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Cleaner, Faster, Cheaper

Impacts of the Inflation Reduction Act and a Blueprint for Rapid Decarbonization in the PJM Interconnection

By Qingyu Xu, Neha Patankar, Mike Lau, Chuan Zhang, and
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Note: This study is published in the spirit of a working paper for public dissemination prior to peer review. Final publications based on this report will be subject to further peer review and may be revised. The content of this report, including any errors or omissions are the responsibility of the authors alone.

Table of Contents

Executive Summary

This study employs an electricity system capacity planning model with detailed economic dispatch and unit commitment decisions/constraints to quantitatively answer two key questions:

1. How does the enactment of the federal *Inflation Reduction Act of 2022* impact the cost of electricity, greenhouse gas emissions, and investment in electricity capacity in the PJM Interconnection over the 2023-2035 period?

2. Given new and expanded federal subsidies for clean electricity resources in the *Inflation Reduction Act*, what additional capacity investments and resource deployment would be required and at what cost for the PJM region to reduce greenhouse gas emissions 80-90% by 2035 while maintaining an affordable and reliable electricity supply?

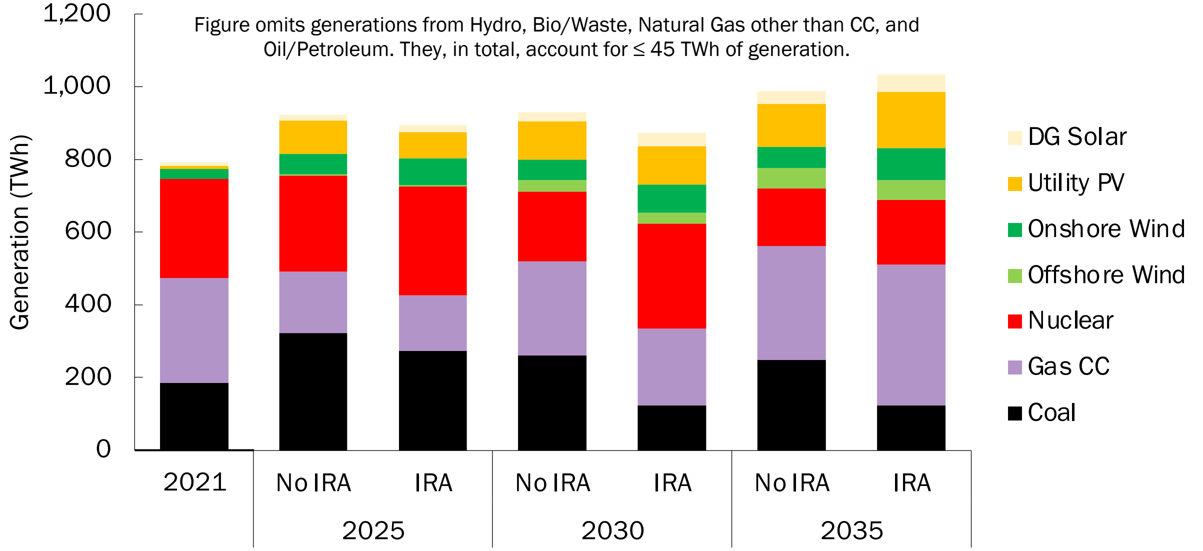
Executive Summary

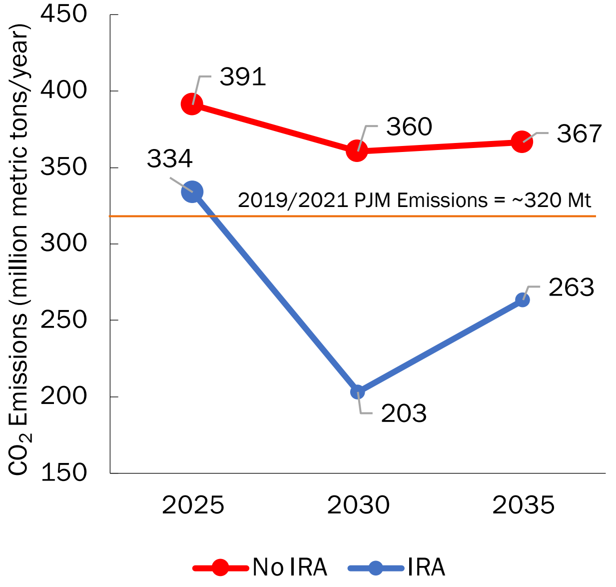
In August 2022, Congress passed and President Biden signed the *Inflation Reduction Act* (IRA), which enacts a comprehensive set of financial incentives (tax credits, grants, rebates, loans) that support all sources of carbon-free electricity, promote vehicle and building electrification and efficiency, and subsidize carbon capture and storage (CCS). **The implementation of IRA means that the full financial weight of the federal government is now behind the clean energy transition.** This will have transformative effects on the economics of decarbonization in the PJM Interconnection (and across the United States).

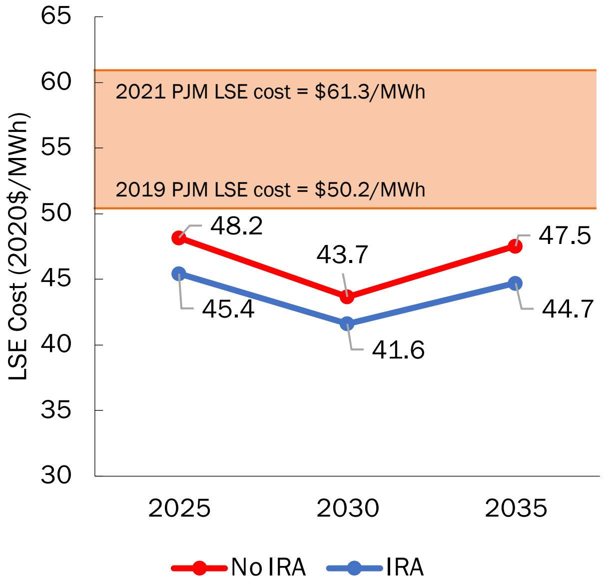
IRA will spark a new, sustained period of growth in PJM electricity consumption, which could rise ~19% from 2021 to 2030. The law also subsidizes the cost of deploying new renewable energy capacity and maintaining the region's existing nuclear fleet. As a result, this study finds that **clean electricity could supply 60% [58-66% across sensitivities] of PJM demand in 2030**, up from 48% [43-61%] without enactment of IRA. However, **realizing this potential will require a dramatic acceleration in the pace of wind and solar interconnection and transmission expansion in the PJM Interconnection.**

The growth of lower-cost, carbon-free electricity under **IRA will significantly reduce CO_2 emissions from PJM power generation, which could fall 37% [3-66%] from 2019/2021 levels.** In contrast, PJM emissions would increase 12% [0-15%] from 2021 levels without IRA. However, **PJM emissions may rebound after 2032 when a production tax credit for existing nuclear reactors established by IRA is set to expire.** Unless equivalent policy support is extended beyond 2032, our modeling finds 12 GW [0-33 GW] of the PJM nuclear fleet is likely to retire by 2035, with new natural gas capacity and generation increasing to fill the resulting gap and meet growing demand, reversing some of the emissions progress achieved through 2030.

In addition to driving down greenhouse gas emissions, **IRA also lowers the cost of electricity supply in the PJM region.** We find the average cost of bulk electricity supply for PJM load serving entities (LSEs), including transmission expansion and state policy requirements, will be about $42/MWh [~$40-45/MWh] in 2030, **about 5-10% lower than without IRA**, and well below costs paid in 2019 (~$50/MWh) and 2021 (~$61/MWh). The primary sources of cost savings are reduced wholesale energy prices, lower costs to meet state clean energy policy goals (due to federal subsidies), and growing demand (which spreads fixed costs over more MWh).

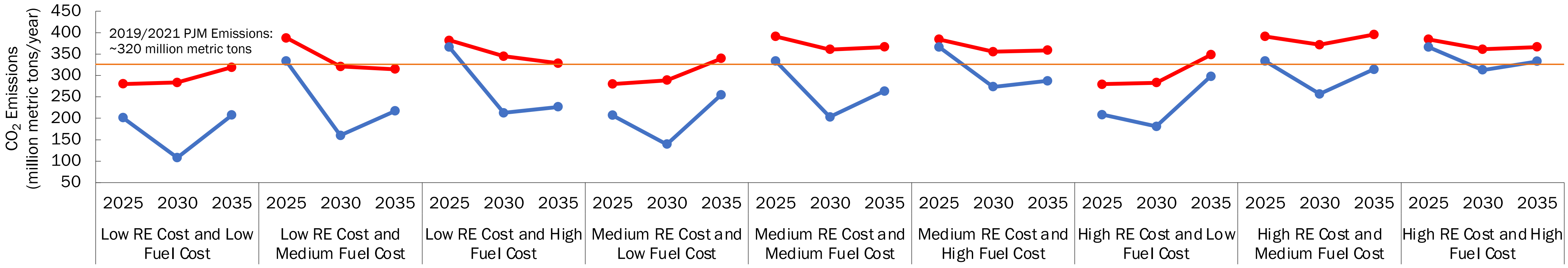


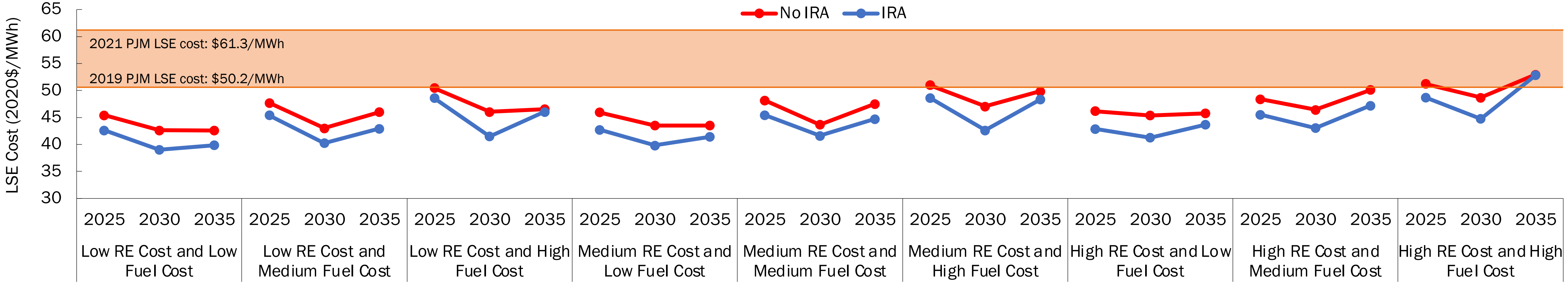




*Note: figures above depict results for mid-range fuel cost, mid-range renewable and battery CAPEX scenario, and mid-range load growth scenario. Sensitivity ranges across other modeled scenarios are presented in the text of this summary in brackets following results for the mid-range scenario. See next page for range of cost and emissions outcomes under other sensitivities.

Executive Summary – Part 1: Sensitivity to fuel and renewable energy costs





Sensitivity Level*	Fuel Cost – Natural Gas Price ($/MMBTU)	Fuel Cost – Coal Price ($/MMBTU)	Renewable/Battery Cost
Low	2025: 3.13; 2030: 2.72; 2035: 2.80	2025: 1.95; 2030: 1.84; 2035: 1.77	NREL ATB 2022 Advanced
Medium	2025: 4.36; 2030: 3.46; 2035: 3.64	2025: 2.08; 2030: 1.92; 2035: 1.89	NREL ATB 2022 Moderate
High	2025: 5.47; 2030: 5.16; 2035: 5.88	2025: 2.18; 2030: 2.03; 2035: 2.01	NREL ATB 2022 Conservative

* Note that the sensitivity table shows the fuel price of the U.S. national average price; modeled fuel prices are further differentiated by region and month of the year.

Executive Summary

While IRA puts the PJM region on a path to lower-cost electricity and lower greenhouse gas emissions, the **new federal policy is not sufficient to drive deep decarbonization of the PJM interconnection on its own.**

Fortunately, by subsidizing the cost of all new carbon-free electricity resources, **IRA also makes it cheaper and easier for PJM states to reduce emissions further while preserving affordability.**

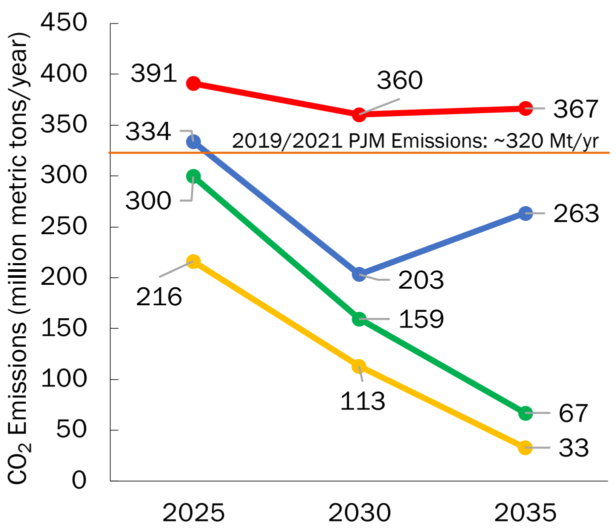
Part 2 of this study presents a cost-optimized blueprint of the additional capacity investments and resource deployment required for the PJM region to deeply decarbonize over the 2023-2035 period.

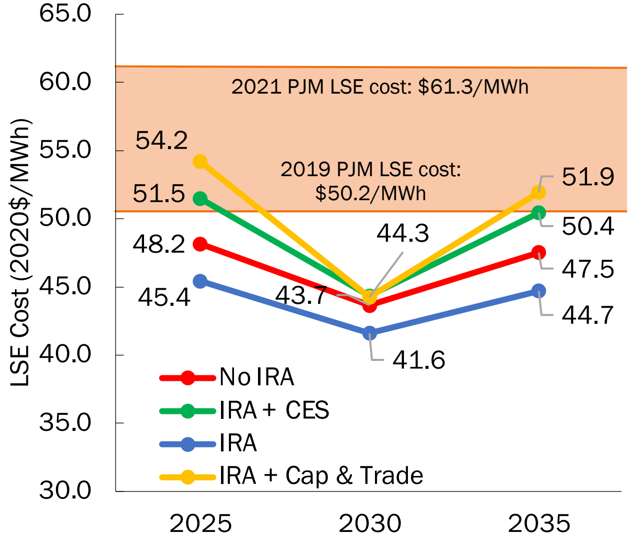
Specifically, we apply two stylized policy constraints and model the evolution of the PJM capacity mix and operations to meet those constraints:

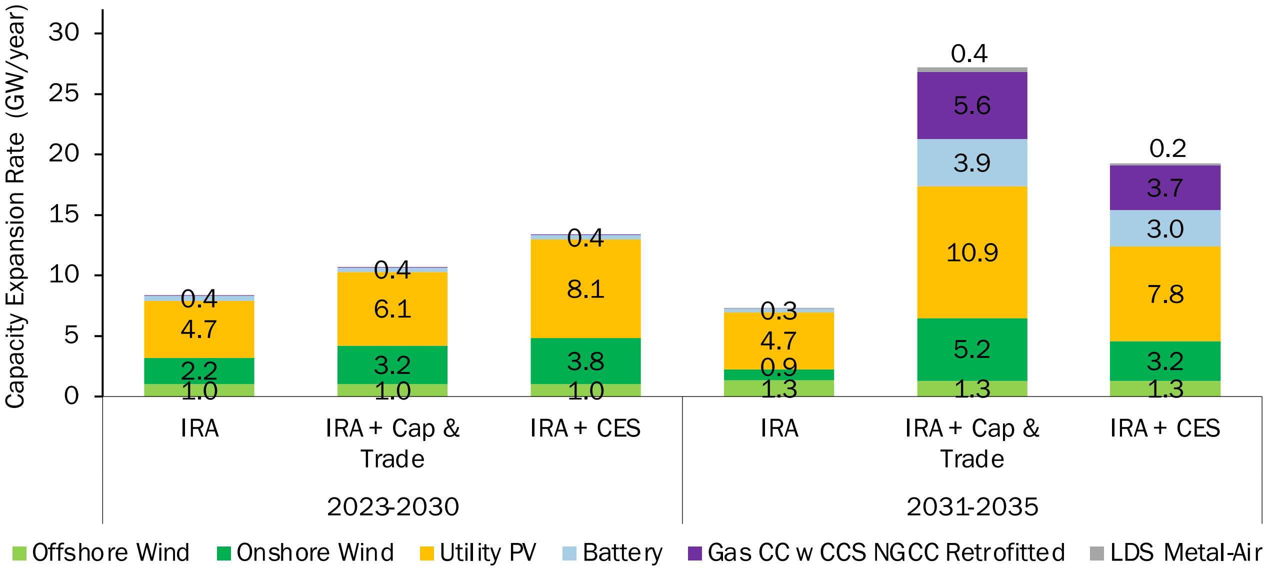
1. A clean electricity standard (CES) requiring increased shares of carbon-free electricity generation in the region (55% clean share by 2025, 70% by 2030, 85% by 2035), and;
2. A CO_2 emissions cap and trading scheme (cap & trade) requiring decreasing region-wide emissions (58% below 2005 emissions by 2025, 80% by 2030, 95% by 2035)

This study finds that, **due to passage of IRA, the PJM region could cut CO_2 emissions from power generation by 80-90% by 2035 while keeping average bulk electricity supply costs for LSE's comparable to or lower than levels experienced in recent years** (2019 & 2021).

However, deep decarbonization in the PJM region will require much more rapid expansion of low-carbon electricity resources and supportive transmission expansion above and beyond the rates of deployment made economical by IRA. By 2035, the region will also likely deploy more advanced 'clean firm' resources like gas power plants with carbon capture and storage (CCS) or long-duration electricity storage technologies (LDS), to replace coal- and gas-fired power capacity. We also identify and map several affordable resource portfolios and spatial patterns for clean electricity resource siting across the PJM region, demonstrating that the region has some flexibility to address local priorities and concerns.







*Note: figures above depict results for mid-range fuel cost, mid-range renewable and battery CAPEX scenario, and mid-range load growth scenario. See the main report for the range of cost and emissions outcomes under other sensitivities.

Modeling Framework and Key Cost Assumptions

GenX, an open-sourced & highly configurable capacity expansion planning model

- Optimization-based model (LP or MILP)
- Objective:
  - Minimize system cost (equivalent to maximizing welfare w/opportunity cost of price elastic demand curtailment)
- Decision variables:
  - Generation / storage / inter-regional transmission expansion, retirement, and operations
- Subject to
  - Operation limits and unit commitment
  - Hourly operations and variability of renewable resources & demand (in this study: across 27 7-day long representative periods)
  - Siting constraints and renewable energy supply curves
  - Policies including carbon pricing, cap & trade RPS/CES, and technology-specific mandates
  - Resource adequacy requirements (capacity reserve margin/capacity market)
- Modular and transparent code structure developed in Julia + JuMP

The global electricity system is undergoing a major transformation

In response, researchers at MIT and Princeton have developed **GenX**, an online tool for investment planning in the power sector.

MIT Energy Initiative

PRINCETON UNIVERSITY ZERO LAB Zero-carbon Energy Systems Research and Optimization Laboratory

The electricity sector is transforming

Electricity is central to national and global efforts to reduce carbon emissions. This sector is being reshaped with the deployment of variable renewable energy (VRE), energy storage, and innovative uses for distributed energy resources (DERs). At the same time, electrification of other sectors has the potential to improve energy efficiency overall, while also reshaping patterns of electricity demand and enabling the decarbonization of these end-uses. These changes—many of which may accelerate and deepen in future years—challenge current industrial practice for planning electricity systems.

Central to the planning process are models for making cost-optimal investments to meet future scenarios. Most current modeling workflows are missing aspects of spatial and temporal variability in inputs, operational flexibility, and interactions with other sectors. New tools are needed for the changing electricity landscape, including improved electricity resource capacity planning models.

New tool for electricity system planning

The MIT Energy Initiative and Princeton University's Zero-carbon Energy systems Research and Optimization (ZERO) Lab have developed an open-source tool for investment planning in the power sector, offering improved decision support capabilities for a changing electricity landscape.

GenX, a least-cost optimization model, takes the perspective of a centralized planner to determine the cost-optimal generation portfolio, energy storage, and transmission investments needed to meet a pre-defined system demand, while adhering to various technological and physical grid operation constraints, resource availability limits, and other imposed environmental, market design, and policy constraints.

Highly configurable

- Modular and transparent code structure developed in Julia + JuMP
- Adjustable level of technology operating constraints and advanced technology options
- Linear programming (LP) model or mixed integer linear programming model (MILP)
- Produce energy, capacity, and procured ancillary service prices
- Co-optimize transmission network expansion
- Co-optimize capacity and hourly operations decisions for a full year or representative periods
- Single- or multi-period investment planning
- Can model a range of policies from emissions caps and clean electricity standards to tax incentives
- Easily connect with other power system data pre-processing tools like PowerGenome
- Modeling to generate alternatives to produce diverse range of alternative near-least-cost portfolios

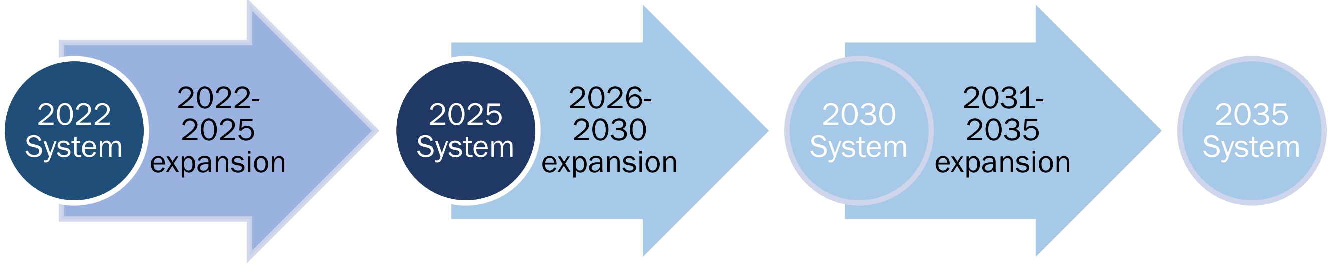
See http://genx.mit.edu for overview and link to open source code & documentation

GenX planning framework

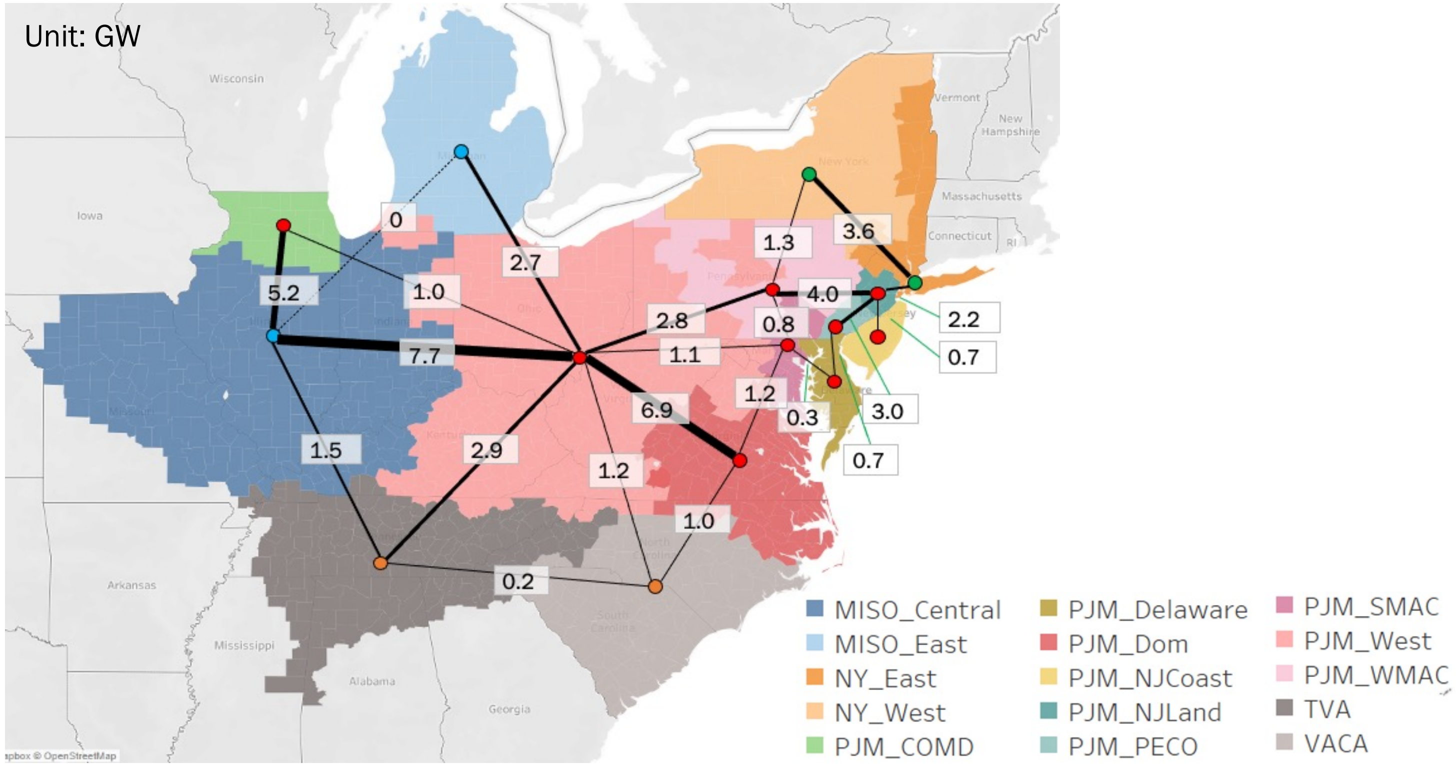
Assumptions in this study:

- Data populated by open-sourced power system data and scenario compiler, *PowerGenome*
- 15-zone network: based on EPA Integrated Planning Model (IPM) zones; 9 PJM zones, 6 neighboring zones
- Existing Generation Data: EIA 860m @ June 2022
- Wind and solar candidate project areas (4km x 4 km) from REPEAT Project grouped into 311 resource clusters in the study region;
- Load: per unit time-series from NREL *Electrification Futures Study*; vehicle & heating stock values from REPEAT Project.
- Climate year: 2012 (removing Hurricane Sandy impact)
- Base capital cost and sensitivity: NREL *Annual Technology Baseline 2022*; Regional multipliers: *EIA Annual Energy Outlook 2020*;
- Base fuel cost assumption and sensitivities: EIA *Annual Energy Outlook 2022* adjusted in 2023-2025 planning period to reflect current elevate prices; monthly natural gas price variation based on 2019 historical prices from EIA.
- State- and Regional level policies: as enacted by Dec. 2021
- Capacity reserve requirement for PJM based on NERC planning margin

Expansion proceeds 'myopically' in three planning stages
(results from the 1st stage become inputs for the 2nd stage, results from 2nd stage become inputs for 3rd stage)



Starting Transmission Capacity in 2022

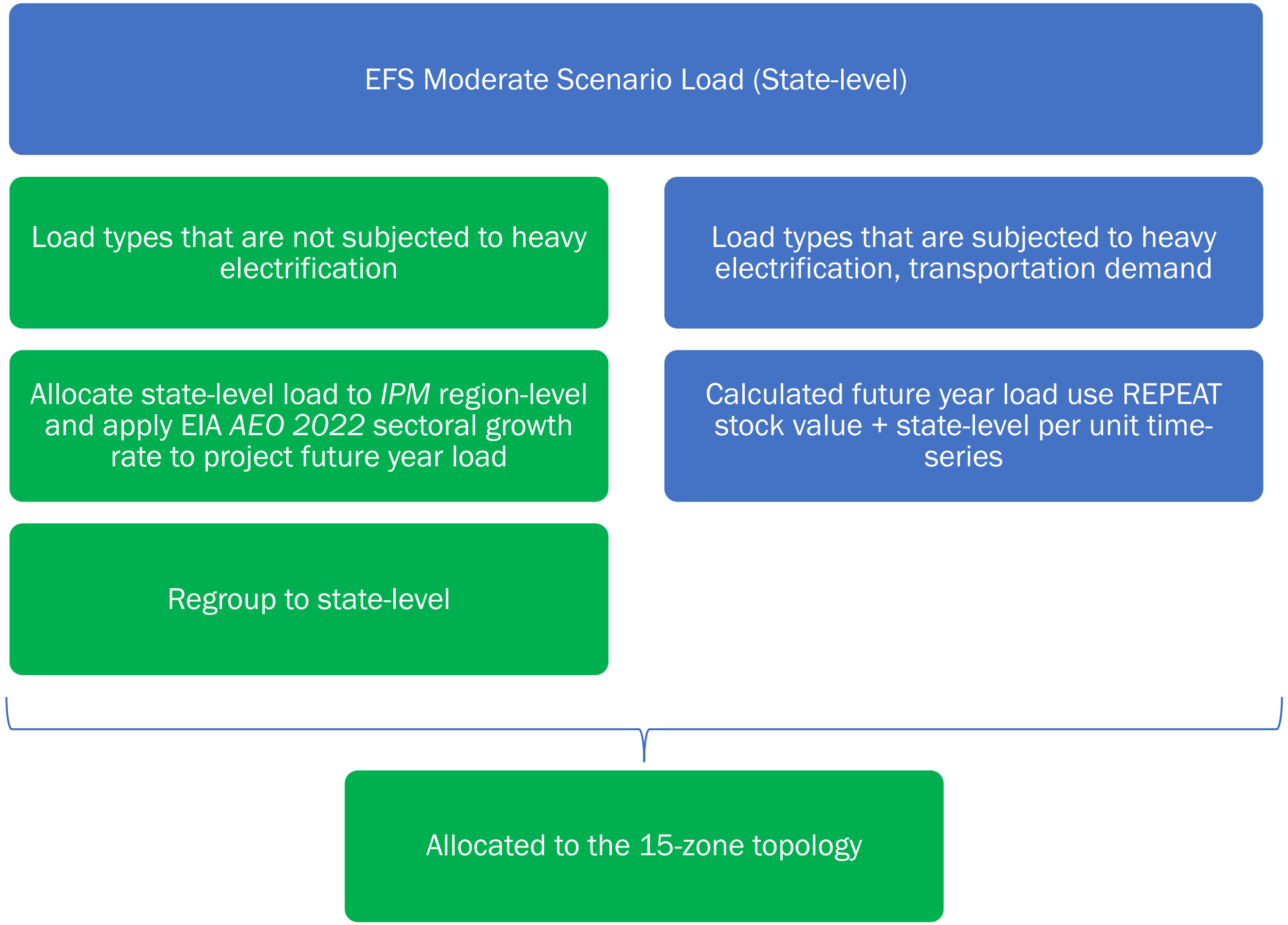


Load projection

The projected load (electricity demand) for this study is a result of combining per-unit profiles from the NREL *Electrification Future Study* (*EFS*), vehicle and heating stock values from the REPEAT project, and sectoral growth rates from EIA *Annual Energy Outlook 2022* (*AEO 2022*).

REPEAT Project provides the stock value of each demand technology that consumes energy, for example, light-duty vehicles (per vehicle) or heating pumps for commercial space heading & cooling (per MMBTU capacity).

State-level per unit time-series are 8760-hour electricity usage profiles of demand technologies – e.g., the MW consumption per MMBTU capacity of a dual-use heat pump. These per-unit time series are calculated from NREL's *EFS* study by the ZERO Lab. The MW electricity usage profiles of electric vehicles are further adjusted by temperatures in the climate year 2012 with the methodology demonstrated in Yuksel and Michalek, (2015).



NREL, "Electrification Futures Study - Demand-Side Scenarios", 2018: https://www.nrel.gov/docs/fy18osti/71500.pdf
ZERO Lab, "Rapid Energy Policy Evaluation and Analysis Toolkit (REPEAT)," 2022: https://repeatproject.org/
EIA, "Annual Energy Outlook 2022," 2022: https://www.eia.gov/outlooks/aeo/
Yuksel and Michalek," Effects of Regional Temperature on Electric Vehicle Efficiency, Range, and Emissions in the United States," *Environ. Sci. Technol.* 2015, 49, 3974-3080

Fuel prices and CO_2 content

Fuel prices are first downloaded from *AEO 2022*. Fuel prices in 2025 are adjusted higher, reflecting the fuel price surge caused by the Russia-Ukraine War. We assume the fuel price will return to the level that EIA projected for 2030 and 2035. Furthermore, the annual average natural gas prices are differentiated monthly based on the 2019 monthly natural gas price fluctuation.

Fuel Price ($/MMBTU)		West North Central			Middle Atlantic			East North Central			South Atlantic			Biomass	Uranium
Year	Scenario	Coal	Natural Gas	Distillate Oil	Coal	Natural Gas	Distillate Oil	Coal	Natural Gas	Distillate Oil	Coal	Natural Gas	Distillate Oil		
2025	High	1.76	5.75	21.93	2.16	5.29	28.45	2.10	5.25	21.78	2.57	6.57	26.46	5.00	0.69
	Medium	1.68	4.57	20.01	2.06	4.21	25.96	2.01	4.18	19.87	2.45	5.23	24.14	5.00	0.69
	Low	1.57	3.29	17.70	1.93	3.02	22.97	1.88	3.00	17.59	2.30	3.75	21.36	5.00	0.69
2030	High	1.63	5.44	17.26	2.06	4.44	23.73	1.96	4.92	17.21	2.35	5.83	21.82	5.00	0.70
	Medium	1.55	3.65	15.65	1.95	2.98	21.51	1.86	3.30	15.06	2.23	3.91	19.78	5.00	0.70
	Low	1.48	2.87	15.06	1.87	2.34	20.69	1.78	2.59	15.01	2.13	3.07	19.03	5.00	0.70
2035	High	1.63	6.15	18.38	1.97	4.86	24.95	1.97	5.28	18.32	2.39	6.41	23.01	5.00	0.71
	Medium	1.53	3.81	16.37	1.84	3.01	22.22	1.84	3.27	16.31	2.24	3.97	20.49	5.00	0.71
	Low	1.44	2.93	15.32	1.73	2.31	20.80	1.73	2.51	15.27	2.11	3.05	19.18	5.00	0.71

	Coal	Natural Gas	Distillate Oil
CO_2 Content (Metric Ton/MMBTU)	0.09552	0.05306	0.07315

Natural Gas Multiplier	Jan.	Feb.	Mar.	Apr.	May	Jun.	Jul.	Aug.	Sep.	Oct.	Nov.	Dec.
East North Central	142%	120%	132%	106%	104%	97%	95%	90%	93%	80%	103%	90%
West North Central	137%	160%	134%	93%	93%	84%	89%	77%	89%	88%	103%	112%
Middle Atlantic	168%	137%	127%	95%	91%	87%	87%	81%	79%	74%	99%	100%
South Atlantic	142%	112%	114%	102%	102%	92%	91%	87%	92%	83%	102%	101%

East North Central fuel region covers PJM ComEd and PJM West; the West North Central fuel region covers MISO East (lower Michigan) and MISO Central; the Middle Atlantic fuel region covers NYISO, PJM East MAAC, and West MAAC; the South Atlantic fuel region covers PJM South MAAC, TVA, and Carolinas.

Technology cost: renewable energy and Li-ion battery

Technology cost assumptions are obtained from NREL *Annual Technology Baseline 2022* (*ATB 2022*), with High = NREL's conservative, Medium = NREL's Moderate, and Low = NREL's Advanced; CAPEX and FOM are the average of costs for each year in the planning stage – e.g., the cost in 2022-2025 is the average of the 2023 cost, 2024 cost, and 2025 cost. The final investment cost, used as an input to GenX, is equal to the (annuitized CAPEX x regional multiplier) + spur line cost. Weighted average cost of capital (WACC) is from NREL *ATB 2022* and reflects real (inflation adjusted) costs. The following table reflects the cost before any applicable tax credit.

2020USD		Utility Photovoltaic Lifetime = 30 years, WACC = 2.6%		Onshore Wind Lifetime = 30 years, WACC = 3.8%		Offshore Wind Lifetime = 30 years, WACC = 4.4%		Li-ion Battery, Duration = 1-10 hours (optimized by GenX), Lifetime = 15 years, Roundtrip Efficiency = 85% , WACC = 2.6%			
Year	Scenario	CAPEX ($/kW)	FOM ($/kW-year)	CAPEX ($/kW)	FOM ($/kW-year)	CAPEX ($/kW)	FOM ($/kW-year)	CAPEX ($/kW)	FOM ($/kW)	CAPEX (Energy, $/kWh)	FOM (Energy, $/kWh-year))
2023-2025	High	1159.0	20.3	1277.2	43.0	3501.7	111.0	218.5	5.5	283.6	7.1
	Medium	1027.7	18.8	1257.2	41.4	2957.6	97.1	241.7	6.0	233.4	5.8
	Low	983.1	18.1	1157.2	39.6	2696.5	90.2	181.3	4.5	235.4	5.9
2026-2030	High	1152.4	20.1	1096.4	43.0	3349.0	105.8	198.5	5.0	257.7	6.4
	Medium	845.5	16.4	1056.2	39.8	2747.6	89.3	255.7	6.4	179.4	4.5
	Low	741.0	14.8	855.4	36.1	2470.8	81.4	130.8	3.3	169.8	4.2
20312035	High	1090.3	19.2	991.1	42.7	3229.4	101.5	189.5	4.7	246.1	6.2
	Medium	734.2	14.9	927.2	38.1	2584.4	82.8	254.7	6.4	151.7	3.8
	Low	597.1	12.9	677.9	32.8	2295.6	74.1	105.7	2.6	137.2	3.4

Technology cost: firm resources

Technology costs are obtained from NREL *ATB 2022*; NGCC and NGCT use NREL's moderate case; NGCC w CCS use NREL's conservative case; CAPEX and FOM are the average of each year in the period – e.g., the cost in 2022-2025 is the average of the 2023 cost, 2024 cost, and 2025 cost. The final investment cost, used as an input to GenX, is equal to the (annuitized CAPEX x regional multiplier) + spur line cost + carbon pipeline cost (for power plants with CCS, if applicable). Furthermore, CO_2 injection costs for NGCC w/CCS are treated as a variable cost and calculated based on NETL 2017 report; all PJM CCS power plants modeled in this study are assumed to inject the captured CO_2 into the Illinois basin. To retrofit an existing NGCC plant to NGCC w/ CCS, the cost is 60% of a new NGCC plant with CCS; to repower a retired coal-fired power plant to NGCC w/ CCS, the cost is 89% of a new NGCC plant with CCS. Furthermore, retrofitting and repowering utilize the built interconnection line, and therefore the spur line cost is ignored. These assumptions are adopted from the REPEAT Project. Metal-Air long-duration energy storage cost is obtained from Baik et al. (2021). The following tables reflect the cost before any applicable tax credit.

2020 USD	Natural Gas Combined Cycle (NGCC) Lifetime = 30 years, WACC = 3.3%				Natural Gas Combustion Turbine (NGCT) Lifetime = 30 years, WACC = 3.3%				Natural Gas Combined Cycle with CCS with 90% capture rate Lifetime = 30 years, WACC = 3.9%, Injection cost = $18.7/metric ton			
Year	CAPEX ($/kW)	FOM ($/kW-year)	VOM ($/MWh)	Heat Rate (MMBTU/kWh)	CAPEX ($/kW)	FOM ($/kW-year)	VOM ($/MWh)	Heat Rate (MMBTU/kWh)	CAPEX ($/kW)	FOM ($/kW-year)	VOM ($/MWh)	Heat Rate (MMBTU/kWh)
2023-2025	951.0	28.0	2.0	6.36	834.8	21.0	5.0	9.72	Expandable only in 2026-2035			
2026-2030	921.9	28.0	2.0	6.36	793.0	21.0	5.0	9.72	2307.6	67.0	6.0	7.16
2031-2035	899.3	28.0	2.0	6.36	766.9	21.0	5.0	9.72	2211.1	67.0	6.0	7.16

Advanced Clean Firm Technologies	Advanced Nuclear Lifetime = 40 years, WACC = 3.3%				Metal-Air Storage (50-200 hours) Lifetime = 25 years, WACC = 2.6%, Round-trip efficiency = 42%		
	CAPEX ($/kW)	FOM ($/kW-year)	VOM ($/MWh)	Heat Rate (MMBTU/kWh)	CAPEX ($/kW)	CAPEX (Energy, $/kWh)	FOM ($/kW-year)
Only available in 2031-2035	4300.0	146.0	2.84	10.44	1200.0	12.0	30.0

- NTEL 2017, National Energy Technology Laboratory. 2017. "FE/NETL CO2 Saline Storage Cost Model." U.S. Department of Energy. Last Update: Sep 2017 (Version 3)
- Baik et al. 2021. "What is different about different net-zero carbon electricity systems?" Energy and Climate Change, Volume 2, 100046, 2021, DOI: 10.1016/j.egycc.2021.100046

Capacity potential, capacity factor, CAPEX cost multiplier, and spur line cost for renewables

Model Regions	Utility-scale Photovoltaic				Onshore Wind				Offshore Wind				Li-ion Battery*
	Potential (GW)	Capacity Factor**	CAPEX Multiplier^	Spur line Cost Annuity ($/kW-year)	Potential (GW)	Capacity Factor	CAPEX Multiplier^	Spur line Cost Annuity ($/kW-year)	Potential (GW)	Capacity Factor	CAPEX Multiplier^	Spur line Cost Annuity ($/kW-year)	CAPEX Multiplier
MISO Central	110.9	26.3-26.7%	1.018	2.0-11.9	48.1	34.5-50.5%	0.955	2.5-24.8	No potential				1.035
MISO East (Lower Michigan)	15.4	26.1%	1.008	8.7	4.8	40.5-45.9%	1.144	4.9-36.5	No potential				1.002
NYISO East	2.8	25.6-26.2%	1.197	9.0-99.0	2.7	30.8-49.6%	1.372	15.8-54.0	14.9	44.2-47.6%	1.006	61.5-75.4	1.027
NYISO West	16.3	25.2%	1.008	9.3	13.3	40.3-53.2%	1.544	16.0-25.3	No potential				1.004
PJM ComEd	123.6	25.6-26.9%	1.069	3.7-49.3	31.7	41.6-45.0%	1.264	18.0-32.1	No potential				1.010
PJM EMAAC Delmarva	3.1	26.0-26.2%	1.038	4.8-13.1	No potential				15.2	44.2-45.3%	1.000	44.3-52.9	1.007
PJM Dominion	60.5	25.4-26.2%	0.977	1.5-54.5	9.9	33.3-50.8%	1.318	8.0-25.3	18.5	43.9-46.1%	1.041	41.6-56.8	1.007
PJM EMAAC New Jersey Coastal	0.8	26.0%	1.038	4.9-6.3	No potential				8.3	44.6-45.7%	1.000	41.3-43.2	1.007
PJM EMAAC New Jersey Inland	24.1	25.4-25.7%	1.038	5.7-41.7	No potential				22.7	44.8-46.7%	1.000	42.5-46.4	1.007
PJM EMAAC PECO	6.2	25.4-26.0%	1.038	1.6-22.2	0.6	36.8-42.9%	1.266	4.2-19.3	No potential				1.007
PJM SMAAC	2.7	25.6-26.0%	1.038	4.8-29.0	0.1	33.4%	1.266	28.4	No potential				1.007
PJM WEST	173.2	25.3-26.8%	0.980	1.9-49.7	28.3	28.2-50.0%	0.955	4.3-27.6	No potential				0.997
PJM WMAAC	15.8	25.4-25.6%	1.038	3.2-22.4	5.3	43.0-47.4%	1.266	8.8-29.1	No potential				1.007
SERC-TVA	71.8	26.0-26.4%	0.963	2.2-9.7	50.6	34.4-43.6%	0.955	4.3-17.4	No potential				1.026
SERC-Carolinas	75.2	25.5-25.8%	0.997	2.4-19.8	No potential				70.9	39.4-44.2%	0.900	45.3-338.9	1.033

* Li-ion Battery is assumed to be deployed close to the main grid, and thus the spur line cost is ignored
** Capacity factors here reflect annual average availability of the capacity before curtailment; GenX takes inputs of hourly profiles and optimizes variable renewable energy dispatch, which may include curtailment.
^ Capex multiplier modifies the CAPEX reported on p. 14 and reflects local variations in cost of labor, land acquisition, materials, etc. (Source: EIA *AEO 2020*).

