CAPSTF’s analysis update

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Disclaimer

- Results are preliminary and subject to change based on model development, and refinement of assumptions.
- Results are not forecasts.
- This study is complementary to the “Energy Transition in PJM: Resource Retirements, Replacements & Risks” study but targets different questions:
  - This study: *equilibrium* modeling of alternative clean energy market designs’ impacts on retirement and investment decisions; deliberately abstracts from present issues like interconnection bottlenecks.
  - “RRRR” study: *balance-sheet* approach to retirements, and activations, seeking to identify potential near-term resource adequacy risks that may arise absent enhanced market signals under discussion at RASTF and CAPSTF.

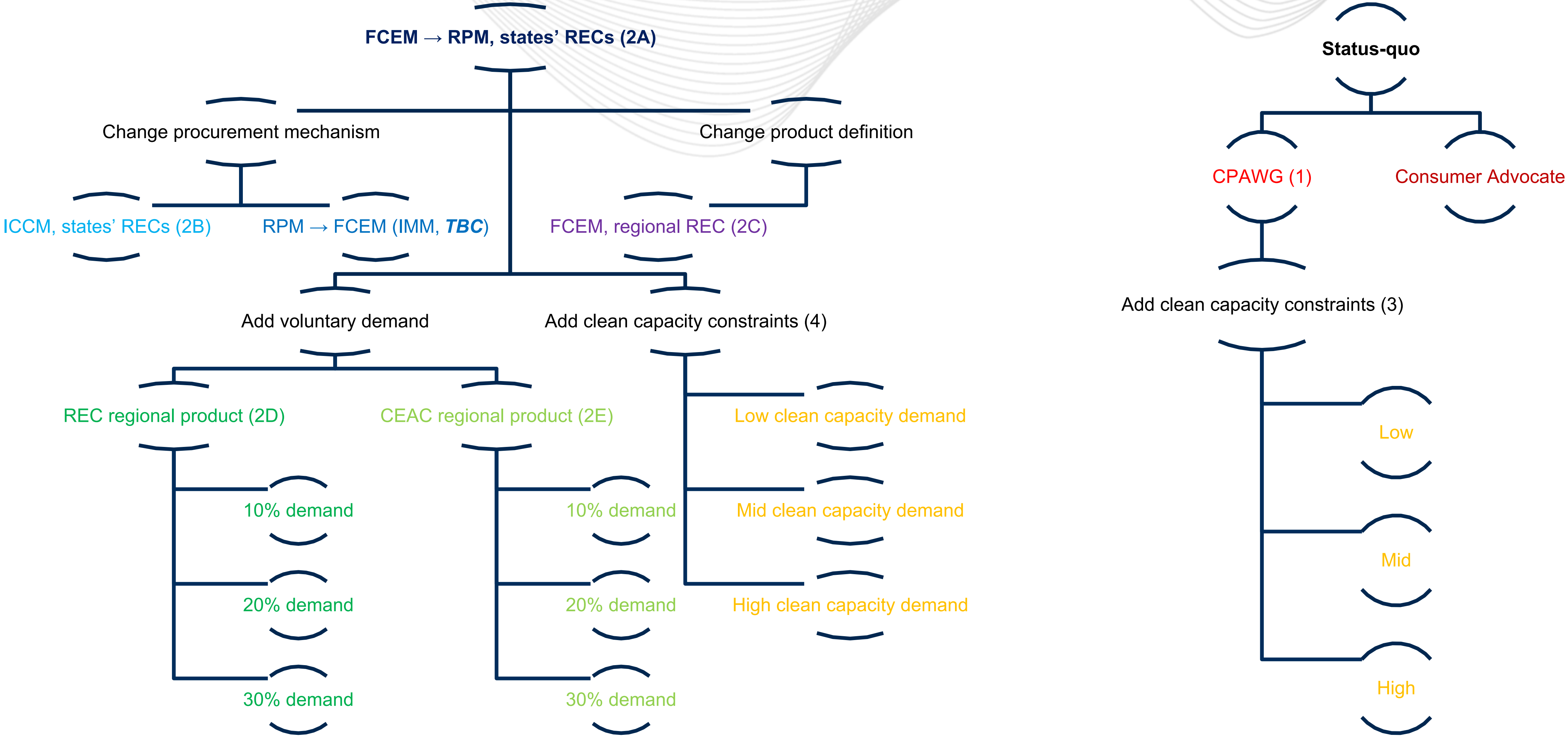
Key findings

- As found in December, the integrated (ICCM) or sequential procurement (FCEM+RPM) of clean energy and capacity lead to similar outcomes. States' policy coordination on a common product also has limited impacts (regional vs. state-specific RECs)
- Clean capacity constraints:
  - Accelerate the entry of renewables
  - Significantly alter investments across technologies and locations
  - Costs for states expressing these targets increase substantially
  - But capacity costs drop for states without these targets
- Voluntary demand for clean attributes:
  - Accelerates the entry of renewables
  - And *lowers* costs for PJM load

Assumption changes (complete assumptions in appendix)

- Build of new gas plants now allowed anywhere (in December update, only in PA, OH, WV, IN, KY)
  - Consistent with assumptions in (now FERC accepted) PJM Quadrennial Review of RPM’s VRR demand curve and Net CONE
- Policy retirements aligned with those in “Energy Transition in PJM: Resource Retirements, Replacements & Risks”
  - Uniformly spread over three years (example suppose there is a policy affecting a 300MW plant in 2028; we assume exits of 100MW in each year between 2026-2028)

