Iberian Peninsula Blackout:
A Trade-Off Between Operational Risk and Consumer Cost

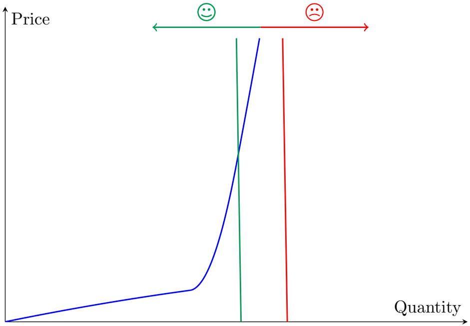
Daniel Daví-Arderius
University of Barcelona

Christoph Graf
New York University

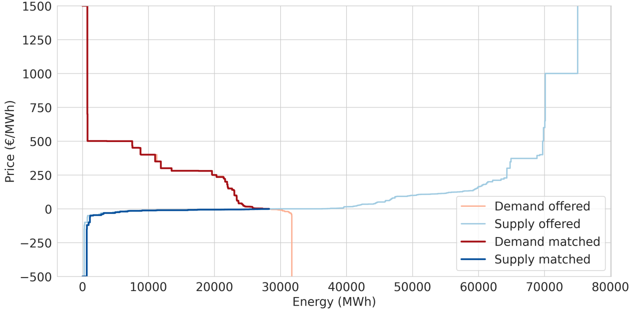
15th Energy and Climate Economics Conference
Toulouse
June 4, 2026

Motivation

Resource Adequacy Challenge



(Potential) Operational Reliability Challenge



Day-Ahead Market Bids and Offers in the Spanish bidding zone for the day and hour of the Iberian Blackout (April 28, 2025, Hour 13). Source: `https://omie.es`.

Motivation (Cont'd)

- **Blackouts Offer Lessons:** Electricity blackouts are rare but catastrophic events that reveal systemic weaknesses
- **U.S. vs. Europe**
  - Recent blackouts in the U.S. (e.g., Winter Storm Uri, 2021, Winter Storm Elliott, 2022) involved **resource adequacy failures** (insufficient generation)[1]
  - The **2025 Iberian Peninsula Blackout** (Spain/Portugal) was primarily an **operational reliability event** (voltage oscillation and cascade tripping)
- **European Market Design:** Markets clear sequentially assuming an unconstrained grid ("copper plate"). System operators (SOs) must make **corrective adjustments** (redispatch) to ensure secure real-time operation if initial schedules are infeasible
- **Before** the blackout the Spanish SO arguably redispatched focusing on renewable integration and having redispatching costs in mind
  After the blackout redispatch volumes/costs (direct and CO2-emissions related) increased significantly (reassessment of risks, focusing on reliability)

[1] On the economics of reliability, see, e.g., Joskow and Tirole [2007], Gorman [2022], Wolak [2022], Borenstein et al. [2023]

Real Time

In real time:

1. Aggregate supply must be equal to aggregate demand (energy balance)
   - But also the locational pattern of power generation and consumption must honor the physical laws governing the grid (power flows subject to the limits of the transmission and distribution system)
2. Security constraints such as various ancillary services, e.g., spinning reserve and reactive support (voltage control)
3. "Positioning" of power plants relevant for the next real-time periods (resource commitment decisions and ramp/limit constraints) [see, e.g., Graf et al., 2022, Jha and Leslie, 2025]

Failing to provide those essential services in real time can compromise system security and, in the worst case, lead to substantial cascading power outages or even to the collapse of the system.

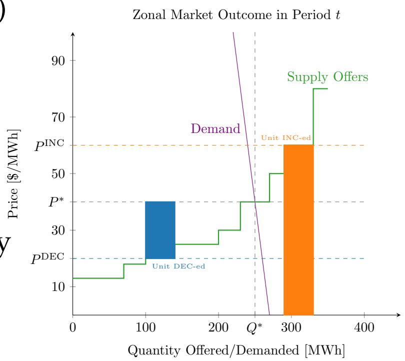
Simplified/Zonal EU Market Design

- Often only energy balance constraint accounted for in the DA and intraday (ID) markets (can lead to schedules that will violate system constraints other than the energy balance constraint)
  - In some cases "zonal" market clearing
- Secondary mechanisms (redispatch market, congestion management) to deal with system constraints such as congestion, voltage control, frequency, reserves, etc.
- Sequential procurement of energy and ancillary services
- Artificial divide between the "market" and the "grid"
  - The market operator runs DA and ID markets, while the SO runs the redispatch market

