Empirical Estimates of Transmission Value using Locational Marginal Prices

Dev Millstein, Ryan Wiser, Will Gorman, Seongeun Jeong, James Kim, Amos Ancell
Lawrence Berkeley National Laboratory

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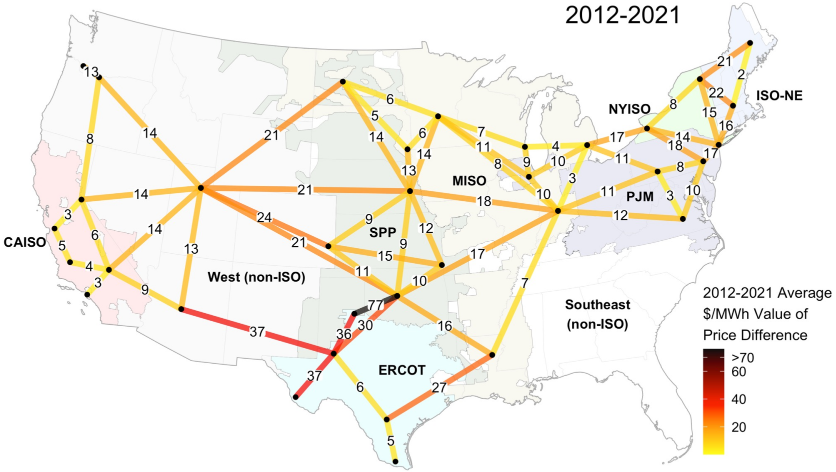
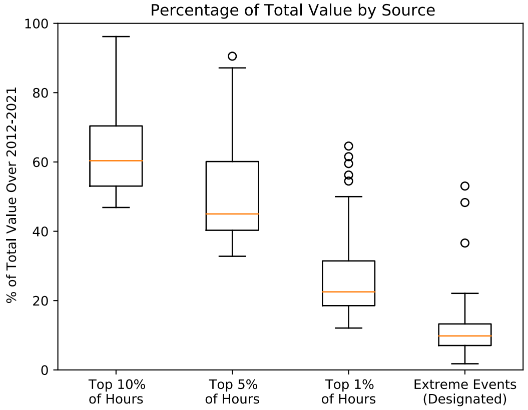
High-Level Summary

- We developed a metric that approximates the production cost savings from transmission
  - Production cost savings often account for *roughly* half of total transmission value
- We found many instances of high transmission values across the full study time period (2012 – 2022) with particularly large values in 2021 and H1 2022
- Transmission value was concentrated in a small number of hours (5% of hours ≈≈ 50% of value)
- High value hours occurred well beyond named weather events or NERC identified periods of grid stress and occurred most during infrequent but ‘normal’ operational conditions
- Transmission planners and energy modelers may *substantially* underestimate the production cost portion of transmission value if not properly accounting for these high value hours





Introduction and motivation

- Transmission can help reduce the system-wide costs of supplying electricity and can also improve grid reliability and resiliency
- Build decisions depend on the cost benefit tradeoffs
- **An important challenge in transmission planning and coordination is estimating the full range of benefits that transmission investments provide**
- This study focuses on a subset of total transmission value – congestion value – because there is concern in the literature that congestion value is often underestimated in transmission planning studies
- Congestion value is related to production cost savings, which is an important component of total transmission benefits (roughly half) and is a commonly estimated benefit of transmission
- By using empirical data, our analysis accounts for transmission benefits inclusive of extreme weather and other high value conditions (e.g., generator or infrastructure outages, forecast uncertainty, etc.)
- Forward-looking models of production cost and congestion savings are challenged in projecting value during more extreme weather conditions and other high value conditions

Goals and scope

- Our goal with this analysis is to examine historical pricing trends and spatial differences to gain insight into possible transmission benefits that are often overlooked
- This analysis does not provide a comprehensive estimate of transmission value
- The analysis does provide new insight into one portion of total transmission value: the value of congestion relief, or the arbitrage value of linking two locations with different prices, including during more extreme grid conditions and high value hours