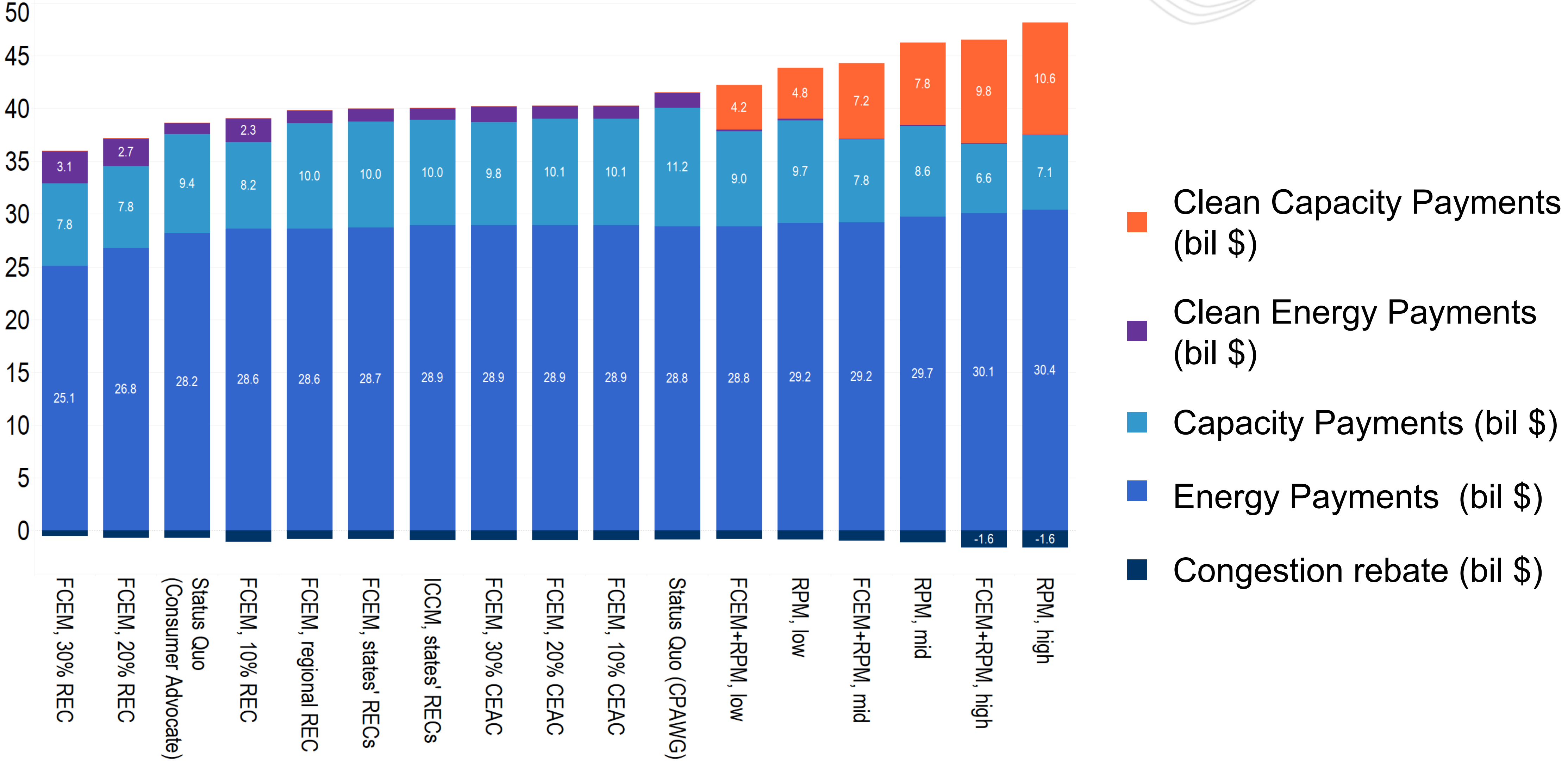
Scenarios’ map



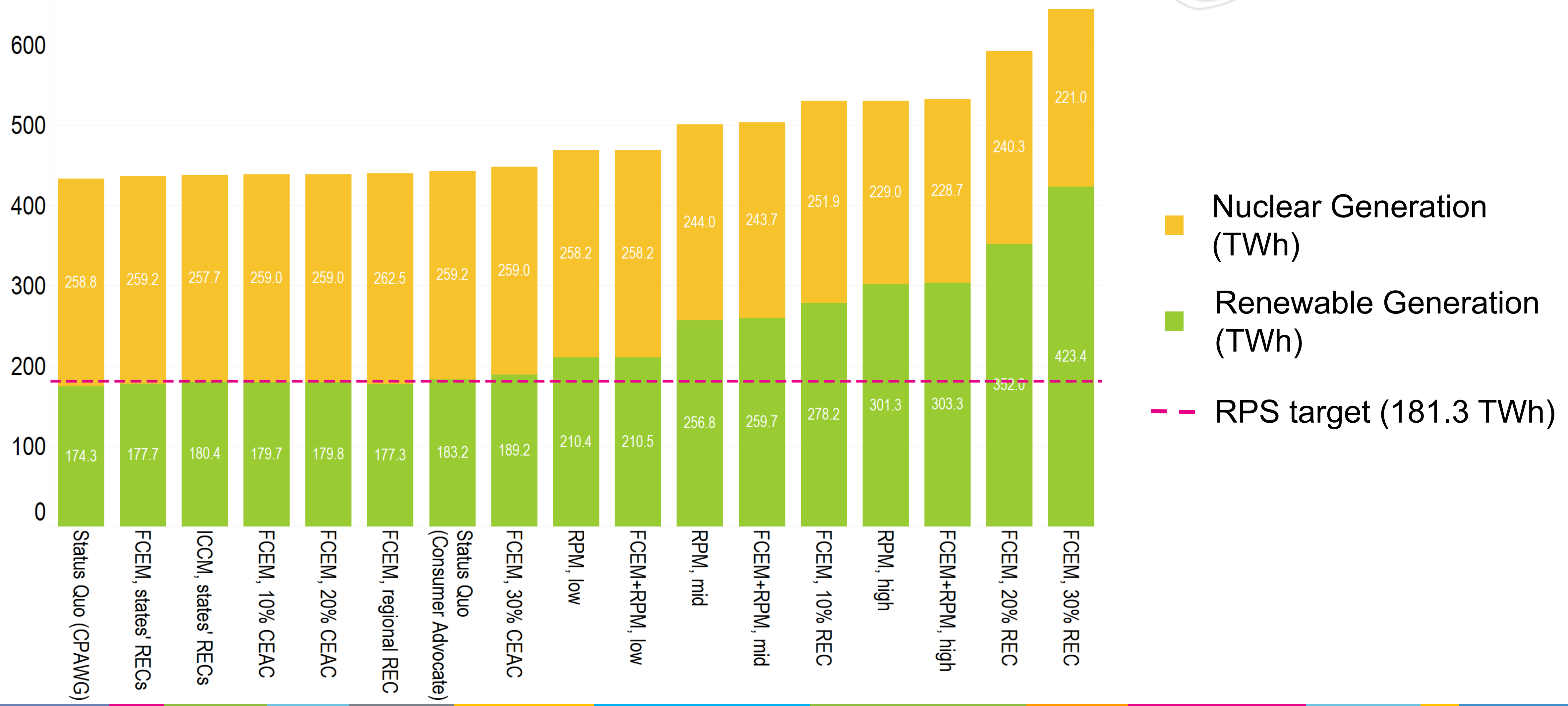
Scenarios' description

- FCEM→RPM, states' RECs (2A): Forward Clean Energy Market (FCEM) with states' specific RECs followed by capacity market (RPM). Label used in figures **FCEM, states RECs**
- ICCM, states' RECs (2B): single Integrated Clean energy and Capacity Market for the two product types; label in figures **ICCM, states RECs**
- RPM → FCEM (IMM): as 2A but invert the ordering of FCEM and RPM; to be completed
- FCEM→RPM, regional REC (2C): as 2A but with a common regional REC instead of states' RECs; label in figures **FCEM, Regional REC**
- Add voluntary demand for the regional REC (2D): same as 2A but with added 10%, 20%, 30% voluntary renewable energy demand with 5% slope; label in figures **FCEM, X% REC**
- Add voluntary demand for the regional REC (2E): same as 2D but the voluntary demand is for a regional clean product (includes nuclear); label in figures **FCEM, X% CEAC**
- Add clean capacity demand (4): same as 2A but with added clean capacity constraints (low, mid, high) for states with RPS programs; label in figures **FCEM+RPM, low/mid/high**
- Status quo, CPAWG (1) and Consumer Advocate: as 2A but the fixed cost in sellers' forward market offers is multiplied by 1.05 in CPAWG's case and 0.95 in the Consumer Advocate case
- Status quo with clean capacity constraints (3): same as CPAWG (1) but with added clean capacity constraints (low, mid, high) for states with RPS programs; label in figures **RPM, low/mid/high**

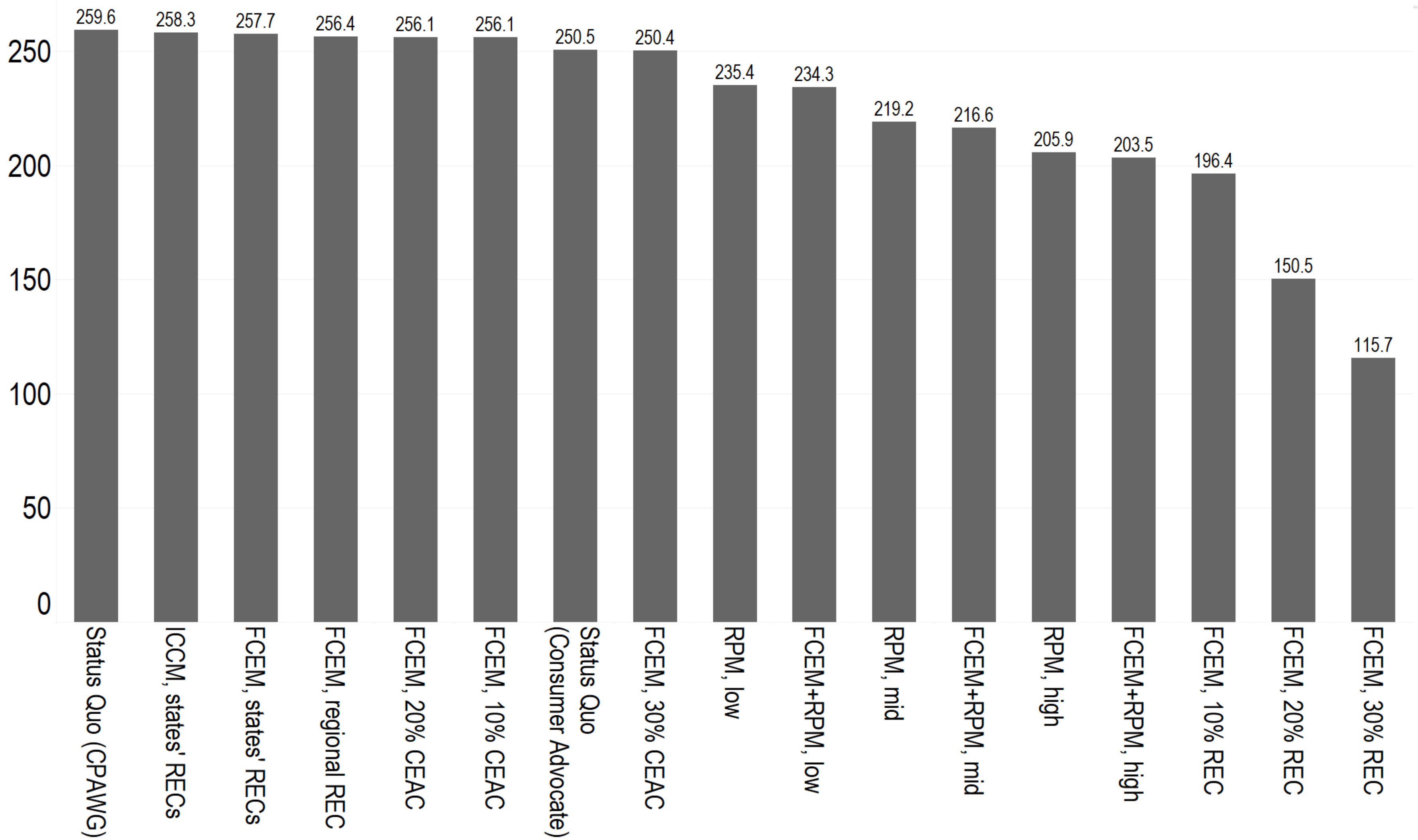
Load costs (2023-2030 average; bil $)



Renewable and nuclear generation (2030 levels; TWh)