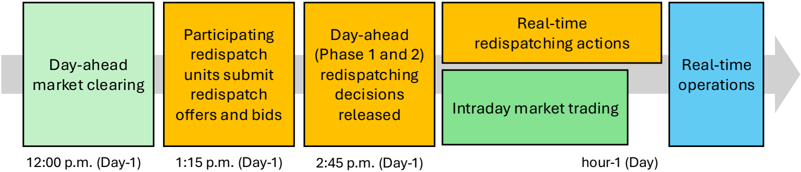
The U.S. short-term wholesale market design follows a two-settlement structure, consisting of a day-ahead (DA) market and a real-time (RT) market, which are in sync (DA mimics RT in terms of considered real-time system constraints). Both markets price energy, congestion, and losses, while market clearing co-optimizes commitment, energy, transmission, and ancillary services. The market design integrates engineering and economics and resulting locational marginal prices (LMPs) support the secure operations of the grid in real-time and does not require redispatch [see, e.g., Graf et al., 2022, Hogan, 2021, Wolak, 2021, Graf, 2025]. Generally, we refer to Bohn et al. [1984], Hogan [1998, 1999], Wilson [2002], Cramton [2017], Hirth and Schlecht [2019], Graf et al. [2020, 2021], Eicke and Schittekatte [2022], Davi-Arderius and Schittekatte [2023], Brown [2024], Buchsbaum et al. [2024], Brown et al. [2025], and Leslie and Billimoria [2025] on the "Engineering Economics of Electricity Markets."

Redispatching

- SO faces market schedules leading to, e.g., a transmission constraint violation [see, e.g., Graf et al., 2020, 2021, Graf, 2025, Brown and Reguant, 2026]
- Generator gets redispatched, i.e., dispatched up (INC) or down (DEC), to e.g., change flows and relieve transmission constraint violation, ensure sufficient reserves, and provide voltage control
- Deviations from the generator's schedule are settled pay-as-offered (INC) / pay-as-bid (DEC)
- Often use of disintegrated tools aiming to sequentially solve constraint violations (in an interconnected system governed by Kirchhoff's laws, resolving one binding locational constraint can cause others to become binding)
- Final consumers typically paying for redispatch actions



Spanish Market Timeline



When should operating schedules be physically feasible?

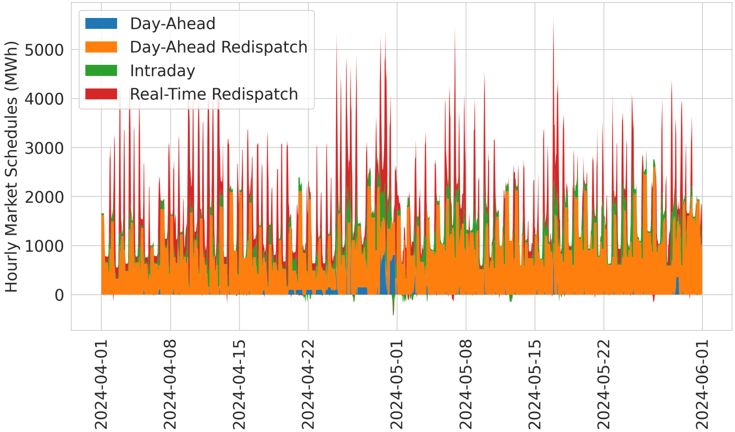
"Here and now"

- Redispatch right after the day-ahead market has cleared
- Redispatch on the spot could turn out to be a suboptimal decisions in hindsight (overcommitment)

"Wait and see"

- Redispatch closer to real-time
- Market/system conditions may shift and anticipated real-time security violations may resolve on their own
- If anticipated violations persist or worsen, SO may face challenges securing sufficient reliability resources on short notice

Operational Incentives of the Simplified Market Design (CC Schedules by Market Segment)