CAPEX cost multiplier and spur line cost for firm resources

	Natural Gas Combined Cycle (NGCC)		Natural Gas Combustion Turbine (NGCT)		Natural Gas Combined Cycle with CCS (NGCC w/CCS)			Advanced Nuclear		Metal-Air Storage *
	CAPEX Multiplier	Spur line Cost Annuity ($/kW-year)	CAPEX Multiplier	Spur line Cost Annuity ($/kW-year)	CAPEX Multiplier	Spur line Cost Annuity ($/kW-year)	CO_2 Pipeline cost ($/kW-year)	CAPEX Multiplier	Spur line Cost Annuity ($/kW-year)	CAPEX Multiplier
MISO Central	1.052	2.1	1.051	20.6	1.052	4.1	2.6	1.109	10.3	1.035
MISO East (Lower Michigan)	1.080	2.2	1.083	21.7	1.080	4.3	54.0	1.071	10.8	1.002
NYISO East	1.624	2.7	1.456	27.5		Not Expandable**		1.372	13.7	1.027
NYISO West	1.166	2.7	1.087	27.5		Not Expandable**		1.057	13.7	1.004
PJM ComED	1.249	2.7	1.237	27.5	1.249	5.5	2.6	1.217	13.7	1.010
PJM EMAAC Delmarva	1.192	2.7	1.123	27.5		Not Expandable**		1.107	13.7	1.007
PJM Dominion	1.102	2.7	1.018	27.5		Not Expandable**		1.018	13.7	1.007
PJM EMAAC New Jersey Coastal	1.192	2.7	1.123	27.5		Not Expandable**		1.107	13.7	1.007
PJM EMAAC New Jersey Inland	1.192	2.7	1.123	27.5		Not Expandable**		1.107	13.7	1.007
PJM EMAAC PECO	1.192	2.7	1.123	27.5		Not Expandable**		1.107	13.7	1.007
PJM SMAAC	1.192	2.7	1.123	27.5		Not Expandable**		1.107	13.7	1.007
PJM WEST	0.976	2.7	0.958	27.5	0.976	5.5	35.5	0.978	13.7	0.997
PJM WMAAC	1.192	2.7	1.123	27.5		Not Expandable**		1.107	13.7	1.007
SERC-TVA	0.944	2.0	0.948	20.1	0.944	4.0	6.5	1.019	10.0	1.026
SERC-Carolinas	0.911	2.0	0.914	20.1		Not Expandable**		1.009	10.0	1.033

* Metal-Air Storage is assumed to be deployed close to the main grid, and thus the spur line cost is ignored
** Natural Gas Combined Cycle with CCS is assumed to be infeasible if distance from the Illinois basin for geologic storage.
^ Capex multiplier modifies the CAPEX reported on p. 15 and reflects local variations in cost of labor, land acquisition, materials, etc. (Source: EIA *AEO 2020*).

Federal tax credits

IRA provides developers of carbon-free electricity resources with the option to select a 30% Investment Tax Credit (ITC) *or* a Production Tax Credit (PTC) valued at $26/MWh* for 10 years. We assume that offshore wind & new nuclear will select the ITC and onshore wind & utility-scale PV will select the PTC, based on calculation of the lifetime discounted value of each credit for each wind or solar resource cluster (See Figure M-1) and nuclear site. Energy storage will be eligible for a 30% ITC, CCS generators are eligible for 45Q credit for CO2 storage, and existing nuclear units receive new PTC worth up to $15/MWh from 2024-2032.

Technology	IRA Rule	Model Input**
Offshore wind, nuclear, and storage	30% ITC	28% ITC.
Onshore Wind	$26/MWh* for 10 years	2020USD $9.7/MWh, assuming a 30-year lifetime, WACC = 3.8%.
Utility-level PV	$26/MWh* for 10 years	2020USD $8.8/MWh, assuming a 30-year lifetime, WACC = 2.6%.
Carbon Capture and Sequestration	$85/metric ton CO_2e for 12 years	2020USD $39.9/metric ton CO_2e, assuming a 30-year lifetime, WACC = 3.9%.
Existing Nuclear	Up to $15/MWh^	Prevent existing nuclear from retiring before 2032.

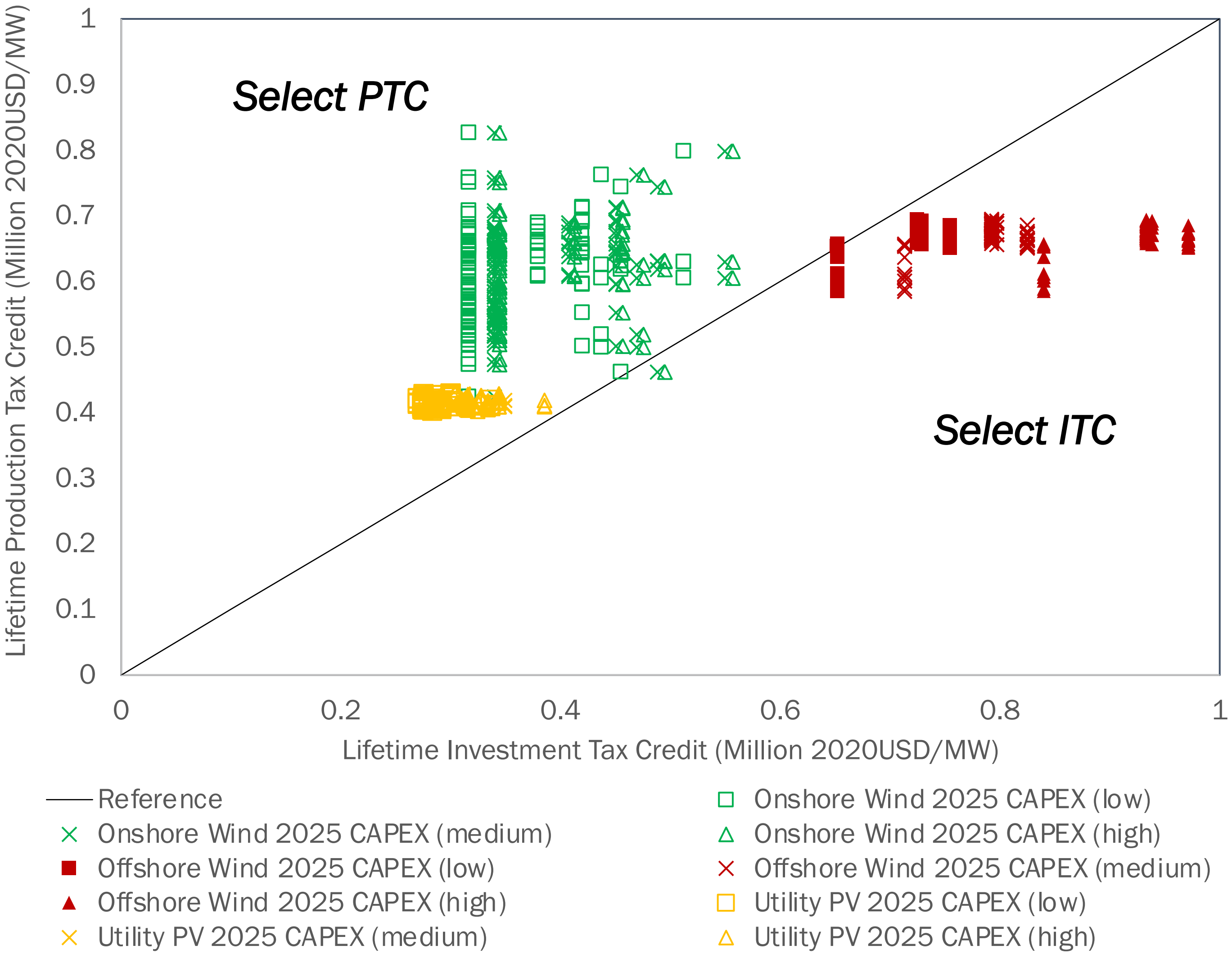


Figure M-1: Discounted lifetime production tax credit (PTC) versus investment tax credit (ITC) for wind and utility-scale PV. *Using NREL ATB 2022's CAPEX for 2025, this figure shows that offshore wind developers would likely select ITC while onshore wind and utility-level PV developers would likely select PTC. New nuclear development will select ITC like the offshore wind because of the high capital investment cost.*

* $26/MWh is in 2022 USD; if converted to 2020 USD, PTC is about $22.6/MWh.

** We assume that tax credits other than 45Q will incur a transaction cost of 7.5% to transfer the credit value to a third party. 45Q is eligible for election of direct payment over five consecutive years, so we assume its value is fully monetized by the recipient without transfer.

^ If energy, capacity & ancillary services revenue is >$25/MWh, the subsidy is reduced by 80 cents per dollar over $25.

Wind and solar candidate project areas

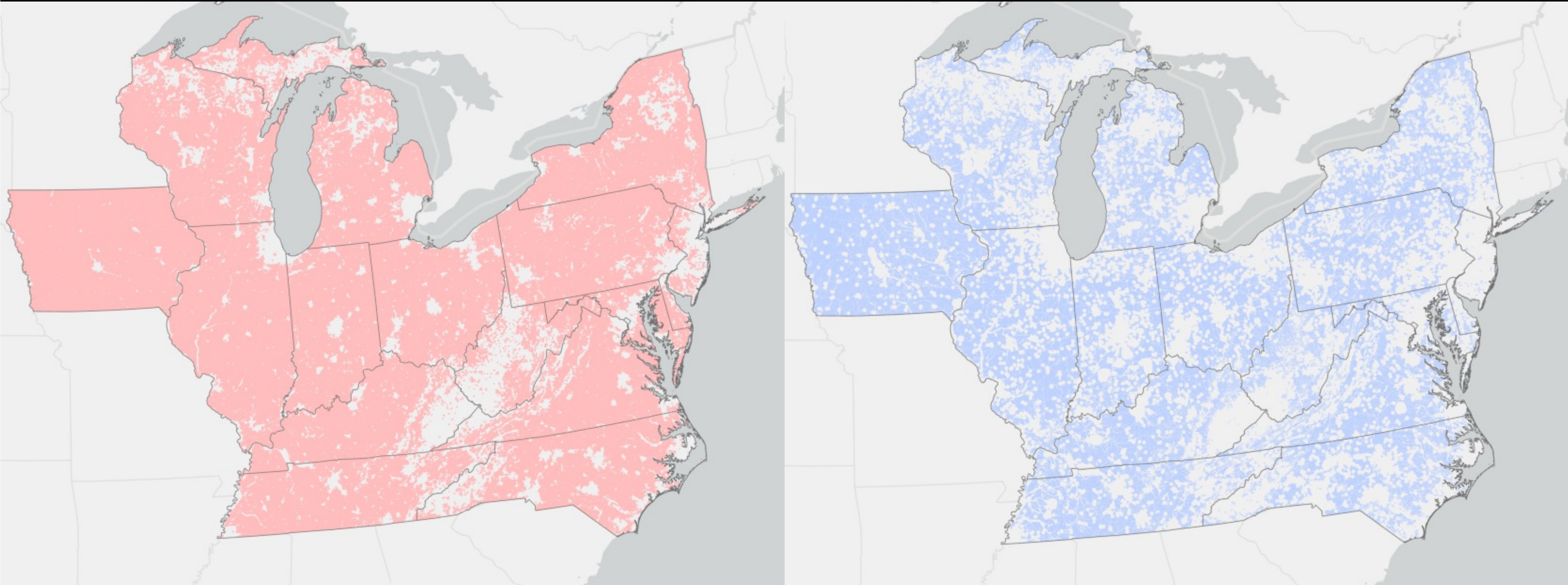


Figure M-2: Candidate project areas (CPAs) for utility-scale solar PV (left) and onshore wind (right) used in this modeling study.

Candidate project areas (CPAs) are the portion of 4km by 4km grid cells suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes). For details and geospatial files, see Leslie et al. (2022), "Wind and Solar Candidate Project Areas for Princeton REPEAT Project" available at: https://doi.org/10.5281/zenodo.4726433.

Main Results

This study employs an electricity system capacity planning model with detailed economic dispatch and unit commitment decisions/constraints to quantitatively answer two key questions:

1. How does the enactment of the federal *Inflation Reduction Act of 2022* impact the cost of electricity, greenhouse gas emissions, and investment in electricity capacity in the PJM Interconnection over the 2023-2035 period?
2. Given new and expanded federal subsidies for clean electricity resources in the *Inflation Reduction Act*, what additional capacity investments and resource deployment would be required and at what cost for the PJM region to reduce greenhouse gas emissions 80-90% by 2035 while maintaining an affordable and reliable electricity supply?

Part 1: Impact of Inflation Reduction Act on the PJM System

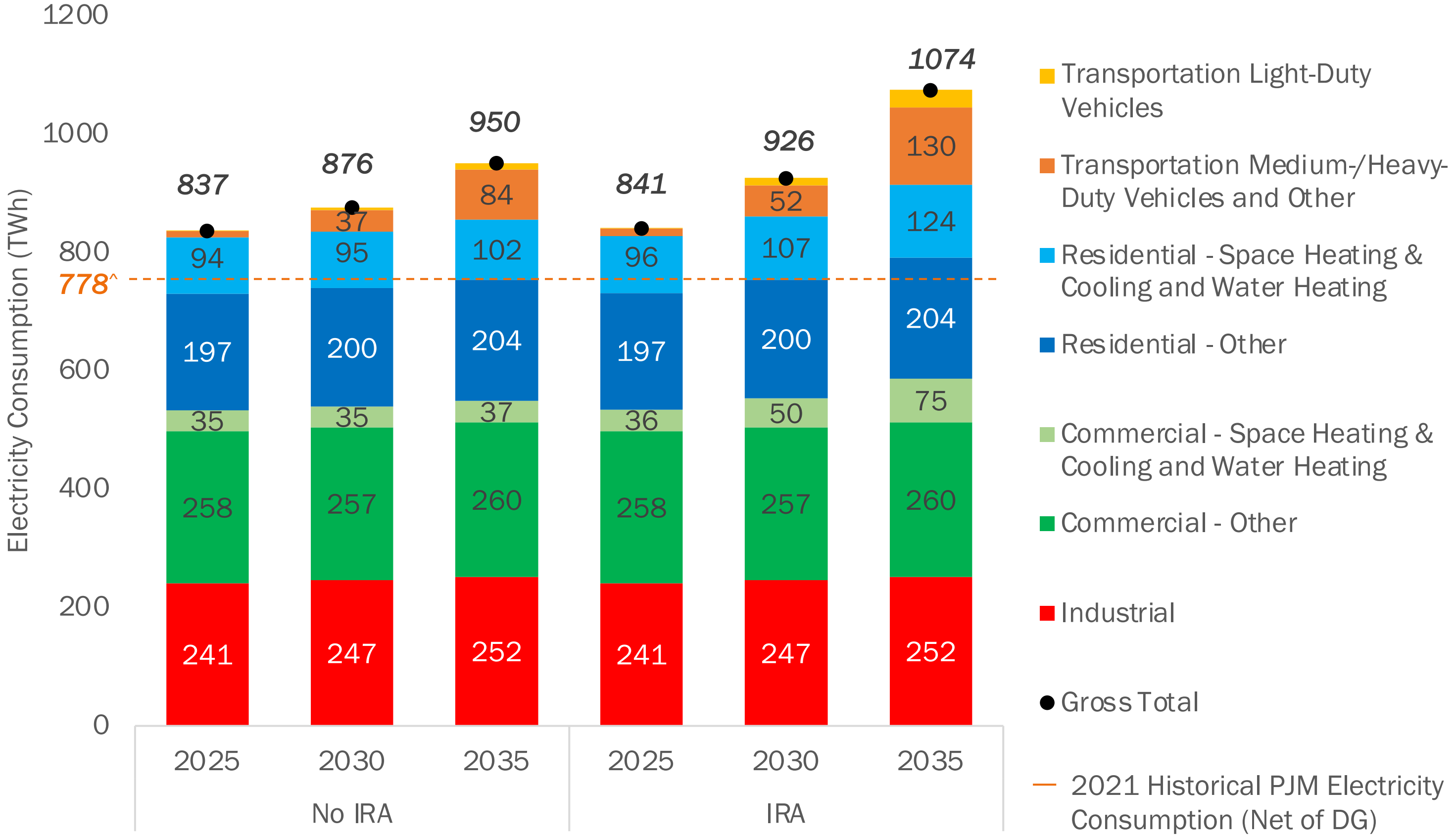
In August 2022, Congress passed and President Biden signed into law the *Inflation Reduction Act* (IRA), which enacts a comprehensive set of financial incentives that support all sources of carbon-free electricity, promote vehicle and building electrification and efficiency, and subsidize carbon capture and storage (CCS), among other policies. Implementation of IRA means that the full financial weight of the federal government is now behind the clean energy transition. This will have transformative effects on the economics of decarbonization in the PJM Interconnection (and across the United States). Herein we model the impacts of IRA on the cost of electricity, greenhouse gas emissions, and investment in electricity capacity in the PJM Interconnection over the 2023-2035 period

Key IRA policies affecting the supply and demand for electricity include provisions to:

- Accelerate **electrification** of transportation and space and water heating and improve **energy efficiency** via a package of tax credits, grants, and rebates;
- Restore the full value of the production tax credit ($26/MWh in 2022 USD) and investment tax credit (30% of capital costs) for renewable electricity while extending the availability of the credit to any **carbon-free electricity generation** that commences construction before the year after U.S. power sector CO_2 falls to 25% of 2022 levels *or* 2033, whichever comes *later* (with bonus credit available for deployment in fossil energy communities and/or use of domestic content);
- Provide a new 30% investment tax credit for stand-alone **energy storage** (with same term of eligibly and bonus credit opportunities as above);
- Establish a new production tax credit worth up to $15/MWh from 2024-2032 to preserve **existing nuclear power plants**;
- Restore and extend the 30% investment tax credit for **residential solar PV** through 2032 (with bonus credit for deployment in low-income communities);
- Extend and increase the 45Q tax credit for **carbon capture and storage (CCS)** to $85/t for projects commencing construction before the end of 2032;
- Create a new production tax credit worth up to $3/kg for **clean hydrogen** production for projects commencing construction before the end of 2032;
- Enact new production subsidies for **manufacturing of wind power, solar power, and energy storage components and critical materials** in the United States;
- Offer low-interest **loans and loan guarantees** through new and expanded programs at the Department of Energy Loan Programs Office.

For a detailed section-by-section summary of all energy provisions in the *Inflation Reduction Act* see http://bit.ly/REPEAT-Policies

IRA incentivizes higher growth of PJM demand and more distributed generation installation.



Gigawatt	*2021 Historical*	2025 No IRA	2030 No IRA	2035 No IRA	2025 IRA	2030 IRA	2035 IRA
Gross Peak Demand	*152*	162	163	170	178	190	214
DG Capacity	6*	9	15	20	11	20	27

Figure 1: IRA's impact on the electricity demand and distributed solar capacity.
Demand scenarios generated from the REPEAT Project. Numbers <30 TWh are omitted in the figure. New Jersey's DG capacity was further updated from NJ's solar installation and pipeline reports in July.

Passage of IRA is likely to begin a new period of sustained growth in demand for electricity by accelerating electrification of transportation and space & water heating.

Under IRA, projected PJM electricity consumption in 2035 could be ~38% greater than 2021 historical levels and peak demand could increase by ~41% (+62 GW). Compared to a No IRA benchmark case, IRA will increase 2035 PJM electricity consumption by ~13% and peak demand by ~12%

Furthermore, IRA provides a long-term extension of subsidies for distributed solar PV adoption, which could see an increase of 7 GW in PJM DG solar capacity by 2035 relative to No IRA case (+21 GW vs. 2021).

* Source: Mooney (2021), "Distributed Solar and Battery Generation Update," PJM Interconnection
^ Source: Monitoring Analytics, LLC (2021), "State of the Market Report for PJM, Volume 2: Detailed Analysis".
767 TWh reported net demand + estimated 11 TWh of estimated DG solar generation

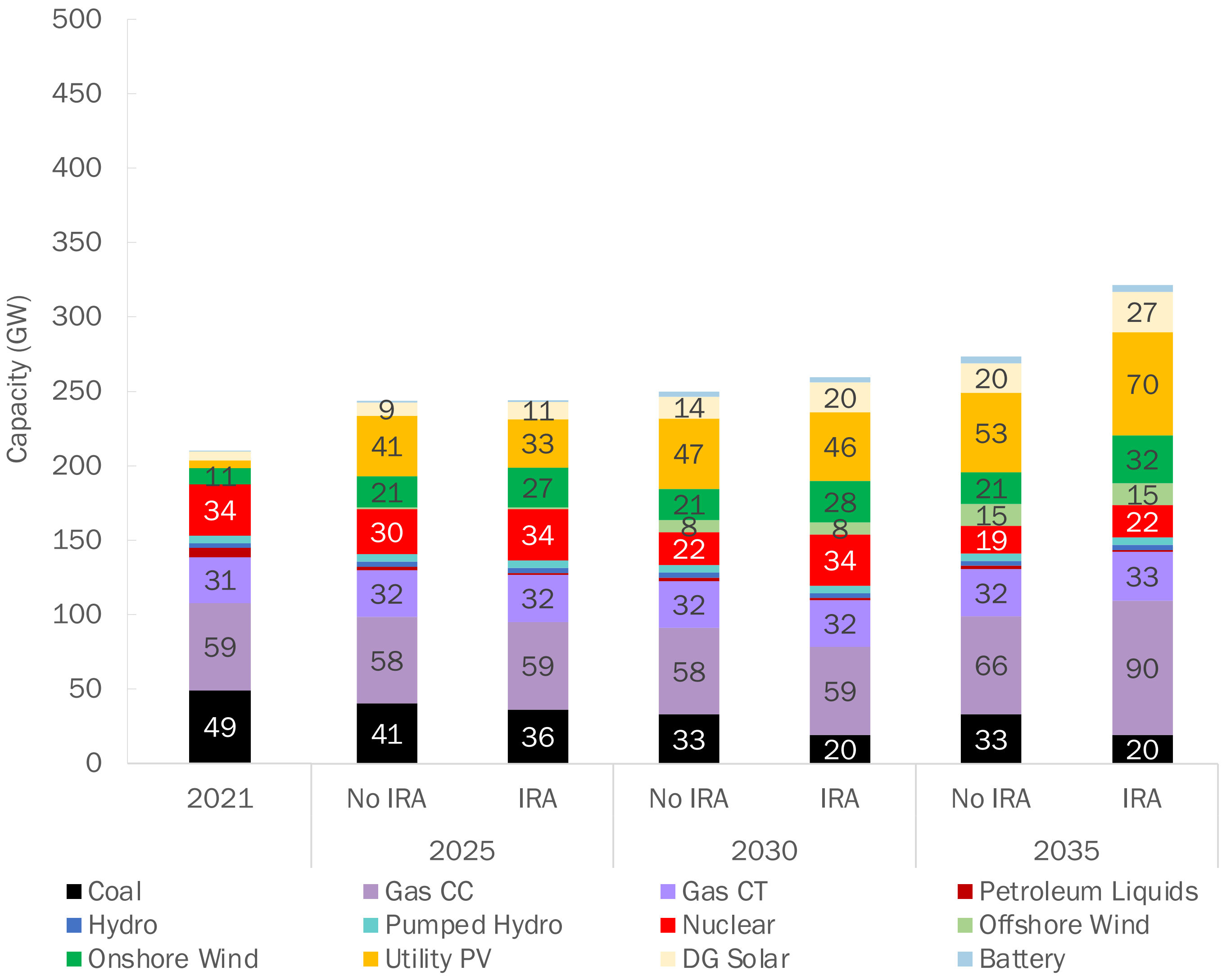


Figure 2: PJM capacity mix (medium fuel cost/medium RE cost scenario).
In the 2021 Benchmark, there are 2.3 GW of biomass, 0.5 GW of Gas ICE, and 11.3 GW of Gas Steam not shown. In the right panel, there are 0.4 GW of biomass not shown. DG solar capacity it as an exogenous input not optimized in model. Data labels ≤5 GW are not shown.

IRA incentivizes wind and solar deployment and preserves existing nuclear, crowding out coal-fired power plants.

IRA incentivizes more renewable energy deployment, especially onshore wind (+21 GW vs 2021) and both distributed (+21 GW) and utility-scale solar PV (+65 GW).

Notably, while IRA subsidizes offshore wind capacity, we find little additional deployment is incentivized. Instead, IRA makes it cheaper for PJM states to meet offshore wind mandates.

A new production tax credit for existing nuclear units will preserve PJM nuclear capacity through 2032, when the subsidy is scheduled to end. If equivalent policy support is not extended, however, economic retirement of nuclear units is likely to resume by 2035 (12 GW retired in the medium case; zero if fuel prices are high; 100% of fleet retires if the fuel prices are low), leading to expanded natural gas capacity to fill the gap and keep up with growing demand.

IRA incentivizes wind and solar deployment and preserves existing nuclear, crowding out coal-fired power plants (continued).

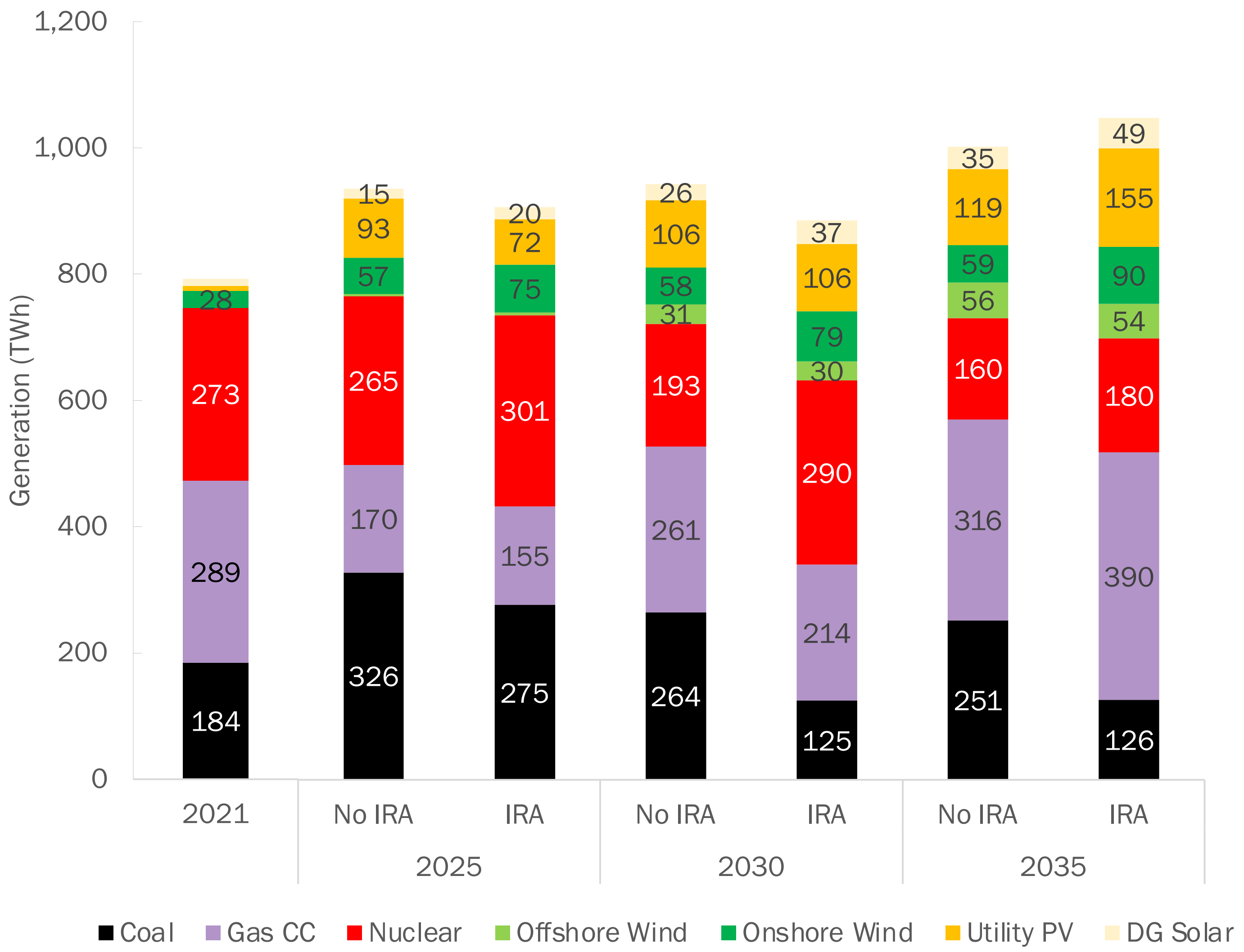


Figure 3: PJM annual electricity generation (medium fuel cost/medium RE cost scenario).
In the 2021 benchmark, biomass, NG CT, steam, hydro, and oil generation is not shown, which accounted for 43.6 TWh of total. In the right penal, there are 3.3 TWh of Biomass, 7.6 TWh of Hydro, and <2TWh of Natural Gas Combustion Turbine generation not shown; the model does not optimize DG solar capacity it as an exogenous input not optimized in model.

Through 2030, IRA significantly reduces coal-fired generation across PJM, primarily by preserving existing nuclear reactors and expanding onshore wind generation.

By 2030, clean energy sources, including renewables, hydro, biomass, and nuclear, will account for 60% [58-66% across sensitivities] of PJM's total generation, up from 48% [43-61%] in 2030 without IRA.

However, following expiration of the IRA production tax credit for existing nuclear in 2032 (and absent equivalent sustained support), PJM's nuclear fleet will once again face the threat of economic retirements. Nuclear plant closures and load growth from electrification would then lead to an increase in natural gas-fired generation in 2035, resulting in higher emissions than in 2030, despite continued growth of wind and solar.

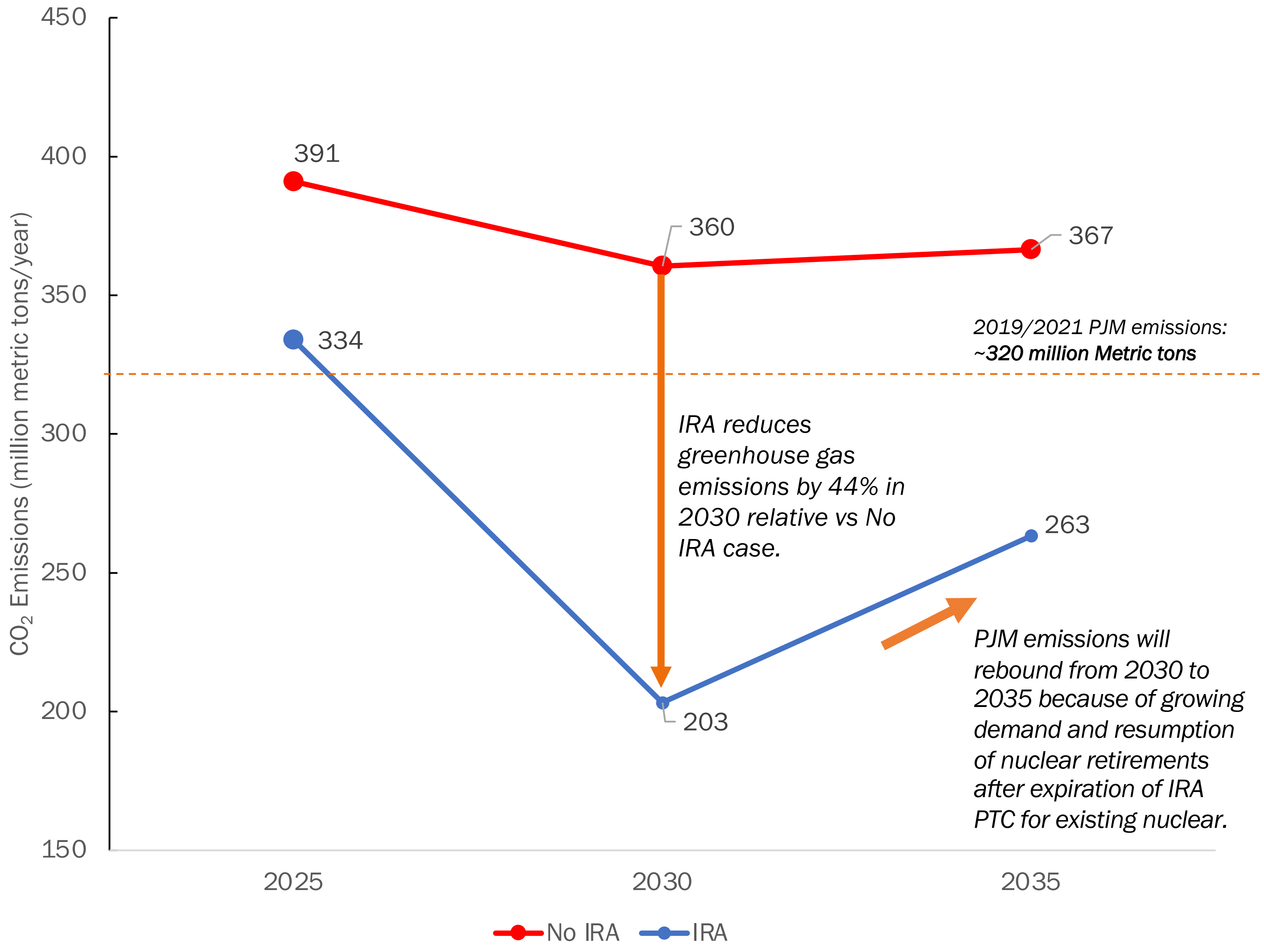


Figure 4: PJM system CO_2 emissions (medium fuel cost/medium RE cost scenario).
Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

IRA reduces both greenhouse gas emissions and the cost of electricity supply in the PJM region.

IRA incentivizes more renewable energy additions and delays retirement of the PJM nuclear fleet. These trends crowd out coal and natural gas generation and lead to significantly lower greenhouse emissions in the PJM footprint, especially during the period of 2023-2030. IRA cuts 2030 PJM emission almost in half (by 44%), relative to the No IRA benchmark case and reach 37% [3-66%] below 2019/2021 levels.

However, because IRA's support for nuclear ends in 2032, part of the PJM nuclear fleet will likely face economic pressure to retire by 2035. PJM emissions would consequently increase from 2033-2035 due to a combination of robust demand growth due to electrification and nuclear plant closures, which requires new natural gas capacity (see p. 23) and increased gas-fired generation (p. 24).

IRA reduces both greenhouse gas emissions and the cost of electricity supply in the PJM region (cont.)

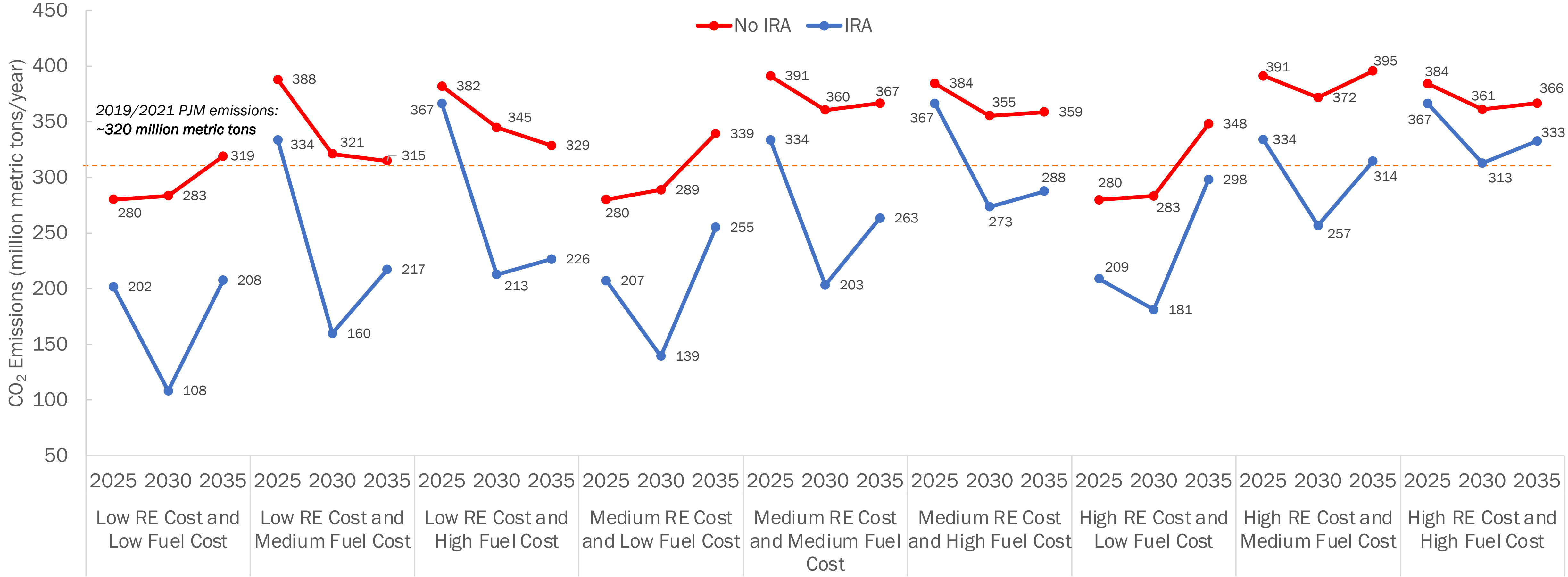
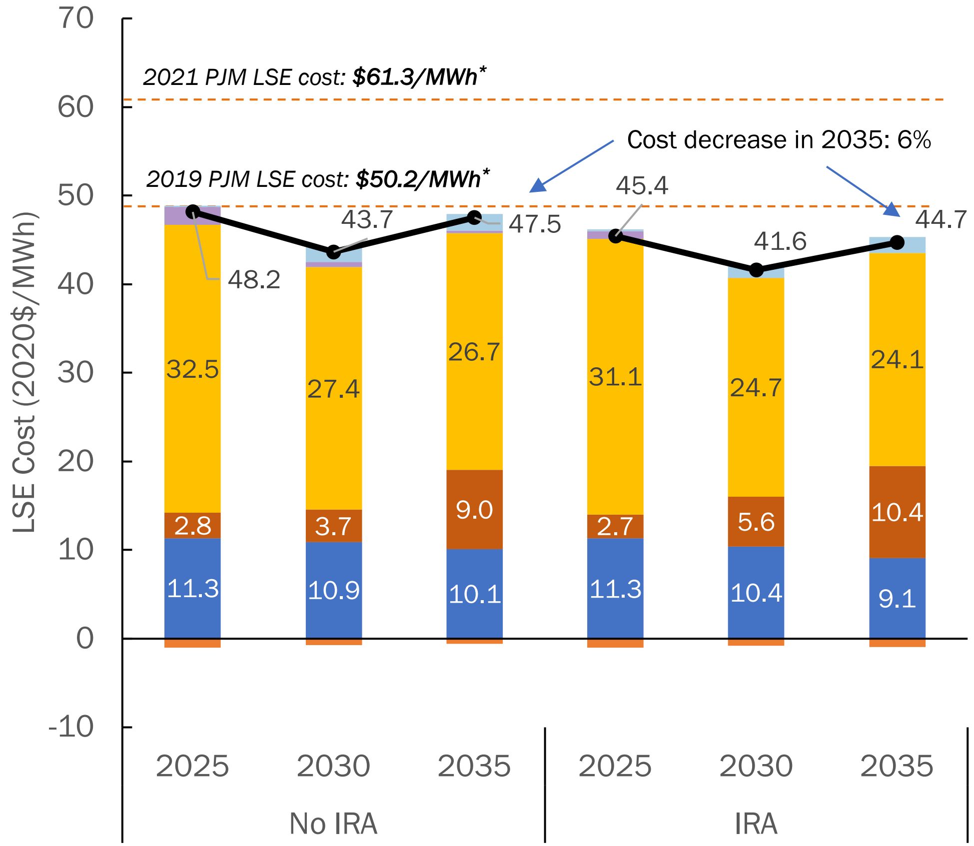


Figure 5: PJM system CO_2 emissions (all sensitivities).

IRA drives significant emissions reductions through 2030 in all sensitivities. Because of electricity demand growth incentivized by IRA and the lack of nuclear support after 2032, a rebound in PJM emissions through 2035 is also observed in all sensitivities. The rebound is less significant if fuel prices are high, which increases revenues for existing nuclear reactors and reduces retirements. However, the emissions increase is not entirely eliminated even in cases with no nuclear retirements, indicating that sustained support for existing nuclear beyond 2032 is insufficient on its own to drive PJM deep decarbonization. We explore this more in Part 2.

Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

IRA reduces both greenhouse gas emissions and the cost of electricity supply in the PJM region (cont.)



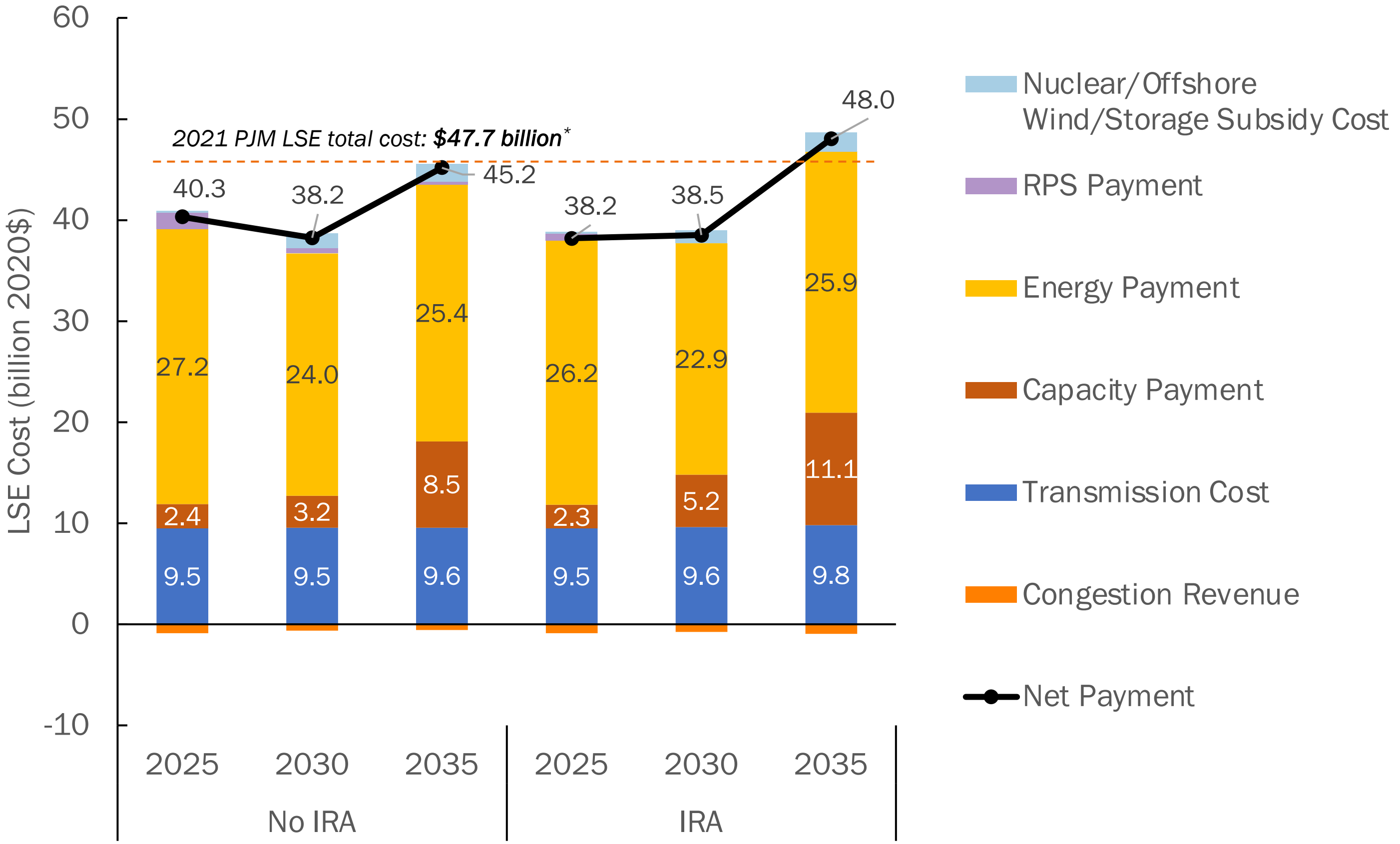


Figure 6: PJM load-serving entity bulk supply cost per MWh (left) and total (right) (medium fuel cost/medium RE cost case).
Includes only transmission-level or 'bulk supply' costs, excluding the cost at the distribution level, such as costs for distribution network upgrades due to load growth and distributed solar PV. Transmission cost includes both transmission payment for existing transmission and the expanded transmission lines.

IRA reduces the cost per MWh of electricity supply for PJM load-serving entities (LSEs) in 2030 by 5%-10% compared to the counterfactual without IRA. The cost savings are primarily the net impact of lower energy prices but higher capacity prices. PJM needs more transmission (and thus higher total transmission payment), but the transmission cost per MWh decreases due to load growth.

* Source: Monitoring Analytics, LLC (2021), "State of the Market Report for PJM." Note: Modeled costs underestimate the impact of transmission congestion on average energy costs due to the zonal resolution of model. Meanwhile, 2019 & 2021 benchmark costs exclude any state subsidies for specific technologies (e.g. nuclear, offshore wind, batteries), while modeled costs include these subsidies. The comparison of modeled and benchmark costs is thus approximate, but closely comparable.

The cost decrease due to IRA is robust against the cost sensitivities.

