MW)	Site Control (MW)	Planning (MW)	Total (MW)
Australia					11,250	11,250
China	5.5	242.8			1,800	2,048
Colombia					500	500
France	2.0	90.2			1,790	1,882
Ireland					5,510	5,510
Italy					6,915	6,915
Japan	5.0	16.8			195	216
New Zealand					2,000	2,000
Norway	5.9	95.0	1.0		6	108
Philippines					7,425	7,425
Portugal	25.0				350	375
Saudi Arabia					500	500
South Korea					3,855	3,855
Spain		2.3			2,341	2,343
Sweden					14,650	14,650
Taiwan					7,486	7,486
United States			12.0	6,042.0	154	6,268
United Kingdom	80.0		205.0		28,981	29,266
Total	123.4	447.1	218.0	6,042.0	95,698	102,529

Only ~125 MW of
floating offshore wind
is operating today

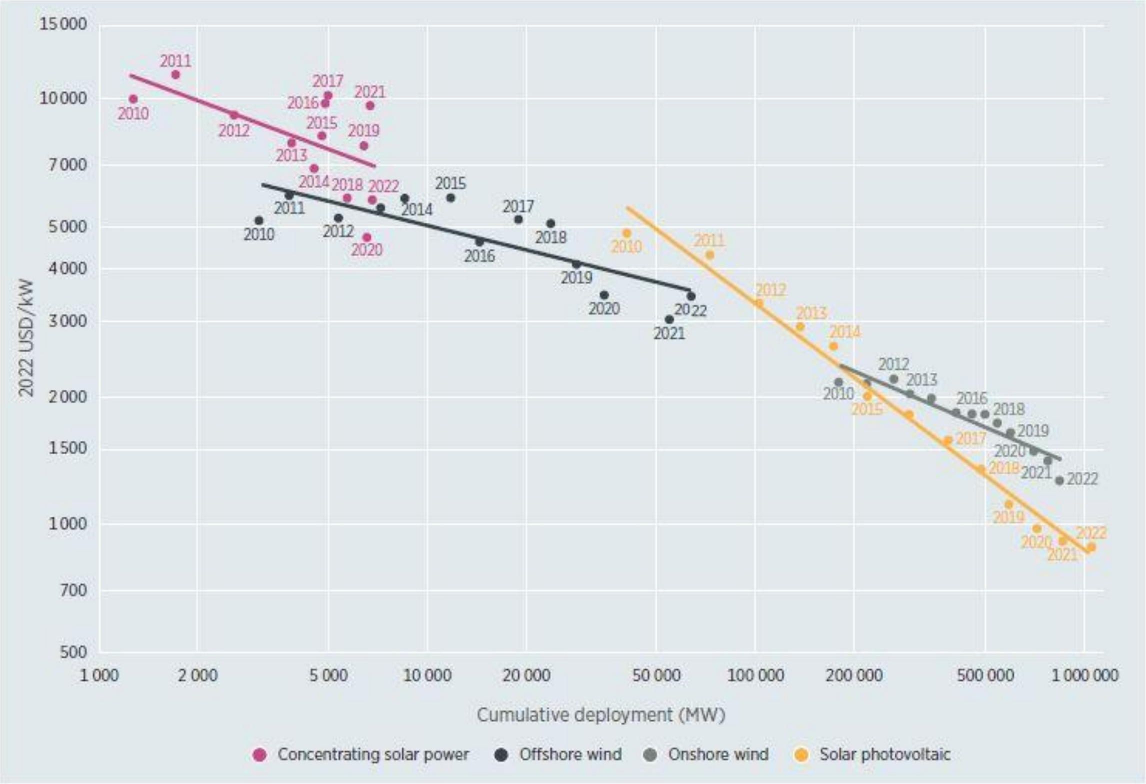
Key Learnings from Offshore Wind Procurement Processes Outside CA

- A number of east coast states have issued several rounds of solicitations for fixed-bottom offshore wind over the past several years
    - Many of these solicitations have instituted price caps beyond which offshore wind will not be procured
    - Several states (NY, NJ) have considered non-price criteria (such as economic impacts, project viability, environmental impacts) in addition to price criteria in bid evaluation
- A number of full-scale projects on the east coast started with pilot projects before scaling up
    - Maine has referred to this as a "1-10-100" approach of building out 1, 10, and then 100 turbines
- Some east coast states (NY, NJ, MD) have issued solicitations for offshore wind Renewable Energy Certificates (ORECs) while others (MA, RI, CT) have sought bundled PPAs
- Most offshore wind procurement on the east coast has been through a centralized procurement entity (NY, NJ, MD) or joint IOU procurements led by the state or multiple states jointly (MA, RI, CT)
- More than east coast states, California has more options to procure other shorter lead time resources (solar+storage, onshore wind) if offshore wind is not economic to build at large scales, which provides an additional offramp

Key Learnings from Other Emerging Technologies

- Other technologies that began as emerging technologies, such as solar thermal, solar PV, Li-ion batteries, and geothermal, were evaluated to assess the factors that can contribute to success or failure at achieving cost declines with scale
- Favorable government policy is frequently required to encourage early R&D, demonstration projects, and incentives for early adoption
  - Government funding for emerging technology research (e.g. solar, wind)
  - Financial incentives for project developers (e.g. ITC/PTC, net metering)
  - Procurement orders or mandates (e.g. EVs)
- Technologies must demonstrate that they have overcome technical challenges and other barriers to commercialization
  - Some technologies will not overcome this hurdle despite government support for market transformation (e.g. solar thermal, hydrogen fuel cell vehicles, nuclear)
- Favorable project economics and strong private-sector interest enable deployment at scale (e.g. solar PV, storage, EVs)

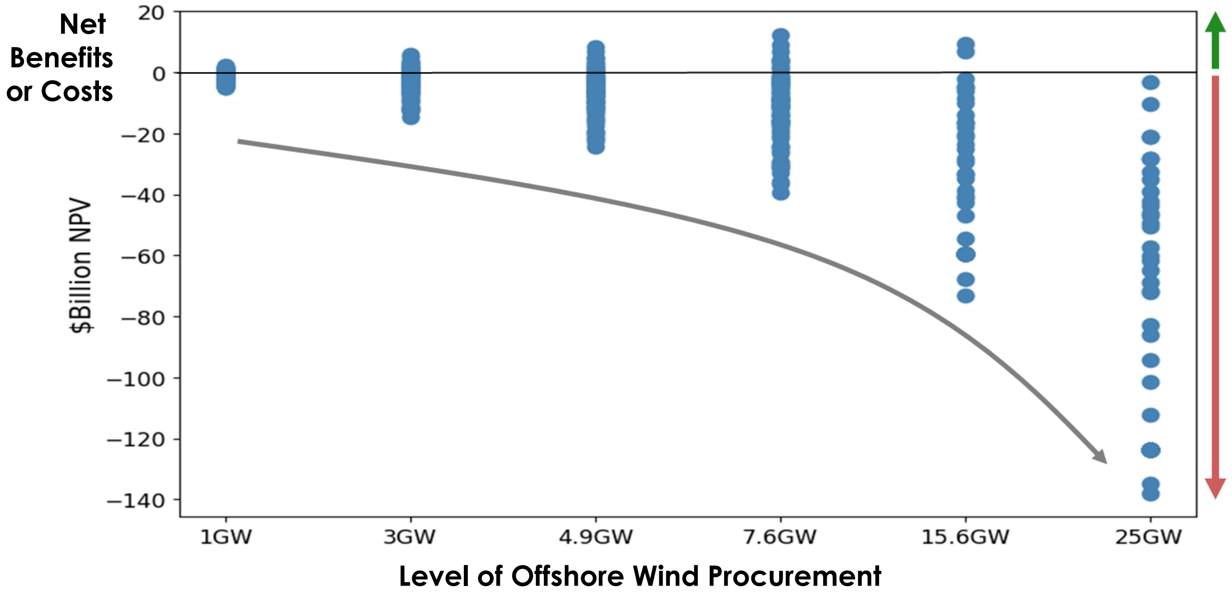
Figure 1.11 The global weighted average total installed cost learning curve trends for solar PV, CSP, and onshore and offshore wind, 2010-2022



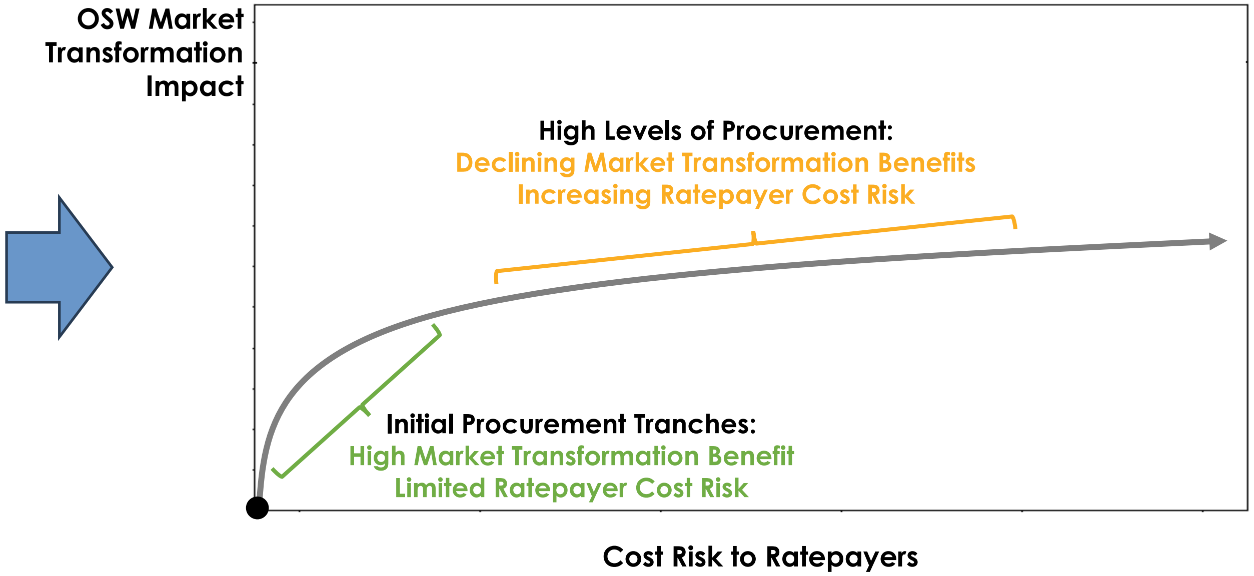
Source: IRENA Renewable Power Generation Costs in 2022

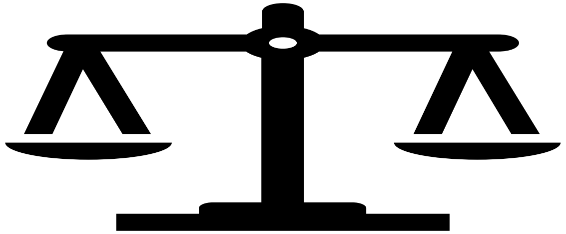
Seeking to balancing the benefits of developing the CA offshore wind industry against the cost risk to ratepayers

RESOLVE cost-benefit analysis



Offshore wind procurement





Cost Risk to Ratepayers

Quantitative analysis shows offshore wind may have net cost to ratepayers, a risk that may increase with high levels of procurement

Offshore Wind Market Transformation

Initiating procurement of offshore wind can support technology advancement, infrastructure development, and potentially future cost reductions

Offshore Wind Procurement Considerations

Risk Management Strategies During Solicitation Process

Possible strategies for competitive solicitation (required in AB 525):

1. Set a **cost cap** that determines quantity procured during a solicitation
    a. Some east coast states (e.g. Maryland and Virginia) have used publicly published caps in solicitations while others (e.g. New York) have used confidential caps
        - Publicly published caps promote transparency, but may lead bidders to simply bid at the cap (lowering competitiveness and/or underbidding to fall at/below cap)
        - Confidential caps promote competitiveness, but may lead to fewer bids below the cap
    b. If no projects are bid under the price cap, hold off on procurement until future solicitations
    c. In the event of a project having higher-than-expected costs, rather than renegotiate contracts, plan to accelerate future solicitations in which projects can re-bid
2. Undertake a **joint agency review process** following receipt of developer bids to inform final volume procured
    a. CPUC/DWR ratepayer impact analysis and market alternatives analysis (such as analysis undertaken as part of this AB1373 need assessment)
3. Incorporate **non-economic factors**, such as economic impacts and project viability, into bid evaluation criteria

While procurement and development activities take place for full-scale deployment of large projects, pilot or demonstration projects can provide useful information on technology feasibility and risk.

The 60 MW CADEMO floating offshore wind project may be a sufficient demonstration project for Morro Bay area and a pilot project may be useful before full-scale project development at Humboldt

Risk Management Strategies During Risk of Project Failure

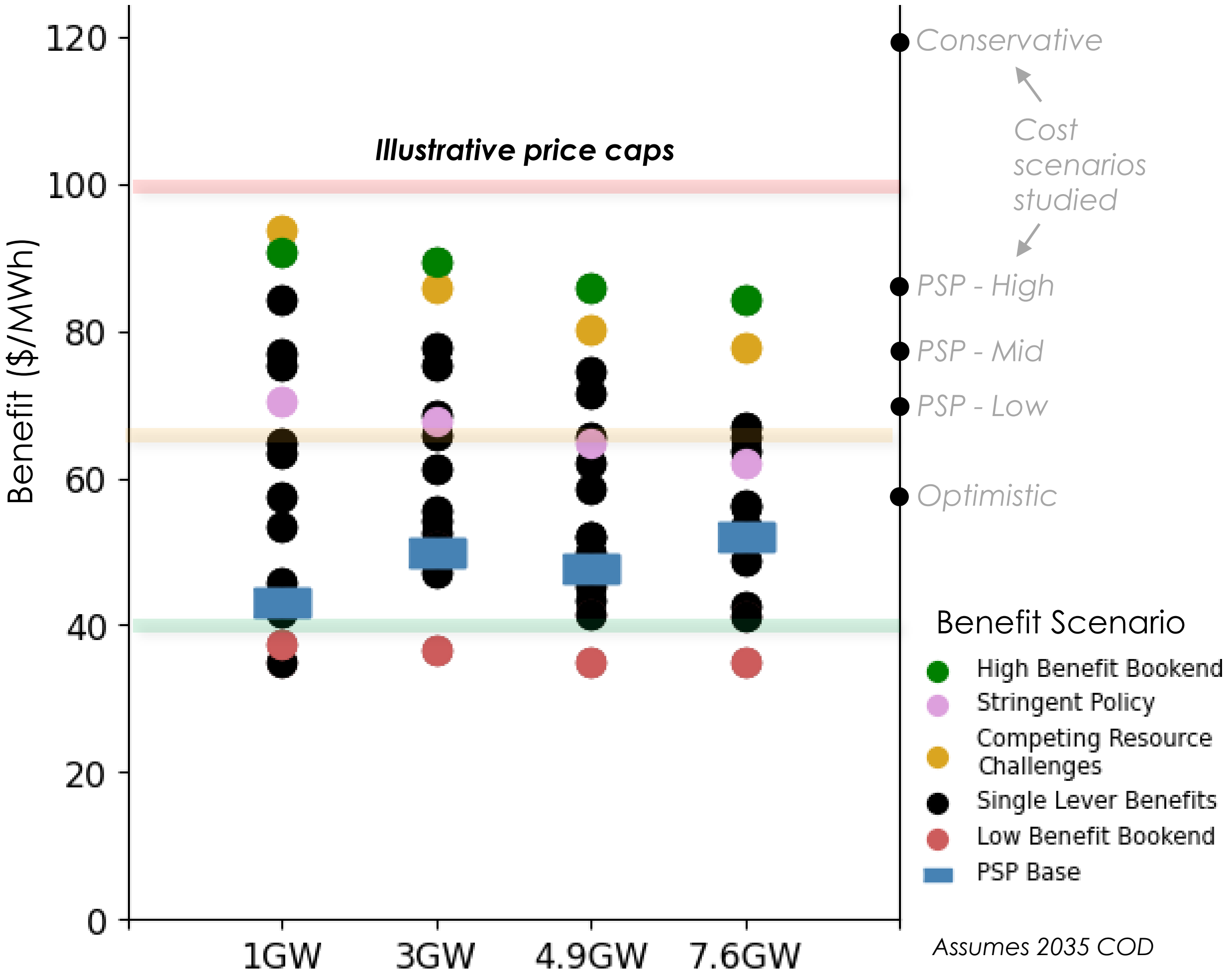
Options if projects are facing potential project failure in the event of higher-than-bid project costs:

1. Renegotiate contracts (i.e. enable developer to recover higher costs than originally contracted)
    a. Renegotiations can help delay deployment, but could lead to increased ratepayer risk and reduced market competitiveness
2. Cancel project/enable project failure and seek procurement in future solicitations
    a. Projects could be rebid with updated costs in future solicitations
    b. Acceleration of future solicitations could help mitigate delays to deployment

Cost-benefit analysis can inform a price cap

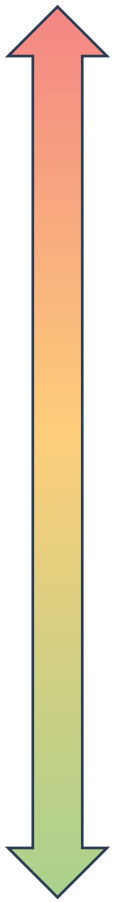
***Benefits** of offshore wind from avoided resource costs provide breakeven points for OSW that **can help inform price caps** on PPA prices*

Range of Offshore Wind Benefits



Assumes 2035 COD

Ratepayer Cost Risk



High Risk
Price Cap >$90/MWh
Very likely ratepayer costs… but may support initial deployments

Medium Risk
Price Cap ~$50-90/MWh
Less certain ratepayer impacts… balances ratepayer risk

Low Risk
Price Cap <$50/MWh
Very likely ratepayer benefits… but unrealistic near-term prices for floating OSW

- *If benefits < PPA price, OSW will increase ratepayers costs*
- *If benefits > PPA price, OSW will decrease ratepayer benefits*
- ***Price cap for initial amount (e.g., 1 GW) could be set higher*** if market transformation benefits are seen outweighing ratepayer costs
- ***After that, a declining price cap could be instituted*** for additional procurement to A) limit ratepayer impacts amidst declining marginal benefits, and B) encourage cost reductions to justify continued centralized procurement
  - This ***could limit procurement in the first round of AB1373 procurement*** to enable time for the industry to demonstrate further cost reduction

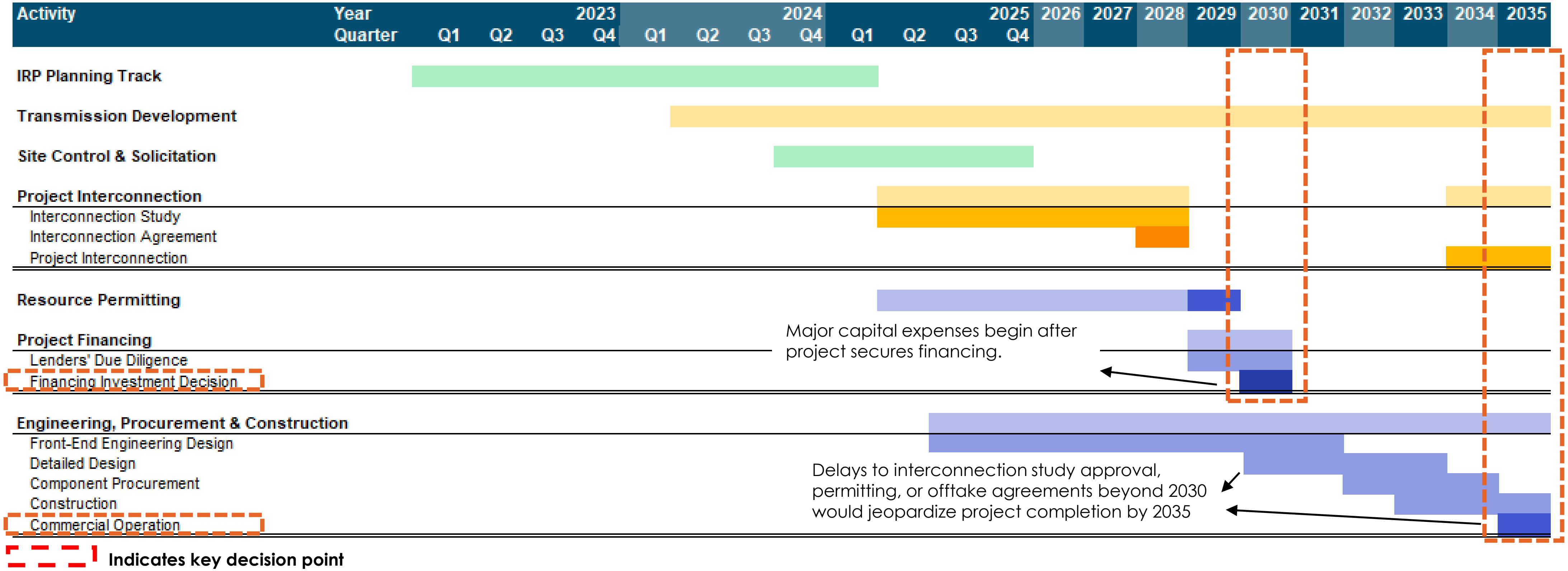
Values shown here are in real 2022$ and should be adjusted for inflation as needed to align with OSW bids

Considering Humboldt transmission

- Building out transmission for at least 1.6 GW of Humboldt offshore wind as currently proposed in the CAISO's 2023-2024 Draft Transmission Plan
- A federal Department of Transportation (DOT) grant for $427M to fund construction of a marine terminal at Humboldt to support construction of OSW turbines was announced in January 2024
- Large uncertainty around cost and timeline for North Coast transmission warrants special focus/consideration of its development implications
- The CPUC should consider transmission costs in addition to bids for Morro Bay and Humboldt received from an all-source solicitation to make a comparison of **total costs** to ratepayers for offshore wind buildout in Morro Bay vs. Humboldt

Summary of Analysis of Other Long Lead-Time (LLT) Resources

Resource Development Timeline



Major capital expenses begin after project secures financing.

