Evolution of bulk power system interconnection queues: Historical trends in generator interconnection timelines and costs

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Bulk Power System Learning Modules Educational Training for Regulators Amidst an Evolving Electricity System

NARUC

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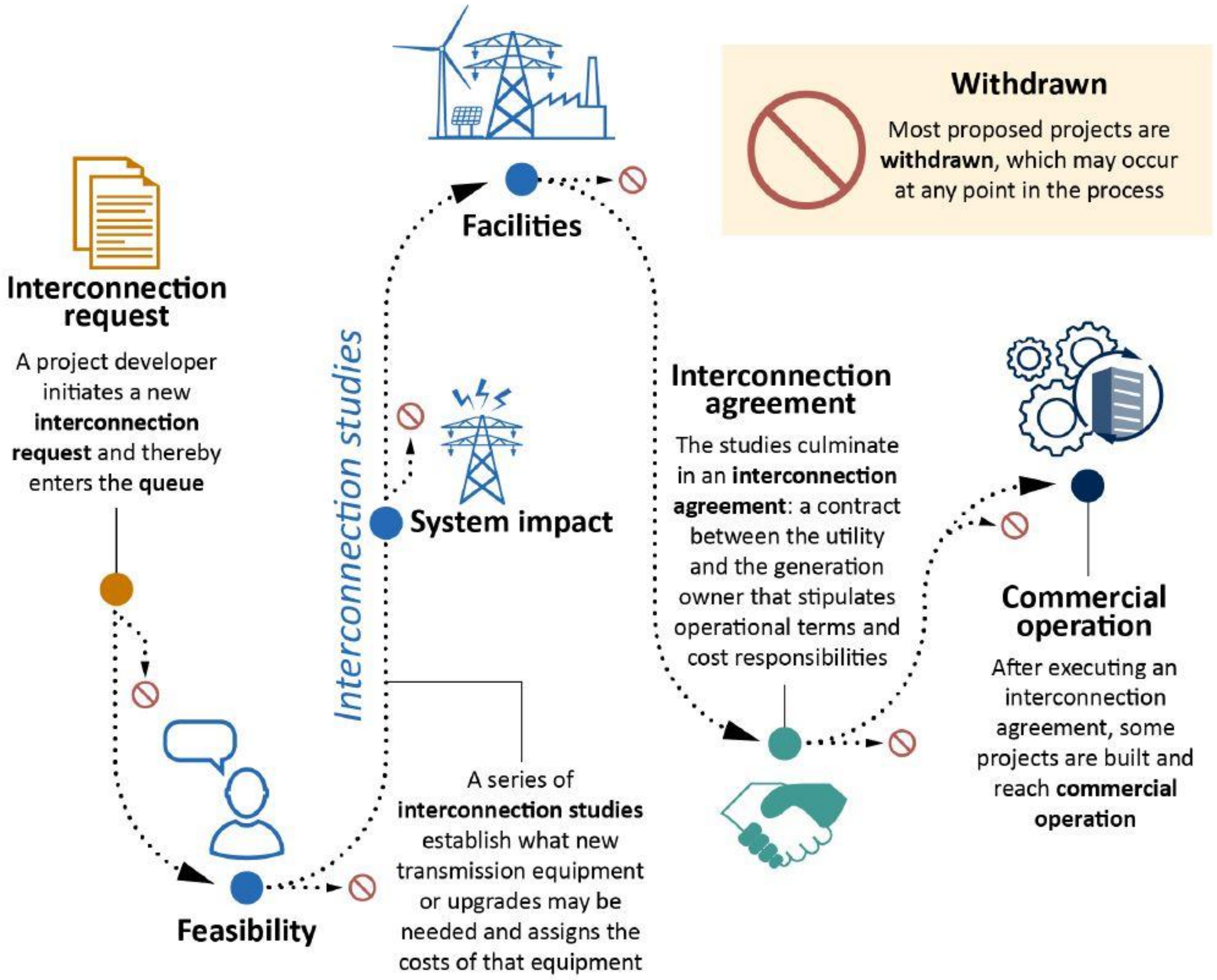
Current interconnection process was designed in 2003 for an electricity system with fewer, larger, centralized power plants (though RTOs have implemented some reforms)



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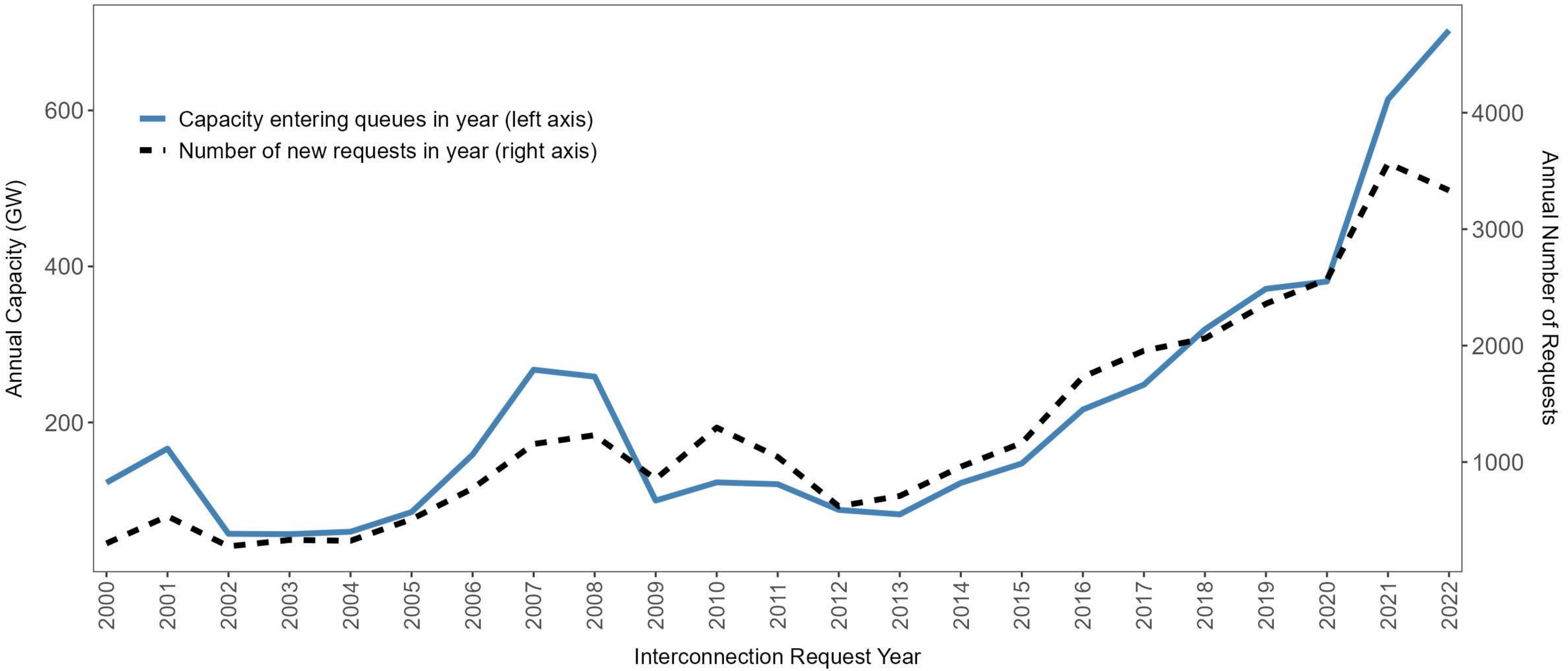
- Transmission grid operators require new projects looking to connect to the grid to undergo a series of impact studies
- These studies determine the grid upgrades necessary to allow projects to connect safely and reliably, and allocate the cost of those upgrades
- Withdrawals can result in multiple re-studies: a vicious cycle of delays, backlogs & higher costs

There has been a substantial increase in annual interconnection requests (both in terms of number and capacity) since 2013; over 700 GW added in 2022 alone

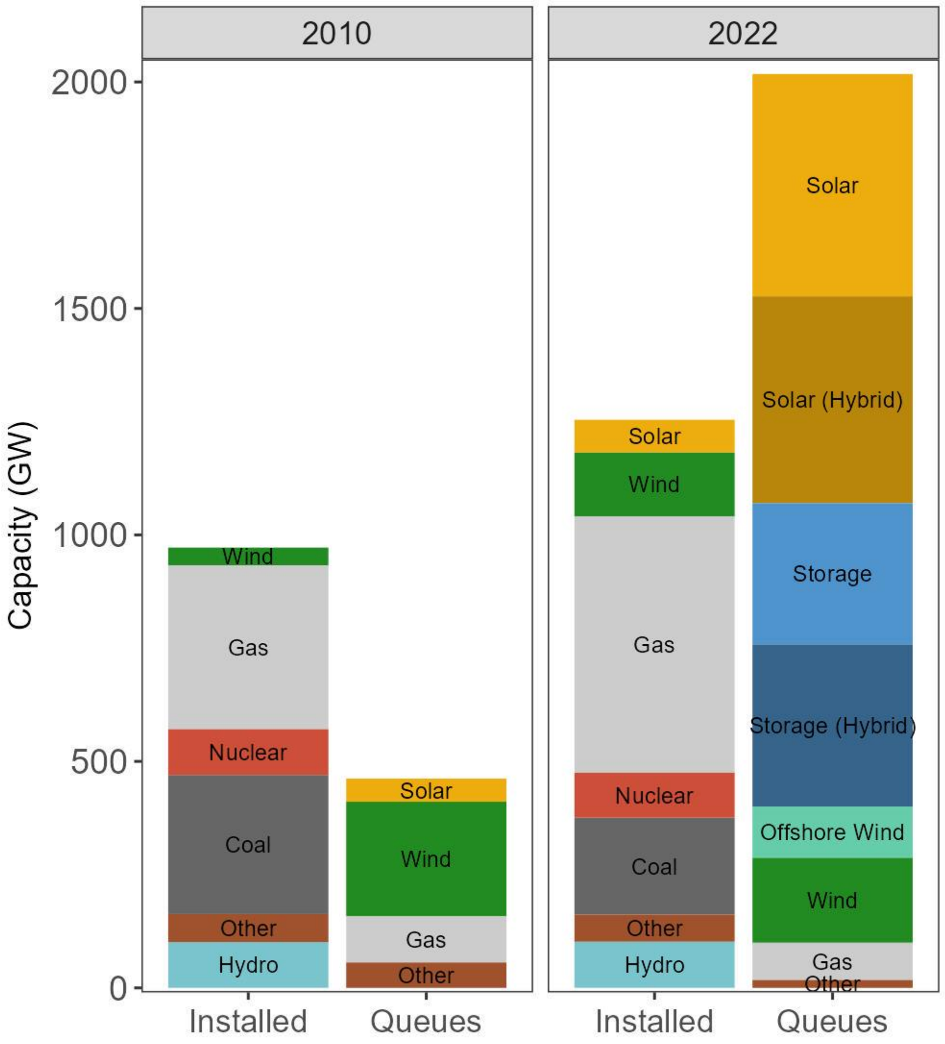


Decrease in new requests in 2022 likely driven by “pauses” on new requests in CAISO and PJM (see slide 7).