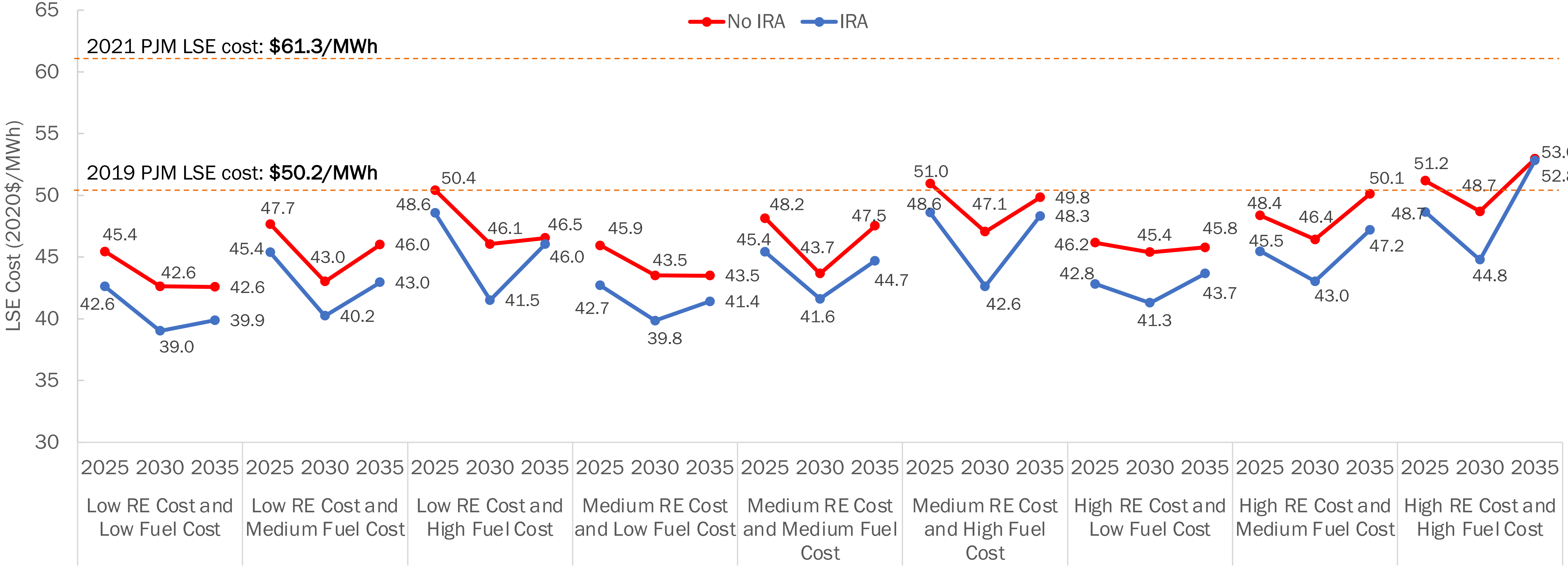


Figure 7: PJM load-serving entity bulk supply cost per MWh (all sensitivities).

The cost decrease due to IRA is robust across sensitivities. Furthermore, in most of the sensitivities, the cost under IRA is well below the costs paid in 2019 ($50.2/MWh) and below 2021 costs ($61.3/MWh) in all sensitivities. Costs increase in 2035 vs 2030 across all sensitivities as subsidies from IRA for existing nuclear reactors end and reactors retire, leading to higher capacity market and energy prices to induce investment in replacement capacity..

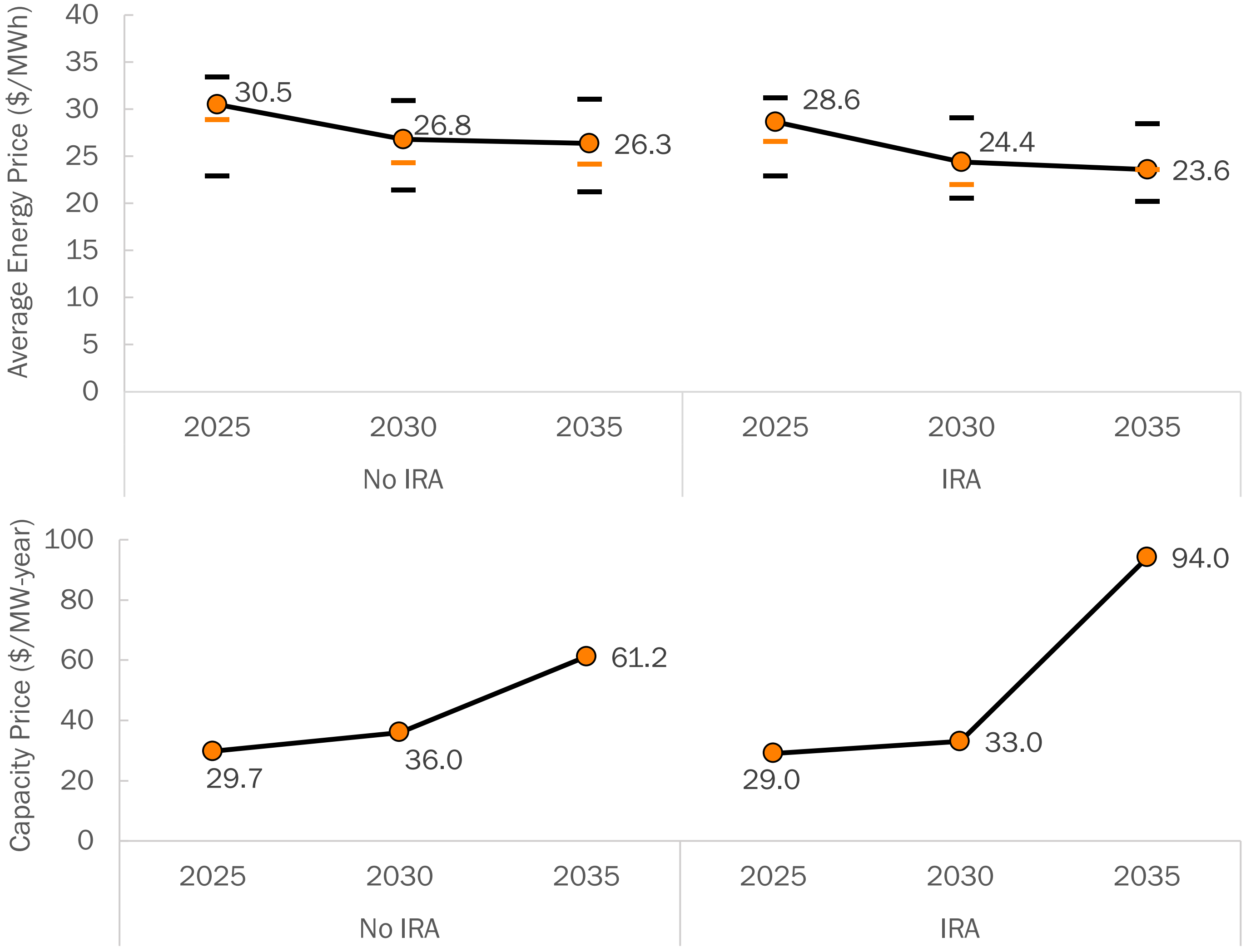


Figure 8: Load-weighted average locational marginal price (upper) and capacity market price (lower) for the PJM West model region (medium fuel cost/medium RE cost case).
Horizontal bars for the energy price show the 1st, 2nd, and 3rd quartiles of the LMP distribution, and dots denote the price average. Costs are in 2020 USD.

IRA suppresses PJM's energy price but increases the capacity price

IRA lowers PJM costs primarily by reducing energy prices. In 2021, the load-weighted energy price of PJM was $38.0/MWh (2020 USD), and our results show that the energy prices without IRA would have been $30.5/MWh, $26.8/MWh, and $26.3/MWh in 2025, 2030, and 2035, under the medium fuel cost/medium RE cost assumptions.

The large amount of low-marginal cost clean generation supported by IRA suppresses PJM energy prices, reducing the load-weighted average price to $28.6/MWh, $24.4/MWh, and $23.6/MWh in 2025, 2030, and 2035 (in medium fuel cost/medium RE cost case).

The capacity price of the 2023/2024 PJM-RPM base auction was $30/MW-day (in 2020 USD). Our results show that the capacity price of PJM in the near term (2023-2025) will stay around the current level. However, the capacity price will increase over 2031-2035, as nuclear retirements require entry of new gas capacity.

Federal tax credit payments to PJM generators will total $8 billion per year in 2030

IRA supports clean energy investment and production by providing transferable tax credits to clean generators. Modeled results estimate that the tax credits collected by PJM generators will peak in 2026-2030 at $8.1 billion/year [$7.1-9.2 billion across sensitivities], with 49-65% of the support going to wind, solar, and storage developers/owners, and the remainder to existing nuclear power plants. The production tax credit for existing nuclear is set to sunset after 2032, while new carbon-free electricity resources coming online in the 2031-2035 period will retain access to IRA subsidies.

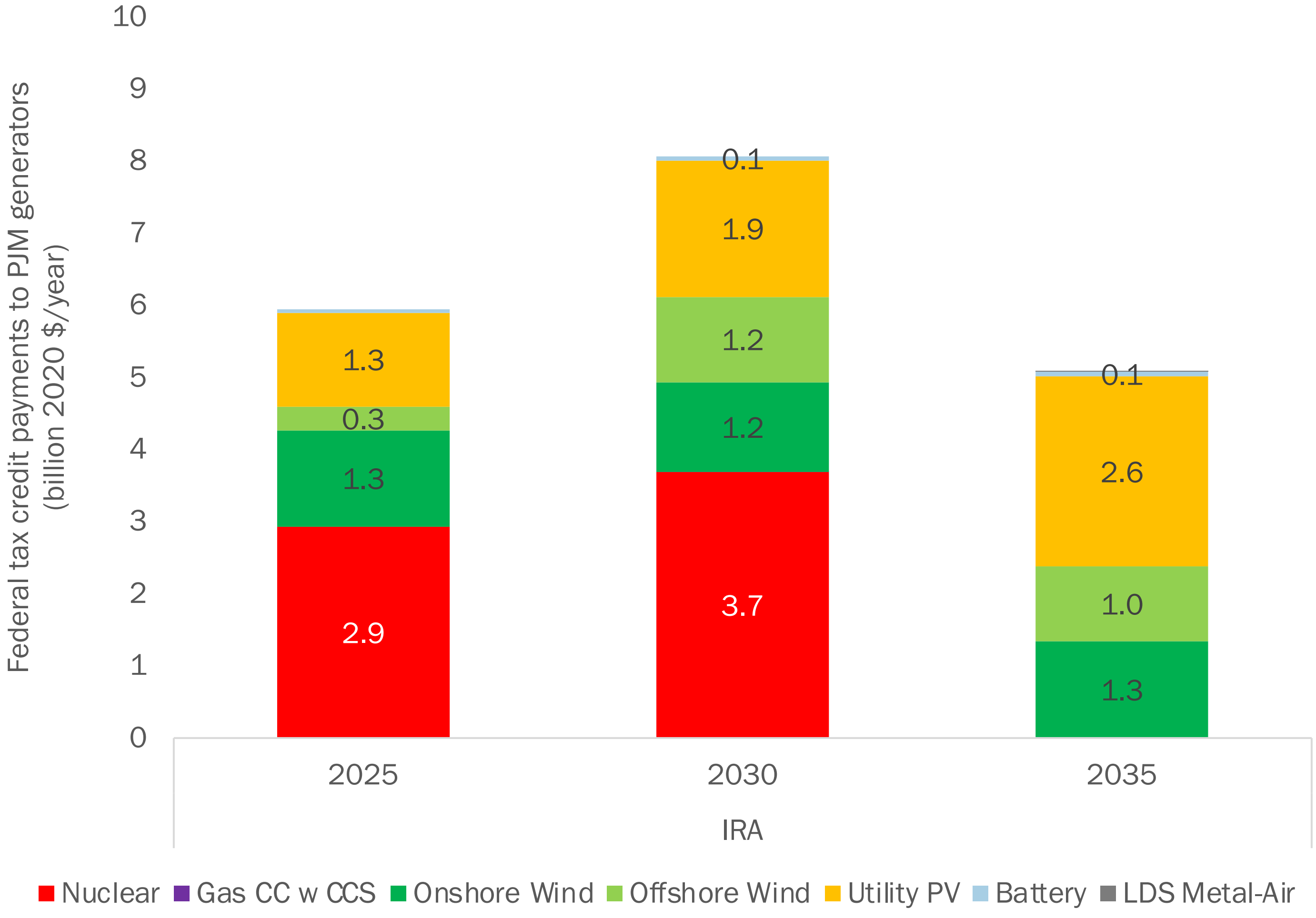


Figure 9: Federal tax credit payments to PJM generators under IRA (medium fuel cost/medium RE cost case).

The PJM generation interconnection process must speed up to take full advantage of low-cost wind & solar resources.

Even without passage of IRA, the PJM system is expected to face a surge of wind, solar, and battery energy storage capacity additions before 2030, with our modeling identifying 7.6 GW/year [7.5-7.7 across sensitivities] in the least-cost capacity mix, significantly faster than the recent historical pace in PJM (~2 GW/year).

Under IRA, the pace of onshore wind deployment accelerates further, bringing the annual average pace of PJM wind, solar, and battery additions to 8.3 GW/year [7.2-11.3] before 2030.

Note that in the medium fuel cost/medium RE cost case depicted at right, solar PV deployment under IRA is effectively unchanged over the 2023-2030 period. This is due to partial substitution from existing nuclear retained under IRA (and retired without the law). In high fuel cost sensitivities, nuclear is retained with or without IRA, and IRA accelerates solar PV growth (see sensitivity results). Solar also accelerates from 2031-2035.

Capacity Addition (MW)	2017	2018	2019	2020	2021	2022 (reported by EIA in June)	*Average (2019-2022)*
Battery	1.0	40.8	20.4	-	17.0	30.5	*17*
Utility PV	568.2	326.0	674.5	864.3	449.8	395.4	*596*
Onshore Wind	614.6	470.8	603.8	1326.3	1777.8	2046.2	*1,439*
Offshore Wind	-	-	-	-	12.0	-	*3*

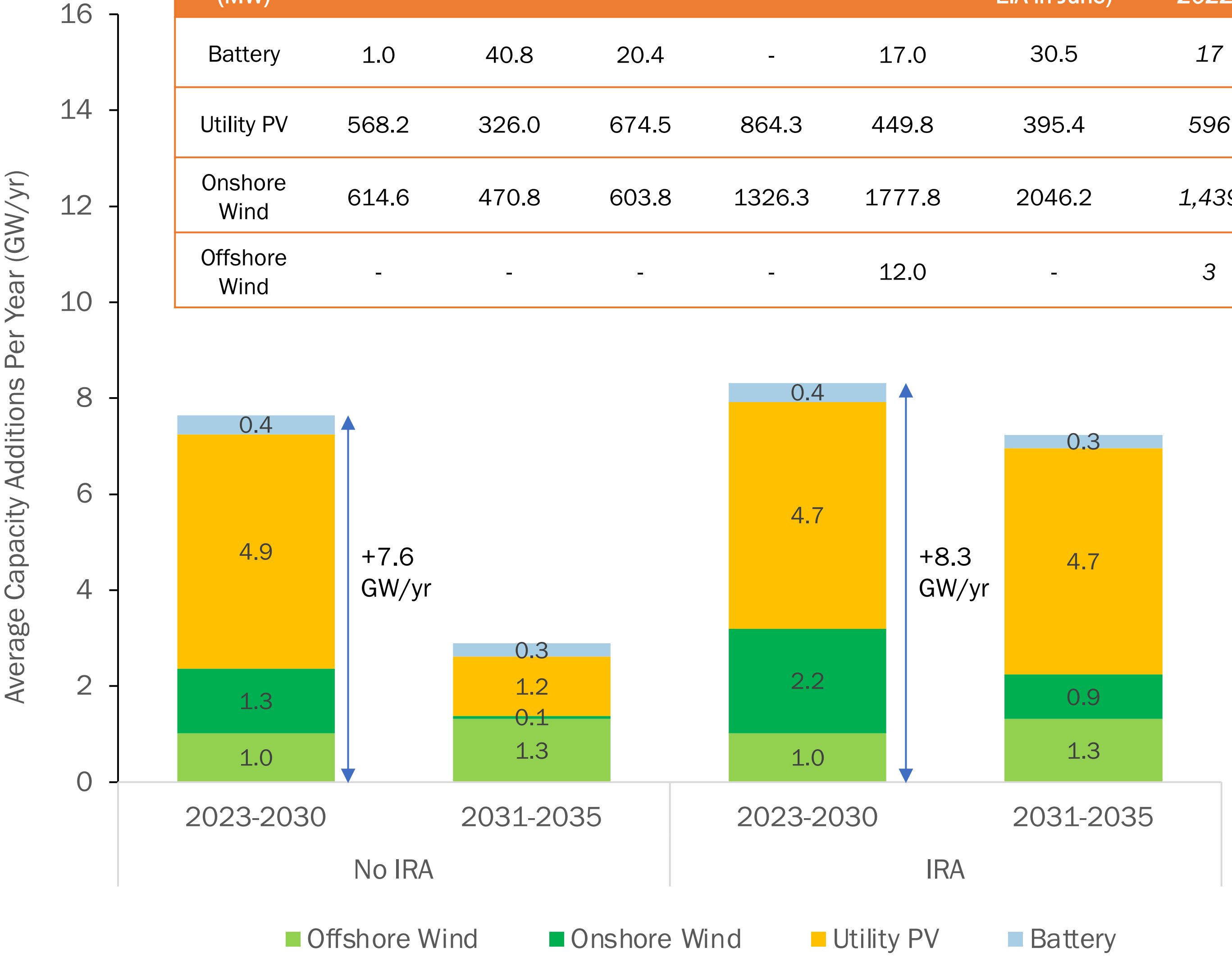


Figure 10: PJM average transmission-level capacity additions per year for wind, solar and Li-ion batteries (medium fuel cost/medium RE cost scenario).

The PJM generation interconnection process must speed up to take full advantage of low-cost wind & solar resources (continued).

Proposed projects in the PJM new services interconnection queue are currently sufficient to more than meet modeled cumulative capacity additions through 2030 and 2035.

While far less than 100% of projects in the queue are ever completed, new projects are being proposed at a rapid pace as well, with another 9.4 GW of onshore wind, 1.8 GW of offshore wind, 45.6 GW of utility-scale solar PV, 26.6 GW of stand-alone battery storage and 14.6 GW of hybrid utility solar PV + storage projects entering the PJM queue in 2021 alone*, even before IRA's passage.

This expressed interest from developers indicates that the industry believes it is more than capable of deploying capacity at the rates modeled in this study, but reforms to accelerate the PJM interconnection and cost allocation process are likely necessary to realize this pace of growth and accelerate annual additions well beyond recent historical rates.

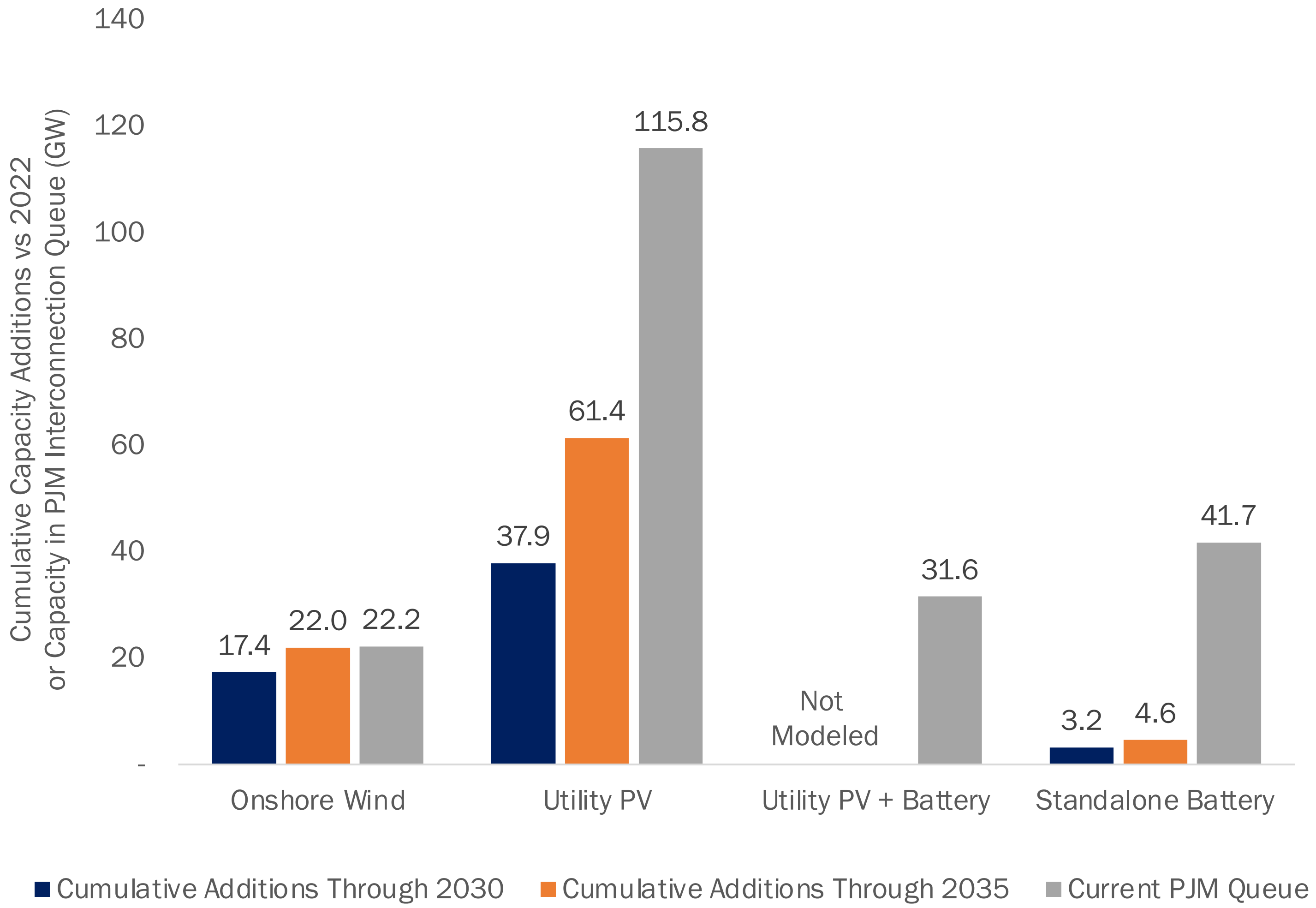


Figure 11: Cumulative PJM transmission-level capacity additions under IRA vs 2022 for wind, solar and Li-ion batteries compared to PJM interconnection queue as of end of 2021* (medium fuel cost/medium RE cost scenario).

* Source: LBNL (2022), "Generation, Storage, and Hybrid Capacity in Interconnection Queues," Electricity Markets and Policy Group, Lawrence Berkeley National Laboratory, available at https://emp.lbl.gov/generation-storage-and-hybrid-capacity

The PJM region needs to expand both inter- and intra-regional transmission under IRA

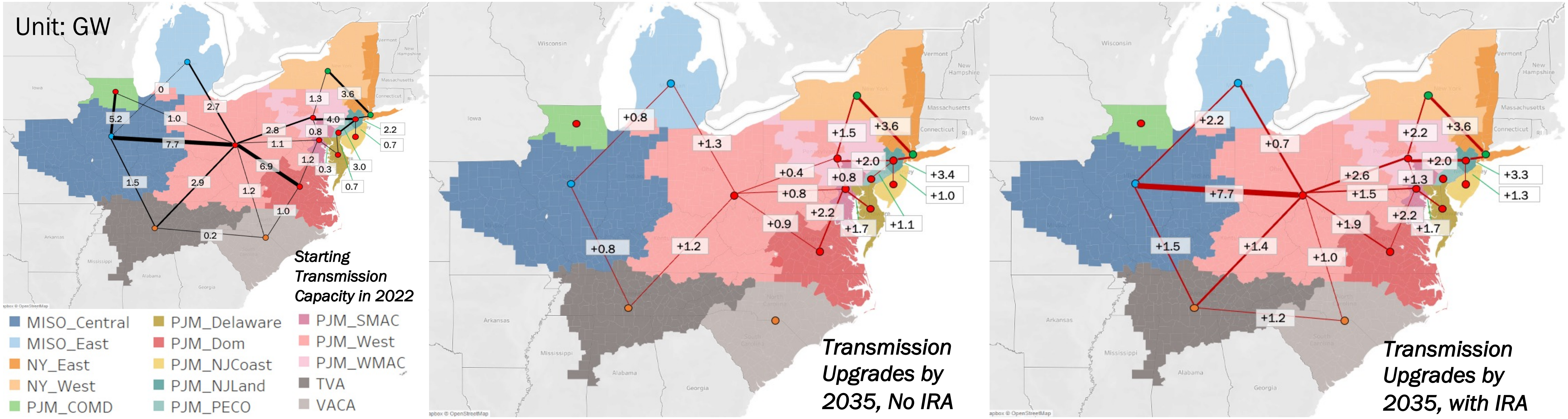
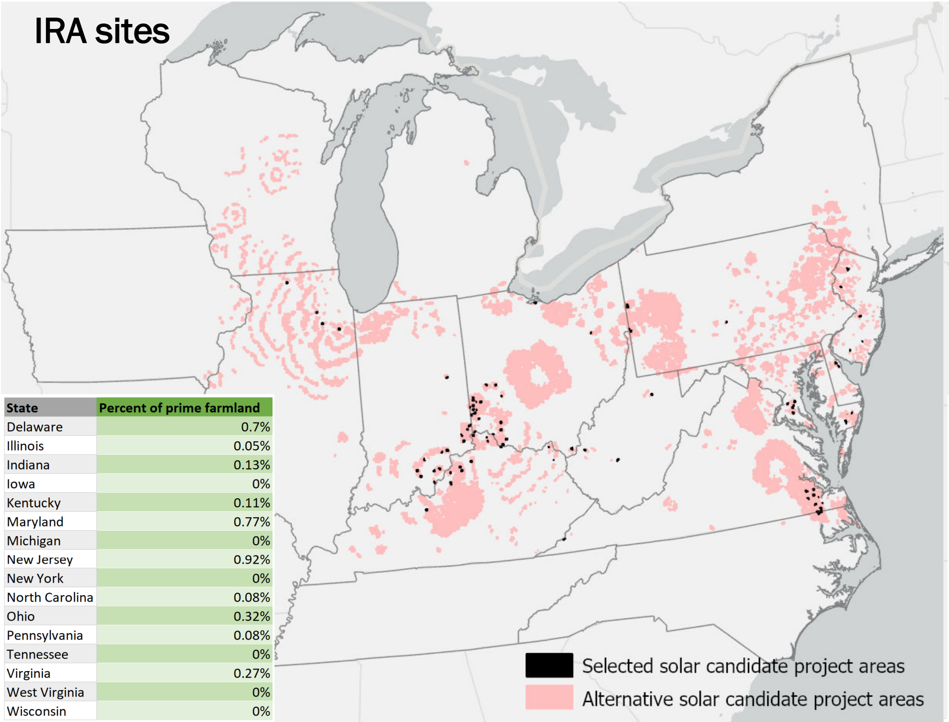


*Figure 12: PJM transmission starting capacity (left) and cumulative transmission upgrade by 2035 under No IRA case (middle) and IRA case (right) (medium fuel cost/medium RE cost case)**

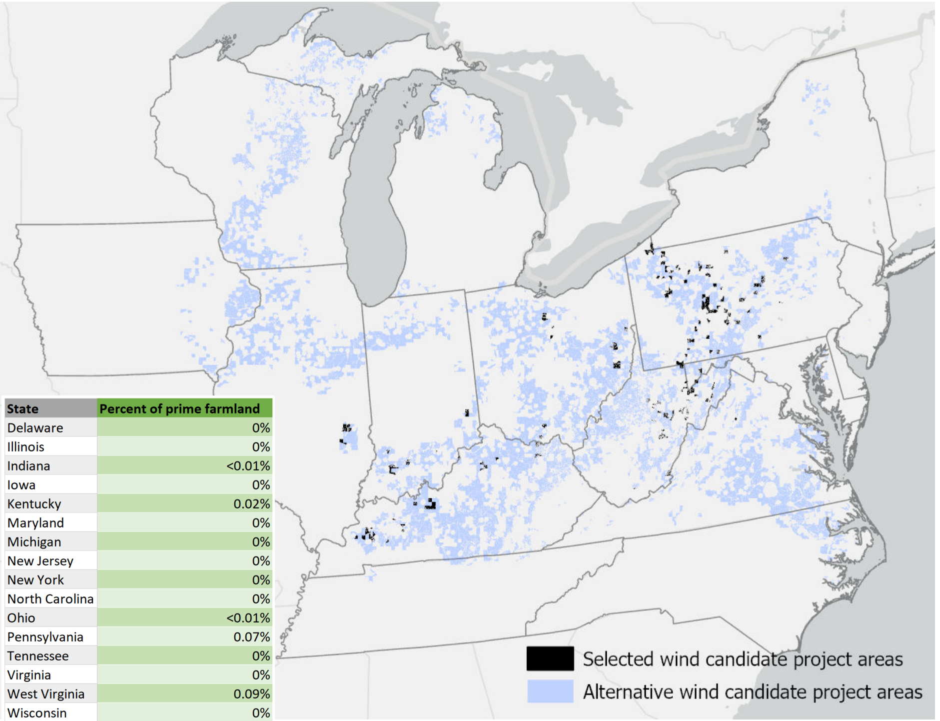
Although IRA does not directly provide tax credits for transmission upgrades, accommodating surging clean energy installation and serving rapid electricity demand growth requires PJM to expand its transmission infrastructure. Modeled results for least-cost system expansion include significant additions of transmission capacity between 2023 and 2035, both within model regions (for wind and solar interconnection) and between these regions (inter-regional transmission). Many transmission upgrades are needed between MISO and PJM and between the Western PJM and Mid-Atlantic Area Council (MAAC) areas of the PJM Interconnection.

* In this study, we assume transmission capacity can at most be doubled in one decade or be expanded at a rate of 750 MW (the typical thermal rating of one 345kV single circuit transmission line) per 5 years, whichever is greater. The limitation is set to approximate the limitation from the long lead time of transmission expansion

There are multiple affordable blueprints for deployment of wind & solar across PJM



State	Percent of prime farmland
Delaware	0.7%
Illinois	0.05%
Indiana	0.13%
Iowa	0%
Kentucky	0.11%
Maryland	0.77%
Michigan	0%
New Jersey	0.92%
New York	0%
North Carolina	0.08%
Ohio	0.32%
Pennsylvania	0.08%
Tennessee	0%
Virginia	0.27%
West Virginia	0%
Wisconsin	0%



State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	<0.01%
Iowa	0%
Kentucky	0.02%
Maryland	0%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	<0.01%
Pennsylvania	0.07%
Tennessee	0%
Virginia	0%
West Virginia	0.09%
Wisconsin	0%

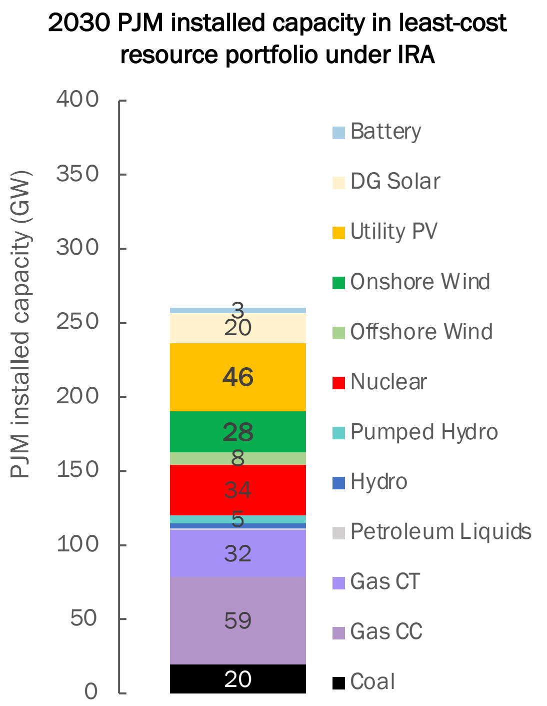


Figure 13: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA (medium fuel cost/medium RE cost case)

The maps above illustrate the distribution of 'candidate project areas'* (CPAs) where utility-scale solar PV and onshore wind power could be sited across modeled states in 2030 under IRA. The selected CPAs consistent with the modeled least-cost portfolio are in black. The full range of potential sites that could be developed in alternative portfolios that still satisfy all modeled constraints at an affordable cost^ are shown in lighter red (solar) and lighter blue (wind). The percentage of each state's prime farmland hosting solar PV or wind infrastructure is included in the tables associated with each map (and is generally a *de minimis* share).# These maps illustrate the degree of flexibility in siting wind and solar resources across PJM represented across feasible alternative CPAs. See the IRA Scenario appendix for maps of selected additional portfolios.

* Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433. See p. 19.

^ Plotted alternative CPAs are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Prime farmland areas occupied by solar and wind facilities reflect an estimate of the area directly occupied by solar arrays, wind turbines, roads, substations, etc. and equals ~1% of the total wind farm spatial extent and ~91% of the solar PV farm spatial extent (based on GIS analysis of existing wind and solar facilities from *Net-Zero America study*).

Part II: A Cost-Optimized Blueprint for PJM Deep Decarbonization

While IRA puts the PJM region on a path to lower-cost electricity and lower greenhouse gas emissions, the new federal policy is not sufficient to drive deep decarbonization of the PJM interconnection on its own. Part 2 of this study presents a cost-optimized blueprint for the additional capacity investments and resource deployment required for the PJM region to deeply decarbonize over the 2023-2035 period. We model least-cost resource portfolios under two stylized policy instruments…

	CO_2 Cap-and-Trade	Clean Electricity Standard (CES)
Reference point	2005 @ 0.607 metric ton/MWh of load; (2019/2021 emissions are 32% below 2005).	2020 @ 40% of load is clean energy
2025 Level	58% Emission Reduction from 2005 level	55% of gross load + storage/transmission loss supported by clean energy
2030 Level	80% Emission Reduction from 2005 level	70% of gross load + storage/transmission loss supported by clean energy
2035 Level	95% Emission Reduction from 2005 level	85% of gross load + storage/transmission loss supported by clean energy
No dirtier rule	For non-PJM regions, apply separate CO_2 cap/CES at the same level (no trading permitted between regions)	
Other policies	Other policies stay the same as business-as-usual, including RGGI and state-level RPS/CES.	

PJM can cut PJM CO_2 emissions 80-90% by 2035 while keeping electricity supply costs comparable to or lower than recent years

Thanks to passage of IRA, deep decarbonization of the PJM region is now achievable while maintaining electricity supply costs roughly comparable to or even lower than prices experienced in recent years.

PJM could achieve an 85% clean energy share by 2035 (CES case) at bulk electricity supply cost of $50.4/MWh [$44.3-59.8/MWh across sensitivities], while emissions could be cut to 95% below 2005 levels (Cap-and-Trade case) at a cost of $51.9/MWh [$45.6-64.2/MWh]. This range of possible costs to deeply decarbonize the PJM system compare to 2019 average supply cost of $50.2/MWh and 2021 cost of $61.3/MWh.

While total costs are roughly comparable, the composition of supply costs would differ under each hypothetical policy construct, with a higher share of payments for clean energy attributes (and lower energy market prices) under a CES vs. higher energy market prices under cap-and-trade.

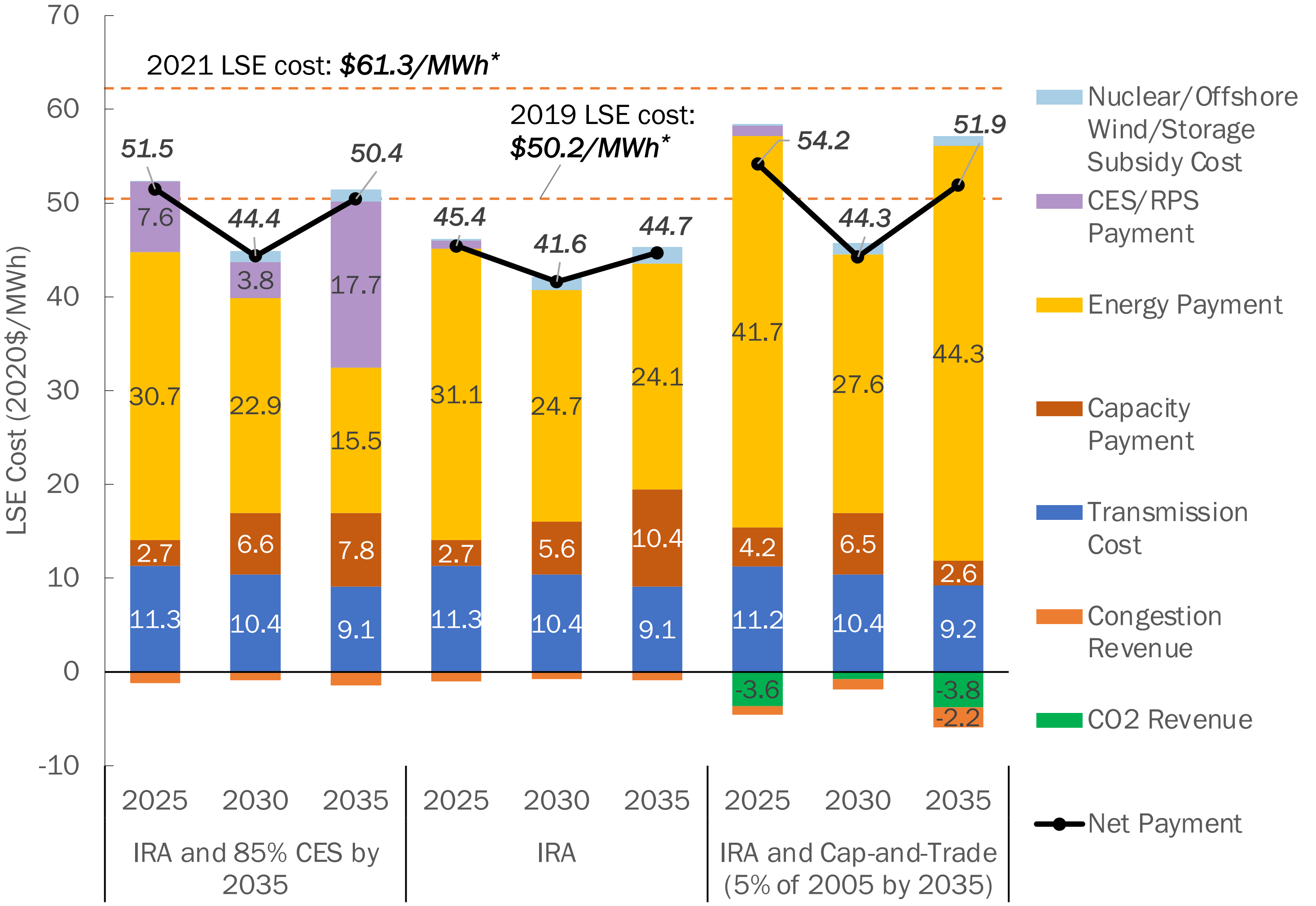


Figure 14: PJM load-serving entity bulk supply cost per MWh under IRA (center) and cases with CES (left) and cap-and-trade (right) (medium fuel cost/medium RE cost case).
Includes only transmission-level or 'bulk supply' costs, excluding the cost at the distribution level, such as costs for distribution network upgrades due to load growth and distributed solar PV. Transmission cost includes both transmission payment for existing transmission and the expanded transmission lines.

* Source: Monitoring Analytics, LLC (2021), "State of the Market Report for PJM." Note: Modeled costs underestimate the impact of transmission congestion on average energy costs due to the zonal resolution of model. Meanwhile, 2019 & 2021 benchmark costs exclude any state subsidies for specific technologies (e.g. nuclear, offshore wind, batteries), while modeled costs include these subsidies. The comparison of modeled and benchmark costs is thus approximate, but closely comparable.

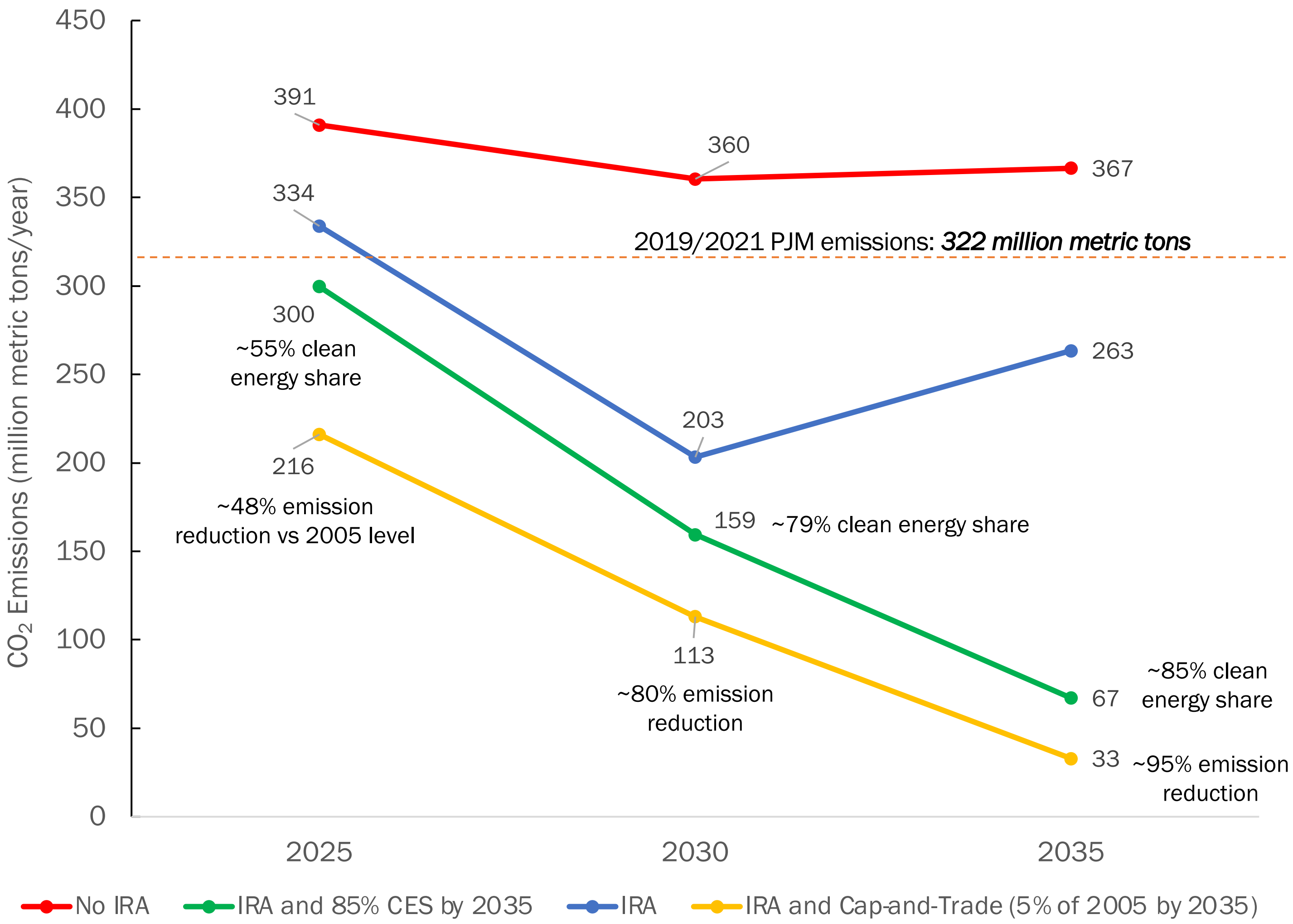


Figure 15: PJM system CO_2 emissions under IRA and cases with CES and cap-and-trade (medium fuel cost/medium RE cost case).

Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

PJM can cut CO_2 emissions 80-90% by 2035 while keeping electricity supply costs comparable to or lower than recent years (cont.)

By subsidizing the cost of all new carbon-free electricity resources, IRA makes it cheaper and easier for PJM states to reduce emissions further while preserving affordability.

Under the hypothetical regional CO_2 cap-and-trade program modeled here, annual PJM emissions fall to 33 million metric tons, a nearly 90% reduction from 2019/2021 emissions.

A clean electricity standard (CES) requiring 85% carbon-free electricity share by 2035 would reduce PJM emissions to 67 [60-125] million metric tons, a reduction of ~60-80% from 2019/2021 levels across sensitivities. The wider variation of emissions outcomes under a CES is driven by fuel price and renewable energy cost variations across sensitivity cases (see Sensitivity results below).

