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Queued Up: Status and Drivers of Generator Interconnection Backlogs

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Transmission and Interconnection Summit

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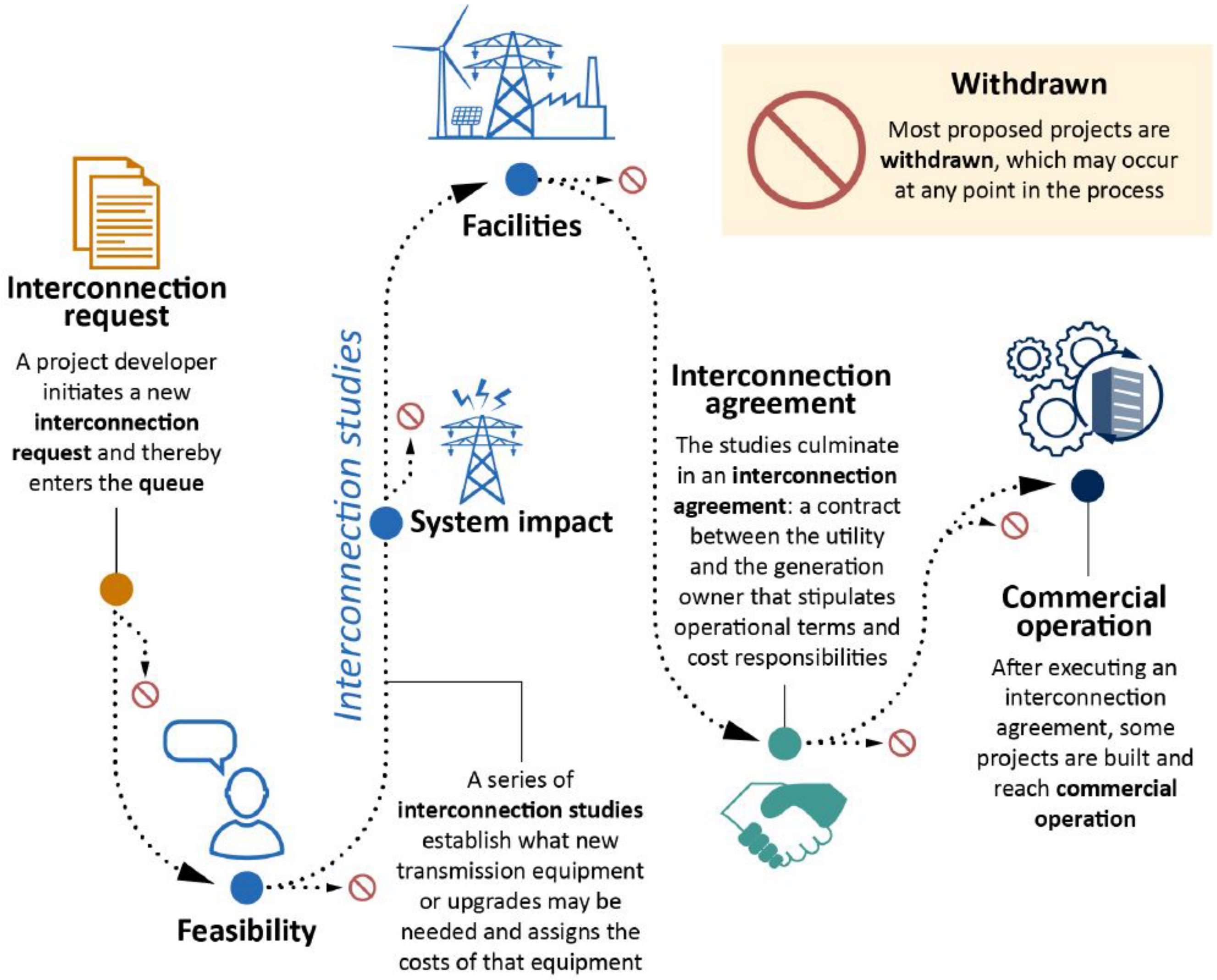
Outline

- Current status of U.S. interconnection queues
- Evidence of a problem:
  - 1. Delays and bottlenecks
  - 2. Increasing interconnection costs
- Looking ahead: Reforms and solutions

NOTE: Focus on transmission interconnection, not distribution/DER interconnection

Thanks to DOE, and especially the i2X program, for supporting this work

Current grid interconnection process was designed in 2003 for an electricity system with fewer, larger, centralized power plants



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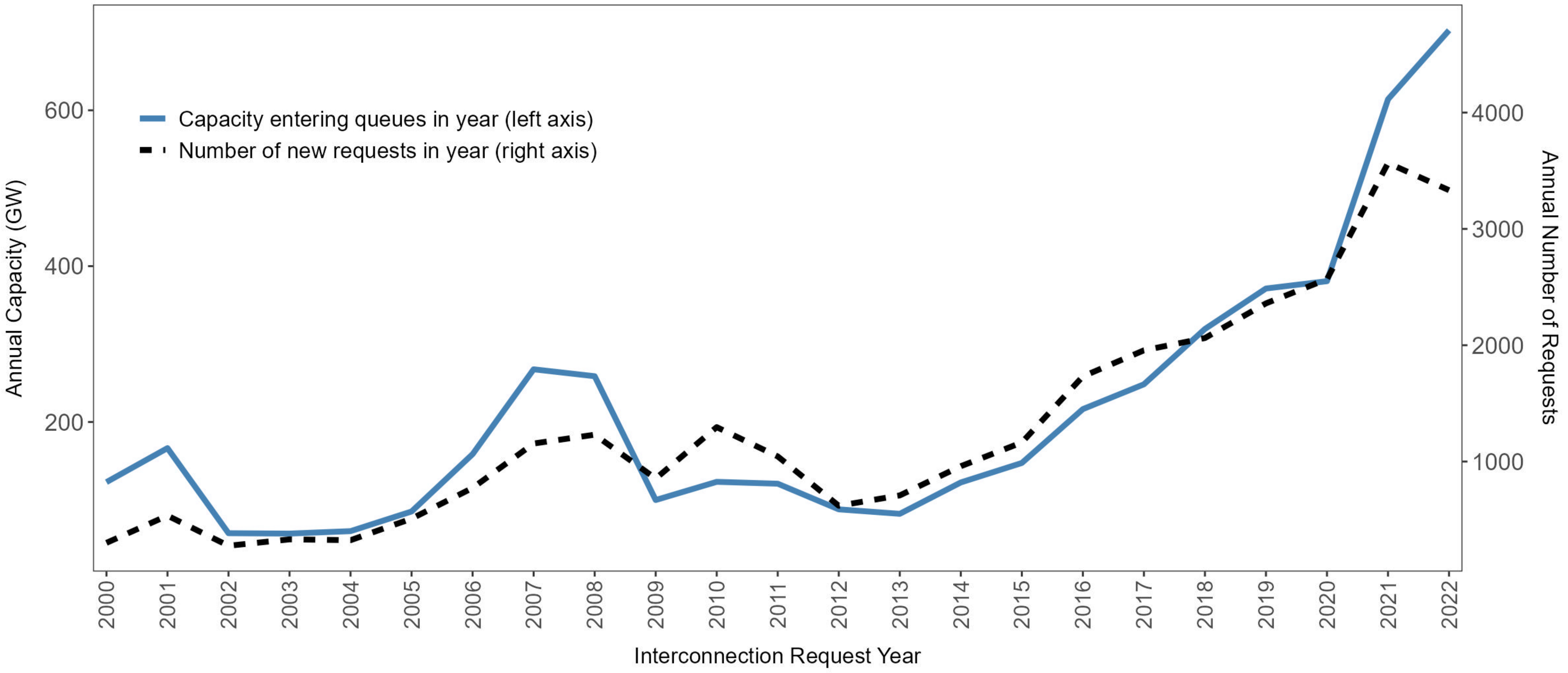
- Transmission grid operators require new projects looking to connect to the grid to undergo a series of impact studies
- These studies determine the grid upgrades necessary to allow projects to connect safely and reliably, and allocate the cost of those upgrades
- Withdrawals can result in multiple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

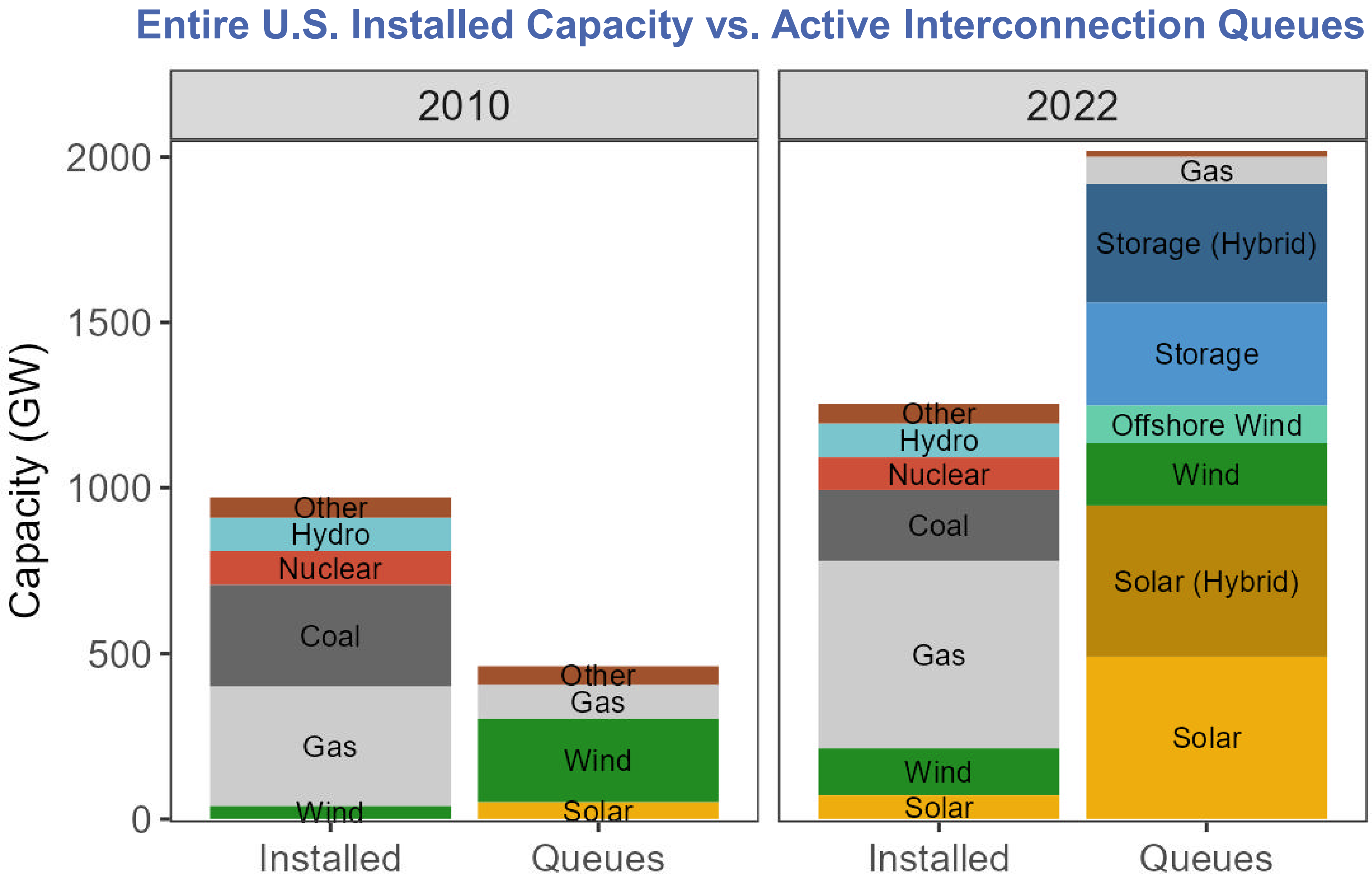
There has been a substantial increase in annual interconnection requests (both in terms of number and capacity) since 2013; over 700 GW added in 2022 alone



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Notes: (1) This total annual volume includes projects with a queue status of "active", "suspended", "withdrawn", or "operational".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 grid interconnection queues (~2,000 GW) exceeds the installed capacity of the entire U.S. power plant fleet (~1,250 GW)

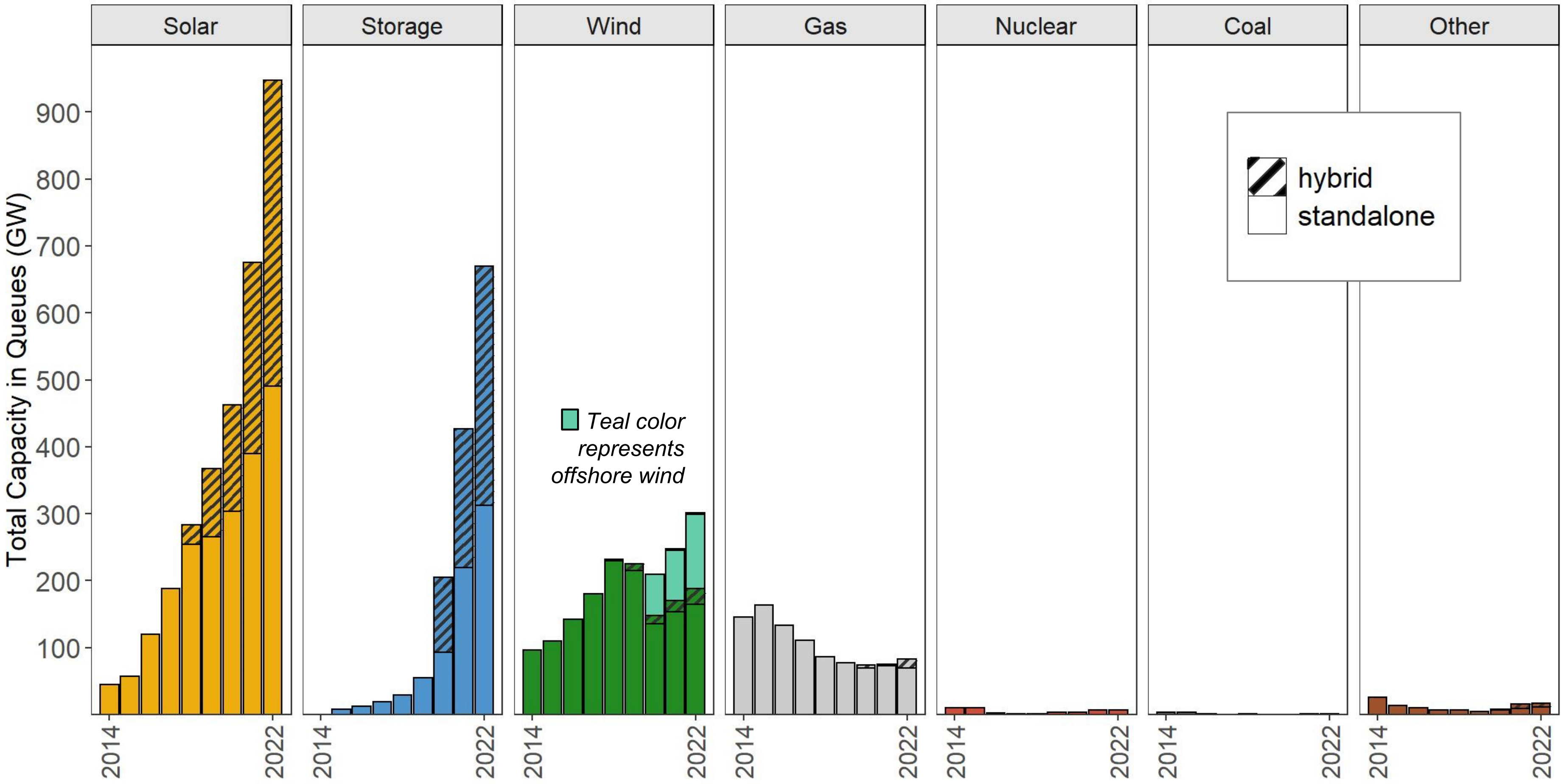


More than 95% of active capacity in interconnection queues is zero-carbon

Source: Berkeley Lab, "Queued Up". 2023

Notes: (a) Hybrid storage in queues is estimated for some projects. (b) Total installed capacity from EIA-860, December 2022.