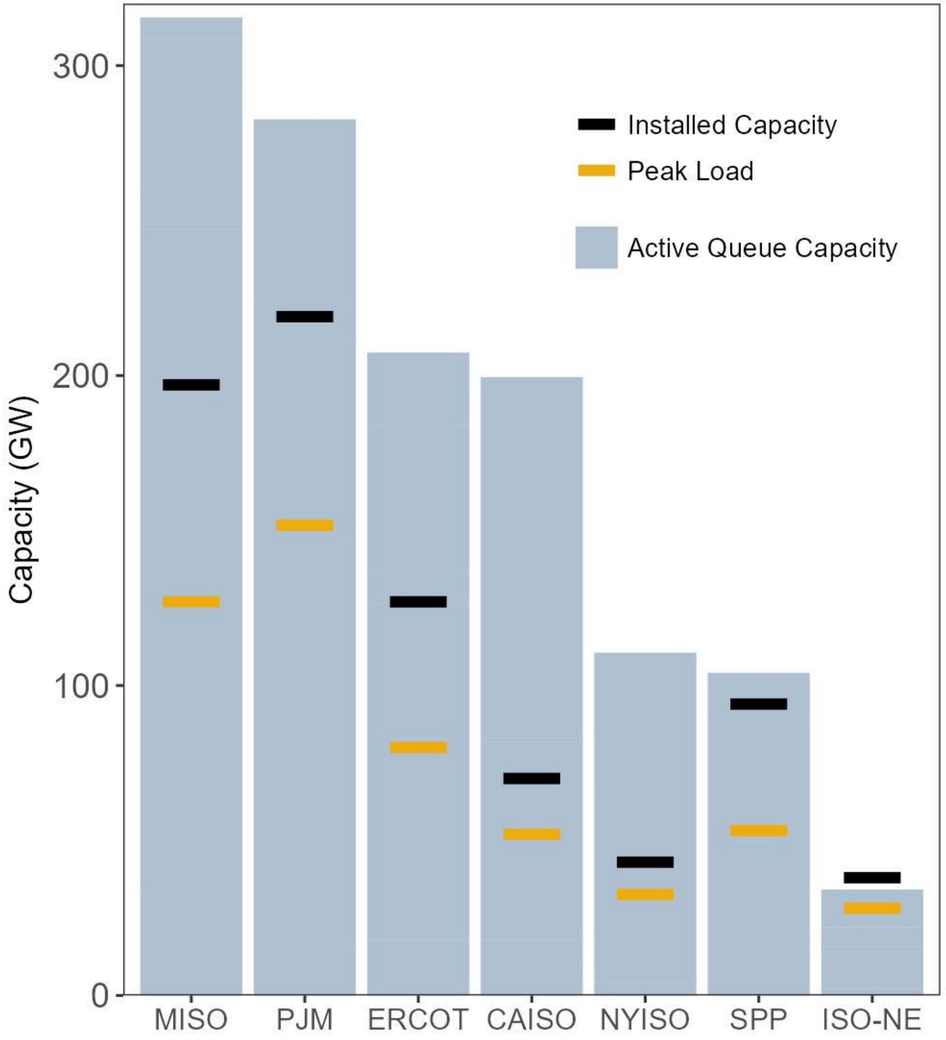
Notes: (1) This total annual volume includes projects with a queue status of "active", "suspended", "withdrawn", or "operational".
(2) All values – especially for earlier years – should be considered approximate.

Active capacity in queues (>2,000 GW) exceeds installed capacity of entire U.S. power plant fleet (~1,250 GW), as well as peak load and installed capacity in most ISO/RTOs

Entire U.S. Installed Capacity vs. Active Queues



RTO Installed Capacity & Peak Load vs. Active Queues

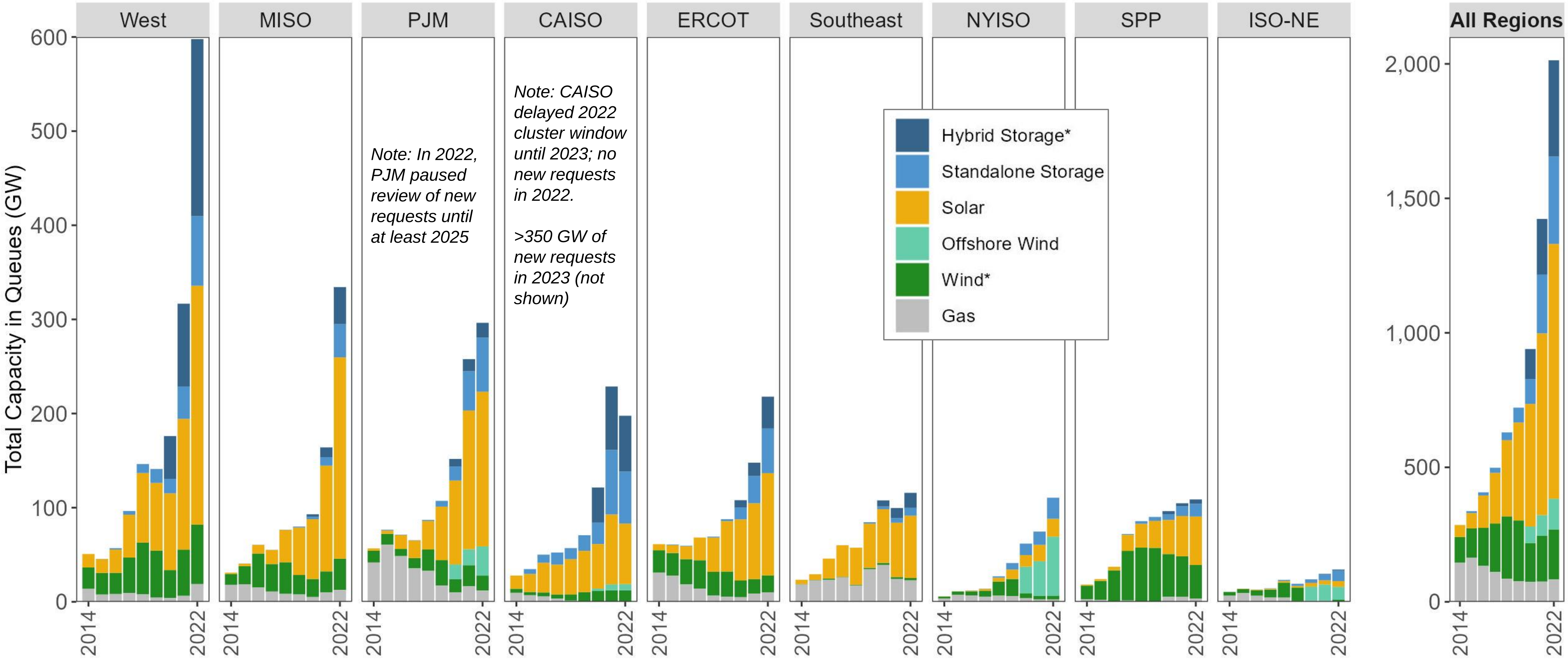


Comparisons of queue capacity to installed capacity or peak load should also consider generators' contributions to resource adequacy, for example their "effective load carrying capability" (ELCC). As variable resources, solar and wind contribute a smaller percentage of their nameplate capacity to resource adequacy compared to dispatchable generation like natural gas.

Decarbonizing the electric sector therefore requires higher levels of *installed* solar and wind capacity to achieve the same resource adequacy contributions. High levels of storage can offset this need to some degree. Electrification of buildings and transport will also result in load growth.

Notes: (a) Hybrid storage in queues is estimated for some projects. (b) Total installed capacity from EIA-860, December 2022. (c) RTO installed capacity from FERC Annual State of the Markets Report (https://www.ferc.gov/media/report-2021-state-markets). Peak load data from RTO websites.

Active queue capacity highest in the non-ISO West (598 GW), followed by MISO (339 GW) and PJM (298 GW). Solar and storage requests are booming in most regions.



*Notes: (1) *Hybrid storage capacity is estimated for some projects using storage:generator ratios from projects that provide separate capacity data, and that value is only included starting in 2020. Storage duration is not provided in interconnection queue data. (2) Wind capacity includes onshore and offshore for all years, but offshore is only broken out starting in 2020. (3) Hybrid generation capacity is included in all applicable generator categories. (4) Not all of this capacity will be built.*

