Estimating the costs of deeply decarbonized US grids; our grid optimization model

For years I've been critical of marginal levelized costs of electricity cited for wind and solar since such measures typically do not incorporate the cost of backup power or energy storage. I also don't trust the rigor of back-of-the-envelope efforts by Lazard and others to estimate so-called "grid firming costs". That's said, I also see little value in computing the levelized cost of wind or solar in isolation even when including the necessary amount of overbuilding and storage, since no one would build a wind-only or solar-only grid in the first place.

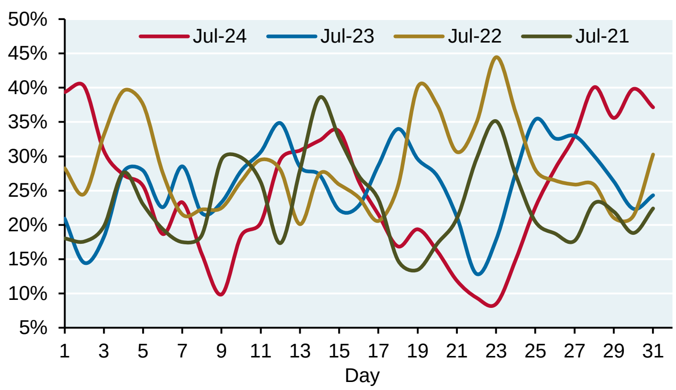
What matters most is **the systemwide cost** of deeply decarbonized grids, an analysis that incorporates whatever benefit comes from inversely correlated (at times) wind and solar power. Our grid optimization model uses real-world data on hourly generation, demand and reserve margins for each of the five largest ISO regions. The goal: determine the configuration of solar, wind, gas, carbon capture and battery storage, combined with existing nuclear and hydro, that can meet demand at the lowest cost and reduce carbon. The grid must be able to handle unexpected spikes in demand *and* unexpected declines in wind and solar power, possibly at the same time. The chart below illustrates how challenging this can be: note how wind generation collapsed on two separate occasions in July 2024.

You cannot estimate this kind of thing using a simplified model; believe me, I've tried. A thorough analysis must reflect hourly location-specific power demand and generation, and also exclude government subsidies[1].

Optimized grids shown on the following pages assume significant expansion of wind and solar power. But as shown in the second chart, the US grid is decarbonizing at just ~1% per year due to site permitting delays, interconnection costs, transmission & distribution bottlenecks and queues of wind and solar already waiting to be connected. That raises substantial questions about the timing of our deeply decarbonized scenarios.

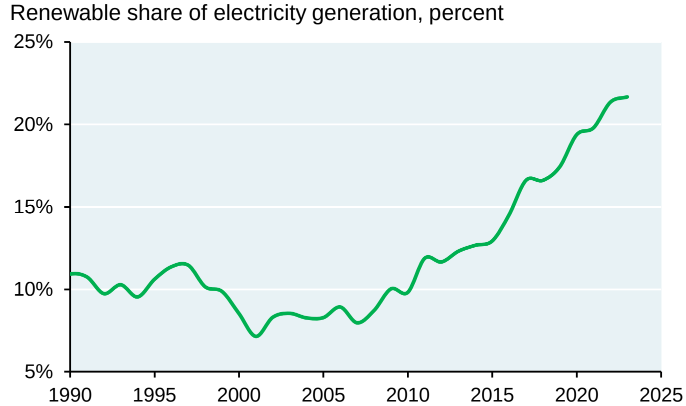
We estimate that system levelized costs of electricity would increase by 16%-32% in today's dollars to increase zero carbon power shares by ~30%, with abatement costs of \$75-\$165 per metric ton of CO_2. I consider these results to be a lower bound since they exclude any future increase in the load due to electrification of transport and home heating, and demand from new data centers. We also do not include estimates of any substation, ramping and integration costs required by highly renewable grids since there are few blueprints to rely on.

National wind capacity factors for July, 2021-2024
Percent



Source: EIA, JPMAM, July 2024

US grid decarbonization
Renewable share of electricity generation, percent



Source: EI Statistical Review of World Energy, JPMAM, 2024

[1] **Why exclude subsidies?** Assume for the sake of argument that the Federal investment tax credit for solar covered 90% of capital costs, which then resulted in wholesale power prices of just 0.5 cents per kWh. Is that what you would assume as the true cost of solar power? I hope not. Taxpayer subsidies are normally excluded from levelized cost of electricity analyses, except by the staunchest ideologues and energy hacks.