Especially strong developer interest in solar (~947 GW) and storage (~680 GW); Hybrid plants represent a large fraction of proposed solar and storage

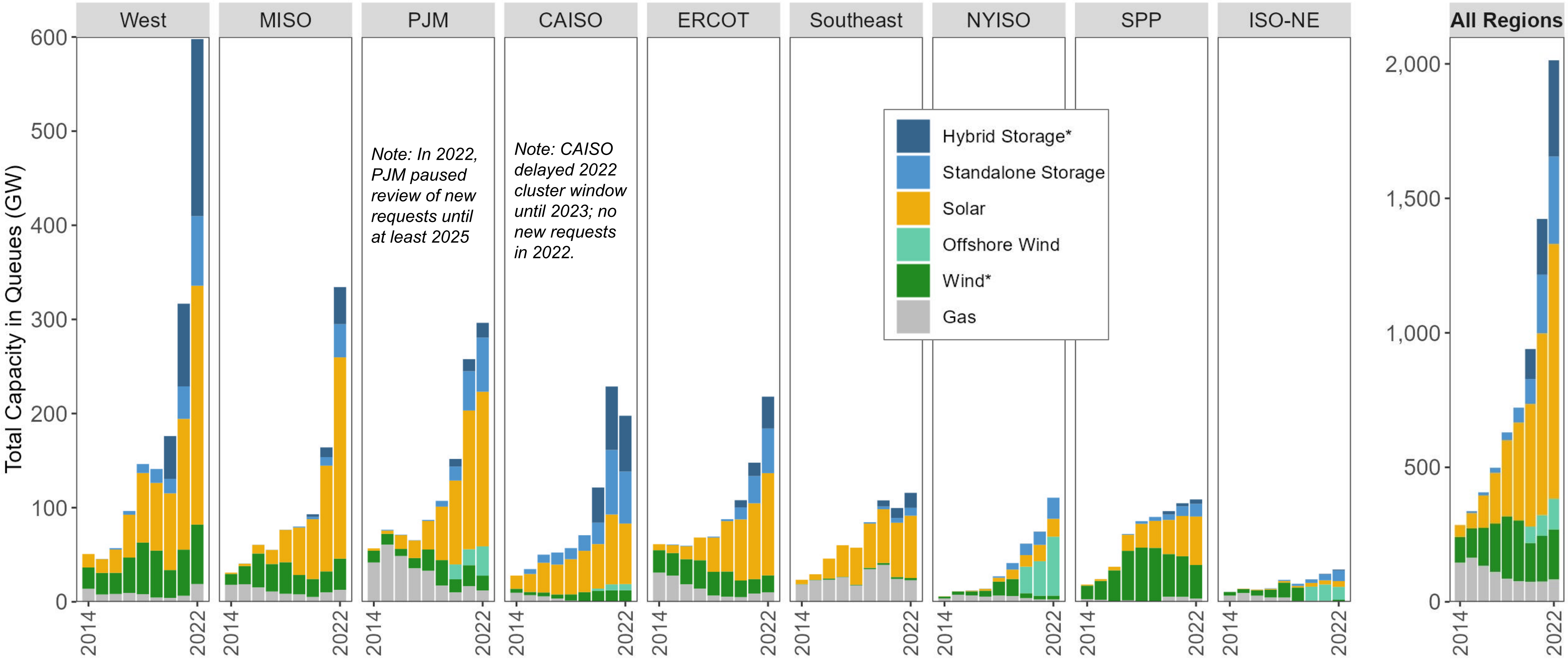


- "**Wind**" includes both onshore and offshore.
- "**Other**" includes
  - Hydropower
  - Geothermal
  - Biomass/biofuel
  - Landfill gas
  - Solar thermal
  - Oil/diesel
- "**Storage**" is primarily (99%) battery, but also includes pumped storage hydro, compressed air, gravity rail, and hydrogen.

See https://emp.lbl.gov/queues to access an interactive data visualization tool.

*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.*

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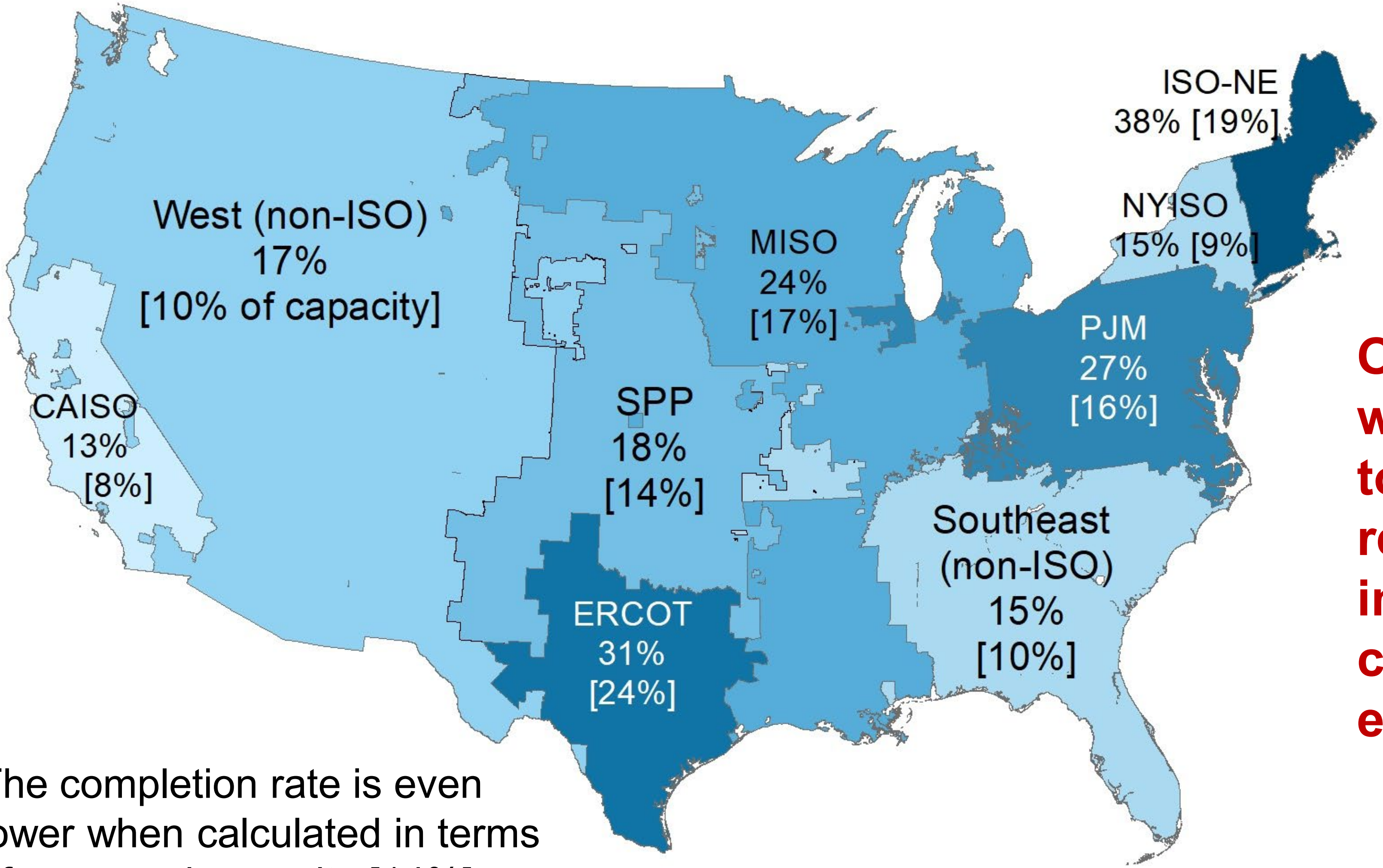
Only 21% of projects that applied for interconnection prior to 2018 have been built – 72% have been withdrawn (7% are still actively trying!)

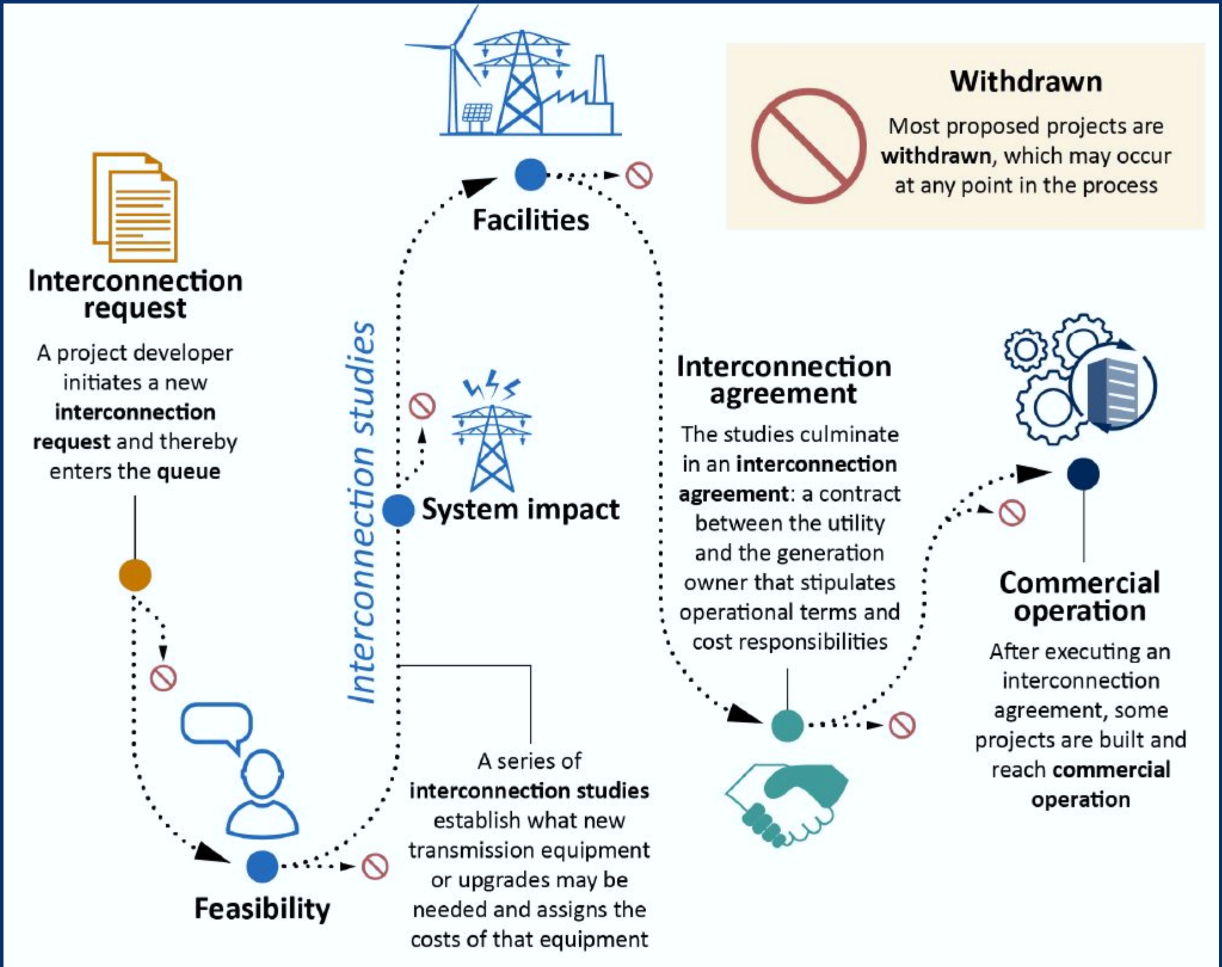


One consequence of high withdrawal rates is the need to restudy the projects that remain in the queue, increasing uncertainty in cost outcomes and further elongating the process

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

Source: Berkeley Lab, "Queued Up". 2023

Evidence of a Problem #1: Increasing timelines



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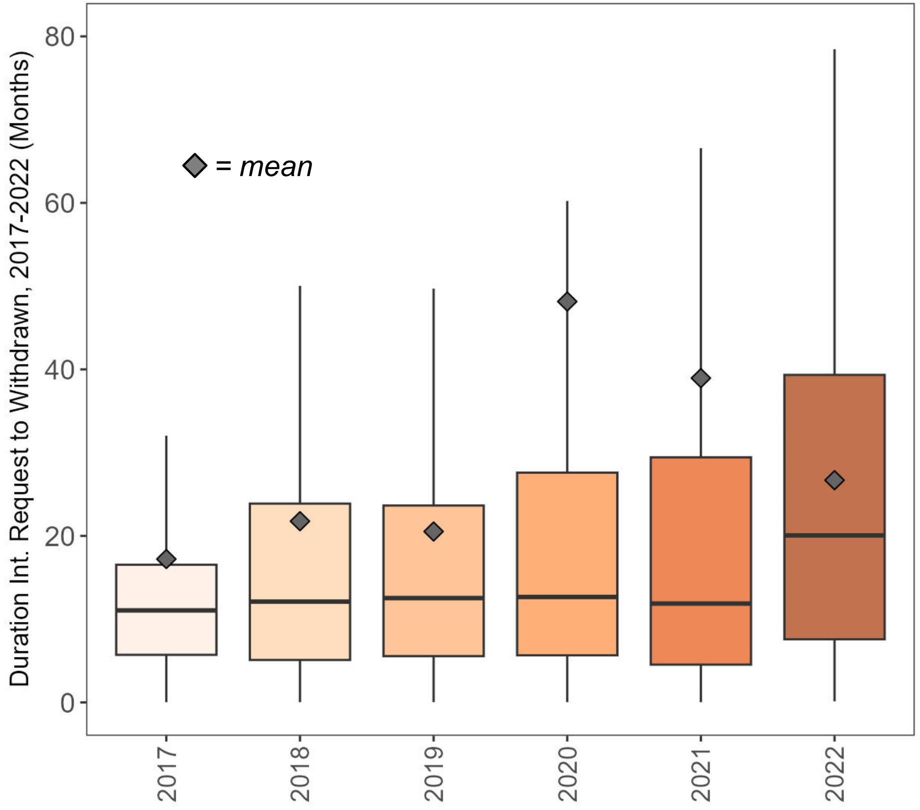
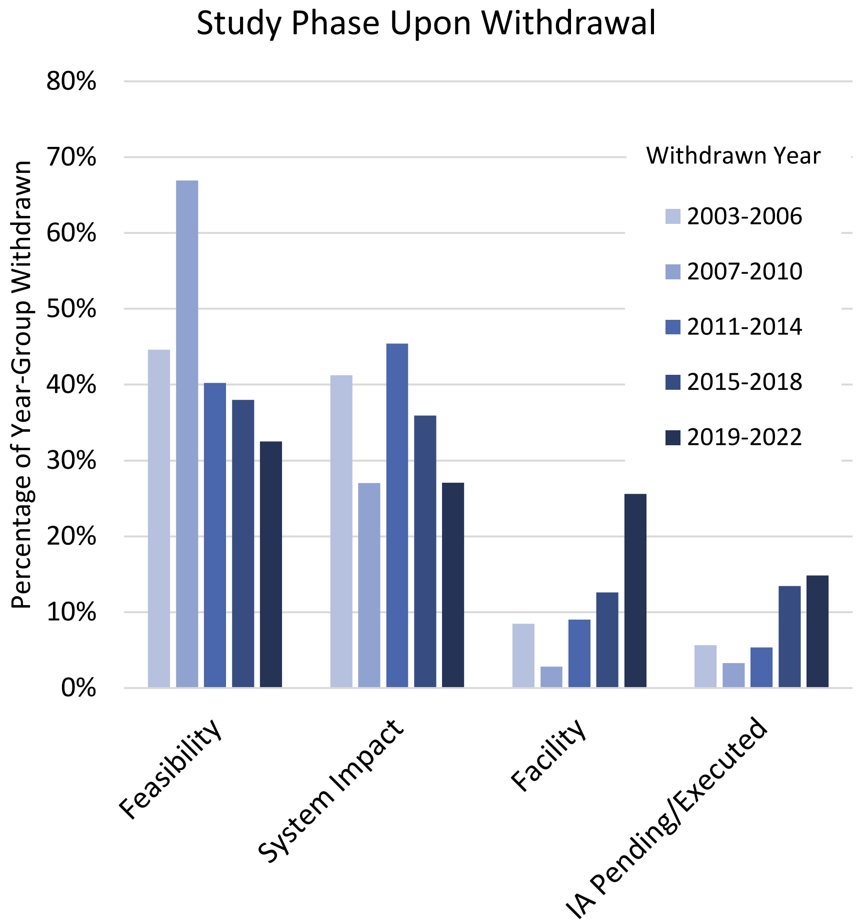
The mean duration prior to withdrawing has edged higher in recent years; later-stage withdrawals are becoming more common