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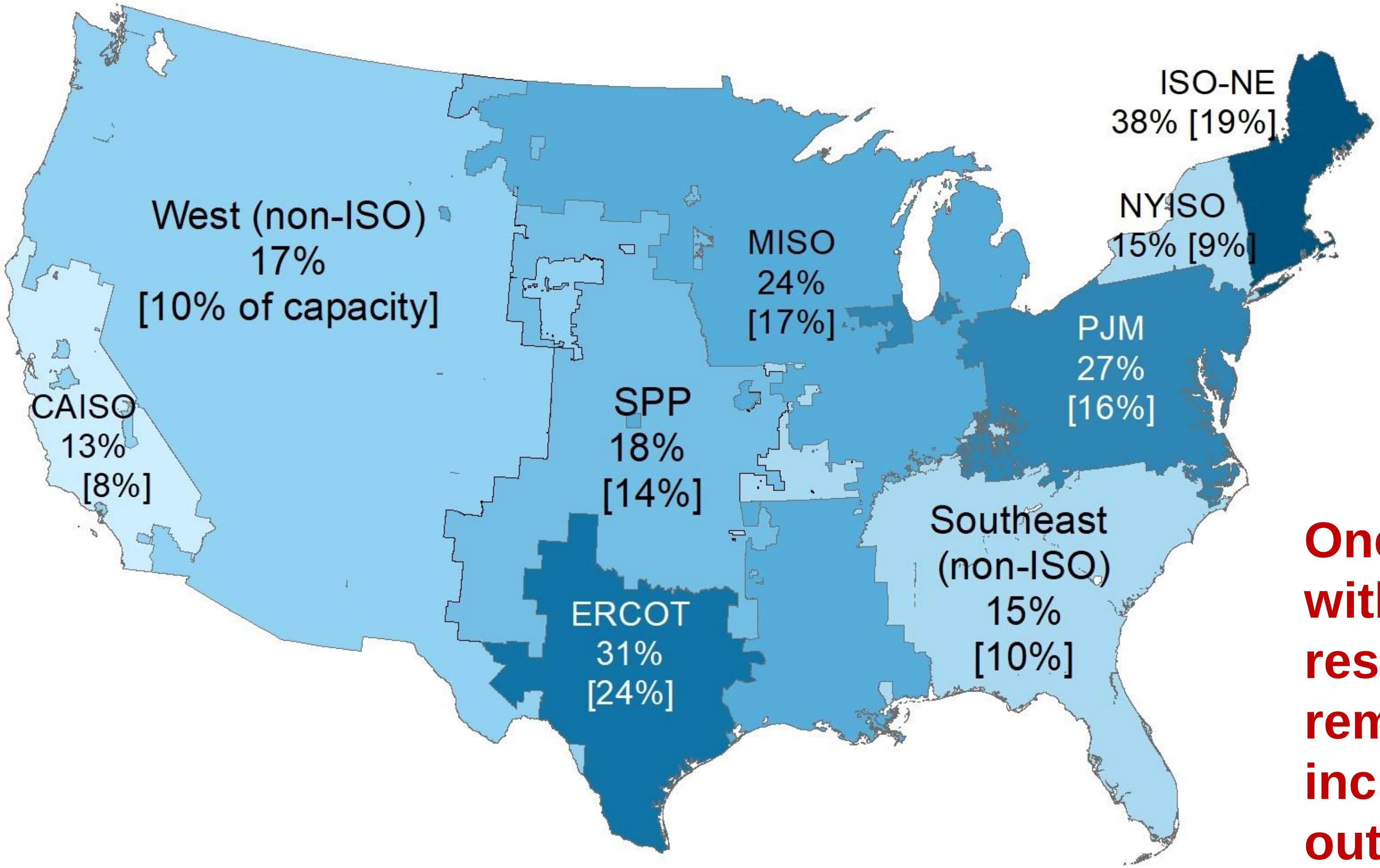
Only 21% of projects that applied for interconnection prior to 2018 have been built – 72% have been withdrawn (7% are still actively trying!)



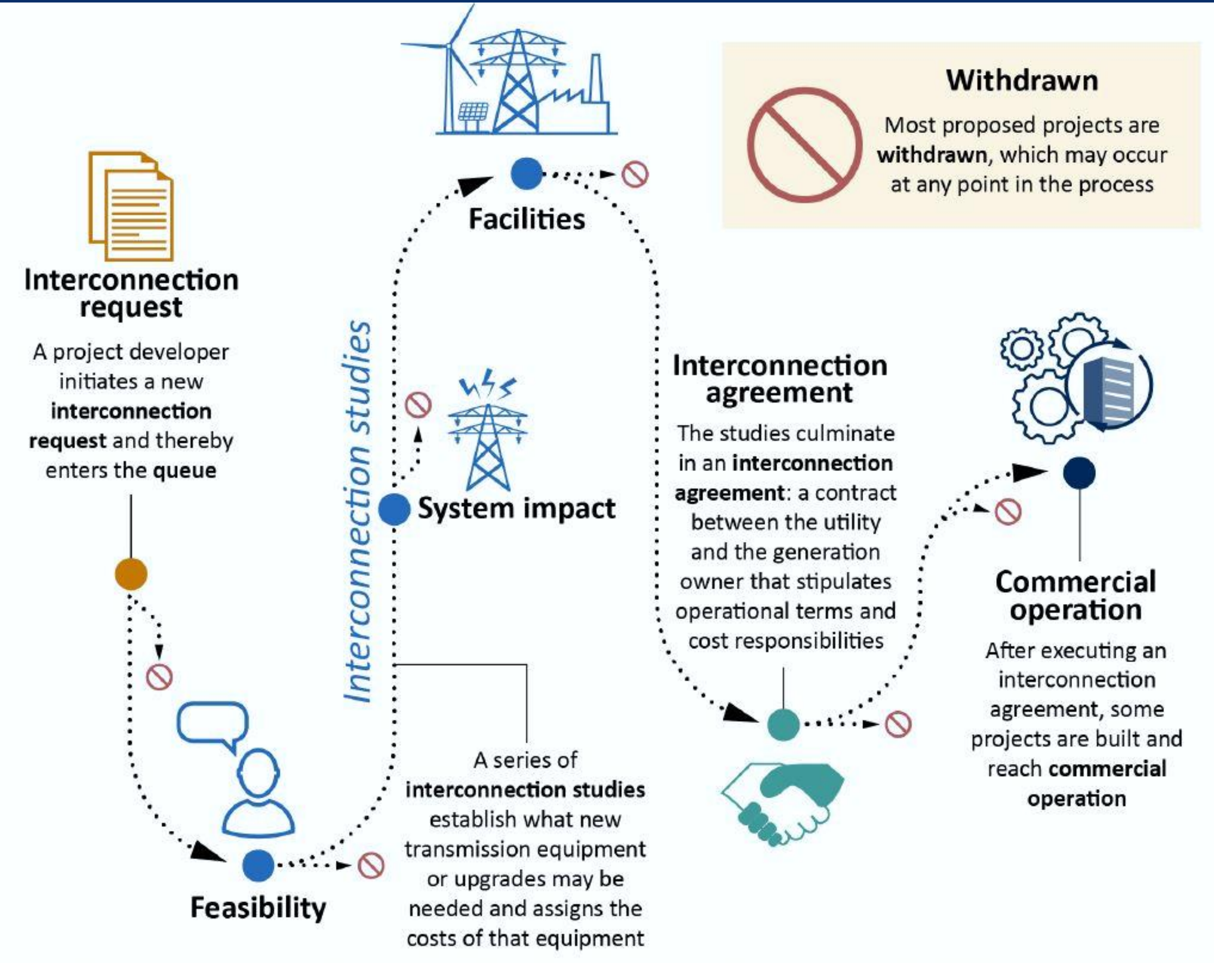
The completion rate is even lower when calculated in terms of proposed capacity [14%].

Solar projects have a lower than average completion rate (only 10% of proposed capacity)

One consequence of high withdrawal rates is the need to restudy the projects that remain in the queue, increasing uncertainty in cost outcomes and further elongating the process

Source: Berkeley Lab, "Queued Up". 2023

Evidence of a Problem #1: Increasing timelines



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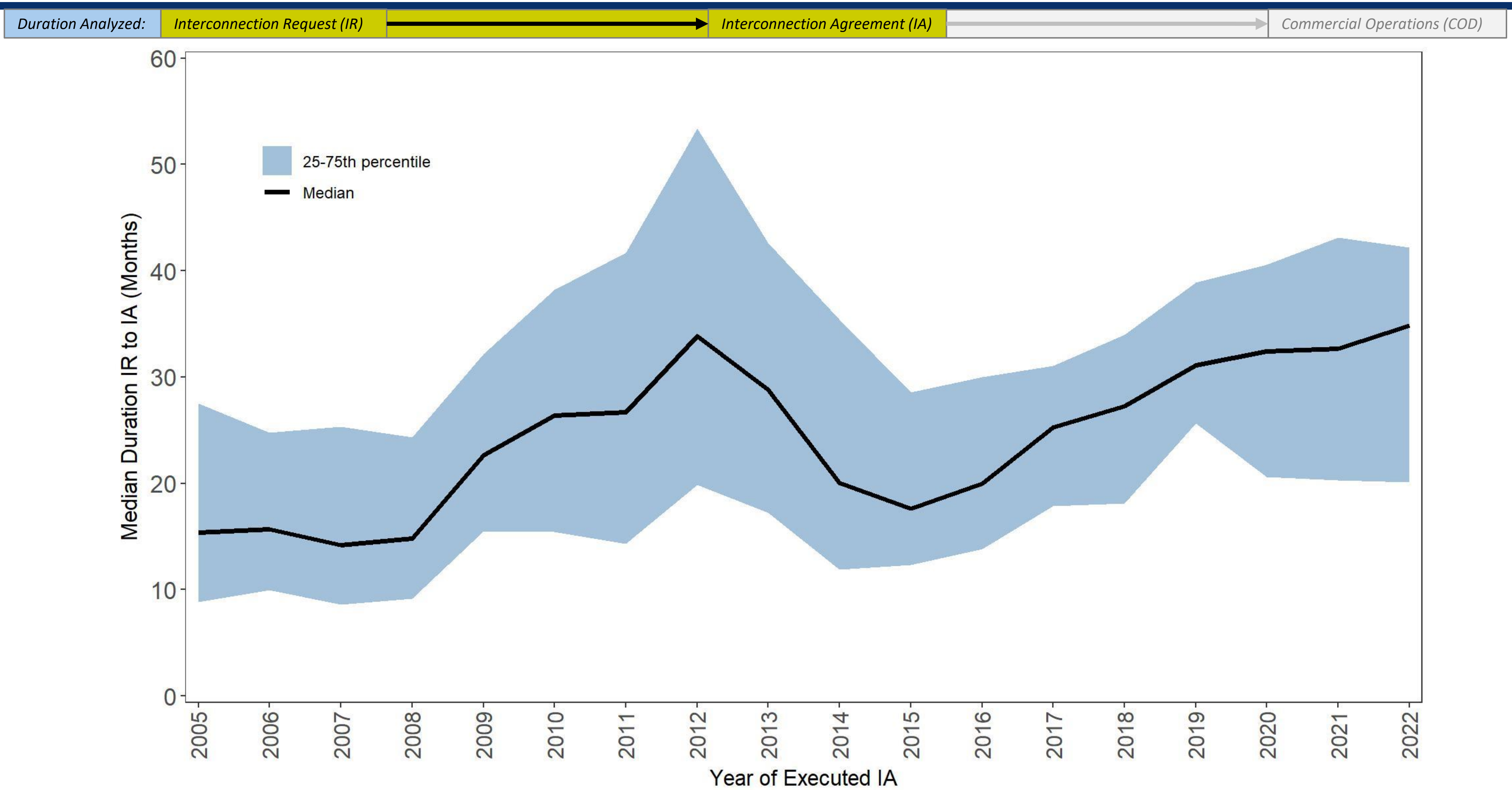
After falling from a 2012 peak, the typical duration from interconnection request (IR) to interconnection agreement (IA) increased sharply since 2015, reaching 35 months in 2022