Grid optimization project: general principles and big picture results

- Systemwide LCOE (levelized cost of electricity) includes amortized capital costs, annual fixed and variable costs, fuel costs and incremental transmission costs for wind and solar
- Our analysis is based on hourly patterns of electricity demand and generation by ISO region. Grids are modeled to meet hourly demand *and* satisfy resource adequacy requirements that incorporate the intermittency of renewable power
- We analyze the five largest ISO regions: CAISO, ERCOT, PJM, MISO and SPP
- Our model can vary solar, wind, gas, carbon capture and two forms of battery storage. We do not assume any changes to existing nuclear or hydro generation; coal is assumed to be decommissioned. In addition to 4-hour lithium ion batteries, we also assume the existence of 100-hour iron air batteries which are now commercially available[2]
- We require optimized grids to increase their renewable share of electricity by at least 20%, and to increase their zero carbon shares by 30% (from wind, solar or natural gas paired with carbon capture)
- We estimate that system levelized costs of electricity would increase by 15%-35% in today's dollars to increase zero carbon power shares by ~30%, with abatement costs of \$85-\$165 per metric ton of CO_2 from the addition of wind, solar and batteries. The table below shows the results; the subsequent pages show scenarios with constraints on the development of new gas capacity and/or carbon capture
- Wind and solar capacity would have to double, triple and in some cases quadruple in size. Even so, in most cases natural gas capacity is still a large share of system capacity given the need to offset decommissioned coal and/or provide backup power

Grid optimization results: no contraints on new gas capacity or CCS

	Current zero carbon share of power	Future zero carbon share of power	Increase in system LCOE	Abatement cost per ton of CO_2	% increase in wind & solar capacity	Lithium ion batt % of W&S capacity	Long duration batt % of W&S capacity	Natural gas share of capacity	CCS share of total gas capacity
CAISO	41%	72%	32%	$166	182%	16%	0%	42%	8%
ERCOT	42%	73%	22%	$108	180%	5%	0%	47%	8%
MISO	31%	62%	16%	$84	214%	0%	0%	60%	6%
PJM	42%	73%	21%	$126	396%	1%	0%	58%	7%
SPP	48%	79%	18%	$100	153%	0%	5%	53%	9%

Source: JPMAM Grid Optimization Project, February 2025

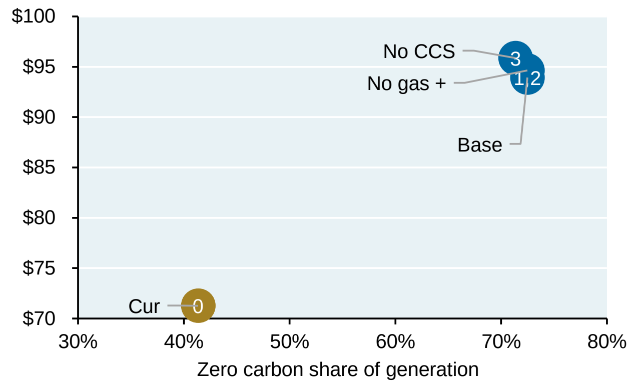
I would like to acknowledge the programming assistance and optimization insights that we received from our colleagues in the Chase Business Modeling Optimization Center.

[2] *"CEC Awards \$30 Million to 100-Hour, Long-Duration Energy Storage Project"*, California Energy Commission, Dec 2023. The company (Form Energy) hit a funding milestone in October 2024, announcing a \$405 million Series F financing round that brought its total funding to more than \$1.2 billion. The company also received \$147 million in DoE funding to build a project in Maine capable of injecting up to 85 MW into the New England grid for up to 100 hours. Form Energy's chemistry taps into existing iron and steel industry supply chains via its factory in West Virginia.