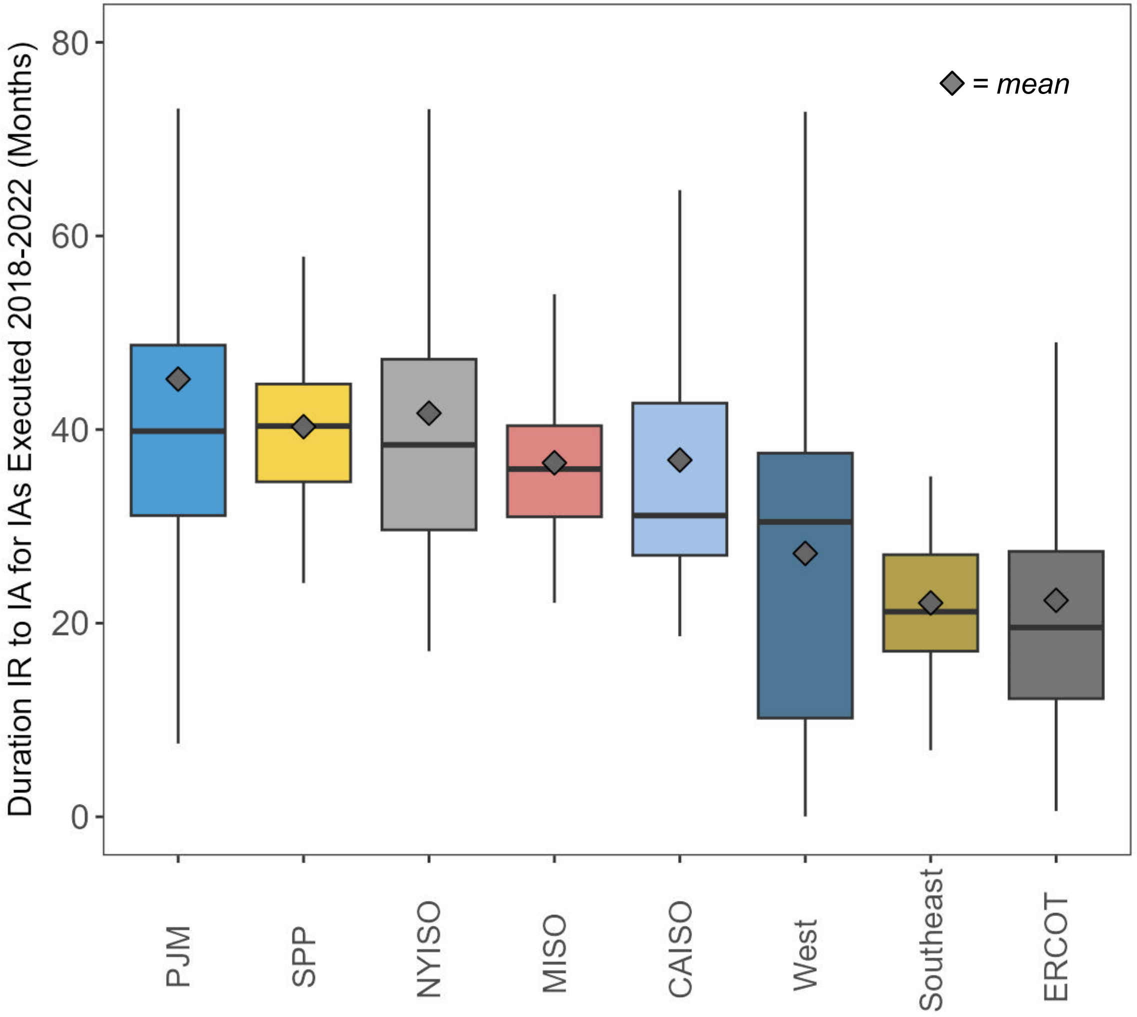
Duration Analyzed:	Interconnection Request (IR)	→	Withdrawn Date	→	Commercial Operations (COD)

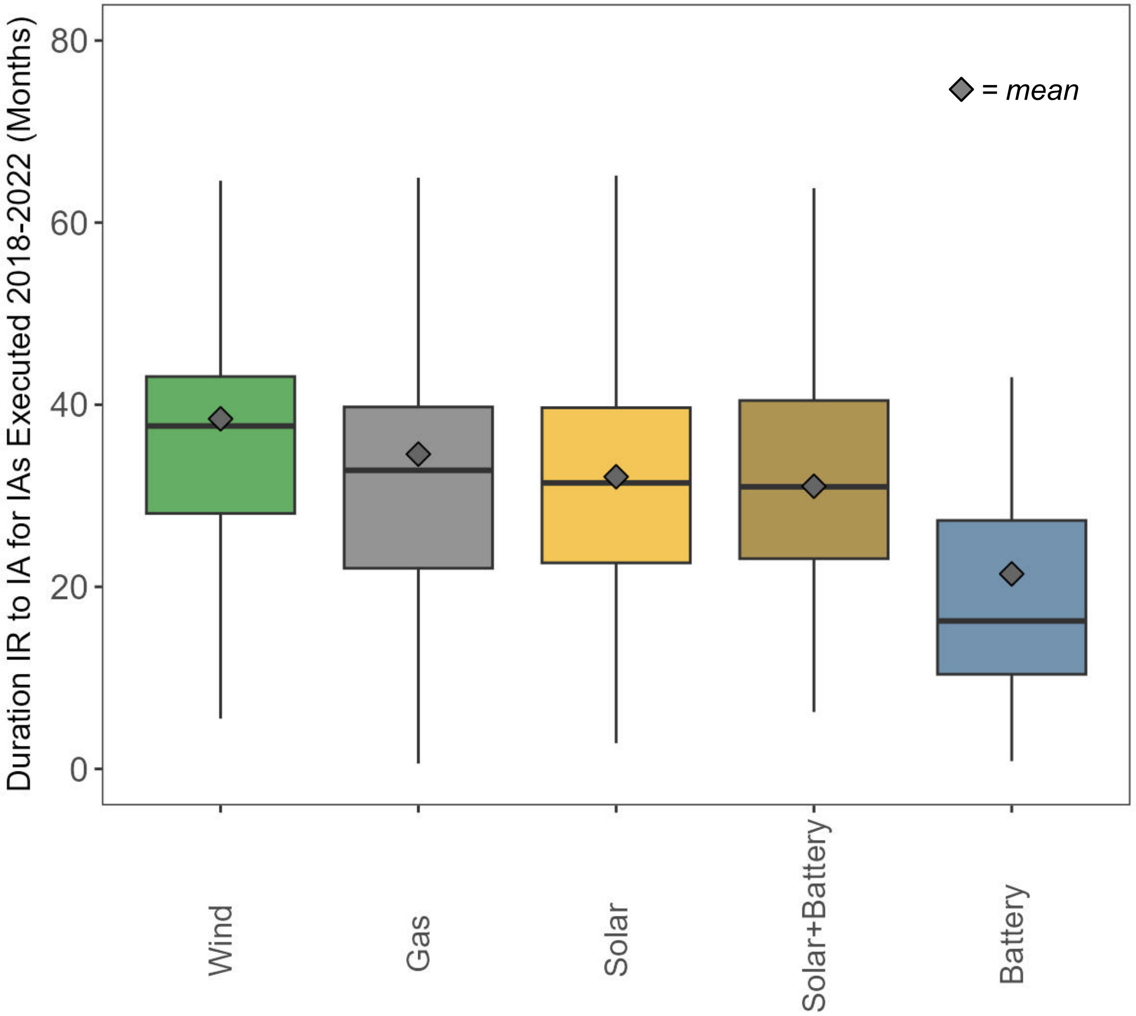




- Some recently-withdrawn projects are waiting longer in the queues before making the determination to withdraw
- Later stage withdrawals can be costly for developers and can disrupt assumptions built into other projects' interconnection studies, necessitating re-studies in some cases and increasing study durations

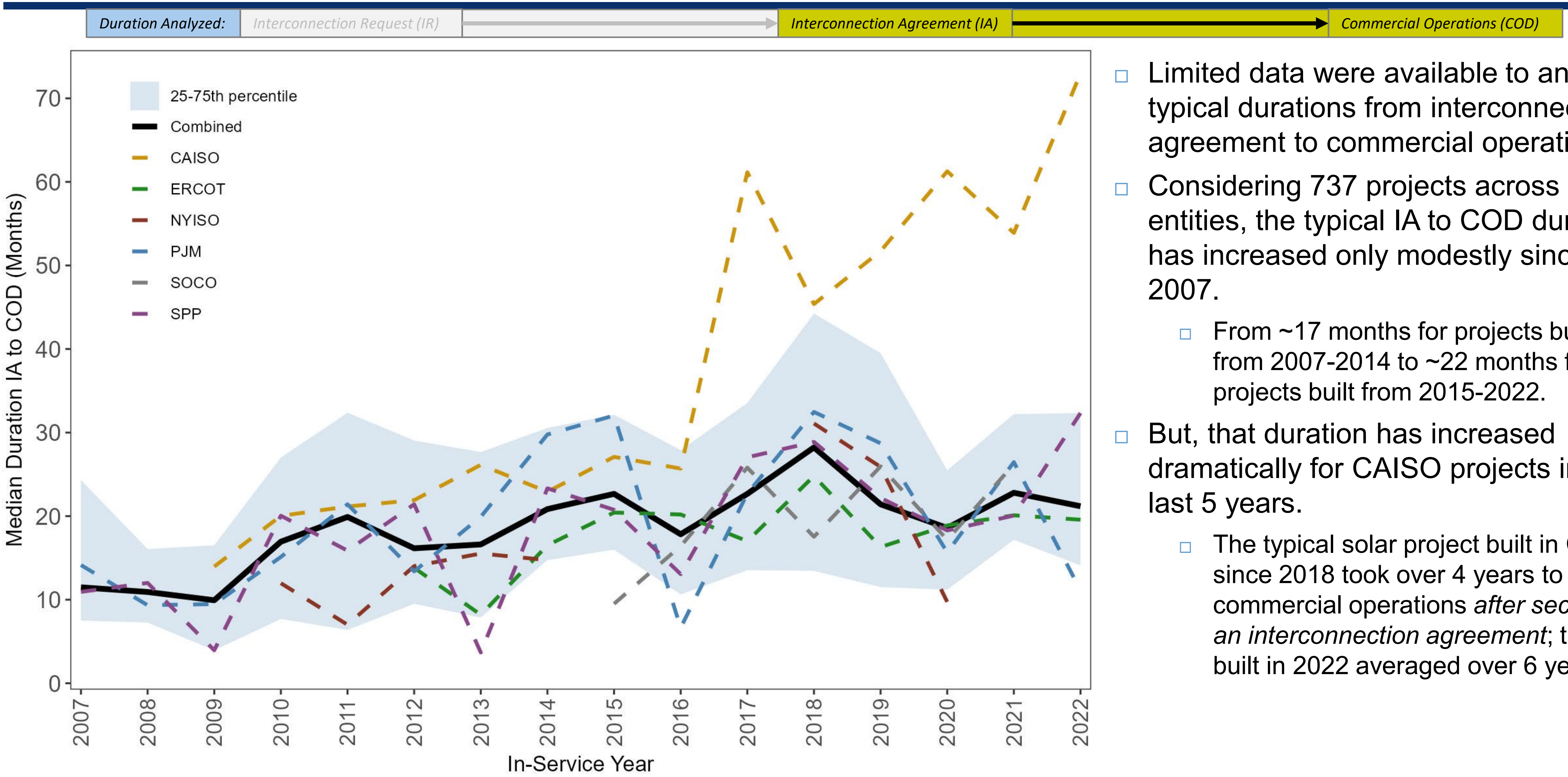
Study duration exceeds 3 years in most grid operating regions; ERCOT and Southeast are faster. Battery projects tend to be processed more quickly than other types





Notes: (1) Data are only shown where sample size is >2 for each region and year. (2) Not all data used in this analysis are publicly available. (3) "West" includes PacifiCorp, Public Service Co. of New Mexico, Idaho Power; "Southeast" includes Southern Company, Seminole Electric Cooperative.

Some delays are also evident *outside* of the interconnection process: procurement / offtake, local permitting, construction, etc.

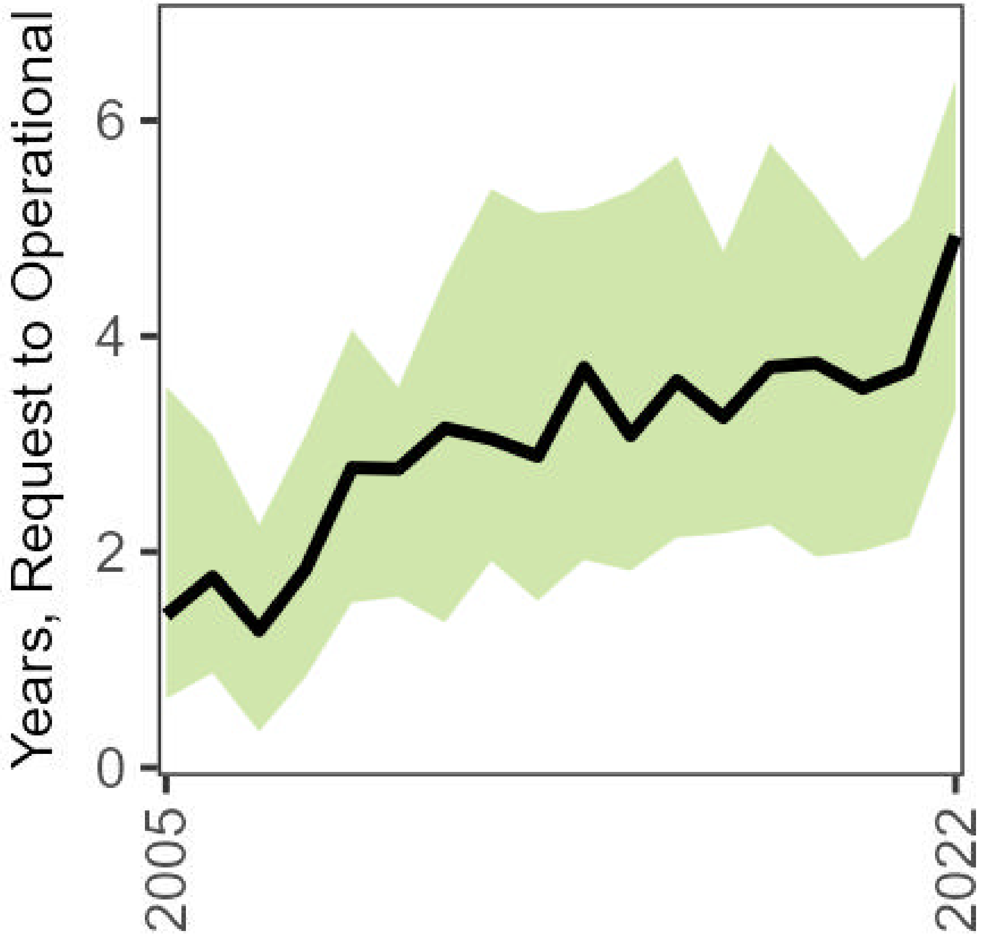


- Limited data were available to analyze typical durations from interconnection agreement to commercial operations
- Considering 737 projects across 6 entities, the typical IA to COD duration has increased only modestly since 2007.
  - From ~17 months for projects built from 2007-2014 to ~22 months for projects built from 2015-2022.
- But, that duration has increased dramatically for CAISO projects in the last 5 years.
  - The typical solar project built in CAISO since 2018 took over 4 years to reach commercial operations *after securing an interconnection agreement*; those built in 2022 averaged over 6 years.

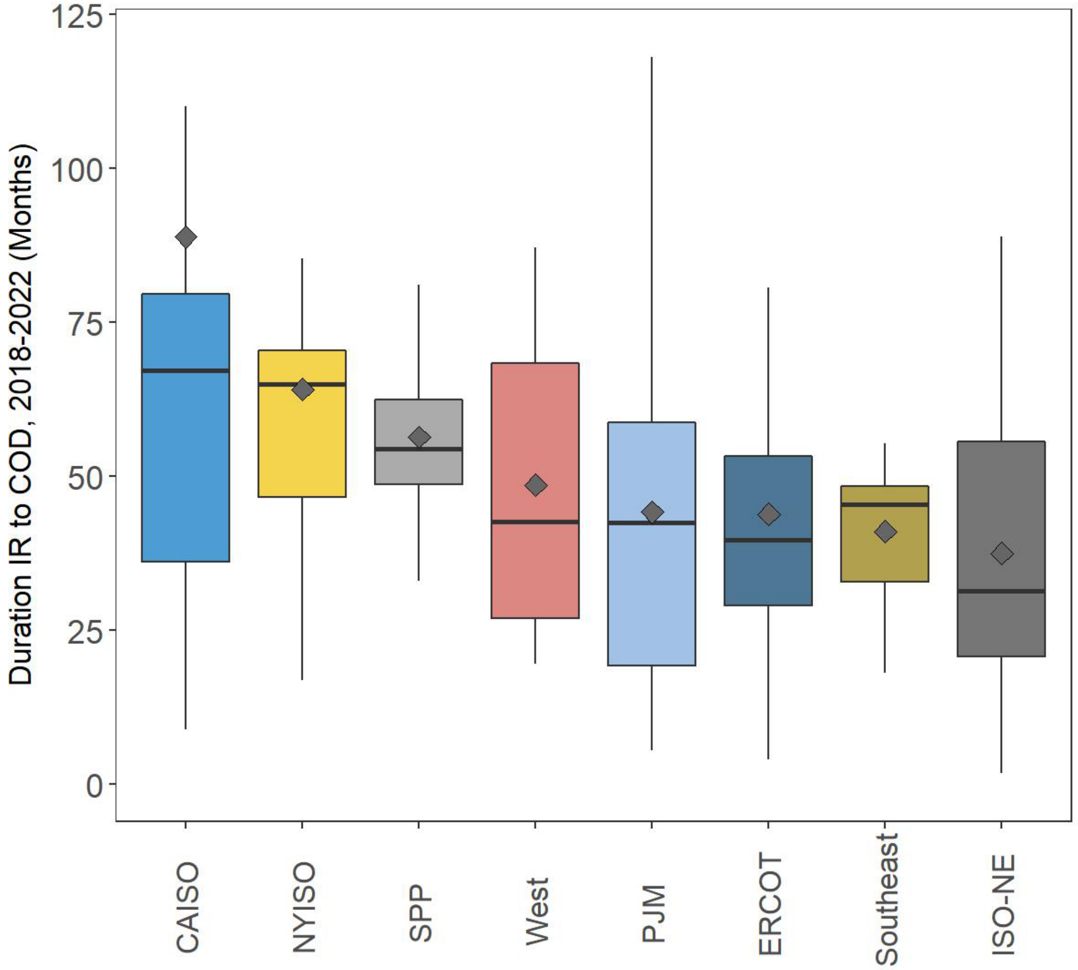
Notes: (1) Data were only available for 737 projects across 5 ISO/RTOs and one utility (Southern Company), out of 3,846 total "operational" projects in the full dataset. (2) Not all data used in this analysis are publicly available.