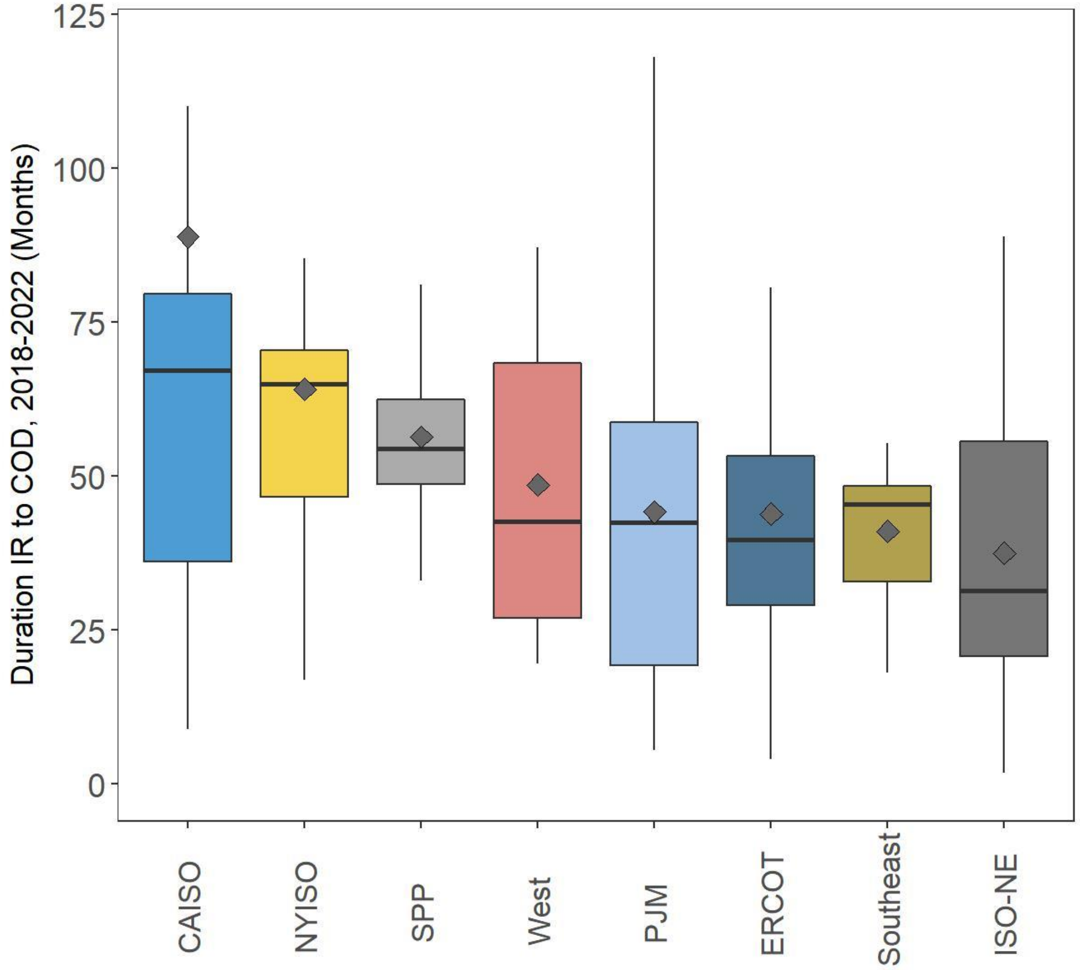


Notes: (1) Sample includes 3,348 projects from 6 ISO/RTOs and 5 non-ISO utilities with executed interconnection agreements since 2005. (2) Not all data used in this analysis are publicly available.

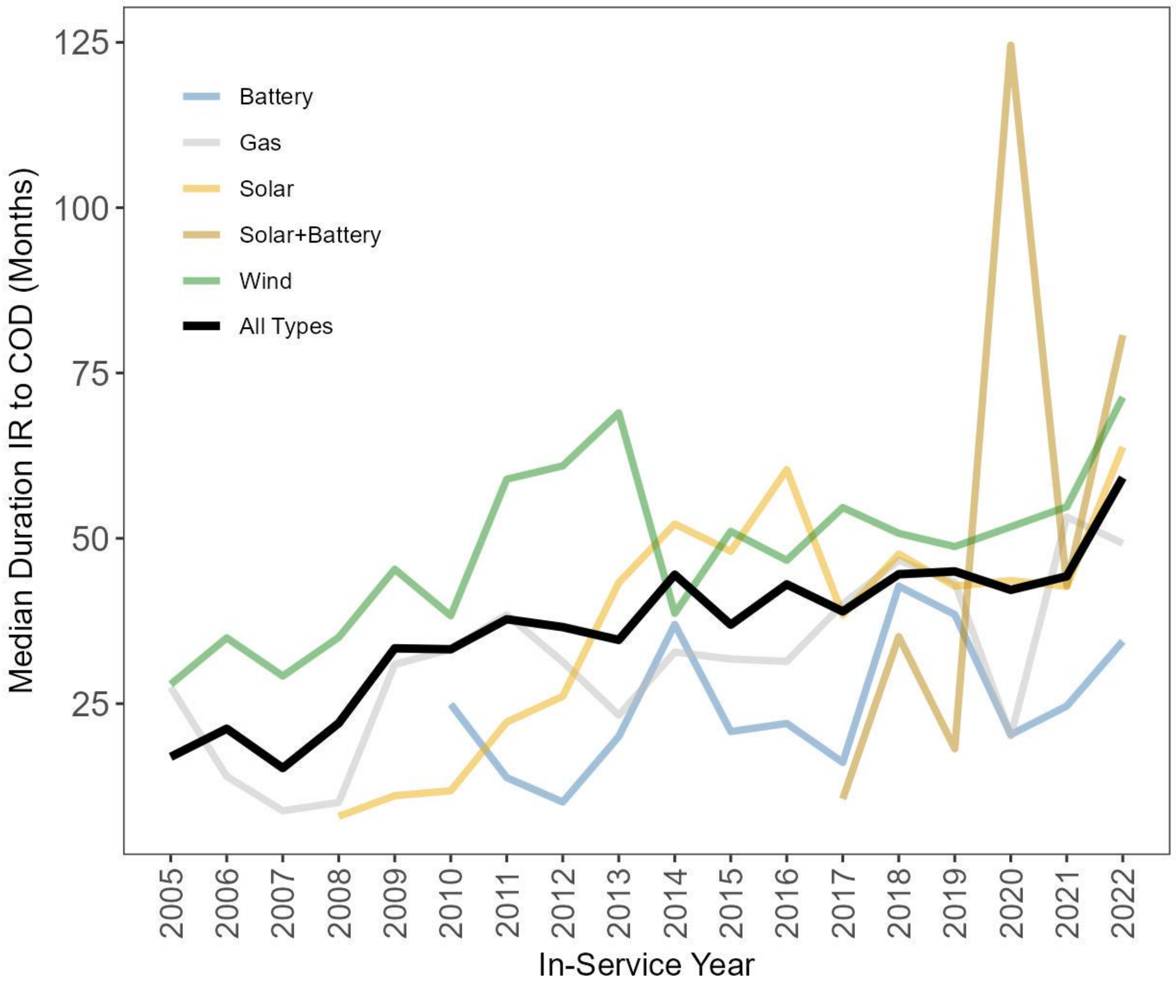
The median duration from interconnection request (IR) to commercial operations date (COD) reached ~5 years for 2022 projects; solar and wind projects take longer than other types

Duration Analyzed: | *Interconnection Request (IR)* → *Interconnection Agreement (IA)* → *Commercial Operations (COD)*

Duration for projects reaching COD from 2018-2022



Median Duration from Interconnection Request to Commercial Operations, by Generator Type



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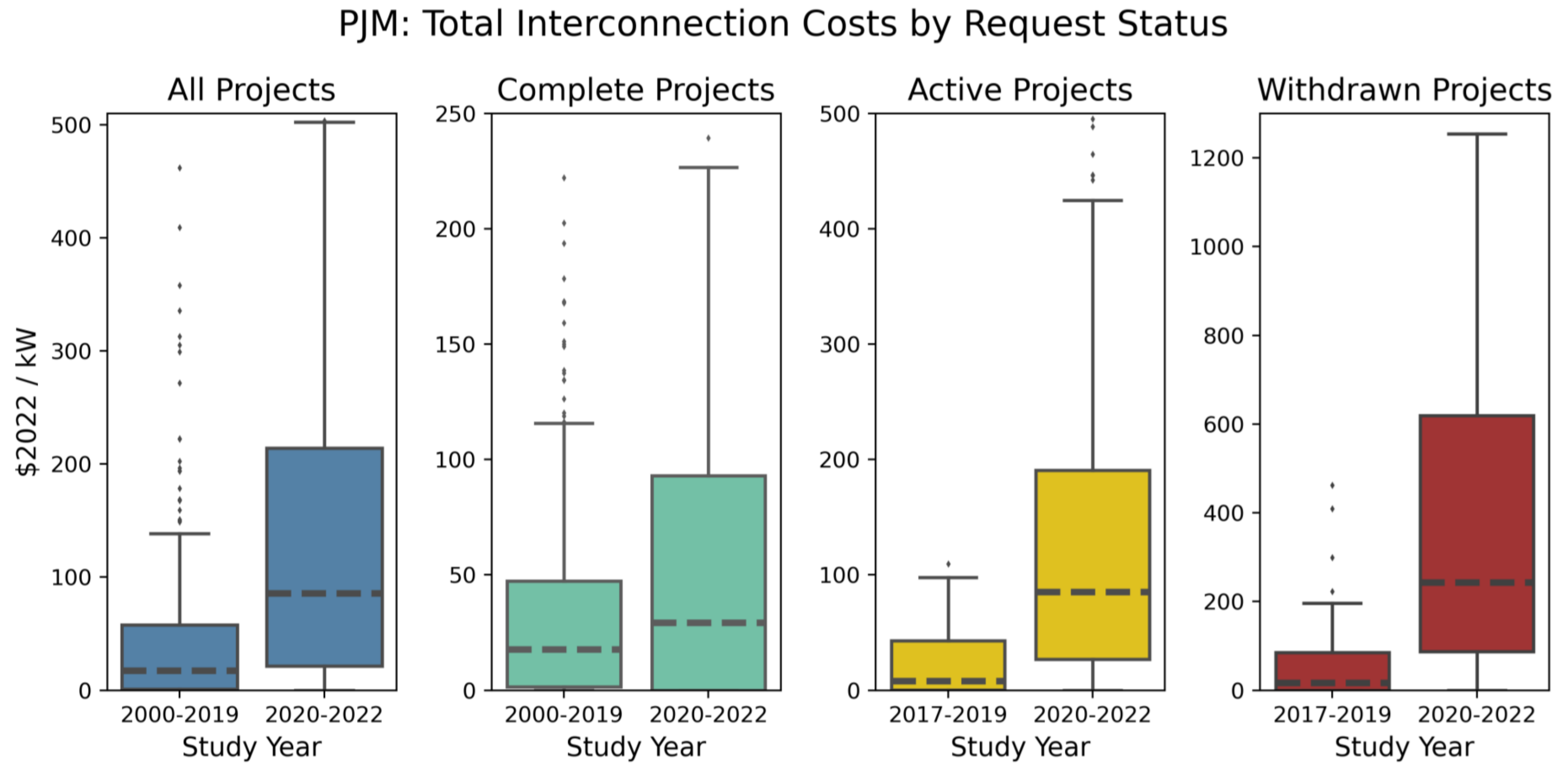
Notes: (1) In-service date was only available for 6 ISOs and 5 utilities representing 58% of all operational projects; . (2) Duration is calculated as the number of months from the queue entry date to the in-service date.

