Assumptions for the Long-Term Distributed Solar Generation and Battery Forecast

Load Analysis Subcommittee

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Purpose

- Starting this year, IHS Markit will provide a battery forecast for use in conjunction with the distributed solar forecast.
- Increase transparency of long-term distributed solar and battery forecast that will be used in the 2022 load forecast
- Foster open dialogue in the stakeholder process regarding the major assumptions in the long-term distributed solar and battery forecast
- Any federal or state policy assumptions discussed herein are based on currently mandated and funded policies

PJM Solar Forecast 2021: Key Assumptions

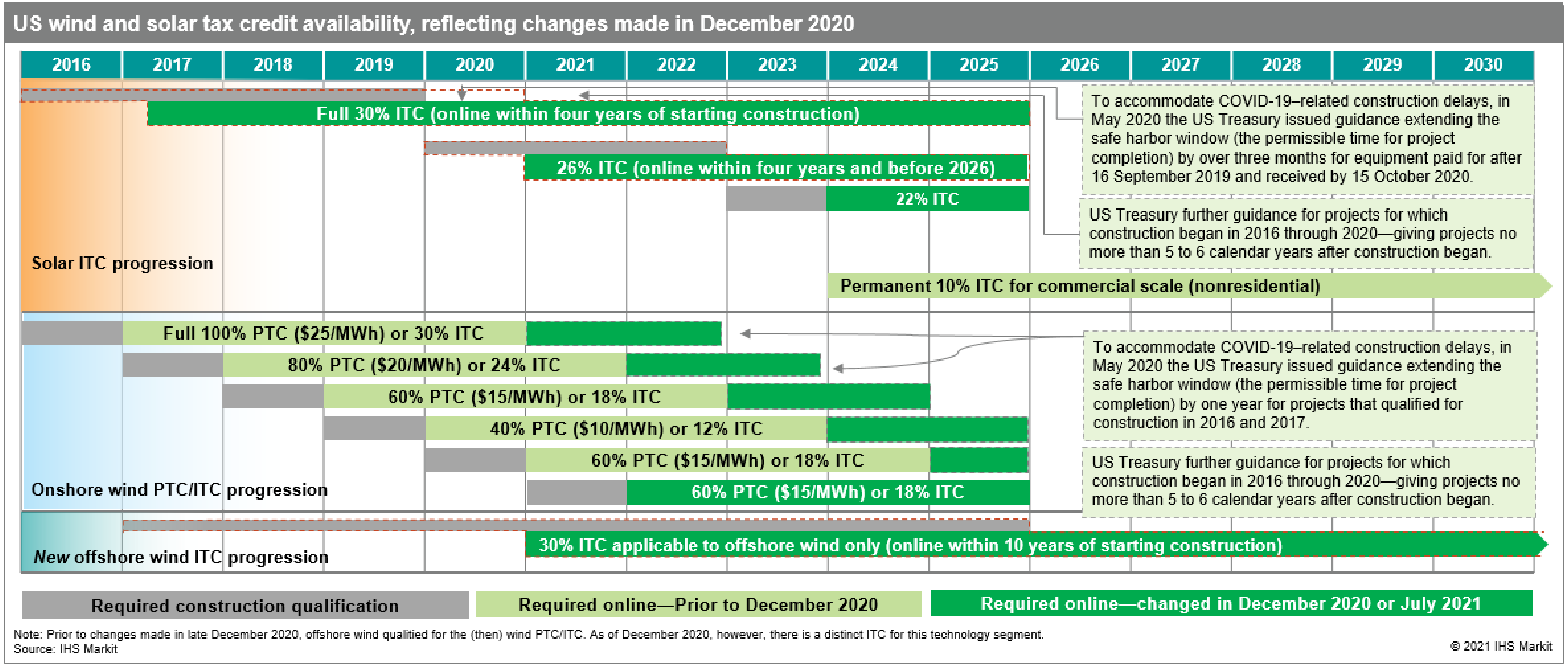
Solar forecast scenario overview

Assumptions	Scenario 2: "Base case"
Federal policy support	Current ITC schedule
NEM policies and retail rate structures	From 2021 to 2025, utilities adopt (and regulators approve) changes to NEM and retail rate structures, which result in a more cost-based approach to customer-sited solar compensation (see slide 5); current detailed state NEM policy (see slides 6–8).
Solar costs ($/kW)	Solar costs decline by 5–17% in nominal terms from 2021 to 2037 (34–42% in real terms).
State policy support	Current RPS policies and state-level incentives are maintained.
Power demand	Base-case demand