ISO grid decarbonization results

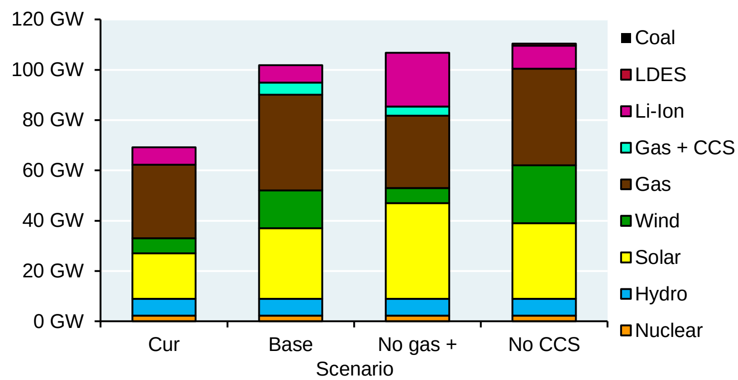
- We run three different scenarios: a base case, No CCS and No New Gas capacity. No CCS is applicable in cases where it is geologically or politically infeasible to build. No New Gas is applicable in places like California where for all practical purposes, new natural gas combined cycle plants cannot be built
- In some cases, No CCS and No New Gas constraints did not substantially impact system LCOE since base case scenarios did not rely on CCS or more gas capacity in a meaningful way
- In base cases, CCS was only used marginally at no more than 10% of total gas capacity
- While decarbonized CAISO and ERCOT grids include new wind and solar, other grids relied almost exclusively on new wind due to their poor solar capacity factors (see charts page 5)
- No New Gas scenarios generally require very large buildouts of utility scale lithium ion battery storage
- Long duration storage is most important in PJM, MISO and SPP when there are constraints on the ability to add more gas capacity, or to build CCS. We model LDES at its assumed future cost of $2 mm per MW rather than its current cost of $4.2 mm per MW. We also assume that within ISO regions, electricity is frictionlessly fungible. In reality, there are logistical constraints within ISOs that prevent power from being easily moved, in which case LDES could provide additional value in ways our model cannot capture

CAISO optimized grids: 32%-34% increase in LCOE
System levelized cost per MWh, 2024$



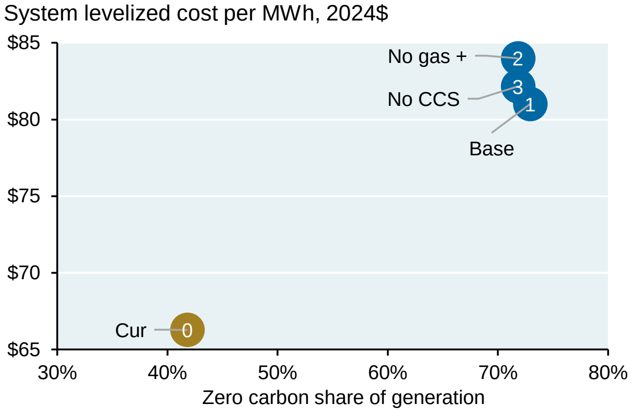
Source: JPMAM Grid Optimization Project, January 2025

CAISO capacity by source
GW



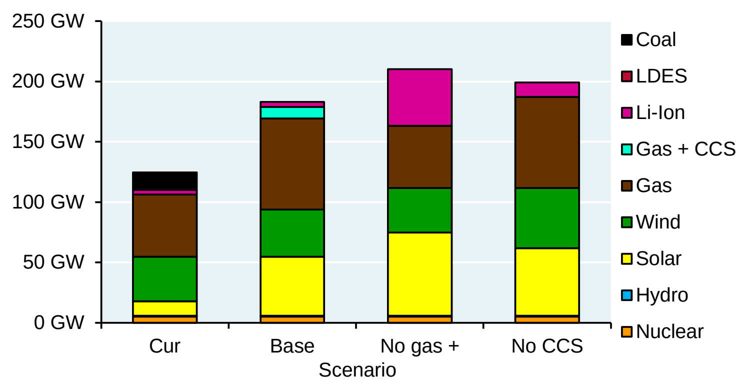
Source: JPMAM Grid Optimization Project, January 2025

ERCOT optimized grids: 22%-27% increase in LCOE
System levelized cost per MWh, 2024$