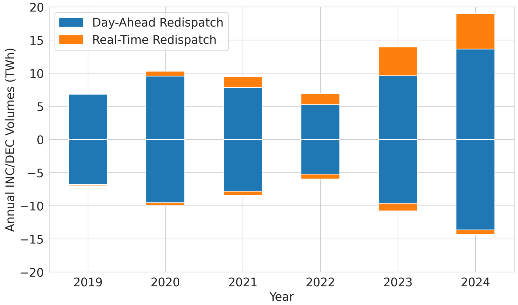


- Hourly Aggregate Combined Cycle (CC) Schedules by Market Segment in April and May 2024
- Almost no CC schedules emerged after the day-ahead market
- But in real-time, there is still demand for those units (given their additional services they offer to the grid)

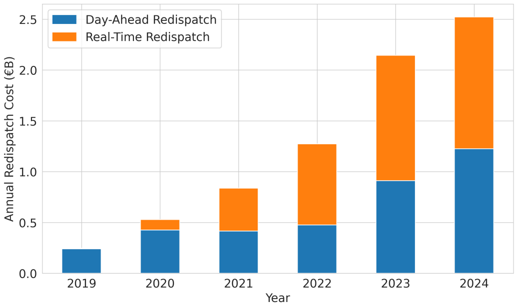
The Rising Cost of Reactive Intervention: Spain (2019–2024)

Redispatch, intended as a last-resort tool, has increased substantially in many EU member states, leading to significantly higher costs and volumes [Hirth and Schlecht, 2019, Graf et al., 2020, 2021, Davi-Arderius et al., 2025, Brown and Reguant, 2026, Graf et al., 2026]

Volumes



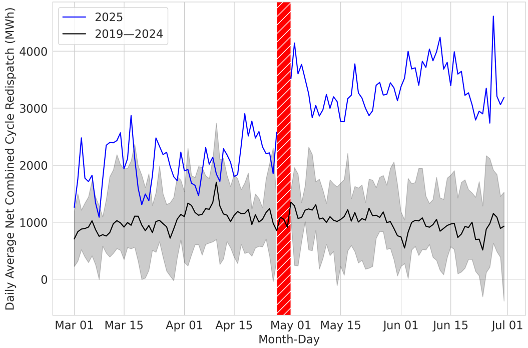
Costs



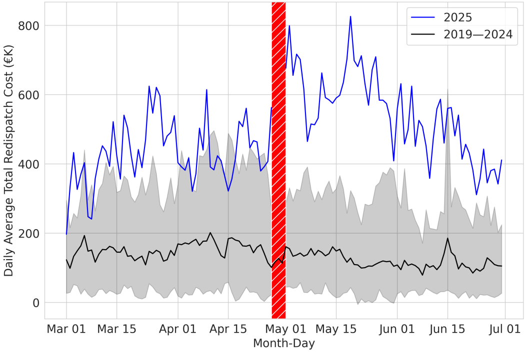
SO Response: A Shift Towards Operational Security

SO seems to have implemented more conservative operational mode post-blackout; more combined cycle (CC) gas, resulting in more renewable (IBR) curtailment and increased costs

CC Net Redispatch Volumes



Total Redispatch Cost



Quantifying the Hourly Post-Blackout Effect

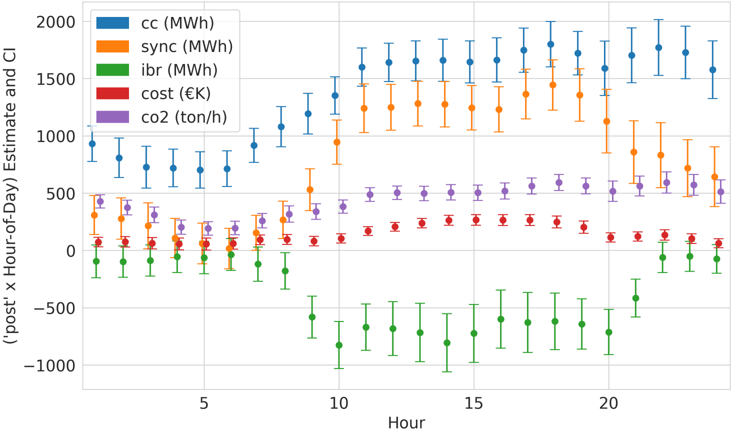
We use an event study model to quantify the effect (δ) of the post-blackout period (hourly data for March–June, 2019–2025) on redispatch outcomes

$$Y_{yh} = \alpha_y + \delta \text{post}_{yh} + \beta X_{yh} + \gamma F_{yh} + \epsilon_{yh}$$