Note: DG = distributed generation. ITC = investment tax credit. PUCs = public utility commissions. DERs = distributed energy resources.

Source: IHS Markit

Current US federal tax credits



RPS and NEM policy assumptions by state

Current RPS policy by state

State	RPS target (percentage of retail sales)*	Solar carve-out percentage of retail sales)*/Distributed carve-outs
DE	25% by 2025, 28% by 2030, 40% by 2035	3.5% by 2025, 5% by 2030, 10% by 2035
DC	100% by 2032	2.85% by 2023, 5.50% by 2032, 10% by 2041
MD	50% by 2030	14.5% by 2030
NJ	50% by 2030*	5.1% by 2021, gradually reduced to 1.1% by 2031
OH	8.5% by 2026	0.5% of total electricity supply in 2026 and thereafter
PA	8% by 2021	0.5% by 2021
WV	-	-
IN	10% by 2025 (voluntary)	-
IL	25% by 2025**	No RPS but required 4 million SRECs by 2030. Utilities must source 10% of eligible electricity sales from renewable energy by 2015, 25% by 2025 and thereafter.
KY	-	-
MI	15% by 2025***	
NC	12.5% by 2021****	0.2% by 2020****
VA	100% by 2045*****	1,100 MW by 2035 (Dominion only), Dominion is required to meet 1% of RPS requirements from DG sources (>1 MW to <3 MW)
TN	-	-

Note: RPS includes solar carve-outs. *New Jersey RPS target only includes Class I renewable technologies and the solar carve-out. **Illinois solar carve-out requires that 50% of the solar procurements must be from distributed/community solar. RPS mandates at least 75% of the standard come from wind and solar. ***Utilities in Michigan have agreed to 25% by 2030. ****RPS compliance in North Carolina can be achieved through energy efficiency and renewable energy credits (RECs) from any state. *****Phase 1 utilities are required to achieve 14% by 2025, 30% by 2030, 65% by 2040, and 100% by 2050 while Phase II utilities are required to achieve 26% by 2025, 41% by 2030, and 100% by 2045. The primary drivers for solar development include existing Public Utility Regulatory Policies Act (PURPA) policy, planned requests for proposal (RFPs), solar resources, solar costs, and the previous state tax credit.

Source: IHS Markit

RPS and NEM policy assumptions by state (continued)

Current RPS and NEM policy by state

State	Utility/territory	NEM cap	NEM system size limits (MW)
DE	All utilities	5% of aggregated customer peak demand (utility can increase the cap)	0.025 (residential), 2 (Delmarva nonresidential), 0.5 (DEC, DEMEC nonresidential)
DC	Potomac Electric Power Co (Pepco)	N/A	For 2021, no more than 140% of the customer's historical 12-month usage, increasing 20% every year until 2024
MD	All utilities	3,000 MW	2 or 200% of customer load
NJ	Investor-owned utilities (IOUs), electric suppliers	None****	100% of customer load
OH	IOUs	N/A	Not to exceed 120% of customer annual average load
PA	IOUs	N/A	0.050 (residential), 3 (nonresidential), 5 (microgrids) (110% of customer's annual load for third-party owned/operated systems)
WV	All utilities	3% of peak demand during previous year	0.025 (residential), 2 (industrial for large IOUs), 0.500 (commercial for large IOUs), 0.050 (C&I for small IOUs)
IN	IOUs	1.5% of utility's summer peak load	1
IL	IOUs, retail suppliers	5% of utility's peak load in prior year	2
KY	IOUs, electric cooperatives except TVA	1% of utility's peak load in prior year	0.045
MI	All utilities	1% of utility's average of the previous 5-year peak load. Voluntary cap increase by Consumers Energy and UPPCO to 2%.	0.15
NC	IOUs, electric suppliers	N/A	2 (residential customer-owned systems), 1 (commercial systems up to 200% of contract demand)
VA	IOUs, electric cooperatives	6% of load, 1% are reserved for low-income customers	0.025 (residential), 3 (nonresidential)
TN	N/A	N/A	N/A