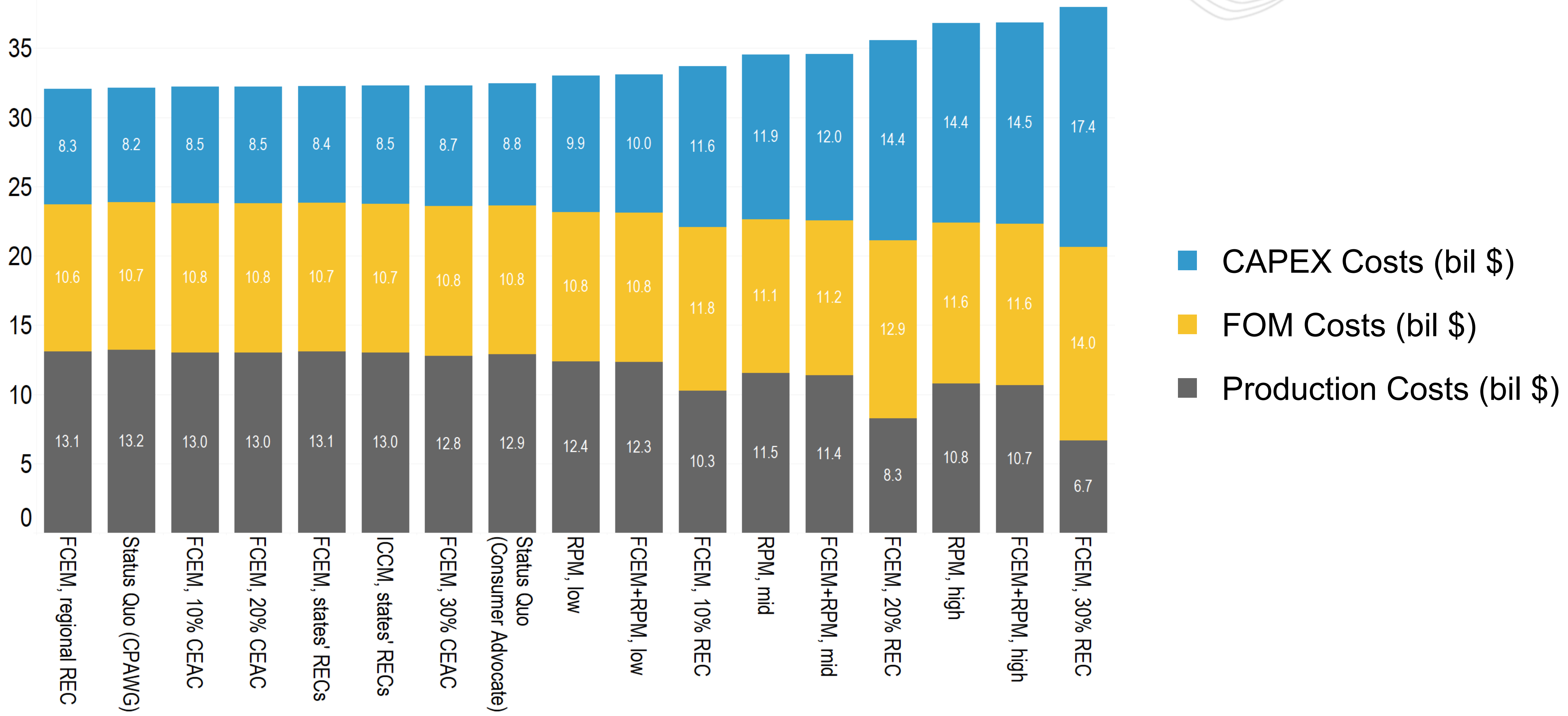


CO2 Emissions in 2030 by scenario (mil. ton)

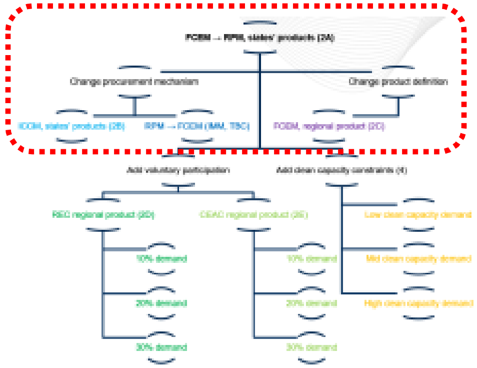


Note: 2023 level in FCEM, states' RECs is 337.2

System costs in 2030 (bil $)

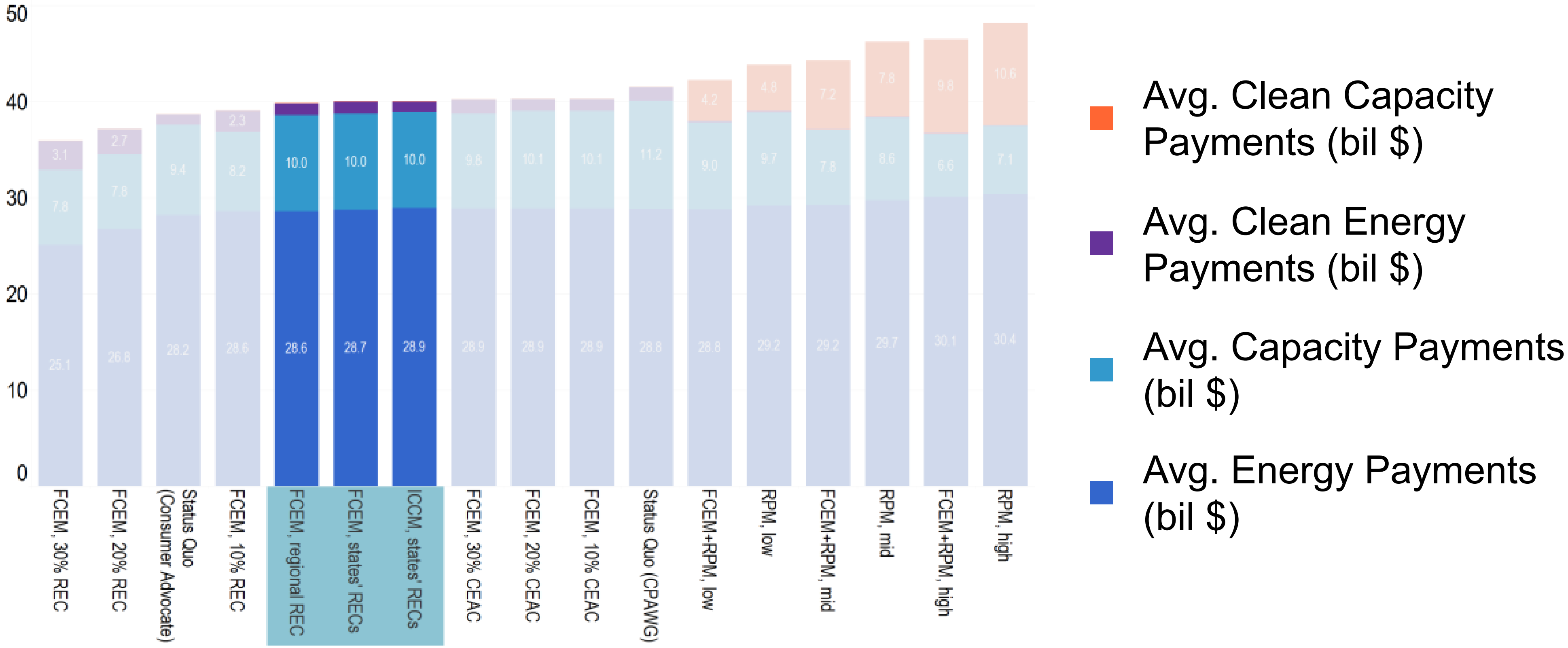


Fundamental market design alternatives:
- Procurement mechanism
- Product definition



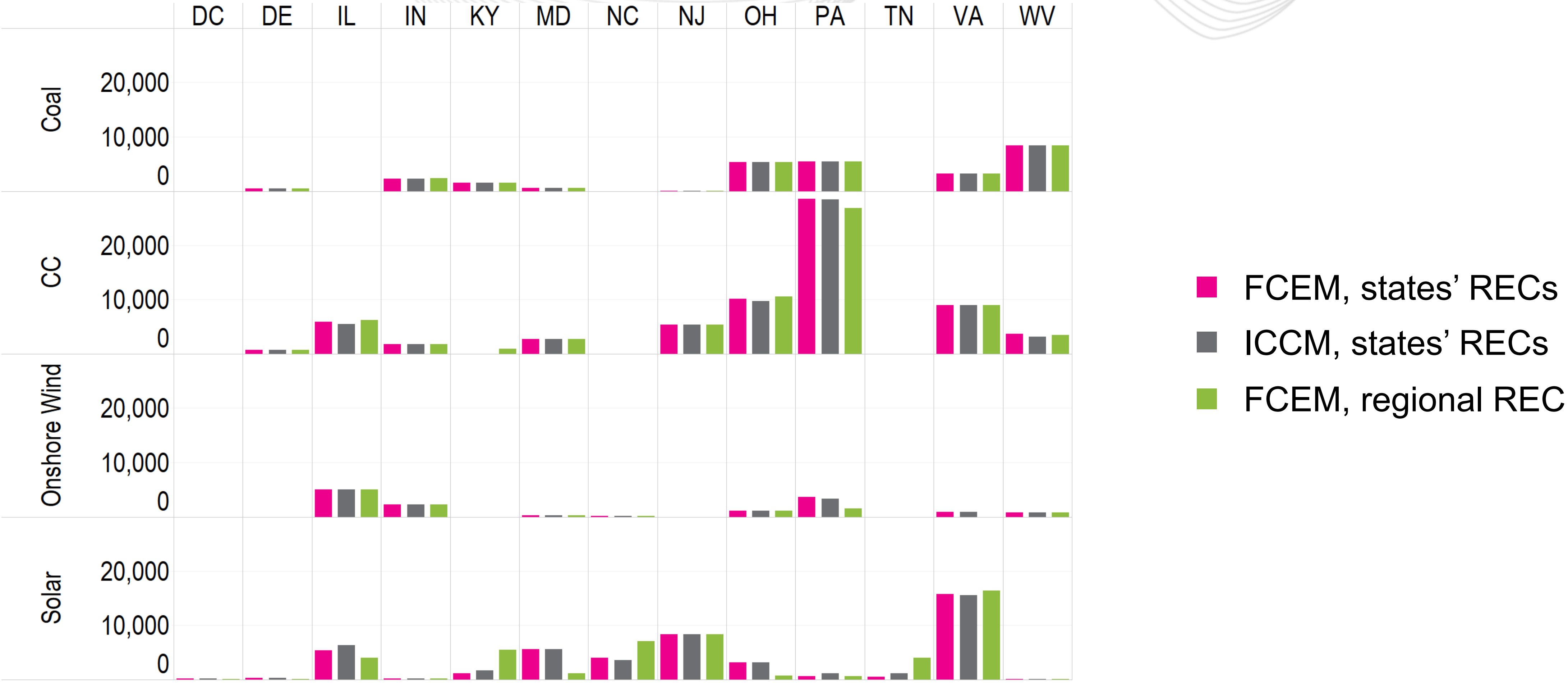
Procurement specifics, modest differences (as found in Dec)

Load payments (average 2023-2030, gross of congestion; bil $)



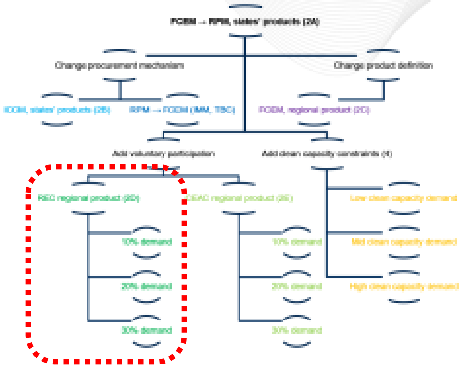
- Exits are mainly determined by policy retirements
- RPS policies broadly consistent with economics
- Transmission capacity limits the location choice of new investments