Delays to interconnection study approval, permitting, or offtake agreements beyond 2030 would jeopardize project completion by 2035

- Financial closing requires site control, permitting, interconnection, and offtake agreements, and construction contracts
- Project financing must be in place by 2030 to avoid risk of delays in project operation beyond 2035

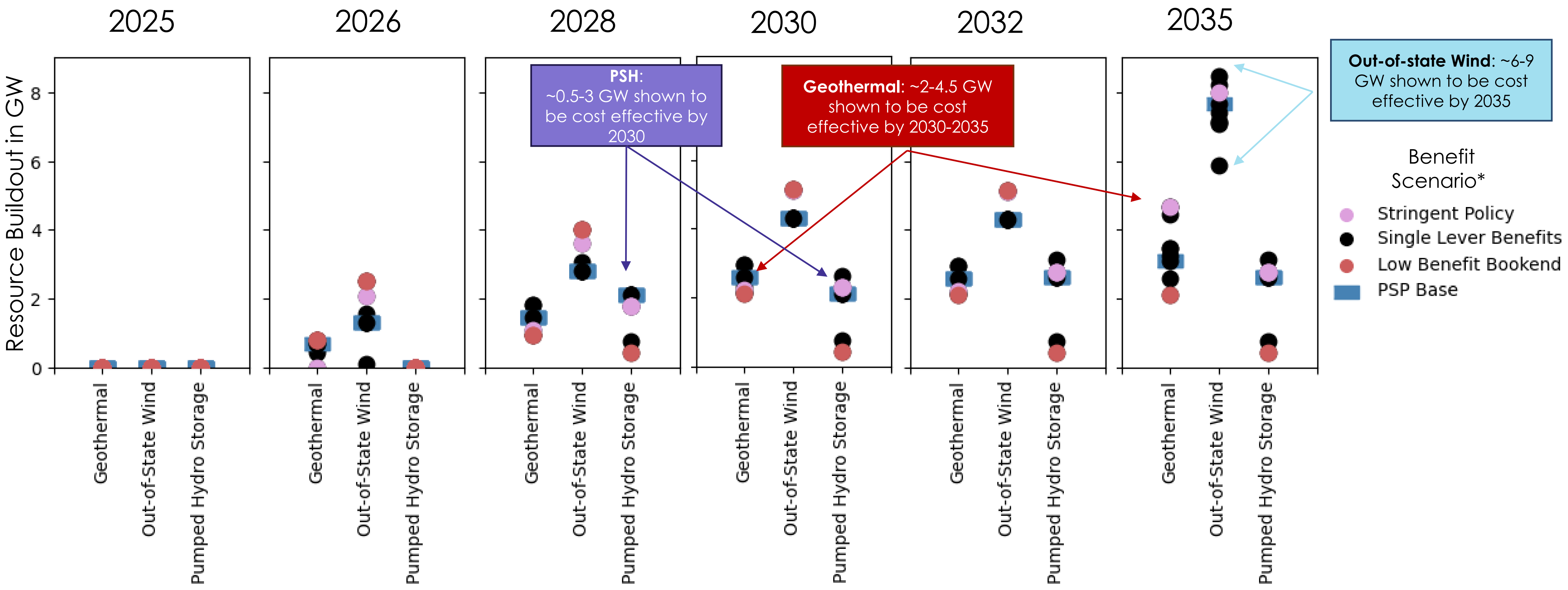
References: IRP Offshore Wind Roadmap (2021), revised to reflect ITC extension and latest estimation of development timeline
Transmission Development in California (2023)

Additional analysis of other LLTs builds on the more comprehensive offshore wind study

- Data on optimal amounts of additional long lead-time (LLT) resources was extracted from the RESOLVE runs considered in the offshore wind analysis*
  - Compared to the offshore wind analysis, the analysis of other LLT resources is less robust since it does not explicitly consider LLT cost risk and does not consider a targeted set of benefit scenarios focused on each LLT
  - However, the analysis still provides useful information to inform optimal builds and timelines for geothermal, pumped storage hydro storage (PSH), and out-of-state (OOS) wind
- Unlike offshore wind, geothermal, PSH, and OOS wind are all existing technologies with a history of procurement in California and the west
  - Market transformation is not the focus, but central procurement could overcome significant procurement challenges.

* Scenarios with resource limits on geothermal, pumped storage hydro and/or out-of-state wind were excluded from this analysis on other LLTs

By 2030-2035, some volume of each LLT resource is optimal, with PSH showing the greatest uncertainty



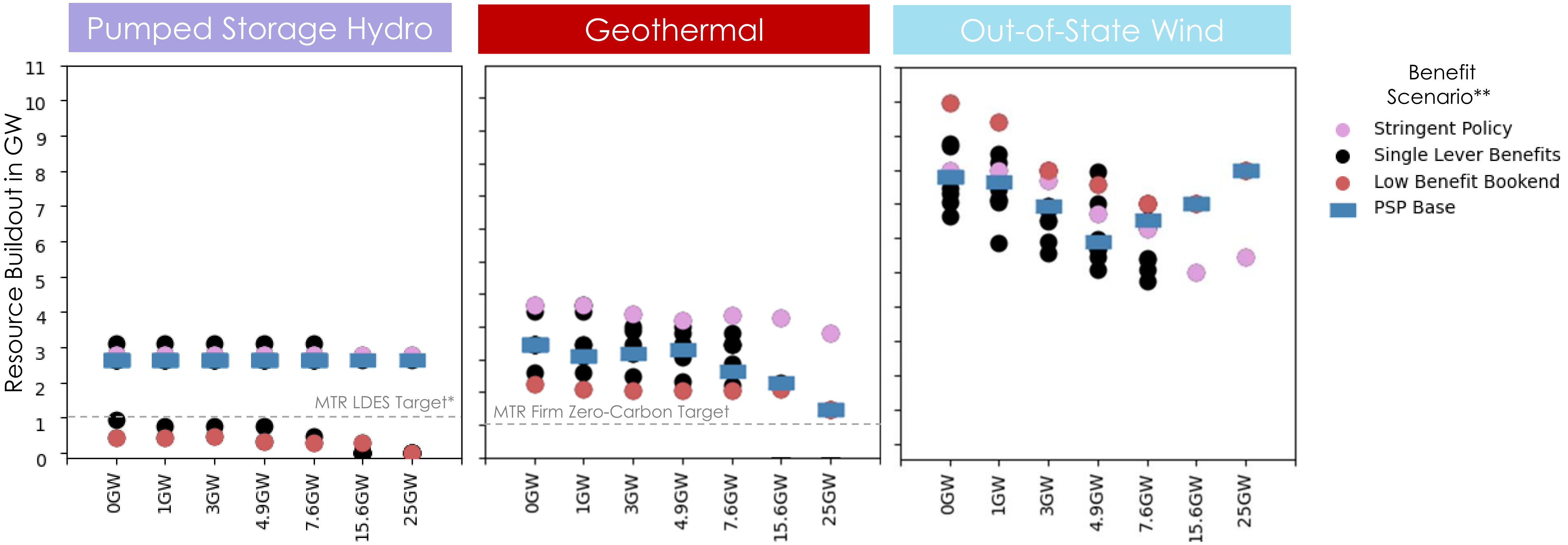
PSH: ~0.5-3 GW shown to be cost effective by 2030

Geothermal: ~2-4.5 GW shown to be cost effective by 2030-2035

Out-of-state Wind: ~6-9 GW shown to be cost effective by 2035

*Benefit scenarios for LLT analysis are same as in offshore wind analysis

Procuring offshore wind at low to moderate volumes has low impact on optimal amounts of other LLT resources in 2035



*PSH is **generally insensitive** to OSW procurement*

*Geothermal is **generally insensitive** to OSW procurement until 7.6-15 GW*

*Optimal OOS wind build is **moderately sensitive** to OSW procurement 3 GW or greater*

* Approximate since nameplate capacity to reach 1 GW LDES ELCC depends on the technologies procured

**Benefit scenarios for LLT analysis are same as in offshore wind analysis

Geothermal

- **Typical project development lifetime**: 7-10 years[1]
- **Optimal resource amounts***: 2.1 - 2.9 GW by 2030, 2.2 - 4.6 GW by 2035
- **Existing procurement orders**: 1 GW (MTR firm zero-carbon renewables) by 2028-2031
- **Can centralized procurement overcome the significant challenges of LSE procurement?**
  - Though longer lead times are required, individual projects are generally not large and have proceeded with LSEs of various sizes in the past without centralized procurement
  - Challenges with sourcing capacity for MTR order have already caused CPUC to delay procurement from 2026 to 2028-2031, indicating major challenges to reach existing procurement targets
    - Challenges are generally focused on expanding the queue of available resources to procure (limited resource sites, long development timelines, limited interconnection queue capacity, etc.)
    - It is unclear whether centralized procurement is the appropriate tool to solves these challenges

[1] DOE Office of Energy Efficiency & Renewable Energy; 7-10 years estimate from site control

**across scenarios with 0 GW of offshore wind

Pumped Storage Hydro

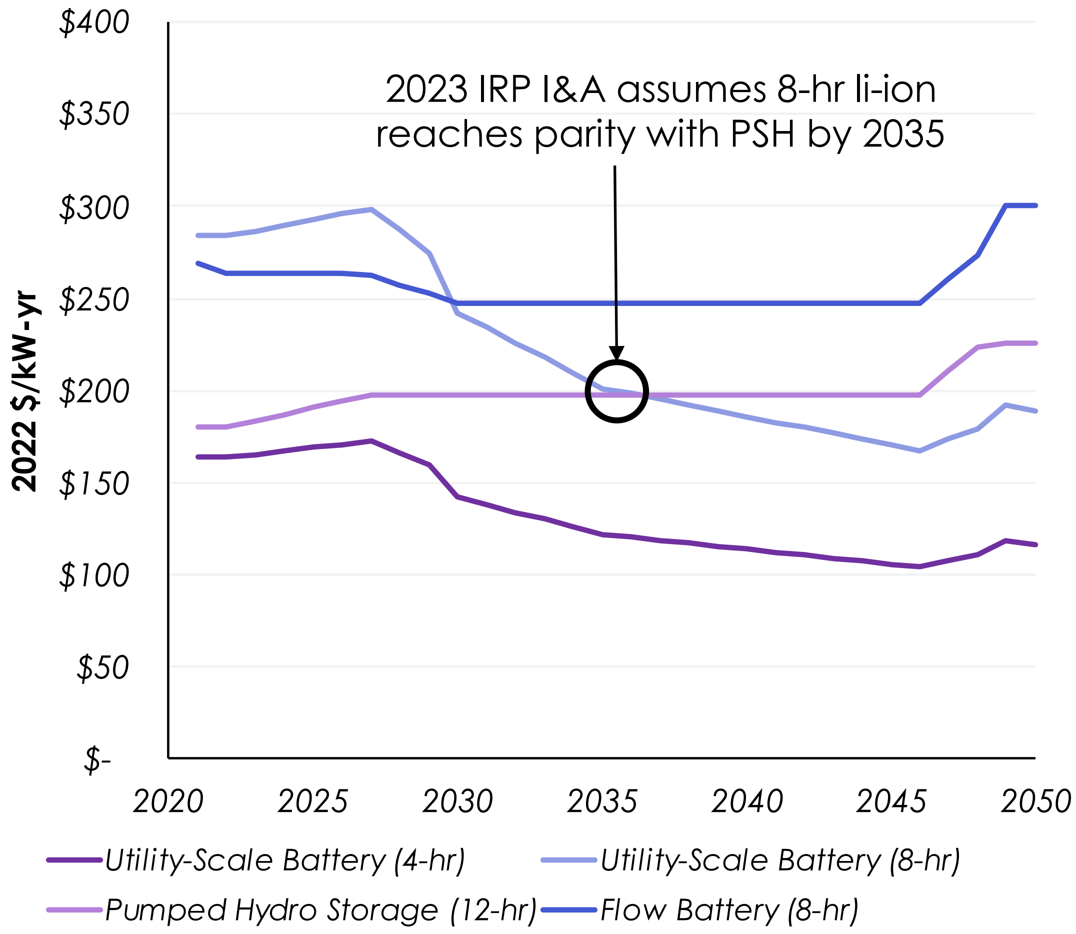
- **Typical project development lifetime**: 8-12 years*
- **Optimal resource amounts****: 0.5 - 2.6 GW by 2030, 0.5 - 3.1 GW by 2035
- **Existing procurement orders**: 1 GW (MTR long-duration storage) by 2028-2031, which may also be met with 8-hr batteries
- **Can centralized procurement overcome the significant challenges of LSE procurement?**
  - Many LSEs have struggled to make significant progress on the sourcing and procurement of the 1 GW long-duration storage ordered through MTR
    - The CPUC has extended the deadline for the 1 GW LDES requirement (for the second time) from the initial 2026 date to 2028-2031 COD
  - Direct alternatives to PSH exist that are more flexible re: modularity, siting, and transmission minimization (i.e., 8-hr li-ion batteries, A-CAES, and other emerging LDES technologies)
  - While PSH may face challenges due to large project sizes, key alternatives exist without the same procurement challenges, which increases the risk to ratepayers of committing to centralized procurement for PSH

* Source: DOE Office of Energy Efficiency & Renewable Energy; 8-12 years estimate from pre-licensing activities

** across scenarios with 0 GW of offshore wind

Alternative long-duration storage technologies

- Pumped storage hydro configurations and costs tend to be highly site specific
  - CPUC IRP I&A uses generic costs based on the 2023 NREL ATB
- Long-duration li-ion batteries and flow batteries are existing commercialized alternatives to PSH
- Additional emerging LDES technologies also exist



Out-of-state Wind

- **Typical transmission project development lifetime**: 10 years
- **Optimal OOS Wind amounts***: 4.3 - 5.2 GW by 2030, 6.7 - 10.1 GW by 2035
- **Can centralized procurement overcome the significant challenges of LSE procurement?**
    - Although the transmission component of out-of-state wind is a long lead-time resource that no one LSE can carry, OOS Tx development is already advancing without centralized procurement
    - Developing new OOS wind resources and associated multi-state transmission lines requires substantial subscription of the transmission capacity and a centralized OOS wind resource procurement may help speed this up, facilitating faster development
        - However, it is unclear that centralized procurement is necessary given examples of merchant-based transmission moving forward with LSE-level contract commitments (SunZia)
        - Centralized procurement could potentially drive higher prices versus a longer, but more competitive process, of sales to multiple LSEs

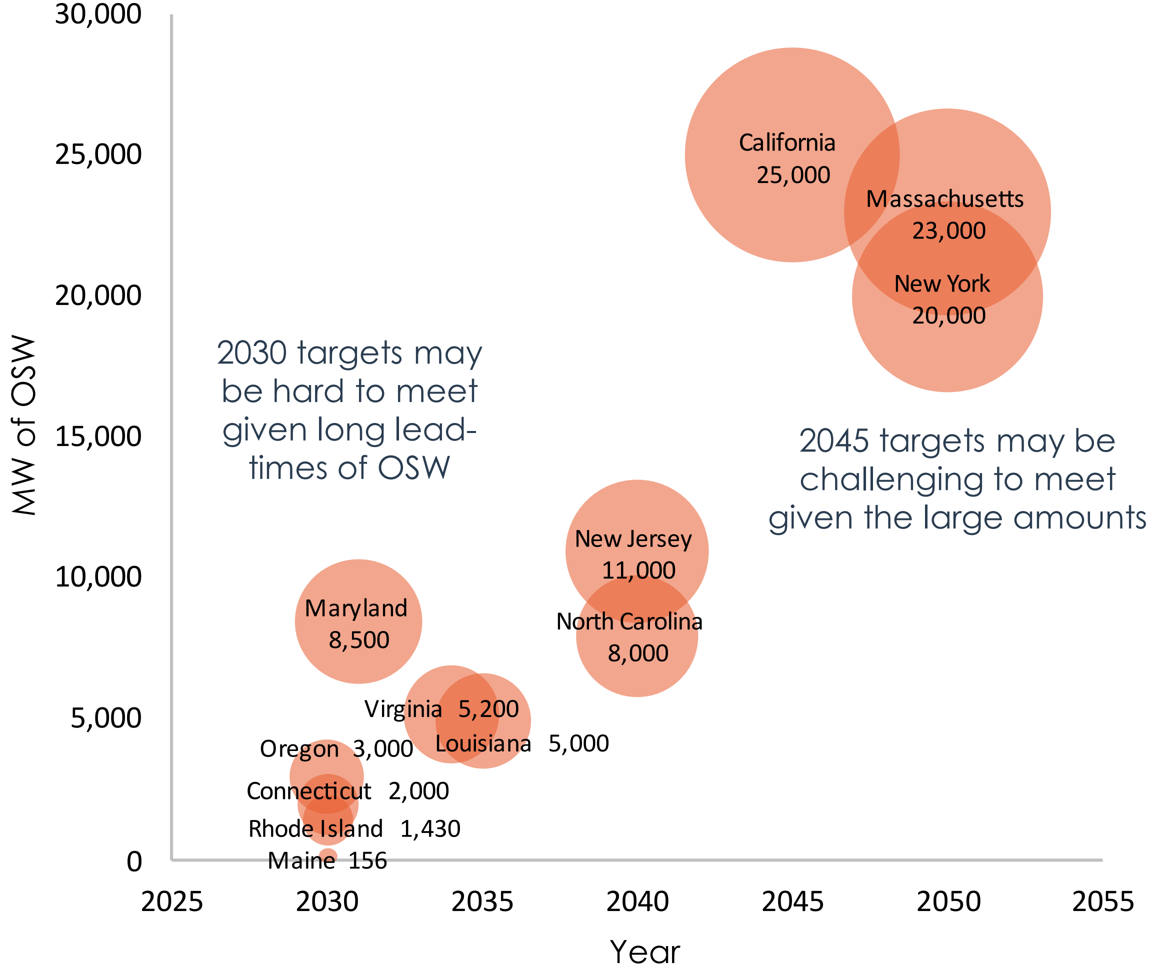
*across scenarios with 0 GW of offshore wind

Appendix A

Offshore Wind Outside California

Overview of Offshore Wind Targets in Other States

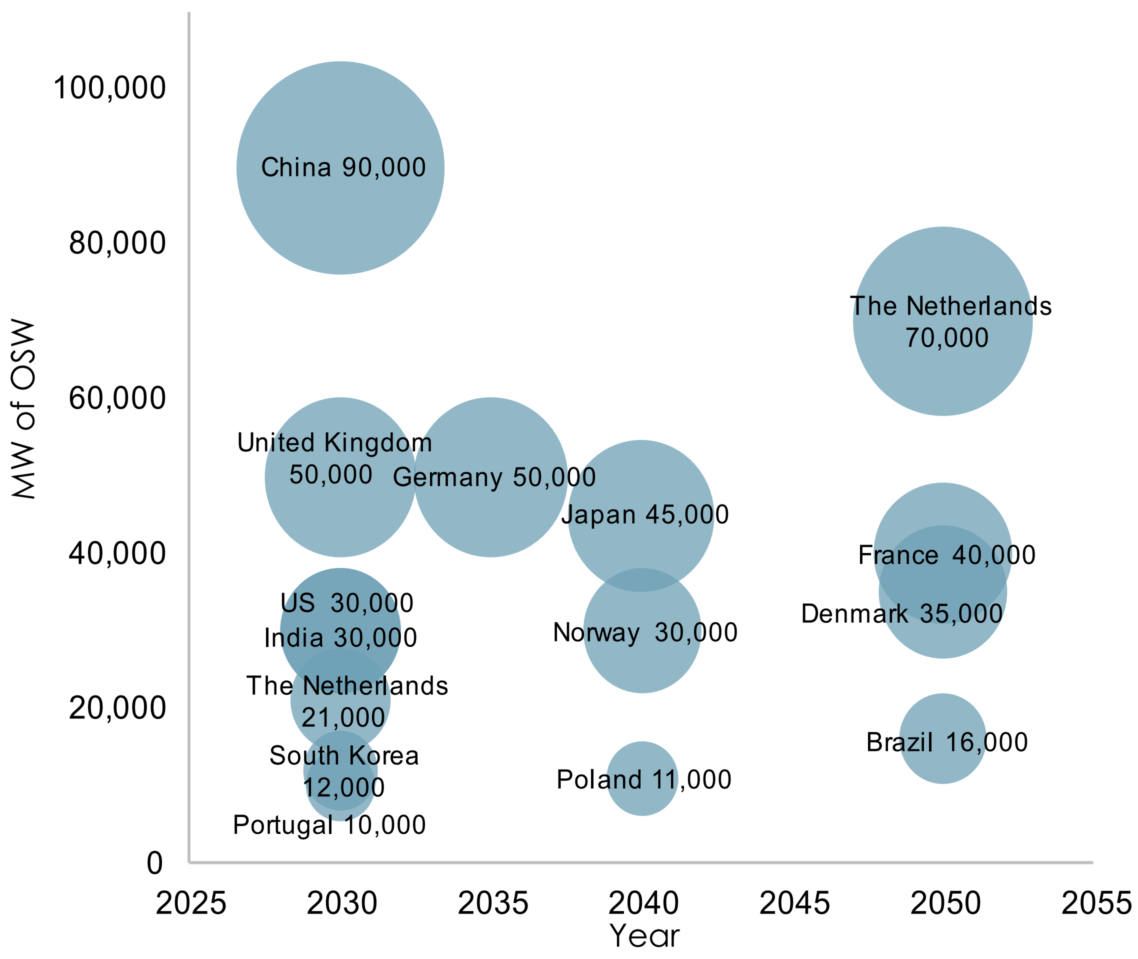
Planning Goals (MW) by State



2030 targets may be hard to meet given long lead-times of OSW

2045 targets may be challenging to meet given the large amounts

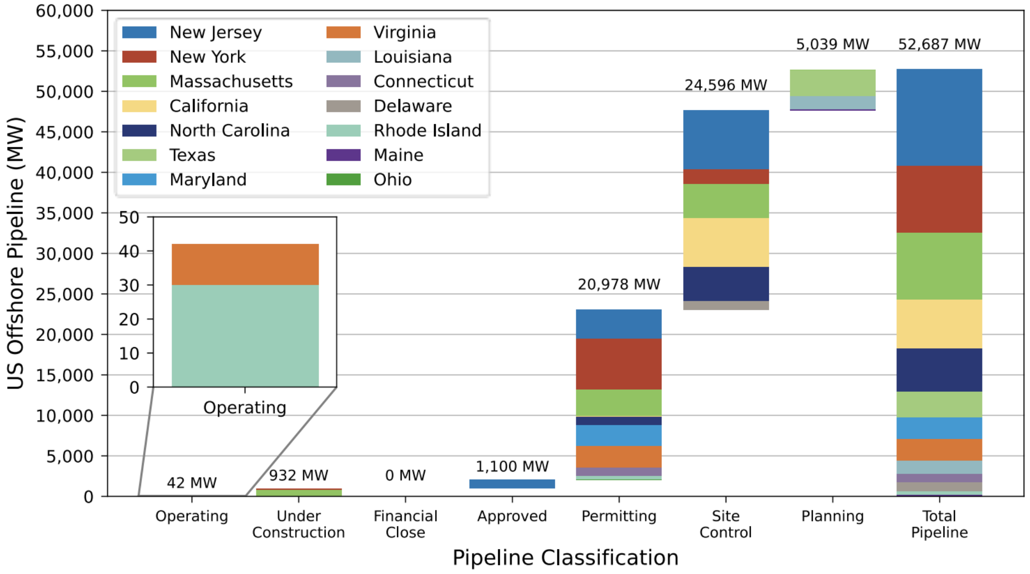
Selected Planning Goals (MW) by Country



Offshore Wind Development Outside CA

- Nearly all offshore wind installed in the U.S. and globally to date has been fixed-bottom projects.
- A number of offshore wind projects in the U.S. (as well as globally) have been cancelled over the past 1-2 years, primarily due to cost increases and supply chain challenges.
    - Many developers are no longer able to build projects at costs originally bid in RFPs. State procurement agencies have been largely unwilling to renegotiate existing contracts and have instead directed projects to rebid (same project but updated costs) in future solicitations.
- The timeline for east coast offshore wind projects between an RFP and COD has been ~8-10 years.