PJM needs a balanced portfolio of resources to deeply decarbonize, including renewables as well as clean firm resources like nuclear, gas-fired power with CCS, and long-duration energy storage

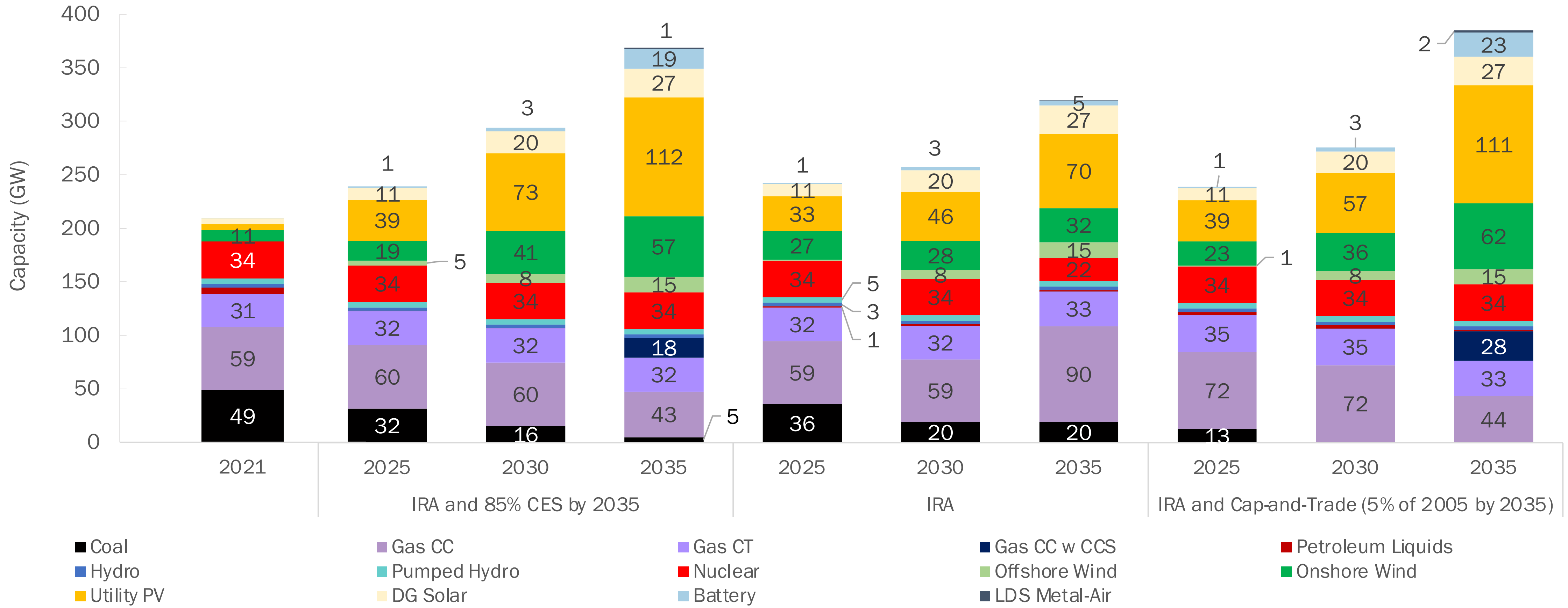


*Figure 16: PJM capacity mix under IRA (center) and cases with CES (left) and cap-and-trade (right) (medium fuel cost/medium RE cost case).**

Deep decarbonization of the PJM region relies on continued expansion of wind and solar as well as extended operation of the existing nuclear fleet and eventual deployment of new 'clean firm' resources to replace (at least in part) natural gas-fired capacity. Given the specific cost assumptions used in this study, gas combined cycle plants with carbon capture and storage (gas CC w/CCS) and a small amount of long-duration storage (LDS, modeled as metal-air batteries) play this key role. Significant installed gas capacity remains as well by 2035, although these gas plants are utilized at a much lower rate than today.

** Figure notes: there is 0.4 GW of biomass capacity not shown in all cases and 0.9 NGCC with CCS repowered from Coal not shown under cap-and-trade in 2035. DG solar capacity is as an exogenous input not optimized in model. Metal-air long-duration storage (LDS) discharge duration = ~50 hours*

PJM needs a balanced portfolio of resources to deeply decarbonize, including renewables as well as clean firm resources like nuclear, gas-fired power with CCS, and long-duration energy storage (cont.)

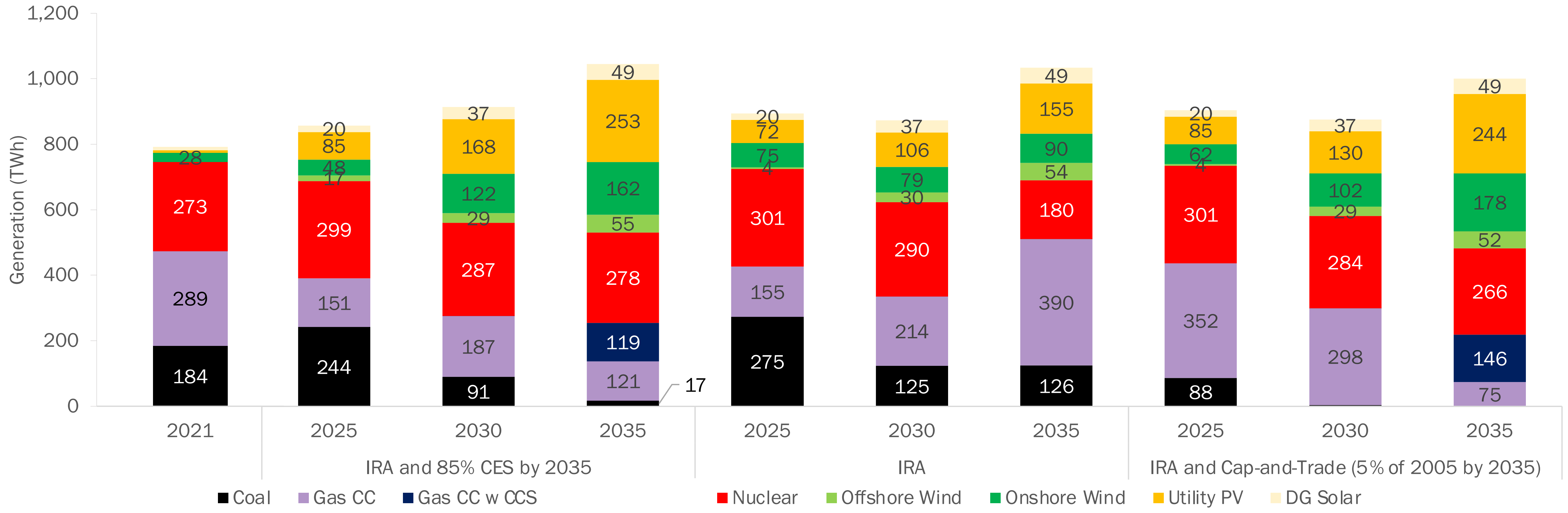


*Figure 17: PJM annual electricity generation under IRA (center) and cases with CES (left) and cap-and-trade (right) (medium fuel cost/medium RE cost case).**

In a cost-optimized, deeply decarbonized electricity generation portfolio, wind and solar grow to supply 61% [55-68%] of PJM electricity by 2035 under cap-and-trade and 49% [38-62%] under a clean electricity standard (CES), while preservation of existing nuclear reactors contributes another 26% [22-27%]. New natural gas plants w/CCS could supply another 15% [10-27%] by 2035 under cap-and-trade or 11% [0-21%] under a CES. Generation from conventional natural gas plants declines ~60-75% relative to 2021 generation. The optimal portfolio does not vary too significantly under the two hypothetical policy instruments, although coal is phased out more rapidly under an emissions cap-and-trade regime that directly penalizes emissions than under a CES or similar policy regime subsidizing non-emitting resources.

** Figure notes: There are 3.3 TWh of Biomass generation, 7.6 TWh of Hydro generation, 4 TWh of coal-repowered NGCC with CCS, and <2TWh of Natural Gas Combustion Turbine (CT) generation not shown in the chart. DG solar generation is as an exogenous input not optimized in model.*

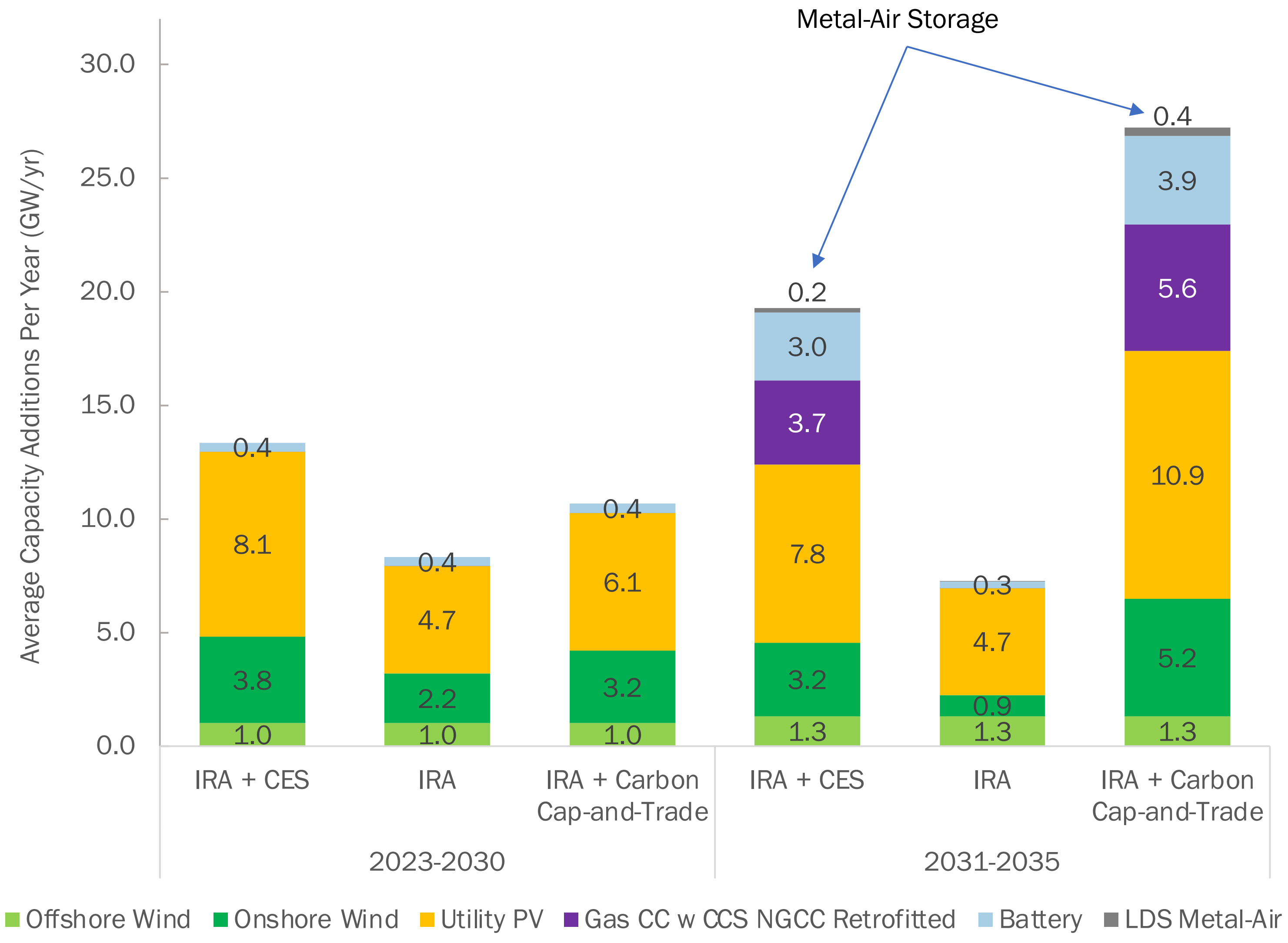


Figure 18: PJM average transmission-level capacity additions per year for wind, solar and Li-ion batteries under IRA (center) and cases with CES (left) and cap-and-trade (right) (medium fuel cost/medium RE cost case).

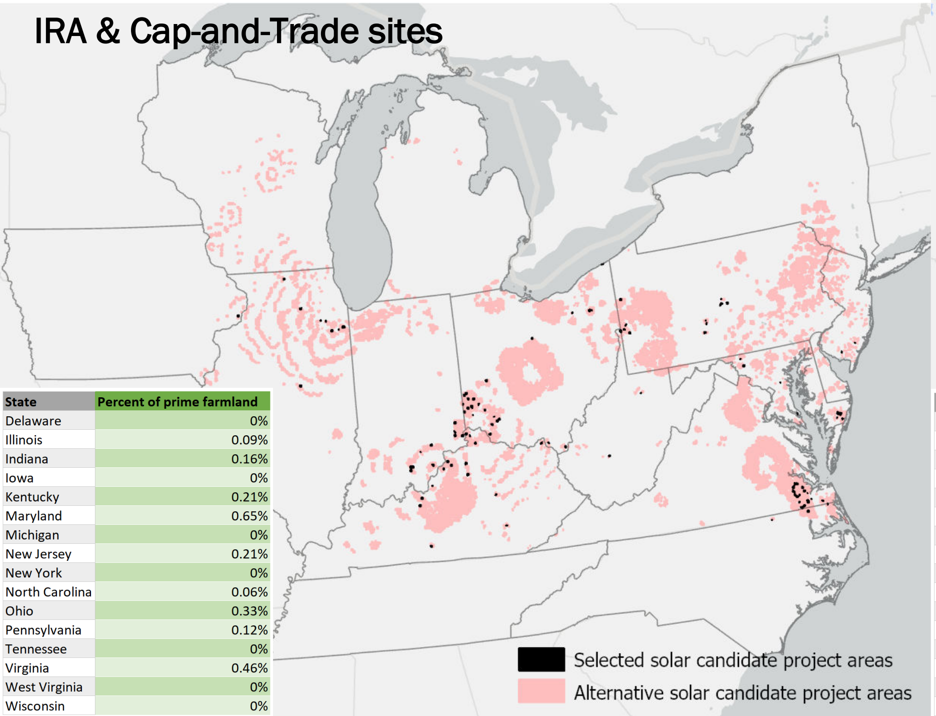
Deep decarbonization requires rapid expansion of low-carbon electricity resources and supportive transmission

Deep decarbonization of the PJM system would require accelerated deployment of clean energy and storage capacity in the next decade, above and beyond the rates of deployment made economical by IRA, raising challenges for the PJM interconnection process.

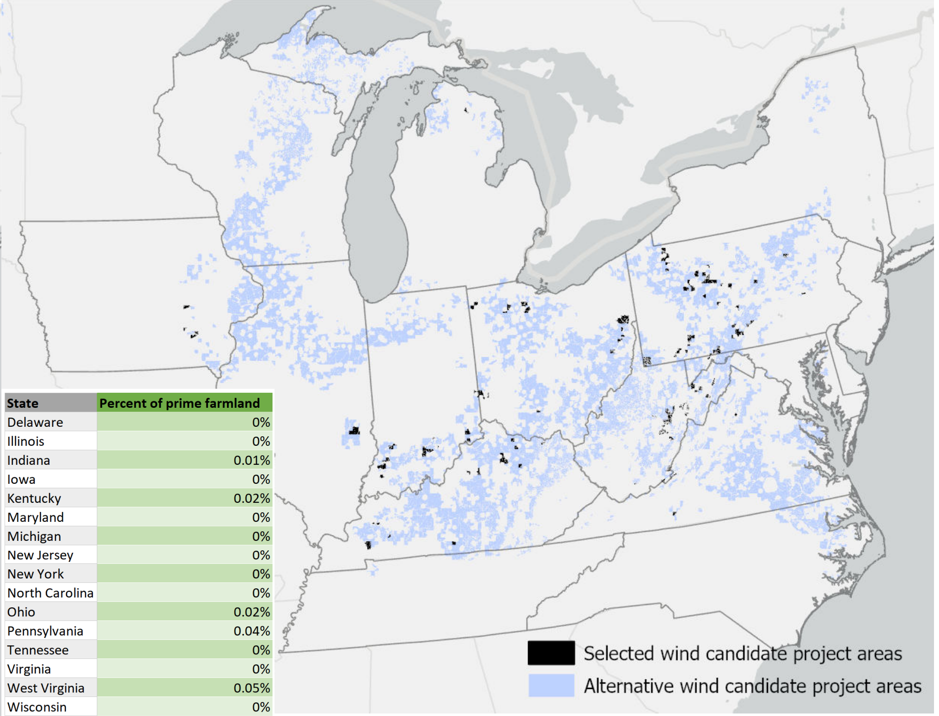
To reach deep decarbonization goals by 2035, the capacity that needs to be interconnected can be as high as 20-27 GW/year by the 2031-2035 period, a 10-fold acceleration relative to the recent average pace of wind, solar, and storage expansion the current speed of 2 GW/year from 2019-2022 and about double the pace incentivized by IRA alone during the 2023-2030 period.

A wide range of candidate sites are available for siting new wind & solar resources

IRA & Cap-and-Trade sites



State	Percent of prime farmland
Delaware	0%
Illinois	0.09%
Indiana	0.16%
Iowa	0%
Kentucky	0.21%
Maryland	0.65%
Michigan	0%
New Jersey	0.21%
New York	0%
North Carolina	0.06%
Ohio	0.33%
Pennsylvania	0.12%
Tennessee	0%
Virginia	0.46%
West Virginia	0%
Wisconsin	0%



State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	0.01%
Iowa	0%
Kentucky	0.02%
Maryland	0%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	0.02%
Pennsylvania	0.04%
Tennessee	0%
Virginia	0%
West Virginia	0.05%
Wisconsin	0%

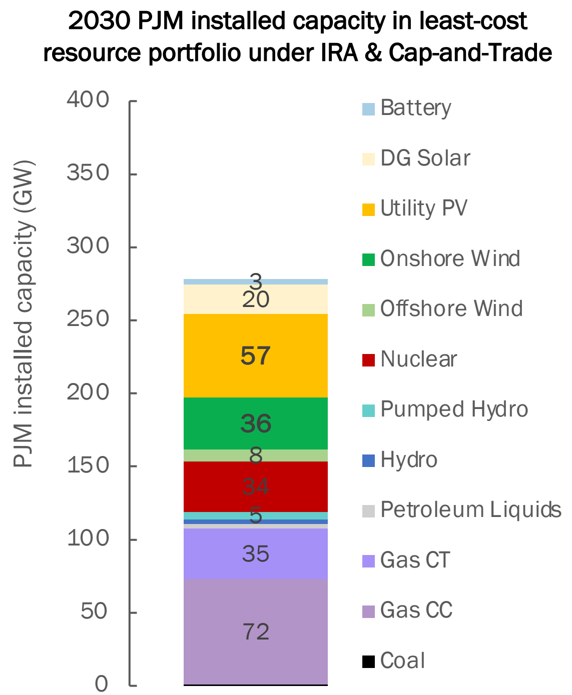


Figure 19: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade (medium fuel cost/medium RE cost case)

The maps above illustrate the distribution of 'candidate project areas'* (CPAs) where utility-scale solar PV and onshore wind power could be sited across modeled states (outlined in darker gray) in 2030 under IRA and a hypothetical emissions cap limiting 2030 PJM emissions to 80% below 2005 levels. The selected CPAs consistent with the modeled least-cost portfolio are in black. The full range of potential sites that could be developed in alternative portfolios that still satisfy all modeled constraints at an affordable cost^ are shown in lighter red (solar) and lighter blue (wind). The percentage of each state's prime farmland hosting solar PV or wind infrastructure is included in the tables associated with each map (and is generally a *de minimis* share).# These maps illustrate the degree of flexibility in siting wind and solar resources across PJM represented across feasible alternative CPAs. See IRA + Cap-and-Trade Scenario appendix for maps of selected additional portfolios.

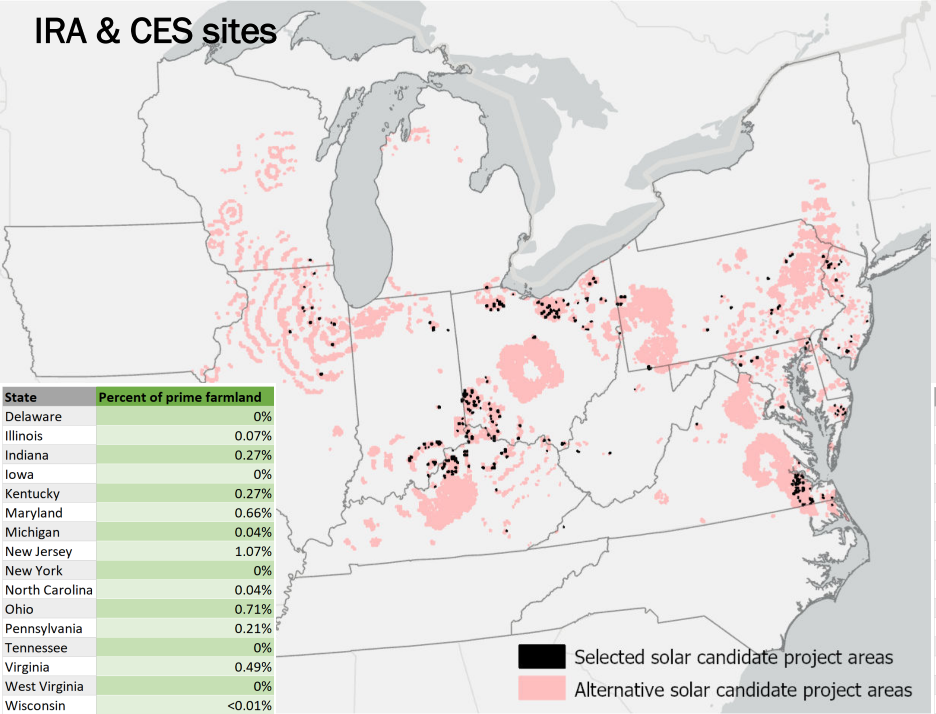
* Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433. See p. 19.

^ Plotted alternative CPAs are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

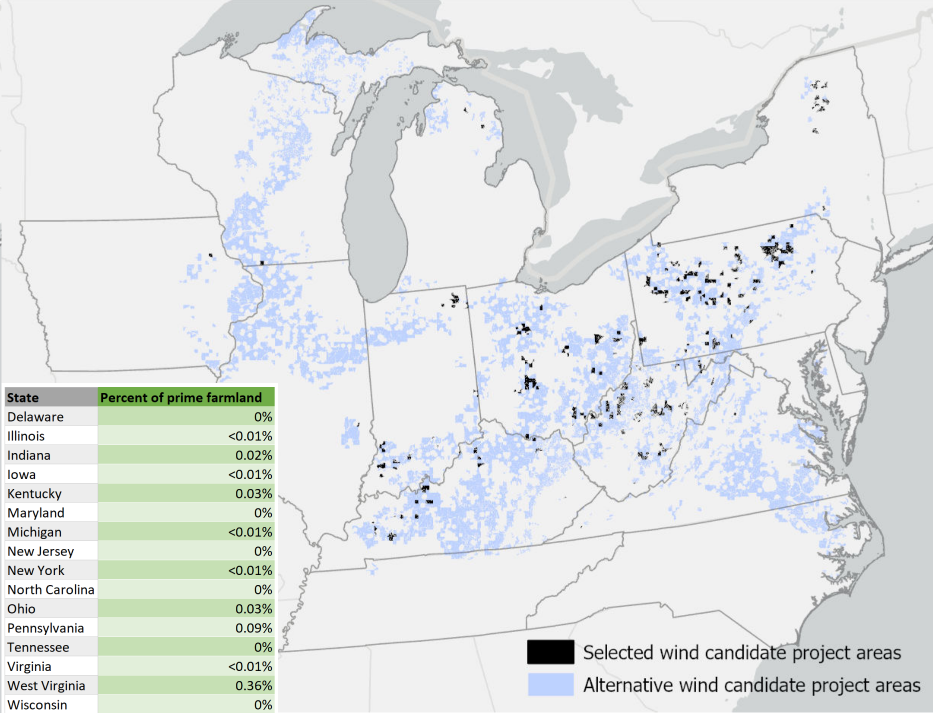
Prime farmland areas occupied by solar and wind facilities reflect an estimate of the area directly occupied by solar arrays, wind turbines, roads, substations, etc. and equals ~1% of the total wind farm spatial extent and ~91% of the solar PV farm spatial extent (based on GIS analysis of existing wind and solar facilities from Net-Zero America study).

A wide range of candidate sites are available for siting new wind & solar resources (cont.)

IRA & CES sites



State	Percent of prime farmland
Delaware	0%
Illinois	0.07%
Indiana	0.27%
Iowa	0%
Kentucky	0.27%
Maryland	0.66%
Michigan	0.04%
New Jersey	1.07%
New York	0%
North Carolina	0.04%
Ohio	0.71%
Pennsylvania	0.21%
Tennessee	0%
Virginia	0.49%
West Virginia	0%
Wisconsin	<0.01%



State	Percent of prime farmland
Delaware	0%
Illinois	<0.01%
Indiana	0.02%
Iowa	<0.01%
Kentucky	0.03%
Maryland	0%
Michigan	<0.01%
New Jersey	0%
New York	<0.01%
North Carolina	0%
Ohio	0.03%
Pennsylvania	0.09%
Tennessee	0%
Virginia	<0.01%
West Virginia	0.36%
Wisconsin	0%

2030 PJM installed capacity in least-cost resource portfolio under IRA & CES

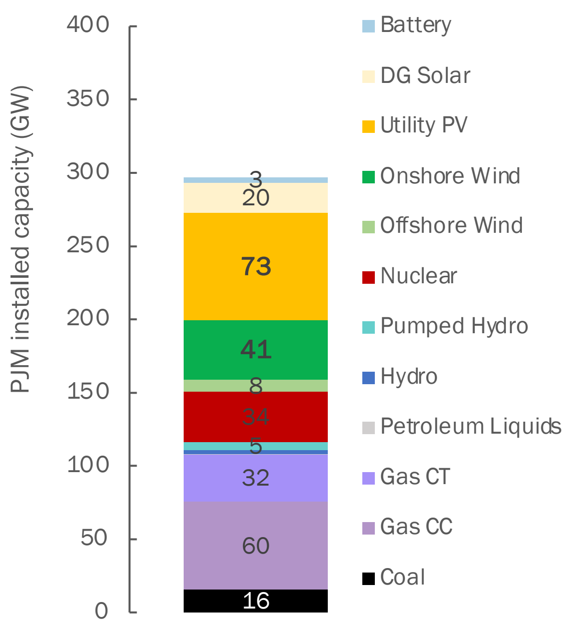


Figure 20: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & CES (medium fuel cost/medium RE cost case)

The maps above illustrate the distribution of 'candidate project areas'* (CPAs) where utility-scale solar PV and onshore wind power could be sited across modeled states (outlined in darker gray) in 2030 under IRA and a hypothetical Clean Electricity Standard requiring 70% clean energy share by 2030. The selected CPAs consistent with the modeled least-cost portfolio are in black. The full range of potential sites that could be developed in alternative portfolios that still satisfy all modeled constraints at an affordable cost^ are shown in lighter red (solar) and lighter blue (wind). The percentage of each state's prime farmland hosting solar PV or wind infrastructure is included in the tables associated with each map (and is generally a *de minimis* share).# These maps illustrate the degree of flexibility in siting wind and solar resources across PJM represented across feasible alternative CPAs. See IRA + Clean Electricity Standard Scenario appendix for maps of selected additional portfolios.

* Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433. See p. 19.

^ Plotted alternative CPAs are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Prime farmland areas occupied by solar and wind facilities reflect an estimate of the area directly occupied by solar arrays, wind turbines, roads, substations, etc. and equals ~1% of the total wind farm spatial extent and ~91% of the solar PV farm spatial extent (based on GIS analysis of existing wind and solar facilities from Net-Zero America study).

Additional Results and Sensitivities by Policy Scenario

No IRA Scenario Results

PJM emissions under No IRA Scenario

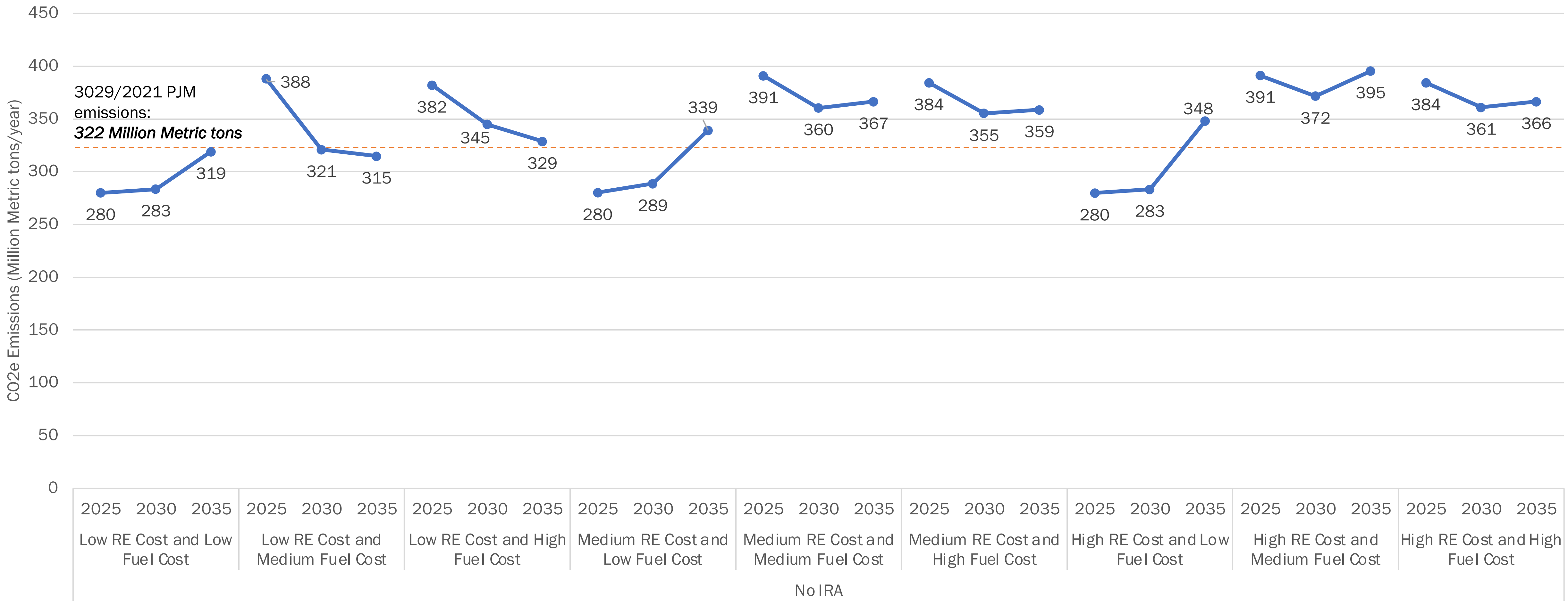


Figure A1-1: PJM system CO_2 emissions under No IRA scenario

Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

PJM bulk electricity supply cost under No IRA Scenario

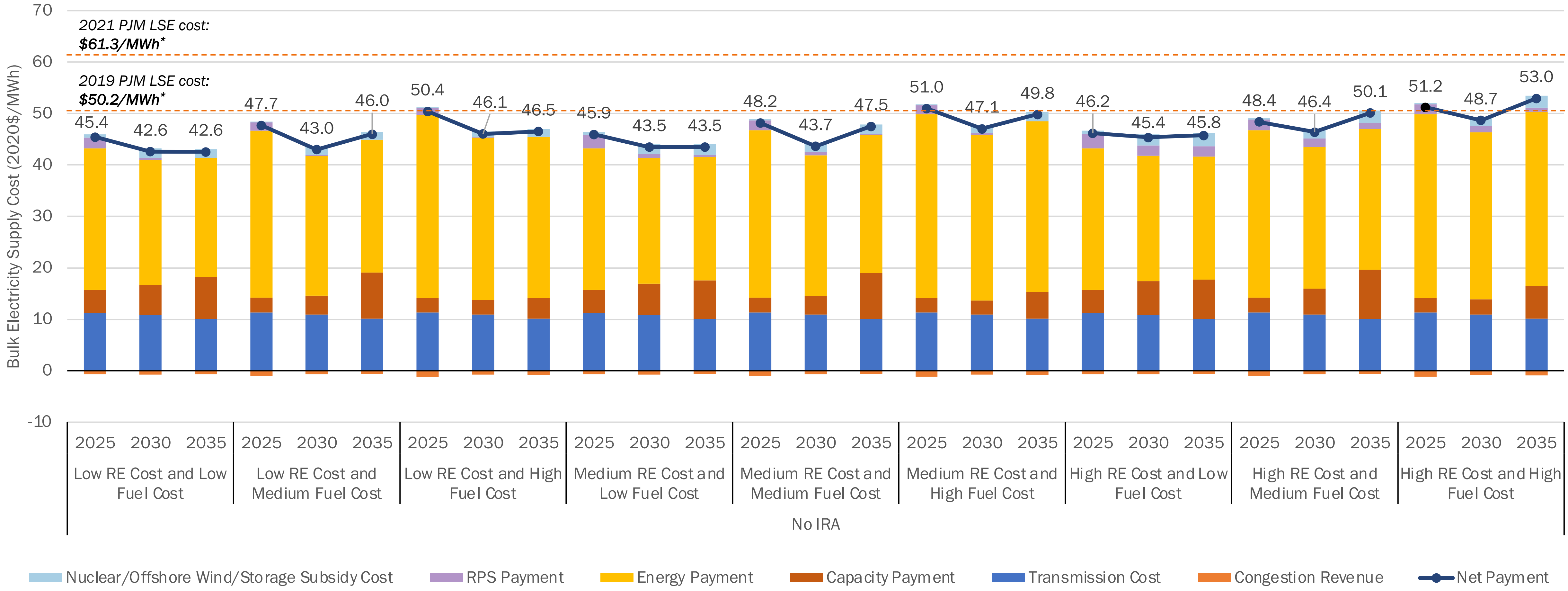


Figure A1-2: PJM load-serving entity bulk supply cost under No IRA Scenario

* Source: Monitoring Analytics, LLC (2021), “State of the Market Report for PJM.” Note: Modeled costs underestimate the impact of transmission congestion on average energy costs due to the zonal resolution of model. Meanwhile, 2019 & 2021 benchmark costs exclude any state subsidies for specific technologies (e.g. nuclear, offshore wind, batteries), while modeled costs include these subsidies. The comparison of modeled and benchmark costs is thus approximate, but closely comparable.

PJM capacity mix under No IRA Scenario

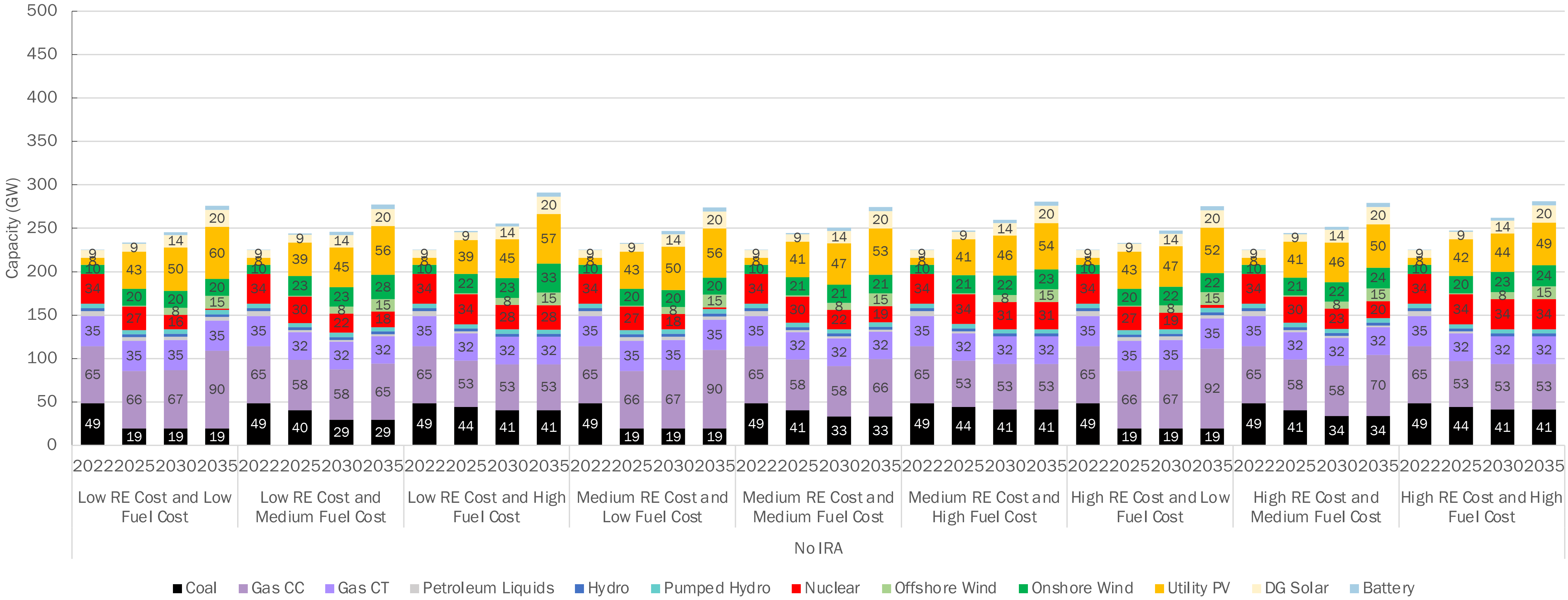


Figure A1-3: PJM capacity mix under No IRA Scenario
Data labels ≤5 GW are not shown. DG solar capacity is as an exogenous input not optimized in model.

PJM annual electricity generation under No IRA Scenario

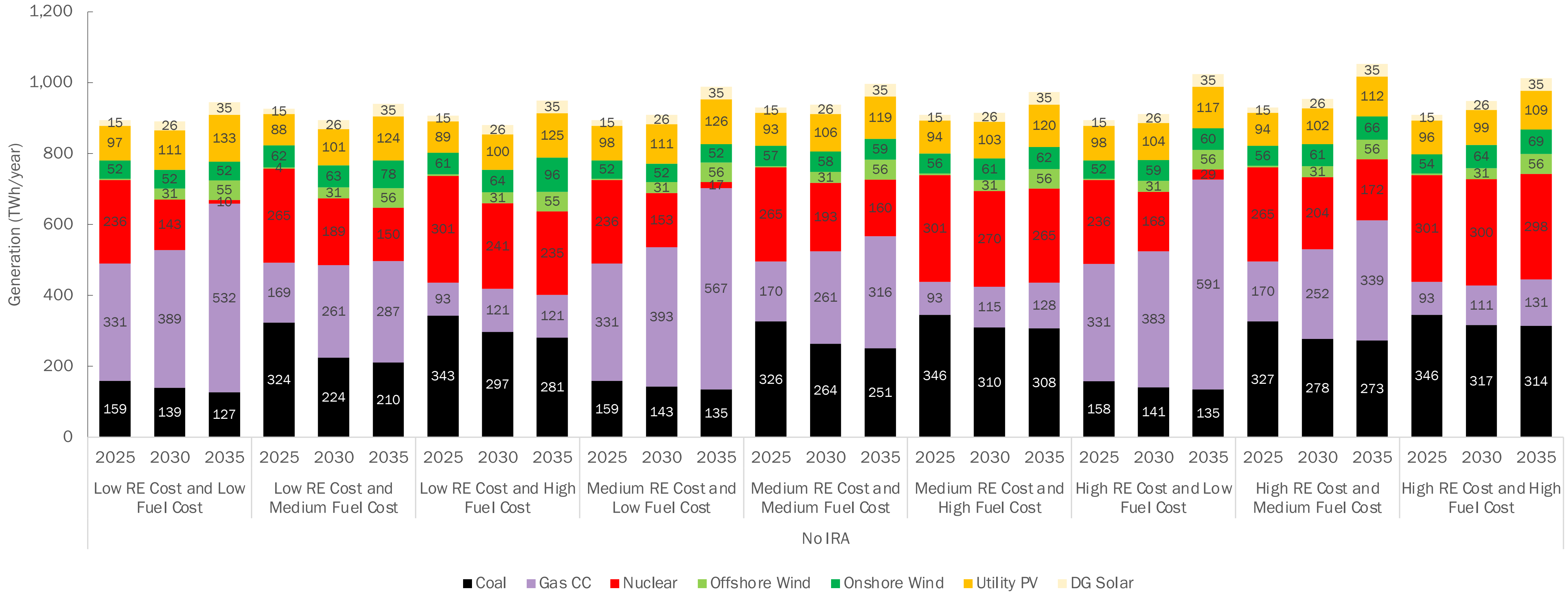


Figure A1-4: PJM annual electricity generation under No IRA Scenario
Data labels <10 TWh are not shown. Generation from Biomass, Hydro, and Natural Gas Combustion Turbines (CT) are all <10 TWh and not depicted above.
DG solar generation is as an exogenous input not optimized in model.

Locational marginal prices (LMP) under No IRA scenario

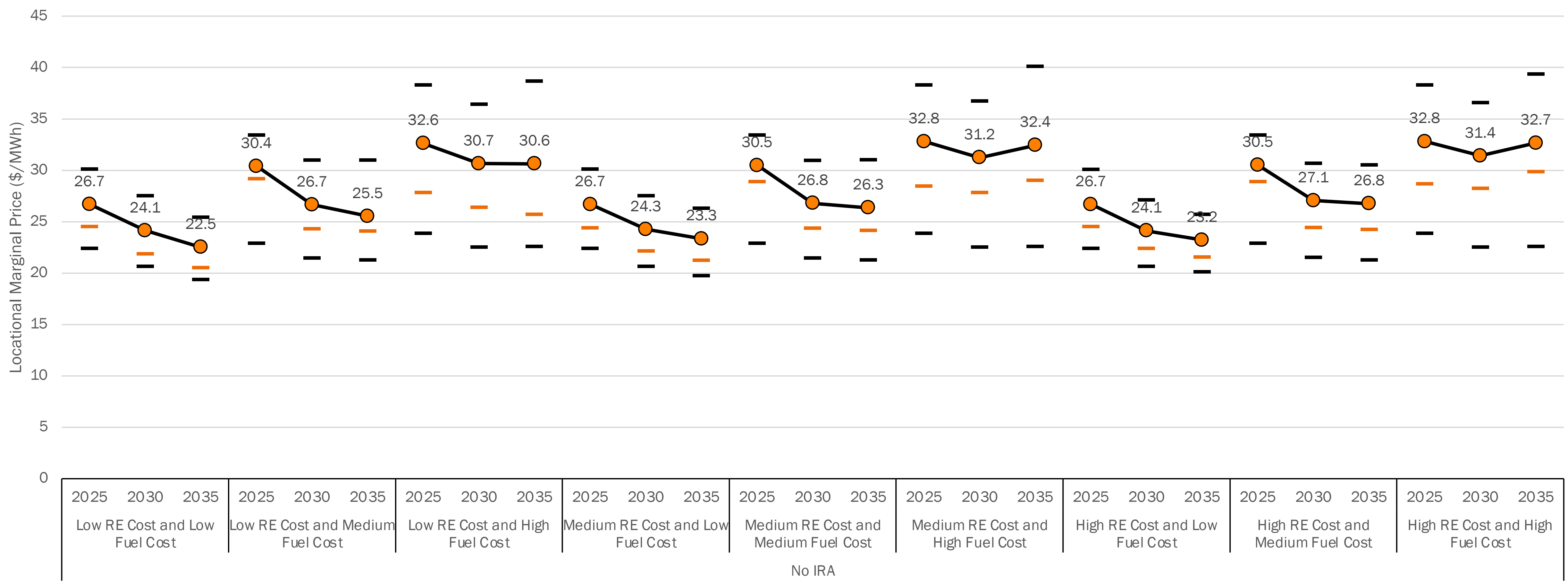


Figure A1-5: Load-weighted average locational marginal price (LMP) for the PJM West model region under no IRA scenario. *Horizontal bars show the 1st, 2nd, and 3rd quartiles of the LMP distribution, and dots denote the price average.*

Capacity market price under No IRA Scenario

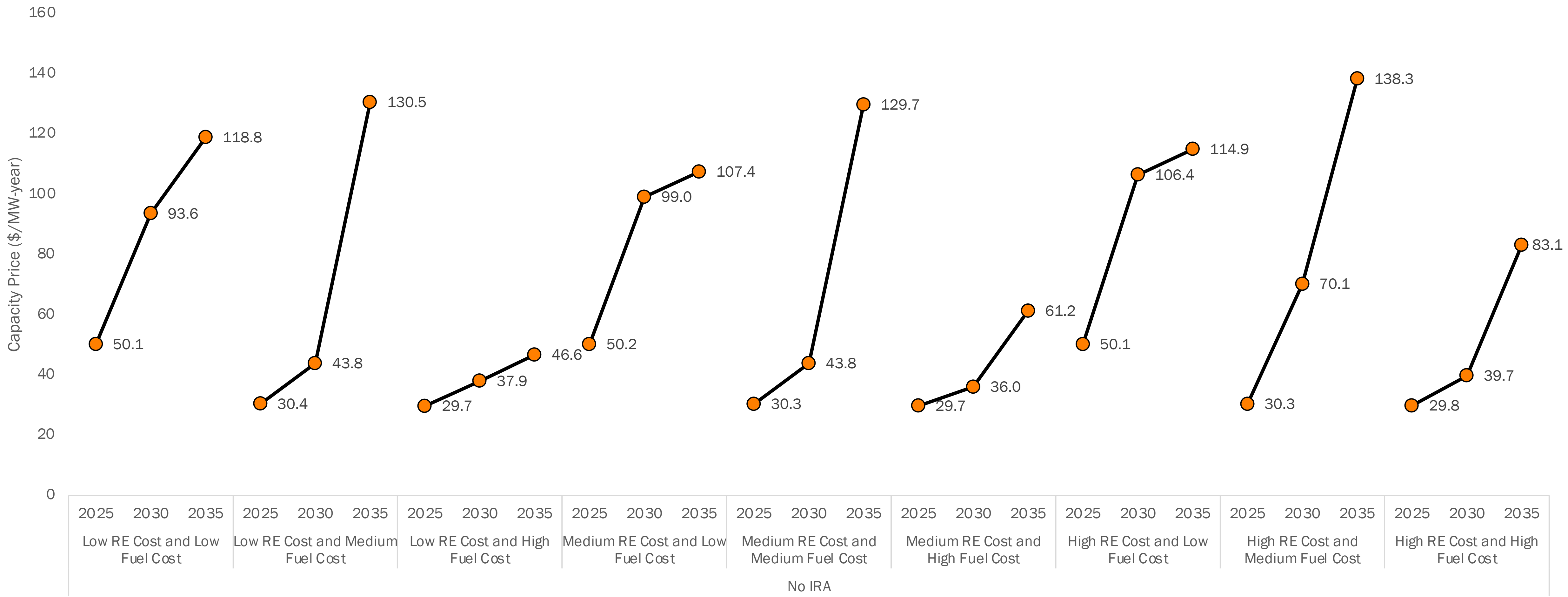


Figure A1-6: Capacity market price faced by generators in the PJM West market region under No IRA Scenario.