MW-ICAP across states and selected technologies in 2030



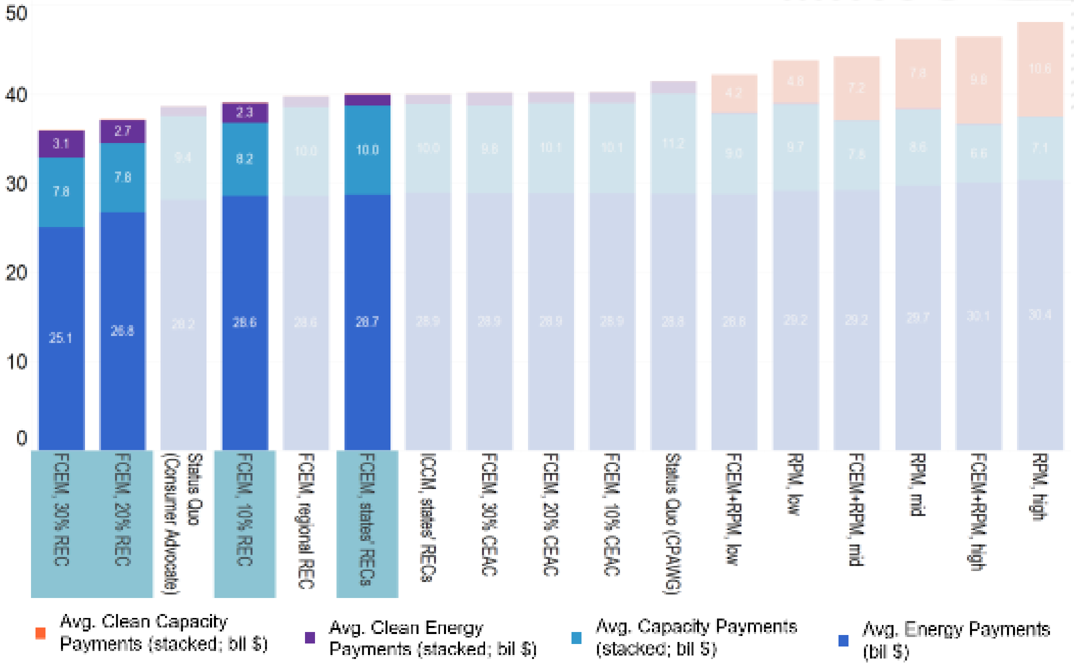
- Buildout broadly unaffected by market design specifics

Voluntary demand participation for regional *REC*

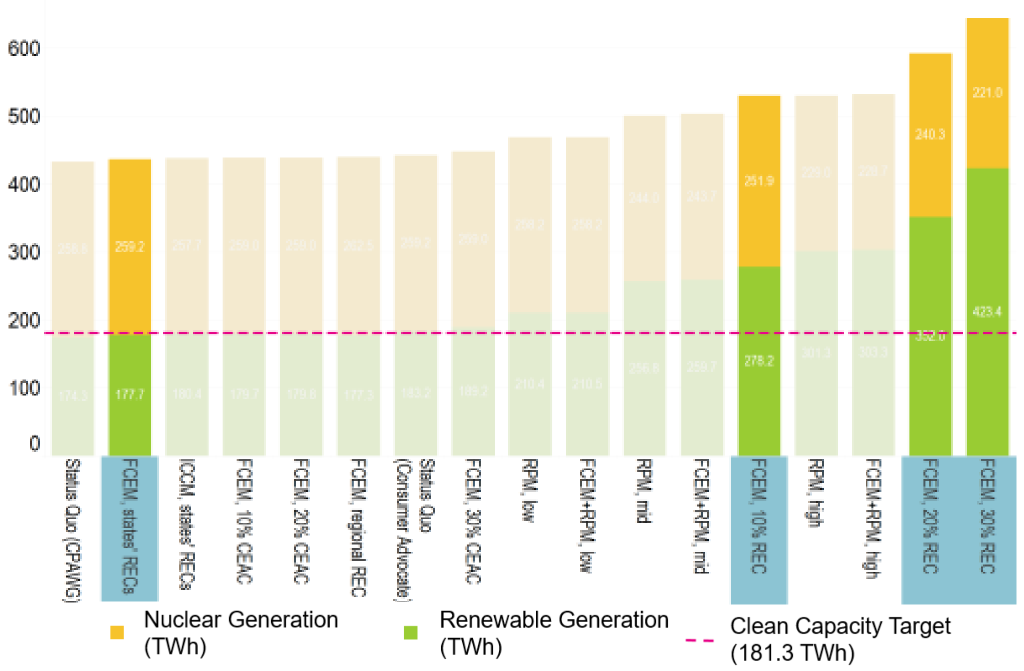


Voluntary demand for the regional REC product lowers load costs and accelerates the energy transition

Load payments (average 2023-2030; bil $)



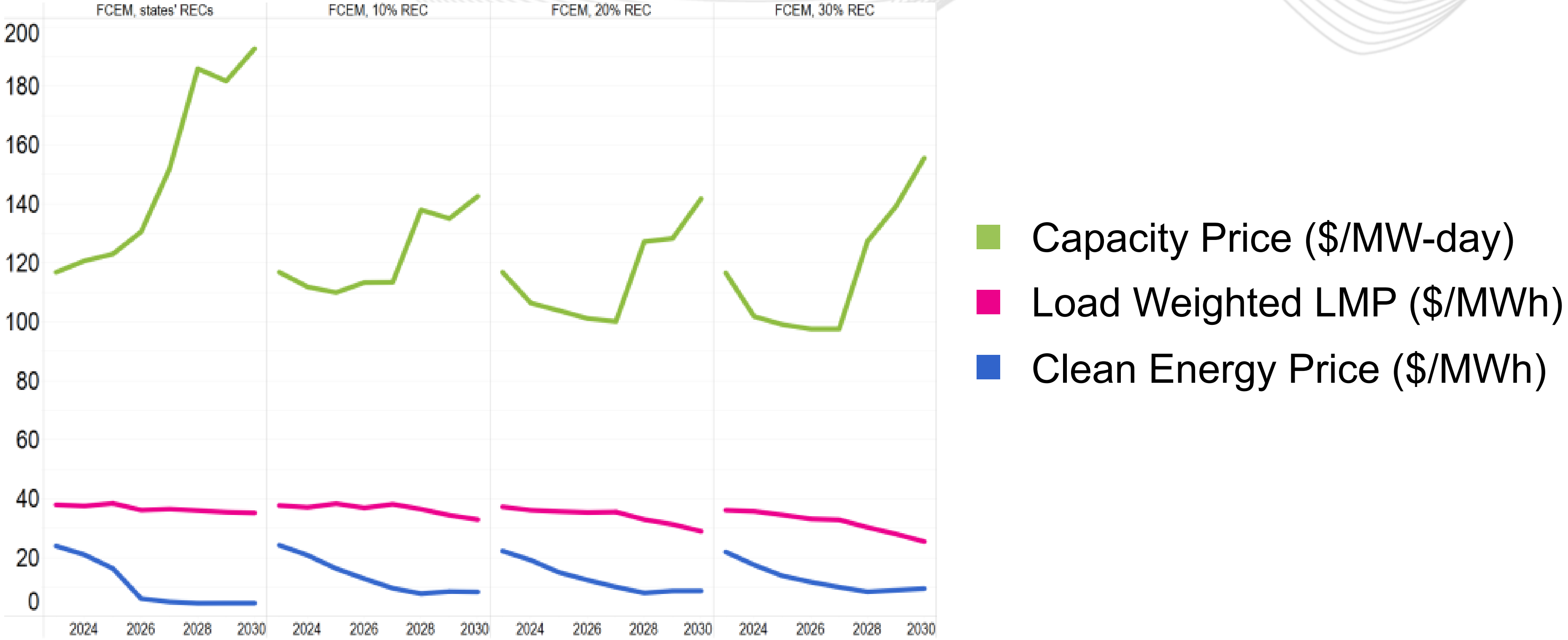
Clean generation (TWh)



Note: modeled voluntary demand is incremental reflecting the hypothesis that a transparent, equal access, centralized market allows more voluntary demand to emerge and be expressed

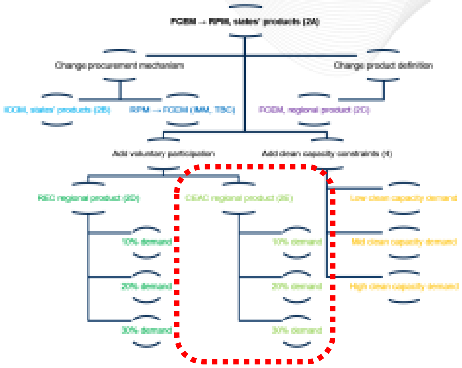
- Voluntary demand increases the REC price
- PJM load pays more for RECs
- *But PJM load pays less for energy and capacity*

Price dynamics: unpacking voluntary participation effects



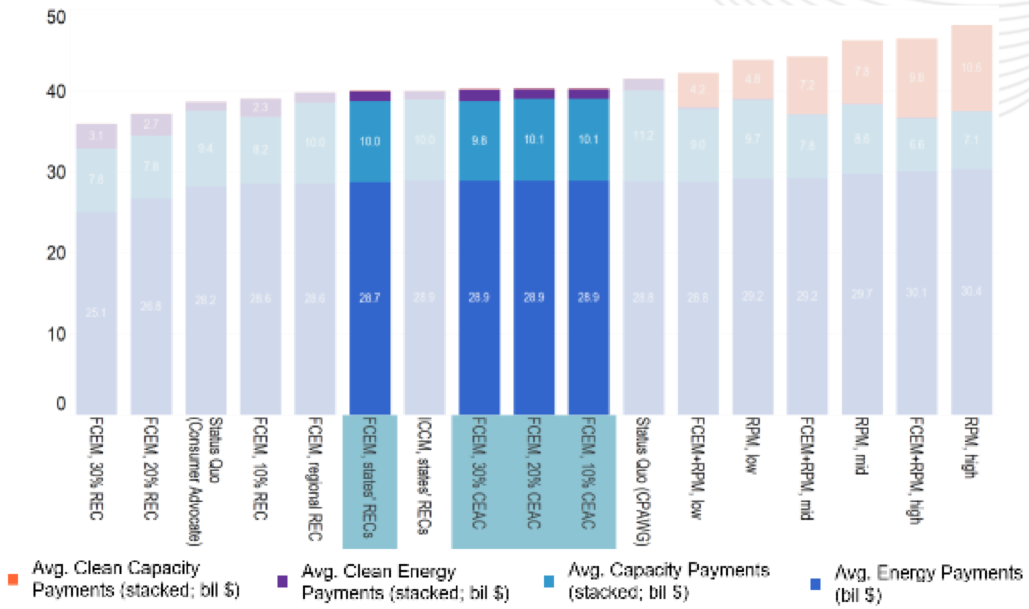
- Voluntary demand payments lower additional capacity revenue needs of new renewable resources, and therefore capacity prices, *ceteris paribus*
- Higher renewable penetration lowers the energy price (displaces some nuclear generation)
- Lower energy prices may result in lower E&AS and therefore higher capacity and REC prices in later years, the higher the voluntary demand