U.S. Offshore Wind Development

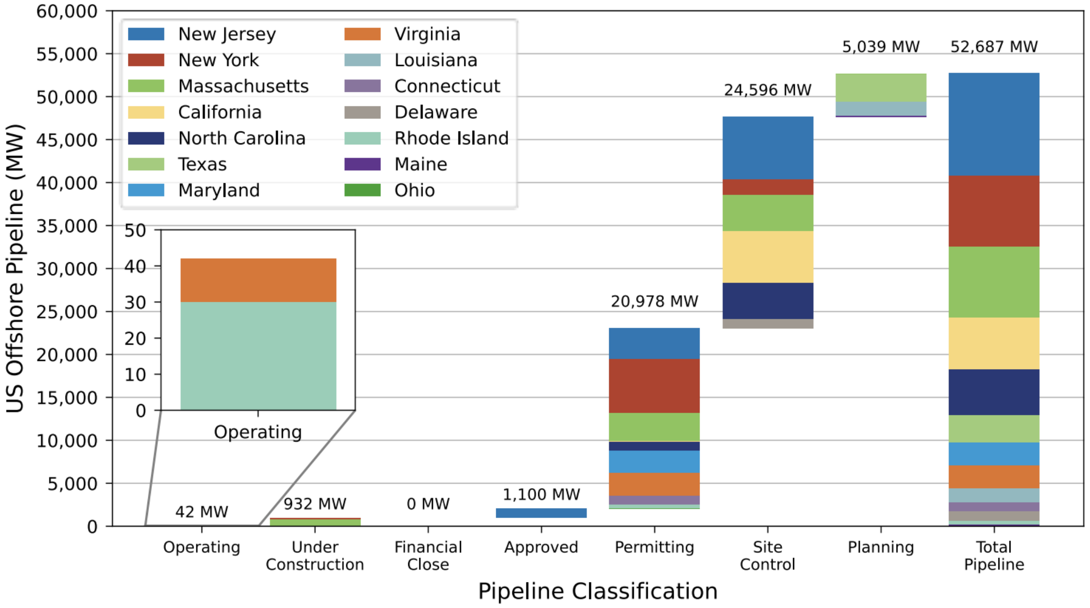


U.S. project pipeline classification by status.

Note: The approval of Ocean Wind occurred on July 5, 2023, after the stated cutoff date of May 31, 2023.

Overview of Global Offshore Wind Deployment

U.S.



U.S. project pipeline classification by status.

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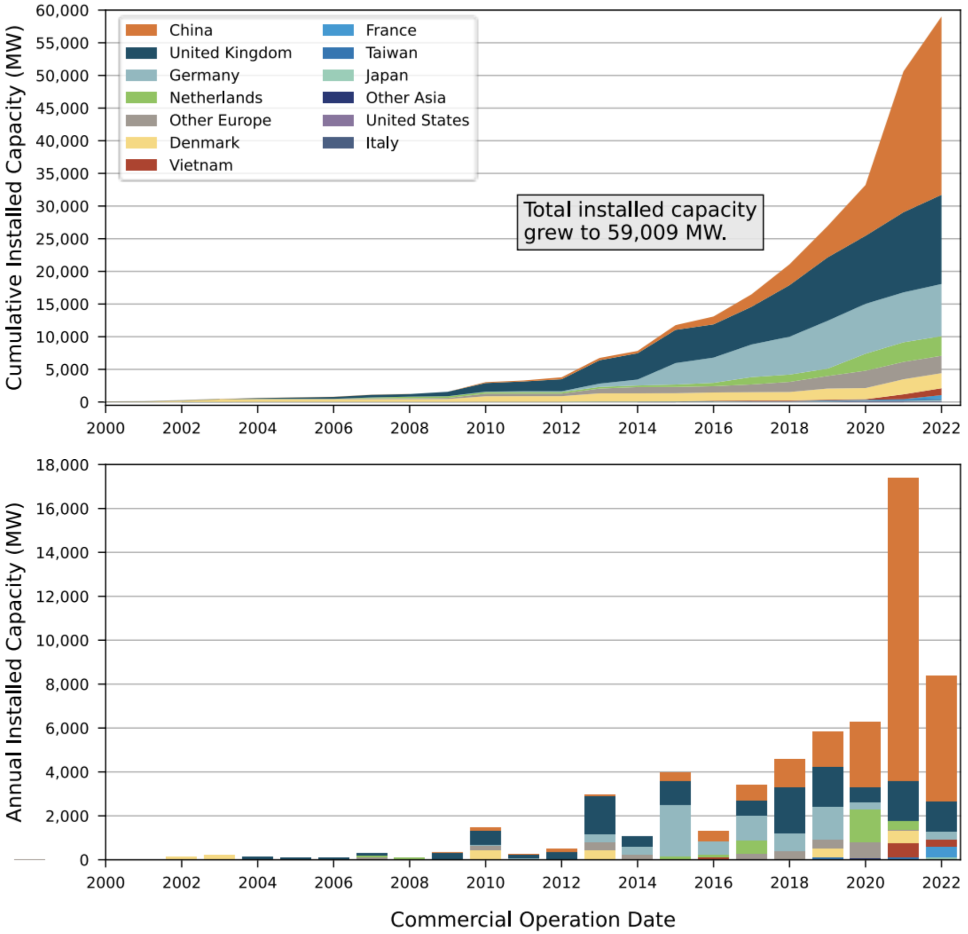
Global

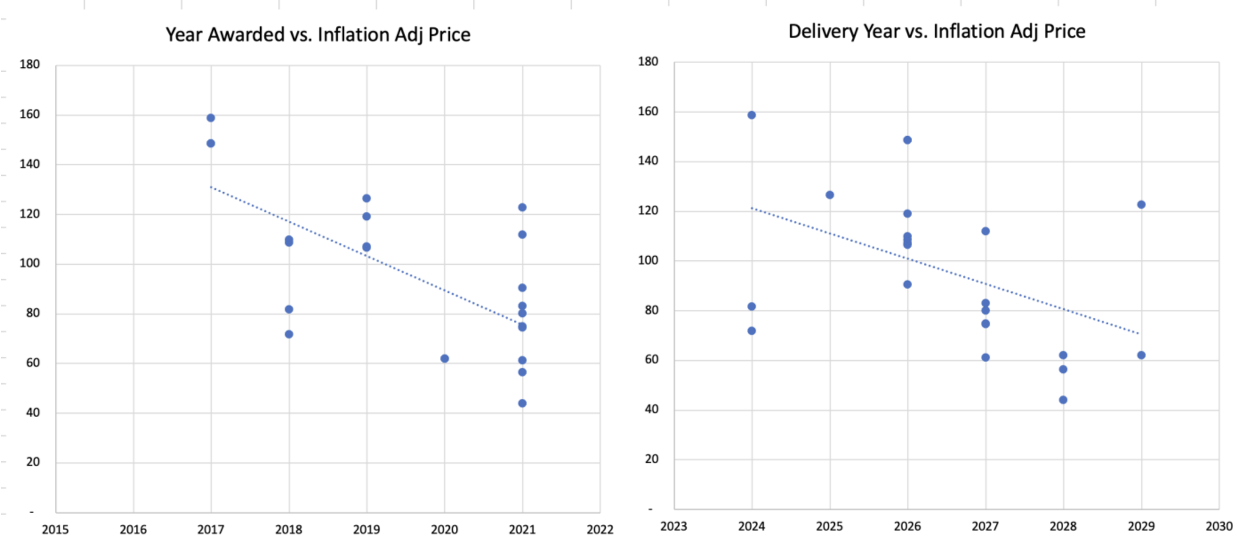


Note: offshore wind capacity shown includes both fixed-bottom and floating offshore wind combined

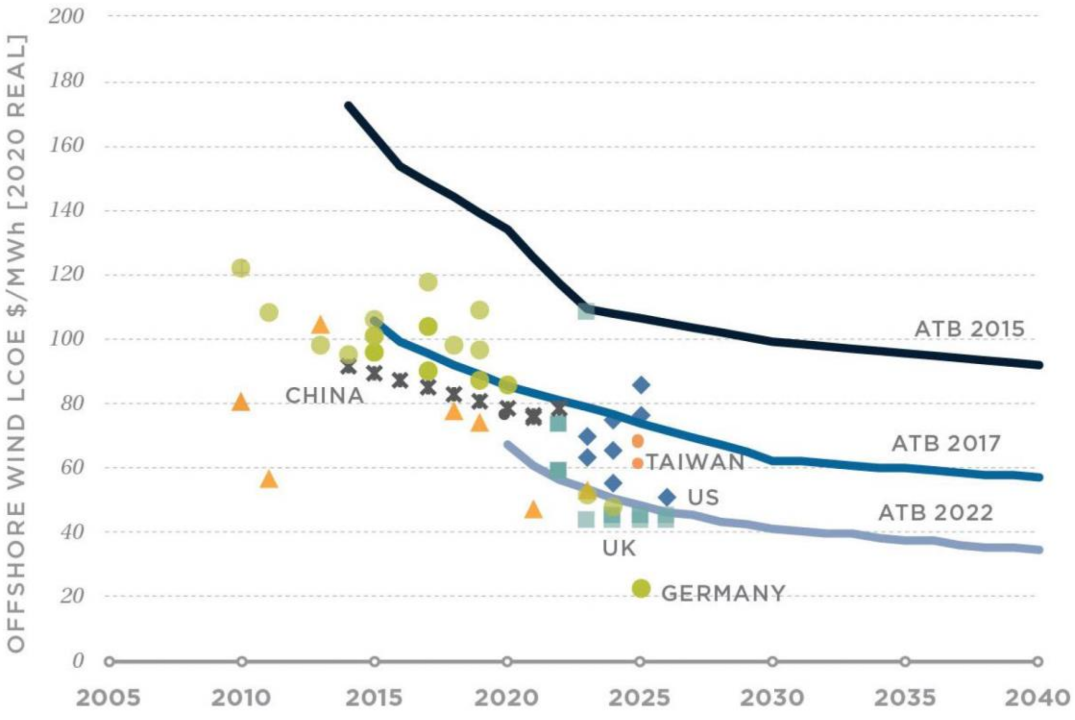
Costs of Global Offshore Wind Deployment To Date

- Offshore wind costs have generally been declining over time, but not as aggressively as forecasted several years ago

U.S. Offshore Wind Prices by Year Awarded and Delivery Year



Global Offshore Wind Price Trends and Projections



Source: [2035 Report, GridLab]

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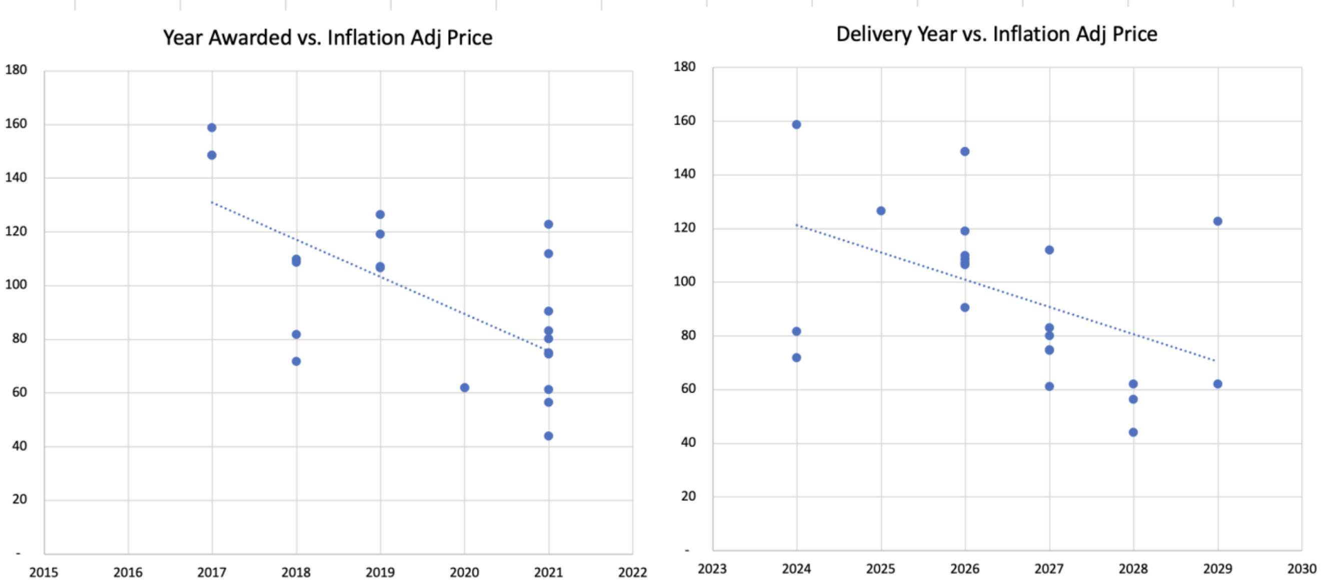
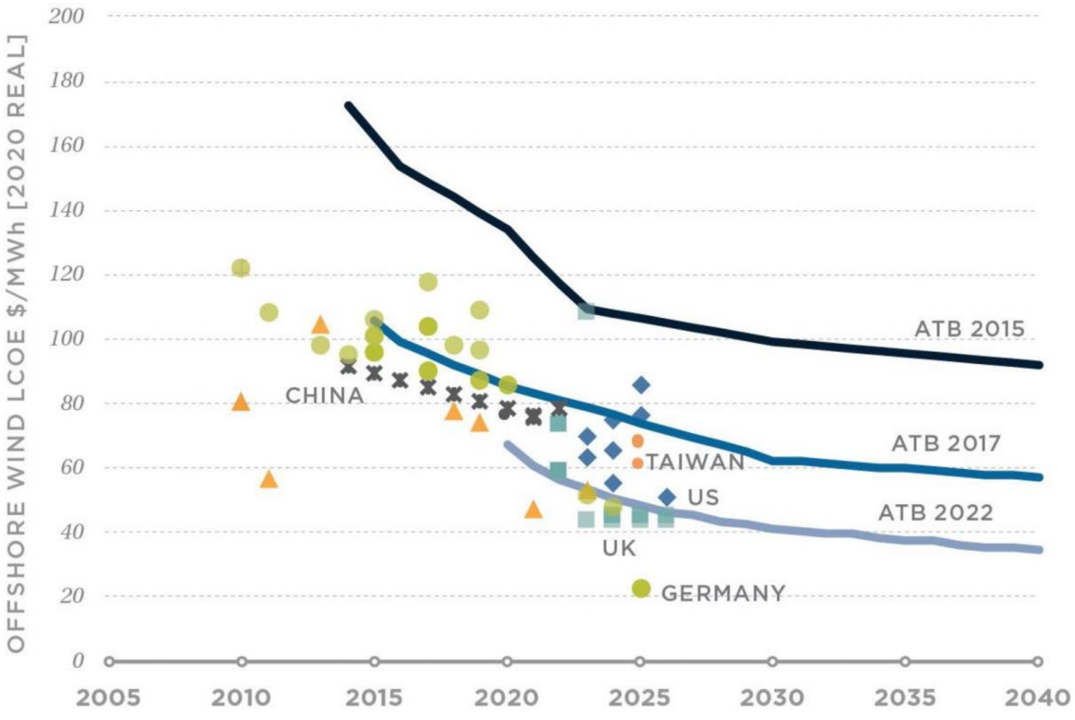


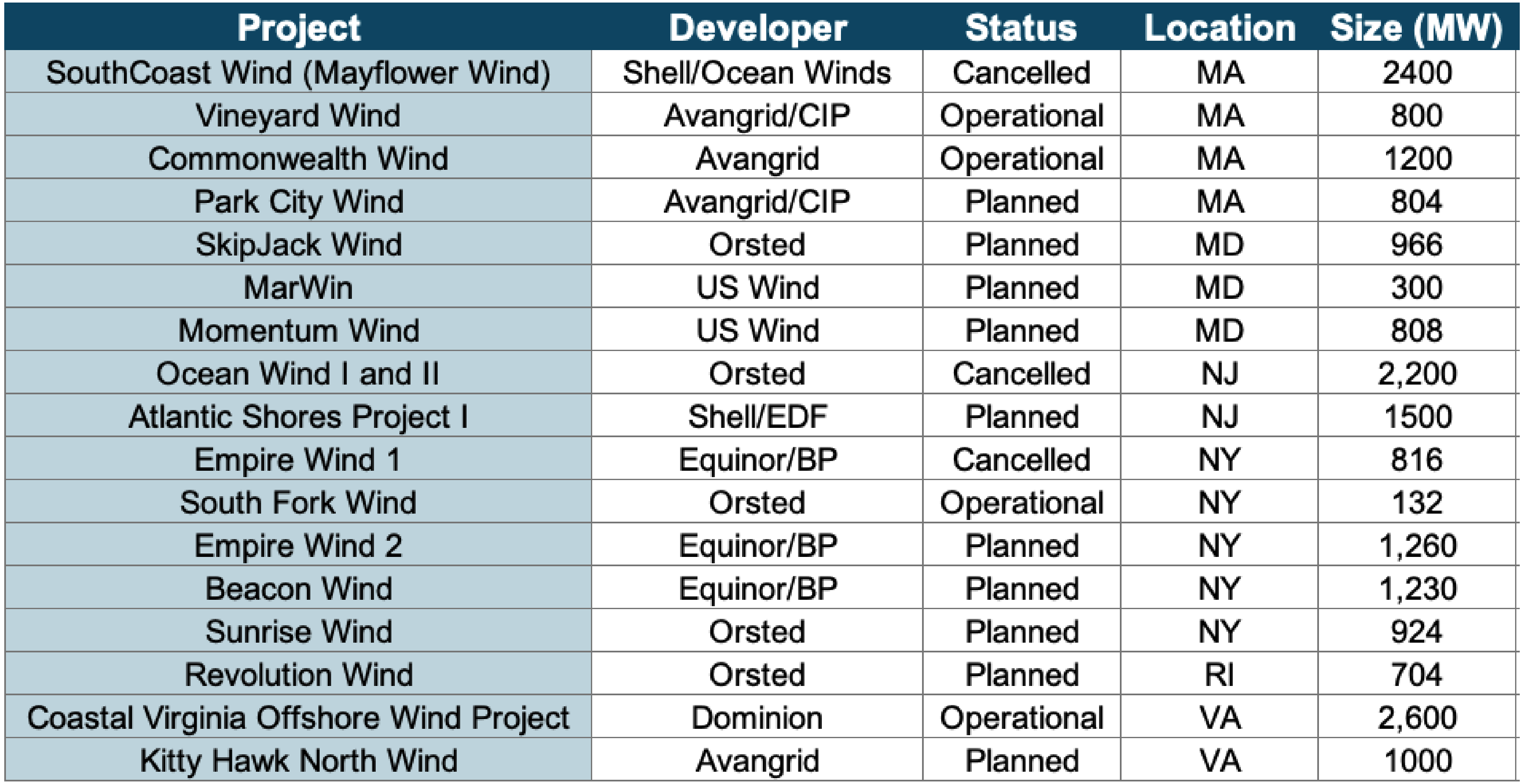
Source: DOE report : https://www.energy.gov/sites/default/files/2023-09/doe-offshore-wind-market-report-2023-edition.pdf

Global Offshore Wind Price Trends and Projections



Source: 2035 Report, GridLab

Overview of Offshore Wind Projects in the U.S.

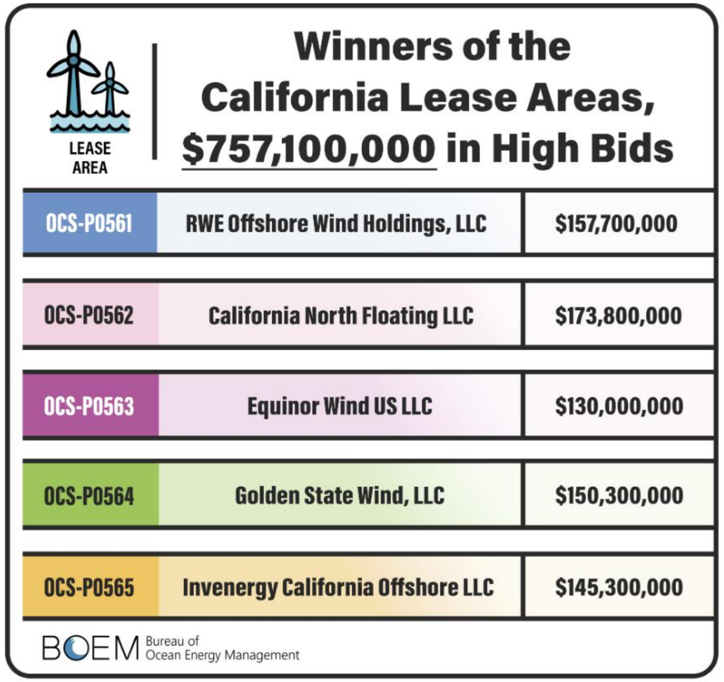


Project	Developer	Status	Location	Size (MW)
SouthCoast Wind (Mayflower Wind)	Shell/Ocean Winds	Cancelled	MA	2400
Vineyard Wind	Avangrid/CIP	Operational	MA	800
Commonwealth Wind	Avangrid	Operational	MA	1200
Park City Wind	Avangrid/CIP	Planned	MA	804
SkipJack Wind	Orsted	Planned	MD	966
MarWin	US Wind	Planned	MD	300
Momentum Wind	US Wind	Planned	MD	808
Ocean Wind I and II	Orsted	Cancelled	NJ	2,200
Atlantic Shores Project I	Shell/EDF	Planned	NJ	1500
Empire Wind 1	Equinor/BP	Cancelled	NY	816
South Fork Wind	Orsted	Operational	NY	132
Empire Wind 2	Equinor/BP	Planned	NY	1,260
Beacon Wind	Equinor/BP	Planned	NY	1,230
Sunrise Wind	Orsted	Planned	NY	924
Revolution Wind	Orsted	Planned	RI	704
Coastal Virginia Offshore Wind Project	Dominion	Operational	VA	2,600
Kitty Hawk North Wind	Avangrid	Planned	VA	1000

- Operational:
  - Capable of delivering power
- Planned:
  - Not yet under construction
- Cancelled:
  - No longer being pursued

Overview of Offshore Wind Development in CA

- The Bureau of Ocean Energy Management (BOEM) held an auction for 5 lease sites in CA (3 in Morro Bay, 2 in Humboldt) in December 2022.
- Winners of the CA lease areas are currently preparing Site Assessment Plans (due June 1, 2024).
- Although there are only 5 eligible bidders for near-term solicitations, there are likely to be enough bidders to maintain competitiveness.