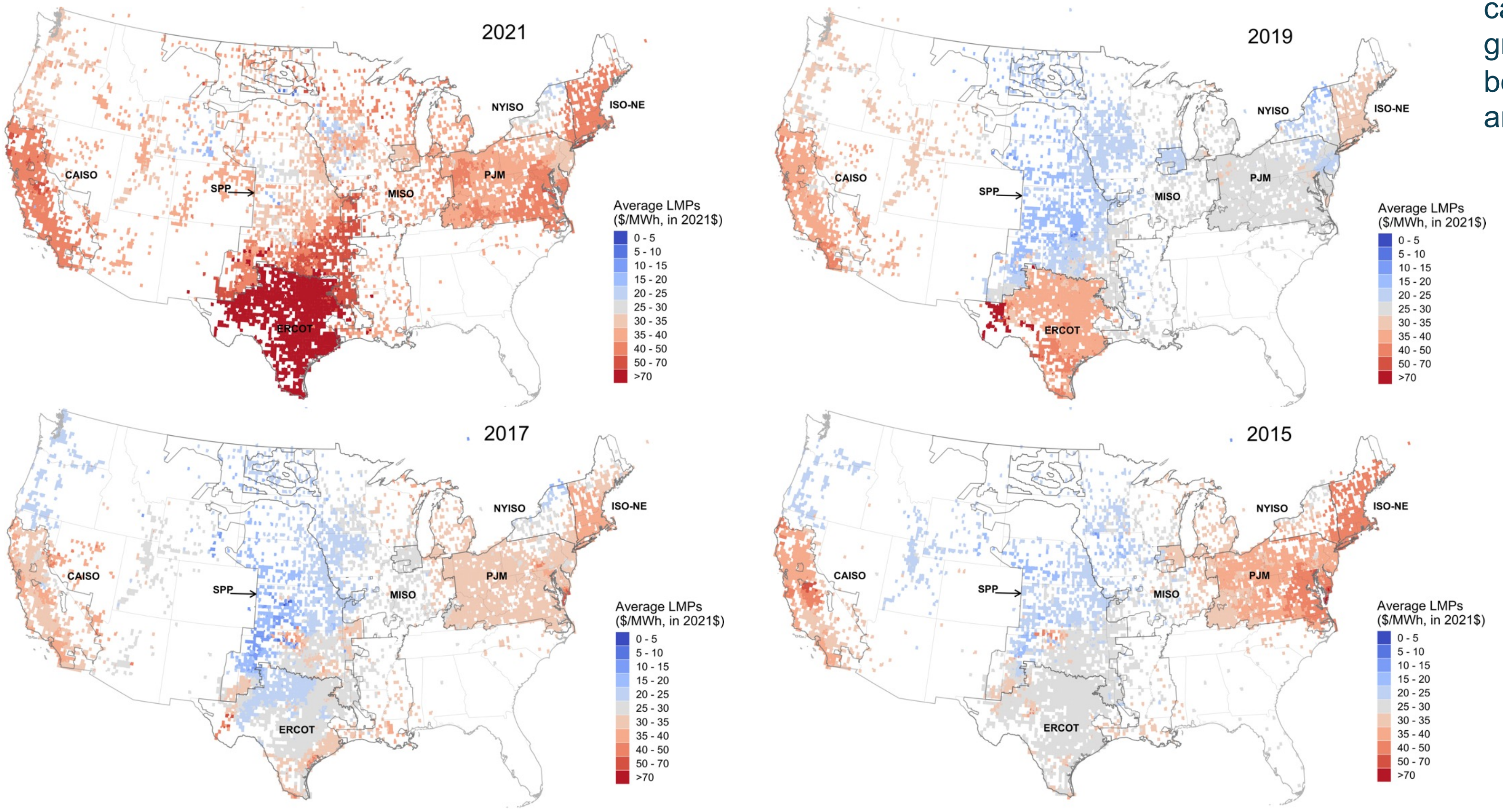
Approach: Analyze local hourly electricity prices

- Differences in real-time nodal electricity prices (LMPs) indicate transmission congestion value
- We examine regional and interregional variability as well as how spatial differences in price vary over years
- Key limitations:
  - Pricing differentials only represent a portion of total transmission benefits
  - Historical values do not necessarily reflect values under changing or future market conditions
  - LMPs are “marginal” prices, thus calculated transmission values are subject to saturation effects
  - LMPs are from energy markets, and benefit estimates do not include capacity market value
  - Some differences in pricing between regions is due to differences in market rules and structure rather than lack of transmission
  - A small portion of LMP differences are due to electrical losses rather than congestion

Real versus nominal dollars: All dollar values shown throughout this document have been converted to the 2021 dollar year based on the Consumer Price Index.