Voluntary demand participation for regional *CEAC*

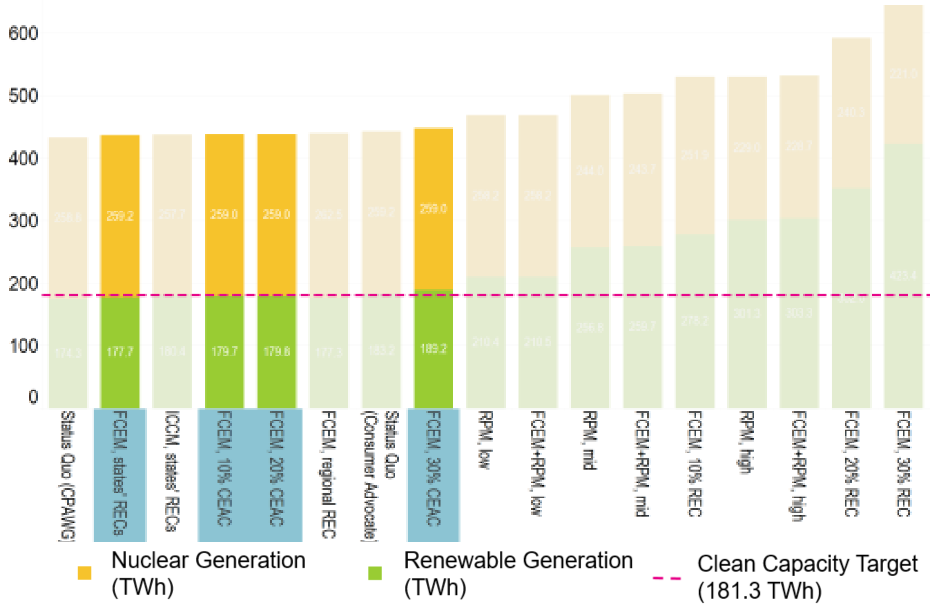


Effects of adding voluntary demand for a regional CEAC

Load payments (average 2023-2030; bil $)



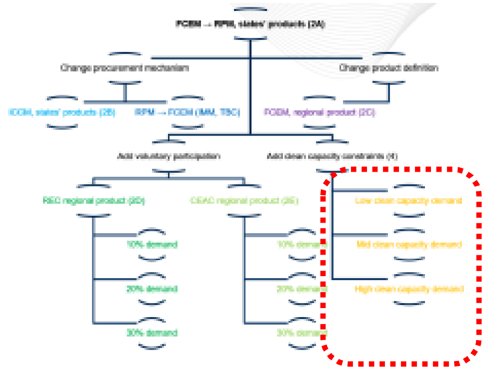
Clean generation (TWh)



- PJM has about 30% nuclear generation
- 10% or 20% CEAC voluntary demand: existing nuclear is sufficient (CEAC price=0, results unaffected)
- 30% voluntary demand: additional renewable generation is built, CEAC price greater than zero
  - voluntary demand has ± 5% slope; CEAC is cheap, the market procures above RPS target

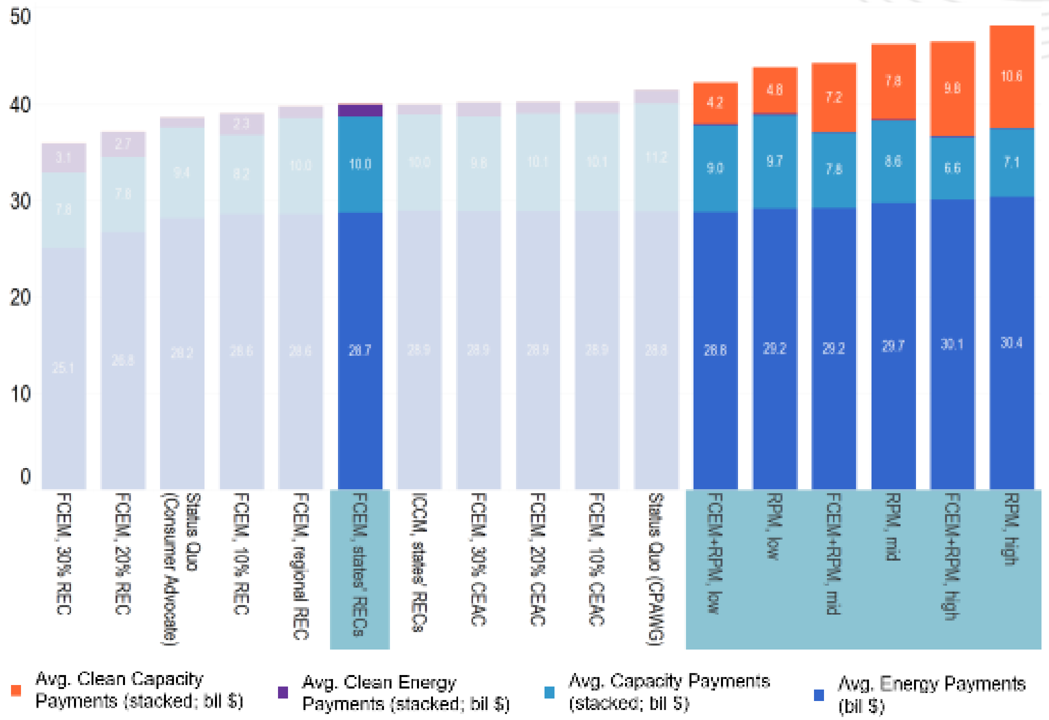
Note: we remove NJ nuclear support. NJ is the only state with nuclear subsidies in the model; these subsidies are assumed to renew automatically through 2030

Clean capacity constraints

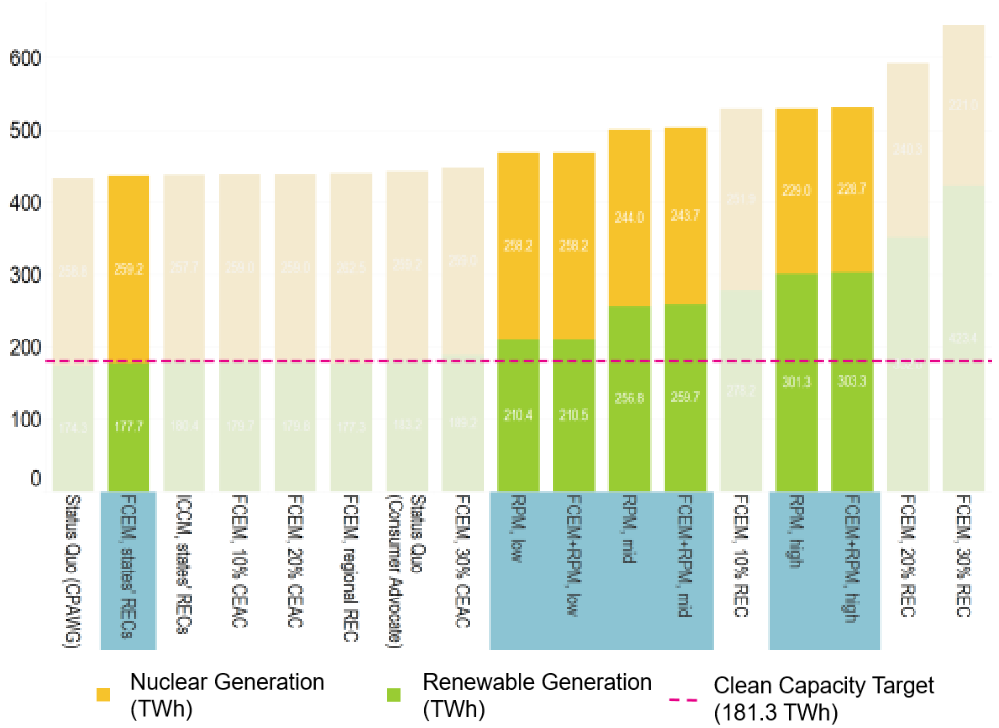


Clean capacity targets raise load costs and clean generation

Load payments (average 2023-2030; bil $)