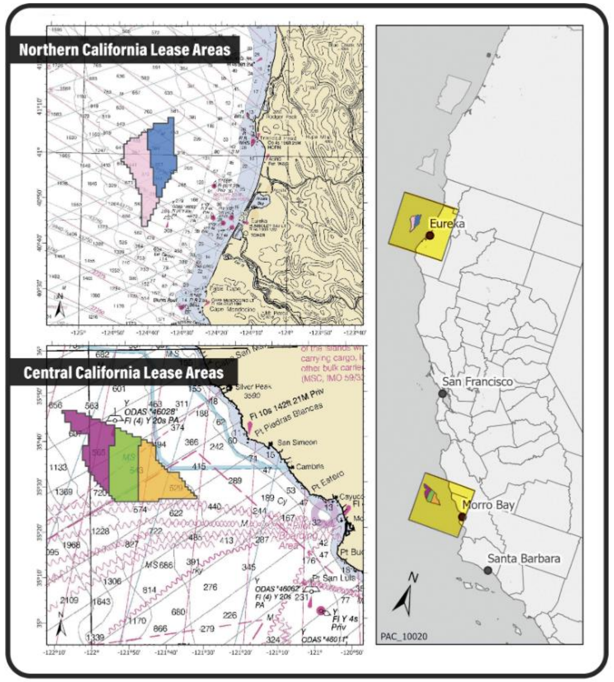


LEASE AREA

Winners of the California Lease Areas, $757,100,000 in High Bids

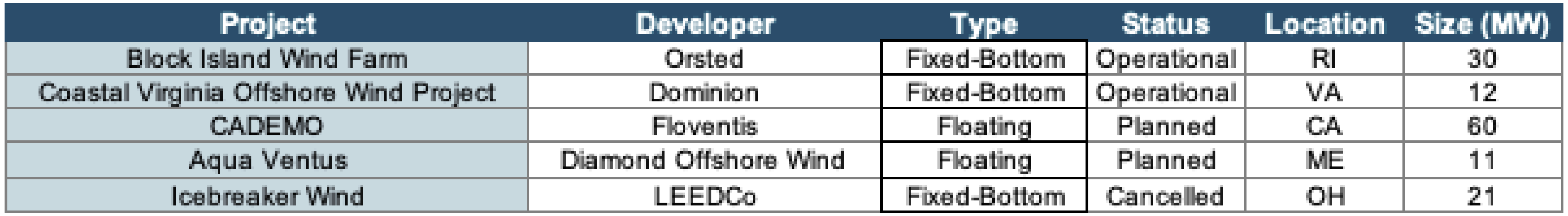
OCS-P0561	RWE Offshore Wind Holdings, LLC	$157,700,000
OCS-P0562	California North Floating LLC	$173,800,000
OCS-P0563	Equinor Wind US LLC	$130,000,000
OCS-P0564	Golden State Wind, LLC	$150,300,000
OCS-P0565	Invenergy California Offshore LLC	$145,300,000

BOEM Bureau of Ocean Energy Management



Pilot Projects in the U.S.

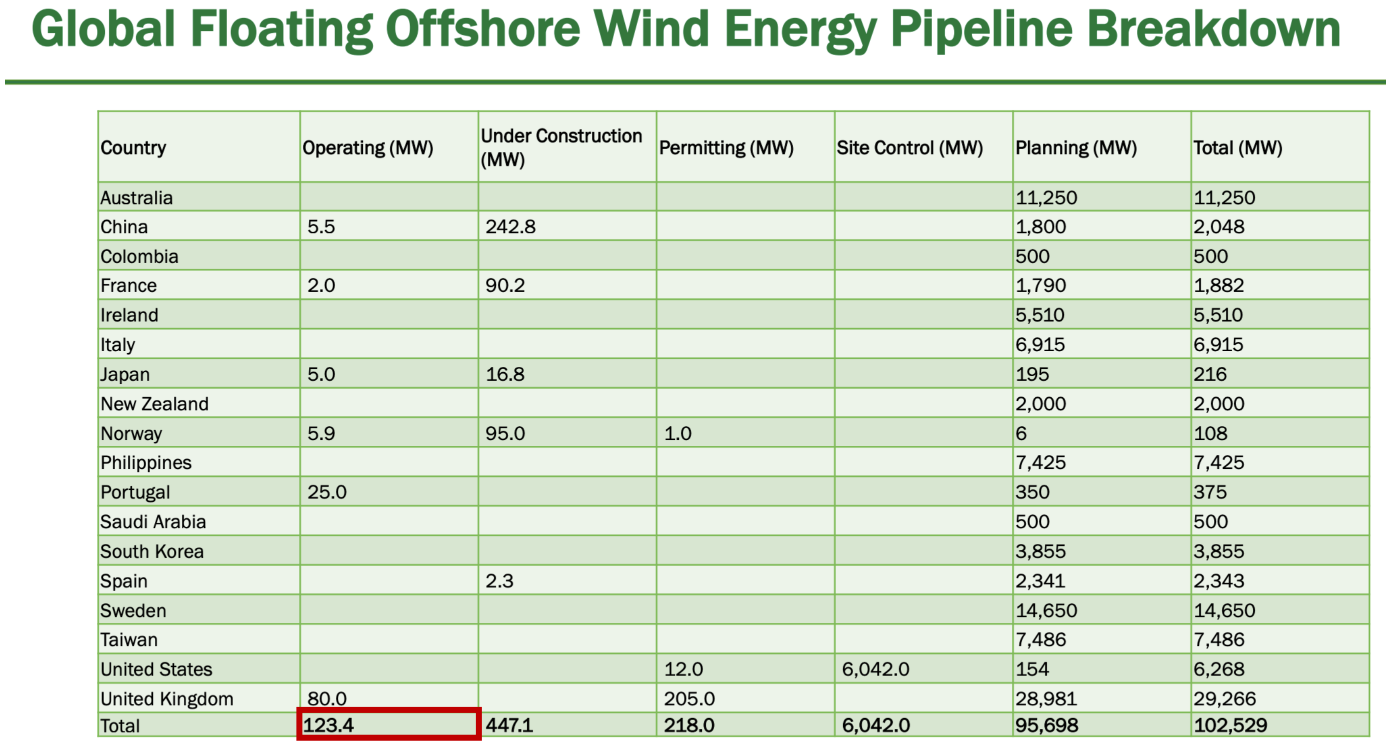
- Fixed-bottom wind development in the U.S. started with several small pilot projects on the east coast.
  - Block Island Wind Farm, a 30 MW demonstration project completed in 2016, was the first commercial offshore wind project in the U.S.
- Some projects will begin with pilot deployments before deploying the full-scale project (e.g. Dominion Energy's 2,600 MW Central Virginia Offshore Wind that began with a 12 MW pilot).
- The CADEMO Offshore Wind Demonstration Project in California is a floating offshore wind demonstration project being developed by Floventis on a local military base. The project has a planned COD of 2026/2027.
- The Aqua Ventus pilot project is a 11 MW floating offshore wind pilot project off the coast of Maine planned to start construction as early as 2024.



Project	Developer	Type	Status	Location	Size (MW)
Block Island Wind Farm	Orsted	Fixed-Bottom	Operational	RI	30
Coastal Virginia Offshore Wind Project	Dominion	Fixed-Bottom	Operational	VA	12
CADEMO	Floventis	Floating	Planned	CA	60
Aqua Ventus	Diamond Offshore Wind	Floating	Planned	ME	11
Icebreaker Wind	LEEDCo	Fixed-Bottom	Cancelled	OH	21

Overview of Floating Offshore Wind

- The state of the art for floating offshore wind projects deployed globally to date have been pilot or small-scale projects (most under 30 MW).
- There are 2 floating offshore wind pilots in the U.S. currently planned – an 11 MW project in Maine starting construction in 2024 and a 60 MW project in California with a targeted 2026/2027 COD.



Global Floating Offshore Wind Energy Pipeline Breakdown

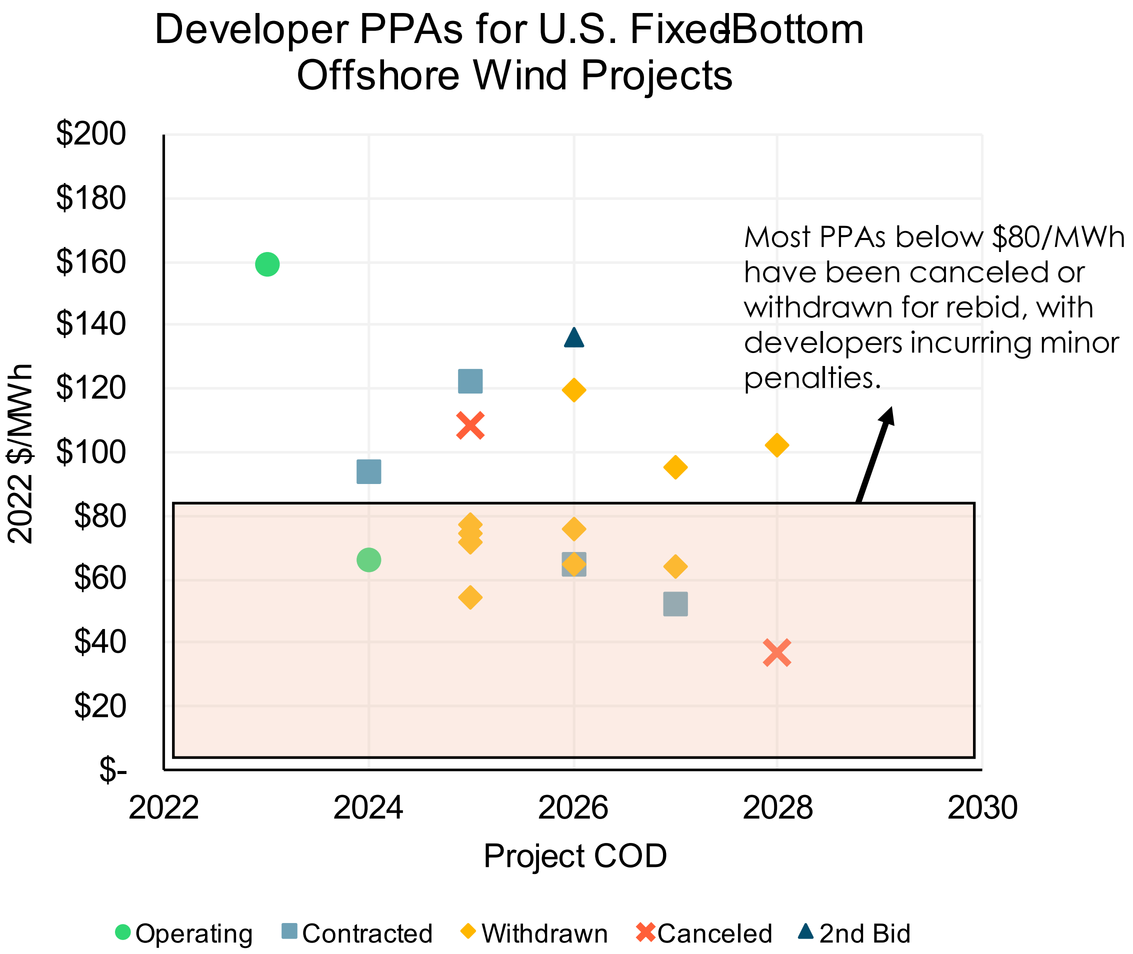
Country	Operating (MW)	Under Construction (MW)	Permitting (MW)	Site Control (MW)	Planning (MW)	Total (MW)
Australia					11,250	11,250
China	5.5	242.8			1,800	2,048
Colombia					500	500
France	2.0	90.2			1,790	1,882
Ireland					5,510	5,510
Italy					6,915	6,915
Japan	5.0	16.8			195	216
New Zealand					2,000	2,000
Norway	5.9	95.0	1.0		6	108
Philippines					7,425	7,425
Portugal	25.0				350	375
Saudi Arabia					500	500
South Korea					3,855	3,855
Spain		2.3			2,341	2,343
Sweden					14,650	14,650
Taiwan					7,486	7,486
United States			12.0	6,042.0	154	6,268
United Kingdom	80.0		205.0		28,981	29,266
Total	123.4	447.1	218.0	6,042.0	95,698	102,529

Only ~125 MW of operating floating offshore wind globally today

Source: DOE's Offshore Wind Market Report: 2023 Edition report, available: https://www.energy.gov/sites/default/files/2023-08/offshore-wind-market-report-2023-edition-summary.pdf

Trends and Challenges for East Coast Offshore Wind

- PPAs for many fixed-bottom offshore wind projects on the east coast of the U.S. are being renegotiated or canceled due to rising costs from:
  - Interest rates
  - Supply chain complications
  - Inflation
- Market is showing it likely cannot sustain $50-$80/MWh bids that were submitted over past several years.
- The market price for fixed-bottom offshore wind PPAs is roughly $80-$120/MWh.

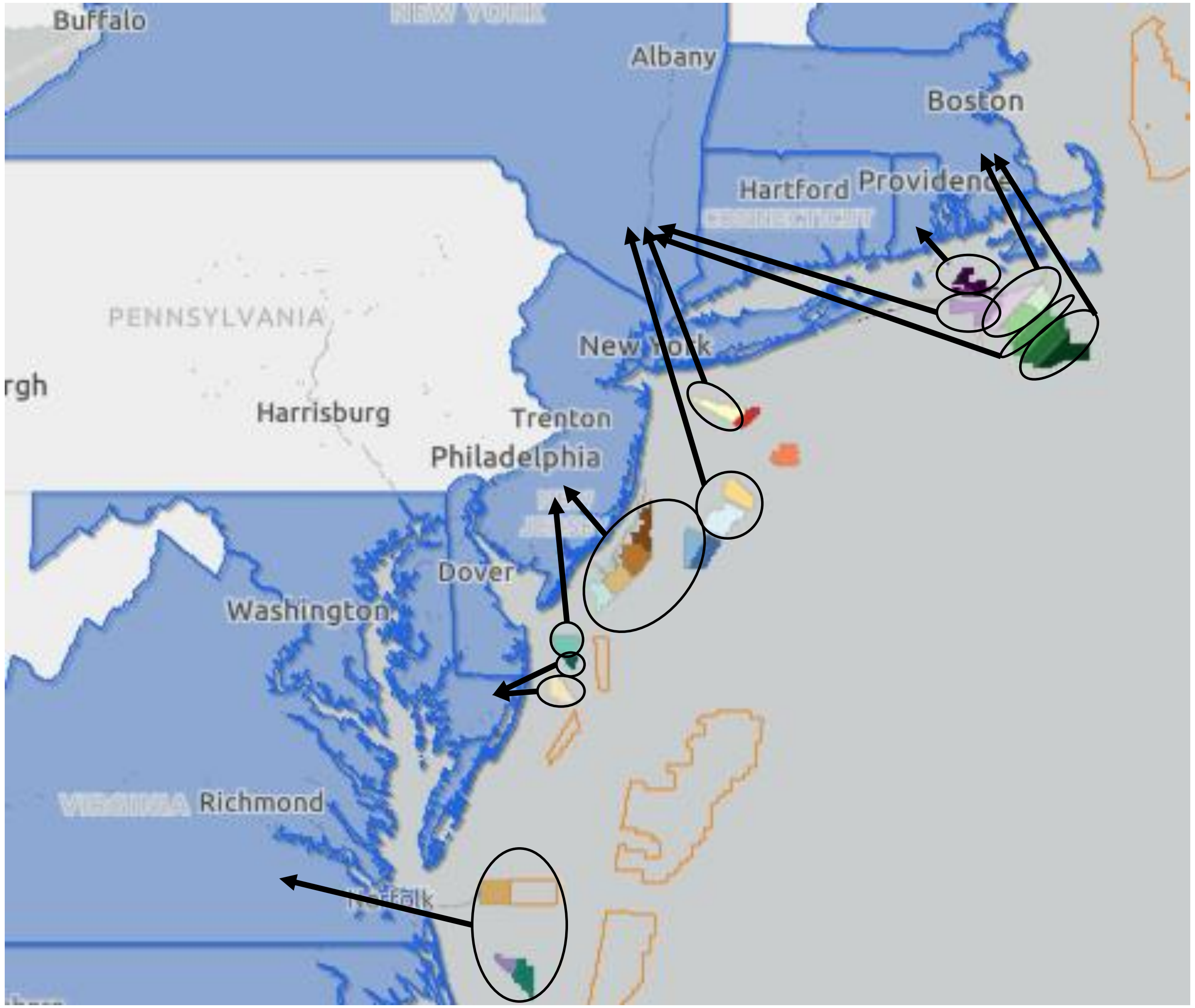


Most PPAs below $80/MWh have been canceled or withdrawn for rebid, with developers incurring minor penalties.

Offshore Wind Procurement and Development Processes Outside CA

- East coast states have issued several rounds of solicitations for fixed-bottom offshore wind over the past several years.
  - Many of these solicitations have instituted price caps beyond which offshore wind will not be procured.
  - Several states (NY, NJ) have considered non-price criteria (such as economic impacts, project viability, environmental impacts) in addition to price criteria in bid evaluation.
  - As projects have faced cost increases due to macroeconomic and supply chain challenges, many developers have sought renegotiations for projects to maintain financial viability. State procurement agencies have been largely unwilling to renegotiate existing contracts and have instead directed projects to bid in future solicitations.
    - States such as NY have accelerated future solicitations once a project is cancelled.
    - Virginia regulators approved a 50/50 cost-sharing mechanism for construction cost overruns between the project developer (Dominion Energy) and ratepayers.
- A number of full-scale projects on the east coast started with pilot projects before scaling up.
  - Maine has referred to this as a “1-10-100” approach of building out 1, 10, and then 100 turbines.

Interconnection Points of East Coast BOEM Leases



- BOEM leases federal land to developers.
- Developers choose which state to bid into based on economic, political, and interconnection factors.
- Some adjacent leases have bid into different states.
- Leases can be held by joint groups of developers, who then develop the project together (i.e. Equinor/BP, Orsted/Shell).

Contract Types in East Coast Offshore Wind Procurement

Contract Type	Description	Jurisdictions Using Contract Type	Pros	Cons
Offshore wind Renewable Energy Certificate (OREC)	Contracts for **environmental attributes only** of electricity generation that can be used to comply with clean energy requirements/targets	NY, NJ, MD	Risks of project are shared across developer and ratepayers	Higher cost of capital due to higher developer risk (from greater revenue uncertainty)
Power Purchase Agreements (PPAs)	Long-term contracts with a pre-specified price for bundled **power and environmental attributes** from electricity generation	MA, RI, CT	Lower cost of capital due to lower developer risk (from greater revenue certainty)	Higher amount of risk on ratepayers
Utility-owned generation (UOG)	Once a developer has completed development of a project, **ownership is transferred to a regulated utility**	VA	Low cost of capital since utility investments can be rate-based	Dependent on utility willingness and proficiency at owning and potentially operating the project

Summary of Recently Completed Procurements

State	Procurement Structure	Procurement Entity	Most Recent Round (Solicitation Year/Year Awarded)	# of bidders	MW Awarded	Online Date	Time from Solicitation to Online Date	Contract Structure
NY	Centralized	NYSERDA	Round 4 (2023/2024)	6	1,734	2026 / 2027	2-3 years*	OREC
NY	Centralized	NYSERDA	Round 3 (2022/2023)	6	4,000	2030	8 years	OREC
NJ	Centralized	Board of Public Utilities	Round 2 (2020/2021)	Not disclosed	2,700	n/a	10 years	OREC
MA	Joint IOU procurement led by state	Dept. of Energy Resources, IOUs	Round 3 (2021/2022)	2	1,600	2030	9 years	PPA
MD	Centralized	Public Service Commission	Round 2 (2020/2022)	Not disclosed	1,200	2030	10 years	OREC

Projects were originally contracted in 2019, cancelled in 2023, and contracted again in 2024

Summary of Ongoing Procurements

State	Procurement Structure	Procurement Entity	Procurement Round Closing	Expected Awards (MW)	Online Date	Time from Solicitation to Target COD	Contract Structure
MA	Multi-state coordination	Dept. of Energy Resources, IOUs	March 2024*	3,600	2032	8 years	PPA
RI	Multi-state coordination	Rhode Island Office of Energy Resources (OER)	March 2024*	1,200	n/a	n/a	PPA
CT	Multi-state coordination	Connecticut Department of Energy & Environmental Protection (DEEP)	March 2024*	2,000	2033*	9 years	PPA
NY**	Centralized	NYSERDA	TBD	TBD	TBD	TBD	TBD

** MA, RI, and CT decided on Jan 18, 2024 to extend the bidding process from January 2024 until March 2024 to allow bidders to incorporate unreleased Treasury IRA guidance into their proposals*
*** Solicitation has been announced but specifics not yet released*

**Before December 31, 2032*

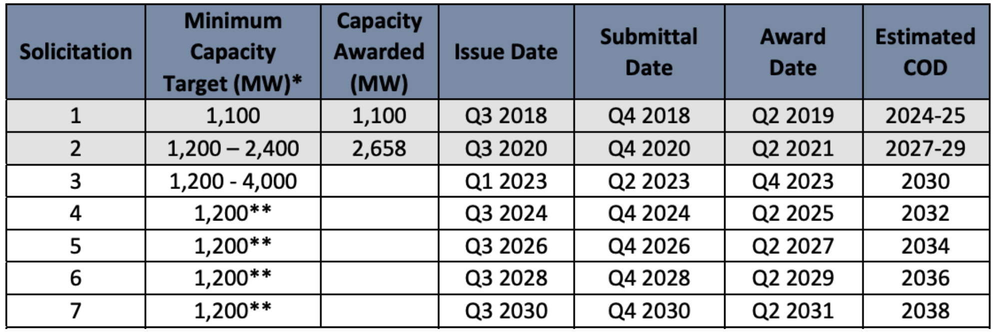
Offshore Wind Procurement Processes – New York

- The New York State Energy Research & Development Authority (NYSERDA) issued a fourth solicitation to procure Offshore Wind Renewable Energy Credits (ORECs) in November 2023 and announced the award of two contracts for 1,734 MW in February 2024
  - The two contracts awarded were for projects originally awarded in 2019 but those contracts were cancelled in 2023
- NYSERDA announced in April 2024 that projects awarded contracts in its third solicitation in 2022/2023 were cancelled due to technical challenges
- As a result of the cancelled projects, NYSERDA announced plans to expedite a fifth solicitation in summer 2024
  - NYSERDA had also expedited its fourth solicitation following project cancellations. In its fourth solicitation, NYSERDA had encouraged projects that had previously cancelled to resubmit. NYSERDA had also streamlined the solicitation process by removing bid requirements that required substantial effort from developers to meet
- Previous solicitations:
  - Solicitation 1 (2018 – 2019): 4 proposals, 2 were awarded (816 MW Empire Wind 1, 880 MW Sunrise Wind)
  - Solicitation 2 (2020 - 2022): 3 proposals, 2 were awarded (1,260 MW Empire Wind 2, 1,230 MW Beacon Wind)
  - Solicitation 3* (2022 – 2024): 6 proposals, 3 were awarded (1,404 MW Attentive Energy One, 1,314 MW Community Offshore Wind, 1,314 MW Excelsior Wind)
- Proposals are evaluated with a weighting of 70% price considerations and 30% non-price considerations
  - 20% of non-price considerations are economic impacts to New Yorkers, which include in-state expenses for labor, goods, and services, interconnection to NYISO, and long-term capital investments in infrastructure and workforce development.
  - 10% of non-price considerations are project viability, which includes a reasonable timeline, technical and logistical feasibility, experience in similar projects, financial commitment, interconnection planning, and environmental mitigation.
- NYSERDA has a confidential OREC benchmark beyond which projects are not considered

**Solicitation 3 are estimated to be executed in Q1 2024, so are not included in analysis on current projects.*

Offshore Wind Procurement Processes – New Jersey

- The New Jersey Board of Public Utilities issued its latest offshore wind solicitation in March 2023 with two awards approved in January 2024.
- Proposals were evaluated with a weighting of 70% price/ratepayer impact considerations and 30% non-price considerations.
  - Non-price considerations included economic impacts and environmental and fisheries impact.
    - Economic impacts includes in-state increases in wages, taxes, in-state expenditures, State gross product, and job creation.
      - Indirect and induced economic effects are weighted 50% and 40% lower than direct effects, respectively.
    - Environmental and fisheries impact considers the proposal's avoidance, minimization, and mitigation of onshore and offshore impacts to land, communities, environmentally and culturally sensitive areas, and commercial and recreational fishing. Net reduction of pollutants is also considered.
  - Project viability was considered in determining proposal eligibility but was not reflected quantitatively.