Evidence of a Problem #2: Increasing cost to connect



ISO-specific briefings and underlying project cost data available at
https://emp.lbl.gov/interconnection_costs

Motivation for Interconnection Cost Trends Analysis

- A critical knowledge gap:
  - As interconnection requests balloon, have associated interconnection costs increased as well?
    - Are interconnection costs a serious entrance barrier for low-carbon generation?
  - Interconnection cost data are not easily accessible
    - Information barrier for developers and other stakeholders resulting in less efficient interconnection process
    - Reliable interconnection cost estimates can only be obtained by entering the queue, not as pre-request information
    - Interconnection cost estimates are rarely provided in an easily digestible format
    - i2X team initiated request for EIA to collect comprehensive data on ongoing basis
- Regulatory agencies like FERC and legislators don’t have clear understanding of cost dynamics, impeding effective policies.

Berkeley Lab Provides Interconnection Cost Data + Analysis: Methods

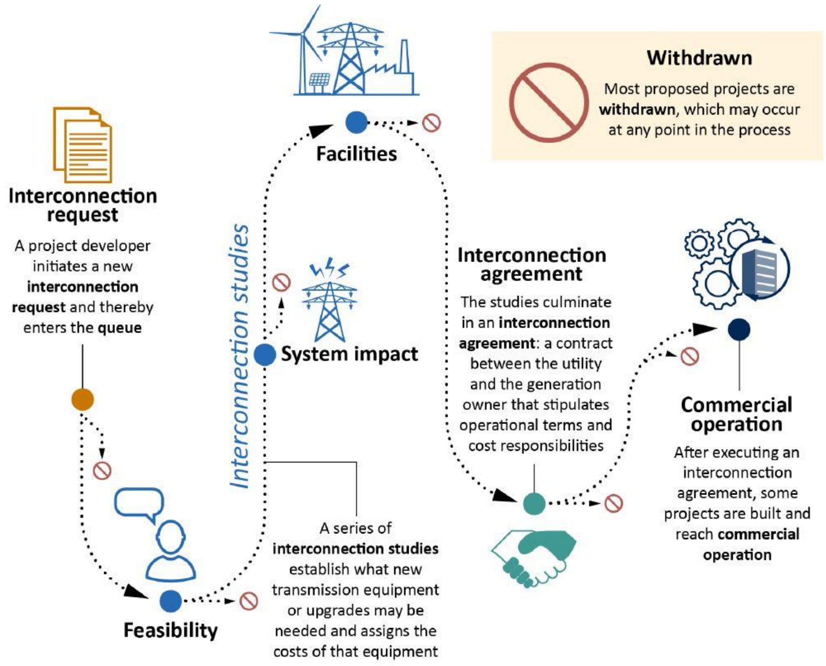
- Collected robust sample of 2500+ project-level interconnection cost estimates in 2022/2023

- Regional coverage: SPP, MISO, PJM, NYISO, and ISONE
  - ERCOT has a “connect & manage” approach with lower interconnection costs
  - CAISO does not disclose project-level interconnection costs
  - Non-ISO regions rarely publish interconnection studies with cost estimates

- Cost data are only a subsample of all projects in the interconnection queues:
  - Interconnection studies are often not yet available for most recent queue entrants
  - RTOs often remove cost publications for older projects
  - Some projects may withdraw before cost estimates are released
  - Focus on new and unique generators (not uprates of existing projects)

- Interconnection cost data are often only available in interconnection studies
  - Require manual scraping: 400-500 person-hours per region

- Temporal coverage: 2000-2023
  - Costs indexed by interconnection study year (not queue entry), real \$2022-terms/kW_{AC} (GDP deflator conversion)
  - Using most recent cost estimate available at time of data collection (mostly spring-summer 2022)



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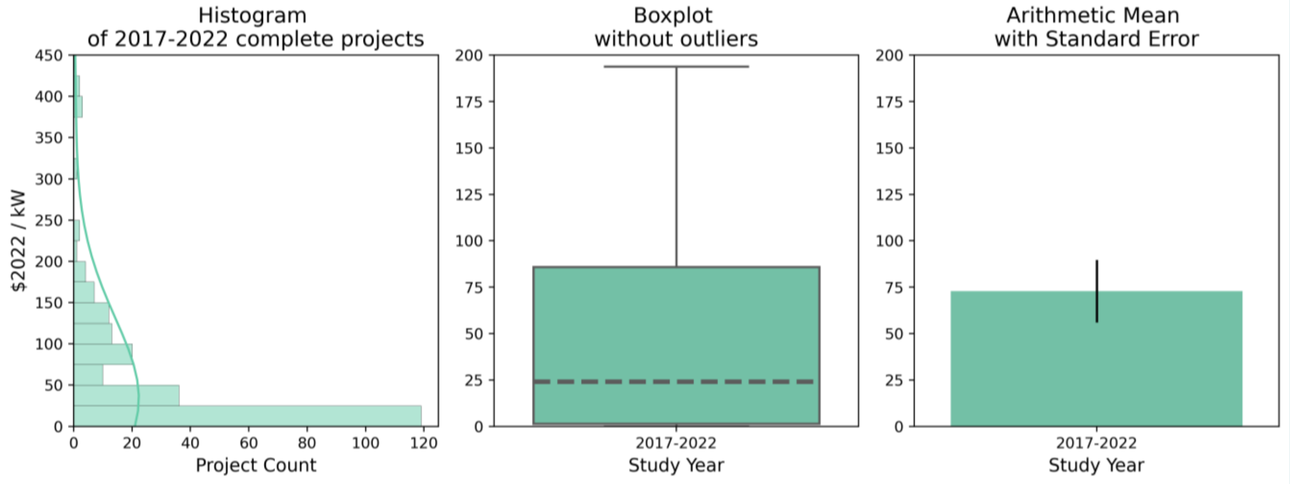
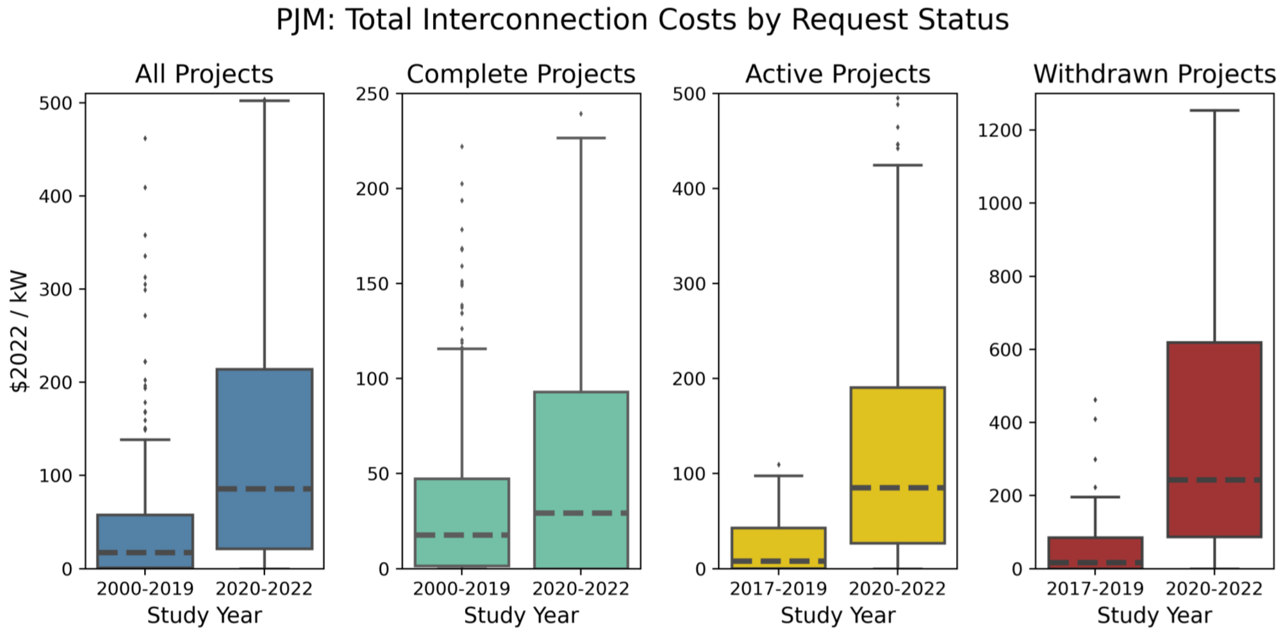
ISO-specific briefings and underlying cleaned cost data collections available at https://emp.lbl.gov/interconnection_costs