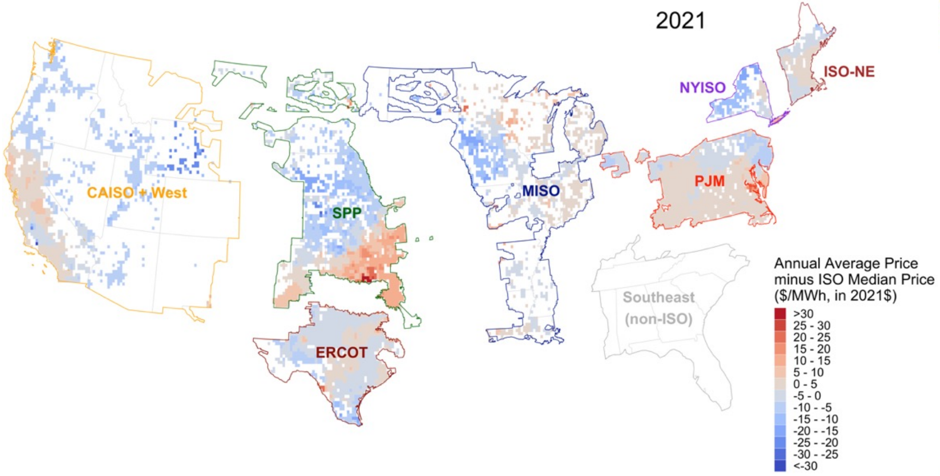
Estimating Transmission Value with Locational (Nodal) Market Prices (LMPs)

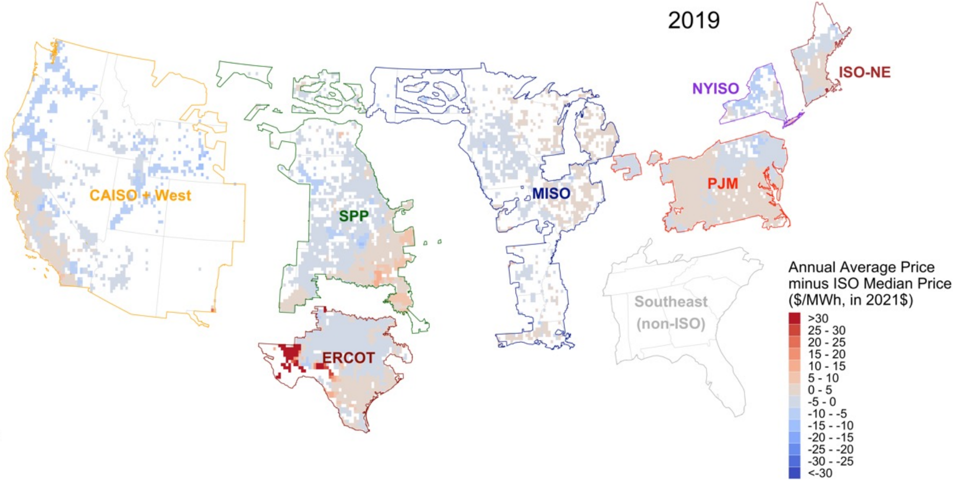
Context: Annual average real-time nodal wholesale electricity prices vary strongly by year and location

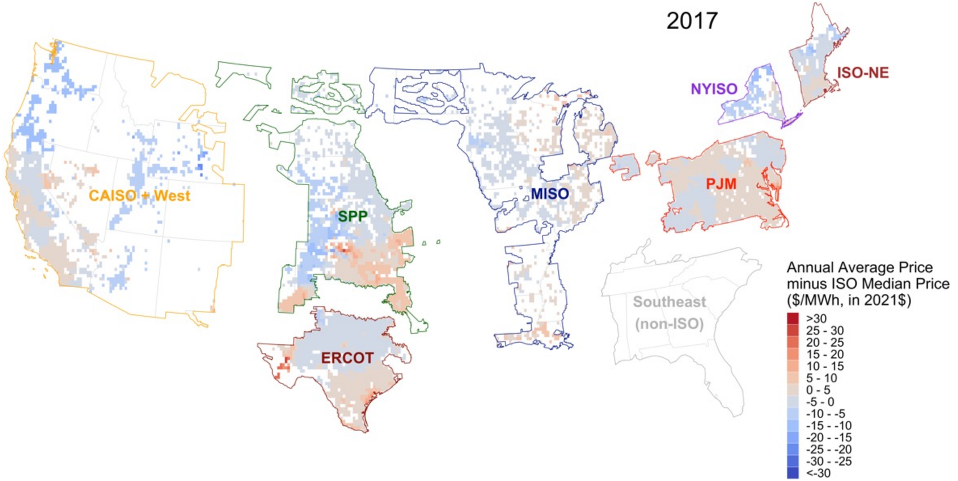


Beyond the clear difference in price between years, one can observe spatial gradients in prices both within regions and across regions