PJM renewable energy credit price under No IRA Scenario

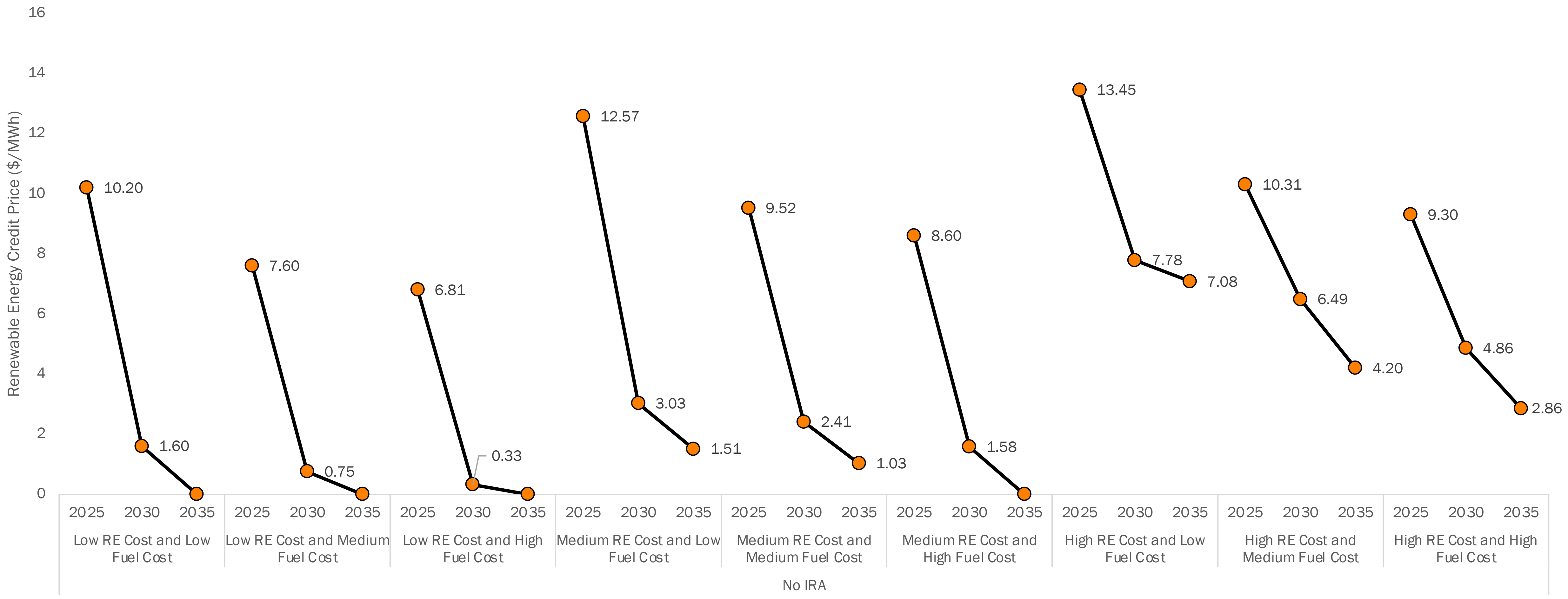


Figure A1-7: PJM renewable energy credit price under No IRA Scenario

IRA Scenario Results

PJM emissions under IRA scenario

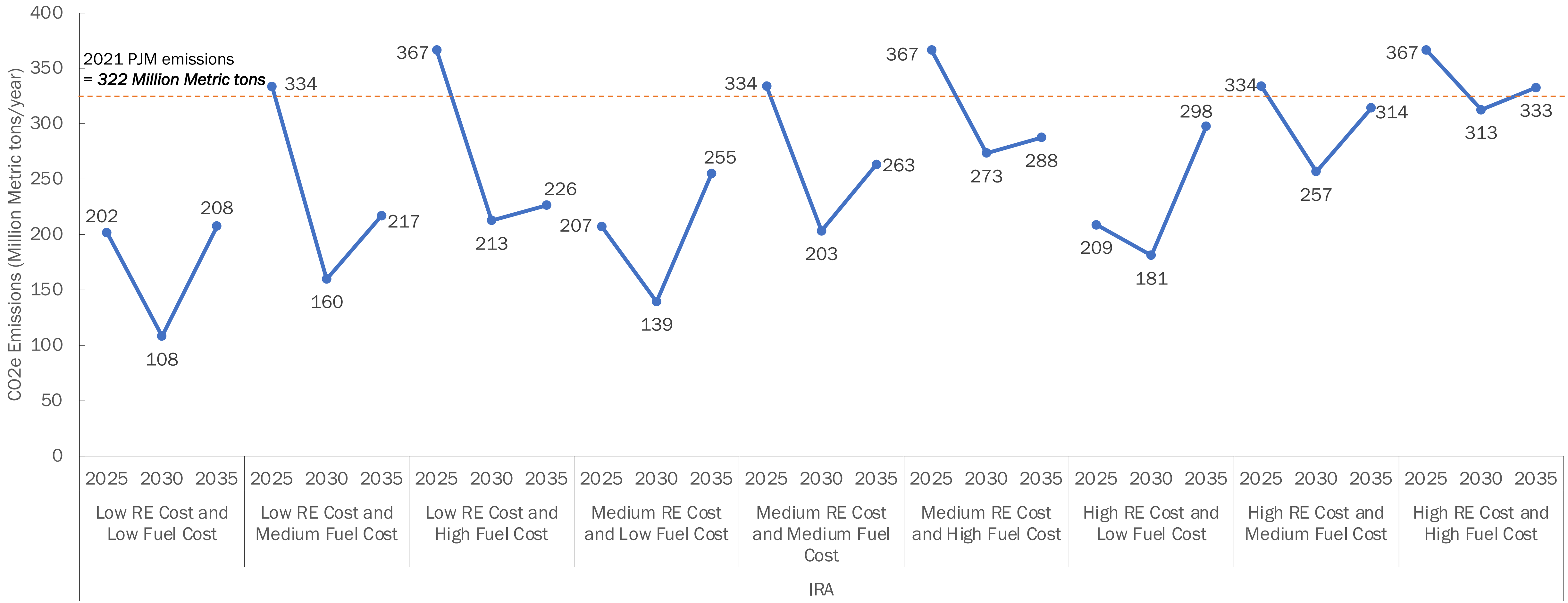


Figure A2-1: PJM system CO_2 emissions under IRA scenario

Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

PJM bulk electricity supply cost under IRA Scenario

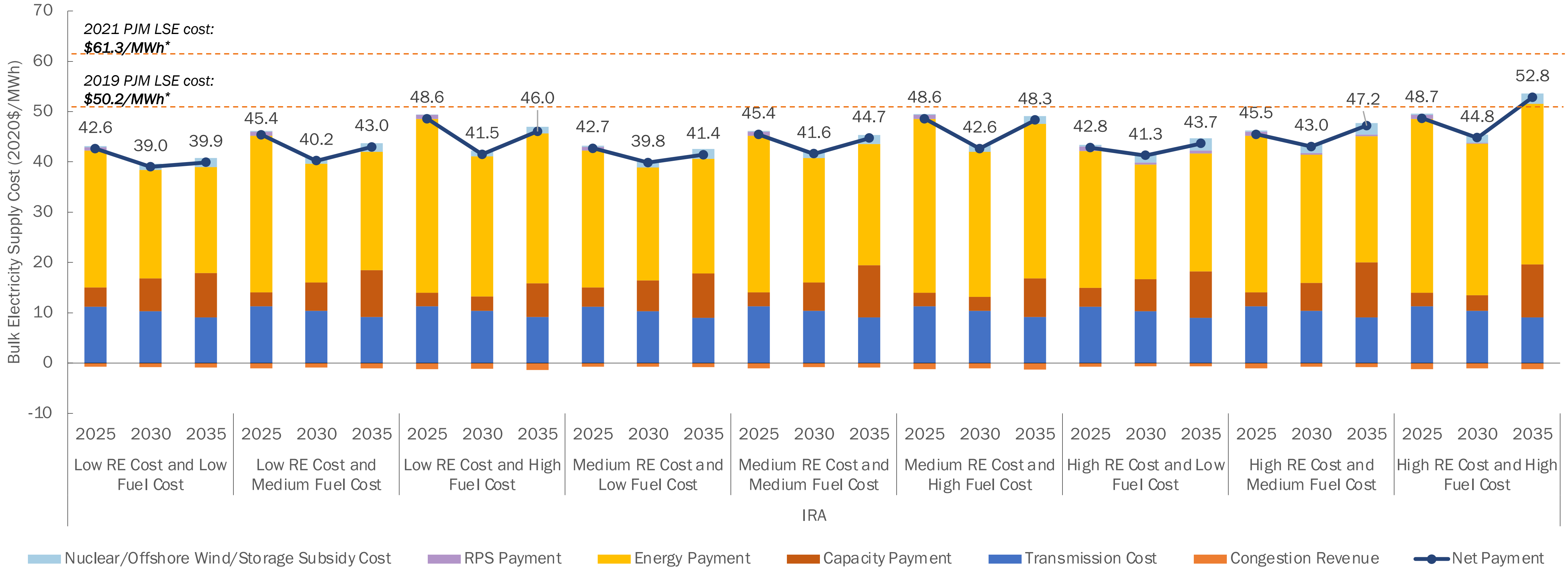


Figure A2-2: PJM load-serving entity bulk supply cost under IRA Scenario

* Source: Monitoring Analytics, LLC (2021), "State of the Market Report for PJM." Note: Modeled costs underestimate the impact of transmission congestion on average energy costs due to the zonal resolution of model. Meanwhile, 2019 & 2021 benchmark costs exclude any state subsidies for specific technologies (e.g. nuclear, offshore wind, batteries), while modeled costs include these subsidies. The comparison of modeled and benchmark costs is thus approximate, but closely comparable.

PJM capacity mix under IRA Scenario

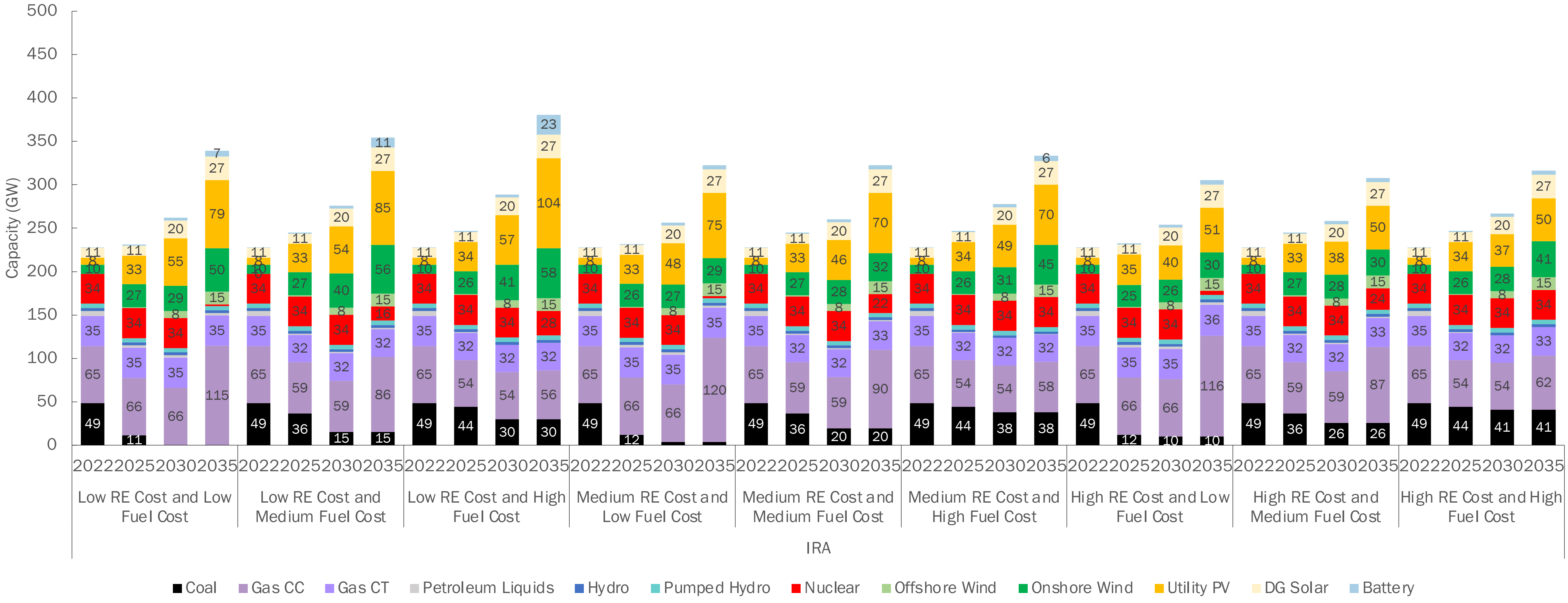


Figure A2-3: PJM capacity mix under IRA Scenario
Data labels ≤5 GW are not shown. DG solar capacity is as an exogenous input not optimized in model.

PJM annual electricity generation under IRA Scenario

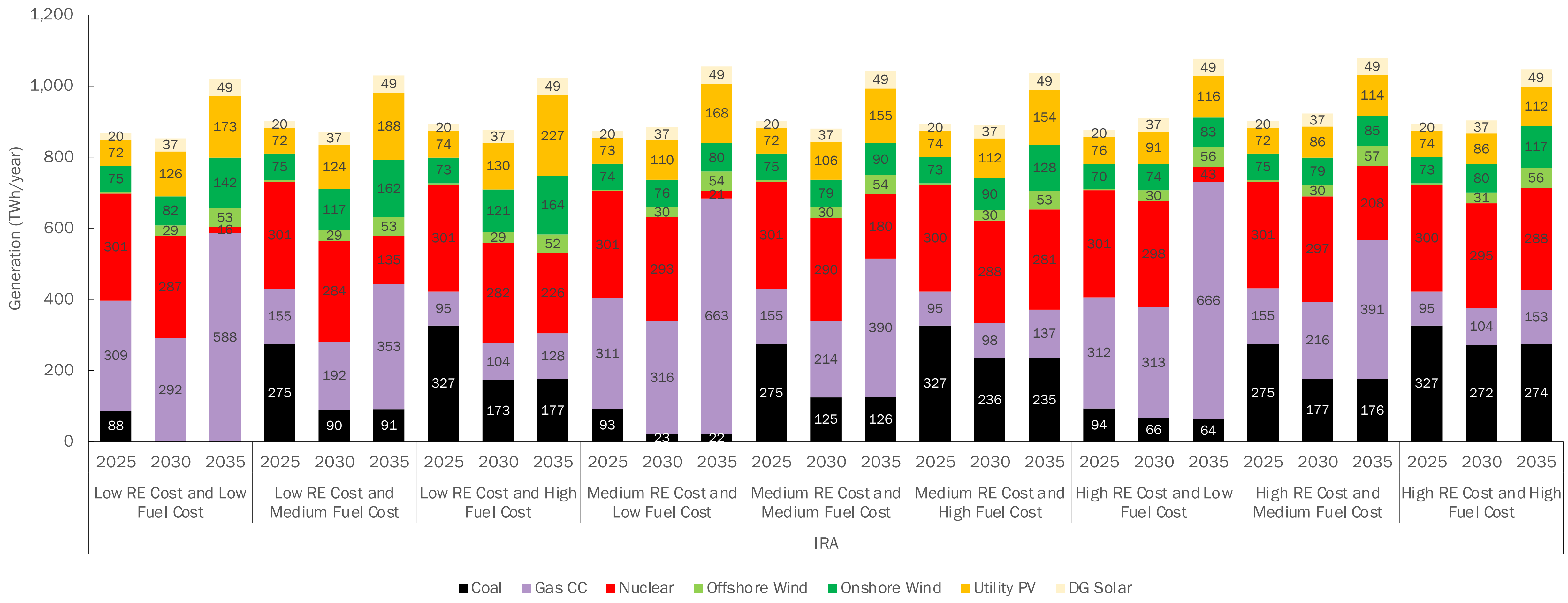


Figure A2-4: PJM annual electricity generation under IRA Scenario
Data labels <10 TWh are not shown. Generation from Biomass, Hydro, and Natural Gas Combustion Turbines (CT) are all <10 TWh and not depicted above. DG solar generation is as an exogenous input not optimized in model.

Locational marginal prices (LMP) under IRA Scenario

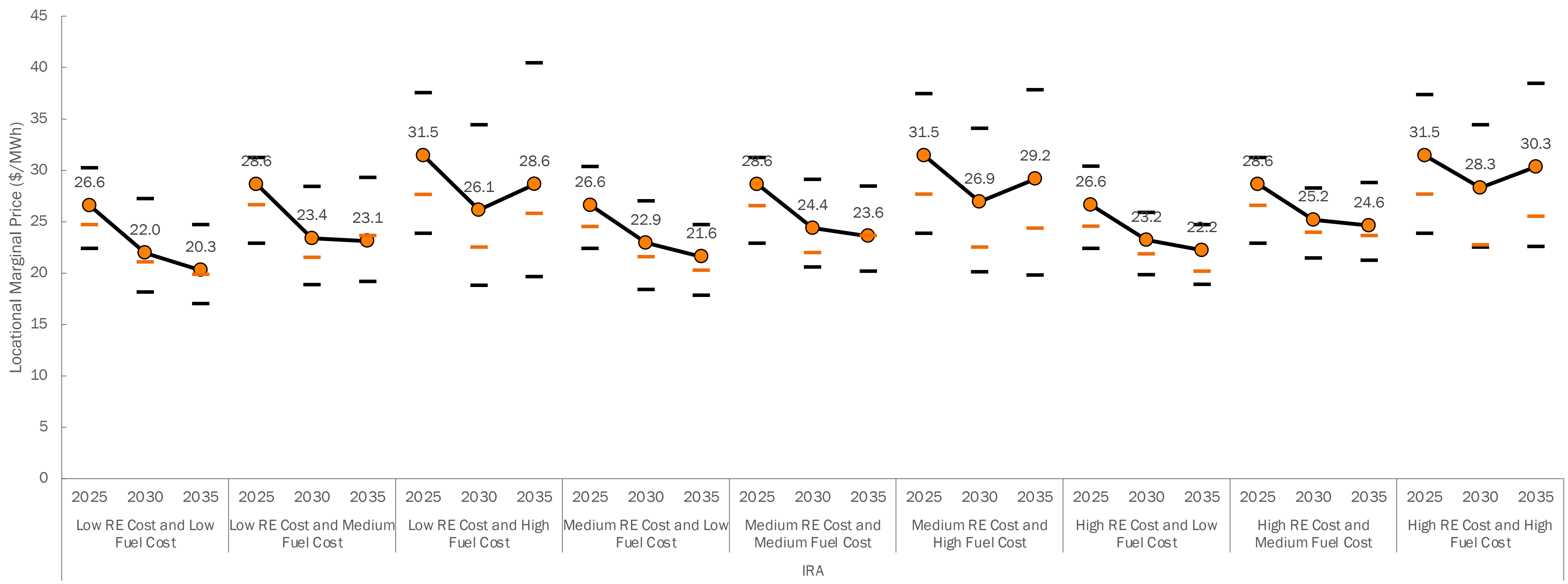


Figure A2-5: Load-weighted average locational marginal price (LMP) for the PJM West model region under IRA Scenario.
Horizontal bars show the 1st, 2nd, and 3rd quartiles of the LMP distribution, and dots denote the price average.

Capacity market price under IRA Scenario

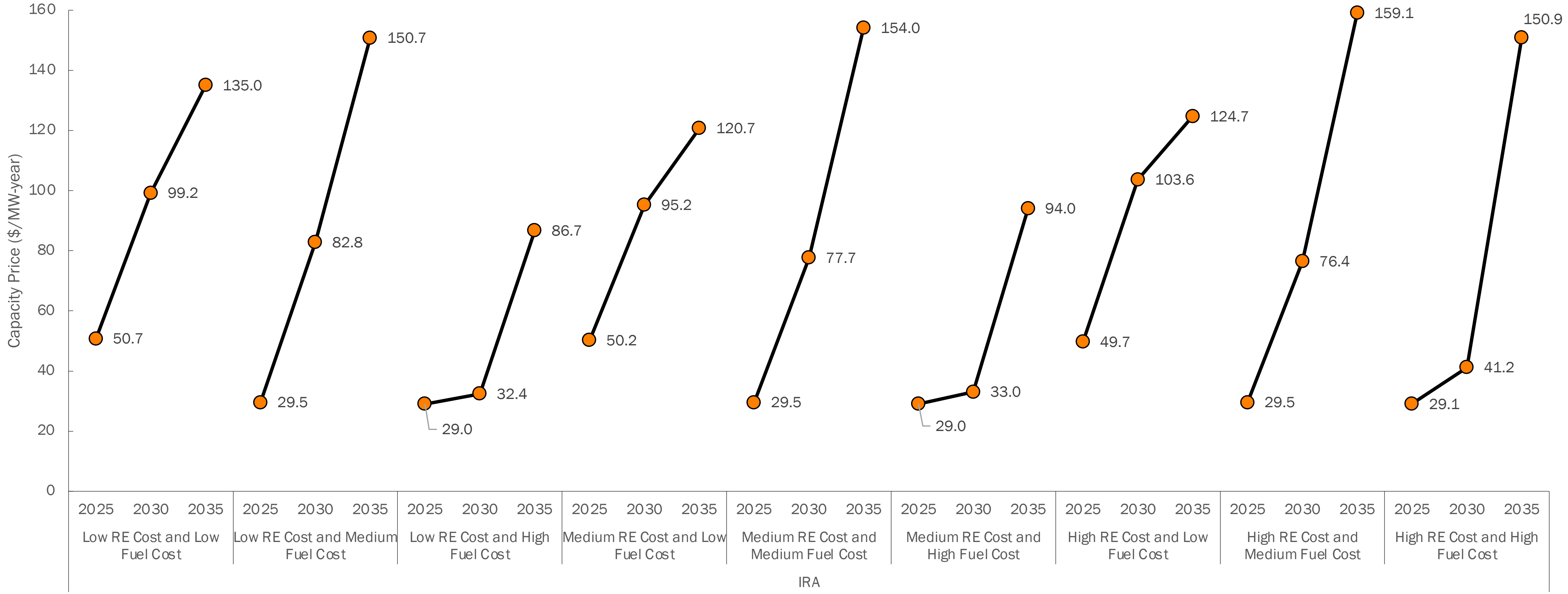


Figure A2-6: Capacity market price faced by generators in the PJM West market region under IRA Scenario.

PJM renewable energy credit price under IRA Scenario

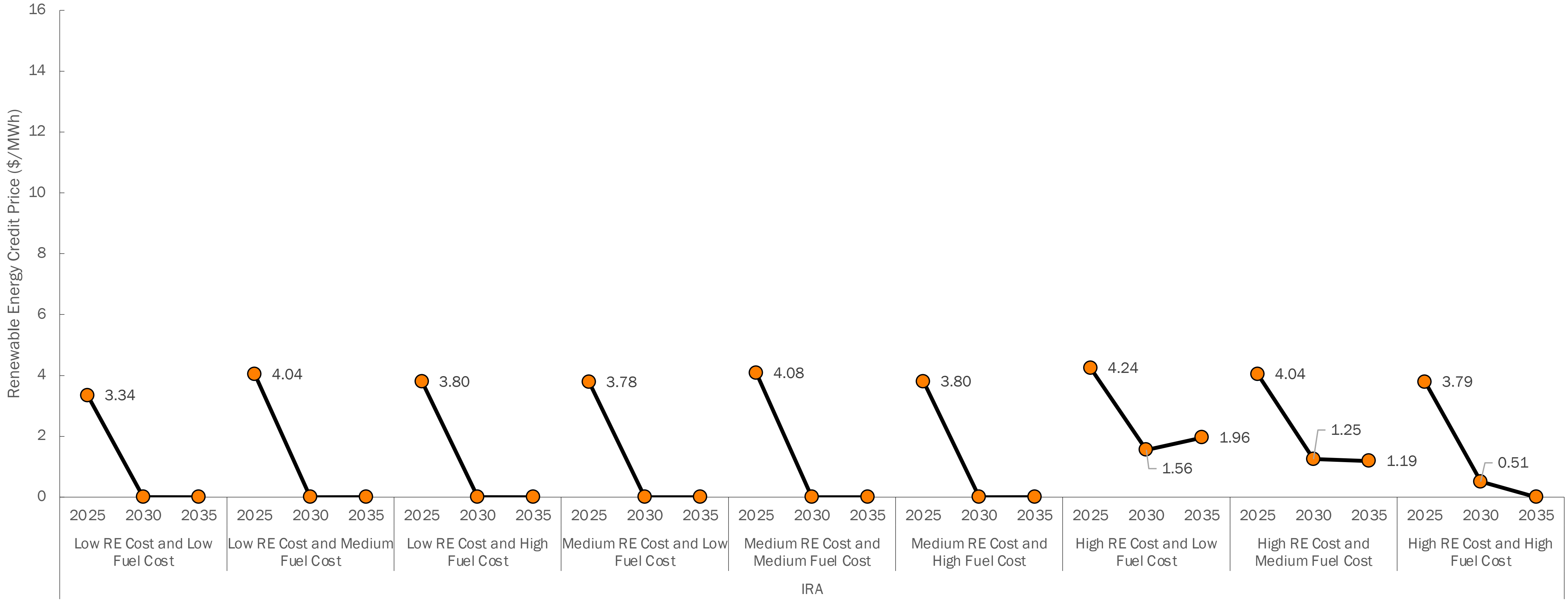


Figure A2-7: PJM renewable energy credit price under IRA Scenario

Federal tax credit payments collected by PJM generators under IRA Scenario

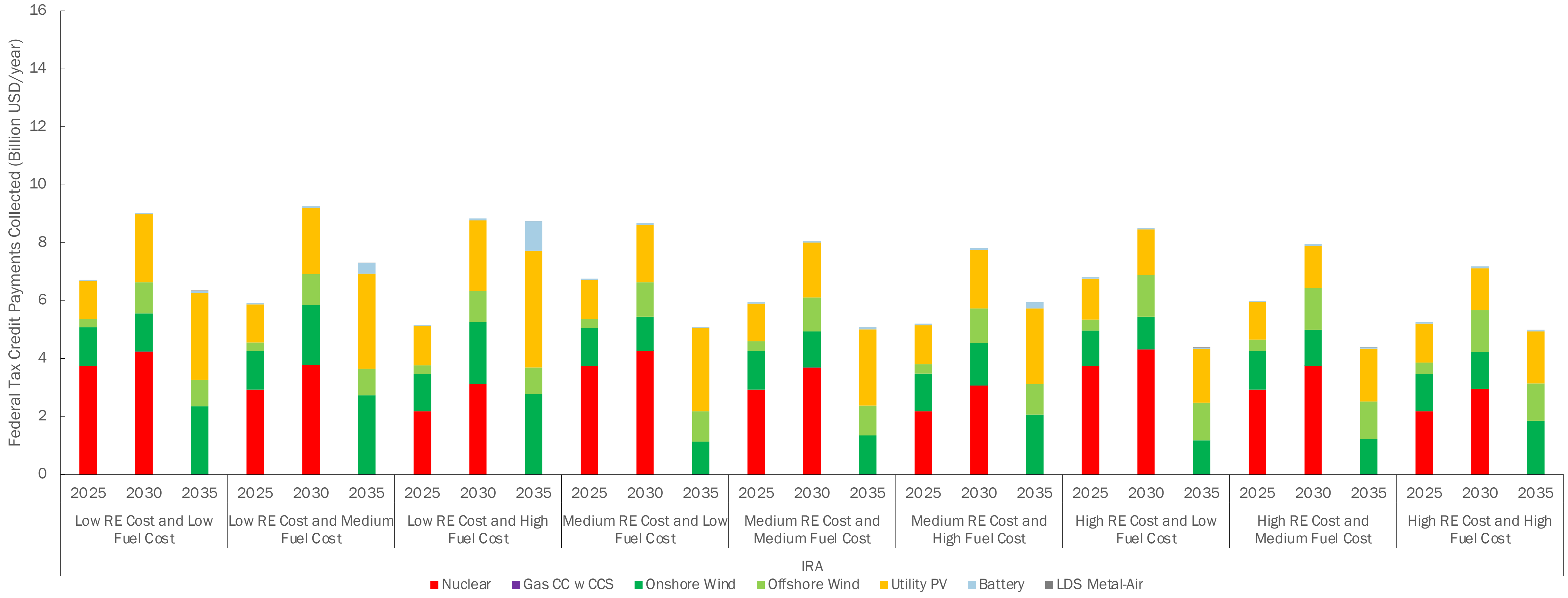
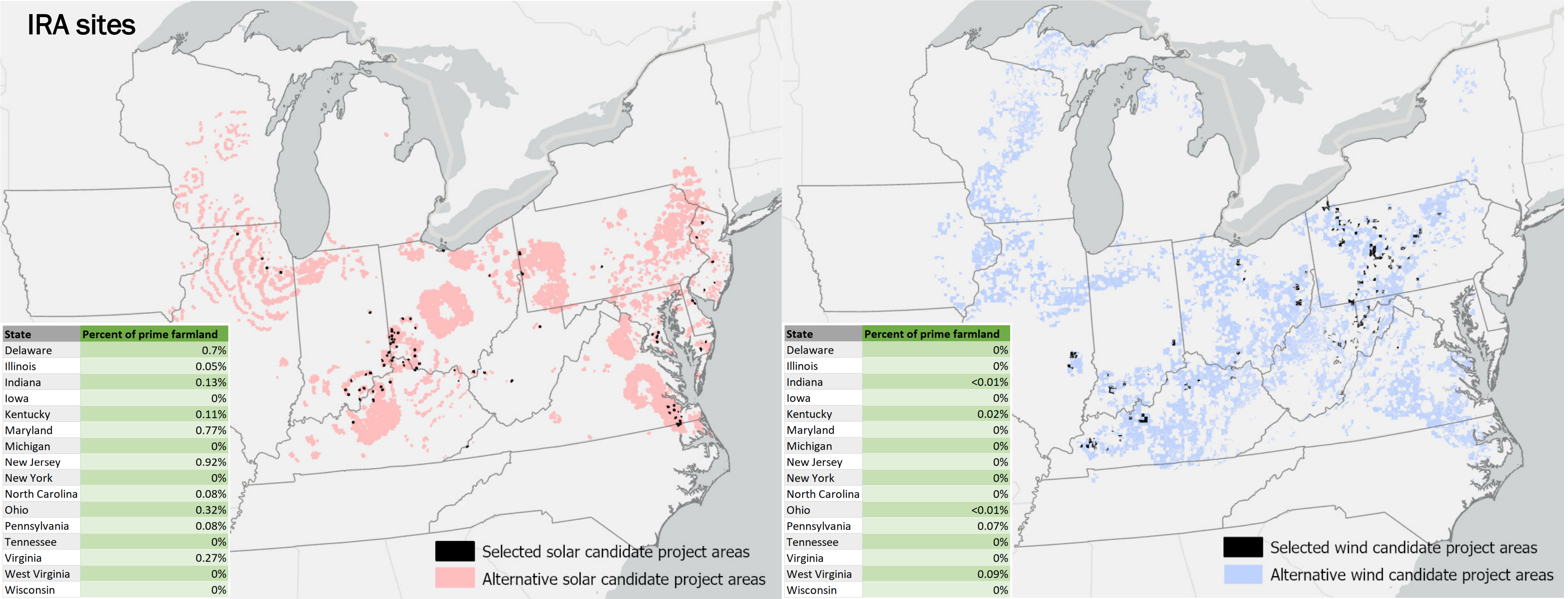


Figure A2-8: Federal tax credit payments collected by PJM generators under IRA Scenario

Spatial deployment of utility-scale solar & wind under IRA – least-cost



State	Percent of prime farmland
Delaware	0.7%
Illinois	0.05%
Indiana	0.13%
Iowa	0%
Kentucky	0.11%
Maryland	0.77%
Michigan	0%
New Jersey	0.92%
New York	0%
North Carolina	0.08%
Ohio	0.32%
Pennsylvania	0.08%
Tennessee	0%
Virginia	0.27%
West Virginia	0%
Wisconsin	0%

State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	<0.01%
Iowa	0%
Kentucky	0.02%
Maryland	0%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	<0.01%
Pennsylvania	0.07%
Tennessee	0%
Virginia	0%
West Virginia	0.09%
Wisconsin	0%

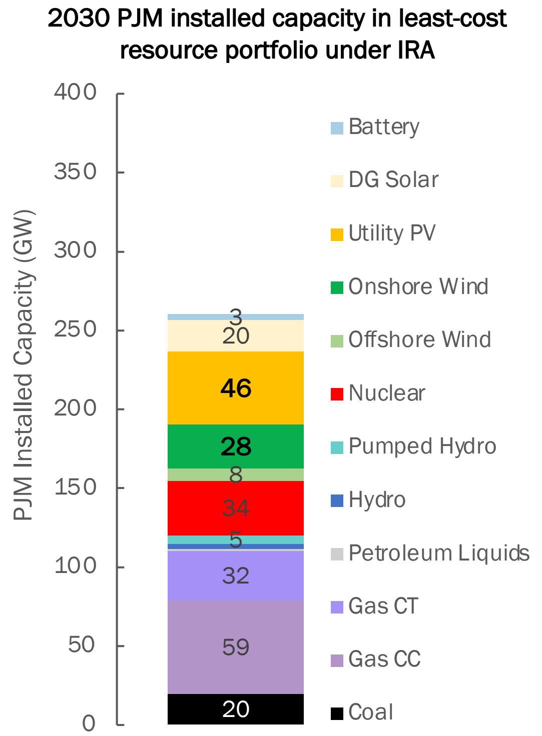
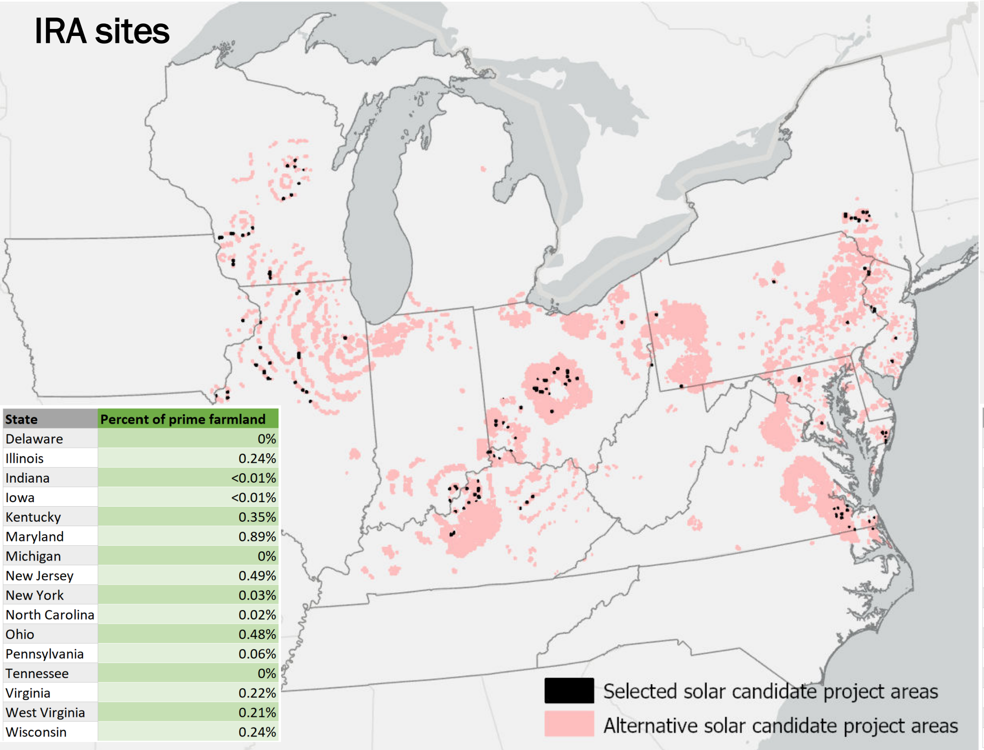


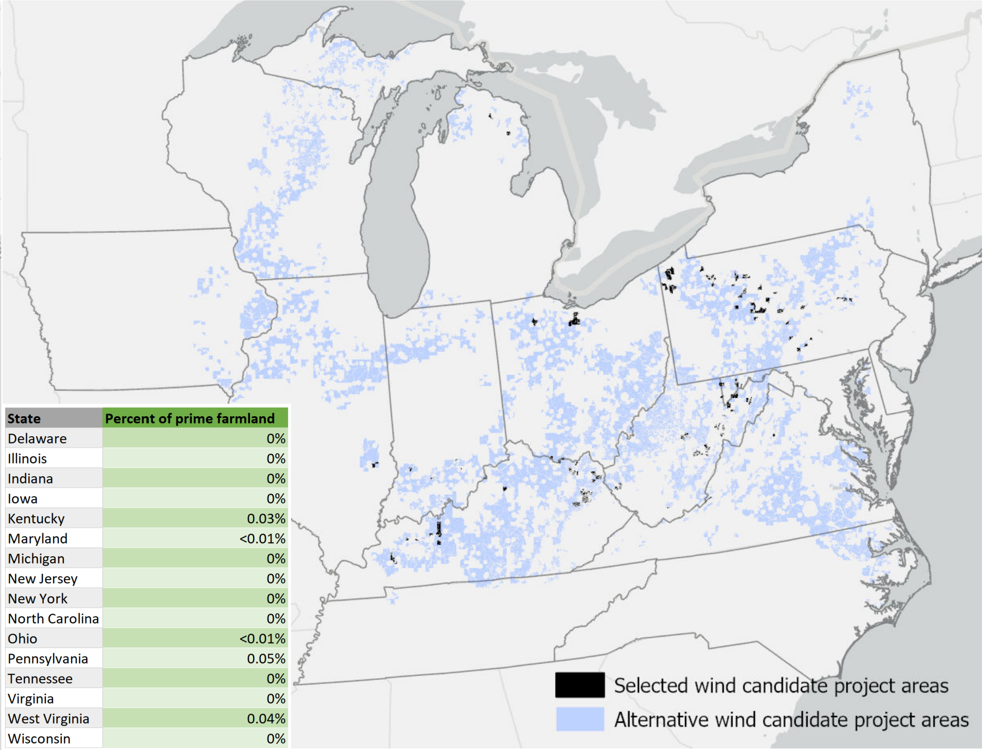
Figure A2-9: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA – Showing selected CPAs for least-cost portfolio (medium fuel cost/medium RE cost case)

Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected CPAs consistent with the modeled least-cost portfolio are in black. Plotted alternative CPAs in lighter red (solar) and lighter blue (wind) are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA – minimum transmission



State	Percent of prime farmland
Delaware	0%
Illinois	0.24%
Indiana	<0.01%
Iowa	<0.01%
Kentucky	0.35%
Maryland	0.89%
Michigan	0%
New Jersey	0.49%
New York	0.03%
North Carolina	0.02%
Ohio	0.48%
Pennsylvania	0.06%
Tennessee	0%
Virginia	0.22%
West Virginia	0.21%
Wisconsin	0.24%



State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	0%
Iowa	0%
Kentucky	0.03%
Maryland	<0.01%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	<0.01%
Pennsylvania	0.05%
Tennessee	0%
Virginia	0%
West Virginia	0.04%
Wisconsin	0%

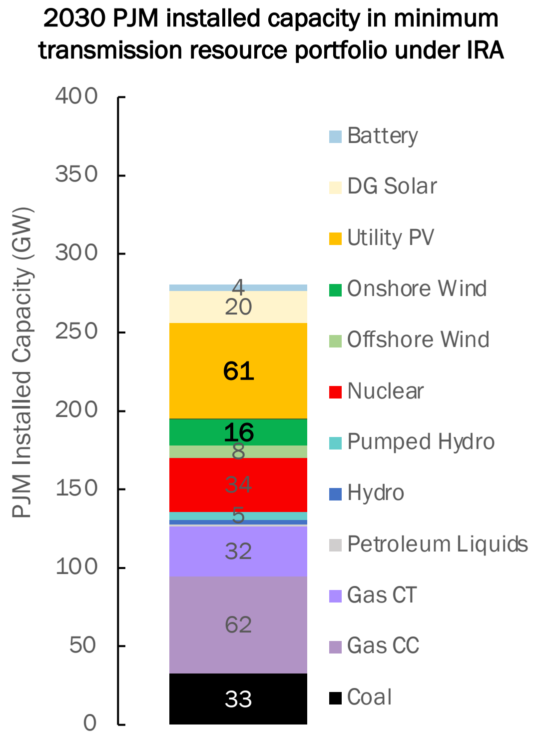
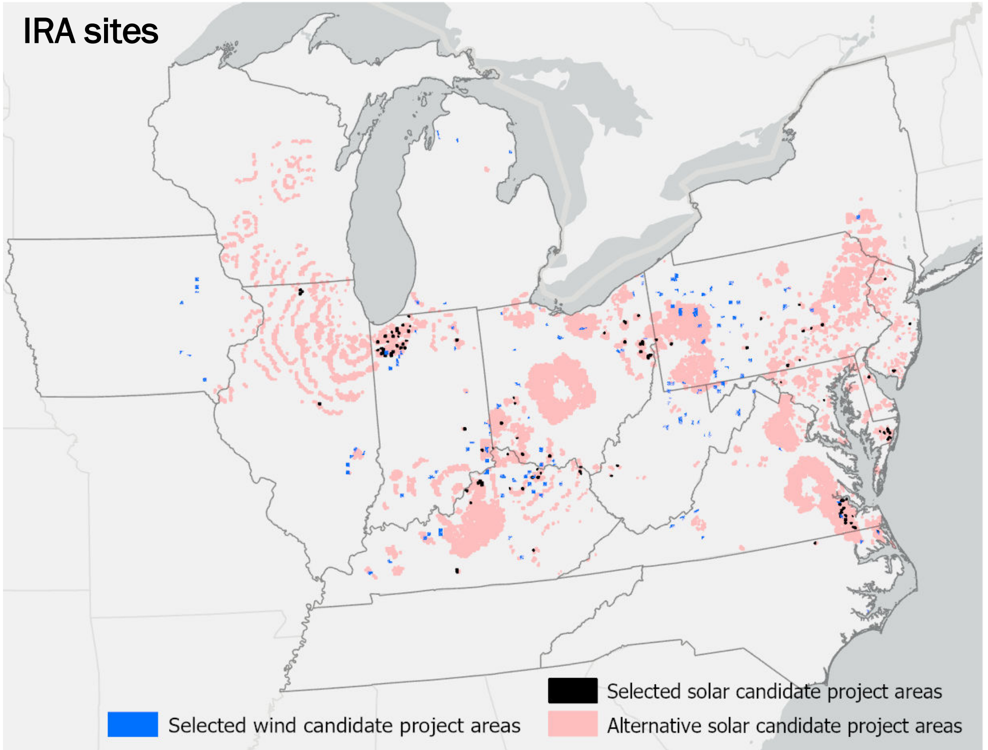


Figure A2-10: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA – Showing selected CPAs for minimum transmission portfolio (medium fuel cost/medium RE cost case)

Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected CPAs consistent with the portfolio that minimizes total transmission build out at a cost no greater than 10% larger than the least-cost portfolio are in black. Plotted alternative CPAs in lighter red (solar) and lighter blue (wind) are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA – maximum spatial equity, solar

State	Percent of prime farmland
Delaware	0.5%
Illinois	0.05%
Indiana	0.47%
Iowa	0%
Kentucky	0.15%
Maryland	0.6%
Michigan	0%
New Jersey	0.84%
New York	0%
North Carolina	0.03%
Ohio	0.22%
Pennsylvania	0.1%
Tennessee	0%
Virginia	0.42%
West Virginia	0.3%
Wisconsin	0%



2030 PJM installed capacity in maximum solar PV spatial equity resource portfolio under IRA

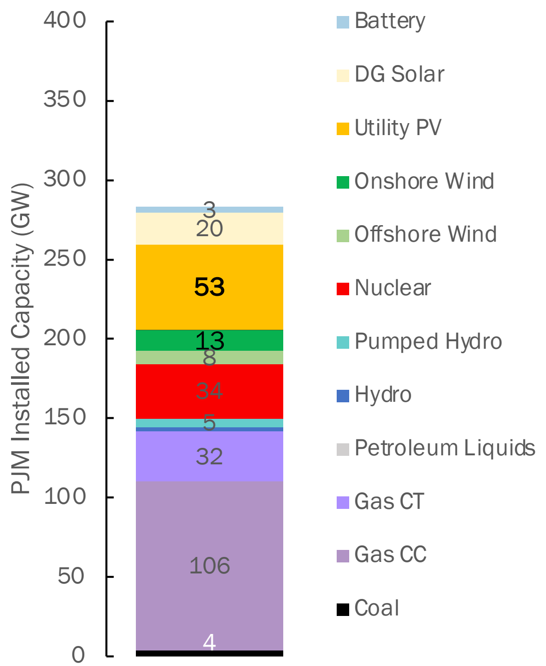
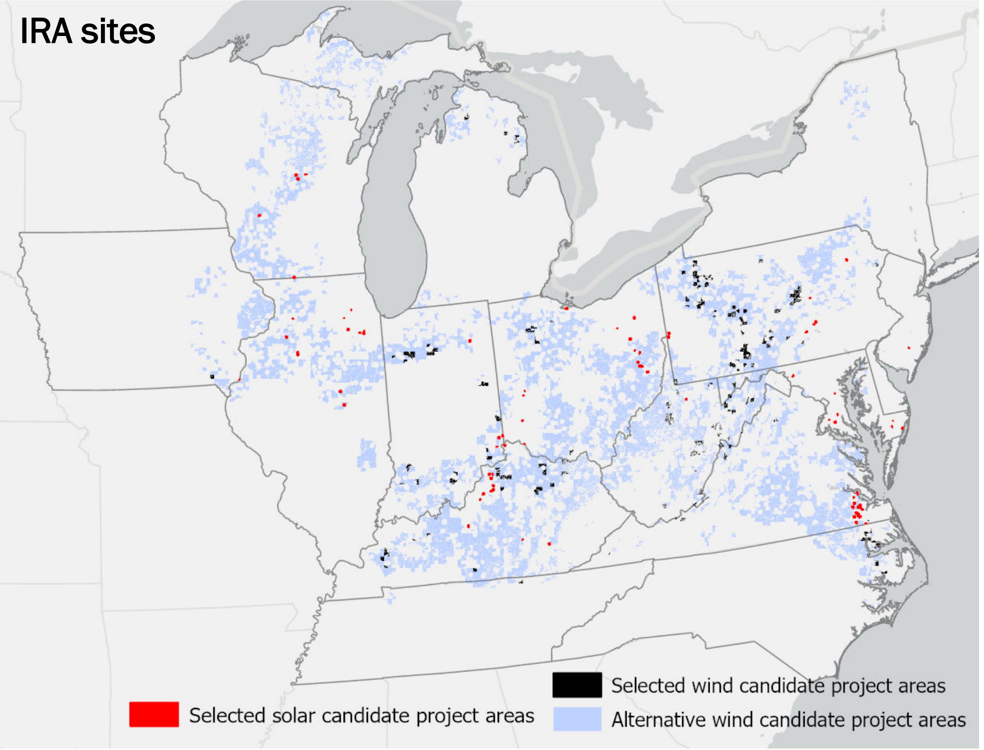


Figure A2-11: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA – Showing selected CPAs for maximum spatial equity for solar PV portfolio (medium fuel cost/medium RE cost case)

Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected solar CPAs consistent with the portfolio that ensures maximum equity in the spatial deployment of utility-scale solar PV across PJM transmission owner zones at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected wind CPAs are in dark blue. Alternative solar CPAs are depicted in lighter red and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA – maximum spatial equity, wind

State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	0.02%
Iowa	0%
Kentucky	0.03%
Maryland	0%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	<0.01%
Ohio	0%
Pennsylvania	0.06%
Tennessee	0%
Virginia	0%
West Virginia	0.09%
Wisconsin	0%



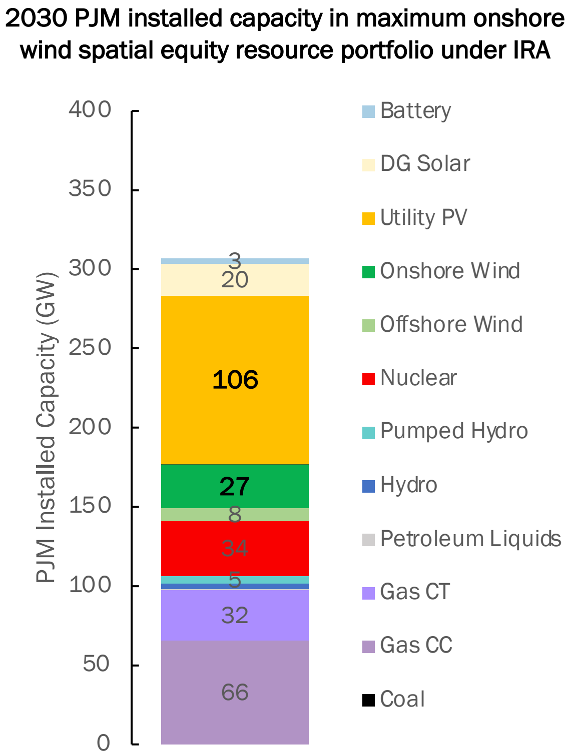
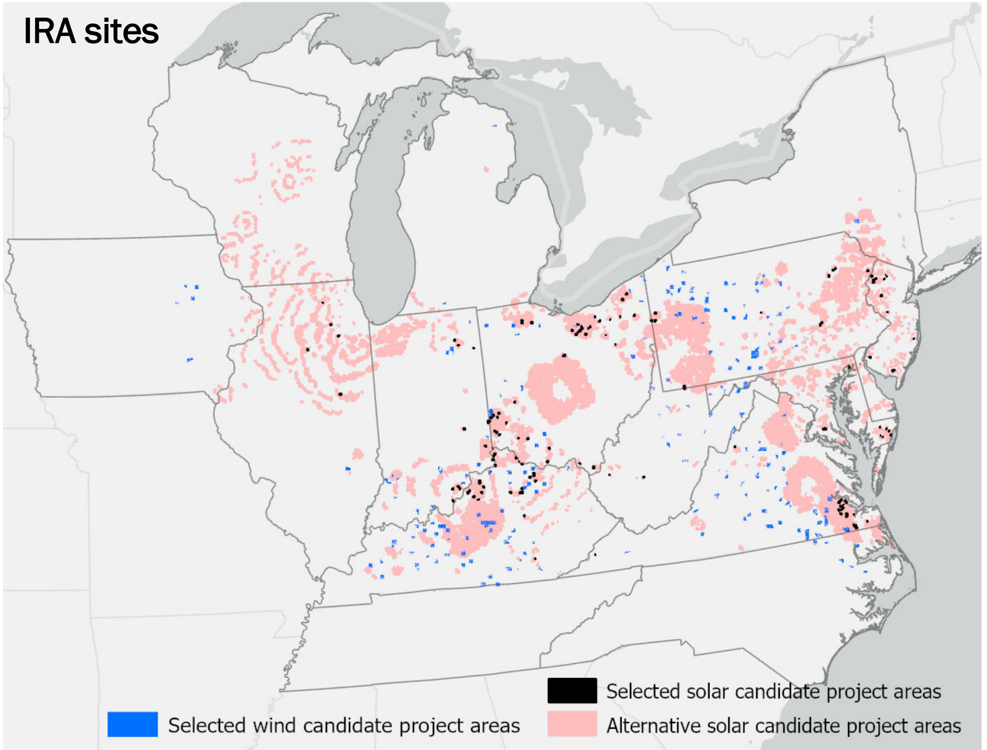


Figure A2-12: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA – Showing selected CPAs for maximum spatial equity for onshore wind portfolio (medium fuel cost/medium RE cost case)

Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected wind CPAs consistent with the portfolio that ensures maximum equity in the spatial deployment of onshore wind across PJM transmission owner zones at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected solar CPAs are in dark blue. Alternative wind CPAs are depicted in lighter blue and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA – maximum solar PV

State	Percent of prime farmland
Delaware	0.14%
Illinois	0.06%
Indiana	0.11%
Iowa	0%
Kentucky	0.29%
Maryland	0.34%
Michigan	0%
New Jersey	1.74%
New York	0%
North Carolina	0%
Ohio	0.63%
Pennsylvania	0.17%
Tennessee	0%
Virginia	0.53%
West Virginia	0%
Wisconsin	0%



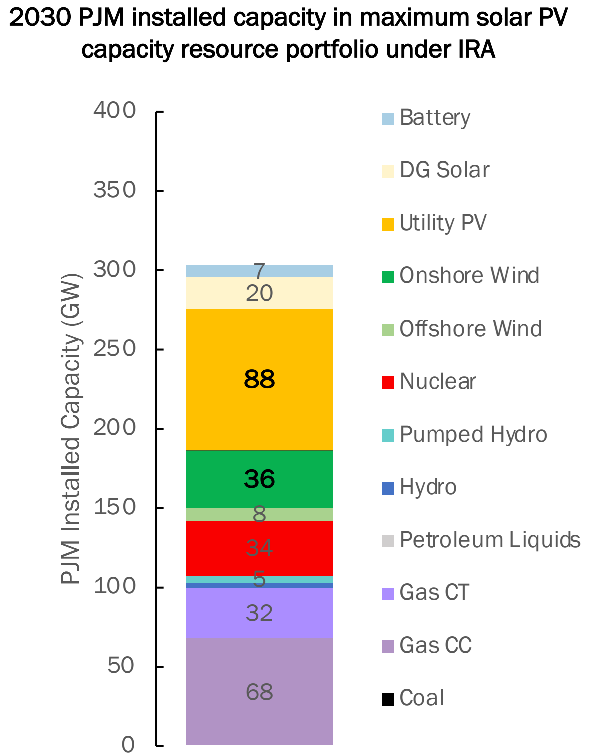
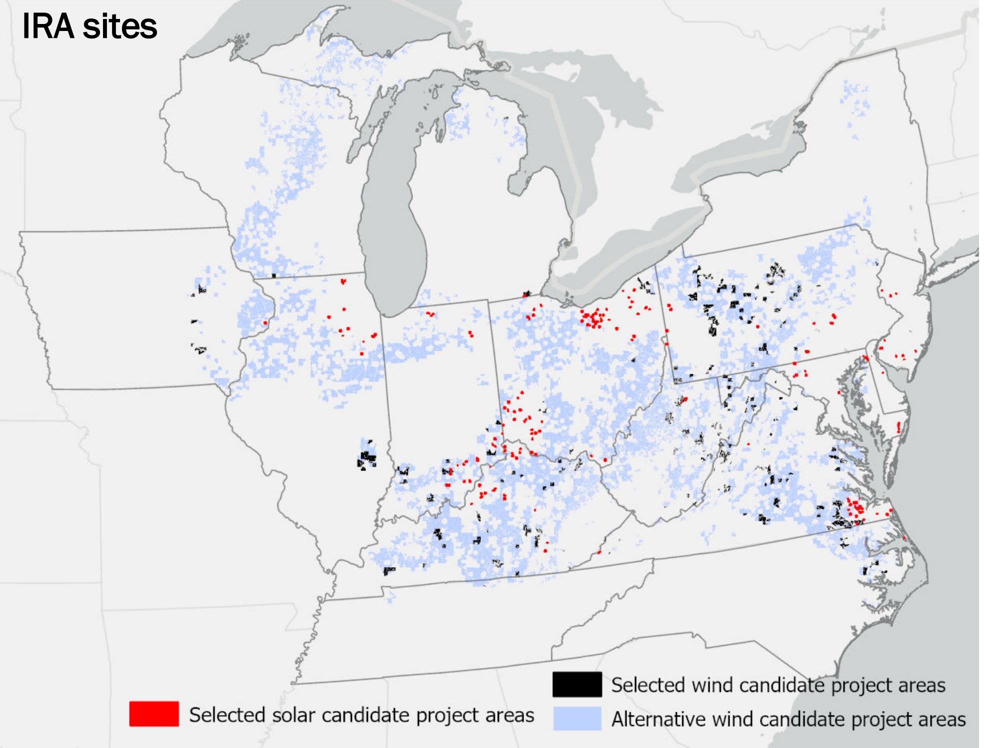


Figure A2-13: Spatial deployment of utility-scale solar PV & wind power in 2030 consistent with modeled portfolios under IRA – Showing selected CPAs for maximum solar PV capacity portfolio (medium fuel cost/medium RE cost case)

Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected solar CPAs consistent with the portfolio that ensures maximum utility-scale solar PV capacity at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected wind CPAs are in dark blue. Alternative solar CPAs are depicted in lighter red and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA – maximum onshore wind

State	Percent of prime farmland
Delaware	0%
Illinois	<0.01%
Indiana	<0.01%
Iowa	0%
Kentucky	0.05%
Maryland	<0.01%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	<0.01%
Ohio	<0.01%
Pennsylvania	0.08%
Tennessee	0%
Virginia	0.08%
West Virginia	0.16%
Wisconsin	0%



2030 PJM installed capacity in maximum onshore wind capacity resource portfolio under IRA

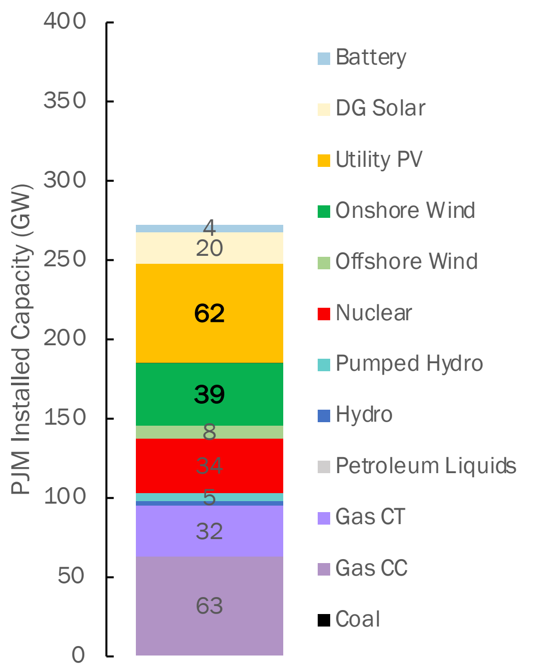


Figure A2-14: Spatial deployment of utility-scale solar PV & wind power in 2030 consistent with modeled portfolios under IRA – Showing selected CPAs for maximum onshore wind capacity portfolio (medium fuel cost/medium RE cost case)

Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected wind CPAs consistent with the portfolio that ensures maximum onshore wind capacity at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected solar CPAs are in dark blue. Alternative wind CPAs are depicted in lighter blue and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

IRA + Cap-and-Trade Scenario Results

PJM emissions under IRA + Cap-and-Trade Scenario

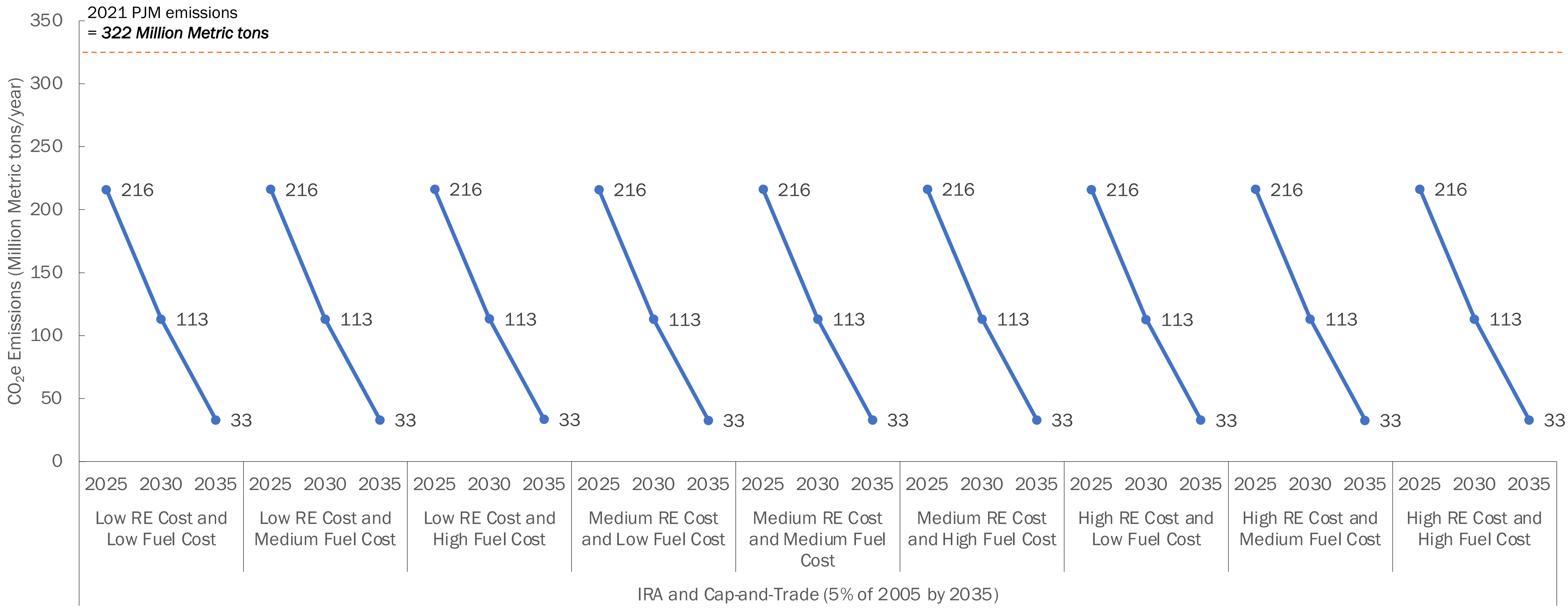


Figure A3-1: PJM system CO_2 emissions under IRA + Cap-and-Trade Scenario
Note that because of the binding emissions cap in this scenario, trends of the emissions are exactly the same in different cost sensitivities

Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

PJM bulk electricity supply cost under IRA + Cap-and-Trade Scenario

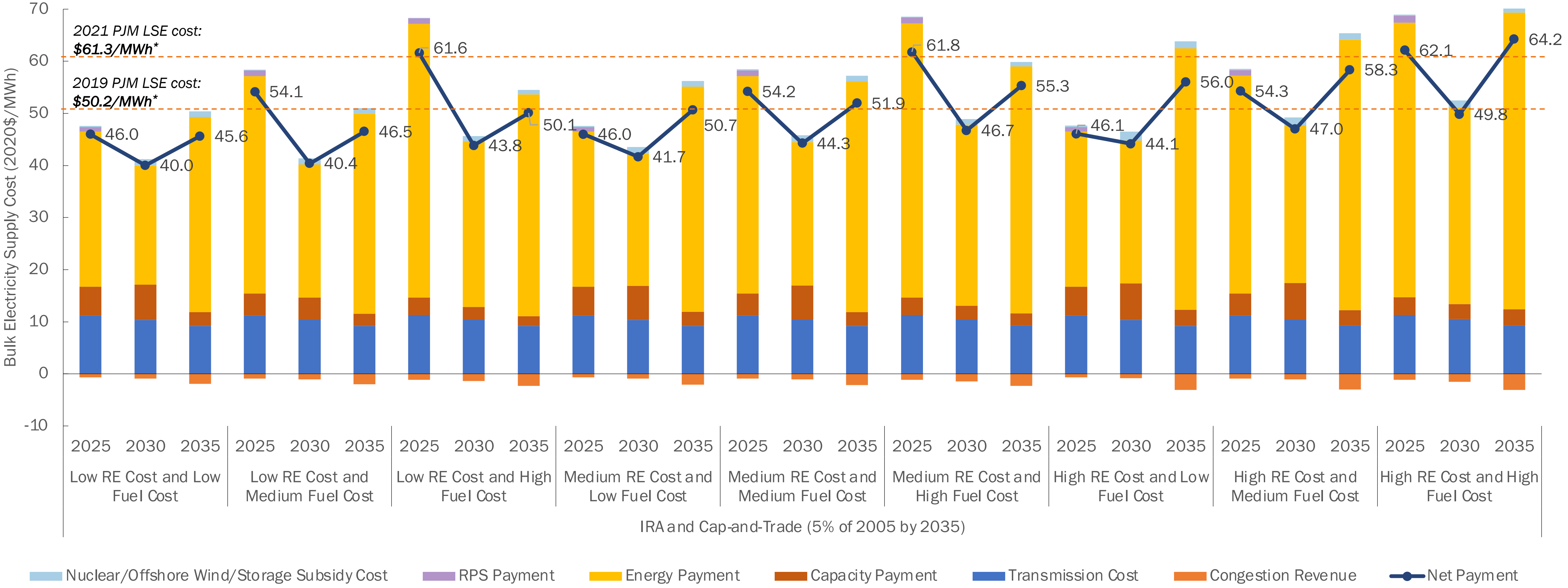


Figure A3-2: PJM load-serving entity bulk supply cost under IRA + Cap-and-Trade Scenario

* Source: Monitoring Analytics, LLC (2021), "State of the Market Report for PJM." Note: Modeled costs underestimate the impact of transmission congestion on average energy costs due to the zonal resolution of model. Meanwhile, 2019 & 2021 benchmark costs exclude any state subsidies for specific technologies (e.g. nuclear, offshore wind, batteries), while modeled costs include these subsidies. The comparison of modeled and benchmark costs is thus approximate, but closely comparable.

PJM capacity mix under IRA + Cap-and-Trade Scenario

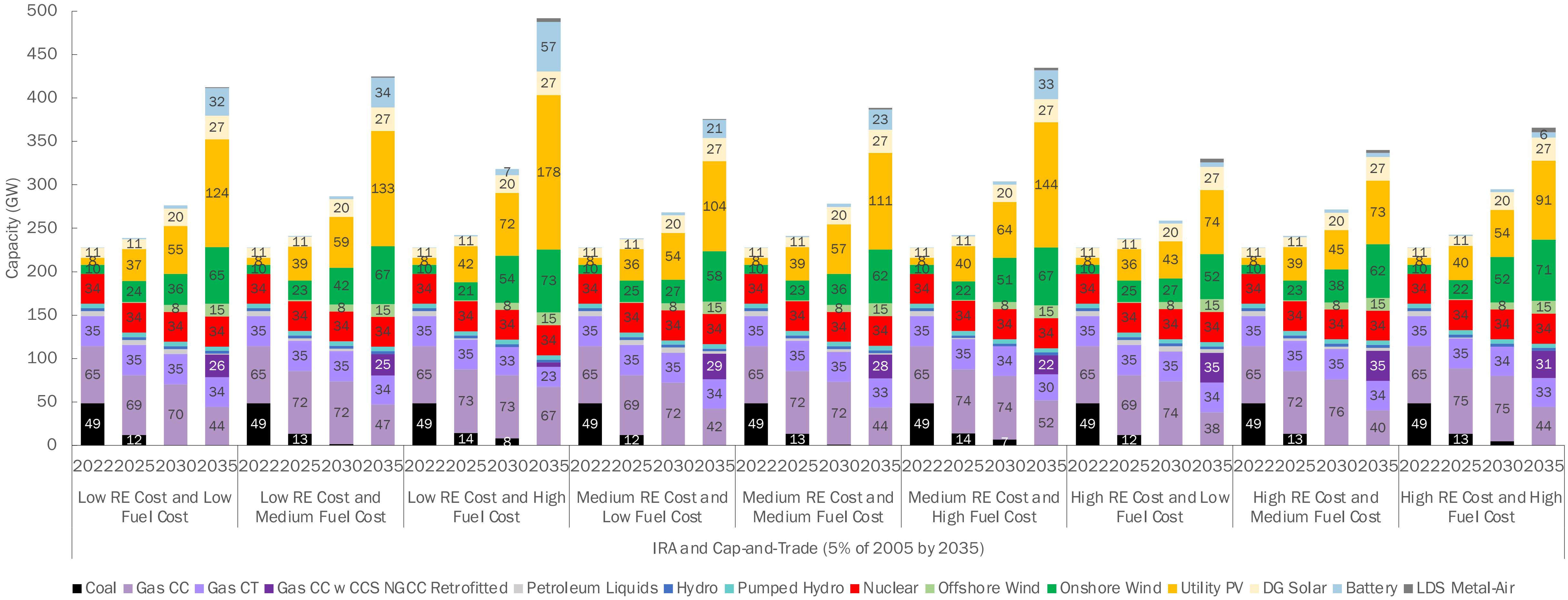


Figure A3-3: PJM capacity mix under IRA + Cap-and-Trade Scenario
Data labels ≤5 GW are not shown. DG solar capacity is as an exogenous input not optimized in model.

PJM annual electricity generation under IRA + Cap-and-Trade Scenario

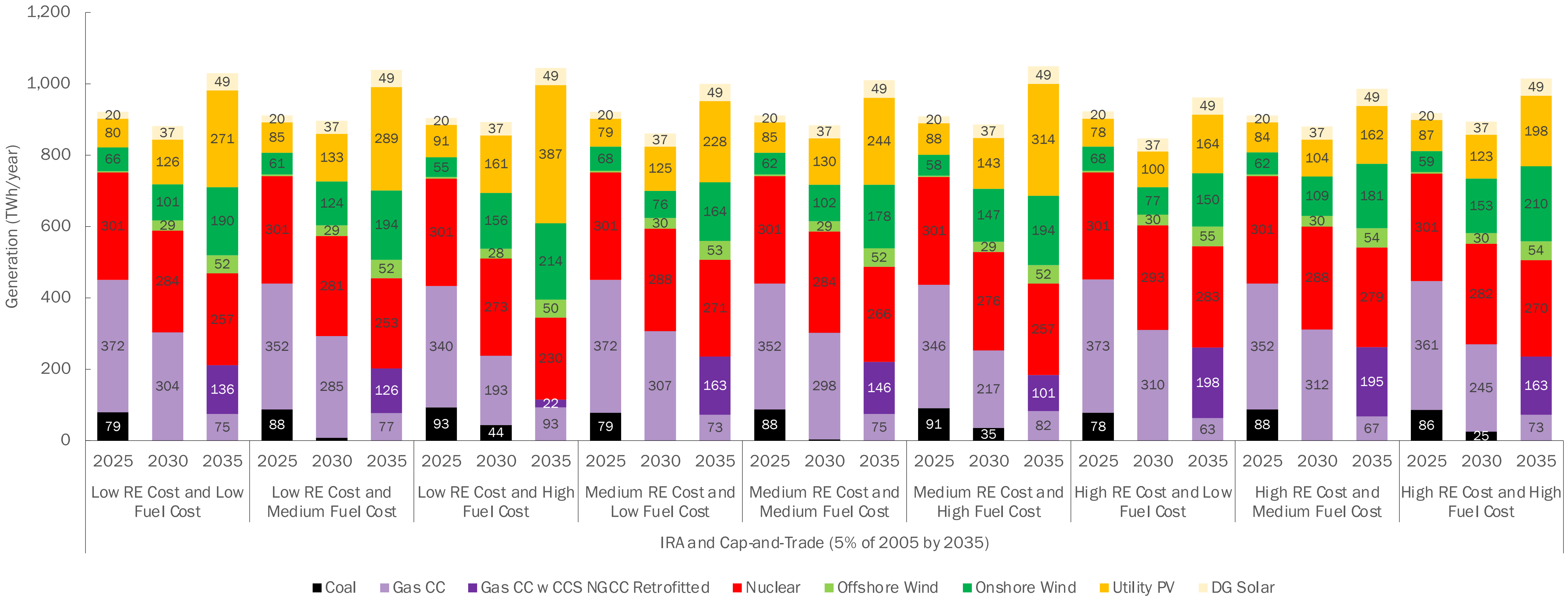


Figure A3-4: PJM annual electricity generation under IRA + Cap-and-Trade Scenario

Data labels <10 TWh are not shown. Generation from Biomass, Hydro, and Natural Gas Combustion Turbines (CT) are all <10 TWh and not depicted above. DG solar generation is as an exogenous input not optimized in model.

Locational marginal prices (LMP) under IRA + Cap-and-Trade Scenario

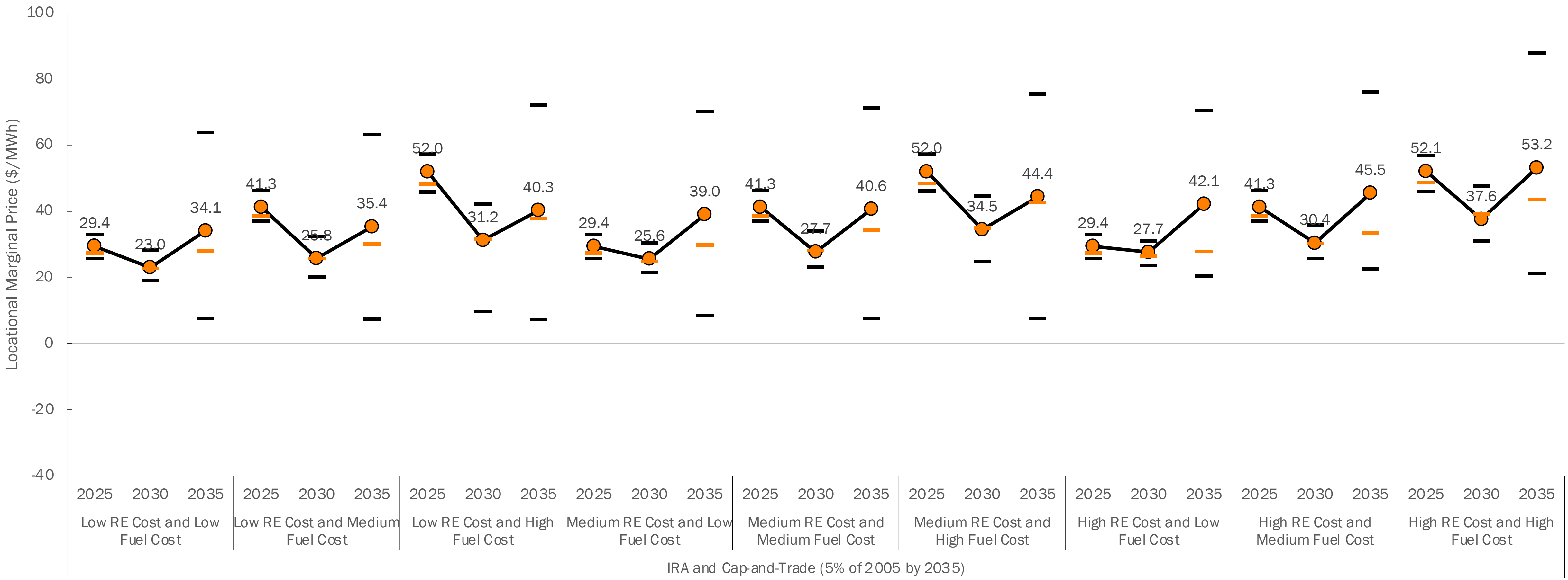


Figure A3-5: Load-weighted average locational marginal price (LMP) for the PJM West model region under IRA + Cap-and-Trade Scenario.
Horizontal bars show the 1st, 2nd, and 3rd quartiles of the LMP distribution, and dots denote the price average.

Capacity market price under IRA + Cap-and-Trade Scenario

Figure A3-6: Capacity market price faced by generators in the PJM West market region under IRA + Cap-and-Trade Scenario.

PJM renewable energy credit price under IRA + Cap-and-Trade Scenario

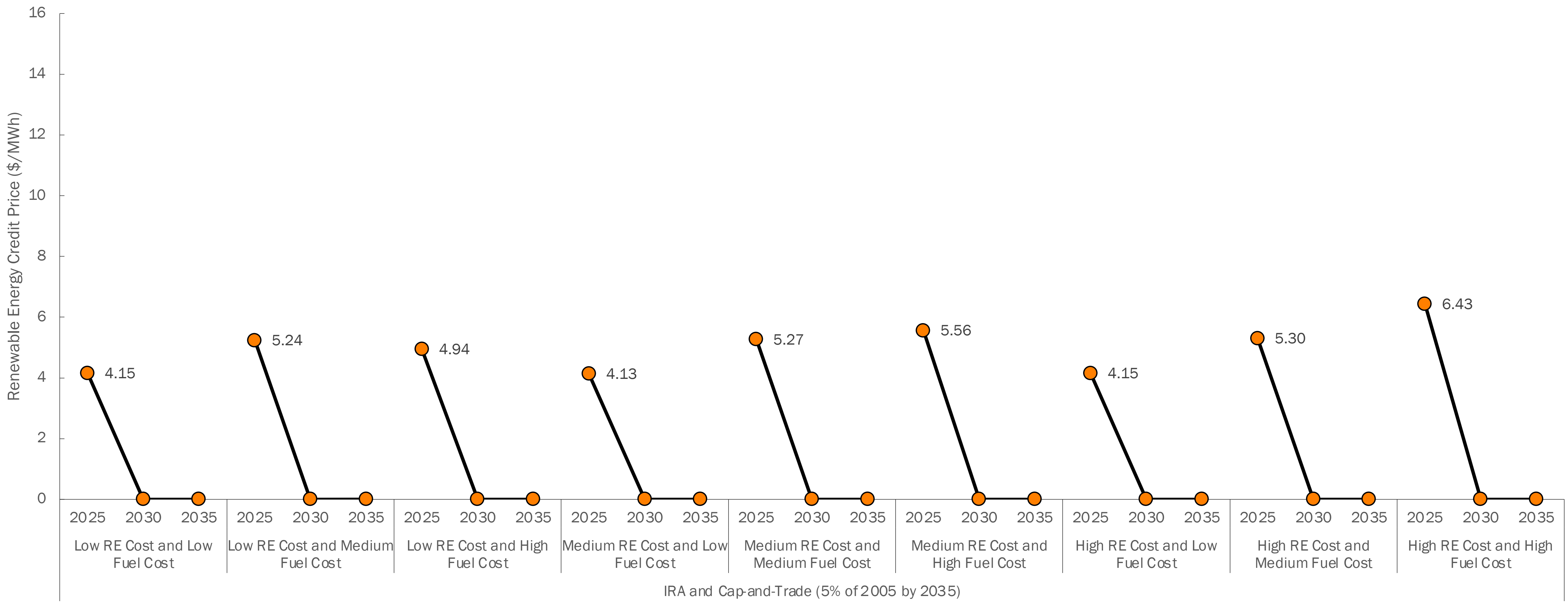


Figure A3-7: PJM renewable energy credit price under IRA + Cap-and-Trade Scenario

PJM carbon price under IRA + Cap-and-Trade Scenario

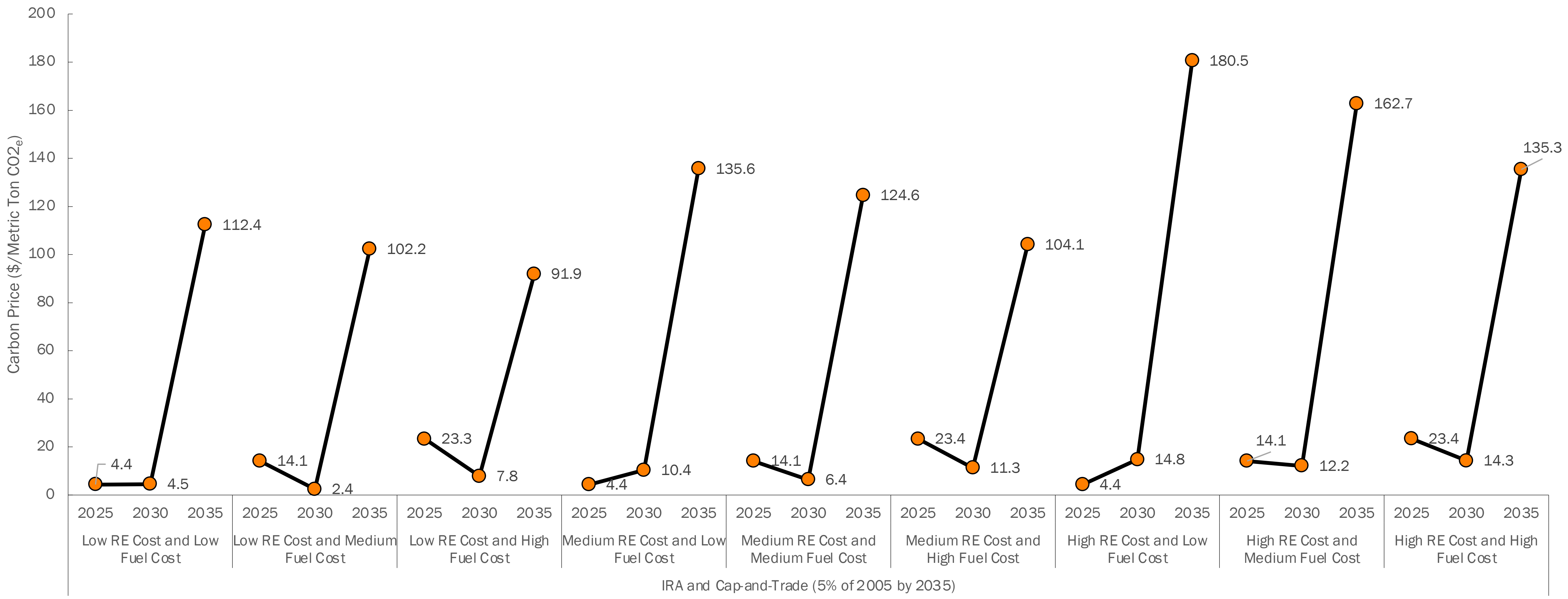


Figure A3-8: PJM carbon price under IRA + Cap-and-Trade Scenario

Federal tax credit payments collected by PJM generators under IRA + Cap-and-Trade Scenario

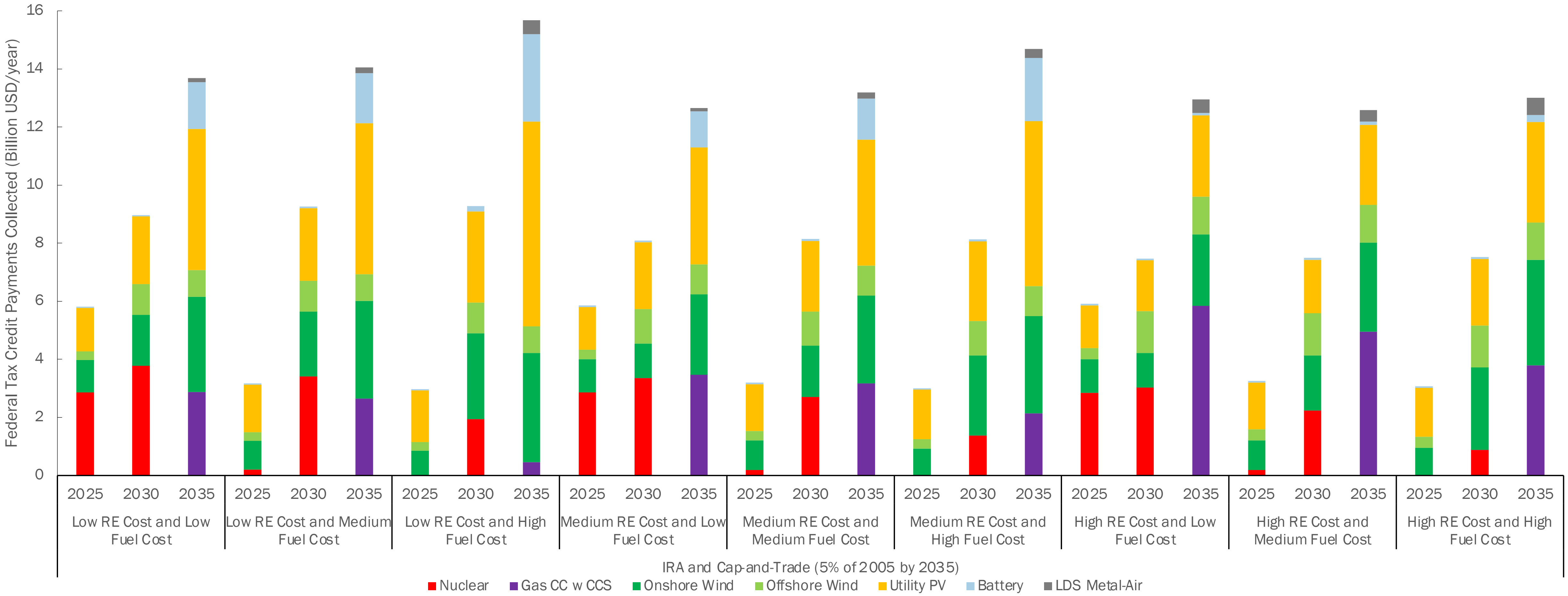
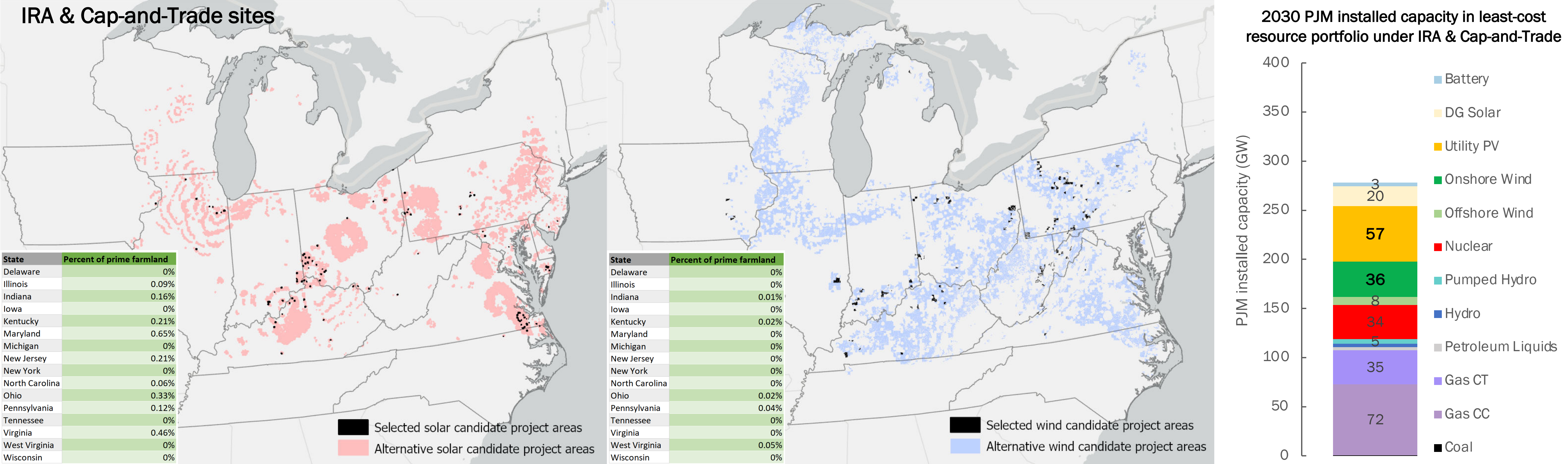


Figure A3-9: Federal tax credit payments collected by PJM generators under IRA + Cap-and-Trade Scenario

Spatial deployment of utility-scale solar & wind under IRA & Cap & Trade Scenario – least-cost