Solicitation	Minimum Capacity Target (MW)*	Capacity Awarded (MW)	Issue Date	Submittal Date	Award Date	Estimated COD
1	1,100	1,100	Q3 2018	Q4 2018	Q2 2019	2024-25
2	1,200 – 2,400	2,658	Q3 2020	Q4 2020	Q2 2021	2027-29
3	1,200 - 4,000		Q1 2023	Q2 2023	Q4 2023	2030
4	1,200**		Q3 2024	Q4 2024	Q2 2025	2032
5	1,200**		Q3 2026	Q4 2026	Q2 2027	2034
6	1,200**		Q3 2028	Q4 2028	Q2 2029	2036
7	1,200**		Q3 2030	Q4 2030	Q2 2031	2038

Offshore Wind Procurement Processes – Maryland and Massachusetts

- Maryland's latest RFP that closed January 1, 2022 sought up to 2,400 MW OSW by 2030
  - Maryland's evaluation criteria included ratepayer impacts, in-state economic benefits, environmental benefits, and other qualitative factors (such as small business and minority ownership).
  - The RFP set an OREC cap at $190/MWh (in $2012) and a residential rate impact cap at $0.88/month (in $2018).

- The Massachusetts Department of Energy Resources and several IOUs jointly issued an RFP for offshore wind in August 2023.
  - In this RFP, Massachusetts eliminated its requirement for each successive round of offshore wind procurement to be cheaper than preceding rounds in 2022.
  - The new RFP allows "alternative indexed pricing proposals", which allows an indexing adjustment up to 15% based on a set of macroeconomic and commodity indices one year after the long-term contract approval.
  - In its latest RFP from August 2023, the total offshore wind energy generation price was uncapped but price requirements for RECs were specified.
    - RECs must be no less than 35% of the total energy generation price and RECs are capped at $40/MWh.

Offshore Wind Procurement Processes – Maine

- In June 2019, the Governor signed a law (LD 994) that required the state PUC to approve the contract for a pilot floating offshore wind project.
    - A 2009 law had required the PUC to conduct a competitive solicitation for proposals for deep-water offshore wind or tidal energy pilot projects.
    - Aqua Ventus, a partnership led by the University of Maine, had been selected from the competitive solicitation in 2014.
    - A final contract between Aqua Ventus , the PUC, and Central Maine Power Company was filed in 2017.
    - Following several PUC procedural delays, the Legislature issued the law in 2019 finding that it was in the best interest of the State to approve the Aqua Ventus/PUC contract and declared an emergency in order to require that the PUC approve the contract.

Offshore Wind Procurement Processes – Virginia

- In 2020, the Virginia legislature passed the Virginia Clean Economy Act (VCEA), requiring Dominion Energy to develop 5,200 MW of OSW by January 1, 2034
- Dominion had the 2,600 MW Coastal Virginia Offshore Wind (CVOW) project approved in fall 2023 and is estimated to begin operating in 2026
  - CVOW had started with a 12 MW pilot that began operations in 2020
- Approval for CVOW included a mandate that if the project did not achieve at least a 42% capacity factor, Dominion would be responsible for replacement energy costs
    - Dominion has pushed back on this mandate, citing variables beyond its control such as weather. The State Corporation Commission (SCC) is currently reconsidering this mandate
- A settlement on construction cost overruns was reached in which Dominion pays 50% and ratepayers pay 50% of cost overruns (up to a certain threshold, beyond which the SCC will reevaluate the cost recovery structure)

Offshore Wind Procurement Processes – United Kingdom

- The UK has a contract-for-differences (CfD) scheme that provides developers a fixed price (“strike price”) for a 15-year contract
  - The UK has held solicitations (called “Allocation Rounds”) annually, with different rules depending on the technology the government wants to encourage
  - The government had gradually lowered the maximum strike price for offshore wind in each successive Allocation Round until the fifth round in 2024. In the fifth round, the maximum strike price for floating offshore wind is increasing from 116 GBP/MWh ($148/MWh equivalent) to 176 GBP/MWh ($224/MWh equivalent)

Case Study: Ørsted Offshore Wind Project Cancellations

Cancellations of Ocean Wind I and II, Sunrise Wind (may be rebid)

Factor	Cause	Description
Supply Chain Challenges	**COVID**	COVID disrupted supply chain processes, increased risk of suppliers being unable to deliver.
	OSW / Clean Energy Goals	Increases in demand for offshore wind due to state and utility targets have led to price increases of turbine components, transmission equipment, and vessels.
	Ukraine War	Fossil fuel price shocks in Europe due to supply shortages from the Ukraine war have led to increased demand (and subsequently, costs) for renewable energy, including offshore wind
Cost Increases and Macroeconomic Factors	**Inflation**	Inflation increased significantly after Sunrise was bid in 2021, leading to higher-than-expected project development costs
	Interest Rates	Higher interest rates have led to higher WACCs and higher costs of capital
Permitting and Interconnection	**Federal Permitting**	The Trump administration had instituted an offshore wind permit moratorium from 2019-2021. Permitting delays such as these can increase project costs, delay revenues, and increase vulnerability to other macroeconomic impacts (inflation)
Policies	**ITC Adder Eligibility**	New Treasury guidance on 10% ITC adders (on top of base 30% ITC) for domestic content and energy communities reduced the probability that Ocean Winds would receive ITC adder
	Rebidding	Ørsted requested a 23% increase in offshore wind REC (OREC) prices for Sunrise Wind in line with construction costs. NYSERDA rejected the petition due to ratepayer impacts and to preserve competitive bidding practices. Ørsted might re-bid this project in NYSERDA’s next RFP.

Supply Chain Risks

- Supply chain risks have been increased due to a combination of **supply chain disruptions** of necessary equipment and components and **increased demand** for offshore wind.
  - Supply chains were disrupted due to impact of COVID on manufacturing and trade.
  - Clean energy targets and the Russia-Ukraine War have both led to increases in demand for renewable energy, including offshore wind.
- Supply chain challenges create an **increased risk of on-time execution of projects** due to challenges of obtaining necessary components and equipment and projects seeking renegotiations or facing cancellation due to higher-than-expected project costs.
- Delays introduced by supply chain challenges further expose projects to macroeconomic risks, such as inflation and high interest rates (additional detail in subsequent slide) and impede revenue streams.
- Fixed-bottom projects have adapted installation approaches to have longer construction timelines but lower supply chain risks.

Cost Increases and Macroeconomic Factors

- Macroeconomic impacts such as inflation and high interest rates have led to increased project costs over the past 1-2 years.
  - Most projects bid before 2023 used a 2% assumption for inflation; inflation was 5-8% in 2021 and 2022.
  - Interest rates increased by 40% (from 2.65% to 3.72%) between 2019 and 2023, leading to higher costs of capital.
- Although high offshore wind costs are likely to persist, the risk of high costs causing project delays/cancellations is likely to go down as developer bids start to reflect price increases.
- Some solicitations in east coast states, such as the most recent NYSERDA solicitations, link OREC pricing to economic indices to mitigate risk from changes in macroeconomic factors.

Federal Permitting Risk and Incentives

Federal Permitting Risk

- Very few projects advanced through the federal permitting process between 2019 and 2021, largely due to the Trump administration's environmental review of offshore wind.
- There is risk of similar federal permitting delays depending on future political climates that could lead to delays in on-time execution of projects.

Federal Incentives

- The Inflation Reduction Act (IRA) includes a 30% Investment Tax Credit (ITC) for all offshore wind projects.
- Projects may be eligible for 10% adders on top of the base 30% ITC depending on the project's domestic content and location within energy communities. The Treasury only just recently issued guidance on eligibility for ITC adders included in the IRA.
    - Developers cited uncertainty and unexpected ineligibility for ITC adders as reasons for project cancellations, but there is likely minimal ongoing risk of developer uncertainty or miscalculation of tax credit eligibility given guidance.

Appendix B

Market Transformation of Other Emerging Technologies

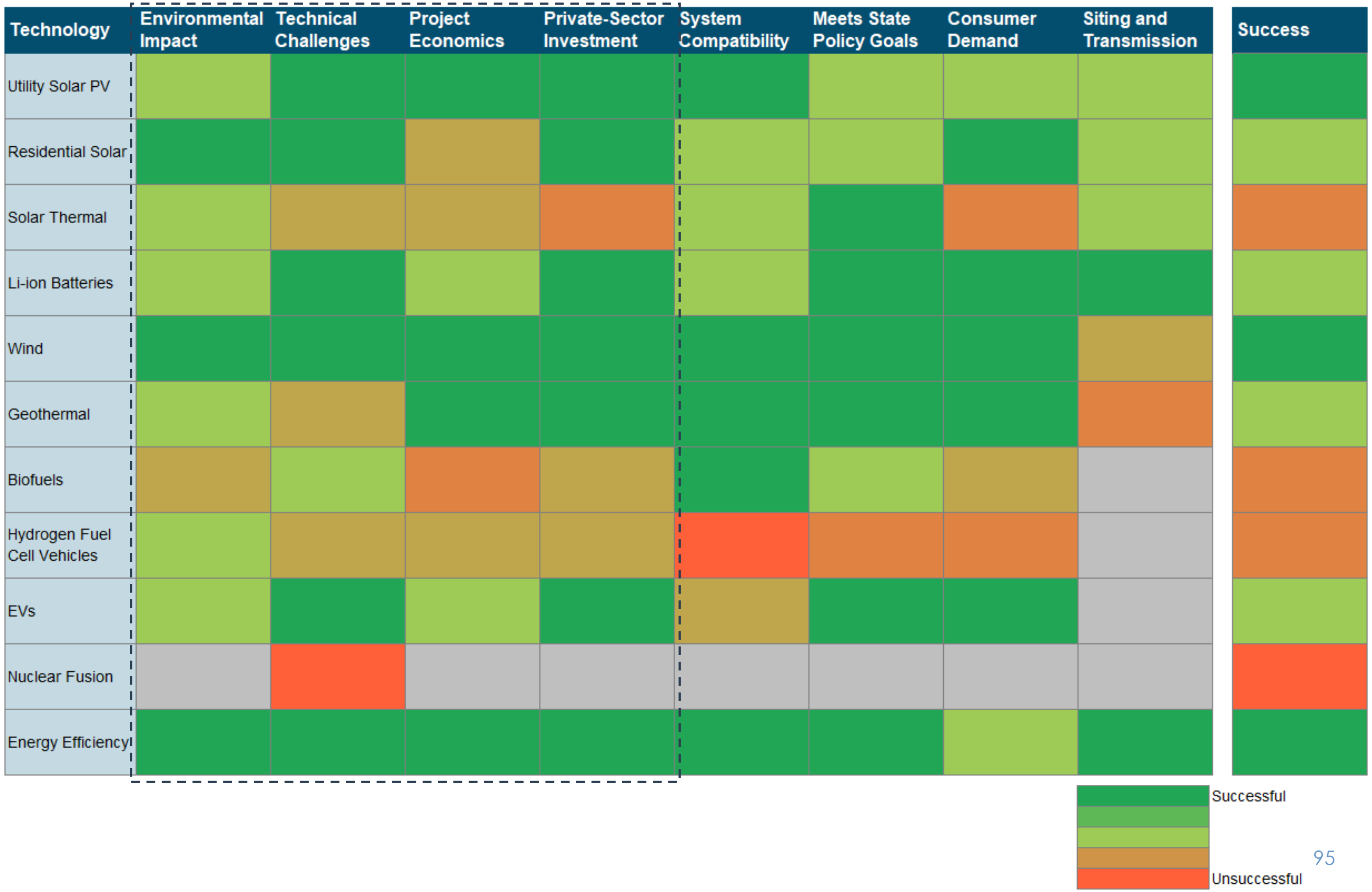
Predictors of Clean Energy Technology Success

Predictors of the ability for clean energy technologies to achieve cost declines with scale include:

1. **Government Policy:** supportive policy, such as mandates/procurement orders, financial incentives, or funding for research and development (R&D)
2. **Environmental Impact:** reduced environmental impact relative to other technology options
3. **Technical Challenges:** challenges associated with the construction and/or operation of the technology
4. **Project Economics:** cost-effectiveness of technology
5. **Private-Sector Investment:** investment from venture capitalists, large corporations, and/or developers/financiers
6. **System Compatibility:** ability for technology to integrate and operate with existing systems
7. **Meets State Policy Goals:** technology supports compliance with state goals/targets
8. **Consumer Demand:** public interest in the buildout and success of technology
9. **Siting and Transmission Barriers:** location-based obstacles to deployment

Success of Emerging Technologies Is Driven by Several Key Factors

- **Government policy** can be a prerequisite to encourage early R&D, demonstration projects, and incentives for early adoption
- Successful emerging technologies have demonstrated **positive environmental impact**, the ability to overcome **technical challenges** and other barriers to commercialization

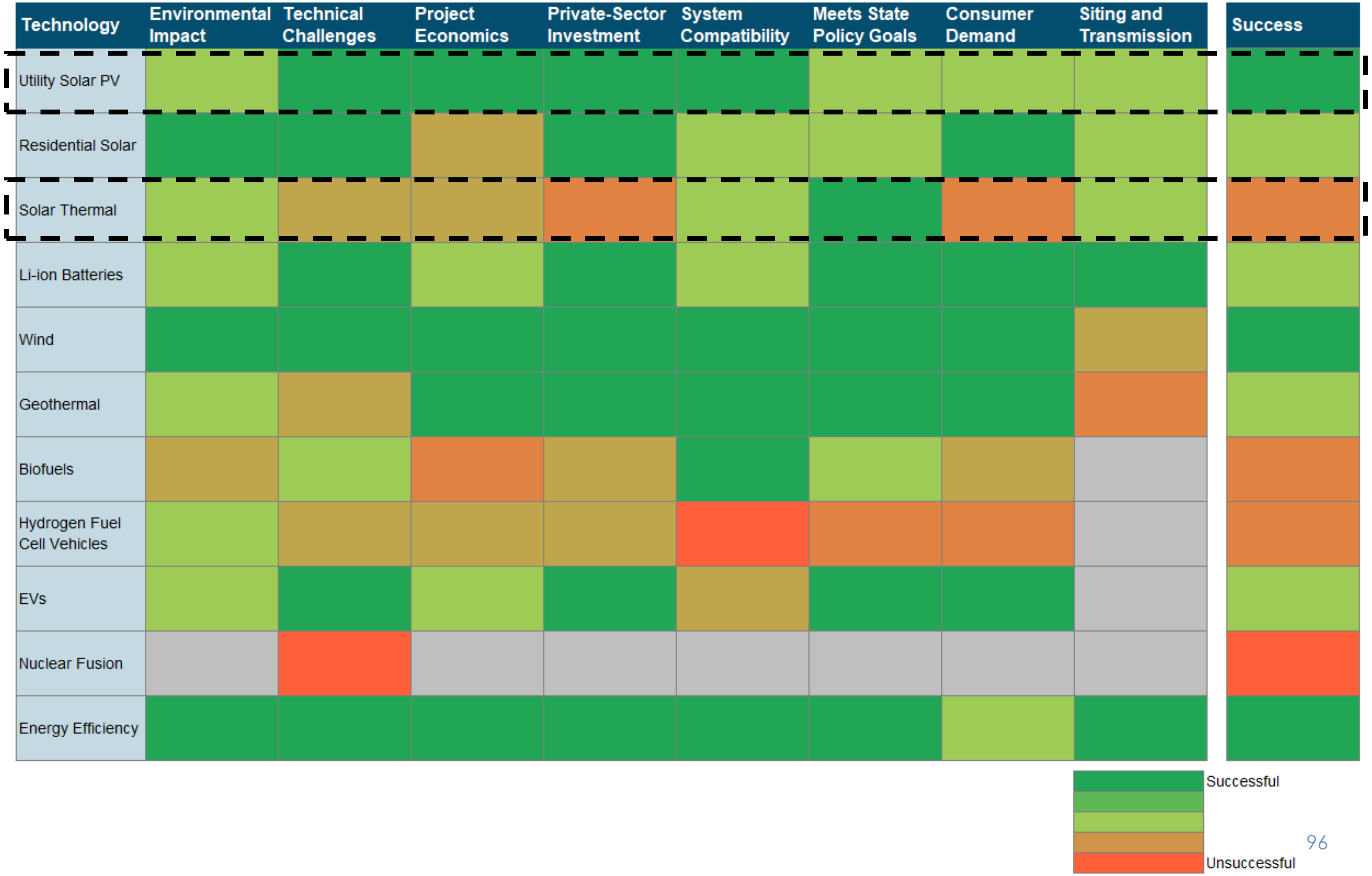


Technology	Environmental Impact	Technical Challenges	Project Economics	Private-Sector Investment	System Compatibility	Meets State Policy Goals	Consumer Demand	Siting and Transmission	Success
Utility Solar PV	🟨	🟩	🟩	🟩	🟩	🟨	🟨	🟨	🟩
Residential Solar	🟩	🟩	🟫	🟩	🟨	🟨	🟩	🟨	🟨
Solar Thermal	🟨	🟫	🟫	🟧	🟨	🟩	🟧	🟨	🟧
Li-ion Batteries	🟨	🟩	🟨	🟩	🟨	🟩	🟩	🟩	🟨
Wind	🟩	🟩	🟩	🟩	🟩	🟩	🟩	🟫	🟩
Geothermal	🟨	🟫	🟩	🟩	🟩	🟩	🟩	🟧	🟨
Biofuels	🟫	🟨	🟧	🟫	🟩	🟨	🟫	⬜	🟧
Hydrogen Fuel Cell Vehicles	🟨	🟫	🟫	🟫	🟥	🟧	🟧	⬜	🟧
EVs	🟨	🟩	🟨	🟩	🟫	🟩	🟩	⬜	🟨
Nuclear Fusion	⬜	🟥	⬜	⬜	⬜	⬜	⬜	⬜	🟥
Energy Efficiency	🟩	🟩	🟩	🟩	🟩	🟩	🟨	🟩	🟩

🟩 Successful
🟩
🟨
🟫
🟥 Unsuccessful

Solar PV vs. Solar Thermal

- Solar PV:
  - Strong government support for R&D, manufacturing (in China), and financing
  - Technical challenges well understood and overcome
  - Falling costs through 2010s spurred strong private-sector investment and favorable project economics
- Solar Thermal:
  - Ongoing technical challenges with heating fluid
  - High costs (without major declines seen in PV prices) and unforced outages
  - Limited investor appetite

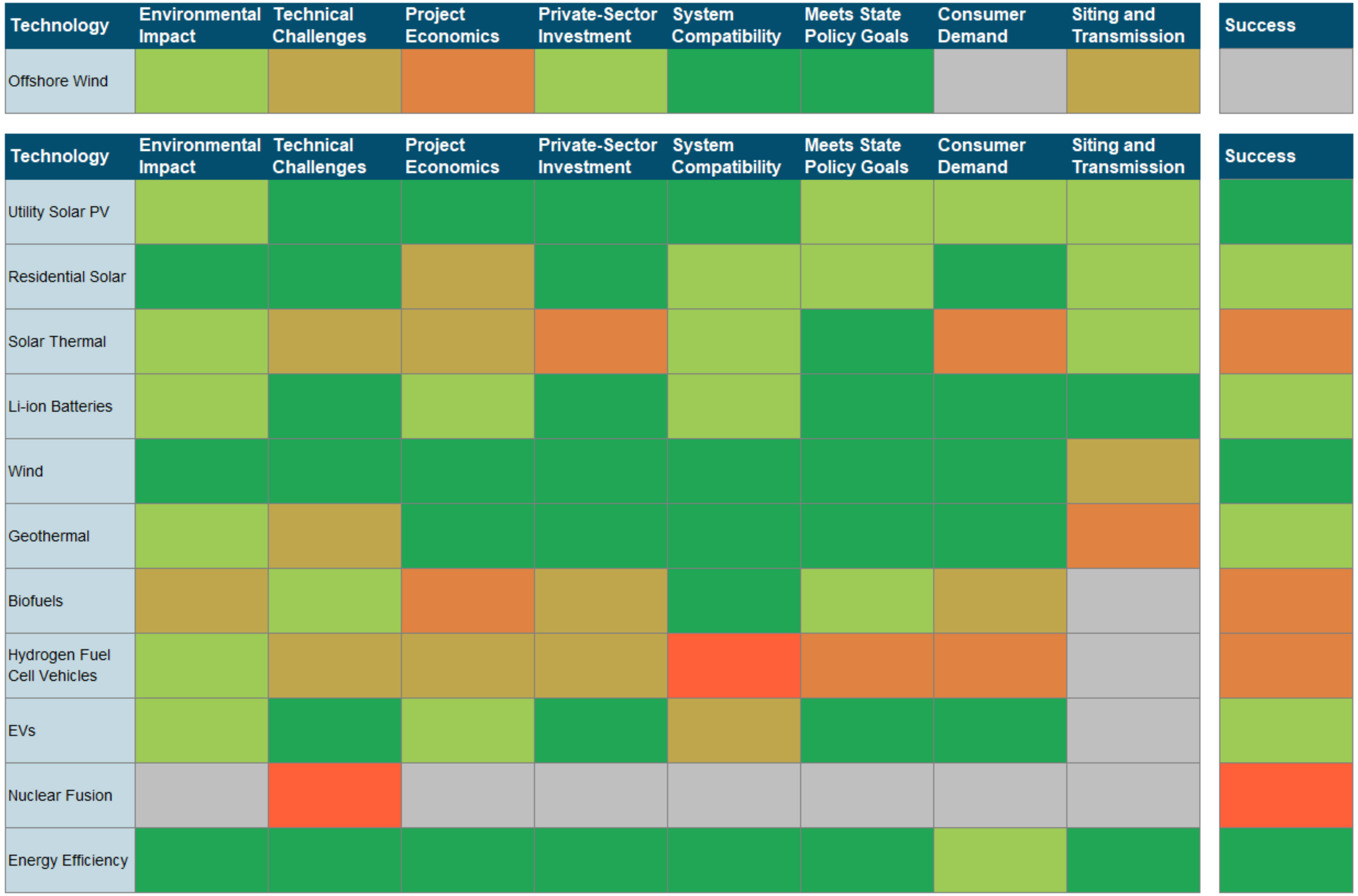


Technology	Environmental Impact	Technical Challenges	Project Economics	Private-Sector Investment	System Compatibility	Meets State Policy Goals	Consumer Demand	Siting and Transmission	Success
Utility Solar PV	🟨	🟩	🟩	🟩	🟩	🟨	🟨	🟨	🟩
Residential Solar	🟩	🟩	🟫	🟩	🟨	🟨	🟩	🟨	🟨
Solar Thermal	🟨	🟫	🟫	🟧	🟨	🟩	🟧	🟨	🟧
Li-ion Batteries	🟨	🟩	🟨	🟩	🟨	🟩	🟩	🟩	🟨
Wind	🟩	🟩	🟩	🟩	🟩	🟩	🟩	🟫	🟩
Geothermal	🟨	🟫	🟩	🟩	🟩	🟩	🟩	🟧	🟨
Biofuels	🟫	🟨	🟧	🟫	🟩	🟨	🟫	⬜	🟧
Hydrogen Fuel Cell Vehicles	🟨	🟫	🟫	🟫	🟥	🟧	🟧	⬜	🟧
EVs	🟨	🟩	🟨	🟩	🟫	🟩	🟩	⬜	🟨
Nuclear Fusion	⬜	🟥	⬜	⬜	⬜	⬜	⬜	⬜	🟥
Energy Efficiency	🟩	🟩	🟩	🟩	🟩	🟩	🟨	🟩	🟩