The median duration from interconnection request to commercial operations date continues to rise, reaching ~5 years for projects completed in 2022; Longest in CAISO

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

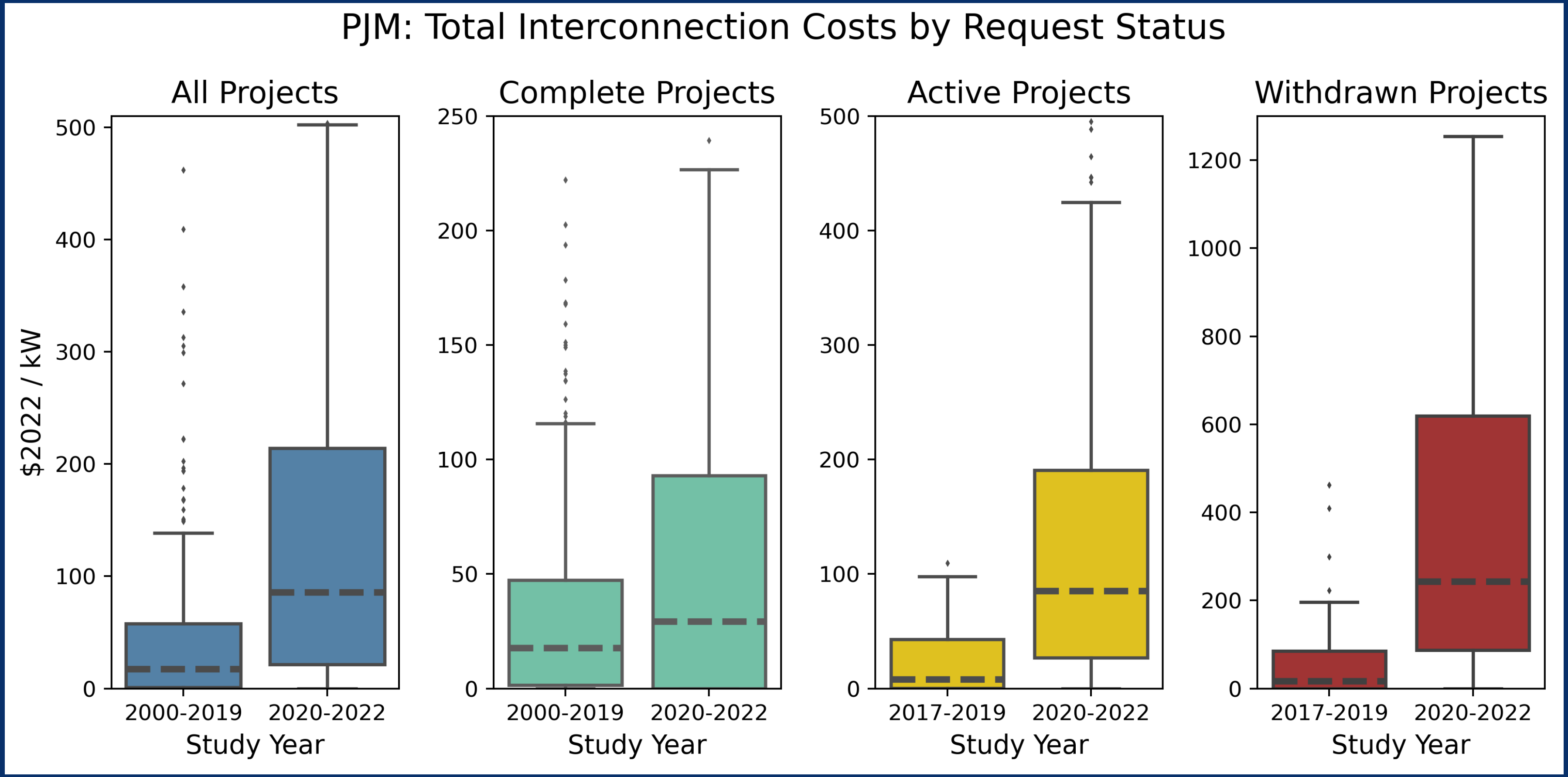


Duration for projects reaching COD from 2018-2022



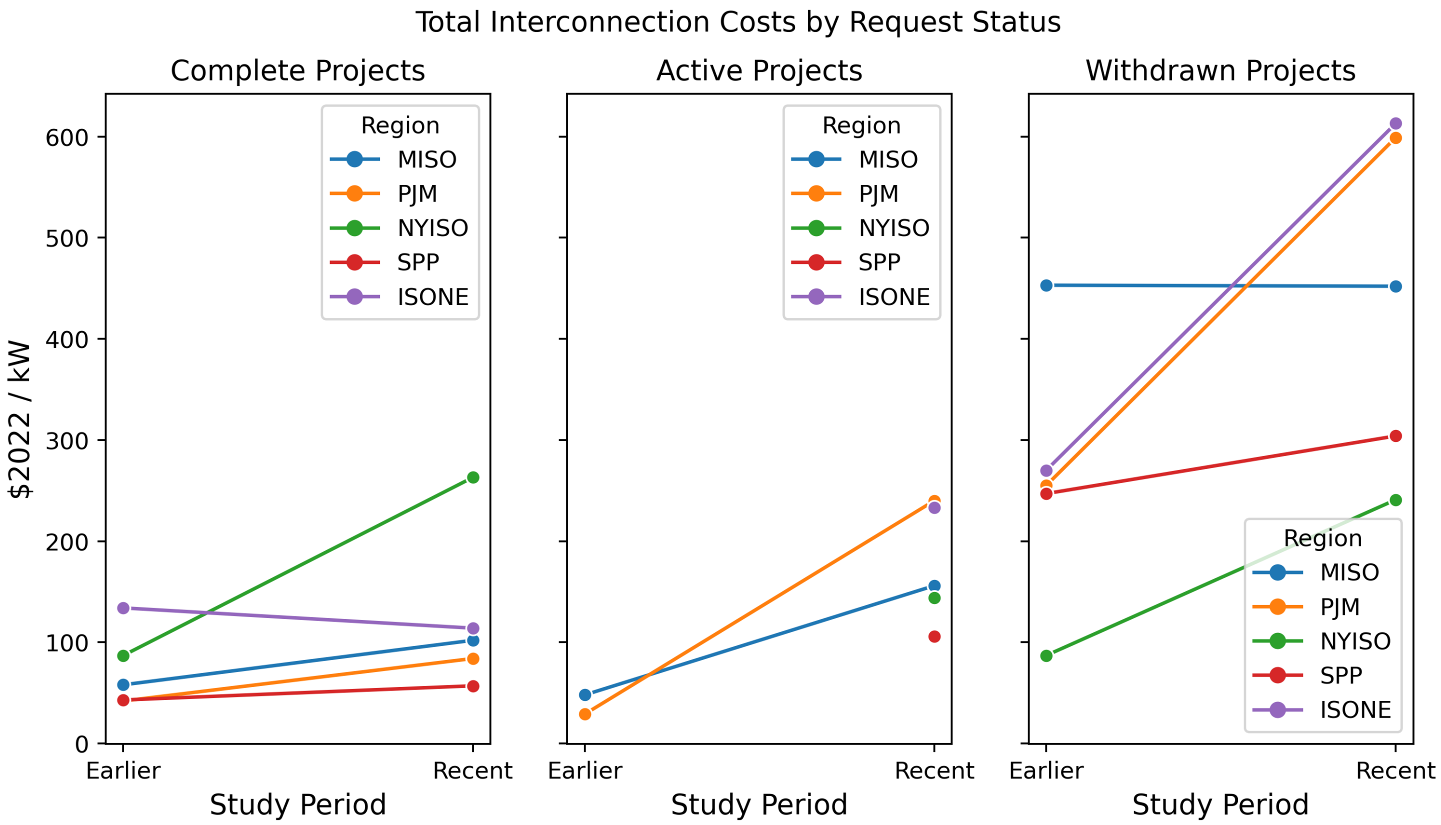
Notes: (1) In-service date was only available for 6 ISOs (CAISO, ERCOT, ISO-NE, NYISO, PJM, SPP) and 5 utilities (Duke, LADWP, PSCo, SOCO, WAPA) representing 58% of all operational projects. (2) Duration is calculated as the number of months from the queue entry date to the in-service date.

Evidence of a Problem #2: Increasing cost to connect



Interconnection costs have grown over time in all studied regions, driven primarily by broader network upgrades (not local interconnection costs)

Average Interconnection Costs

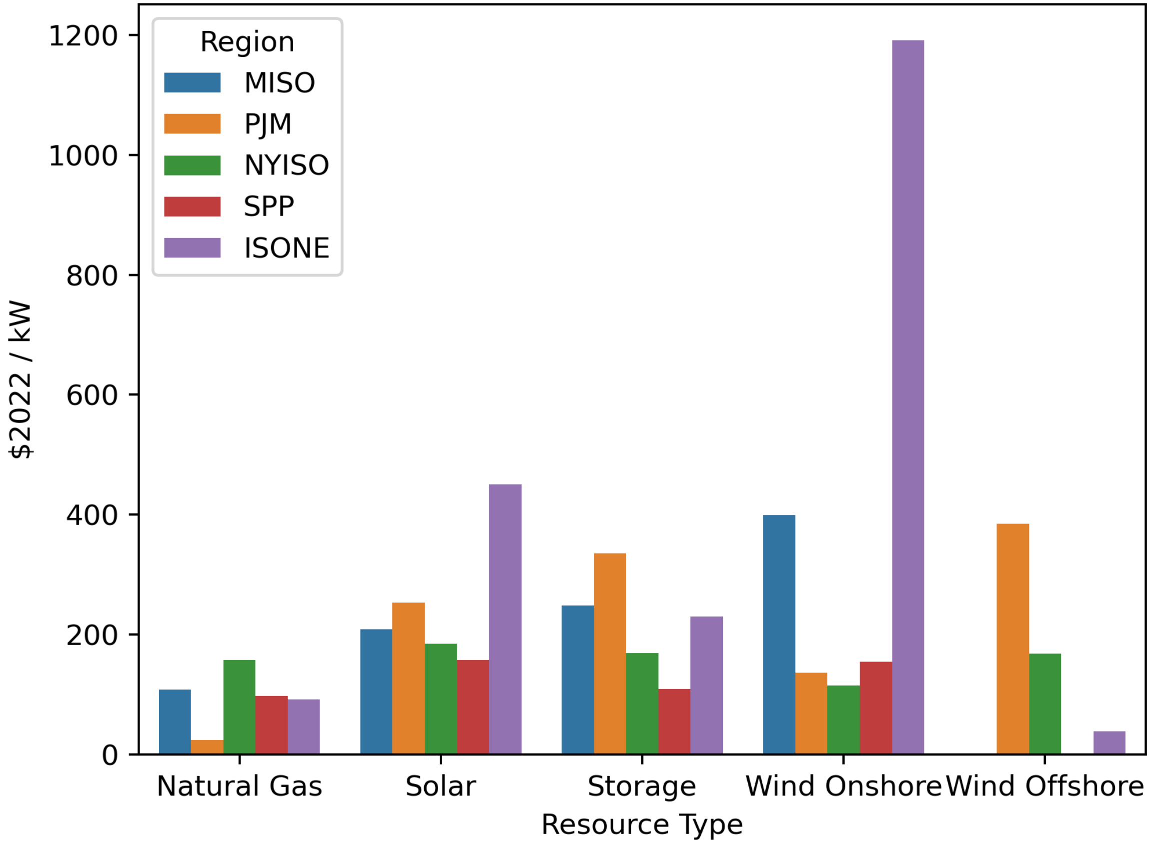


Region	"Earlier" period	"Recent" period
MISO	(2000-) 2018	2019-2021
SPP	2010-2019	2020-2022
PJM	2000/2017 - 2019	2020-2022
NYISO	2006-2016	2017-2021
ISO-NE	2010-2017	2018-2021

- Average interconnection costs have grown across regions and request types:
  - Often doubling for projects that have **completed** all studies
  - increasing even more for **active** projects currently moving through the queues.
  - Projects that **withdraw** have the highest interconnection costs

Renewables and storage often face higher interconnection costs than natural gas

Average Interconnection Costs in Recent Years (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.

	MISO	PJM	NYISO	SPP	ISO-NE
Years represented	2018-2021	2017-2022	2017-2021	2010-2022	2018-2021

A “wicked” problem: multifaceted drivers of interconnection backlogs

General sentiment: we are asking the serial queue process designed in 2003 to do too much. Reforms are needed, but also perhaps a fundamental re-thinking is required given clean energy transformation demanded.

Transmission expansion has been ***limited over the last decade, focused primarily on local reliability upgrades*** → Bulk grid not developing rapidly, leading to ***inadequate transmission*** and to high ***network upgrade costs assigned*** to generators in queue

Developers use queue requests for data collection given low information ***transparency, low entry cost, high network upgrade costs,*** and ***uncertain costs*** given serial nature and re-studies → Enormous ***increase in number and capacity*** of projects in queues, creating ***workflow and workforce challenges*** when relying on existing tools and administrative processes

Lack of ***standardization, inaccurate study data*** & assumptions, low consideration of ***grid-enhancing technologies***, generator technology changes, ***network cost assignment***, and late ***withdrawals*** → Multi-year ***queue delays*** leading to re-studies, ***reliability concerns, high generator-pays upgrade costs***, and frustrated stakeholders (developers and transmission operators alike)

A vicious cycle: the increasing number of requests increase delays and uncertainty, which further incentivizes developers to submit more requests

Proposed reforms are underway at FERC and among most RTOs, but more opportunities remain

FERC NOPR: Queue Reform

- ***Cluster studies***; ***first ready, first served***; higher ***fees & readiness*** criteria
- ***Timeline, process, data, and reporting*** requirements for transmission providers
- Improved and more coordinated process for ***affected system studies***
- Revisions to ***study data & assumptions*** to better match real system/conditions and ensure reliability
- Consideration of ***grid-enhancing technologies***

Possibilities Beyond FERC's Interconnection NOPR

- Proactive ***transmission planning*** and ***enhanced coordination*** between transmission planning and interconnection
- Enhanced ***data transparency*** on transmission availability and possible interconnection costs to pre-screen interconnection requests
- Increasing the ***automation*** of the interconnection study processes
- ***More interconnection resources and staff*** to speed the process; ability for developers to hire third-parties
- Revisiting the ***impact threshold criteria*** that result in network upgrade cost assignment, and review energy-only interconnection process
- ***Revisions to interconnection cost allocation:*** reform of participant funding for network upgrades

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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://emp.lbl.gov/queues interconnection queue analysis and data
- Visit https://emp.lbl.gov/interconnection_costs for research on generator interconnection costs