Source: JPMAM Grid Optimization Project, January 2025

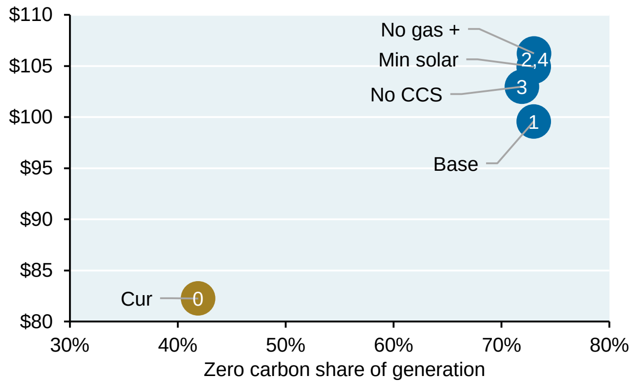
ERCOT capacity by source
GW



Source: JPMAM Grid Optimization Project, January 2025

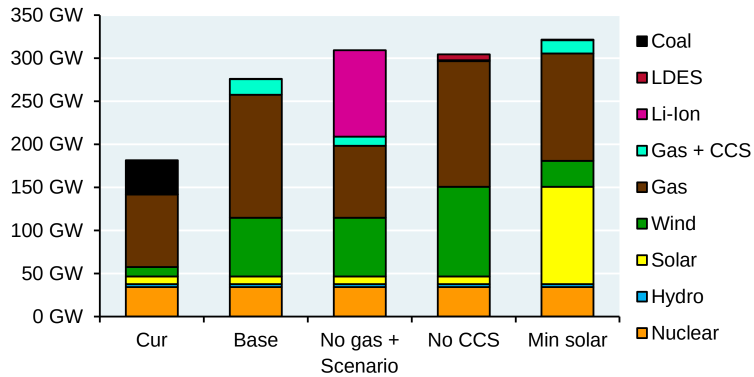
The optimizer did not add any new solar for PJM in the base case, so we forced it to source at least 15% of the load from solar power. It did so (and decreased both wind and natural gas additions), but resulted in another $6 per MWh of system LCOE. In other words, trying to equalize wind and solar shares of generation was a clearly suboptimal solution.

PJM optimized grids: 21%-29% increase in LCOE
System levelized cost per MWh, 2024$



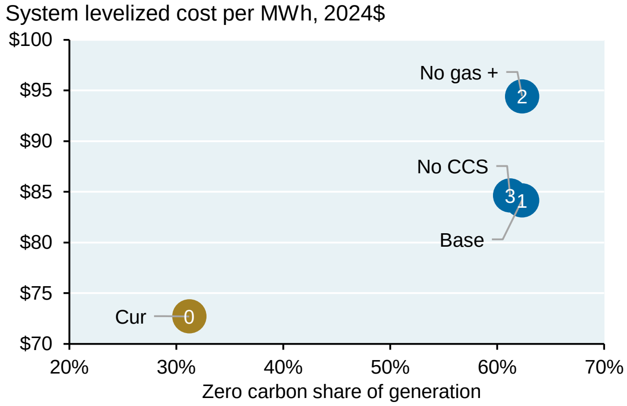
Source: JPMAM Grid Optimization Project, January 2025

PJM capacity by source
GW



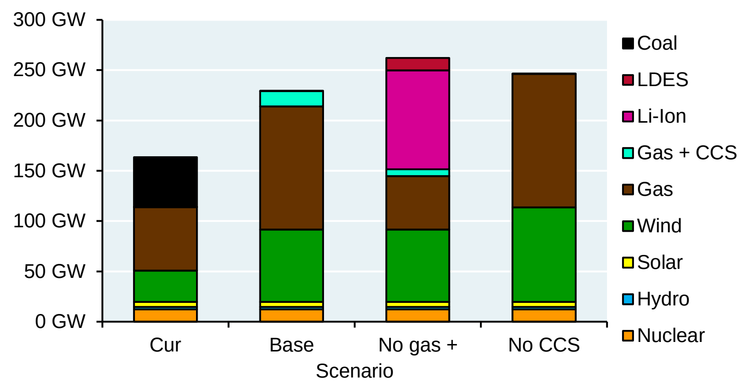
Source: JPMAM Grid Optimization Project, January 2025

MISO optimized grids: 16%-30% increase in LCOE
System levelized cost per MWh, 2024$