🟩 Successful
🟩
🟨
🟫
🟥 Unsuccessful

Application to Floating Offshore Wind

- **Technical Challenges**
  - Floating platforms and undersea cabling
  - Port and vessel infrastructure in California
- **Project Economics**
  - Supply chain issues, rising interest rates, inflation
- **Siting and Transmission**
  - Uncertainty over procurement strategy muddles delivery pathways
- **Government Policy**
  - CPUC can spur market growth via solicitations for floating offshore wind



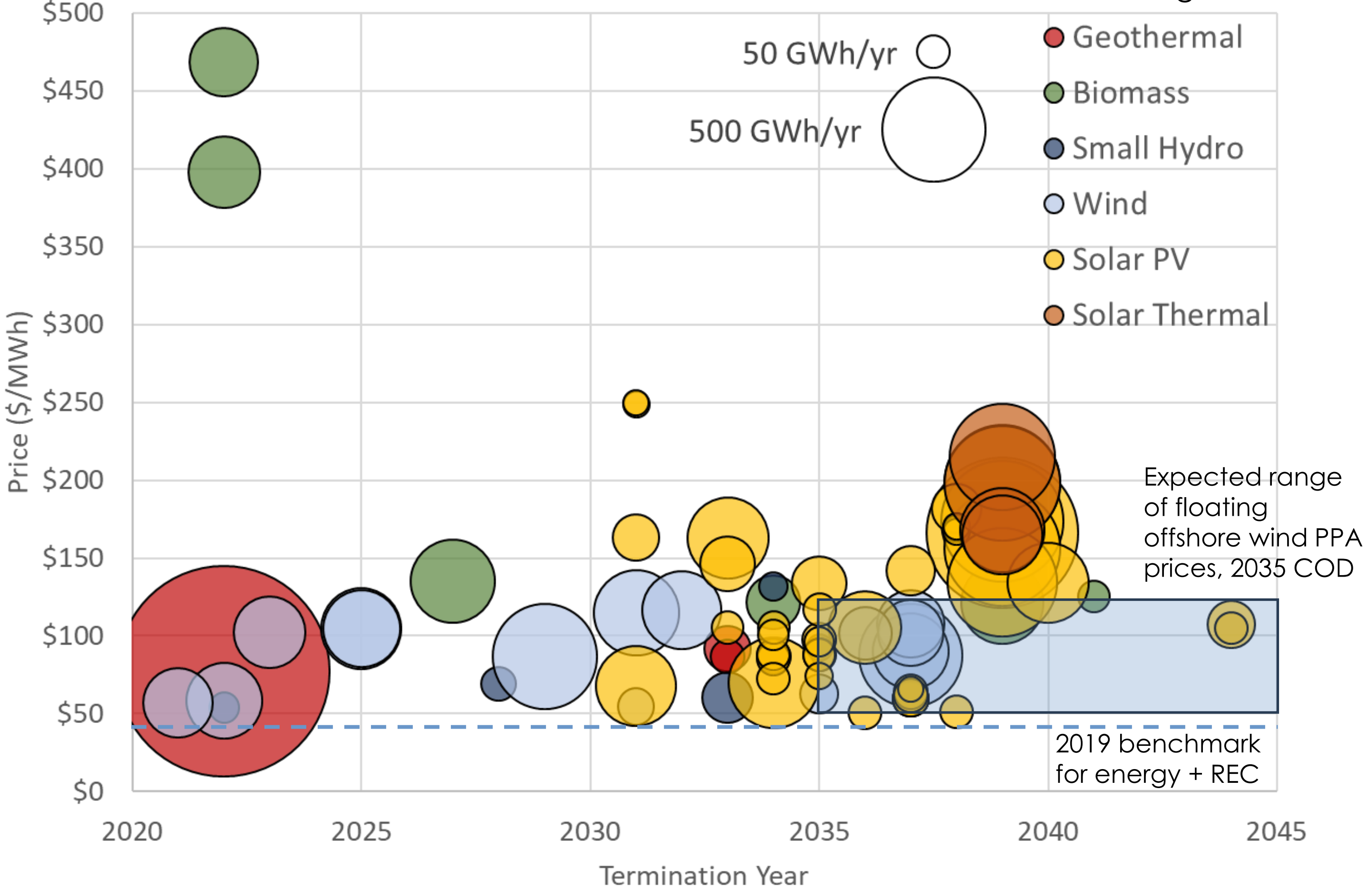
Technology	Environmental Impact	Technical Challenges	Project Economics	Private-Sector Investment	System Compatibility	Meets State Policy Goals	Consumer Demand	Siting and Transmission	Success
Offshore Wind	🟢	🟨	🟧	🟢	🟩	🟩	⬜	🟨	⬜

Technology	Environmental Impact	Technical Challenges	Project Economics	Private-Sector Investment	System Compatibility	Meets State Policy Goals	Consumer Demand	Siting and Transmission	Success
Utility Solar PV	🟢	🟩	🟩	🟩	🟩	🟢	🟢	🟢	🟩
Residential Solar	🟩	🟩	🟨	🟩	🟢	🟢	🟩	🟢	🟢
Solar Thermal	🟢	🟨	🟨	🟧	🟢	🟩	🟧	🟢	🟧
Li-ion Batteries	🟢	🟩	🟢	🟩	🟢	🟩	🟩	🟩	🟢
Wind	🟩	🟩	🟩	🟩	🟩	🟩	🟩	🟨	🟩
Geothermal	🟢	🟨	🟩	🟩	🟩	🟩	🟩	🟧	🟢
Biofuels	🟨	🟢	🟧	🟨	🟩	🟢	🟨	⬜	🟧
Hydrogen Fuel Cell Vehicles	🟢	🟨	🟨	🟨	🟥	🟧	🟧	⬜	🟧
EVs	🟢	🟩	🟢	🟩	🟨	🟩	🟩	⬜	🟢
Nuclear Fusion	⬜	🟥	⬜	⬜	⬜	⬜	⬜	⬜	🟥
Energy Efficiency	🟩	🟩	🟩	🟩	🟩	🟩	🟢	🟩	🟩

Past above market procurement helped to scale California's RPS market

- CA has taken risks on emerging technologies in the past, signing long-term PPA contracts at above-market rates to encourage adoption of new technologies.

Source: S&P Global Market Intelligence



*18,000 GWh/y of contracts. Does not include 1,900 GWh/y of contracts with missing prices and 600 GWh/y of smallest contracts

Appendix C

Modeling Inputs

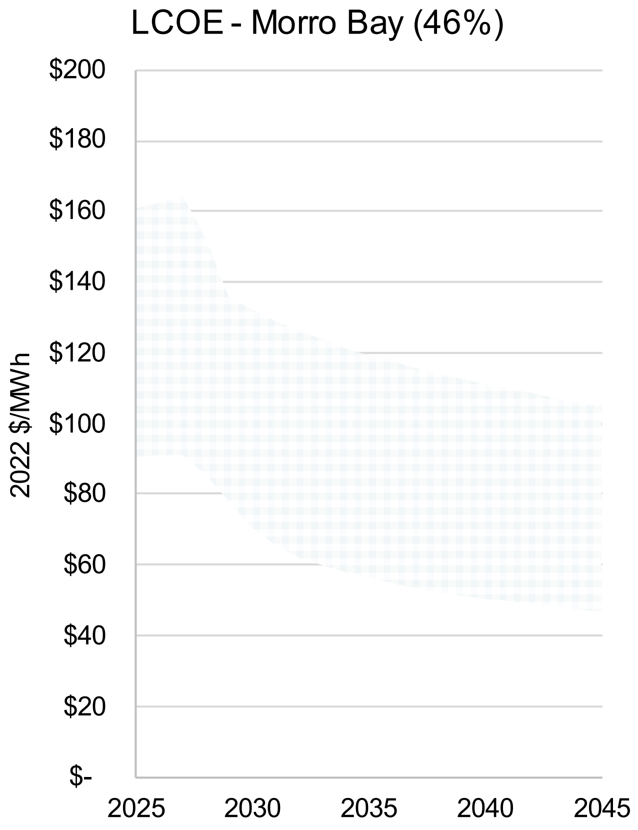
Offshore Wind Resource Cost Literature Review

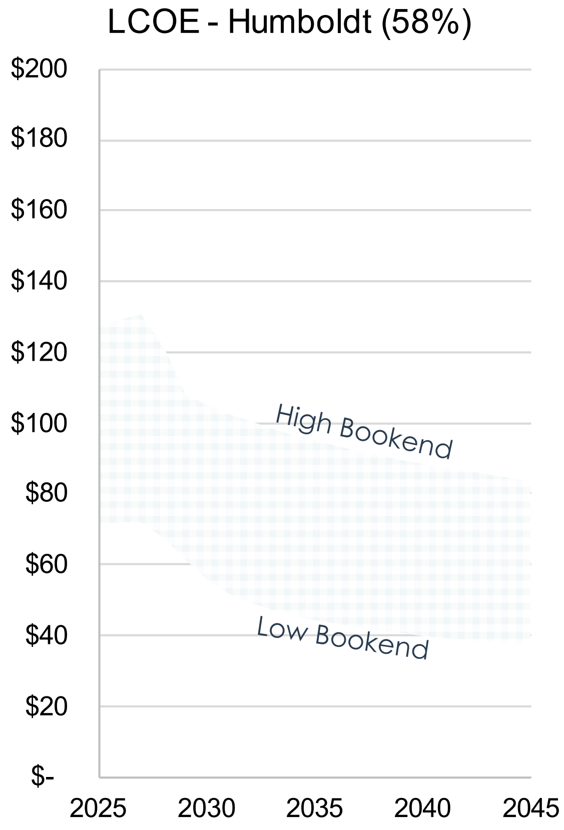
- NREL 2023 ATB. https://atb.nrel.gov/electricity/2023/offshore_wind.
- Beiter, P. et. al. “The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032”. NREL, 2020. https://www.nrel.gov/docs/fy21osti/77384.pdf.
- “Northern California and Southern Oregon Offshore Wind Transmission Study”. Schatz Energy Research Center, 2023. https://schatzcenter.org/pubs/2023-OSW-R2.pdf.
- Blackburne, A. “Analysts Rethink Floating Wind Forecasts as Growing Pains Multiply.” S&P Global Market Intelligence, 2023. https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/analysts-rethink-floating-wind-forecasts-as-growing-pains-multiply-78286784.
- Shields, M. et. al. “A Systematic Framework for Projecting the Future Cost of Offshore Wind Energy”. NREL, 2022. https://www.nrel.gov/docs/fy23osti/81819.pdf
    - NREL FORCE Model, cited by NREL ATB and Schatz

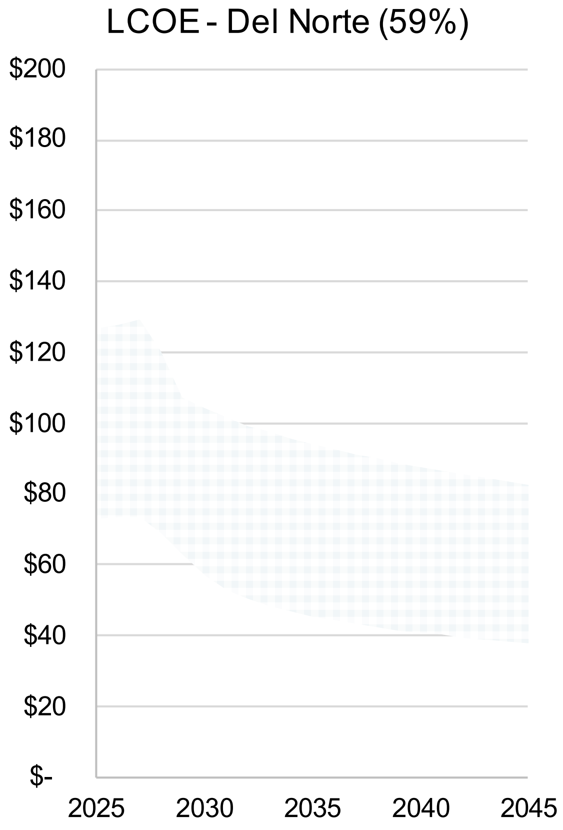
Stakeholder Comments Relating to Offshore Wind Resource Costs

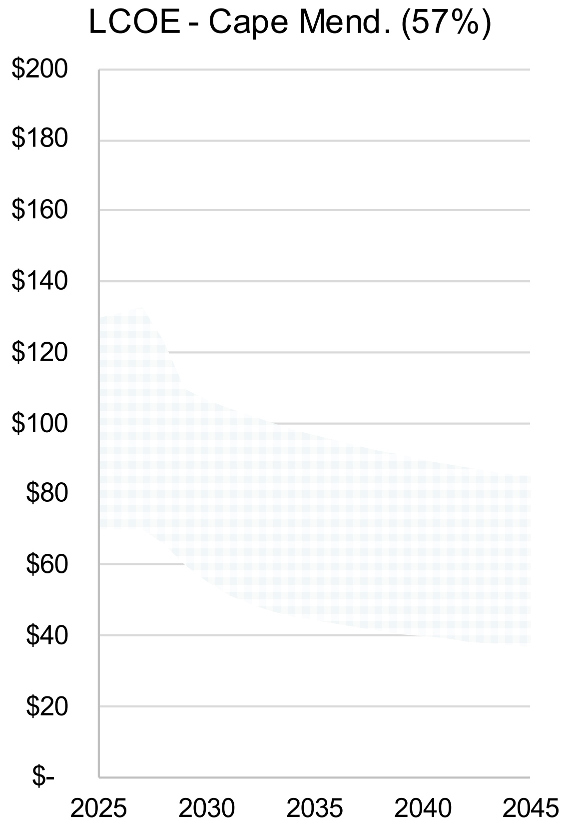
- Recent stakeholder comments have been varied around the inclusion of offshore wind in the PSP and TPP portfolios
- Some stakeholders argued that the current resource costs and the uncertainty around cost reductions made the resource an unfavorable one, and were comfortable with it being left out of the portfolio
- Other stakeholders questioned the cost updates, moving from the 2020 NREL study to higher costs based on the 2023 NREL ATB
    - This is because other competing resources had their costs go down due to IRA impacts, while the cost of offshore wind was increased; impacting the relative economics of offshore wind
    - Additionally, the modifications to the timing of the tax credits (which previously used to drop off after 2035 and was driving the selection of the resource early to benefit from the tax credits) was also impacting the relative economics
    - Some suggested running different cost sensitivities, including the 2020 NREL study and the 2023 NREL ATB trajectories
- Many stakeholders argued for the inclusion of the resource, regardless of whether it was selected in the least-cost portfolio or not. Rationale for this position included:
    - Preserving the consistency with previous TPP portfolios which included resources both at Morro Bay and Humboldt
    - Encouraging the CAISO and the state to plan for LLT transmission development needed to access North Coast resources
    - Highlighting the benefit of a high capacity factor resource like offshore wind in meeting California's clean energy goals
    - Aligning with California's planning goal of 25 GW of offshore wind deployment by 2045
    - Aligning with commercial interest in offshore wind

Levelized Cost of Electricity (No Transmission)


LCOE - Morro Bay (46%)


LCOE - Humboldt (58%)


LCOE - Del Norte (59%)


LCOE - Cape Mend. (57%)

Morro Bay capacity factor (46%) significantly below other sites (57-58%).
Capital costs are held flat through 2027 before following the cost trajectories from NREL ATB (2023 PSP).
Changing financial assumptions in the near-term result in slight increases to LCOE by 2027 before declining.

Offshore Wind Transmission Costs

- Data surveyed:
  - Beiter, P. et. al. “The Cost of Floating Offshore Wind Energy in California Between 2019 and 2032”. NREL, 2020. https://www.nrel.gov/docs/fy21osti/77384.pdf. (NREL 2020) **(*)**
    - Includes site-specific “Grid Connection Costs” for all five California floating offshore wind project sites
  - CAISO 2021-22 Transmission Plan (CAISO 2022) **(*)**
    - Includes limited selection of onshore and offshore transmission upgrade options for Morro Bay and Humboldt Bay; data extrapolated for Cape Mendocino and Del Norte
  - “Northern California and Southern Oregon Offshore Wind Transmission Study”. Schatz Energy Research Center, 2023. https://schatzcenter.org/pubs/2023-OSW-R2.pdf. (Schatz 2023)
    - Explores 3 procurement scenarios for Northern California offshore wind (excludes Morro Bay), and 12 interconnection alternatives among those scenarios
- E3 developed low/mid/high transmission cost sensitivities for North Coast offshore wind projects based on the Schatz 2023 study
  - Assumed $1.25 billion, $1.5 billion, and $2 billion for every 1 GW of installed capacity, respectively

(*) Denotes data source used for 2023 PSP modeling

Transmission Scenarios

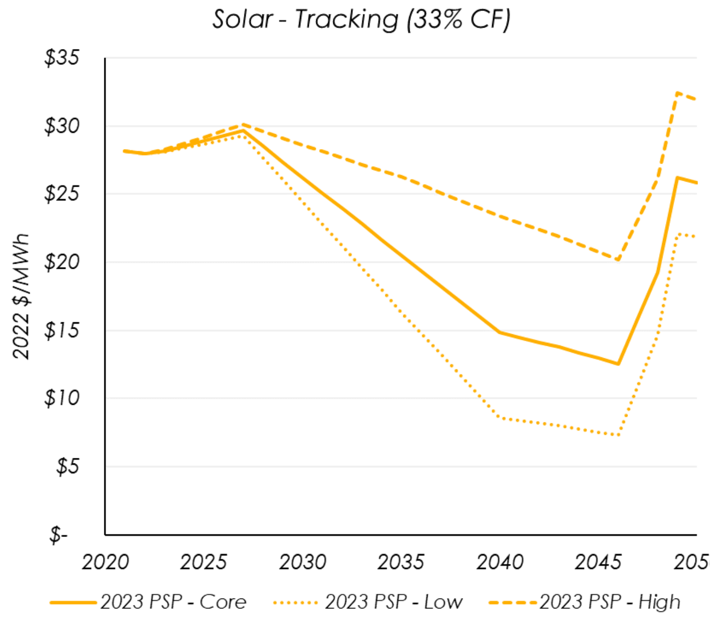
- **Morro Bay** (up to 4.9 GW offshore wind procurement)
    - **$110M** upgrade cost from the CAISO's 2021-22 TPP Report across all procurement and cost scenarios (Morro Bay substation upgrade)
- **Humboldt** (additional 2.7 GW, 7.6 GW total procurement)
    - **$2.3B** upgrade cost from the CAISO's 2021-22 TPP Report where Humboldt is the only North Coast site developed (onshore transmission via Fern Road)
    - High-cost scenario: Costs proportionally increased to **$4.3B**, reflecting larger 2.7 GW project size compared to 1.6 GW from TPP
- **Larger Procurements at North Coast** (>7.6 GW total procurement)
    - Three transmission cost scenarios informed by transmission alternatives studied by CAISO and Schatz 2023 report:
        - Low: **$1.25B** per GW (informed by latest estimates from CAISO)
        - Mid: **$1.5B** per GW (Low Bookend of scenario costs from Schatz 2023)
        - High: **$2B** per GW (2023 PSP / High Bookend of scenario costs from Schatz)

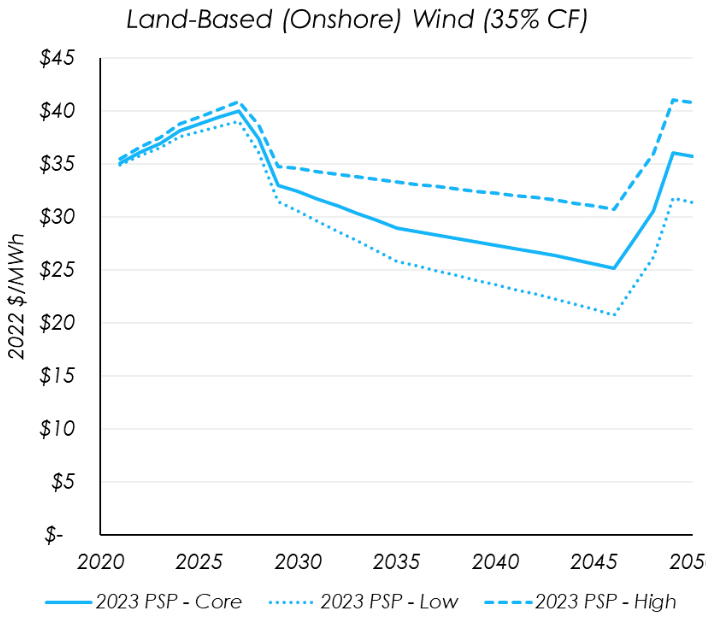
Other Infrastructure Costs

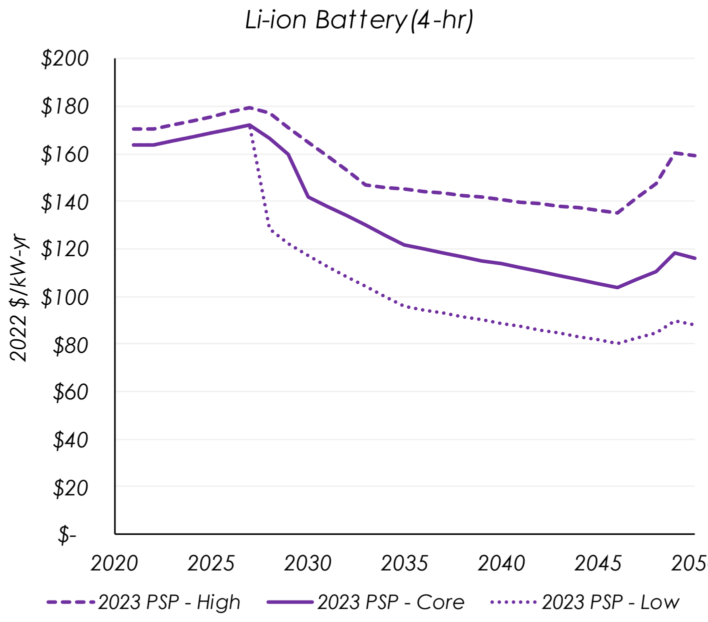
- Other infrastructure costs, such as port and waterfront facility upgrades, have not typically been included in cost estimates used in the offshore wind cost-benefit analysis
- Existing port infrastructure is unable to support buildout of offshore wind in California
- In addition to long lead times for transmission and project development, there is also a long lead time for ports and waterfront facilities
- Other infrastructure costs and the timelines required to make upgrades are an additional considerations that must be taken for an offshore wind procurement order
    - Other agencies or stakeholders may be best equipped to inform these considerations

Competing Resource Costs

- Low and high competing resource costs use the same assumptions as the 2023 Inputs and Assumptions
- Low and high CAISO transmission costs for onshore system upgrades calculated by applying 30% mark-up/down to CAISO transmission upgrade cost data







Resource Build Limits

- Resource build limits are consistent with 24-25 TPP sensitivity assumptions on resource build limitations
- Additional resource build limits apply to land-based wind, geothermal, biomass, and pumped hydro
  - Solar and Li-ion battery storage are not constrained given high resource potentials
- There are two sensitivities for 2035 resource build limits – reduced availability and significantly reduced availability

	All Cases	Reduced Resource Availability	Significantly Reduced Resource Availability
Land-Based Wind Resource Limits	The latest limits for PSP/TPP	Capped at 7 GW	Capped at 3 GW
Geothermal and Biomass	The latest limits for PSP/TPP	Not available after 2028	Not available after 2028
Pumped Storage Hydro	The latest limits for PSP/TPP	Capped at 500 MW	Capped at 500 MW