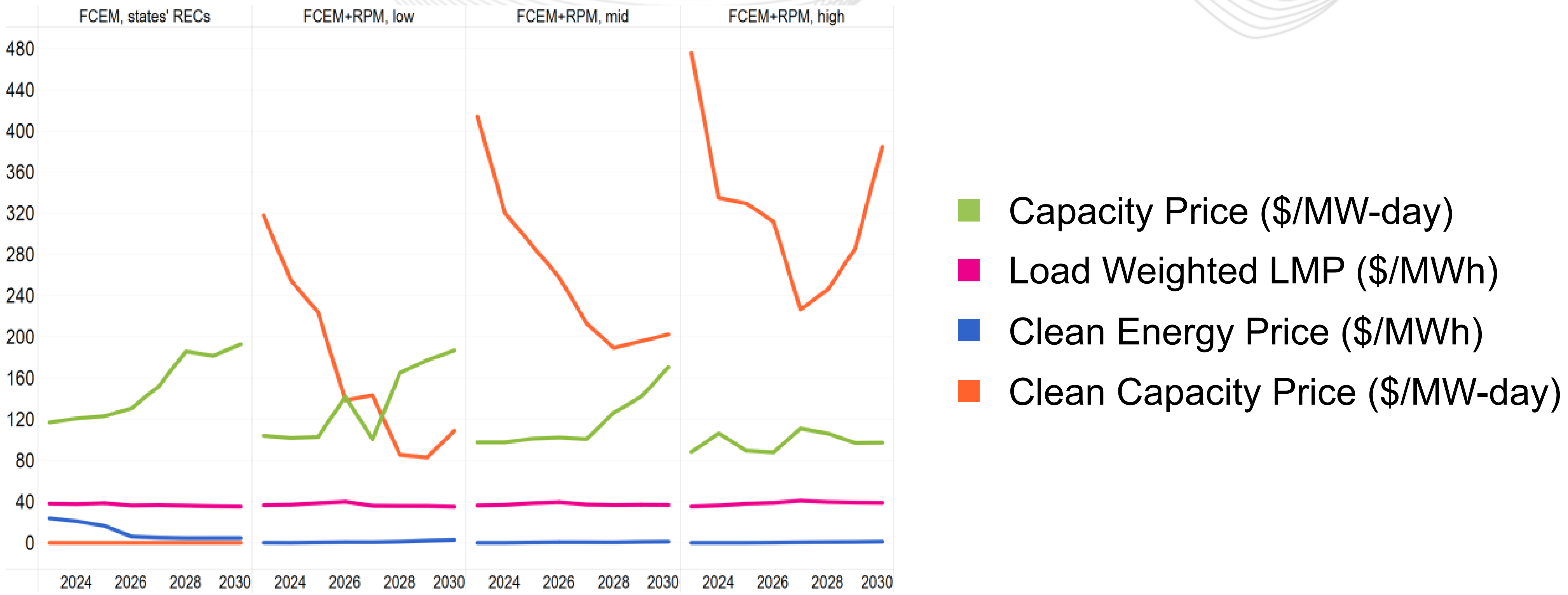


Clean generation (TWh)



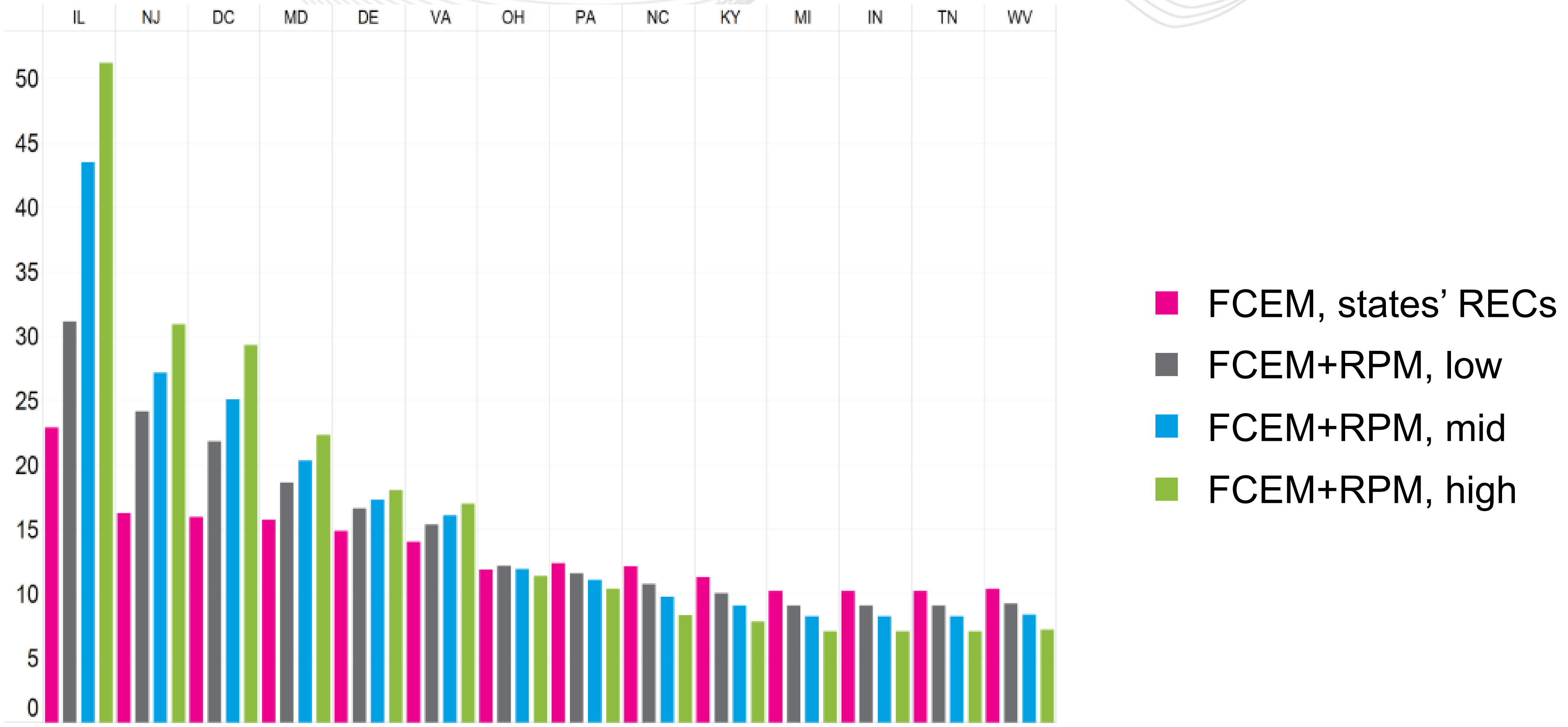
- Clean capacity targets can be met via imports (subject to same LDA structure and CETL as for capacity)
- Clean capacity costs are allocated only to states demanding clean capacity (see below)

Clean capacity targets' effect on other products' prices



- Clean capacity targets lower the price of states' RECs to near-zero
  - The clean capacity constraints lead to clean energy procurement above RPS targets
- And lower capacity prices, esp. in later years muting the effects of policy retirements
  - The clean capacity constraints attract new renewable units in place of fossil units

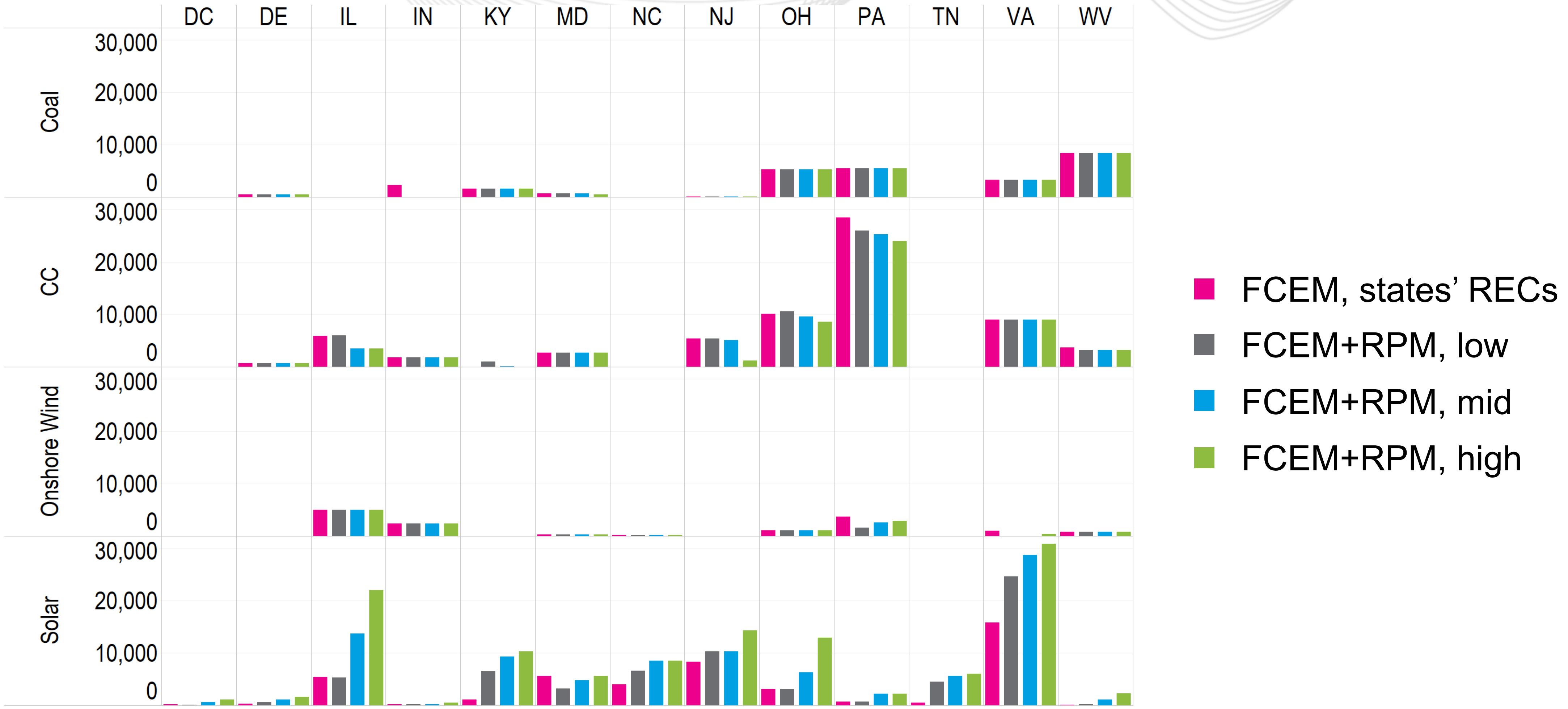
Unitized forward markets costs ($/MWh) by state (2023-2030 avg.)