Acknowledgements:
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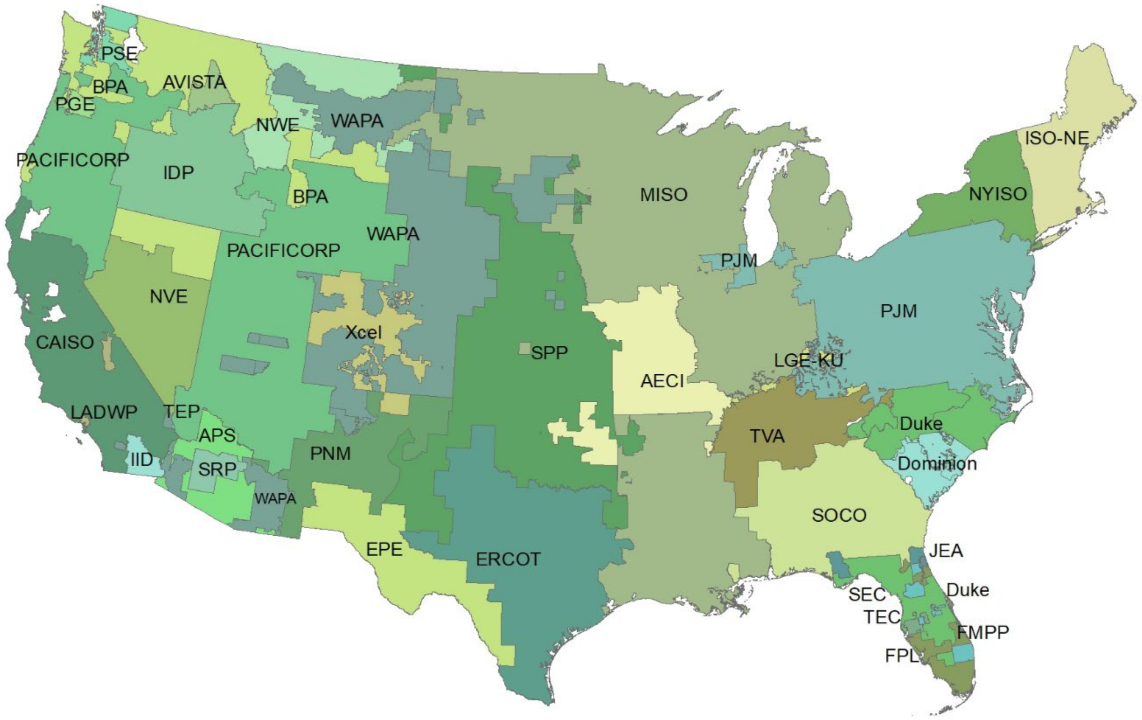
Appendix

Methods and Data Sources

- Data collected from interconnection queues for 7 ISOs / RTOs and 35 utilities, which collectively represent >85% of U.S. electricity load
  - Projects that connect to the bulk power system, not behind-the-meter
  - Includes projects in queues through the end of 2022
  - The full sample includes:
    - 3,846 “operational” projects
    - 10,262 “active” projects
    - 374 “suspended” projects
    - 15,672 “withdrawn” projects
- Hybrid / co-located projects were identified and categorized
  - Storage capacity in hybrids (separate from generator capacity) was estimated based on available data for some projects
- Note that being in an interconnection queue *does not guarantee* ultimate construction



Coverage area of entities for which data was collected
Data source: Homeland Infrastructure Foundation-Level Data (HIFLD)
A full list of included balancing areas can be found in the Appendix
Note that service areas can overlap
No data collected for Hawaii or Alaska

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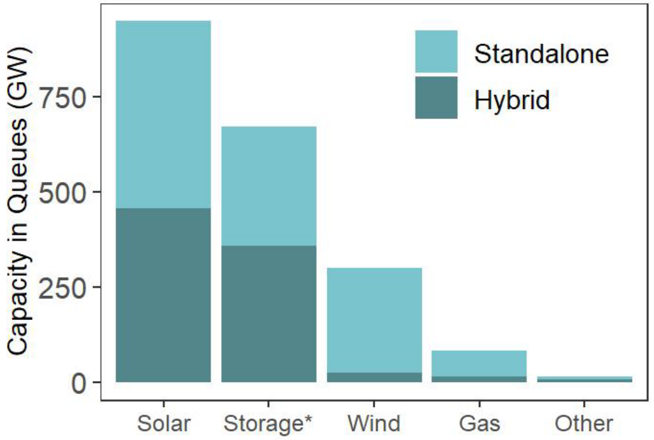
High-Level Findings

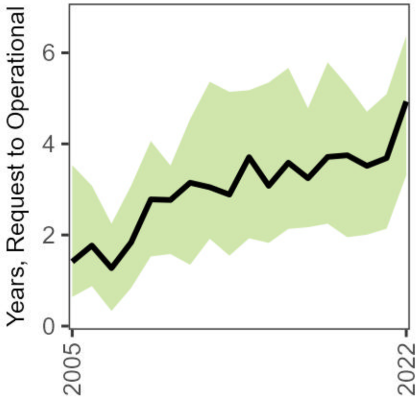
Developer interest in solar, storage, and wind is strong

- Over 10,000 projects representing 1,350 gigawatts (GW) of generator capacity and 680 GW of storage actively seeking interconnection
- Most (~1260 GW) proposed generation is zero-carbon
- Hybrids comprise a large share of proposed projects



Completion rates are generally low; wait times are increasing

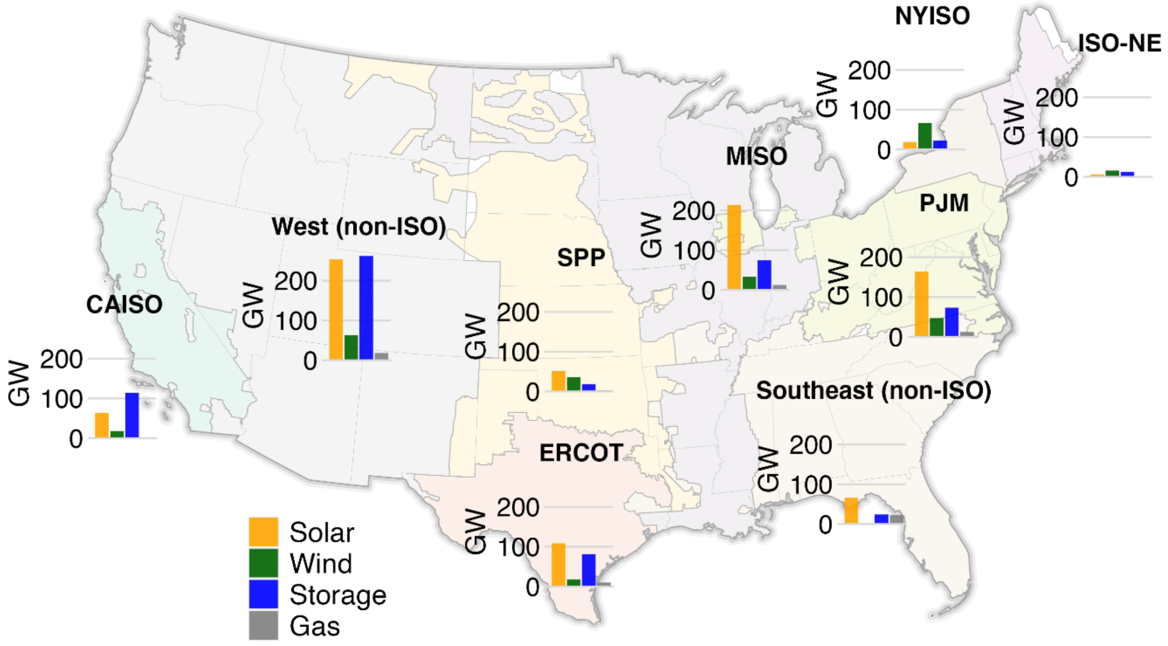
- Only ~21% of projects (14% of capacity) requesting interconnection from 2000-2017 reached commercial operations by the end of 2022



- Completion rates are even lower for wind (20%) and solar (14%)
- The average time projects spent in queues before being built has increased markedly. The typical project built in 2022 took 5 years from the interconnection request to commercial operations[1], compared to 3 years in 2015 and <2 years in 2008.

Proposed capacity is widely distributed across the U.S.

- Substantial proposed solar capacity exists in most regions of the U.S.; 947 GW of solar active in queues
- Wind capacity is highest in NYISO, the non-ISO West, PJM, and SPP, with increasing share of offshore projects
- Storage is primarily in the West and CAISO, but also strong in ERCOT, MISO, and PJM; much in hybrid configurations
- Only 82 GW of gas capacity active in the queues, less than 10% of active solar capacity



1. *In-service date was only available for 58% of all operational projects*

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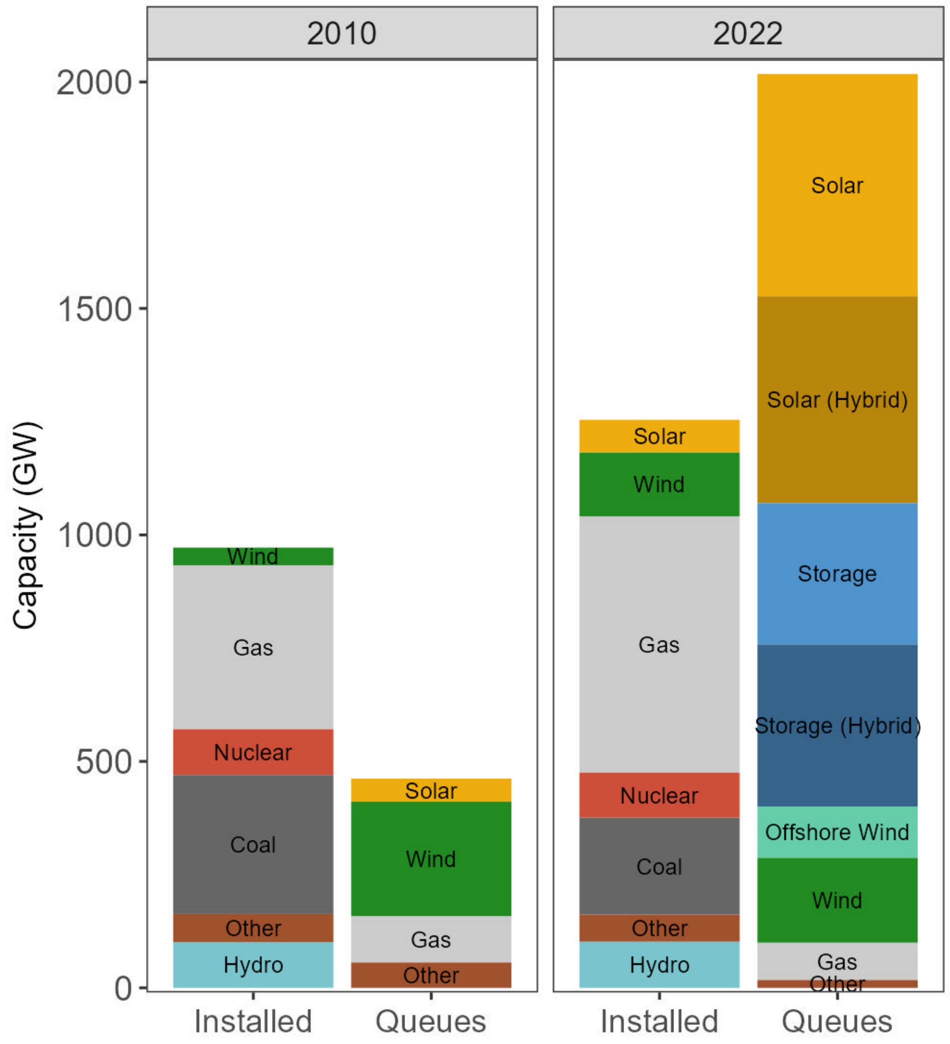
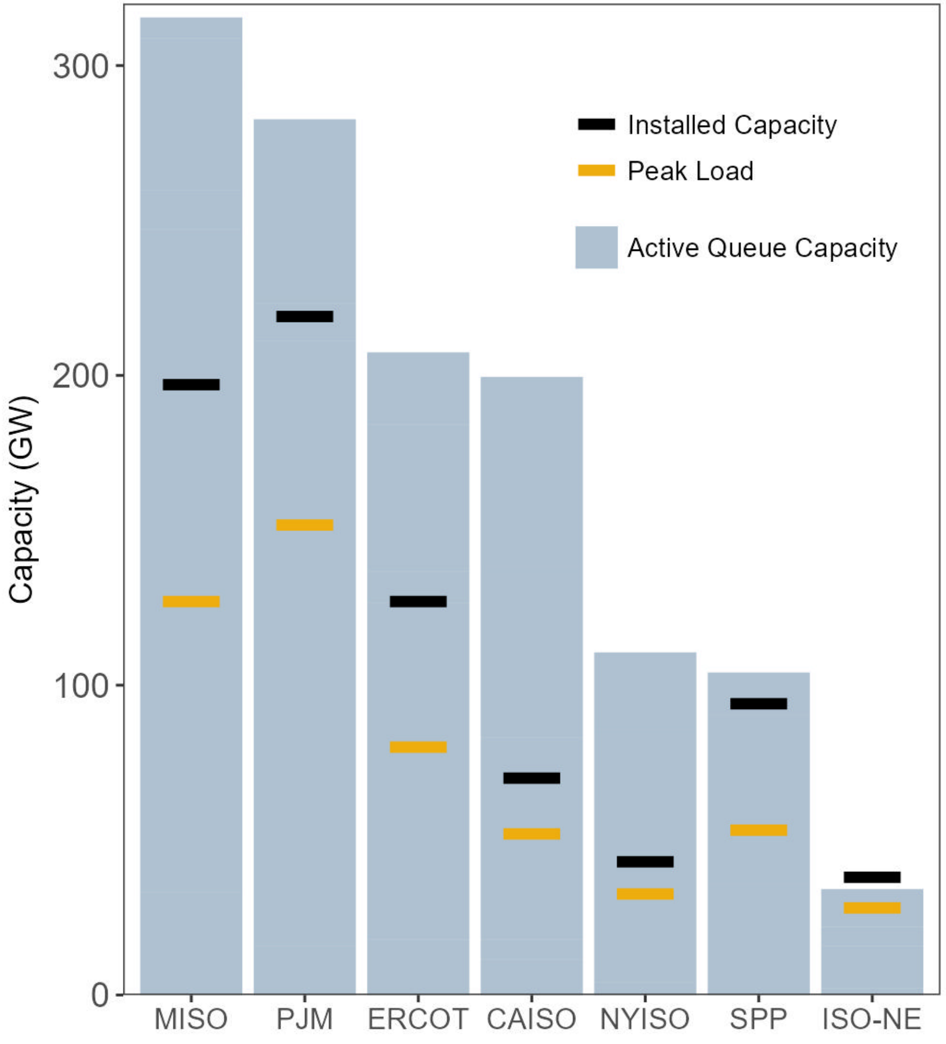
Active capacity in queues (>2,000 GW) exceeds installed capacity of entire U.S. power plant fleet (~1,250 GW), as well as peak load and installed capacity in most ISO/RTOs

Entire U.S. Installed Capacity vs. Active Queues



RTO Installed Capacity & Peak Load vs. Active Queues

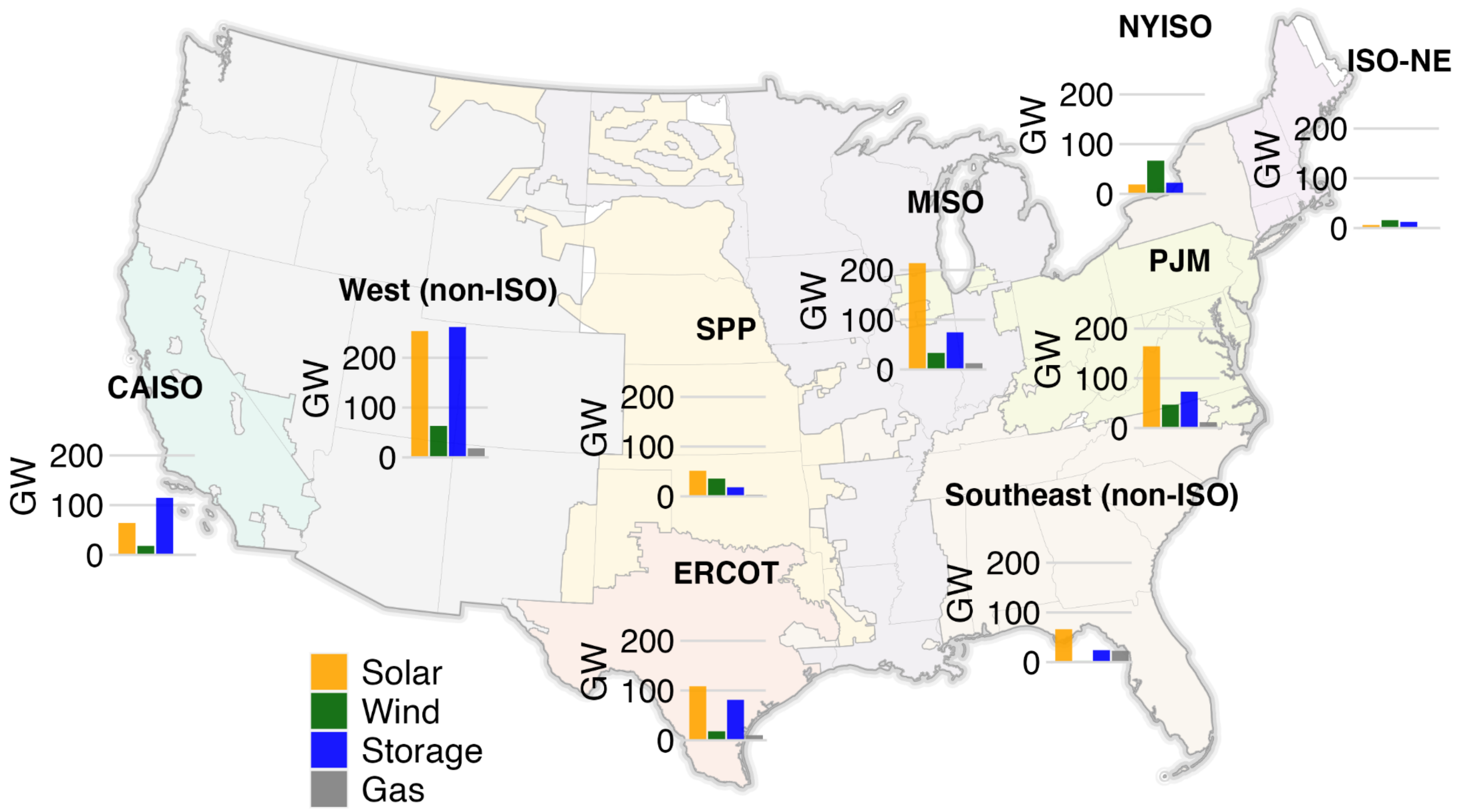


Comparisons of queue capacity to installed capacity or peak load should also consider generators' contributions to resource adequacy, for example their "effective load carrying capability" (ELCC). As variable resources, solar and wind contribute a smaller percentage of their nameplate capacity to resource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