Clean Firm Resource Modeling

- New Allam Cycle with a 100% carbon capture rate represents the availability of clean firm resources to the portfolio
  - First available year in this modeling is assumed to be 2035
    - Aligned with the PSP emerging technology assumptions as well as the first year of offshore wind procurement
  - IRA 45Q PTC is assumed to be available for units operational in 2035, and it is modeled in variable O&M costs instead of fixed costs to allow for alignment between optimized capacity factors and incentives
    - This assumption is different from the PSP analysis where this incentive was modeled in fixed costs with a pre-defined capacity factor
  - Allam Cycle clean firm resources available to the model beyond 2035 are modeled with no IRA incentives

Effective Load Carrying Capability (ELCC) Sensitivities

Offshore Wind ELCC

- Offshore wind ELCC surface multipliers are adjusted up and down to create two additional ELCC ranges while still preserving the locational differences
  - **Base offshore wind ELCC:** ~43-50%
  - **Low offshore wind ELCC sensitivities**: ELCC reduced to 30-35%
  - **High offshore wind ELCC sensitivities**: ELCC increased to 55-65%
- **Long-Duration Energy Storage (LDES) ELCC**
  - Lower LDES ELCC surface multipliers are used for sensitivities (a 30% relative reduction) to the surface multipliers for 8 and 12-hour duration storage technologies (e.g. the 8-hr multiplier in 2035 is reduced from 154% to 118%)
  - Lower capacity value for LDES will make LDES (and solar) less valuable, which should increase offshore wind value (even though less LDES will be avoided per ELCC MW)

High Electrification Sensitivity

- The High Load Sensitivity use the 2022 IEPR Local Reliability Forecast

Case	2026		2030		2035		2039	
	Annual Load (TWh)	Peak Demand (GW)	Annual Load (TWh)	Peak Demand (GW)	Annual Load (TWh)	Peak Demand (GW)	Annual Load (TWh)	Peak Demand (GW)
Default (2022 IEPR Planning Forecast)	**252**	**54.9**	**280**	**58.3**	**319**	**64.0**	**352**	**68.7**
High Electrification (2022 IEPR Local Reliability Load Forecast)	**+3**	**+0.5**	**+12**	**+1.9**	**+27**	**+3.9**	**+35**	**+3.4**

Case	Baseline Demand Case	Transportation Scenario	AAEE Scenario	AAFS Scenario	CARB SIP NOx Rules
Default (2022 IEPR Planning Forecast)	Mid Case	AATE Scenario 3	Scenario 3	Scenario 3	Excluded
High Electrification (2022 IEPR Local Reliability Load Forecast)	Mid Case	Scenario 3	Scenario 2	Scenario 4	Included

Gas Retirements

- Gas retirement sensitivities use the 24-25 TPP sensitivity for High Gas Retirements

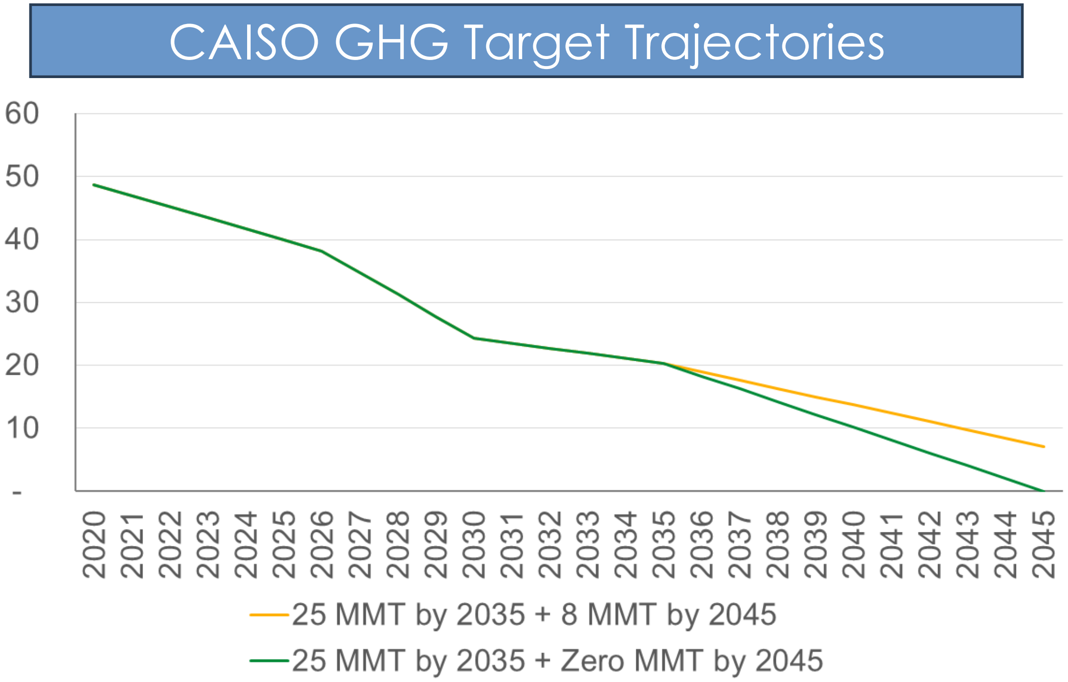
	Gas Capacity Retired 2024-2030	Gas Capacity Retired 2024-2045
Default	**0 GW**	**0 GW**
High Gas Retirement	**3.1 GW**	**12.1 GW**

Note: Retirement amounts reported above excludes OTC retirements in 2024.

- Gas retirements should in theory make offshore wind reliability contributions more valuable, however it is possible that the increased need for long duration storage will offset that value by making solar more valuable

2045 GHG Target

- For the GHG sensitivities, in addition to modeling a Zero MMT target by 2045, we are modeling:
  - All gas forced to retire by 2045
  - No imports for energy
  - No imports for reliability accounting



	CAISO GHG Emission Target (MMT)			
	2035	2039	2040	2045
Default **25 MMT by 2035, 8 MMT by 2045**	20.3	15.0	13.7	7.1
GHG Sensitivity **25 MMT by 2035, 0 MMT by 2045**	20.3	**12.3**	**10.1**	**0**

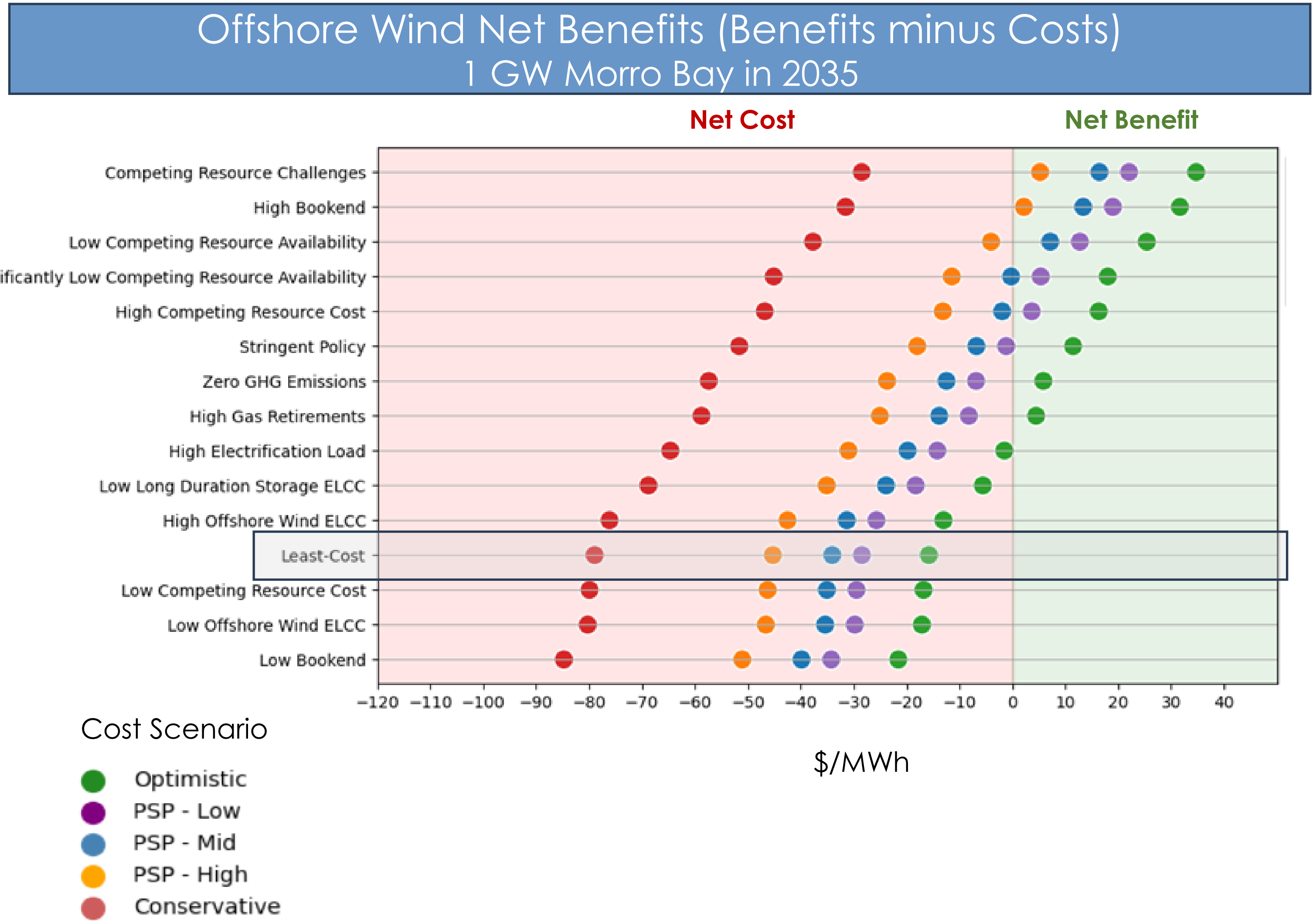
Appendix D

Quantitative Results for All Procurement Amounts

1 GW Morro Bay in 2035 and 2045 Scenario

Net Benefits by Benefit and Cost Scenario

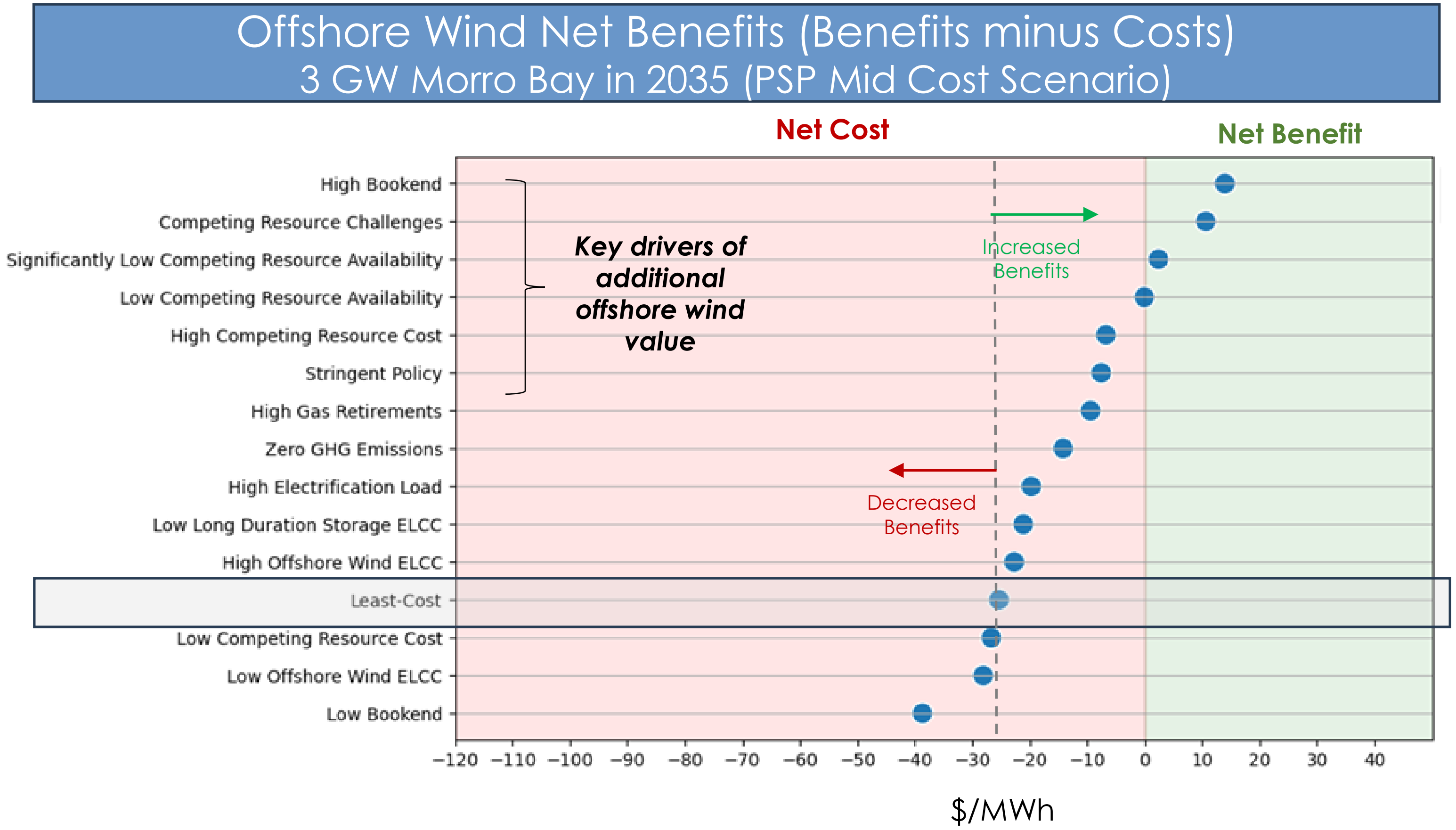
- Under 1 GW of procurement, some scenarios, particularly those with low offshore wind costs, result in net benefits for offshore wind
- Under high offshore wind costs, almost no scenarios produce net benefits for offshore wind



3 GW Morro Bay in 2035 and 2045 Scenario

Impacts of Levers on Offshore Wind Net Benefits

- The biggest impacts to net benefits are from:
  - Competing resource availability or cost
  - Gas retirements
  - Lower GHG emissions in 2045

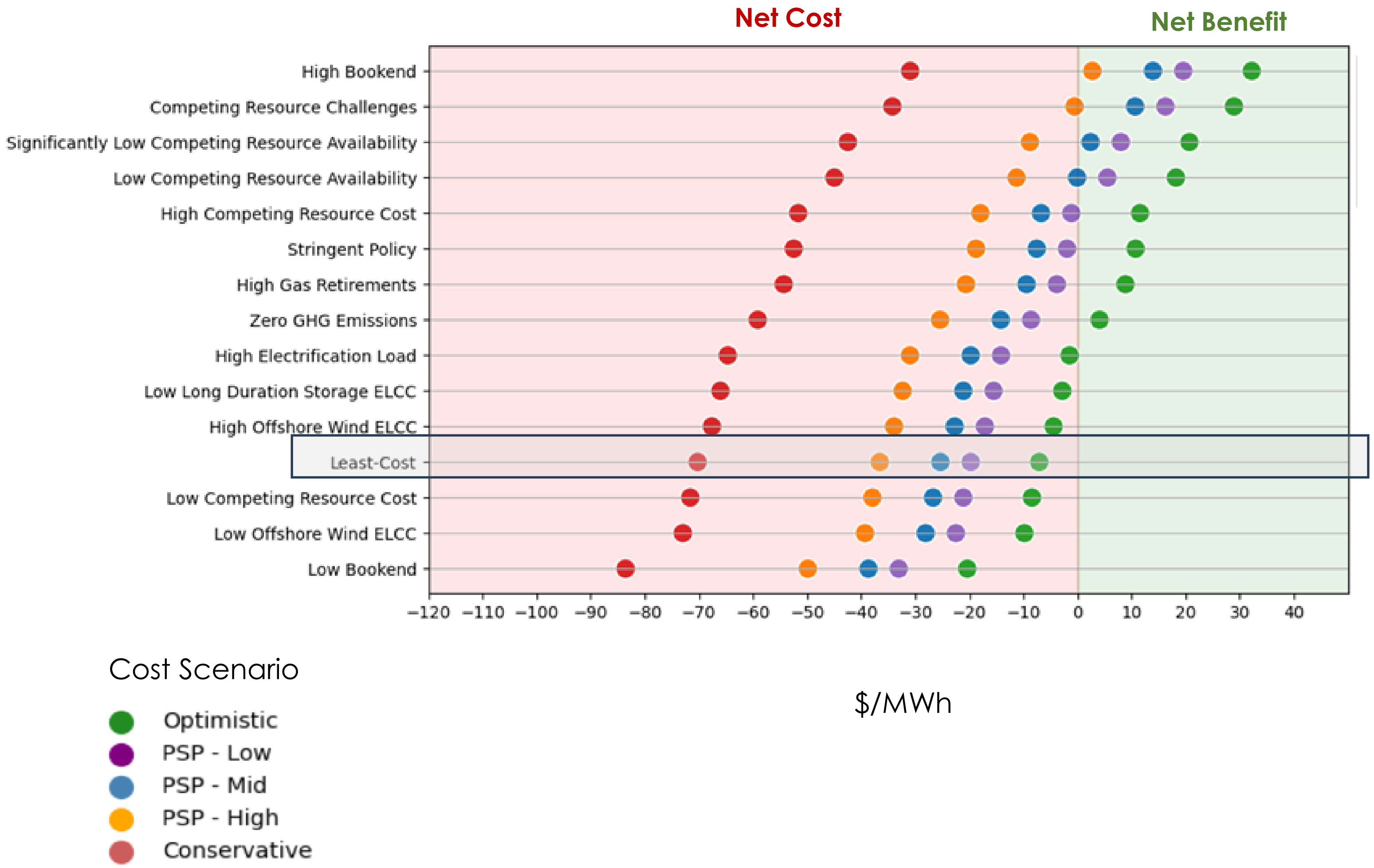


3GW Morro Bay in 2035 and 2045 Scenario

Net Benefits by Benefit and Cost Scenario

- Similar trends seen with 1 GW of procurement also hold true under 3 GW offshore wind

Offshore Wind Net Benefits (Benefits minus Costs)
3 GW Morro Bay in 2035



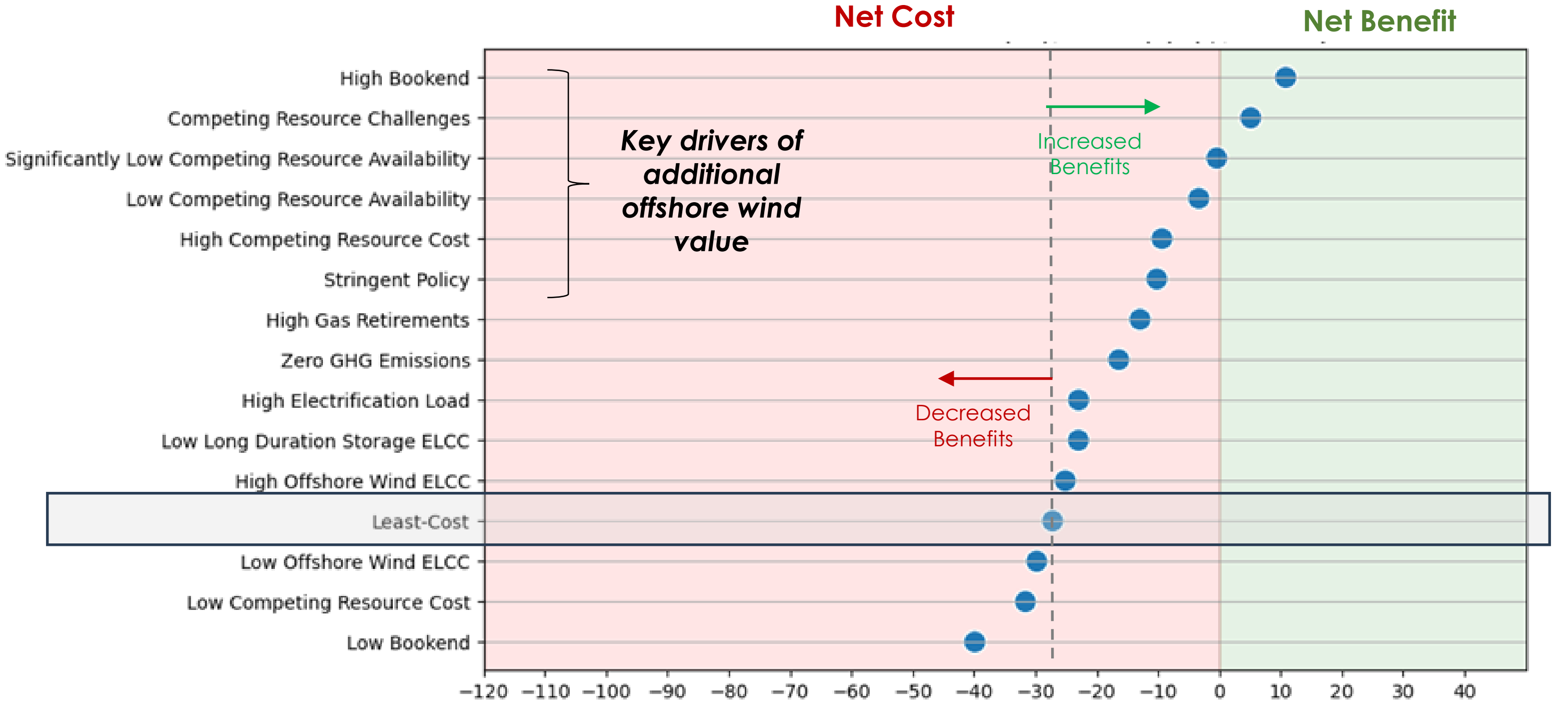
* Assumes 0 MMT carbon emissions grid by 2045, additional gas plant retirements, and even higher electrification loads

4.9 GW Morro Bay in 2035 and 2045 Scenario

Impacts of Levers on Offshore Wind Net Benefits

- Levers have identical impacts on offshore wind net benefits for 3 GW and 4.9 GW of procurement