*NEM remuneration is a tariff structure under which the utility pays customers for excess generation, up to a given amount. The most common arrangement is "full retail rate NEM," in which excess generation is paid the same volumetric price that the customer pays for electricity; so, exports are effectively netted against grid consumption over a given period (typically one year). **NEG over that period is sometimes paid at a lower rate, often based on the utility's avoided cost. ***Total remaining excess kWh at the end of the calendar year (valued at the generation rate) that amounts to greater than $25 will be refunded as a check to the customer, if less than $25 it will be given as a credit. ****While no mandatory cap exists, it as at the discretion of the NJBPU to cap at 5.8% of retail sales. *****TREC = transition renewable energy credits. ******Virtual meter aggregation is limited to the account holder's meters and only those within two miles of the POI.

Source: IHS Markit

RPS and NEM policy assumptions by state (continued)

Current RPS and NEM policy by state			
State	**NEM remuneration for on-site use or export generation***	**NEG remuneration****	**Community solar**
DE	Retail	Retail	Virtual net metering
DC	Retail	Carries over at retail rate indefinitely, at generation rate for systems over 100 kW***	Virtual net metering (less than 5 MW)
MD	Retail	Credited to customer's next bill at retail rate; reconciled annually in April at the commodity energy supply rate	Pilot program
NJ	Base $152 TREC price ($0.152/kWh), nonresidential rooftop receives full TREC and ground mount receives 60%; residential rooftop, ground-mount, and carport receive 60%*****	Fixed $152 TREC price ($0.152/kWh)	85% of TREC Price ($0.12920/kWh)
OH	Less than retail	Credited to next bill at unbundled generation rate (includes energy component but excludes capacity-related compensation	None
PA	Retail	Credited at retail rate for a year, then any leftover excess is credited at generation and transmission portion of the retail rate, but not the distribution	Virtual meter aggregation******
WV	Retail (credits cannot reduce monthly bills below the fixed monthly charge)	Retail	Virtual net metering
IN	Full retail through 2047 for net metering facilities installed through 2017 and through 2032 for those installed through 2022; 125% of average energy market price for facilities installed after 2022 or 1.5% cap is met.	Full retail through 2047 for net metering facilities installed through 2017 and through 2032 for those installed through 2022; 125% of average energy market price for facilities installed after 2022 or 1.5% cap is met.	None
IL	Retail (TOU for customers paying TOU rates)	Credited to next bill at retail rate, excess at end of year is granted to utility	Virtual net metering
KY	Less than retail	Utility will purchase all electricity produced at the rate set by the PSC, instead of the retail rate	Utility-run program
MI	Approximately 50% of retail	Less than retail	None
NC	Retail	Carries over at retail rate, granted to utility at beginning of summer billing period	Utility-run program
VA	Retail	Retail	Utility-run program
TN	N/A	Retail	None

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Source: IHS Markit

RPS and NEM policy assumptions by state (continued)