PJM example: Interconnection cost data can be quite skewed

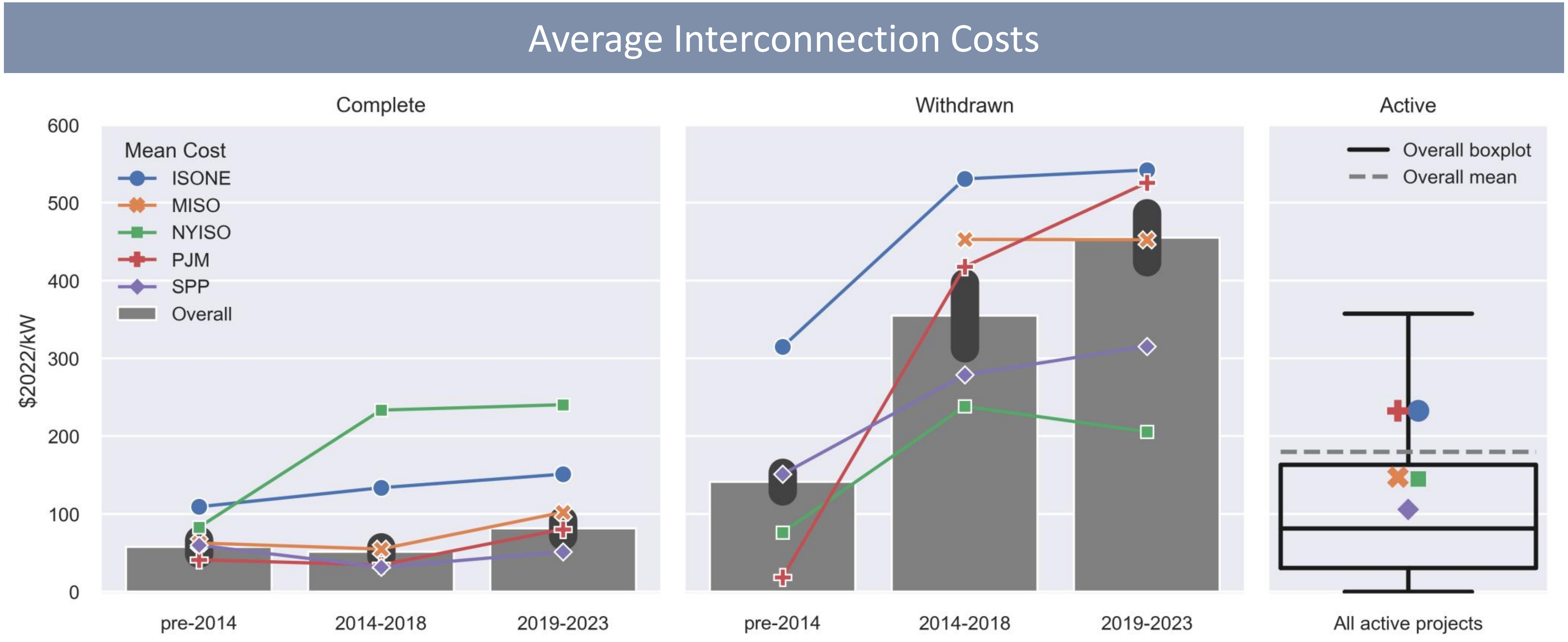


- Cost data often do not have normal distribution:
  - Many projects with very low interconnection costs
  - Some projects with very high interconnection costs that influence sample mean



- Most trends presented today also hold when looking at typical (median) projects:
  - For example, median total interconnection costs have also risen over time for each respective request status

Interconnection costs have grown over time in all studied regions



- Average interconnection costs have grown across regions and request types:
  - Often doubling for projects that have **completed** all studies
  - Projects that **withdraw** have the highest interconnection costs
  - **Active** projects currently moving through the queues have higher costs than those that completed all studies.

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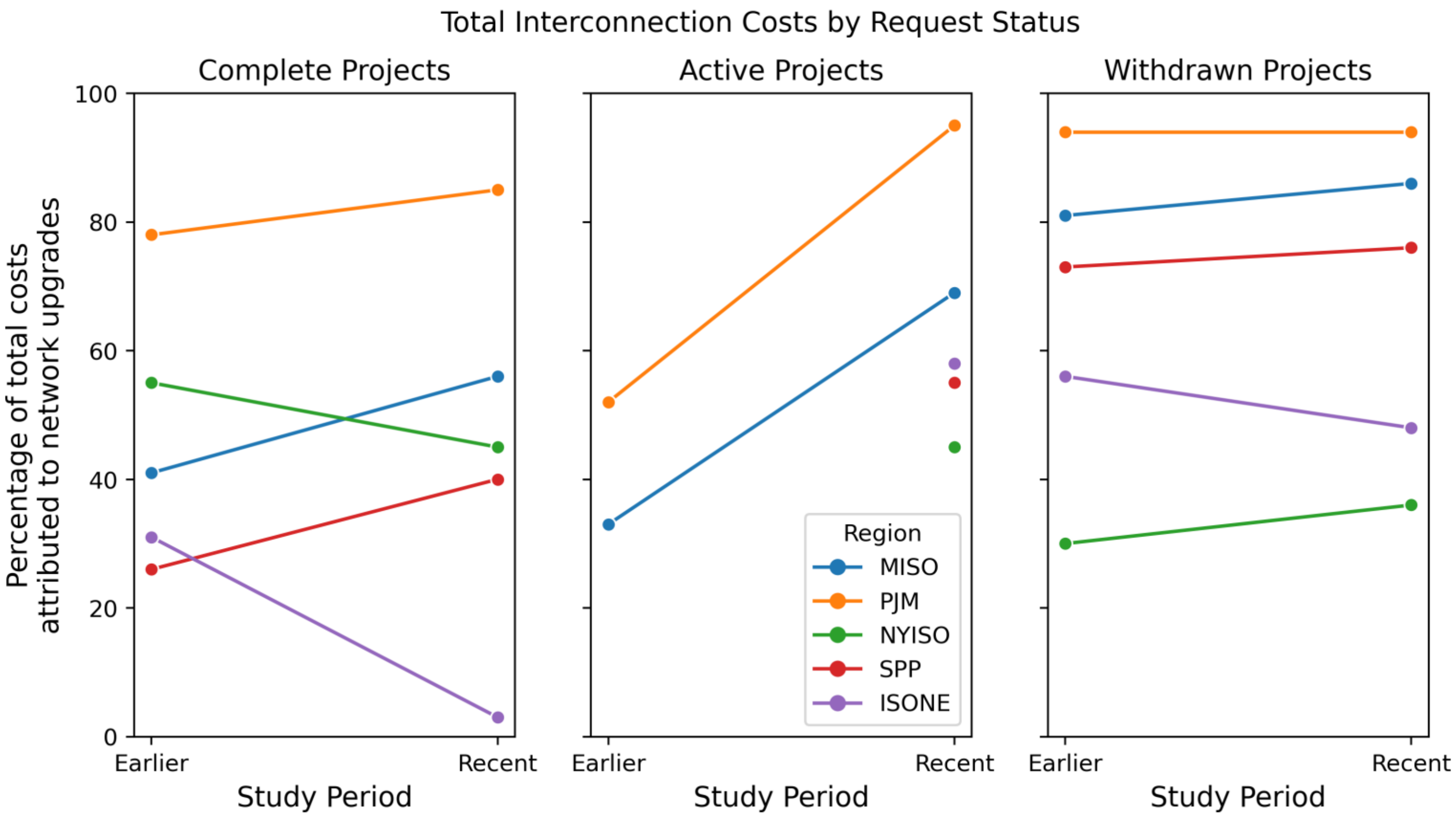
Broader network upgrades triggered by new interconnection requests mostly behind recent cost increases (not local interconnection costs)

Average Network Cost Share of Total Interconnection Costs



Interconnection Cost Components

Point of Interconnection (POI) or Interconnection / Attachment Facilities Costs:

- Interconnection station and transmission line extensions
- Often excludes other infrastructure (step-up transformer, spur lines…)

Network Costs:

- Broader transmission network upgrades triggered by reliability or stability violations caused by a new generator.
- May require modest upgrades (breakers) or reconstruction of several high-voltage transmission lines.
- Costs may be shared by multiple generators that contribute to the upgrade and are usually paid for by project developers in the ISOs that we studied.

Region	"Earlier" period	"Recent" period
MISO	2018	2019-2021
SPP	2010-2019	2020-2022
PJM	2017-2019	2020-2022
NYISO	2006-2016	2017-2021
ISO-NE*	2010-2017	2018-2021

** ISO-NE: Cost components only available for ~50% of analyzed projects*

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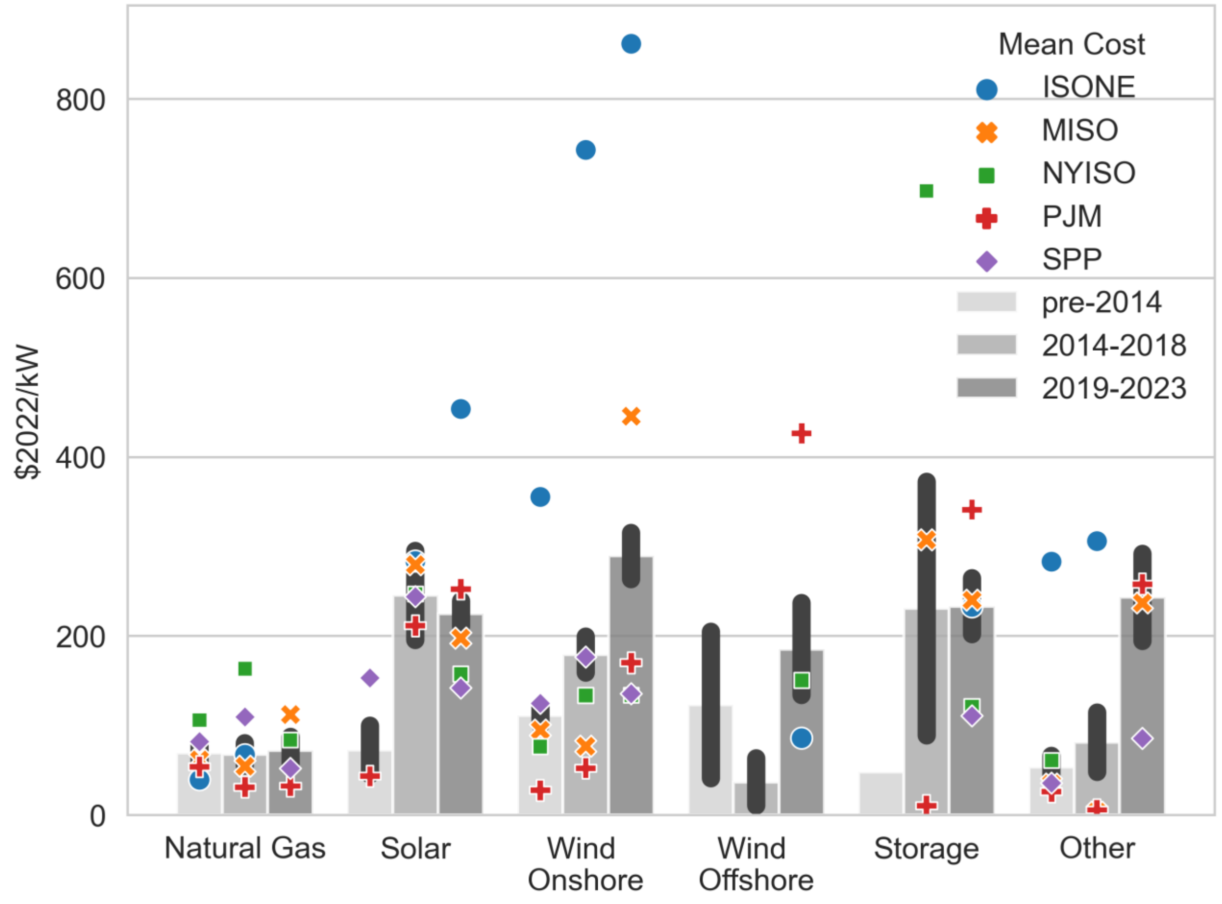
Renewables and storage often face higher interconnection costs than natural gas

Average Interconnection Costs over Time
(includes projects that withdraw application)



Offshore Wind costs exclude transmission investments offshore

- Solar costs are fairly consistent across regions:
  - Completed: 5-10% of total project Capex
  - Withdrawn: 20-40%
- Wind costs have greater variation:
  - Completed: 3%-16% of total project Capex
  - Withdrawn: 10%-40%
- Storage expensive despite (or because of?) its locational flexibility

Hypothesis:
Renewables are often located in more rural areas where the existing transmission system is weaker, requiring costlier network upgrades.