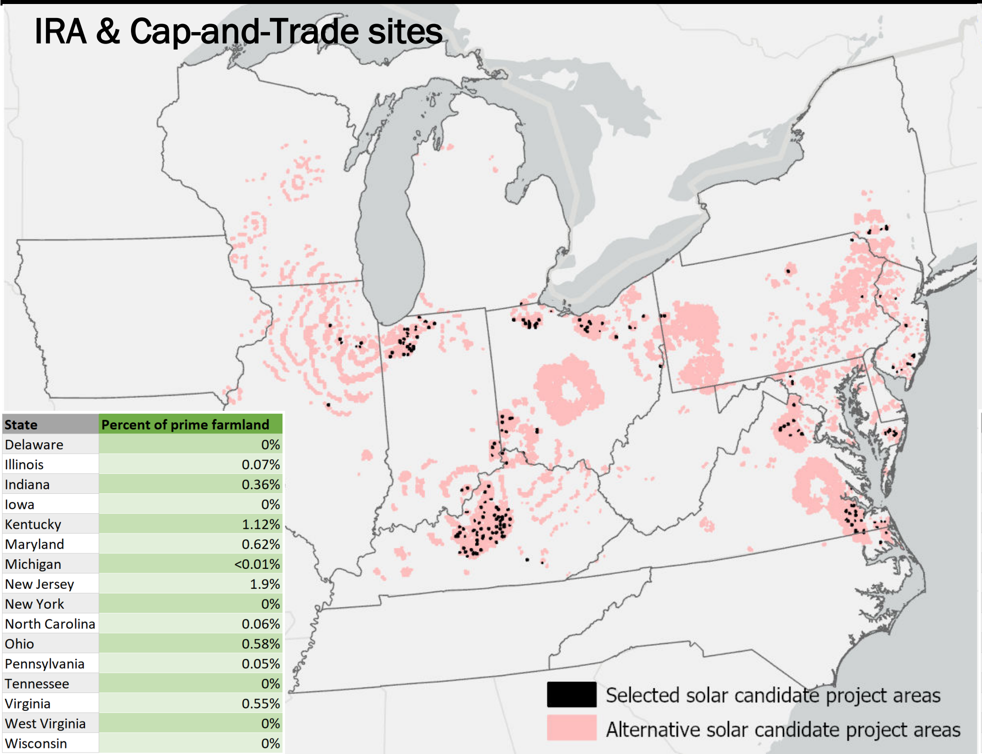
State	Percent of prime farmland
Delaware	0%
Illinois	0.09%
Indiana	0.16%
Iowa	0%
Kentucky	0.21%
Maryland	0.65%
Michigan	0%
New Jersey	0.21%
New York	0%
North Carolina	0.06%
Ohio	0.33%
Pennsylvania	0.12%
Tennessee	0%
Virginia	0.46%
West Virginia	0%
Wisconsin	0%

State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	0.01%
Iowa	0%
Kentucky	0.02%
Maryland	0%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	0.02%
Pennsylvania	0.04%
Tennessee	0%
Virginia	0%
West Virginia	0.05%
Wisconsin	0%

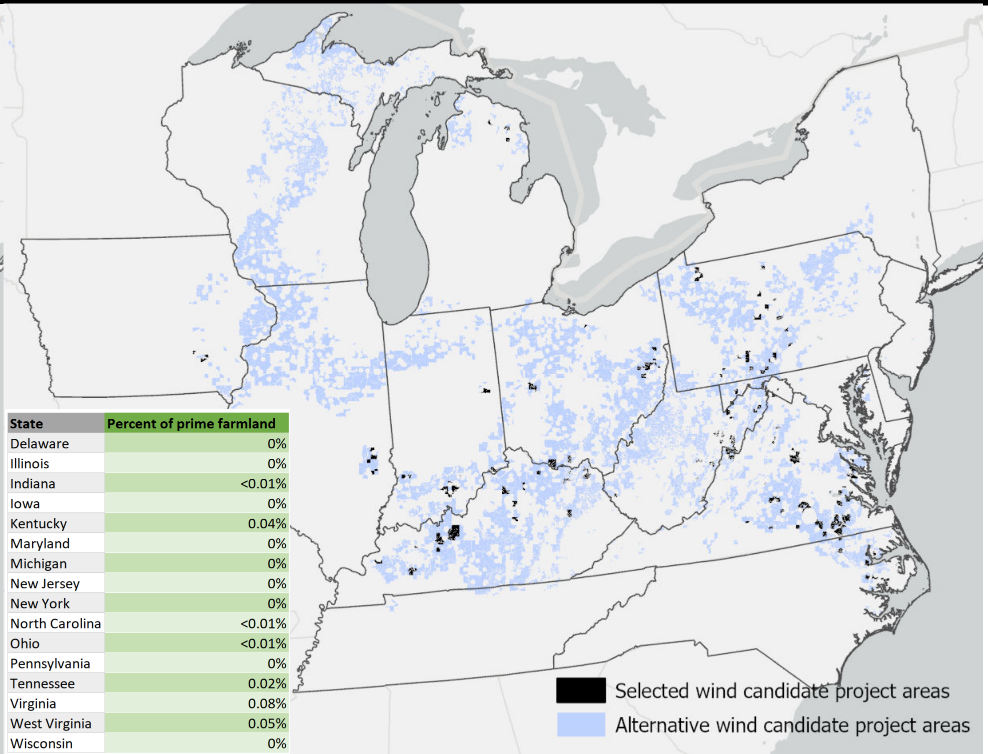
Figure A3-10: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade – Showing selected CPAs for least-cost portfolio (medium fuel cost/medium RE cost case)

Modeled CO2 emissions cap in 2030: 80% below 2005 emissions. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected CPAs consistent with the modeled least-cost portfolio are in darker red (solar) or blue (wind). Plotted alternative CPAs in lighter pink (solar) and lighter blue (wind) are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Cap & Trade Scenario – minimum transmission



State	Percent of prime farmland
Delaware	0%
Illinois	0.07%
Indiana	0.36%
Iowa	0%
Kentucky	1.12%
Maryland	0.62%
Michigan	<0.01%
New Jersey	1.9%
New York	0%
North Carolina	0.06%
Ohio	0.58%
Pennsylvania	0.05%
Tennessee	0%
Virginia	0.55%
West Virginia	0%
Wisconsin	0%



State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	<0.01%
Iowa	0%
Kentucky	0.04%
Maryland	0%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	<0.01%
Ohio	<0.01%
Pennsylvania	0%
Tennessee	0.02%
Virginia	0.08%
West Virginia	0.05%
Wisconsin	0%

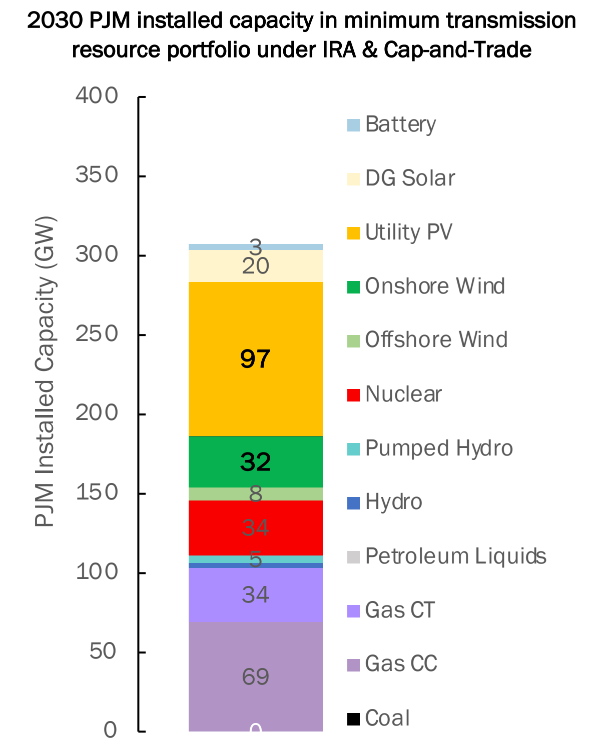
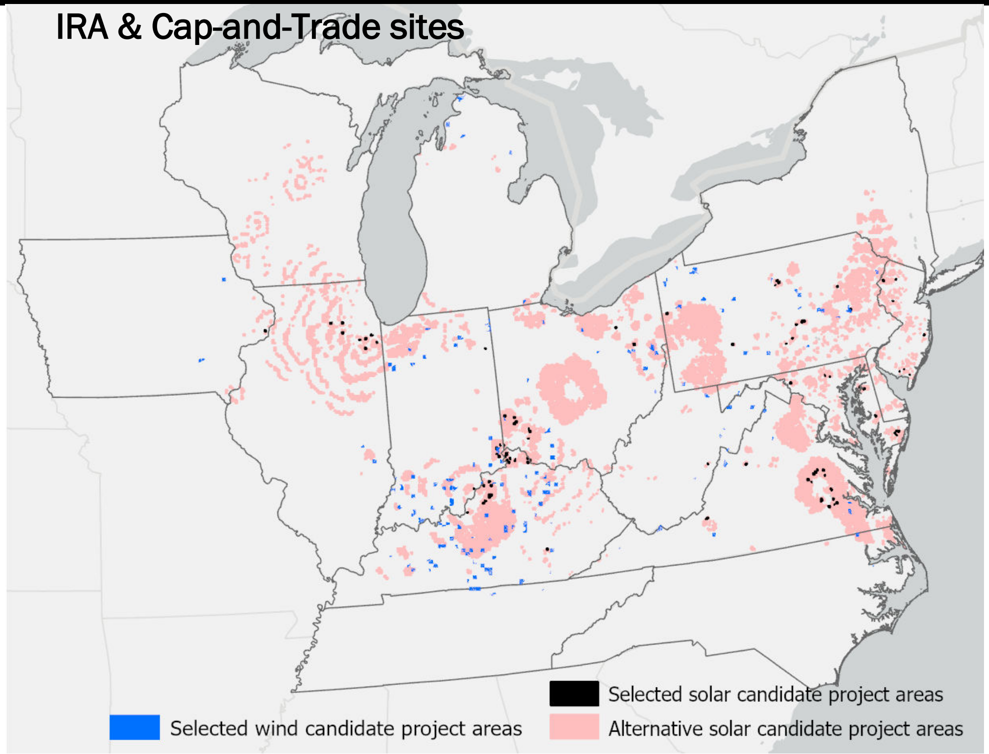


Figure A3-11: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade – Showing selected CPAs for minimum transmission portfolio (medium fuel cost/medium RE cost case)

Modeled CO2 emissions cap in 2030: 80% below 2005 emissions. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected CPAs consistent with the portfolio that minimizes total transmission build out at a cost no greater than 10% larger than the least-cost portfolio are in darker red (solar) or blue (wind). Plotted alternative CPAs in lighter pink (solar) and lighter blue (wind) are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Cap & Trade Scenario – maximum spatial equity, solar

State	Percent of prime farmland
Delaware	0%
Illinois	0.07%
Indiana	0.04%
Iowa	0%
Kentucky	0.31%
Maryland	1.02%
Michigan	0%
New Jersey	0.26%
New York	0%
North Carolina	0%
Ohio	0.17%
Pennsylvania	0.23%
Tennessee	0%
Virginia	0.34%
West Virginia	0%
Wisconsin	0%



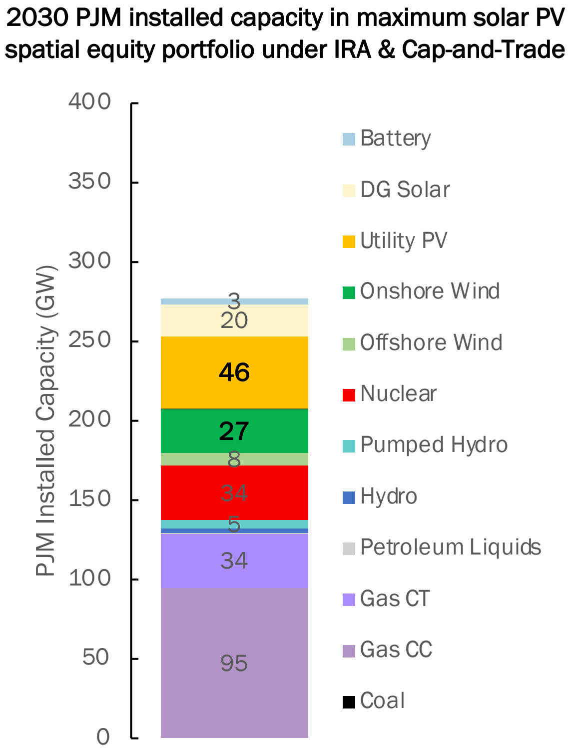
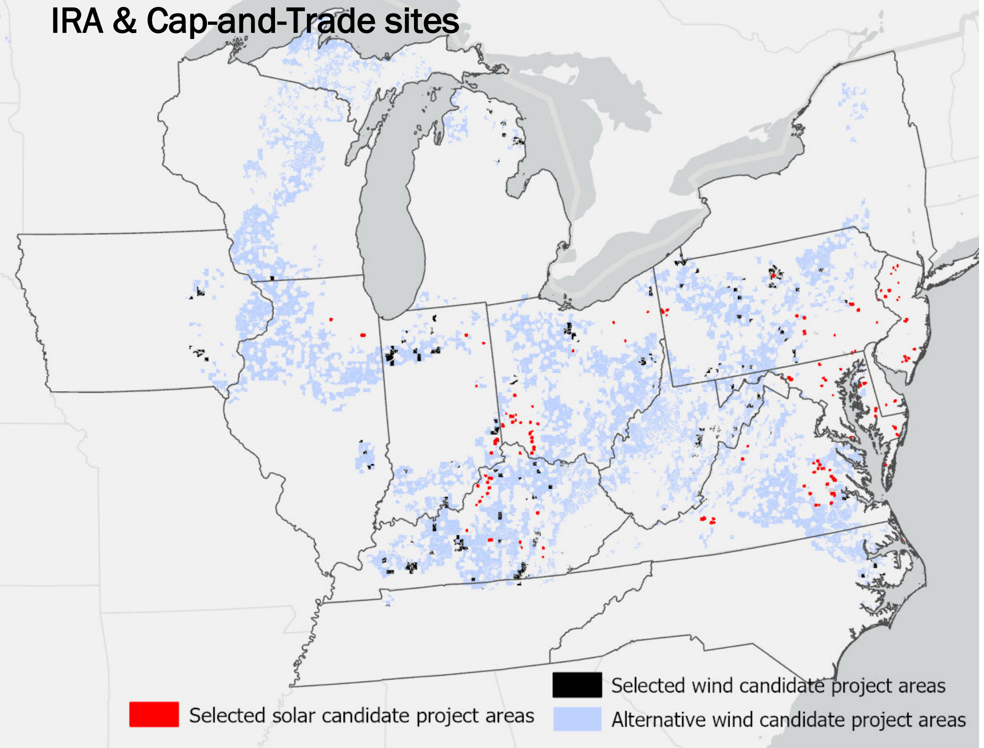


Figure A3-12: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade – Showing selected CPAs for maximum spatial equity for solar PV portfolio (medium fuel cost/medium RE cost case)

Modeled CO2 emissions cap in 2030: 80% below 2005 emissions. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected solar CPAs consistent with the portfolio that ensures maximum equity in the spatial deployment of utility-scale solar PV across PJM transmission owner zones at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected wind CPAs are in dark blue. Alternative solar CPAs are depicted in lighter red and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Cap & Trade Scenario – maximum spatial equity, wind

State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	0.02%
Iowa	0%
Kentucky	0.04%
Maryland	0.04%
Michigan	0%
New Jersey	0%
New York	<0.01%
North Carolina	0%
Ohio	<0.01%
Pennsylvania	0.03%
Tennessee	0%
Virginia	<0.01%
West Virginia	0.02%
Wisconsin	0%



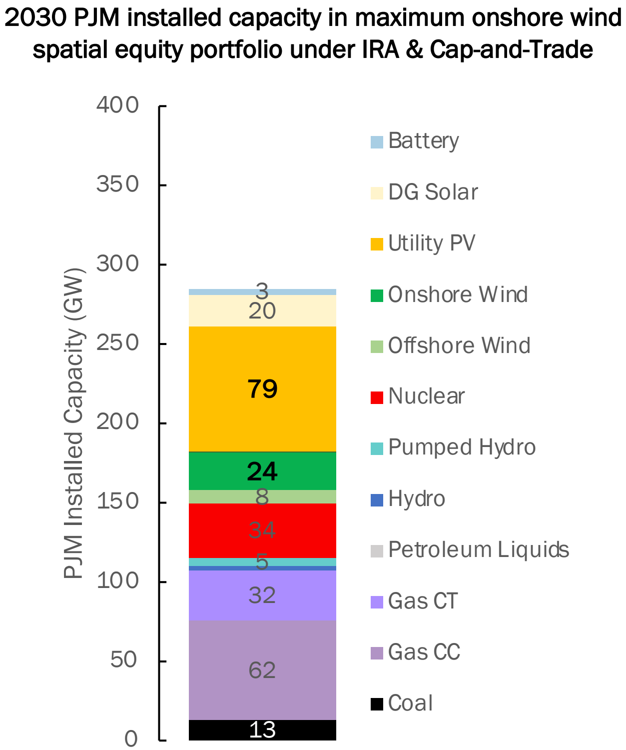
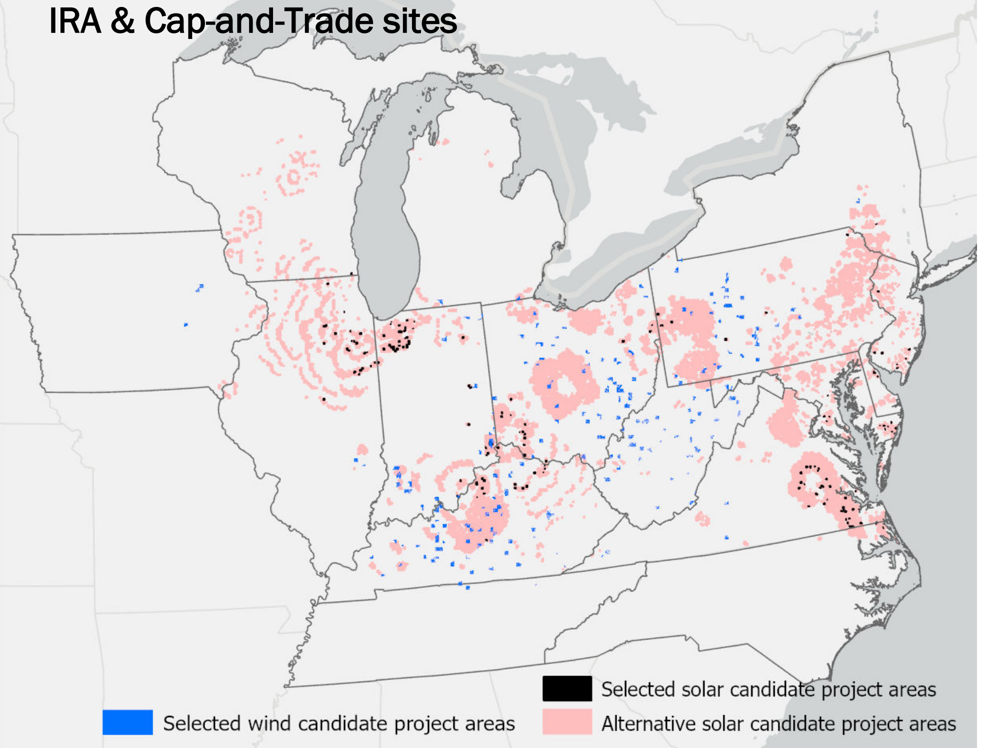


Figure A3-13: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade – Showing selected CPAs for maximum spatial equity for onshore wind portfolio (medium fuel cost/medium RE cost case)

Modeled CO2 emissions cap in 2030: 80% below 2005 emissions. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected wind CPAs consistent with the portfolio that ensures maximum equity in the spatial deployment of onshore wind across PJM transmission owner zones at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected solar CPAs are in dark blue. Alternative wind CPAs are depicted in lighter blue and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Cap & Trade Scenario – maximum solar PV

State	Percent of prime farmland
Delaware	0.7%
Illinois	0.23%
Indiana	0.55%
Iowa	0%
Kentucky	0.21%
Maryland	0.36%
Michigan	0%
New Jersey	1.44%
New York	0%
North Carolina	0.08%
Ohio	0.19%
Pennsylvania	0.15%
Tennessee	0%
Virginia	0.74%
West Virginia	0%
Wisconsin	0.02%



2030 PJM installed capacity in maximum solar PV capacity portfolio under IRA & Cap-and-Trade

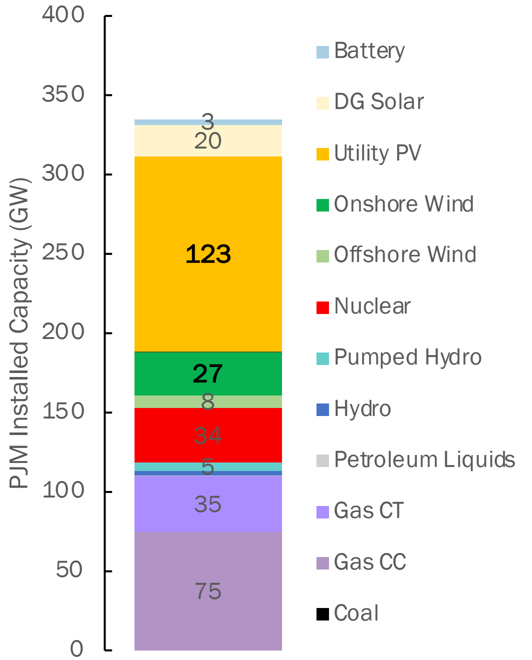
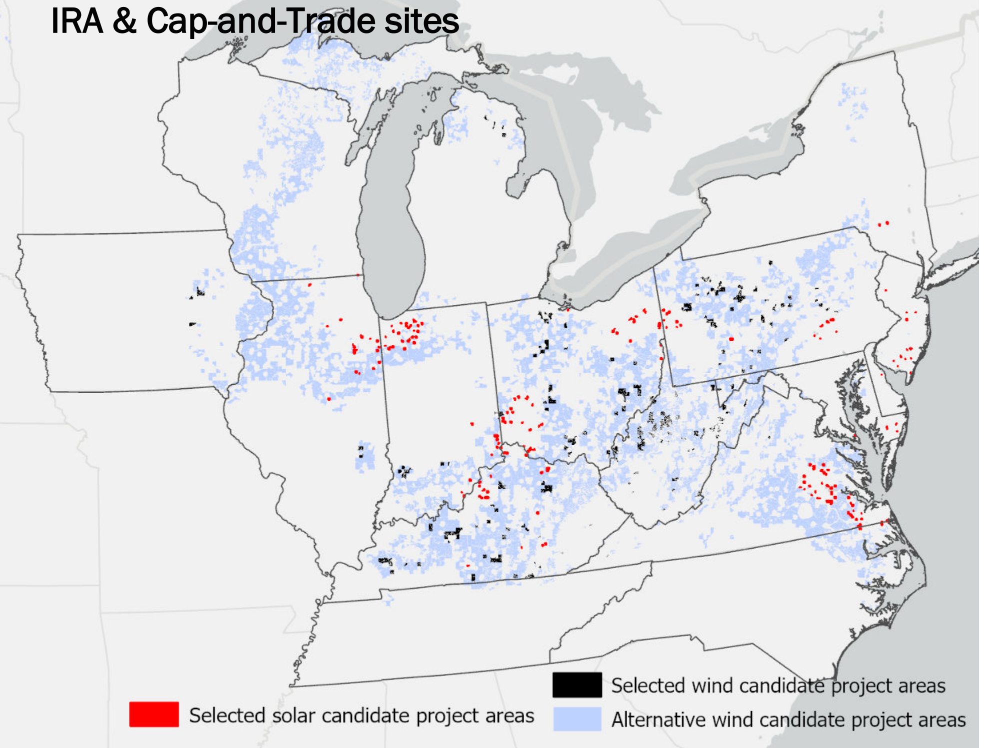


Figure A3-14: Spatial deployment of utility-scale solar PV and wind power in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade – Showing selected CPAs for maximum solar PV capacity portfolio (medium fuel cost/medium RE cost case)

Modeled CO2 emissions cap in 2030: 80% below 2005 emissions. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected solar CPAs consistent with the portfolio that ensures maximum utility-scale solar PV capacity at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected wind CPAs are in dark blue. Alternative solar CPAs are depicted in lighter red and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Cap & Trade Scenario – maximum onshore wind

State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	<0.01%
Iowa	0%
Kentucky	0.05%
Maryland	<0.01%
Michigan	0%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	0.04%
Pennsylvania	0.06%
Tennessee	0%
Virginia	0%
West Virginia	0.37%
Wisconsin	0%



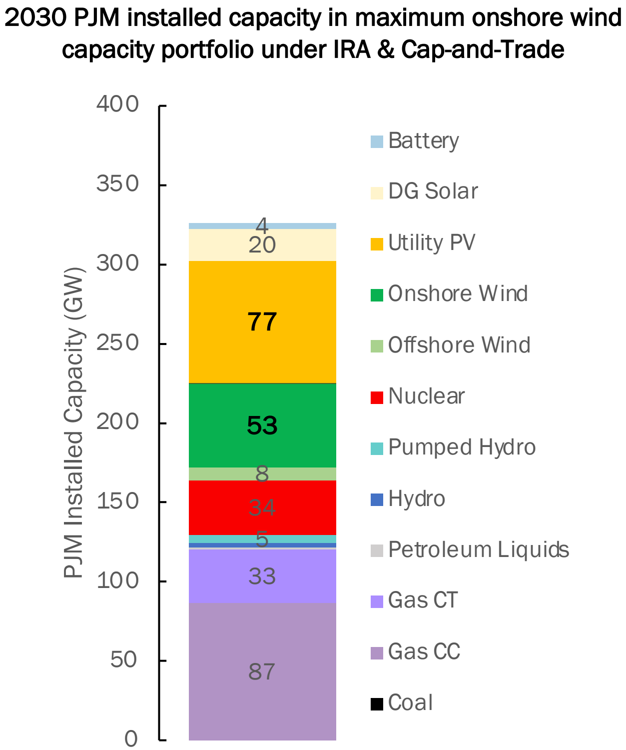


Figure A3-15: Spatial deployment of utility-scale solar PV & wind power in 2030 consistent with modeled portfolios under IRA & Cap-and-Trade – Showing selected CPAs for maximum onshore wind capacity portfolio (medium fuel cost/medium RE cost case)

Modeled CO2 emissions cap in 2030: 80% below 2005 emissions. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected wind CPAs consistent with the portfolio that ensures maximum onshore wind capacity at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected solar CPAs are in dark blue. Alternative wind CPAs are depicted in lighter blue and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

IRA + Clean Electricity Standard Scenario Results

PJM emissions under IRA + Clean Electricity Standard Scenario

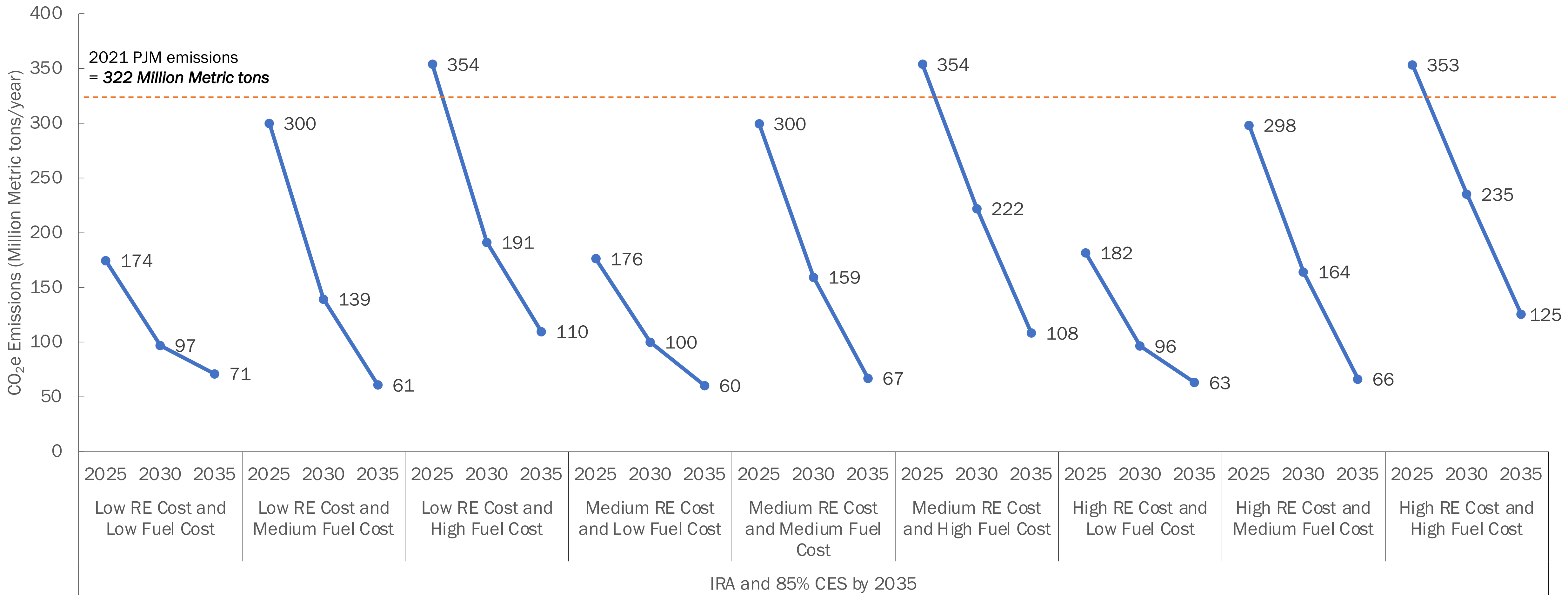


Figure A4-1: PJM system CO_2 emissions under IRA + Clean Electricity Standard scenario

Only emissions from generation within PJM are accounted for above. PJM 2019 and 2021 emissions benchmark is calculated by multiplying the reported average emission rate of the 2021 PJM Emissions Report and the total generation of PJM reported by the PJM State of the Market Report.

PJM bulk electricity supply cost under IRA + Clean Electricity Standard Scenario

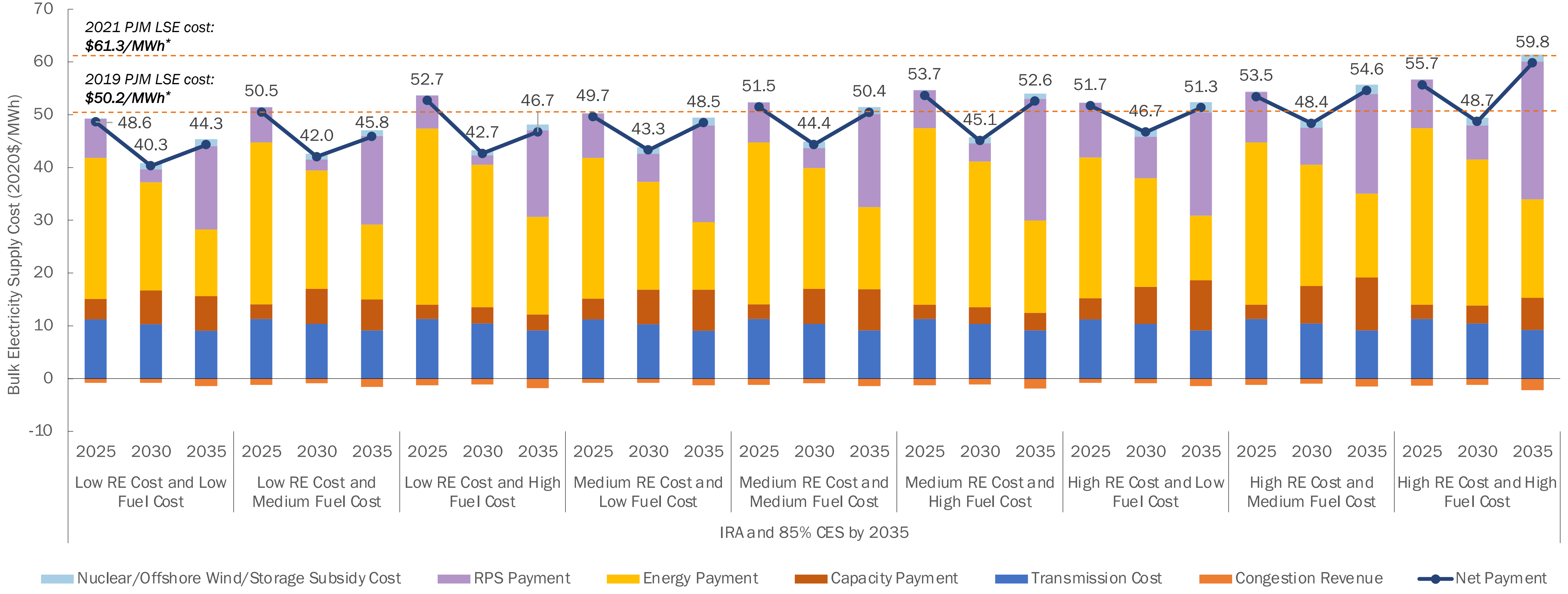


Figure A4-2: PJM load-serving entity bulk supply cost under IRA + Clean Electricity Standard Scenario

* Source: Monitoring Analytics, LLC (2021), "State of the Market Report for PJM." Note: Modeled costs underestimate the impact of transmission congestion on average energy costs due to the zonal resolution of model. Meanwhile, 2019 & 2021 benchmark costs exclude any state subsidies for specific technologies (e.g. nuclear, offshore wind, batteries), while modeled costs include these subsidies. The comparison of modeled and benchmark costs is thus approximate, but closely comparable.

PJM capacity mix under IRA + Clean Electricity Standard Scenario

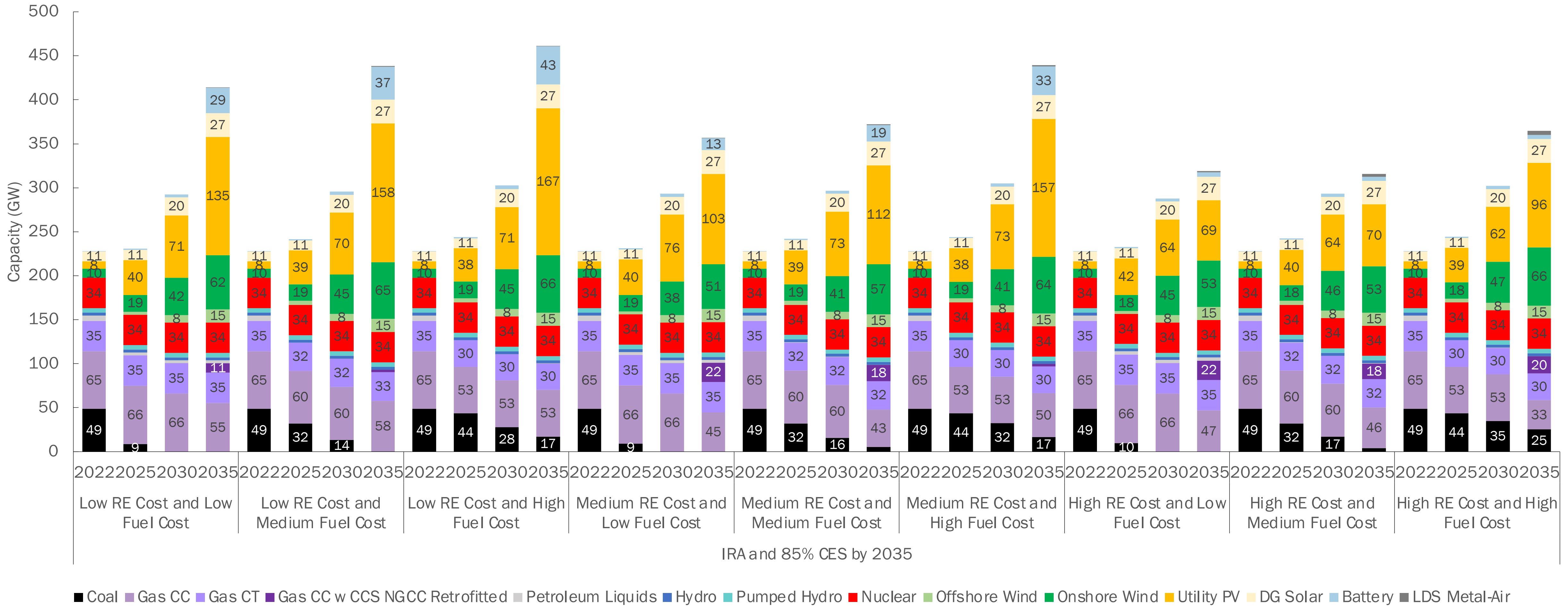


Figure A4-3: PJM capacity mix under IRA + Clean Electricity Standard Scenario
Data labels ≤5 GW are not shown. DG solar capacity is as an exogenous input not optimized in model.

PJM annual electricity generation under IRA + Clean Electricity Standard Scenario

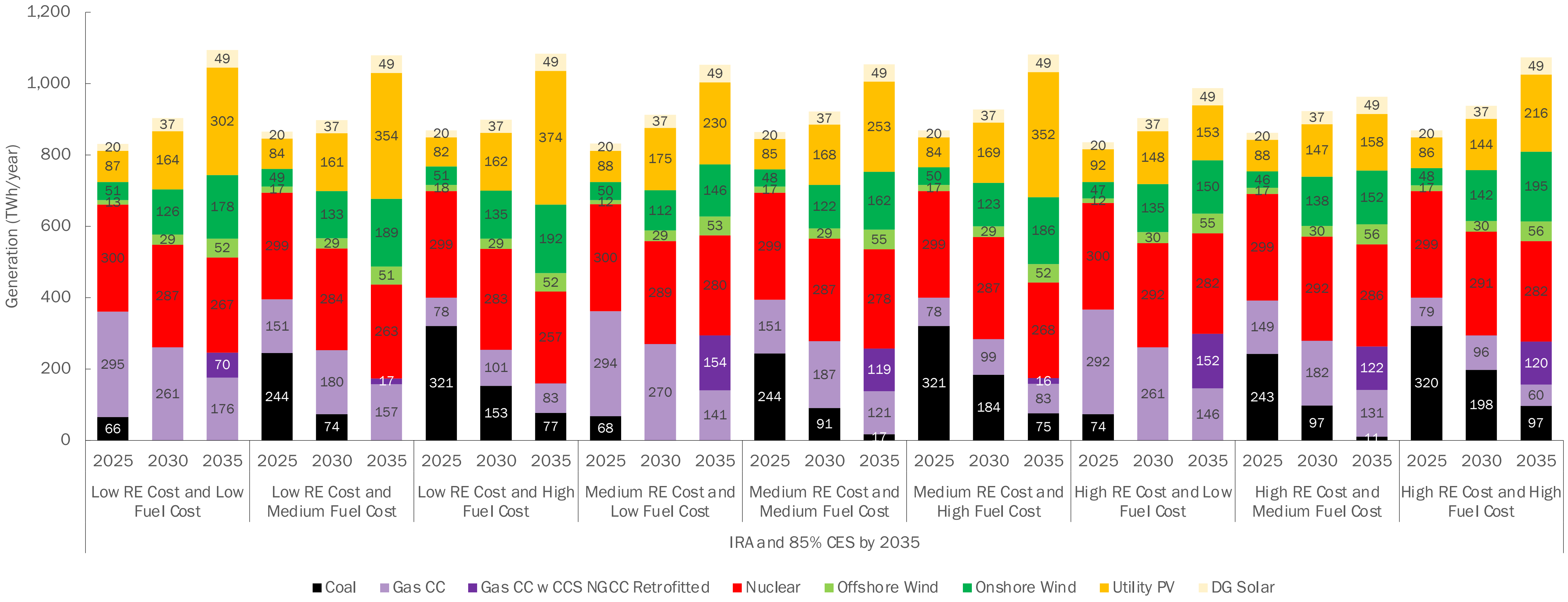


Figure A4-4: PJM annual electricity generation under IRA + Clean Electricity Standard Scenario

Data labels <10 TWh are not shown. Generation from Biomass, Hydro, and Natural Gas Combustion Turbines (CT) are all <10 TWh and not depicted above. DG solar generation is as an exogenous input not optimized in model.

Locational marginal prices (LMP) under IRA + Clean Electricity Standard Scenario

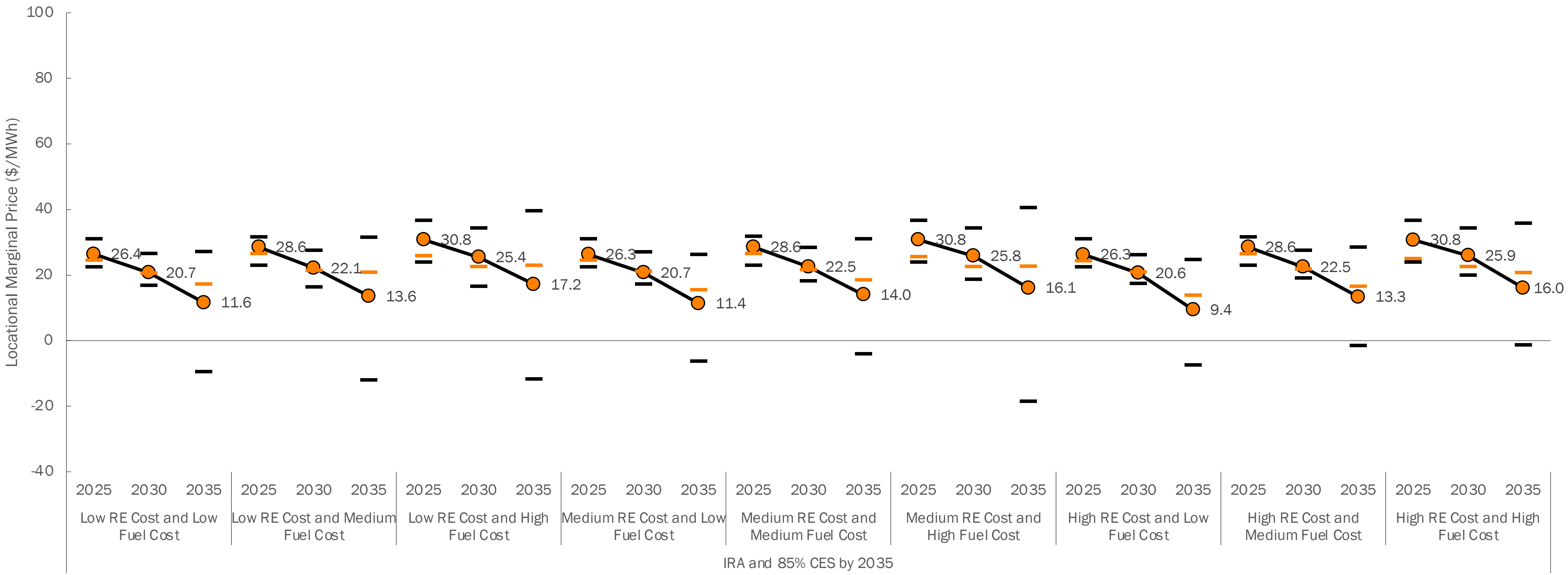


Figure A4-5: Load-weighted average locational marginal price (LMP) for the PJM West model region under IRA + Clean Electricity Standard Scenario.
Horizontal bars show the 1st, 2nd, and 3rd quartiles of the LMP distribution, and dots denote the price average.

Capacity market price under IRA + Clean Electricity Standard Scenario

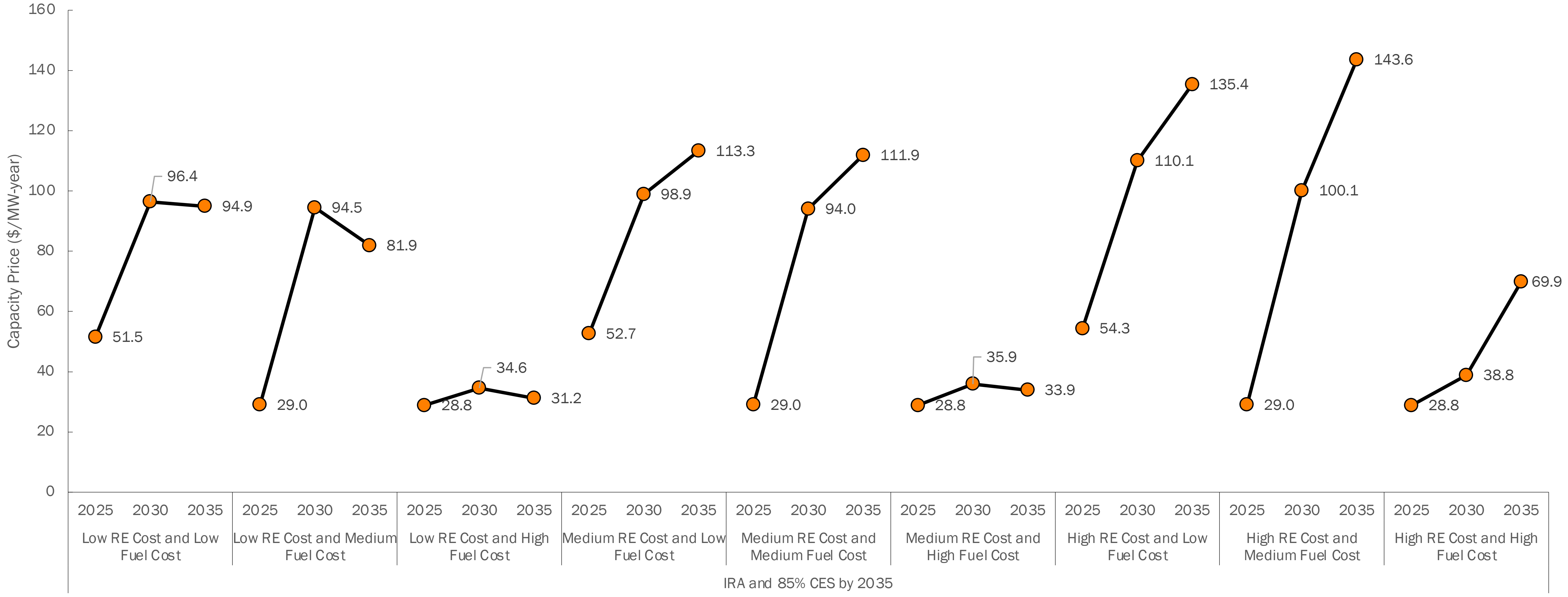


Figure A4-6: Capacity market price faced by generators in the PJM West market region under IRA + Clean Electricity Standard Scenario.