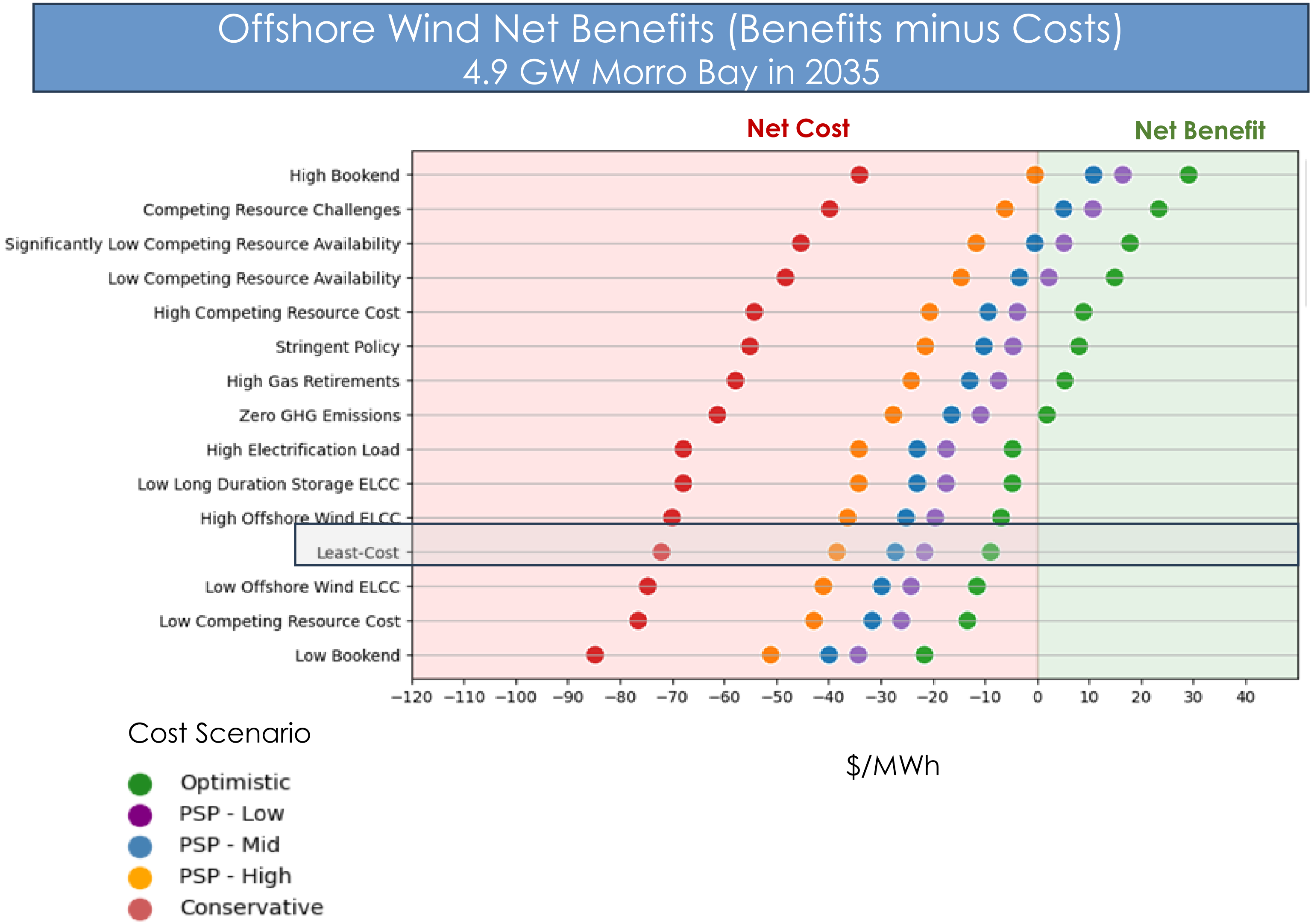
Offshore Wind Net Benefits (Benefits minus Costs)
4.9 GW Morro Bay in 2035 (PSP Mid Cost Scenario)



4.9 GW Morro Bay in 2035 and 2045 Scenario

Net Benefits by Benefit and Cost Scenario

- Net benefits under 4.9 GW have very similar trends to net benefits under 3 GW offshore wind

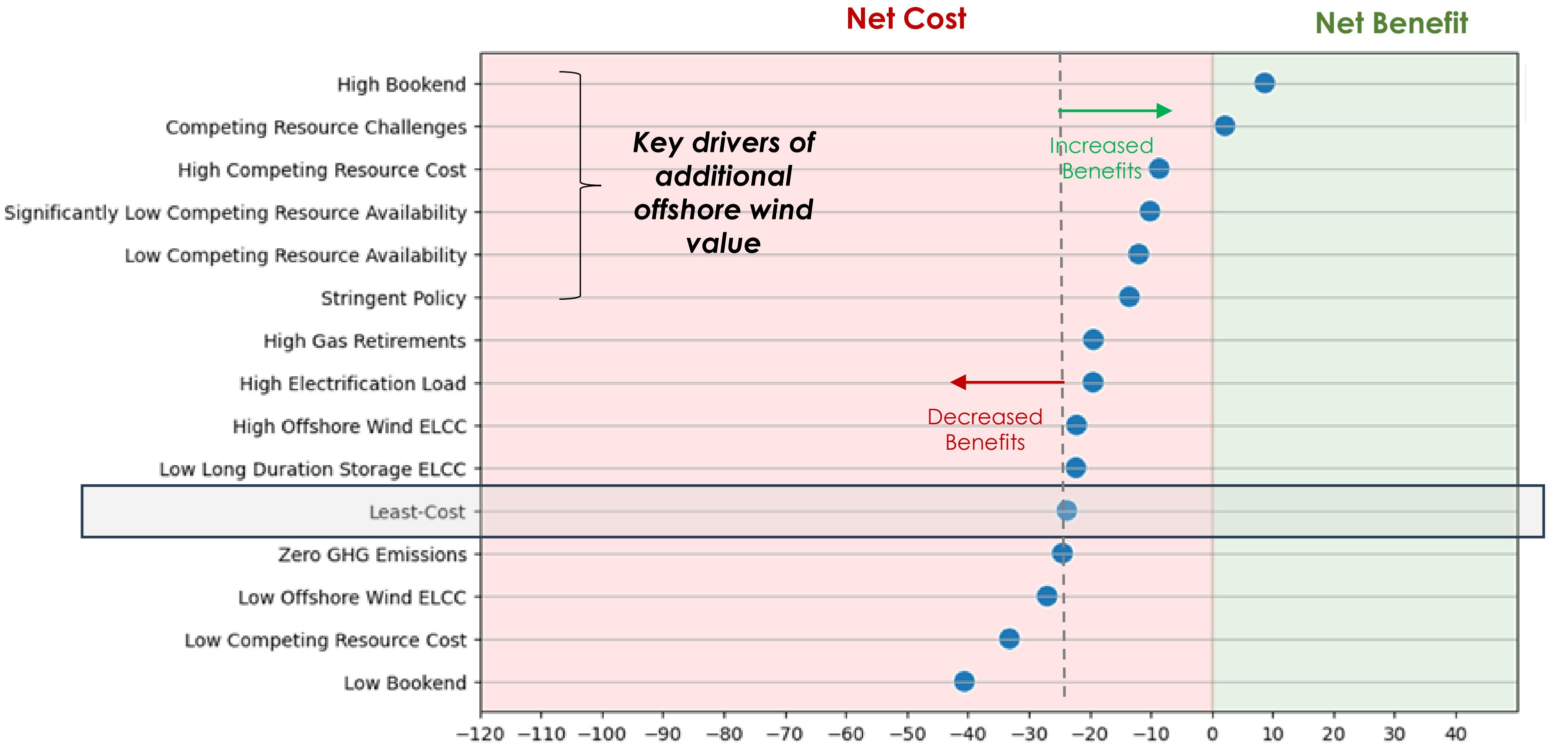


7.6 GW in 2035 and 2045 Scenario

Impacts of Levers on Offshore Wind Net Benefits

- With Humboldt Bay offshore wind included, and a higher amount of procurement overall, the order of individual levers begins to change, though competing resource challenges (higher cost, reduced availability) result in the largest increase in offshore wind value

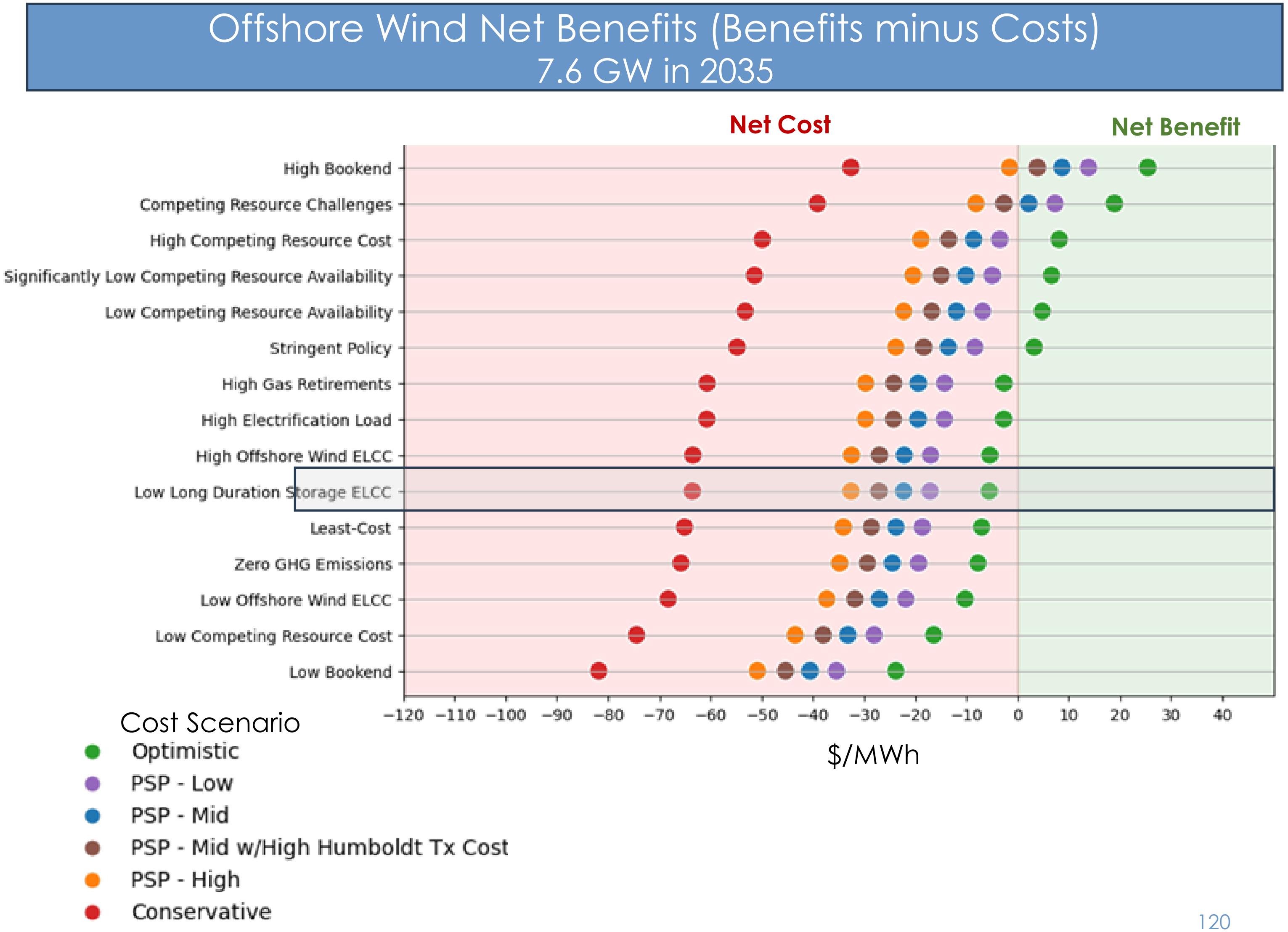
Offshore Wind Net Benefits (Benefits minus Costs)
7.6 GW in 2035 (PSP Mid Cost Scenario)



7.6 GW in 2035 and 2045 Scenario

Net Benefits by Benefit and Cost Scenario

- At 7.6 GW, offshore wind is only economic under a very small subset of scenarios (fewer scenarios than 1-4.9 GW offshore wind)



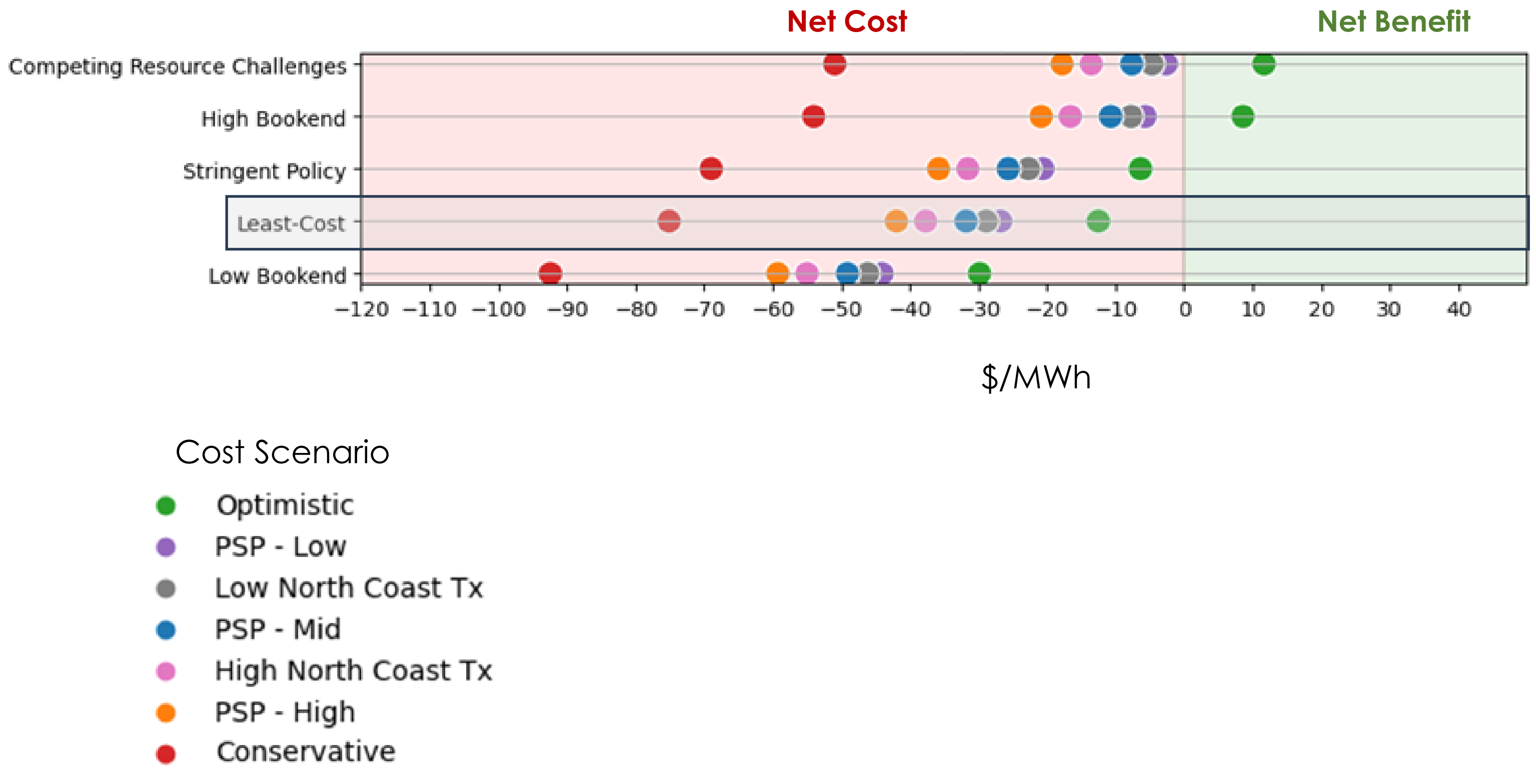
Offshore Wind Net Benefits (Benefits minus Costs)
7.6 GW in 2035

7.6 GW by 2035, 15 GW by 2045 Scenario

Net Benefits by Benefit and Cost Scenario

- At procurement amounts above 7.6 GW, additional cost sensitivities due to low/high transmission cost sensitivities are introduced
- At 15.6 GW by 2045, offshore wind is only economic under extreme scenarios that assume very low offshore wind costs

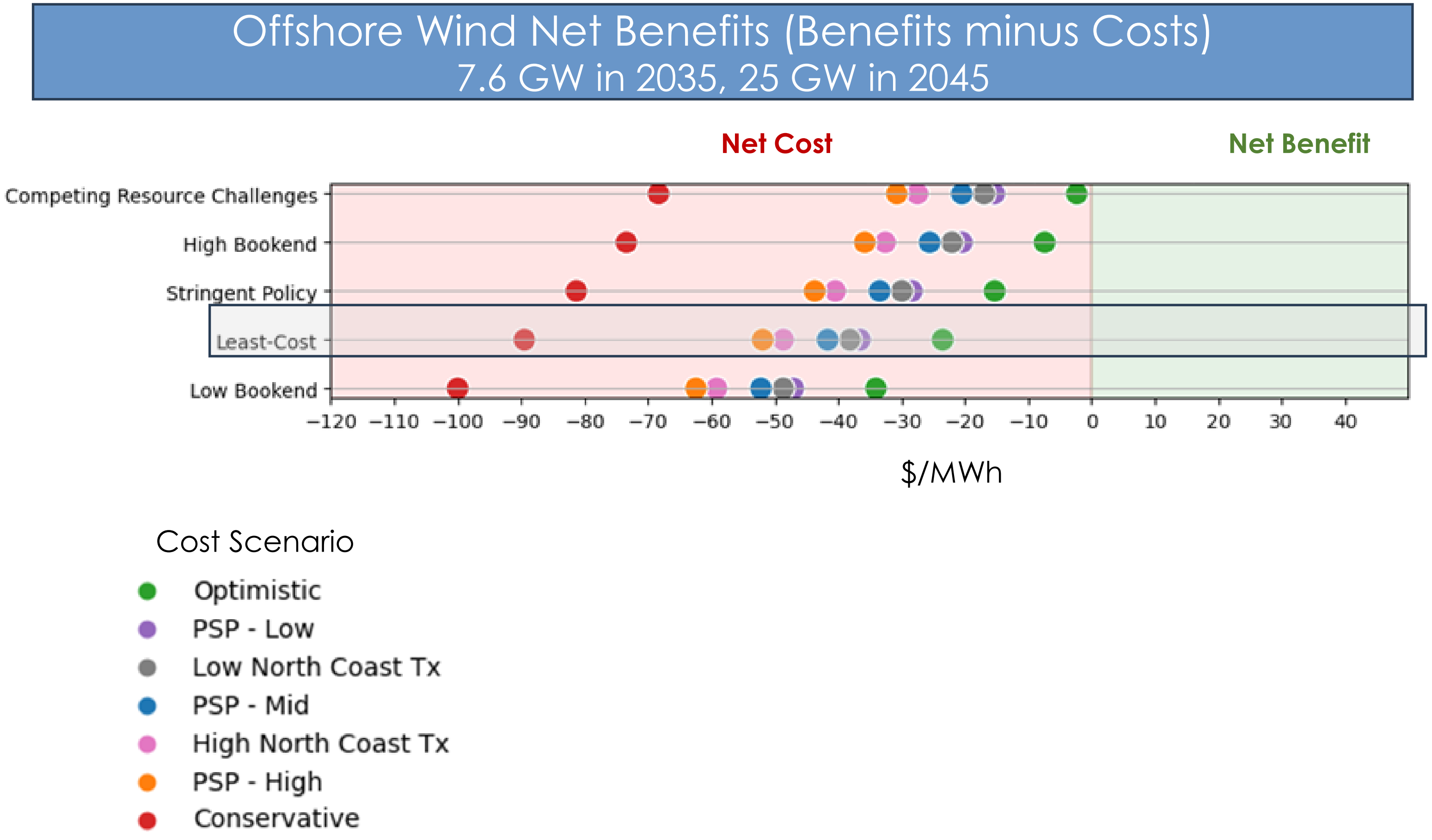
Offshore Wind Net Benefits (Benefits minus Costs)
7.6 GW in 2035, 15 GW in 2045



7.6 GW by 2035, 25 GW by 2045 Scenario

Net Benefits by Benefit and Cost Scenario

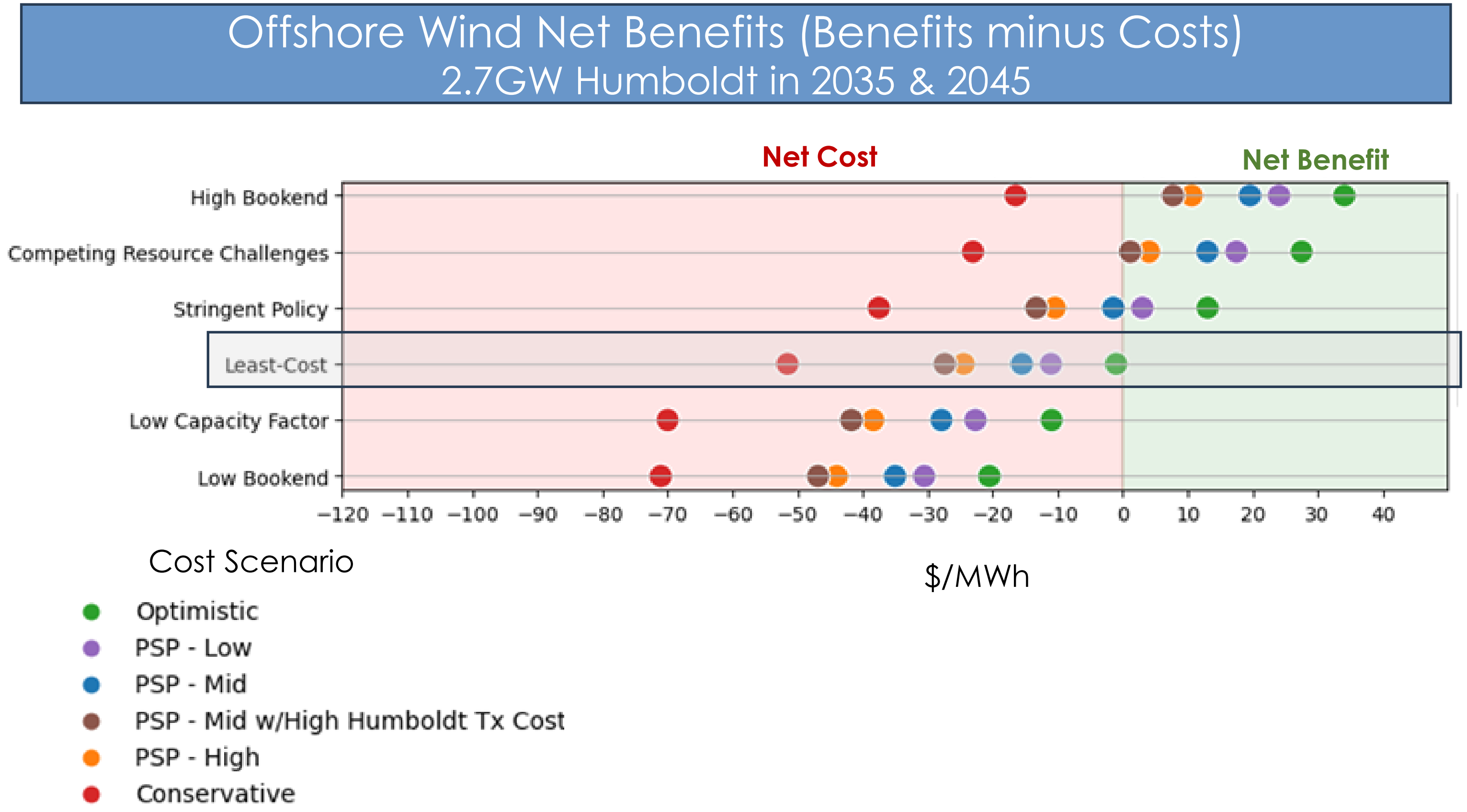
- At 25 GW by 2045, offshore wind is not economic under any scenarios evaluated



2.7 GW Humboldt in 2035 and 2045 Scenario

Net Benefits by Benefit and Cost Scenario

- Under base assumptions for transmission cost and capacity factor, net benefits are similar between 2.7 GW of Humboldt Bay and 3 GW of Morro Bay


Offshore Wind Net Benefits (Benefits minus Costs)
2.7GW Humboldt in 2035 & 2045