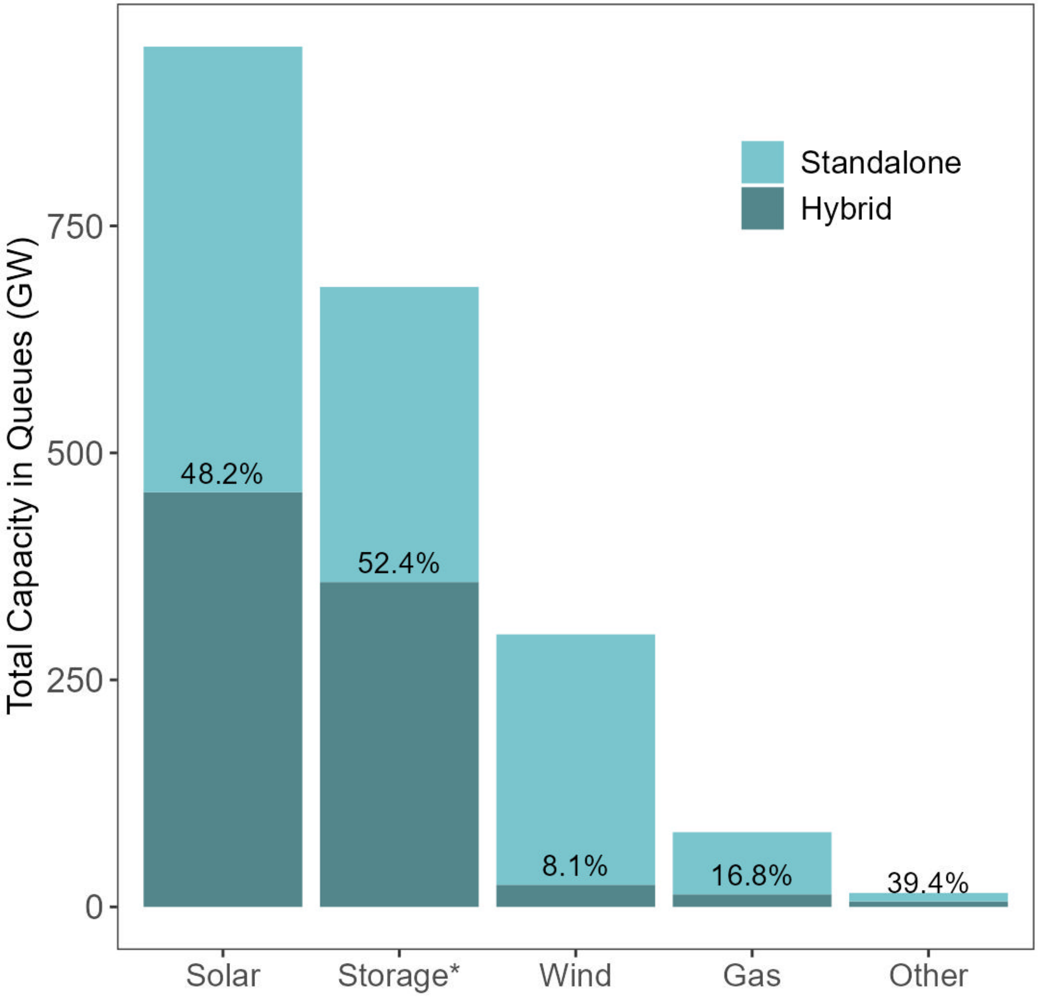
Active interconnection requests are growing in all regions; highest for solar (~950 GW), storage (~680 GW), and wind (~300 GW, including 113 GW offshore)



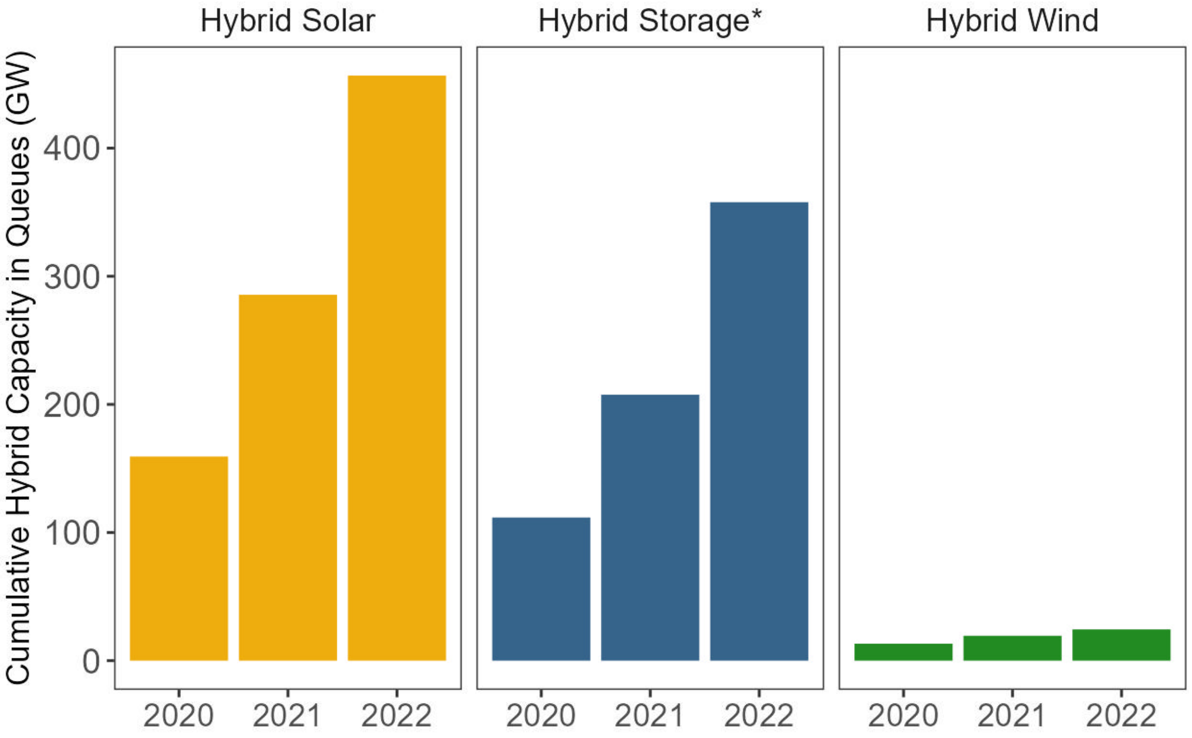
Solar and storage requests are booming in most regions; after being overwhelmed in 2021, CAISO and PJM "paused" new requests in 2022

Source: Berkeley Lab, "Queued Up". 2023

Interest in hybrid plants has increased over time: Hybrids comprise 52% of active storage capacity (358 GW), 48% of solar (457 GW), and 8% of wind (24 GW)



**Hybrid storage capacity is estimated using storage:generator ratios from projects that provide separate capacity data*

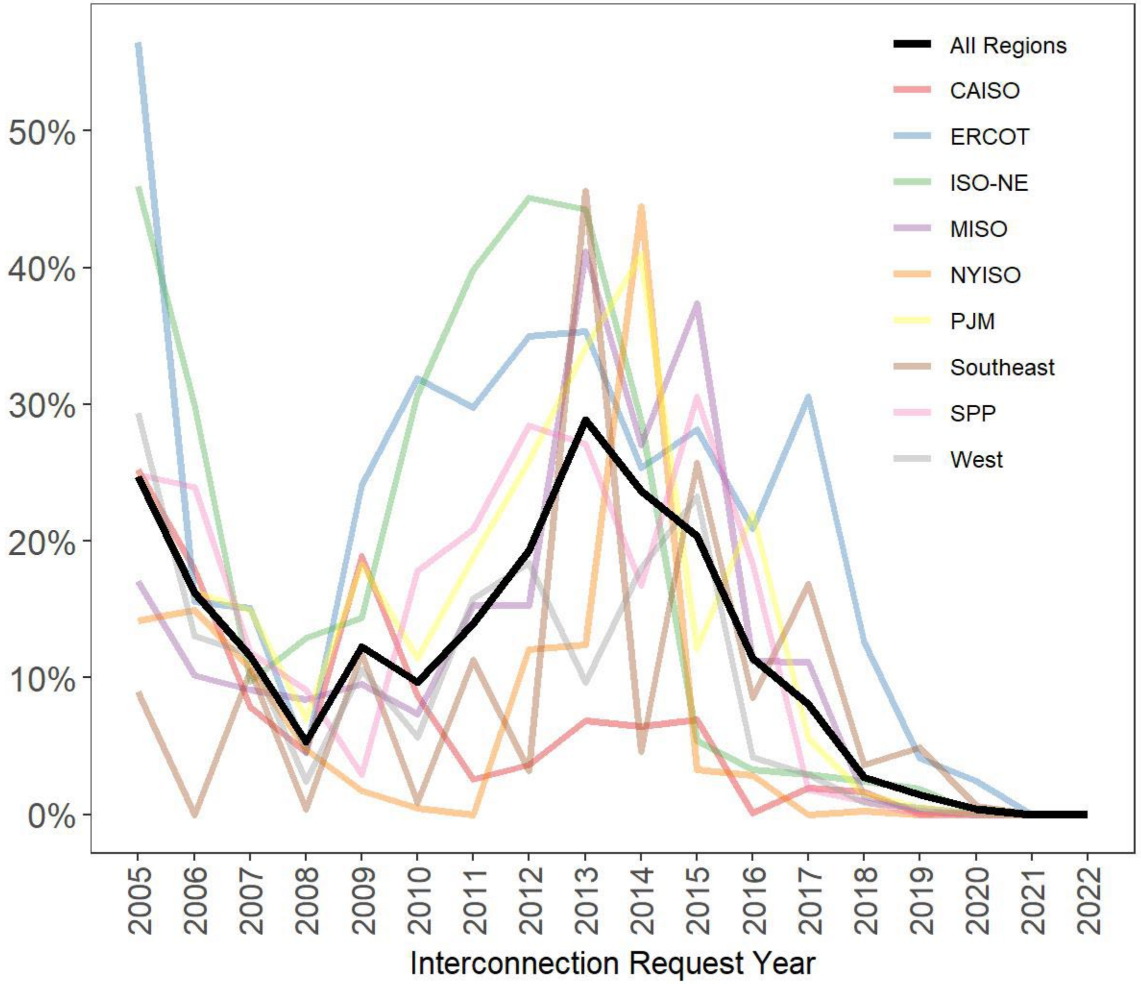


- **Solar Hybrids** include: Solar+Storage (431 GW), Solar+Wind (3 GW), Solar+Wind+Storage (8 GW)
- **Wind Hybrids** include: Wind+Storage (19 GW), Wind+Solar (1 GW), Wind+Solar+Storage (4 GW)
- **Storage Hybrids** may be paired with any generator type; most are paired with solar
- **Gas Hybrids** include: Gas+Solar+Storage (13 GW), Gas+Storage (0.4 GW), Gas+Solar (0.3 GW) [not shown above]

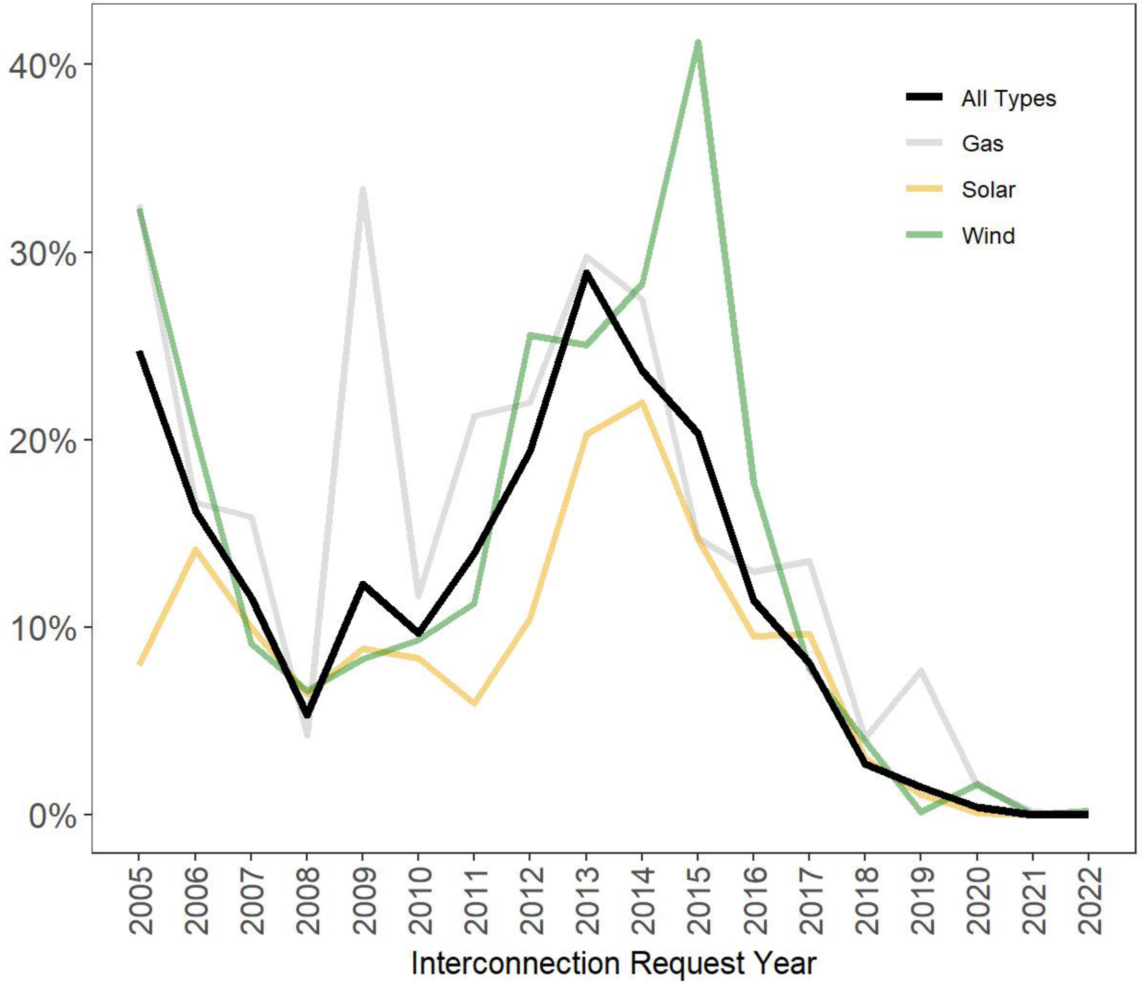
Notes: (1) Some hybrids shown may represent storage capacity added to existing generation; only the net increase in capacity is shown; (2) Hybrid plants involving multiple generator types (e.g., Wind+Solar+Storage) show up in all generator categories, presuming the capacity is known for each type.