- Clean capacity constraints lower forward markets costs in other states

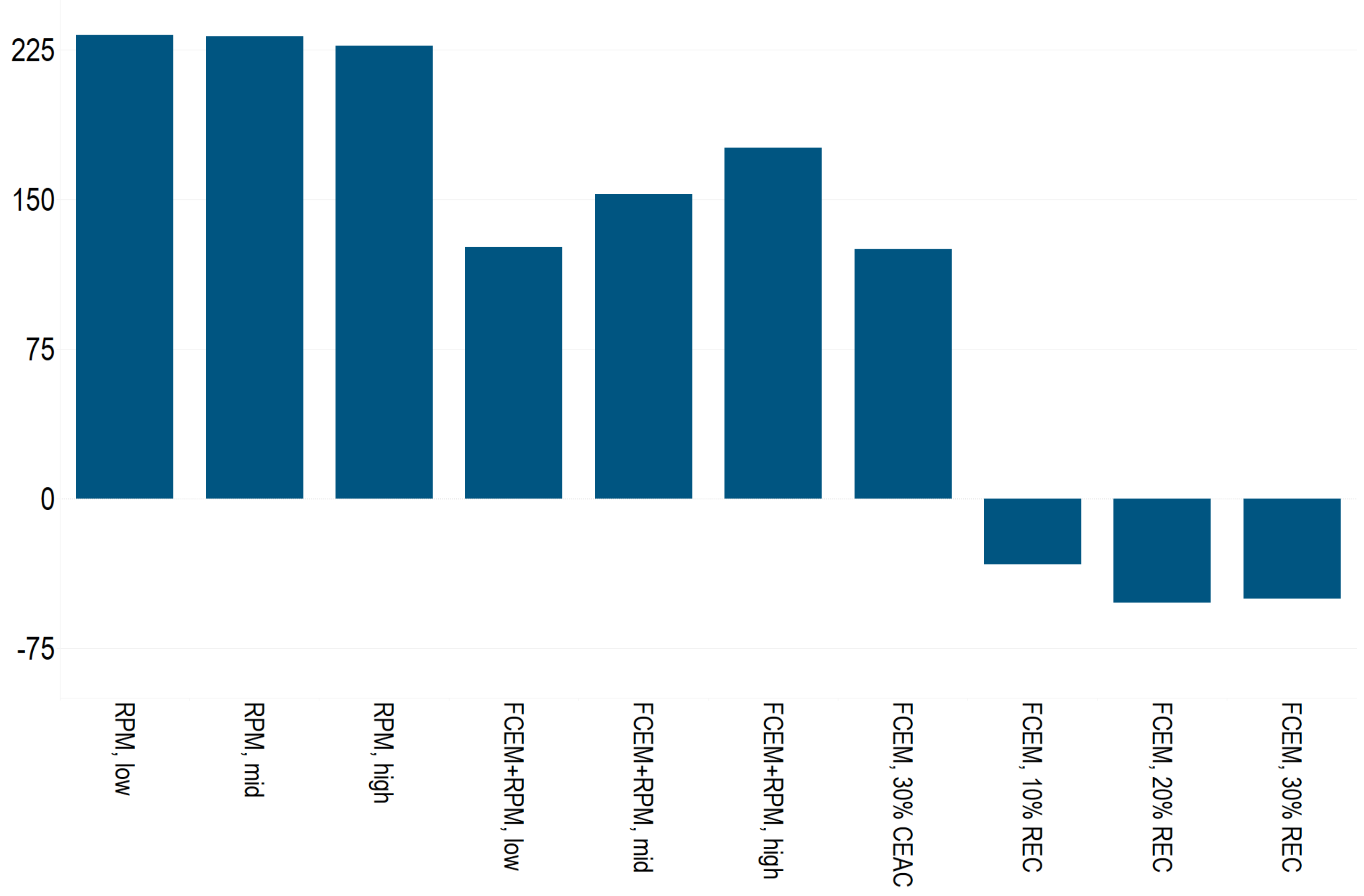
Unitized forward markets costs = (capacity pmt + clean capacity pmt + clean energy pmt) / load

Nameplate by state and selected technologies in 2030 (MW)

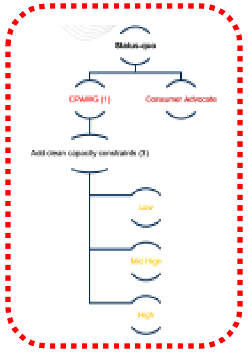


- More solar in all states (especially IL, VA, NC, KY, OH) and less combined cycle in PA, OH, NJ, IL

CO2 Reduction Cost ($/ton) Relative to case FCEM, states' RECs



Status quo

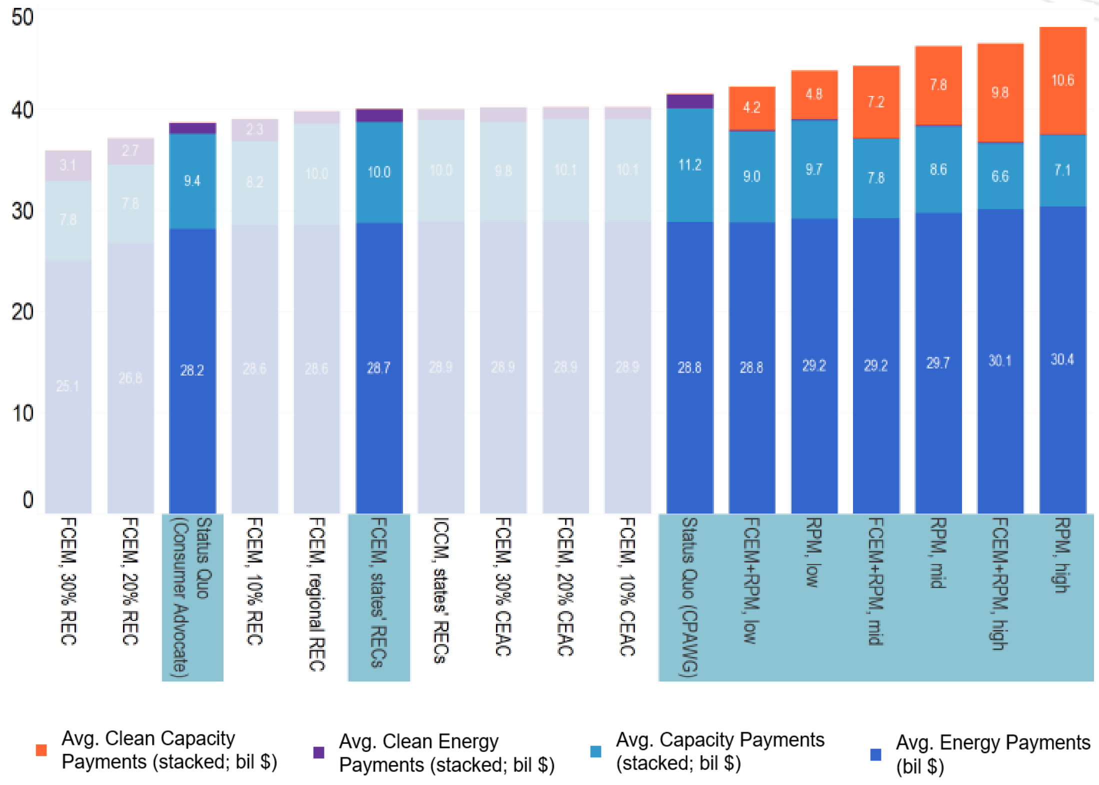

Status quo
Consumer Advocate
Add clean capacity constraints (3)
Low
Mid High
High

Status quo results follow bidding behavior assumptions

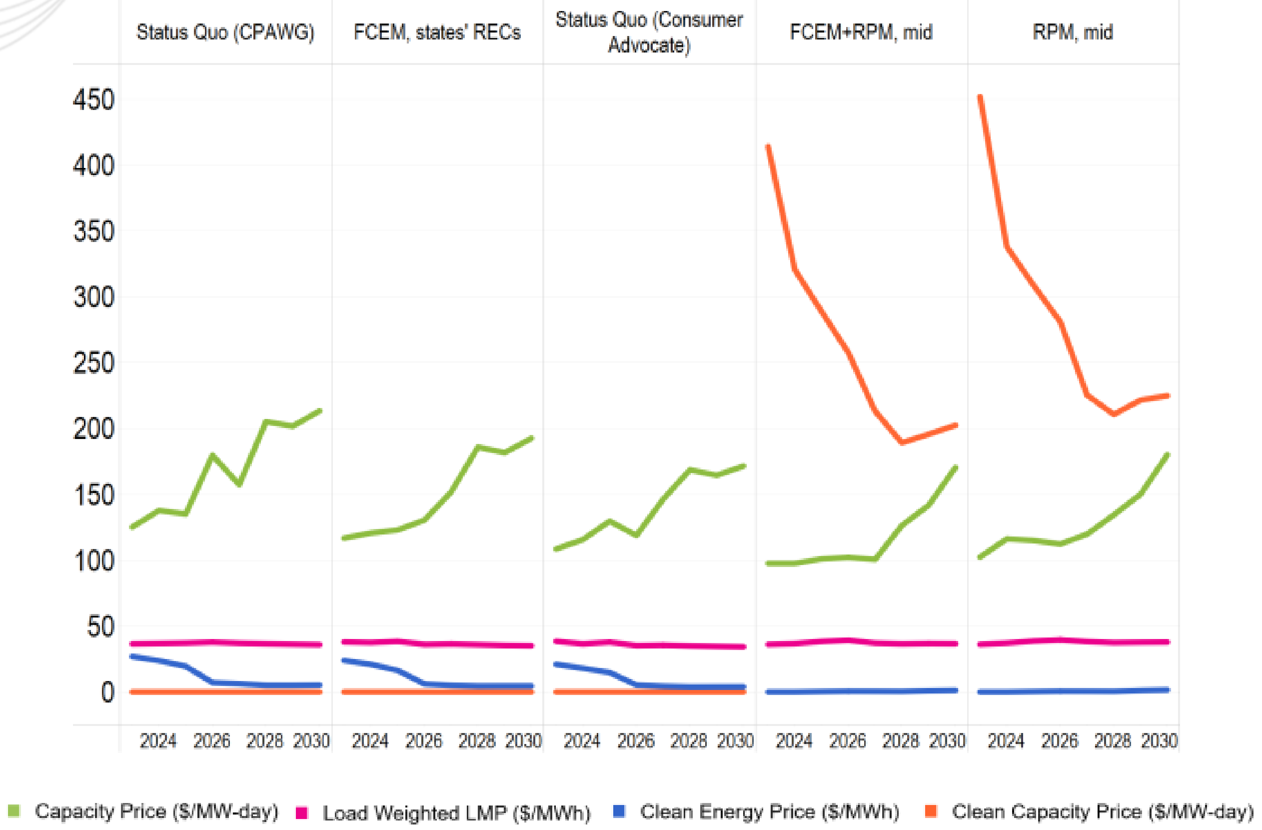
- In CPAWG's request, resources' offers embody an adder reflecting transaction costs that are assumed to exist in today's market for RECs and mitigated under centralized procurement
    1. Capacity and clean energy prices, and load costs are higher than in the FCEM+RPM with states product case (CPAWG's 2A)
    2. Similarly, load costs with clean capacity constraints are higher than in corresponding cases with the FCEM
- In the Consumer Advocate's request, resources offer at a discount in the status quo compared with the FCEM, reflecting assumed benefits of multi-year commitment and custom provisions
    1. Capacity and clean energy prices, and load costs are higher than in the FCEM+RPM with states product case (CPAWG's 2A)

Load costs and products' prices

Load payments (average 2023-2030; bil $)



Products prices ($/MW-day and $/MWh)



Data overview

The model uses inputs from Energy Exemplar's Eastern Interconnection dataset, NREL's 2022 Annual Technology Baseline, PJM processing of publicly available data, PLEXOS for production cost simulation, and PJM's proprietary models for forward markets and market dynamics simulations.