Current RPS and NEM policy by state

State	Unbundled energy attribute certificates	Virtual power purchasing allowed	Renewable energy offerings from utilities or electric suppliers/green tariff	Production for self-consumption—net metering*
DE	Allowed	Allowed	Retail choice	Up to 2 MW
DC	Allowed	Allowed	Retail choice	Up to 1 MW
MD	Allowed	Allowed	Retail choice	Up to 2 MW
NJ	Allowed	Allowed	Retail choice	Cannot exceed on-site load
OH	Allowed	Allowed	Retail choice	No size limit
PA	Allowed	Allowed	Retail choice	Up to 3 MW
WV	-	Allowed	-	Up to 2 MW
IN	-	-	Green tariff enabled to guarantee sufficient RECS; does not require new build	No size limit under green tariff
IL	Allowed	Allowed	Retail choice	Up to 2 MW
KY	Voluntary	-	Green tariff enabled	Up to 45 kW
MI	Allowed	-	-	No size limit
NC	Allowed	Allowed**	Green tariff in development	Up to 1 MW
VA	Allowed	Allowed***	Green tariff enabled	Up to 1 MW
TN	-		-	-

Note: Green tariffs only include programs where utilities build new renewables on behalf of corporate customers. * Production for self-consumption—net metering refers to the NEM system size limits outlined by state or utility specific policies **In specific utilities. ***Applies to agricultural sites and school districts for projects up to 10 MW capacity.

Source: IHS Markit

Federal and regional energy storage policy assumptions

Federal and regional energy storge policy assumptions		
Category	**Policy**	**Base case**
Federal	Investment Tax Credit (ITC)	Updated phaseout schedule owing to COVID-19, assuming four-year "under construction" guidance (deadline increased to 15 October) or ending 31 December 2023. BESS only eligible if colocated with solar PV and charged directly from associated resource for first five years of operation.
Regional	PJM capacity market (as applicable to battery)	Assume Minimum Offer Price Rule (MOPR) is revised All other existing market rules, including draft effective load-carrying capability (ELCC) values, remain in place over forecast period
State/city	Energy storage targets	Remain in current form
State	Tax credits	Remain or expire as currently scheduled
State	Incentives (e.g., rebates)	Assume Virginia's and New Jersey's utilities roll out an incentive program for BTM batteries in effort to comply with state target. Other states remain unchanged

Note: BESS = battery energy storage system. BTM = behind the meter.

Source: IHS Markit

Battery policies by state

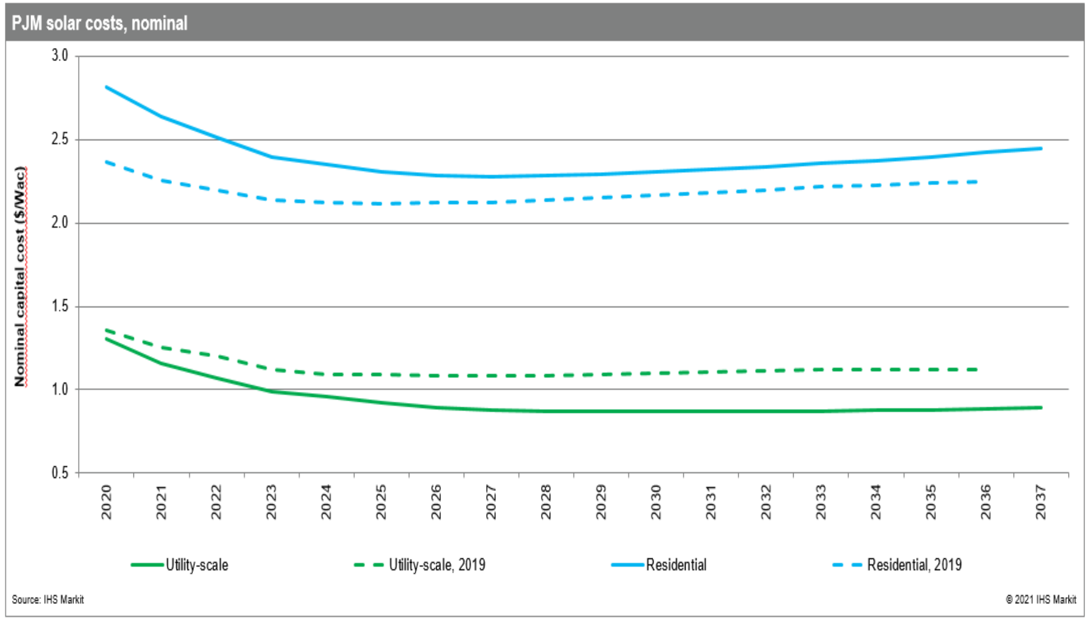
Detailed state energy storage policy assumptions