	CC	IBR	Cost	CO2
post (hourly)	+1.4 GWh	−0.4 GWh	+€0.14M	+437 tCO2
post (annually)	+11.9 TWh	−3.5 TWh	+€1.2B	+3.8 MtCO2
2024	13.7 TWh	−9.2 TWh	€2.5B	7.1 MtCO2
post vs. 2024	+87%	+38%	+49%	+54%

- **CC Redispatch:** Net hourly CC volumes $\Uparrow\approx$1.4 GWh (INC)
- **IBR Redispatch:** Net hourly IBR (solar photovoltaics and wind) volumes $\Downarrow\approx$0.4 GWh (increased curtailment/DEC)

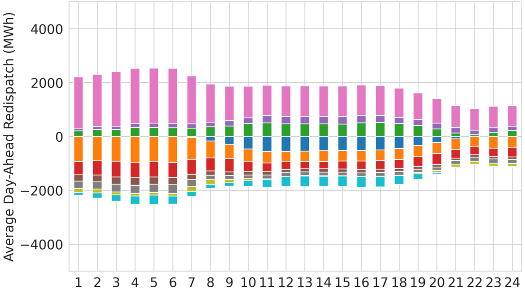
Post-Blackout Effects on Outcomes by Hour-of-Day

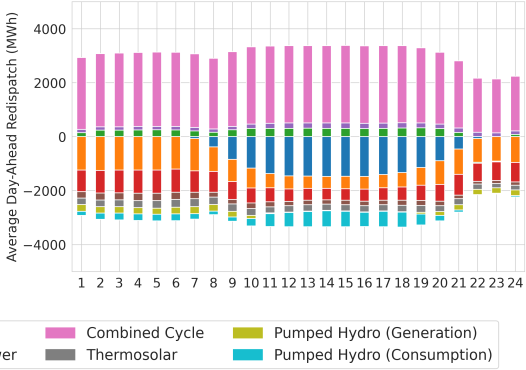


- **CC/Sync Generation Redispatch:** INC more pronounced during day
- **IBR Redispatch (solar photovoltaics and wind curtailment):** DEC more pronounced during day
- **Total Redispatch Costs / Redispatch-induced CO2 Emissions:** More pronounced during day

Shift to Day-Ahead Redispatch

SO shifted redispatch actions to the DA stage to resolve operational constraints earlier, reducing the "wait and see" risk associated with redispatching closer to RT



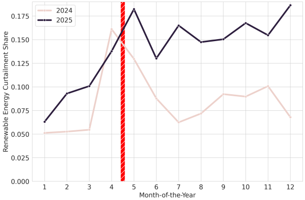


- **Day-Ahead** Post-blackout effects (δ) **more pronounced in DA stage** (e.g., CC INC +1.44 GWh; IBR DEC −0.73 GWh)
- **Real-Time** (RT) redispatch generally decreased or showed opposite signs

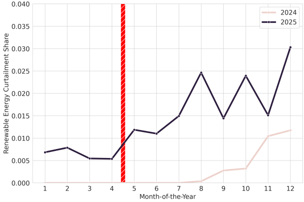
Spillover Effects

- Positive spillover effects from (cross-border) transmission: Resource adequacy benefits in extreme weather events (if spatially uncorrelated), overall economic benefits from more cross-border trade [Hausman, 2025, Canniére, 2026], and increased competitiveness [Ryan, 2021, Graf and Wolak, forthcoming]
- Negative spillover (contagion) effect: Operational disruptions can propagate across interconnected power systems. Harmonize operational reliability standards across interconnected grids.
- Cross-regional learning spillovers: Major disruptions in one region can lead grid operators elsewhere to revise risk assessments and preparedness measures.

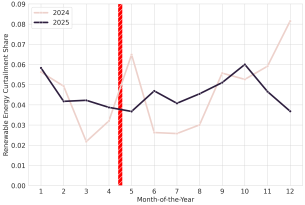
Spain



Portugal



Germany



Conclusion and Discussion

- Evidence that Spanish SO has switched to a more conservative operating mode post-blackout (arguably to decrease the operational risk)
- More redispatch actions earlier on rather than waiting until closer to real-time
- Redispatch of more fossil-fuel generating units at the expense of renewable (wind and solar) generation
  - Estimated (rough) annual increase in redispatch costs of €1.2B and €436M in redispatch-induced CO2 damages (valued at €114/tCO2; social cost of carbon of €188/tCO2 net of 2025 average EU-ETS price of €74/tCO2).
  - Actual annual redispatch cost: €3.8B in 2025 vs. €2.5B in 2024
- In any electricity market the effective competition takes place through the actual, potentially constrained, network [Ryan, 2021, Hausman, 2025, Graf and Wolak, forthcoming]. A short-term wholesale market design that supports the secure system operation *from the outset* rather than having SOs to reactively correct infeasible market schedule might be beneficial

Thank You for Your Attention!