PJM clean energy attribute credit price of IRA + Clean Electricity Standard Scenario

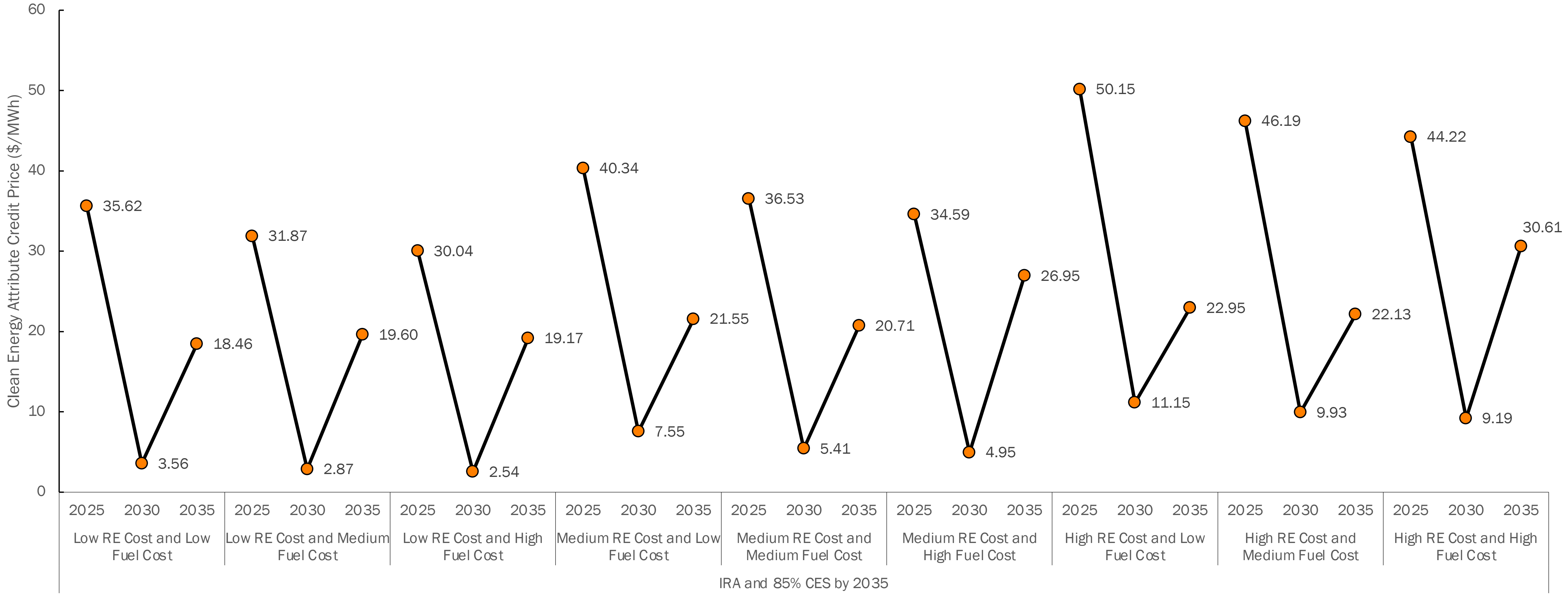


Figure A4-7: PJM clean energy attribute credit price under IRA + Clean Electricity Standard Scenario
Note the scale is different from the other policy scenarios

Federal tax credit payments collected by PJM generators under IRA + Clean Electricity Standard Scenario

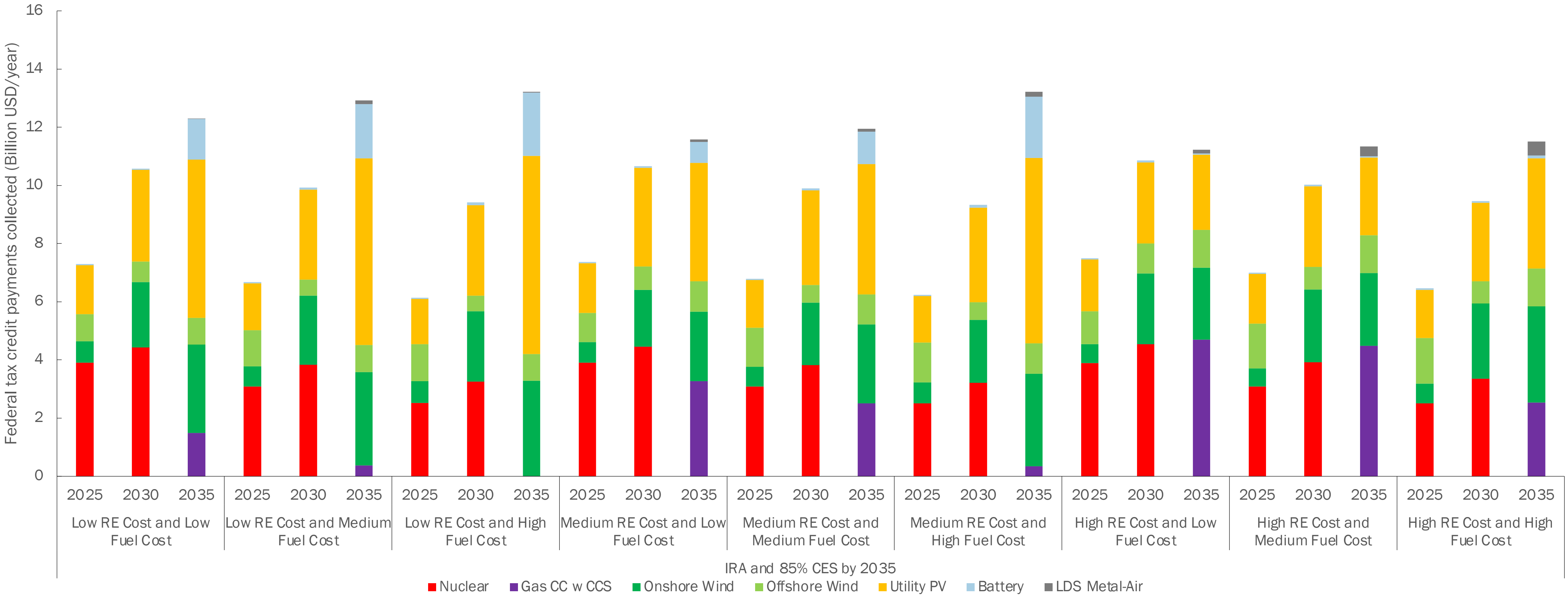
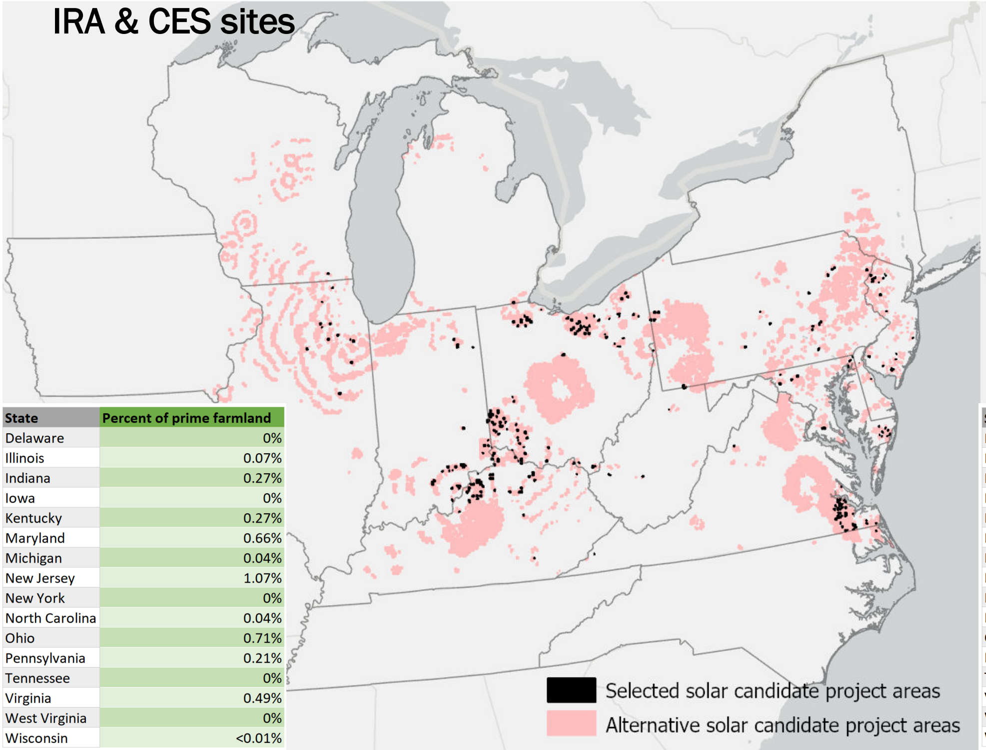
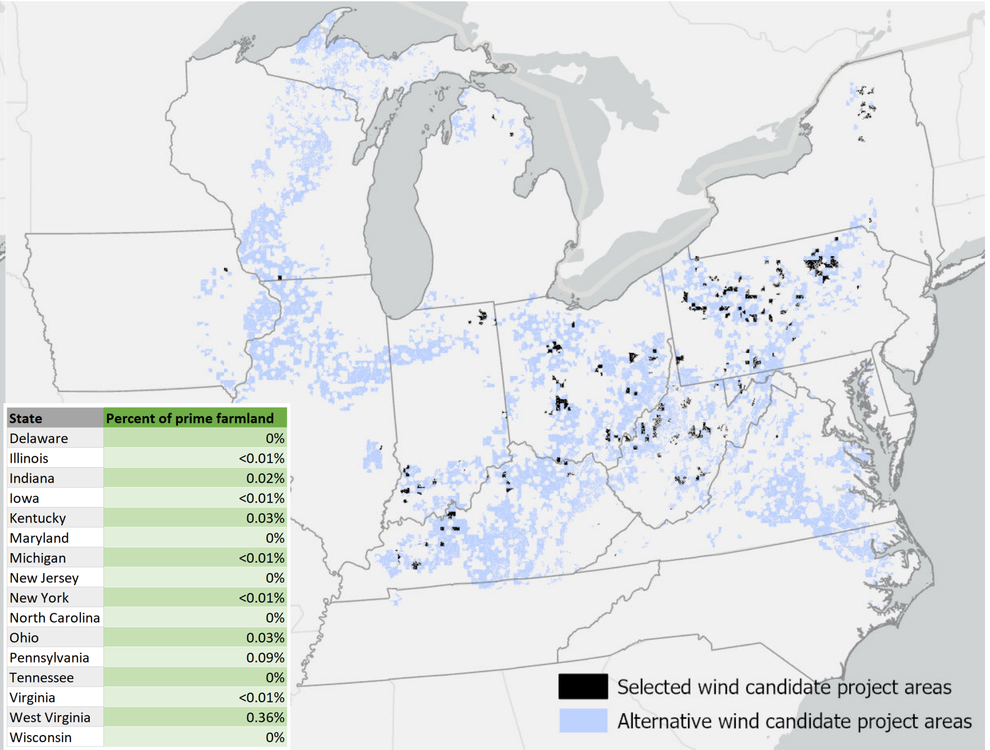


Figure A4-8: Federal tax credit payments collected by PJM generators under IRA + Clean Electricity Standard Scenario

IRA & CES sites



State	Percent of prime farmland
Delaware	0%
Illinois	0.07%
Indiana	0.27%
Iowa	0%
Kentucky	0.27%
Maryland	0.66%
Michigan	0.04%
New Jersey	1.07%
New York	0%
North Carolina	0.04%
Ohio	0.71%
Pennsylvania	0.21%
Tennessee	0%
Virginia	0.49%
West Virginia	0%
Wisconsin	<0.01%



State	Percent of prime farmland
Delaware	0%
Illinois	<0.01%
Indiana	0.02%
Iowa	<0.01%
Kentucky	0.03%
Maryland	0%
Michigan	<0.01%
New Jersey	0%
New York	<0.01%
North Carolina	0%
Ohio	0.03%
Pennsylvania	0.09%
Tennessee	0%
Virginia	<0.01%
West Virginia	0.36%
Wisconsin	0%

2030 PJM installed capacity in least-cost resource portfolio under IRA & CES

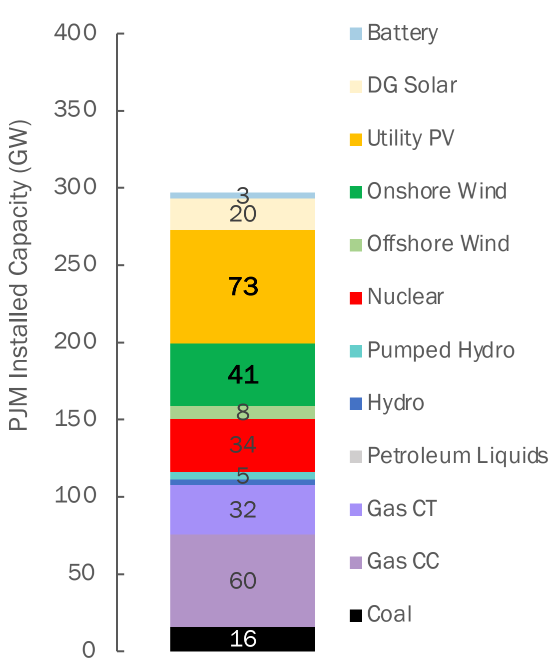
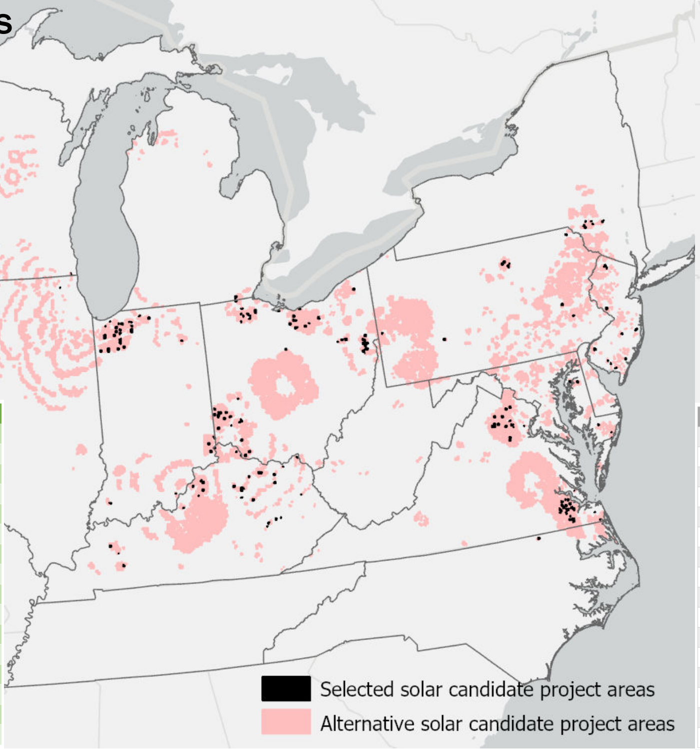


Figure A4-9: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & CES – Showing selected CPAs for minimum transmission portfolio (medium fuel cost/medium RE cost case)

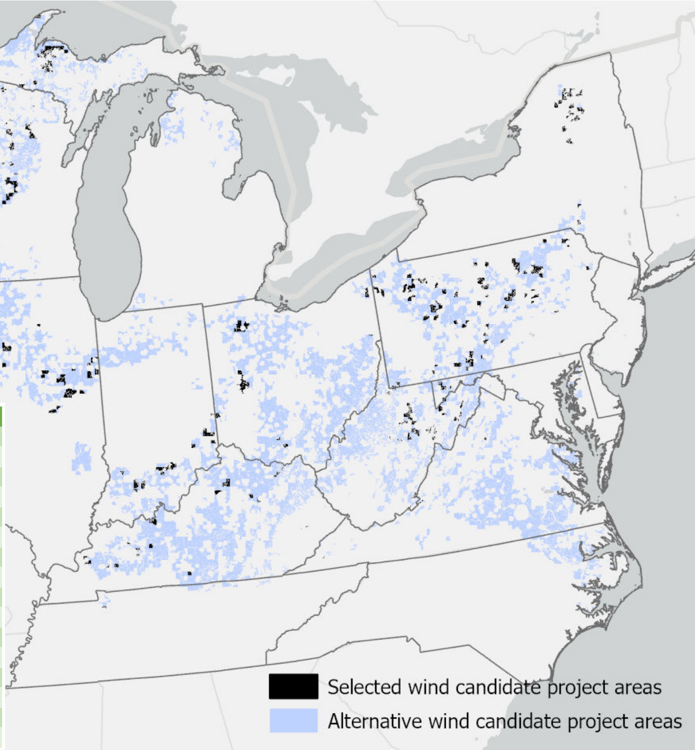
Modeled clean energy share requirement in 2030: 70%. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected CPAs consistent with the modeled minimum transmission portfolio are in darker orange (solar) or blue (wind). Plotted alternative CPAs in lighter orange (solar) and lighter blue (wind) are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Clean Electricity Standard Scenario – minimum transmission

IRA & CES sites



State	Percent of prime farmland
Delaware	0%
Illinois	0%
Indiana	0.42%
Iowa	0%
Kentucky	0.5%
Maryland	0.4%
Michigan	0.04%
New Jersey	2.39%
New York	0%
North Carolina	0.03%
Ohio	0.78%
Pennsylvania	0.14%
Tennessee	0%
Virginia	0.85%
West Virginia	0%
Wisconsin	<0.01%



State	Percent of prime farmland
Delaware	0%
Illinois	0.06%
Indiana	0.02%
Iowa	<0.01%
Kentucky	0.02%
Maryland	0%
Michigan	<0.01%
New Jersey	0%
New York	0%
North Carolina	0%
Ohio	0.03%
Pennsylvania	1.41%
Tennessee	0%
Virginia	0%
West Virginia	0%
Wisconsin	0.05%

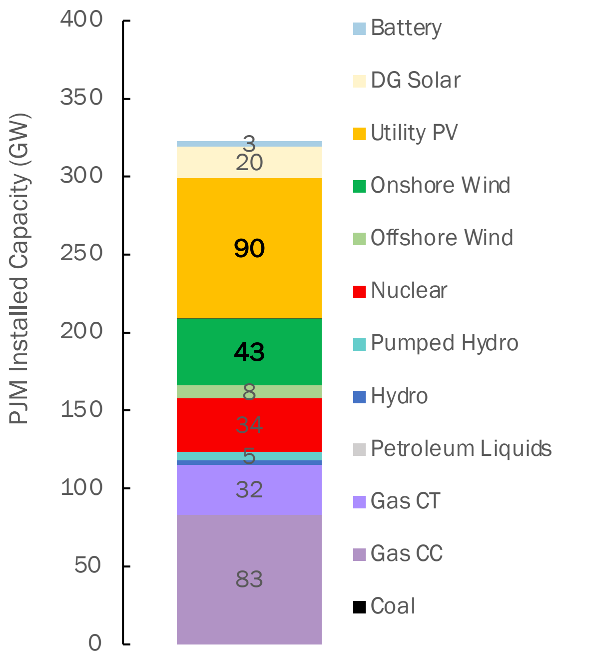
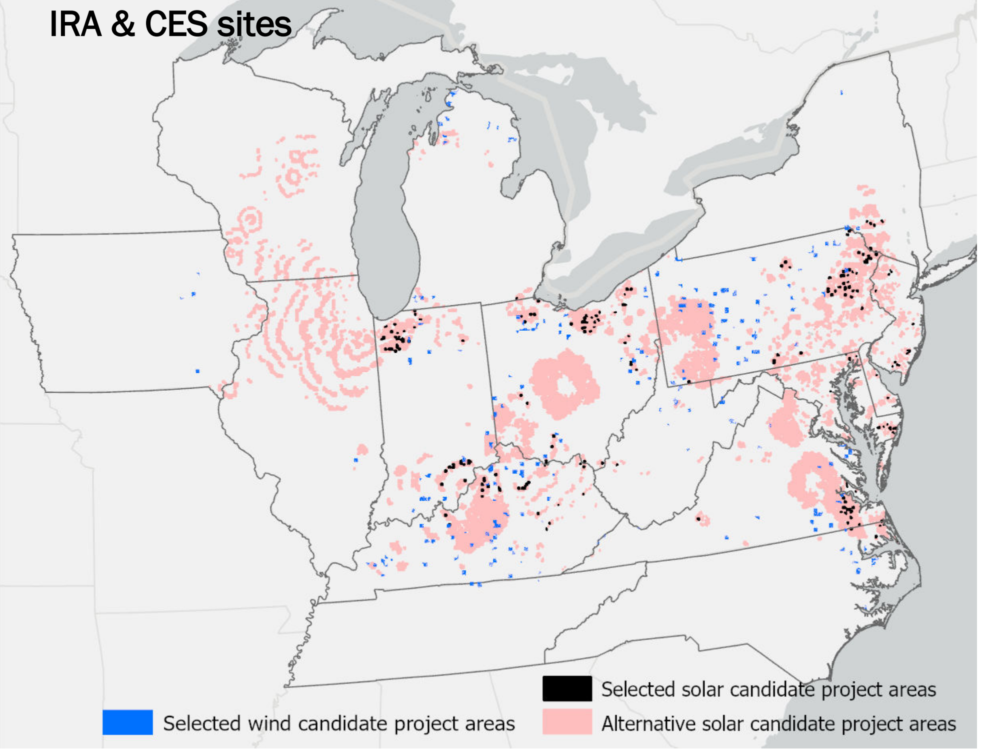


Figure A4-10: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & CES – Showing selected CPAs for maximum transmission portfolio (medium fuel cost/medium RE cost case)

Modeled clean energy share requirement in 2030: 70%. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected CPAs consistent with the portfolio that minimizes total transmission build out at a cost no greater than 10% larger than the least-cost portfolio are in darker red (solar) or blue (wind). Plotted alternative CPAs in lighter pink (solar) and lighter blue (wind) are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

State	Percent of prime farmland
Delaware	0.34%
Illinois	0%
Indiana	0.62%
Iowa	0%
Kentucky	0.36%
Maryland	0.65%
Michigan	<0.01%
New Jersey	0.61%
New York	0%
North Carolina	0.03%
Ohio	0.55%
Pennsylvania	0.45%
Tennessee	0%
Virginia	0.43%
West Virginia	0%
Wisconsin	0%



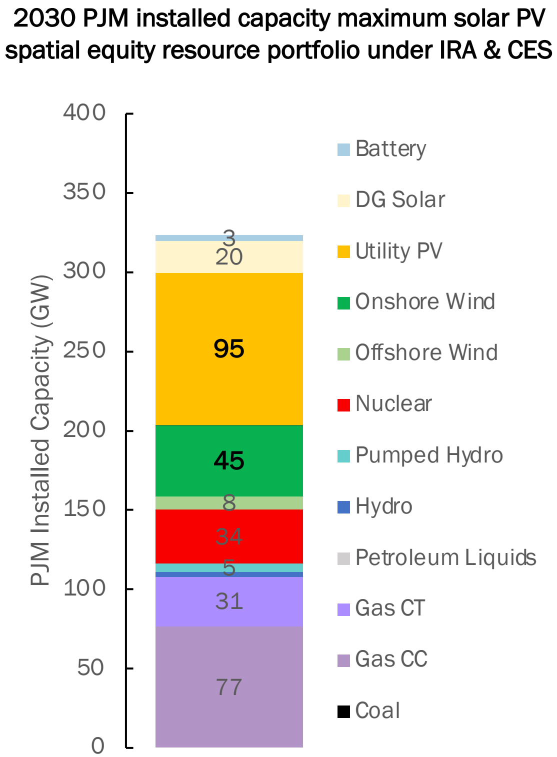
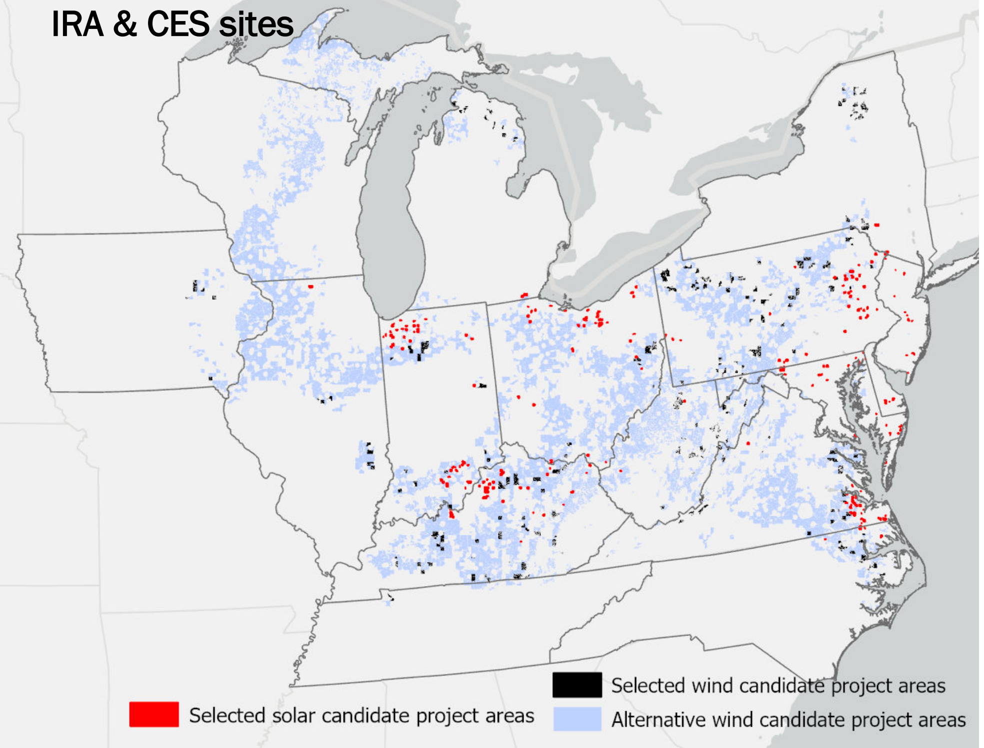


Figure A4-11: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & CES – Showing selected CPAs for maximum spatial equity for solar PV portfolio (medium fuel cost/medium RE cost case)

Modeled clean energy share requirement in 2030: 70%. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected solar CPAs consistent with the portfolio that ensures maximum equity in the spatial deployment of utility-scale solar PV across PJM transmission owner zones at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected wind CPAs are in dark blue. Alternative solar CPAs are depicted in lighter red and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Clean Electricity Standard Scenario – maximum spatial equity, wind

State	Percent of prime farmland
Delaware	0%
Illinois	<0.01%
Indiana	0.02%
Iowa	<0.01%
Kentucky	0.05%
Maryland	0%
Michigan	<0.01%
New Jersey	0%
New York	<0.01%
North Carolina	<0.01%
Ohio	<0.01%
Pennsylvania	0.06%
Tennessee	0%
Virginia	0.03%
West Virginia	0.03%
Wisconsin	0%



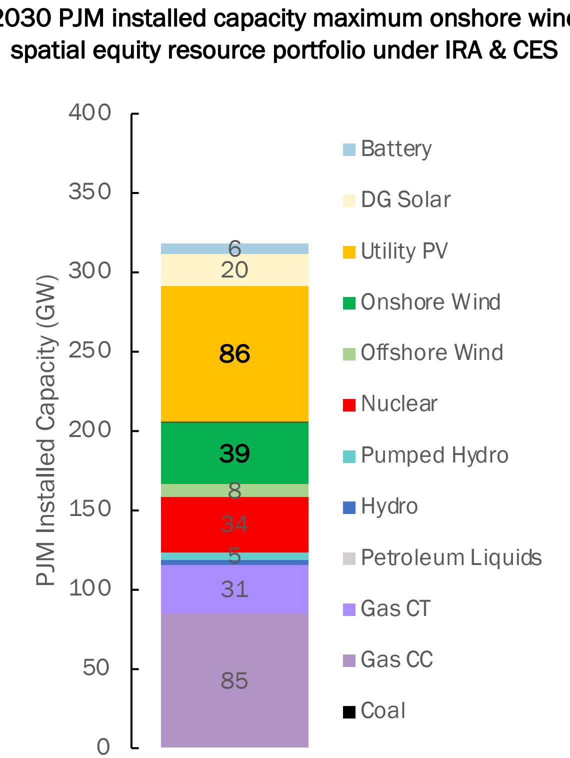
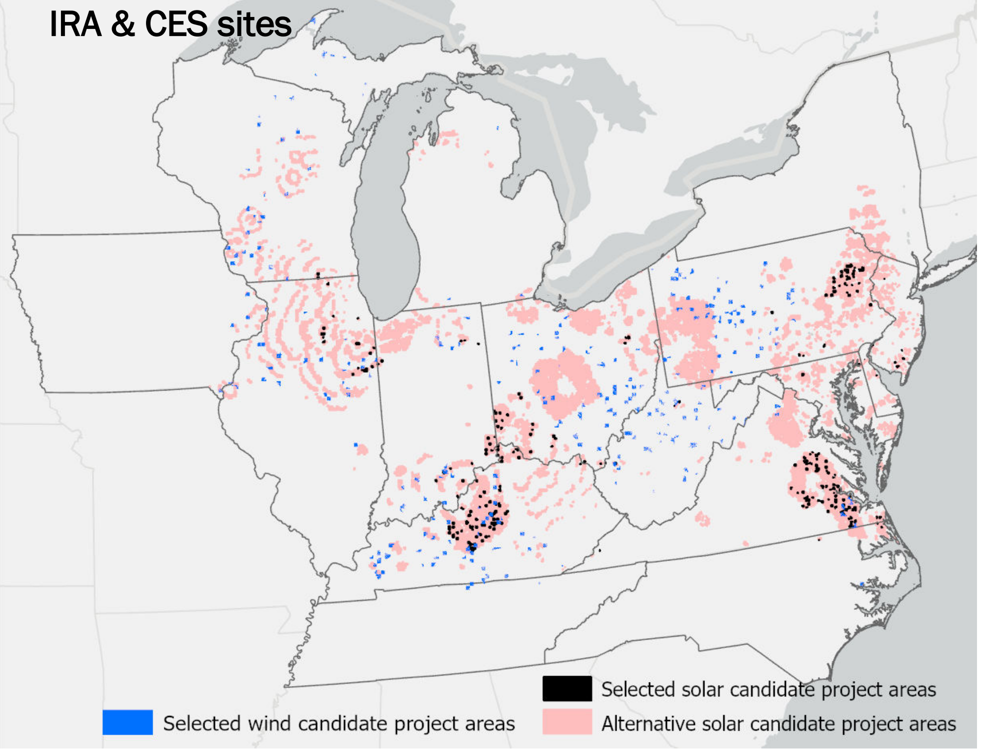


Figure A4-12: Spatial deployment of utility-scale solar PV (left) & wind power (right) in 2030 consistent with modeled portfolios under IRA & CES – Showing selected CPAs for maximum spatial equity for onshore wind portfolio (medium fuel cost/medium RE cost case)

Modeled clean energy share requirement in 2030: 70%. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected wind CPAs consistent with the portfolio that ensures maximum equity in the spatial deployment of onshore wind across PJM transmission owner zones at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected solar CPAs are in dark blue. Alternative wind CPAs are depicted in lighter blue and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Clean Electricity Standard Scenario – maximum solar PV

State	Percent of prime farmland
Delaware	0.14%
Illinois	0.21%
Indiana	0.19%
Iowa	0%
Kentucky	1.35%
Maryland	0.17%
Michigan	0%
New Jersey	1.28%
New York	0%
North Carolina	0.02%
Ohio	0.37%
Pennsylvania	0.35%
Tennessee	0%
Virginia	1.93%
West Virginia	0%
Wisconsin	0.03%



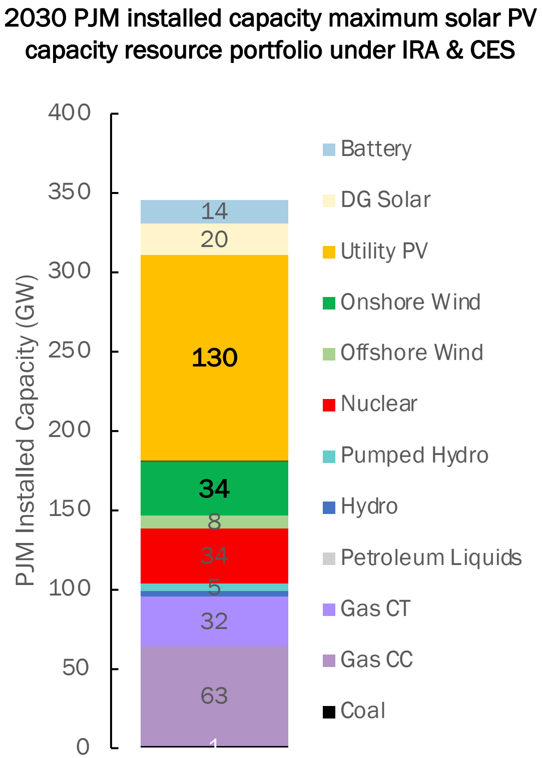
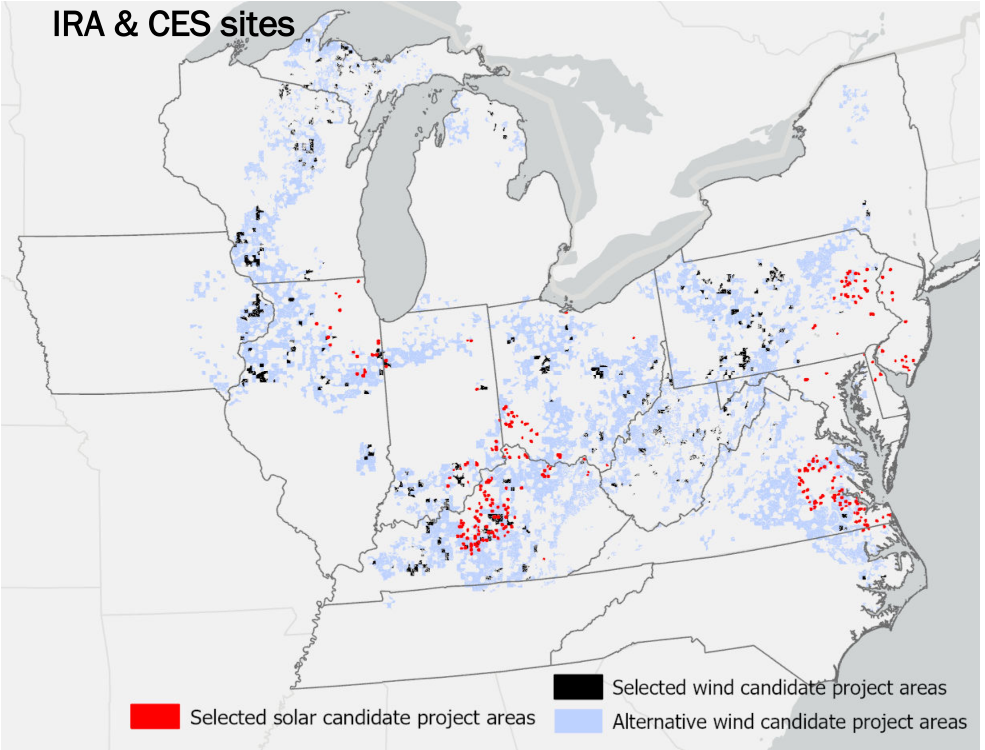


Figure A4-13: Spatial deployment of utility-scale solar PV & wind power in 2030 consistent with modeled portfolios under IRA & CES – Showing selected CPAs for maximum solar PV capacity portfolio (medium fuel cost/medium RE cost case)

Modeled clean energy share requirement in 2030: 70%. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19 Selected solar CPAs consistent with the portfolio that ensures maximum utility-scale solar PV capacity at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected wind CPAs are in dark blue. Alternative solar CPAs are depicted in lighter red and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Spatial deployment of utility-scale solar & wind under IRA & Clean Electricity Standard Scenario – maximum wind

State	Percent of prime farmland
Delaware	0%
Illinois	0.02%
Indiana	0.02%
Iowa	<0.01%
Kentucky	0.06%
Maryland	0%
Michigan	0.01%
New Jersey	0%
New York	0%
North Carolina	<0.01%
Ohio	0.03%
Pennsylvania	0.06%
Tennessee	0%
Virginia	<0.01%
West Virginia	0.13%
Wisconsin	0.04%



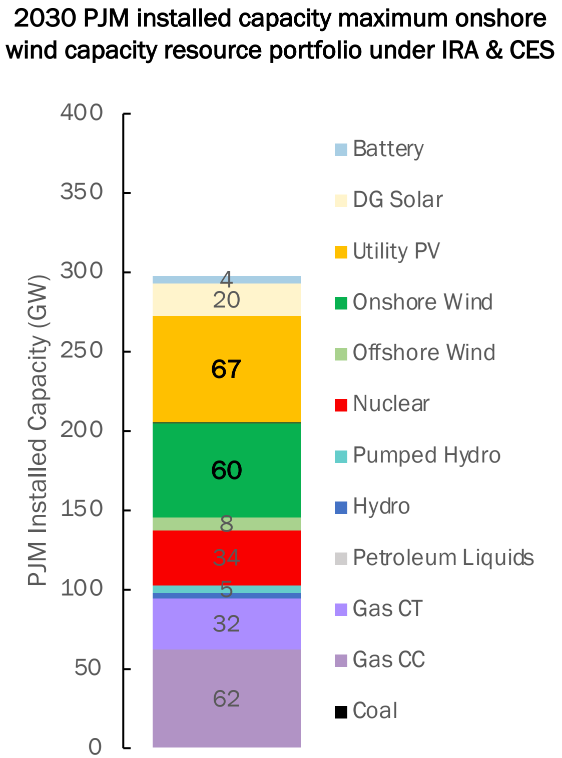


Figure A4-14: Spatial deployment of utility-scale solar PV & wind power in 2030 consistent with modeled portfolios under IRA & CES – Showing selected CPAs for maximum onshore wind capacity portfolio (medium fuel cost/medium RE cost case)

Modeled clean energy share requirement in 2030: 70%. Candidate project areas (CPAs) are the portion of 4km by 4km areas suitable for solar or wind deployment that pass a set of geospatial screens to remove administratively protected and culturally significant areas and areas unsuitable for construction (e.g. wetlands, steep slopes), detailed at https://doi.org/10.5281/zenodo.4726433 (see p. 19). Selected wind CPAs consistent with the portfolio that ensures maximum onshore wind capacity at a cost no greater than 10% larger than the least-cost portfolio are in black and corresponding selected solar CPAs are in dark blue. Alternative wind CPAs are depicted in lighter blue and are developed in at least one alternative portfolio identified via a computational algorithm that systematically identifies alternative resource portfolios that meet all modeled technical, policy, and economic constraints and have a total electricity system cost no greater than 10% larger than the least-cost portfolio.

Appendix

Cost and emissions benchmark calculations

2021 LSE Cost: Monitoring Analytics reported in the 2021 PJM state of the markets (Table 1-8) that in 2021, the total cost of PJM load was $49,992 Million, which includes $699M for ancillary services, $416M for administration and $178M for energy uplift. GenX used in this study does not include ancillary services, PJM administration, and energy uplift payment, and these numbers are taken out of the $49,992M, resulting in $48,699M. Further, in the same report, Monitoring Analytics stated that the total RPS payment of PJM in 2019 is about $1,900M, which we use as a proxy for the RPS payment in 2021. After inflating/deflating to 2020 USD, the total payment we use as a benchmark equals $47,729M. Monitoring Analytics reported that, in 2021, the total load was 767,425 GWh. We estimate that the total DG generation in 2021 is 10.7 TWh (6 GW), and therefore, the gross load is 778.1 TWh. As a result, the 2021 cost benchmark is $61.3/MWh in 2020 USD. Readers should be aware that this LSE cost benchmark does not include reimbursement of carbon revenue and the state-level subsidy paid by ratepayers.

2019 LSE Cost: Monitoring Analytics reported in the 2019 PJM state of the markets (Table 1-8) that in 2019, the total cost of PJM load was $38,850 Million, which includes $557M for ancillary services, $394M for administration and $88M for energy uplift. GenX used in this study does not include ancillary services, PJM administration, and energy uplift payment, and these numbers are taken out of the $38,850M, resulting in $37,811M. Further, in the same report, Monitoring Analytics stated that the total RPS payment of PJM in 2017 is about $925M, which we use as a proxy for the RPS payment in 2019. After inflating/deflating to 2020 USD, the total payment we use as a benchmark equals $39,254M. Monitoring Analytics reported that, in 2021, the total load was 771,929 GWh. We estimate that the total DG generation in 2019 is 9.7 TWh (5.4 GW), and therefore, the gross load is 781.6 TWh. As a result, the 2019 cost benchmark is $50.2/MWh in 2020 USD. Readers should be aware that this LSE cost benchmark does not include reimbursement of carbon revenue and the state-level subsidy paid by ratepayers.

2019/2021 PJM system emission: Monitoring Analytics reported in the 2021 PJM state of the markets (Table 3-61) that the total generation was 841,650.8 GWh, and PJM's annual average emission rate was 843lb/MWh. Consequently, the total emissions of PJM in 2021 were 322 Million Metric tons. Monitoring Analytics reported in the 2019 PJM state of the markets (Table 3-50) that the total generation was 829,162.1 GWh, and PJM's annual average emission rate was 851lb/MWh. Consequently, the total emissions of PJM in 2019 were 320 Million Metric tons.

Monitoring Analytics, "PJM State of the Market," 2021, Available: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021.shtml
PJM, "2017–2021 CO_2, SO_2 and NO_X Emission Rates," 2022, Available: https://pjm.com/-/media/library/reports-notices/special-reports/2021/2021-emissions-report.ashx

RGGI CO_2 emissions budget

Regional Greenhouse Gas Initiative (RGGI) State-level Emission Allowances Budget (Short tons). This study covers all states in **bold**. We assume RGGI's budget will decline per RGGI's 2017 Model Rule Current RGGI authorization does not continue beyond 2030, and we assume that the same budget as in 2030 will be in place in 2035.

State	2022 Base Budget A	Declining per Year B	Third Adjustment for Banked Allowances C	2025 Adjusted Budget A – 3×B - C	2030 Adjusted Budget A – 8×B - C
Connecticut	4,713,516	147,297	774,787	3,496,838	2,760,353
Delaware	3,280,789	102,524	539,282	2,433,935	1,921,315
Maine	2,651,519	81,931	435,697	1,970,029	1,560,374
Maryland	16,281,475	508,796	2,676,277	12,078,810	9,534,830
Massachusetts	11,582,404	361,951	1,903,865	8,592,686	6,782,931
New Hampshire	3,842,274	118,725	631,362	2,854,737	2,261,112
New Jersey	16,920,000	540,000	2,783,029	12,516,971	9,816,971
New York	28,175,777	880,493	4,631,411	20,902,887	16,500,422
Pennsylvania	78,000,000	2,489,370	NA	70,531,890	58,085,040
Rhode Island	1,820,783	56,900	299,292	1,350,791	1,066,291
Vermont	524,247	16,383	86,173	388,925	307,010
Virginia	26,320,000	840,000	4,329,155	19,470,845	15,270,845

Modeled renewable portfolio standards and clean electricity standards

Renewable Portfolio Standards policy numbers obtained from LBNL RPS Summary (Feb, 2021) with IL General RPS updated per the passage of its Climate and Equitable Jobs Act (CEJA) in Sept. 2021.

State	2025	2030	2035
Delaware	24.0%	25.0%	25.0%
District of Columbia	52.0%	87.0%	100%
Illinois	27.5%	40.0%	45.0%
Maryland	40.0%	50.0%	50.00%
Michigan	14.5%	14.2%	13.8%
Missouri	15.0%	15.0%	15.0%
New Jersey	42.3%	54.7%	52.5%
New York	49.2%	70.00%	70.0%
North Carolina	11.9%	11.9%	11.9%
Ohio	8.0%	0.0%	0%
Pennsylvania	18.0%	18.0%	18%
Virginia	24.1%	39.2%	56.7%