State	Energy storage target (MW)	Tax credit
DE		
DC		
MD	Two 5 MW and 15 MWh pilots by 2022	30%**
NJ	2 GW by 2030	
OH		
PA		
WV		
IN	8% storage by 2039***	
IL		
KY		
MI		
NC		
VA	2.7 GW by 2035 (Dominion), 0.4 GW (Appalachian Power Company)	
TN		

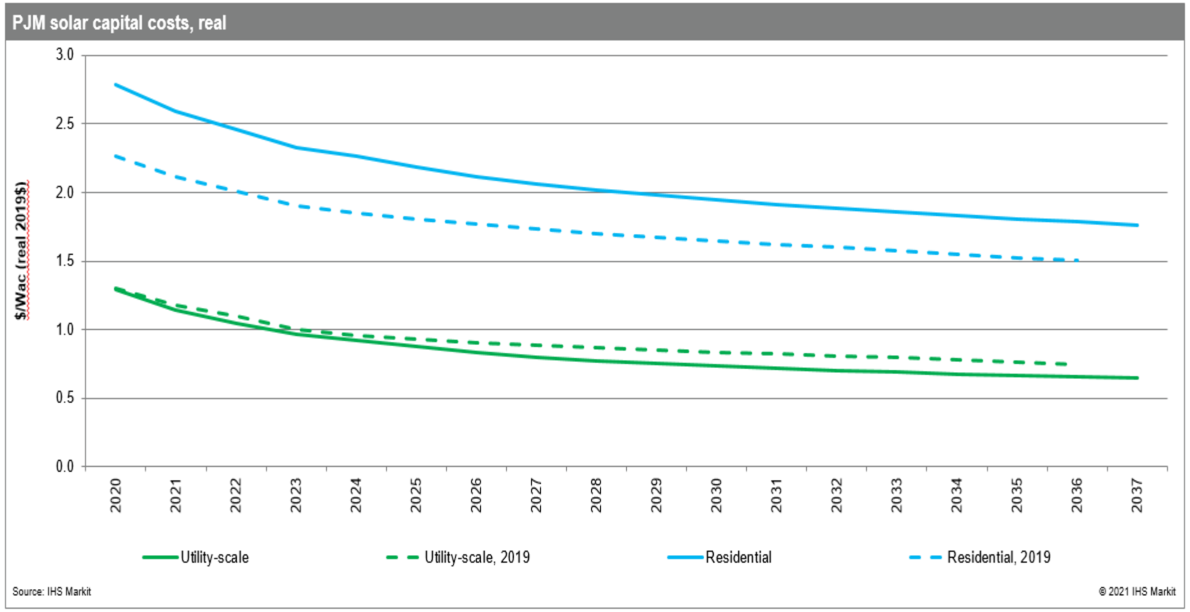
*Maryland's "Energy Storage Pilot Project Act" solicitation offers for IOUs at least two energy storage projects with a cumulative size of at least 5 MW and 15 MWh. **Maryland Energy Administration (MEA) 2018 Energy Storage Tax Credit Program offered 30% tax credit of the total installation costs (up to $5,000 for a residential project and $75,000 for commercial). ***In May 2018, lawmakers passed legislation (S 2314/A 3723) to implement energy storage targets of 600 MW by 2021 and 2 GW by 2030 and requires the BPU to establish a process and mechanism for achieving these targets. ****The regulations instruct Appalachian Power Company and Dominion to construct or acquire 400 MW and 2,700 MW, respectively, of front-of-the-meter energy storage resources by 2035. ***Indianapolis Power & Light's (IPL) 2019 IRP proposes replacing coal power with renewables and storage, amounting to approximately 240 MW based on an assumed installed capacity of 3 GW.