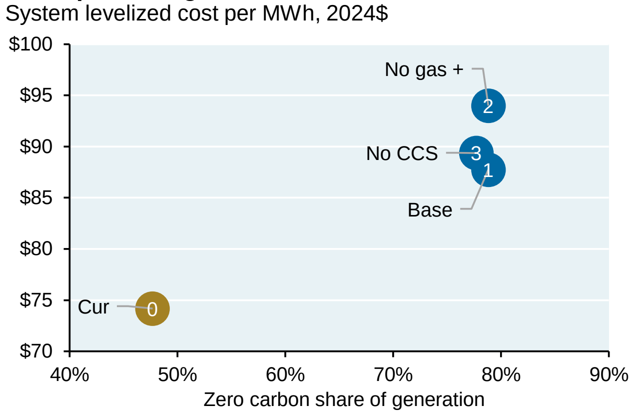
Source: JPMAM Grid Optimization Project, January 2025

MISO capacity by source
GW



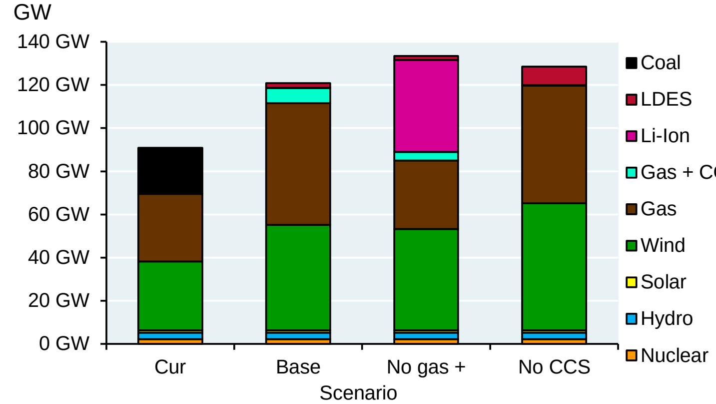
Source: JPMAM Grid Optimization Project, January 2025

SPP optimized grids: 21%-29% increase in LCOE
System levelized cost per MWh, 2024$



Source: JPMAM Grid Optimization Project, January 2025

SPP capacity by source
GW

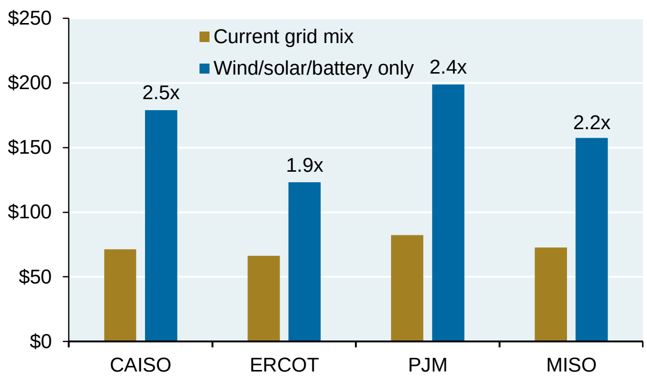


Source: JPMAM Grid Optimization Project, January 2025

What might it cost to completely decarbonize the grid using only solar, wind and batteries?

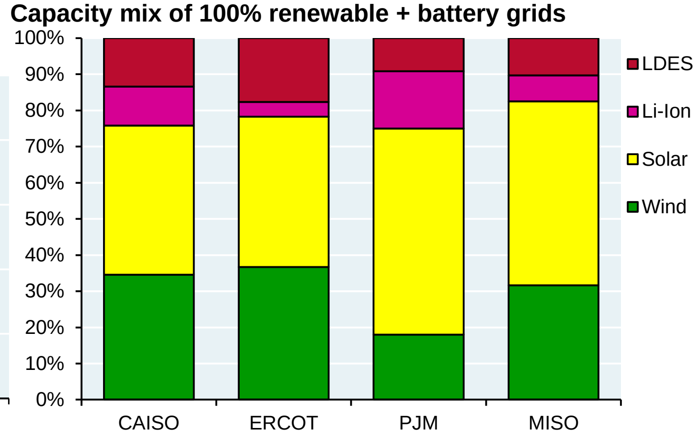
In these scenarios, nuclear, gas, coal and hydro are eliminated and all power demand must be met with solar, wind and both forms of battery storage. System LCOE costs increase by 2.0x-2.5x. Wind and solar capacity would have to grow by 5x to 15x in ERCOT and CAISO, and solar buildouts required in PJM and MISO would be preposterously high (~60x) while wind would have to expand by 5x-15x. I don't think it's worth spending too much time thinking about these exceedingly expensive and unlikely outcomes.