Capacity-weighted completion rates are even lower: Only 14% of all capacity requesting interconnection from 2000-2017 is online; 16% of wind capacity, 10% of solar capacity

Percentage of capacity online by region:

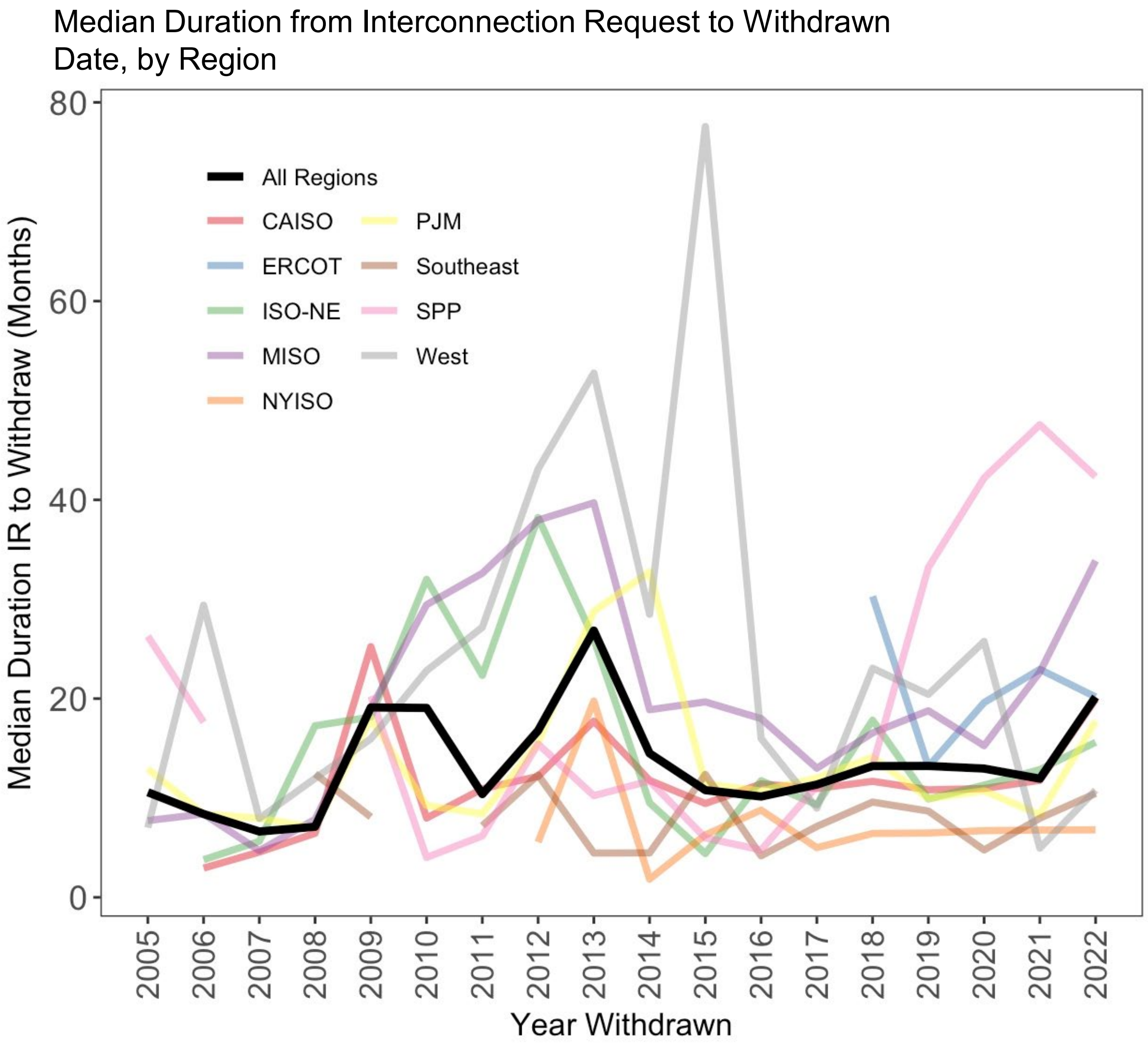


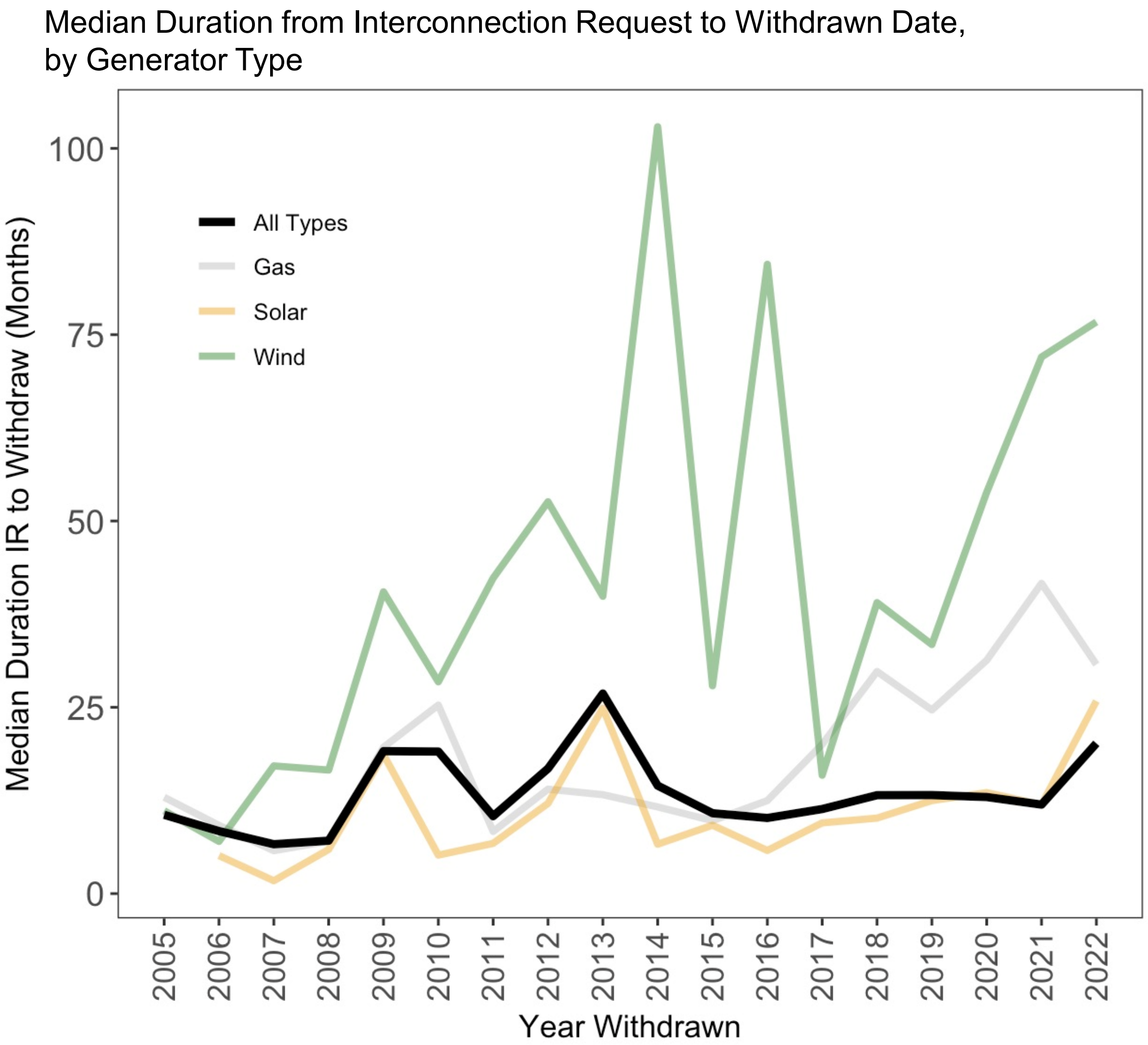
Percentage of capacity online by generator type:



Notes: (1) Completion rate shown here is capacity-weighted, calculated as the capacity that is online by end of 2022 divided by the total capacity requesting interconnection each year. (2) Includes data from 7 ISO/RTOs and 26 utilities.

The median duration from request to withdrawn date ticked up in 2022; wind projects typically spend more time in queues than gas or solar prior to withdrawing





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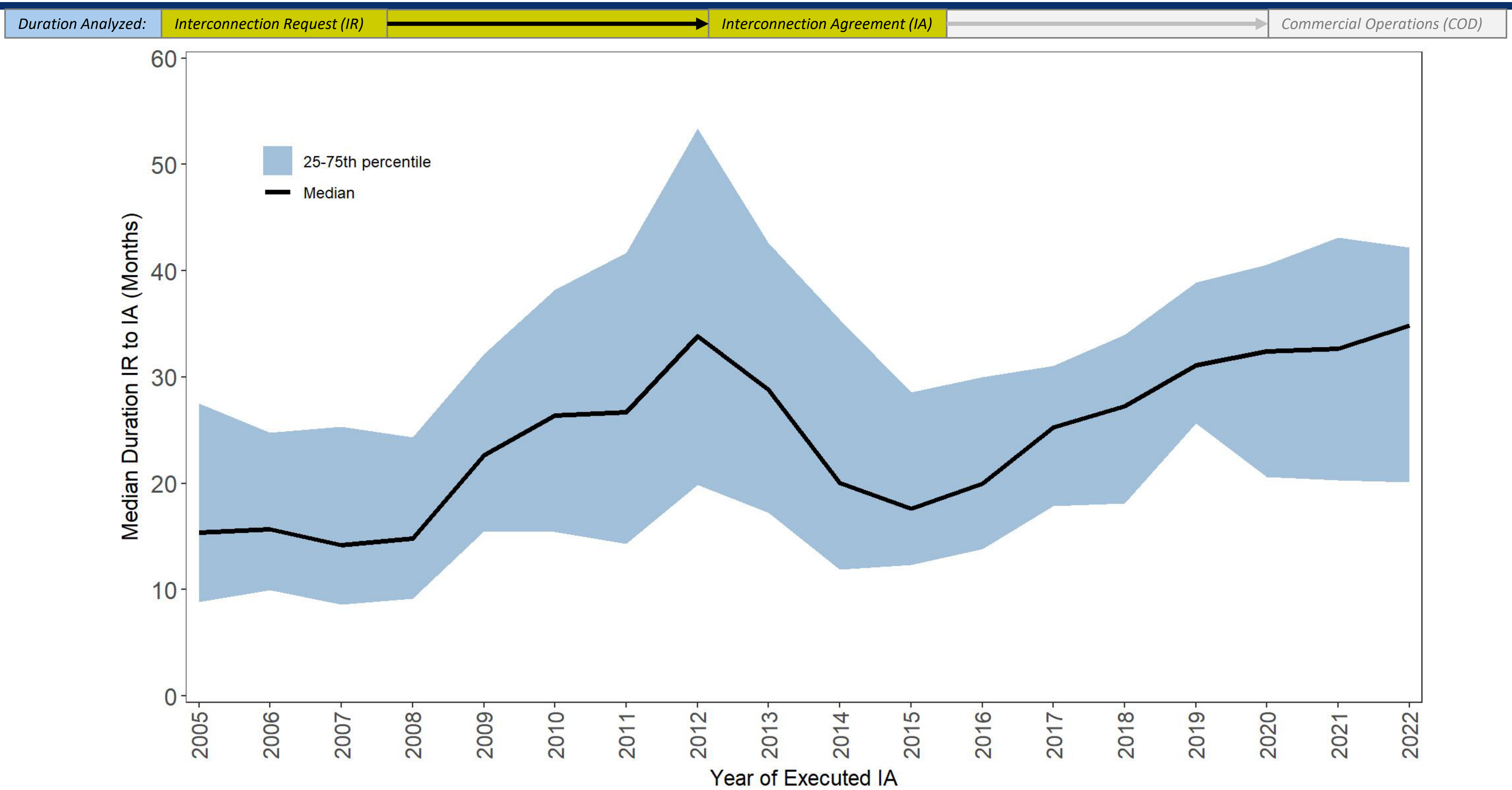
Notes: (1) Withdrawn date was available for 6,323 projects from 5 ISOs and 6 utilities. (2) Duration is calculated as the number of months from the queue entry date to the date the project was withdrawn from queues.

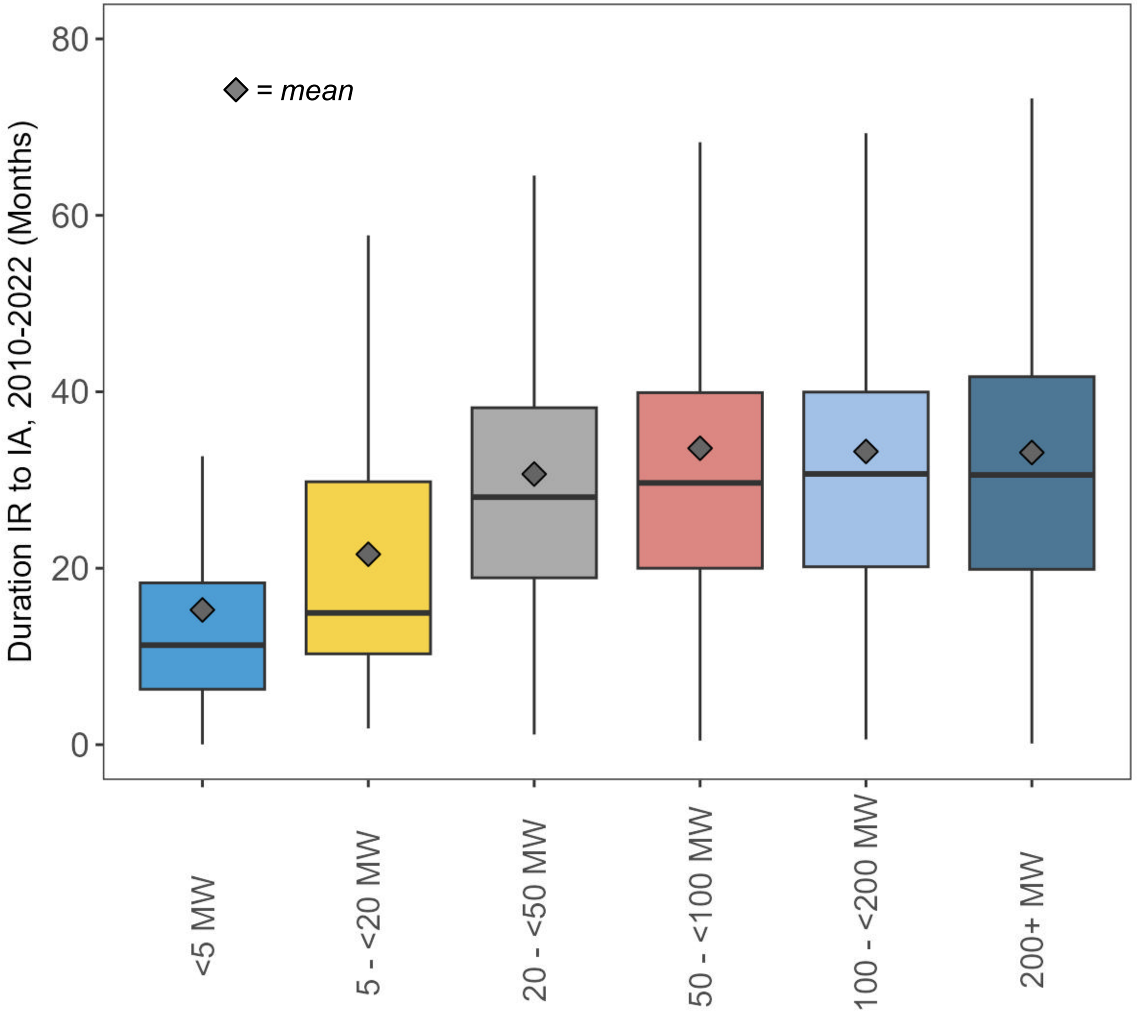
After falling from a 2012 peak, the typical duration from interconnection request (IR) to interconnection agreement (IA) increased sharply since 2015, reaching 35 months in 2022



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.