Raw data files

Model stage	File name	Description	Key
Forward markets	`forward_market_offers.csv`	Unit-level revenue expectations, costs, and offers in the forward markets (ICCM, FCEM, RPM) and unit-level clearing outcomes	scenario, year, resource_id
	`forward_market_products.csv`	Products' targets, nesting structure (e.g. LDAs) and cleared quantities and prices	scenario, year, product_id
Spot market	`spot_market_units_annual.csv`	Units' charateristics (e.g., marginal costs, FOM) and annual energy market outcomes (e.g., generation, profits)	scenario, year, resource_id
	`spot_market_zones_hourly.csv.zip`	Hourly zonal outcomes, e.g. load, generation, imports, exports, LMP, marginal emissions	scenario_index, resource_index, timestamp_index
	`spot_market_generation_hourly_X.csv_zip`	Hourly unit level state-of-charge, generation, net-generation	scenario_index, zone_index, timestamp_index

Indexes for hourly files	`scenarios_index.csv`
	`resources_index.csv`
	`zones_index.csv`
	`timestamp_index.csv`
		Mappings from scenario name to scenario index for reducing hourly files size; similarly for timestamp and resources identifiers	

PJM has created summary data files

- Content
  - Load, generation, forward products' procured quantities and prices, energy payments, profits, load payments, capital, fixed and production costs, nameplate by types, entry/exit of thermal resources
- Three aggregation levels
  - PJM: `pjm_annual_summary.csv`
  - State: `state_annual_summary.csv`
  - State-zone (includes MISO 4): `state_zone_annual_summary.csv`

Forward products' costs allocation

- Forward products are nested: DELMARVA → EMAAC → MAAC → PJM
- Shadow prices and costs must be stacked
- Example for DE products in FCEM, with states products case (CPAWG's 2A)

product_id	parent	share_of_parent_cost	Quantity procured (MW or GWh)	Procurement target (MW or GWh)	Price ($/MW-day or $/MWh)	Procurement costs (mil $)	Stacked prices ($/MW-day or $/MWh)	Stacked procurement costs (mil $)	cost_owner
RTO-renewable_hydro			97993.9	97993.9	22.6	2211	22.6	2211	
DE-solar	RTO-renewable_hydro	0.023	278.0	278.0	7.9	2	30.4	52	DE
RTO-capacity_types			178638.5	171749.0	116.7	7612	116.7	7612	
MAAC-capacity_types	RTO-capacity_types	0.366	69109.6	49305.6	0.0	0	116.7	2788	
EMAAC-capacity_types	MAAC-capacity_types	0.552	33150.9	24601.8	0.0	0	116.7	1540	
PJM_DelmarvaPL-capacity	EMAAC-capacity_types	0.127	5667.5	0.0	0.0	0	116.7	195	PJM_DelmarvaPL

- Costs are split and propagated iteratively from parent to child using *share_of_parent_cost*: 52 = 2 + 0.023 × 2211 (see `CAPSTF - Model inputs.xlsx`, blue and orange tabs for shares derivation)
- Next, energy (capacity) costs are allocated from the state (zone) to the zonal (state) level using *cost_owner* which keys to the shares in `CAPSTF - Model inputs.xlsx`, tab [state-zone_shares]

Next steps

- Answer IMM’s analysis request by simulating the capacity market first and then the forward clean energy market closer to real-time

- Improve modeling and assumptions based on states’ and stakeholders’ feedback

Appendix:
Assumptions, methodology, model assessment

Main assumptions, time and space

- Frequency
  - Annual for forward markets (FCEM, ICCM, RPM, etc.)
  - Hourly for energy market
- Footprint
  - 20 zones + Illinois non-PJM portion (MISO 4)
  - 14 Jurisdictions

    36 distinct zones/jurisdictions (e.g. OH-AEP)
  - Transmission limits between zones
    - import limits into MISO 4 set to 0 when solving capacity market
  - Locations differ in fuel prices and renewables' capacity factors

Main assumptions, resources definition and behavior

- **Resources definition**
  - Representative at the state/zone/technology levels (e.g. OH-AEP-CT)
  - Perfectly dispatchable (e.g. ignore start-up costs and times)
- **Behavior**
  - Existing resources offer:
    - Marginal cost in energy market
    - net-ACR in forward markets
  - New resources offer net-CONE in forward markets (if they clear they become existing and offer net-ACR in subsequent years)
  - In FCEM+RPM, clean resources bid into RPM net of FCEM revenues
  - Only resources clearing in forward markets stay/enter

Main assumptions, expectation formation

- Investors and PJM formulate expectations on energy profits and capacity factors by simulating the energy market *virtually* given cleared resources in latest capacity auction, future demand, fuel prices, and anticipated policy retirements
- In the FCEM case, 2023 expected capacity prices are set using ICCM outcomes, and then updated averaging past expectations and realizations

$$\textit{new expectation} = 0.7\ \textit{past expectation} + 0.3\ \textit{realization}$$

Main assumptions, policy

- States RPS targets
- States mandates for offshore, batteries, solar
- NJ nuclear is subsidized
- CT, CC, and CC with carbon capture and storage (after 2027) can be built anywhere
- Policy retirements as in “Energy Transition in PJM: Resource Retirements, Replacements & Risks” whitepaper

Main assumptions, average ELCC

- Renewables ELCC change over time as per previously released indicative PJM projections for informational purposes only
- Thermal ELCC = 1 – eFORD from 2023/2024 BRA

	2023	2024	2025	2026	2027	2028	2029	2030
Onshore wind	0.150	0.160	0.150	0.140	0.130	0.120	0.110	0.110
Offshore wind	0.400	0.370	0.350	0.340	0.330	0.310	0.300	0.290
Solar (tracking)	0.540	0.540	0.510	0.470	0.440	0.400	0.370	0.320
Battery	0.830	0.820	0.750	0.740	0.730	0.770	0.800	0.890
Run of river	0.960	0.960	0.950	0.930	0.920	0.930	0.940	0.980
CC	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964
CC (ccs)	0.964	0.964	0.964	0.964	0.964	0.964	0.964	0.964
CT	0.955	0.955	0.955	0.955	0.955	0.955	0.955	0.955
IC	0.955	0.955	0.955	0.955	0.955	0.955	0.955	0.955
Nuclear	0.991	0.991	0.991	0.991	0.991	0.991	0.991	0.991
Steam coal	0.872	0.872	0.872	0.872	0.872	0.872	0.872	0.872
Steam gas	0.872	0.872	0.872	0.872	0.872	0.872	0.872	0.872
Pump storage	0.950	0.950	0.950	0.950	0.950	0.950	0.950	0.950
DR	1.090	1.090	1.090	1.090	1.090	1.090	1.090	1.090

Data inputs

- Energy Exemplar's Eastern Interconnection (EI) dataset for fuel prices, renewables' capacity factors, list of existing resources and their characteristics, transmission topology
  - Resources are representative to allow data sharing with stakeholders courtesy of Energy Exemplar
  - Existing nameplates by state/zone/technology aligned with IMM's Q3 2022 state of the market report
- New resources' characteristics are from EI and NREL's 2022 Annual Technology Baseline (CT's major maintenance is in VOM)

Industry trends and model assumptions, fundamental costs

1. Cost pressures from supply chain restructuring and onshoring
   – Brattle’s quad study: CC CONE is 35% higher than in NREL
     ➡ We escalate FOM and CAPEX of all new resources by 35%
2. We use fuel prices from Energy Exemplar’s Eastern Interconnection dataset predating 2022 energy shocks

(1) and (2) lead to higher capacity and REC prices and costs. With NREL’s CONE (which is in line with 2023/2024 BRA), numbers are close to historical averages

Industry trends and model assumptions, policy

3. It will take time for the IRA to fully affect the queue (e.g., IHS)
   - 5pp CAPEX reduction per year down to 70% in 2028
4. Headwinds to new gas generation investments
   - Gas pipeline capacity
   - Investment uncertainty (e.g. policy)

In the model we ignore these headwinds. New gas investments continue to be economic, mainly in PA

5. Congestion in solar and onshore wind construction as in IHS
   – Up to twelve 500 MW completed projects per year and location (state/zone) with 5pp incremental costs (750MW in ComEd)
6. About 10.5GW-ICAP do not participate in RPM
   – Shift model VRR by 5GW-UCAP (or, we could adjust supply)

Model assessment

Results for FCEM with states' RECs in 2023

Quantities

- Annual Load: 766,818 GWh
- Peak Load: 152,967 MW
- ICAP: 203,816 MW
- UCAP: 171,749 MW
- RECs: 97,994

Prices

- LMP ($/MWh): 37.9
- Capacity ($/MW-day): 116.7
- REC Price: $23.9

Payments (mil $)

- Energy (gross of congestions): 29,039
- Capacity: 7,612
- REC: 2,157

Total: $38,809 mil

System Costs (mil $)

- FOM: 8,114
- Annualized CAPEX: 1,176
- Production: 14,359

Total: $23,649 mil

Emissions

- CO_2 (mil ton): 337.2
- NO_x (1000 ton): 109.6
- SO_x (1000 ton): 101.4