System LCOE of 100% renewable + battery grids vs current grids, 2024$ per MWh



Source: JPMAM Grid Optimization Project, January 2025

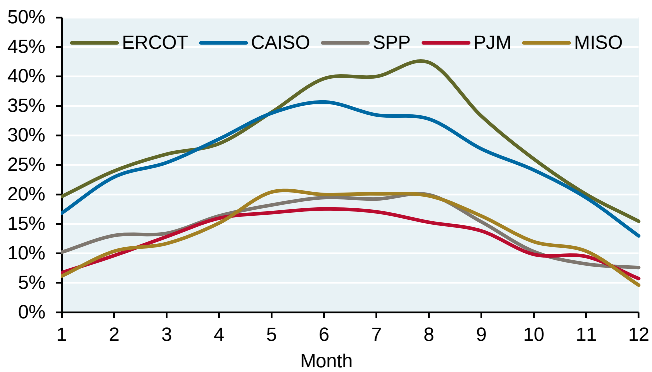
Capacity mix of 100% renewable + battery grids



Source: JPMAM Grid Optimization Project, January 2025

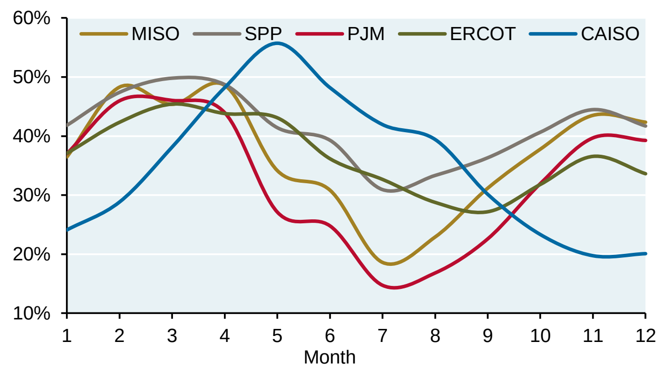
Supporting charts: capacity factors for solar, wind and hydro

Monthly solar capacity factor, 2021-2023
Percent



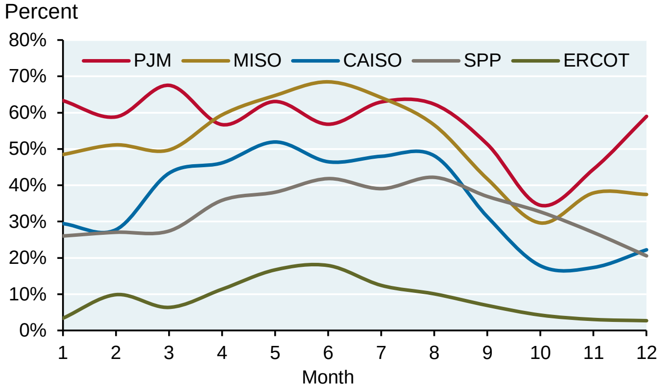
Source: EIA, JPMAM, 2024

Monthly wind capacity factor, 2021-2023
Percent



Source: EIA, JPMAM, 2024

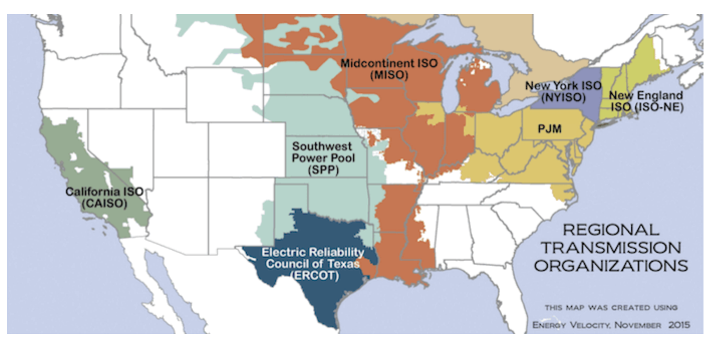
Monthly hydro capacity factor, 2021-2023
Percent