There is a clear step change in IR to IA duration between “small” (<20 MW) and “large” (>20 MW) generator interconnection procedures

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



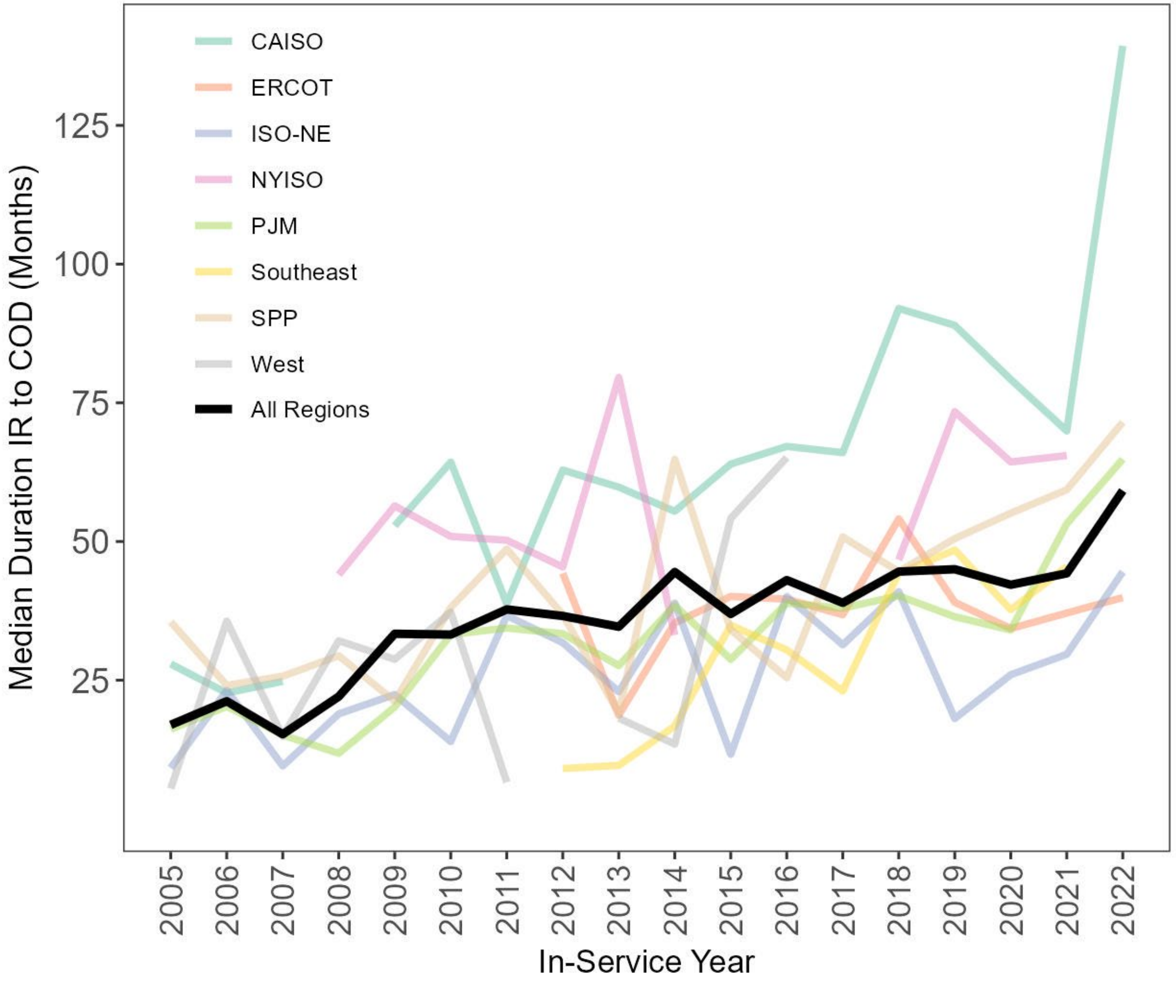
- On average, projects with rated capacity <20 MW complete studies and execute interconnection agreements much faster than larger projects
  - Median is 11 months for projects <5 MW
  - 15 months for projects 5 - <20 MW
- The median duration for projects 20 MW or larger hovers around 30 months across the four larger project groups analyzed
- 20 MW is the threshold between the FERC “large” and “small” generator interconnection procedures (LGIP / SGIP)
  - The median LGIP duration is twice the median SGIP duration for projects in our sample

Notes: (1) Box-plot includes projects executing interconnection agreements from 2010-2022. (2) Duration is calculated as the number of months from the queue entry date to the interconnection agreement date.

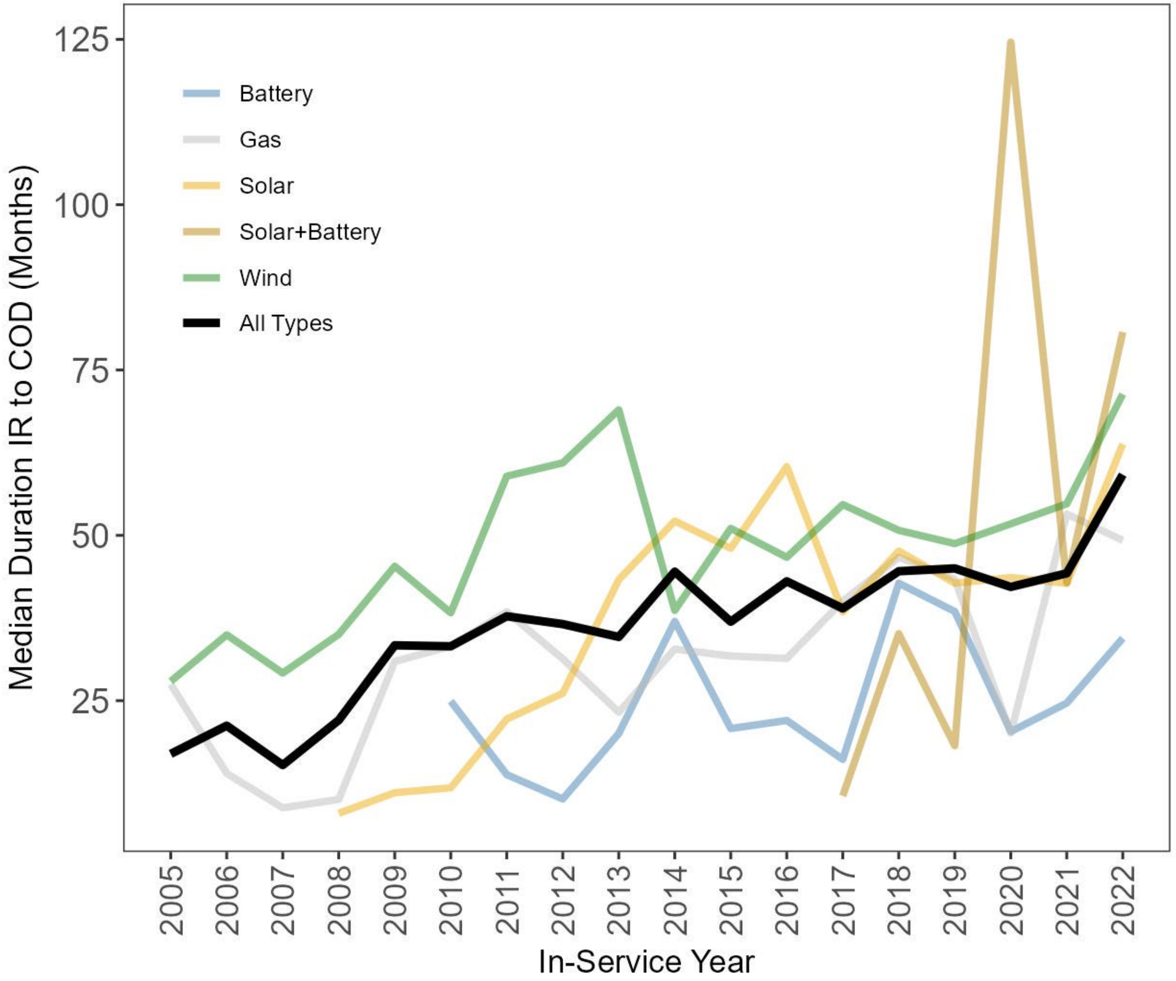
IR to COD timelines are longest in CAISO, NYISO, and SPP; solar and wind projects typically take longer than other types, with standalone battery projects moving fastest to completion

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

Median Duration from Interconnection Request to Commercial Operations, by Region



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



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.

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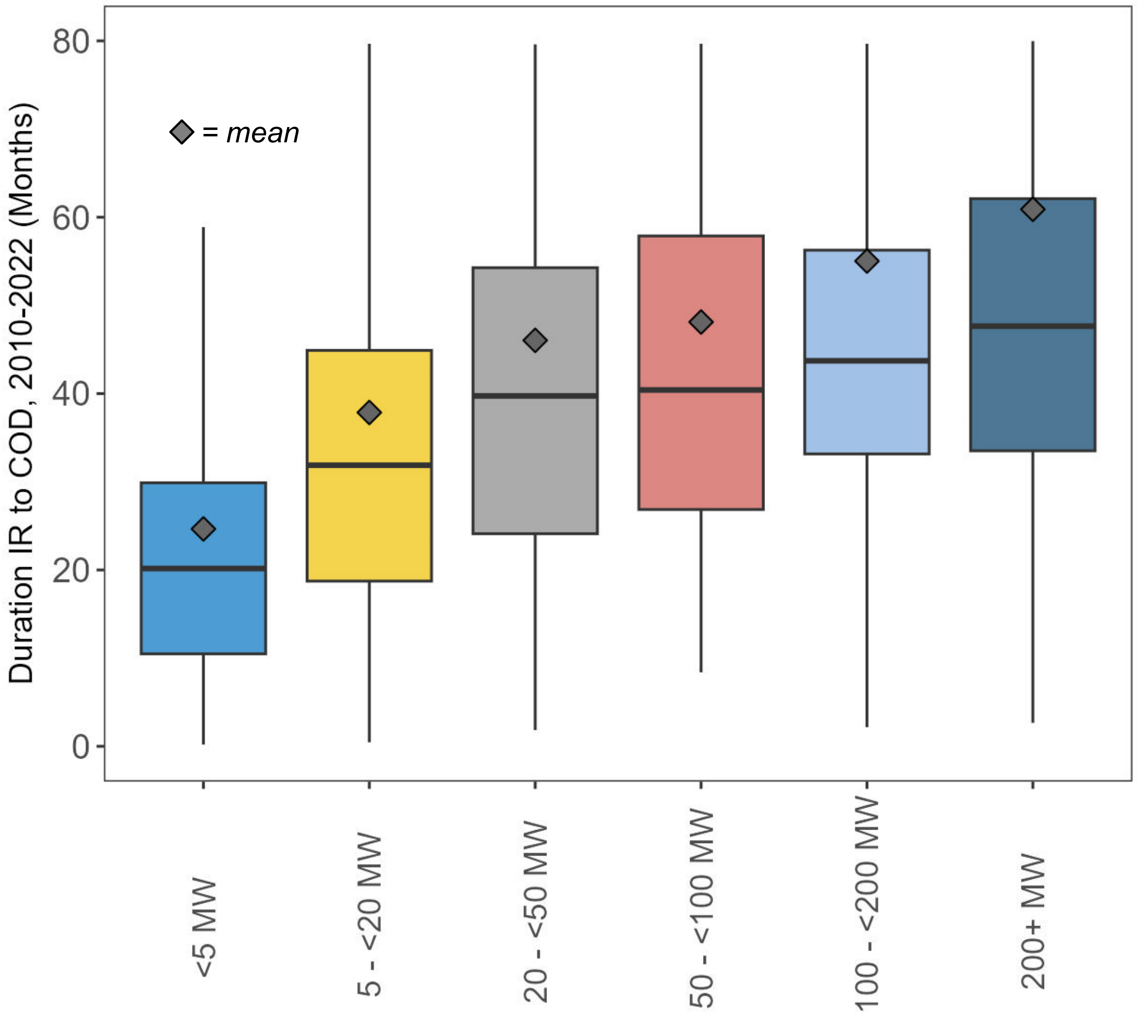
Larger projects have longer development timelines: Typical IR to COD duration increases monotonically by project size (MW)

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

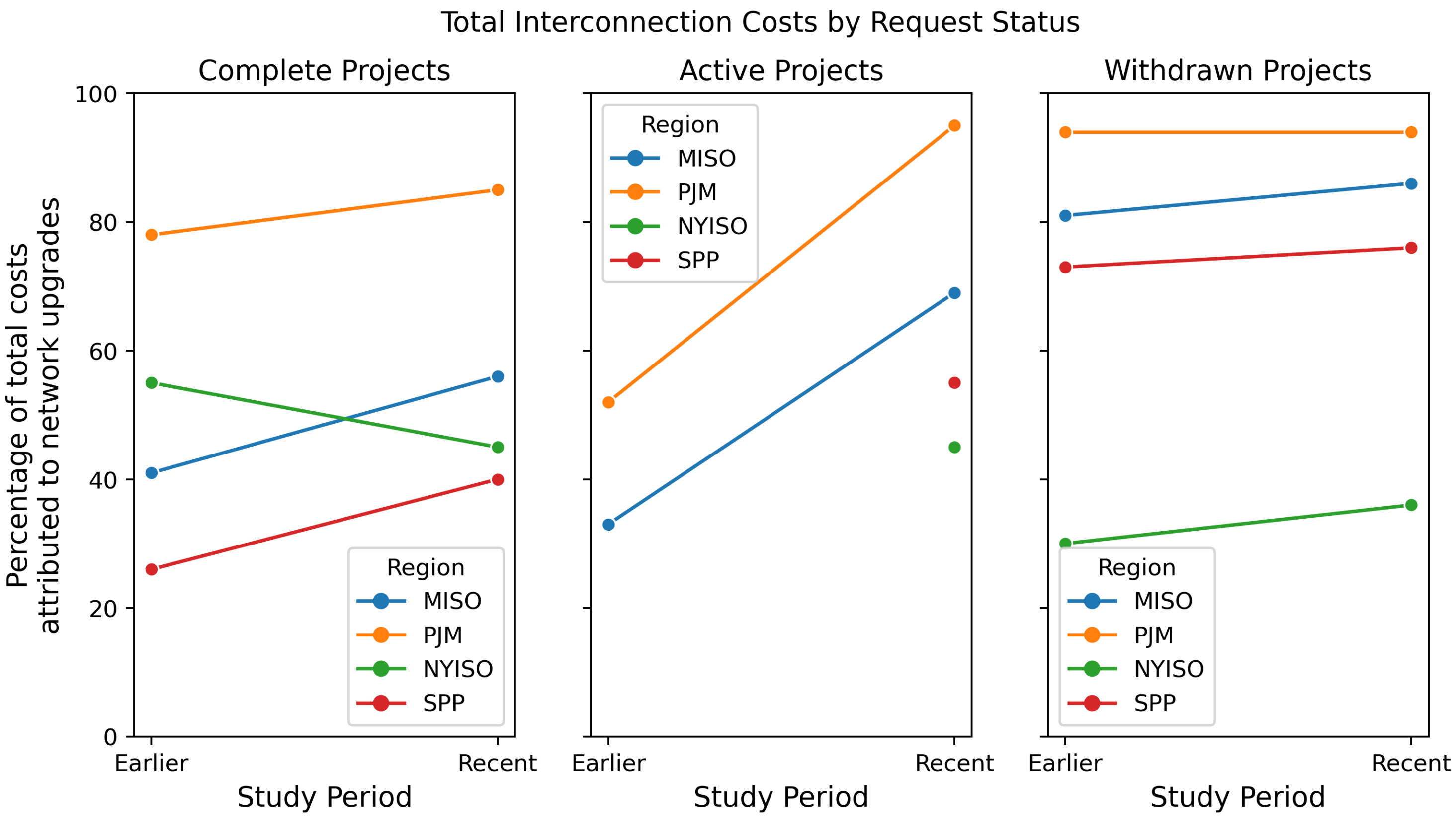


- For the smallest projects in our sample (<5 MW), the median project came online less than 2 years (20 months) after the interconnection request
- The median 5-20 MW project, meanwhile, takes nearly 3 years (33 months) from IR to COD
- Larger projects spend even more time in the interconnection and development process, with the median 100-200 MW project taking >4 years and the median 200+ MW project taking over 4.5 years (55 months) from IR to COD

Notes: (1) Box-plot includes projects reaching commercial operations from 2010-2022. (2) Includes data from 6 ISOs and 5 utilities. (2) Duration is calculated as the number of months from the queue entry date to the in-service date.

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

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Balancing Areas Included In Data:

ISO/RTOs	Other (non-ISO) Transmission Operators				
PJM	Southern Company	Associated Electric Coop.	LG&E & KU Energy	Portland General Electric	Public Service Co. of NM
MISO	Tennessee Valley Authority	PSCO	Salt River Projects	Idaho Power	Avista
ERCOT	Duke/Progress	Santee Cooper	NV Energy	Florida Municipal Power Pool	El Paso Electric
SPP	WAPA	Georgia Transmission Corp.	Navajo-Crystal	Tri-State G&T	Imperial Irrigation District
NYISO	Florida Power & Light	Arizona Public Service	Dominion	Jacksonville Electric Authority	Platte River Power Authority
CAISO	Bonneville Power Admin.	LADWP	Puget Sound Energy	Tucson Electric Power	Black Hills Colorado
ISO-NE	PacifiCorp	Seminole Electric Coop.	Tampa Electric Co.	NorthWestern	Cheyenne Light Fuel & Power