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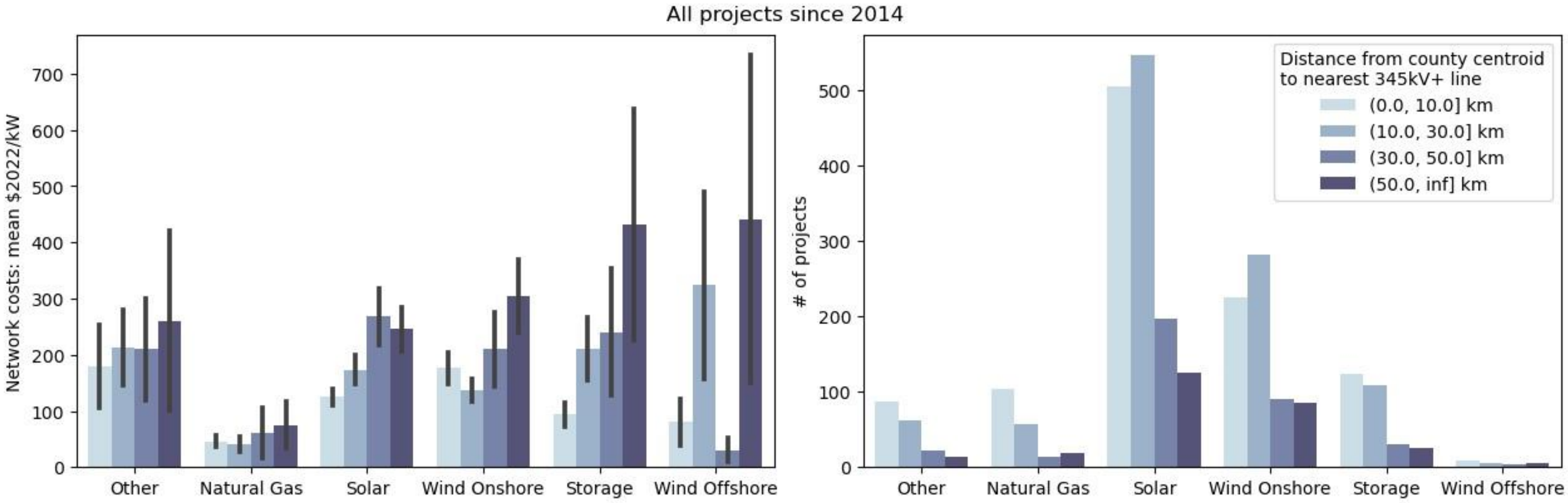
Preliminary investigation shows increasing interconnection costs with project distance to high voltage lines, but it does not explain cost variation by resource type



- Network upgrade costs rises with the distance between project location (approximated by county centroid) and nearest high-voltage transmission line

- But natural gas generators have lower upgrade costs than renewables when accounting for the distance

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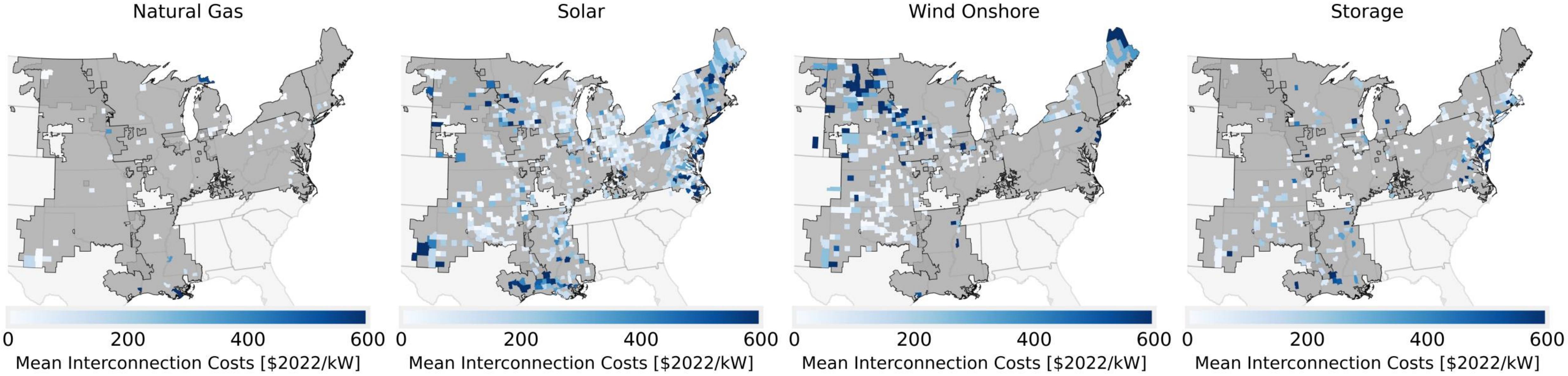
Wind and solar projects in the queues have a wide geographic footprint and include high-cost locations where no or fewer natural gas projects are located

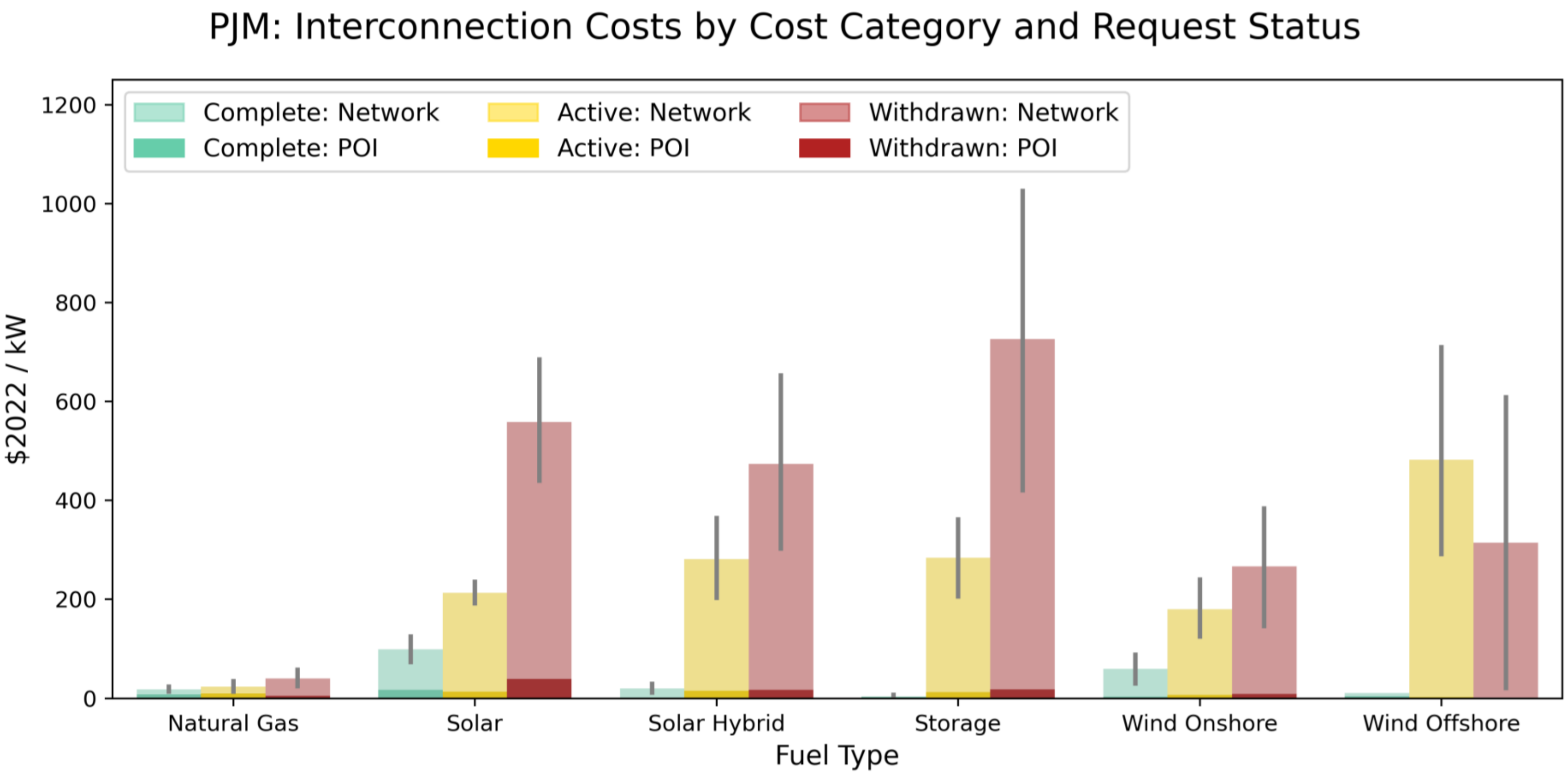
Interconnection Costs 2019-2023 (includes projects that withdraw application)



- Proposed wind and solar generators have a much wider geographic footprint than natural gas

- Natural gas has fewer proposed projects in high-cost areas such as northern SPP, southern MISO, northern ISONE

PJM: Network upgrade costs drive interconnection expenses for renewables, especially for active and withdrawn projects



- POI costs don't vary much, but network costs increase dramatically for active and withdrawn projects.