Source: EIA, JPMAM, 2024

ISO customers

MISO 45 million; CAISO 32 million; PJM 65 million; ERCOT 27 million; SPP 19 million; NYISO 20 million; ISO-NE 8 million



Cost, operating life, duration, round trip efficiency, transmission and load carrying assumptions

Cost, ELCC, planning reserve margin, operating life, battery duration and RTE assumptions

	Capital $/MW	Fixed $/MW/yr	Variable $/MWh	Fuel cost $/MWh	Op life Years	Battery dur. hours	Battery RTE %	Transmission $/MW	ELCC Eff load carrying cap
Wind	$ 1,600,000	$ 32,250			25			$ 240,000	20%
Solar	$ 1,125,000	$ 12,500			30			$ 240,000	25%
Gas	$ 1,176,000	$ 13,730	$ 2.10	$ 22.30	40				90%
Gas w/ CCS	$ 3,140,000	$ 31,060	$ 6.57	$ 24.93	40				90%
Li-ion battery	$ 929,000		$ 5,250		15	4	86%		60%
Hydro	$ 3,421,000	$ 47,060	$ 1.57		50				40%
Iron-air LDES	$ 2,000,000	$ 17,000			30	100	45%		90%
Nuclear	$ 7,777,000	$ 136,910	$ 2.67	$ 6.10	60				95%
Coal	$ 1,333,333	$ 25,000	$ 3.80	$ 33.31	60				90%
				Transmission op life:	60				

Sources:

Lazard 2024	Form Energy	NERC
EIA 2023	PJM, ERCOT, CAISO, MISO, SPP	
JPMAM	LBNL	
MIT	NREL	

Planning reserve margin:	
CAISO	31%
ERCOT	22%
PJM	32%
MISO	26%
SPP	29%

- Lithium ion capital cost includes DC capital costs of $160-$282/kWh plus AC capital costs of $30-$60/kW
- Natural gas costs converted to $/MWh using EIA heat rate assumptions of 6,370 BTU / kWh for natural gas w/o CCS, and 7,124 BTU/kWh for gas + CCS. We assume $3.5 per mm btu for natural gas prices
- The long duration iron air battery is priced at its aspirational cost of $2 mm per MW
- Carbon capture costs that are sourced from the EIA are consistent with other studies from the DoE[3], and data obtained from companies with existing commercial CCS applications
- We do not assume any build-out or decommissioning of nuclear. In other words, within each grid the nuclear cost is a constant that does not change. Same for hydropower
- Coal capital costs are based on the last completed plant in the US (Sandy Creek), adjusted for inflation. These costs only apply to the current case. Coal is decommissioned in all optimized scenarios
- Wind and solar expansion assessed incremental transmission costs as per LBNL (2023) of $105k-$240k per MW, depending on the ISO region[4]

<u>Assumptions and methodology</u>

- The perspective used is a utility in a regulated state that is required to build capacity to meet demand; its assumed discount rate is 9% for purposes of amortizing upfront capital and transmission costs
- Grid configurations are required to meet hourly demand, and to meet annual resource adequacy constraints assuming a 20% planning reserve margin (the lower end of summer reserve margins reported by NERC in their 2022-2023 M-1 analysis). The reserve margin is computed using the effective load carrying capacity measures shown above. ELCC measures are sourced from ISO reports and reflect ELCCs at higher renewable penetration rates, which is consistent with our higher decarbonization targets
- Any carbon capture buildout is assumed to capture 90% of flue gas CO_2 emissions
- To reduce the idiosyncratic impact of any specific year's generation for renewable energy, we created normalized hourly wind, solar and hydro generation vectors using data from 2021, 2022 and 2023. Wind and solar expansions assume gross-up of existing generation
- All demand unmet by renewables and available energy storage is met by natural gas capacity
- Net electricity imports for each ISO are assumed to be zero
- Our LCOE calculations are unsubsidized and do not include production tax credits, investment tax credits, diurnal arbitrage revenue, storage capacity payments or the cost of carbon; or tariffs on imported China solar or batteries

[3] *"Carbon Capture in the Power Sector"*, Bashevkin et al, Department of Energy, April 2024

[4] *"Generator Interconnection Costs to the Transmission System"*, Seel et al, LBNL, June 2023