Source: IHS Markit

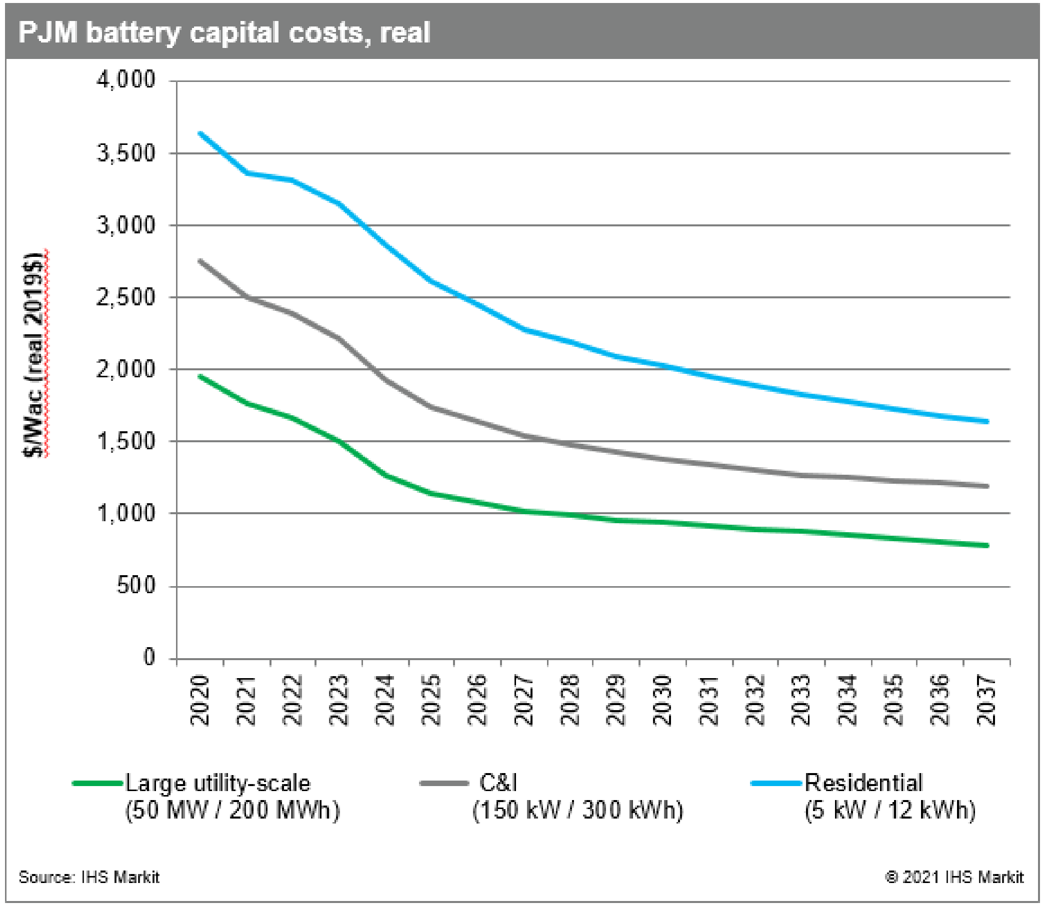
PJM solar capital costs (nominal)



PJM solar capital costs (real)



Battery capital costs (real)



- **Capital costs for residential and C&I BESS are 2.3 times and 1.5 times, respectively, relative to utility-scale.**
  - Soft costs are significantly larger for BTM systems owing to the diseconomies of scale in installation and high customer acquisition costs.
  - Cost declines in the BTM segment will be driven by falling hardware costs.
  - Total project costs decline by approximately 20% across the BTM segment over the 2021–25 period. Hardware costs decline by 30% during that time frame, while soft costs decline by only 2%.
  - A trend toward larger system sizes, enabled by ever-cheaper batteries, will push down per-unit costs in the BTM segment.

Contact

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