Christoph Graf
christoph.graf@nyu.edu

References I

Roger E. Bohn, Michael C. Caramanis, and Fred C. Schweppe. Optimal Pricing in Electrical Networks over Space and Time. The Rand Journal of Economics, 15(3):360–376, 1984.

Severin Borenstein, James Bushnell, and Erin Mansur. The Economics of Electricity Reliability. Journal of Economic Perspectives, 37(4):181–206, 2023. doi: https://doi.org/10.1257/jep.37.4.181.

David M. Brown. Congestion unpriced: Inefficiency and gaming in Ontario's two-schedule electricity market design. The Electricity Journal, 37(1): 107352, 2024. doi: https://doi.org/10.1016/j.tej.2023.107352.

David P. Brown and Mar Reguant. The Price Impacts of Renewable Power: A Tale of Two Sources. International Journal of Industrial Organization, page 103283, 2026. doi: https://doi.org/10.1016/j.ijindorg.2026.103283.

David P. Brown, Derek E.H. Olmstead, and Blake Shaffer. Electricity market design with increasing renewable generation: Lessons from Alberta. The Electricity Journal, page 107484, 2025. doi: https://doi.org/10.1016/j.tej.2025.107484.

Jesse Buchsbaum, Catherine Hausman, Johanna L Mathieu, and Jing Peng. Spillovers from ancillary services to wholesale energy markets. The RAND Journal of Economics, 55(1):87–111, 2024. doi: https://doi.org/10.1111/1756-2171.12459.

Charlotte De Canniére. Market Integration and Market Efficiency: Evidence from Transmission Constraints in the Belgian Electricity Sector. Working paper, 2026.

Peter Cramton. Electricity market design. Oxford Review of Economic Policy, 33(4):589–612, 2017. doi: https://doi.org/10.1093/oxrep/grx041.

Daniel Davi-Arderius and Tim Schittekatte. Carbon emissions impacts of operational network constraints: The case of Spain during the Covid-19 crisis. Energy Economics, 128:107164, 2023. doi: https://doi.org/10.1016/j.eneco.2023.107164.

Daniel Davi-Arderius, Tooraj Jamasb, and Juan Rosellon. Network operation constraints on the path to net zero. Applied Energy, 382:125170, 2025.

Anselm Eicke and Tim Schittekatte. Fighting the wrong battle? A critical assessment of arguments against nodal electricity prices in the European debate. Energy Policy, 170:113220, 2022. doi: https://doi.org/10.1016/j.enpol.2022.113220.

Will Gorman. The quest to quantify the value of lost load: A critical review of the economics of power outages. The Electricity Journal, 35(8):107187, 2022. doi: https://doi.org/10.1016/j.tej.2022.107187.

Christoph Graf. Simplified short-term electricity market designs: Evidence from Europe. The Electricity Journal, page 107486, 2025. doi: https://doi.org/10.1016/j.tej.2025.107486.

Christoph Graf and Frank A. Wolak. Measuring Market Power in Network-Constrained Markets. The RAND Journal of Economics, forthcoming. URL `https://www.nber.org/papers/w34272`.

References II

Christoph Graf, Federico Quaglia, and Frank A. Wolak. Simplified Electricity Market Models with Significant Intermittent Renewable Capacity: Evidence from Italy. NBER Working Papers 27262, National Bureau of Economic Research, 2020. URL `http://www.nber.org/papers/w27262`.

Christoph Graf, Federico Quaglia, and Frank A. Wolak. (Machine) learning from the COVID-19 lockdown about electricity market performance with a large share of renewables. Journal of Environmental Economics and Management, 105:102398, 2021.

Christoph Graf, Federico Quaglia, and Frank A. Wolak. Market Performance Assessment in Locational Markets with Non-convexities. Working paper, 2022. `https://fawolak.org/pdf/NonConvexBenchmark_0.pdf`.