- Interconnection costs are modest for complete projects, but are a development hurdle for those that withdraw:
  - **Wind:** 4% vs. 19% of total project capex
  - **Solar**: 7% vs 38% of total project capex

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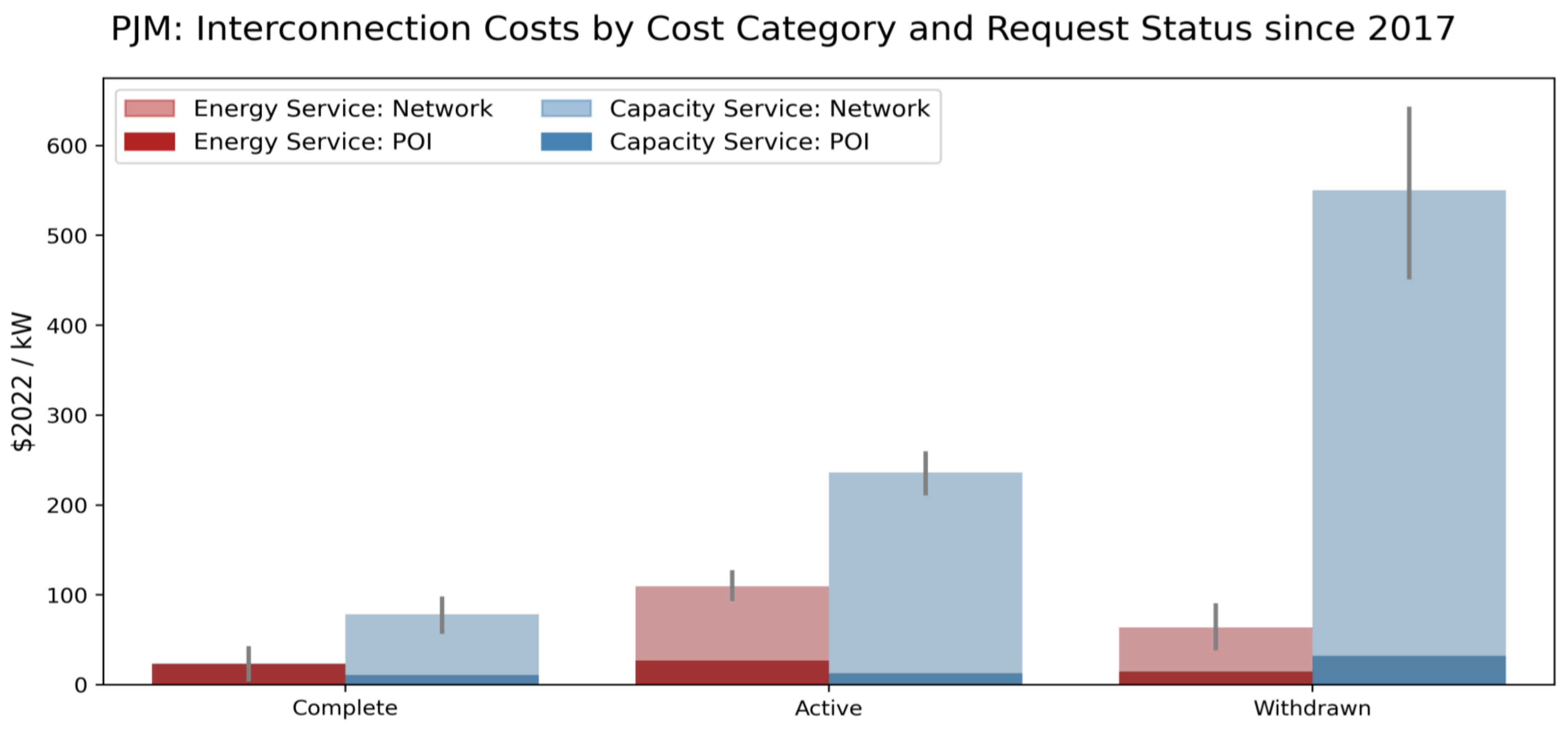
PJM: Most generators request capacity interconnection services at higher costs

Interconnection Service Definitions

Capacity (Network resource interconnection service, **NRIS**): Transmission capacity reservation during high load hours, needed for bidding into resource adequacy markets. May need to pay for additional transmission upgrades.

Energy (Energy resource interconnection service, **ERIS**): May be curtailed before capacity resources during emergency events.

- Nearly all generators choose capacity service (2017-2022: 95% of all projects)
- Network costs for projects with capacity service have risen more than tenfold since 2017 (from $17/kW to $206/kW)



Key Takeaways:

As of the end of 2022, there were over 10,200 projects seeking grid interconnection across the U.S., representing over 1,350 GW of generation and an estimated 680 GW of storage.

- Queues:
  - The combined capacity of solar and wind now active in the queues (1,250 GW) approximately equals the total installed U.S. power plant fleet capacity, and is greater than the estimated 1,100 GW needed to approach a zero-carbon electricity target[2].
    - Solar (947 GW) accounts for >70% of all active generator capacity in the queues, though substantial wind (300 GW) capacity is also in development.
    - Considerable standalone (325 GW) and hybrid (~358 GW[1]) storage capacity has also requested interconnection.
  - Queue backlogs are resulting in longer timelines and delays. The median duration from request to commercial operations now exceeds 5 years.
  - Most of this proposed capacity will not be built. Historically only ~21% of projects (and only 14% of capacity) requesting interconnection from 2000-2017 have reached commercial operations.
- Interconnection costs:
  - Interconnection costs are not available as pre-request information and even costs of completed studies are challenging to collect
  - Costs have grown over time in all studied regions
  - Upgrade requirements of the broader transmission system are the primary cost driver
  - Many projects facing high interconnection costs withdraw from the queue
  - Renewables and storage projects have higher interconnection costs than natural gas power plants
- FERC has implemented major reforms under Order 2023, but there is room for far deeper reform.

Notes: (1) Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data. (2) See https://gridlab.org/2035-report/ (3) Data for this analysis were available for six ISO/RTOs and five utilities.

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More Information:

- Visit https://www.energy.gov/eere/i2x to learn about and participate in the DOE's i2X program
- Visit https://www.energy.gov/eere/i2x/articles/request-information-transmission-system-interconnection-roadmap-draft to comment on the i2x Roadmap
- Visit https://emp.lbl.gov/queues interconnection queue analysis and data
- Visit https://emp.lbl.gov/interconnection_costs for research on generator interconnection costs

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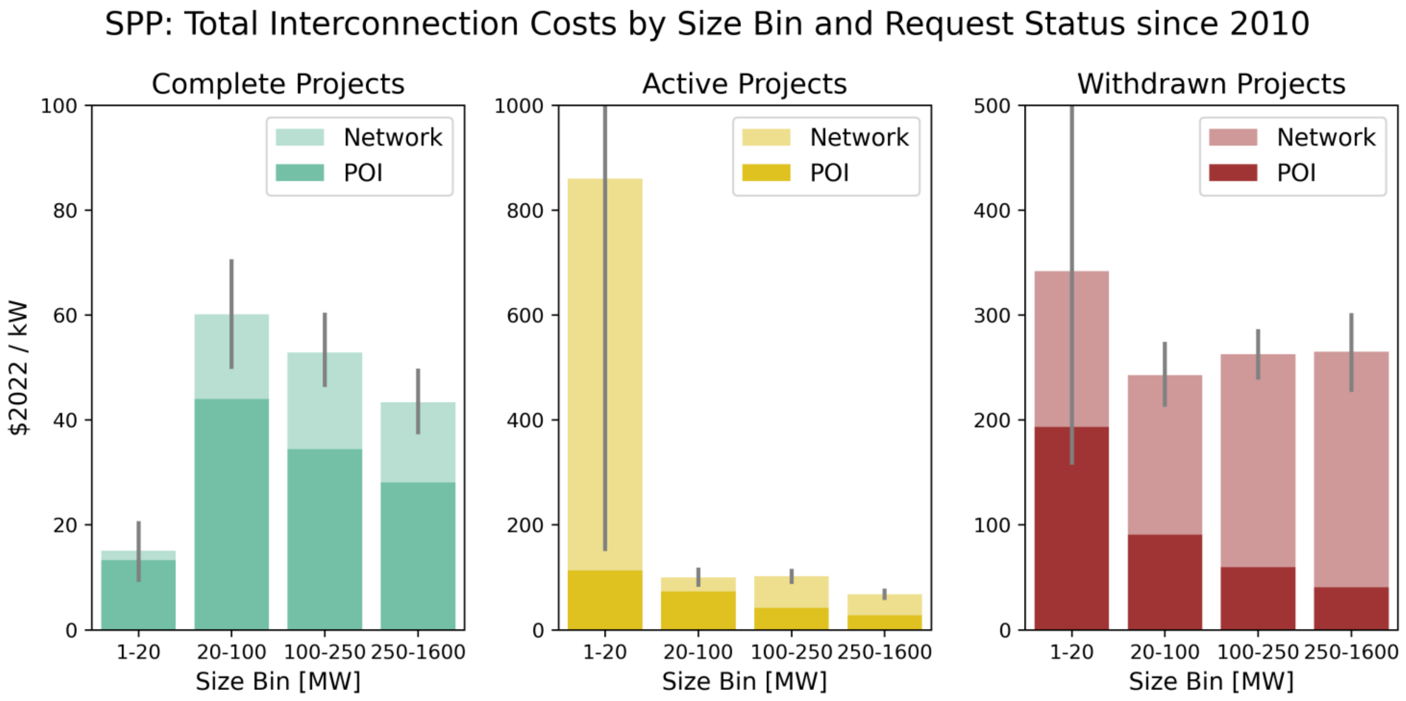
Appendix

SPP: Larger complete generators have lower interconnection costs per kW, especially wind projects

Projects with larger nameplate capacity have greater interconnection costs in absolute terms, but these costs do not scale linearly on a per kW basis for complete projects, falling from $60/kW (medium), $53/kW (large), and $43/kW (very large project size).



- Economies of scale are only present for complete projects but not withdrawn projects, driven by declining POI costs (network costs are stable or increase for withdrawn projects).

- No consistent economies of scale across all fuels. Only among complete projects do we see some evidence for wind and solar, but not for natural gas:

Fuel	1-20 MW	20-100 MW	100-250 MW	250-675 MW
Natural Gas	$20/kW	$6/kW	$52/kW	$26/kW
Solar		$90/kW	$85/kW	
Onshore Wind	$8/kW	$61/kW	$47/kW	$44/kW

NYISO: Costs tend to increase as projects complete more studies

- From Feasibility to System Impact studies:
  - $16/kW average increase
  - Increase between 25% and -5% for majority of projects
  - Mostly network costs
- From System Impact to Facilities studies:
  - $28/kW average increase
  - ≥100% cost increase for more than 25% of projects
  - ≥50% cost change (up or down) for around 50% of projects
  - Increases at POI and in broader network
- **Costs for active projects will likely increase as they progress**

Interconnection cost increase between consecutive studies (mean)