Christoph Graf, Nils Angliviel de La Beaumelle, Robert Huang, Marco Tacke, and Frank A. Wolak. Same, Same But Different: INC/DEC Incentives in Great Britain's Short-Term Wholesale Electricity Market. Working paper, 2026.

Catherine Hausman. Power Flows: Transmission Lines, Allocative Efficiency, and Corporate Profits. American Economic Review, 115(8):2574–2615, 2025. doi: https://doi.org/10.1257/aer.20240276.

Lion Hirth and Ingmar Schlecht. Redispatch Markets in Zonal Electricity Markets: Inc-Dec Gaming as a Consequence of Inconsistent Power Market Design (not Market Power). EconStor Preprints 194292, ZBW - Leibniz Information Centre for Economics, 2019.

William W. Hogan. Getting the Prices Right in PJM: What the Data Teaches Us. The Electricity Journal, 11(7):61–67, 1998. doi: https://doi.org/10.1016/S1040-6190(98)00072-4.

William W. Hogan. Transmission Congestion: The Nodal-Zonal Debate Revisited. Memo, 1999. URL `https://whogan.scholars.harvard.edu/sites/g/files/omnuum4216/files/whogan/files/nezn0208.pdf`.

William W. Hogan. Strengths and weaknesses of the PJM market model. In Jean-Michel Glachant, Paul L. Joskow, and Michael G. Pollitt, editors, Handbook on Electricity Markets, chapter 7, pages 182–204. Edward Elgar, 2021. doi: https://doi.org/10.4337/9781788979955.00013.

Akshaya Jha and Gordon Leslie. Start-up Costs and Market Power: Lessons from the Renewable Energy Transition. American Economic Review, 115 (2):690–724, 2025. doi: https://doi.org/10.1257/aer.20211145.

Paul Joskow and Jean Tirole. Reliability and competitive electricity markets. The RAND Journal of Economics, 38(1):60–84, 2007. doi: https://doi.org/10.1111/j.1756-2171.2007.tb00044.x.

Gordon W. Leslie and Farhad Billimoria. How new (and old) power system operating constraints map to Australia's wholesale electricity market model. The Electricity Journal, page 107489, 2025.

References III

Nicholas Ryan. The Competitive Effects of Transmission Infrastructure in the Indian Electricity Market. American Economic Journal: Microeconomics, 13(2):202–42, 2021. doi: https://doi.org/10.1257/mic.20180191.

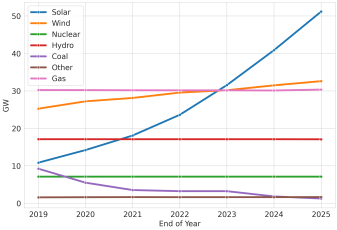
Robert Wilson. Architecture of Power Markets. Econometrica, 70(4):1299–1340, 2002.

Frank A. Wolak. Chapter 4: Wholesale electricity market design. In Handbook on Electricity Markets. Edward Elgar Publishing, 2021. doi: https://doi.org/10.4337/9781788979955.00010.

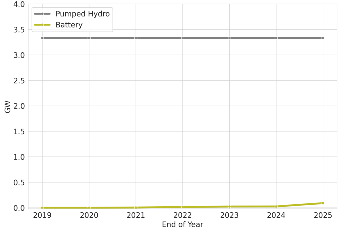
Frank A. Wolak. Long-Term Resource Adequacy in Wholesale Electricity Markets with Significant Intermittent Renewables. Environmental and Energy Policy and the Economy, 3:155–220, 2022. doi: https://doi.org/10.1086/717221.

Market Trends

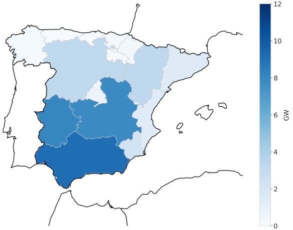
Generation Capacity



Storage Capacity



Solar Capacity (2024)



Source: Red Eléctrica de España (`https://www.ree.es`)

- Exponential solar growth within a short amount of time
- Solar capacity concentrated in the south [load centers are in the center (Madrid) and in the east (Barcelona)]
- **Negligible investment in battery storage**; grid capacity, measured by line length and transformer capacity, relatively stagnant