Context: Annual average pricing gradients shows within-region congestion

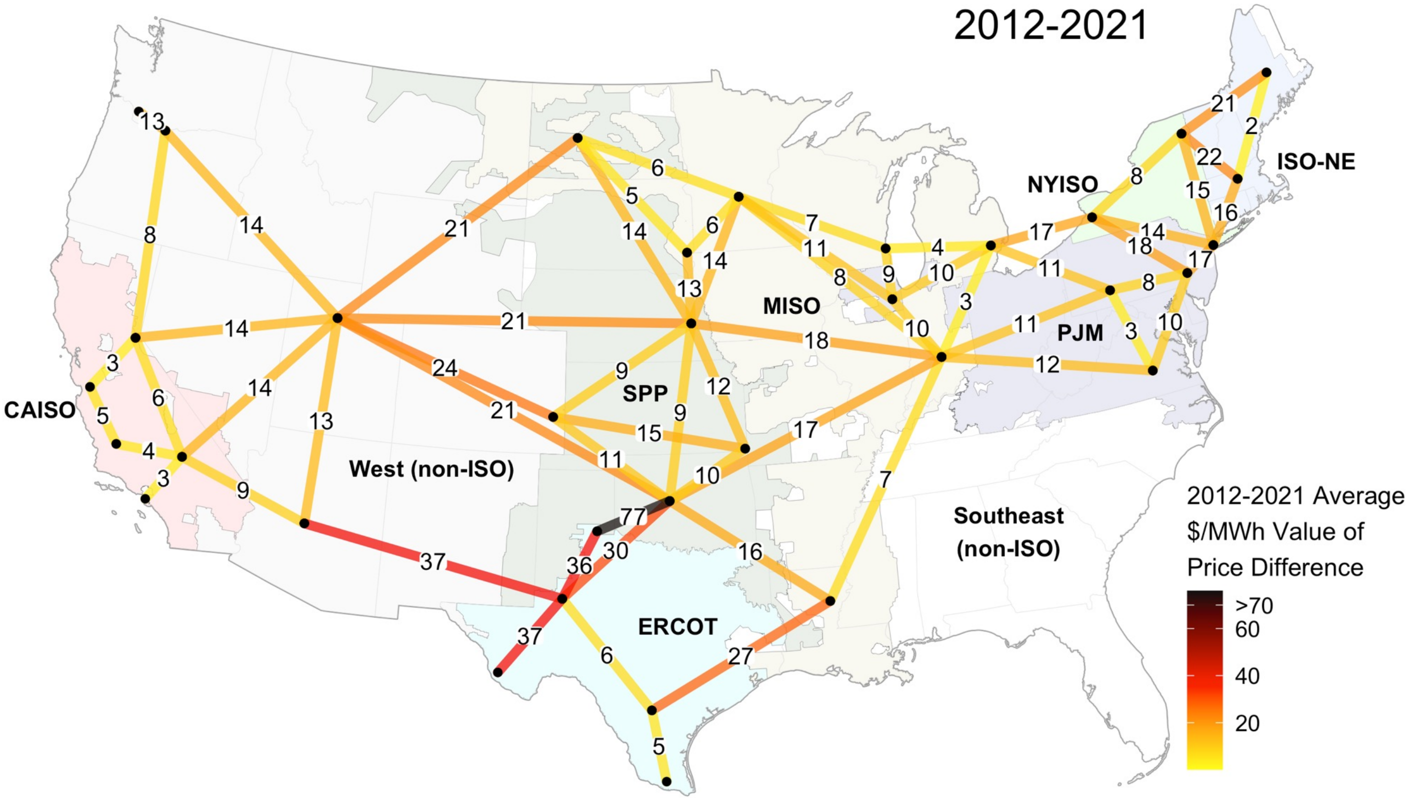






- Within-region spatial gradients in annual average pricing are relatively stable over time
- These gradients represent a lower bound of congestion impacts as they are based on annual prices
- This does not provide insight into interregional congestion
- Transmission could help lower costs in high priced regions

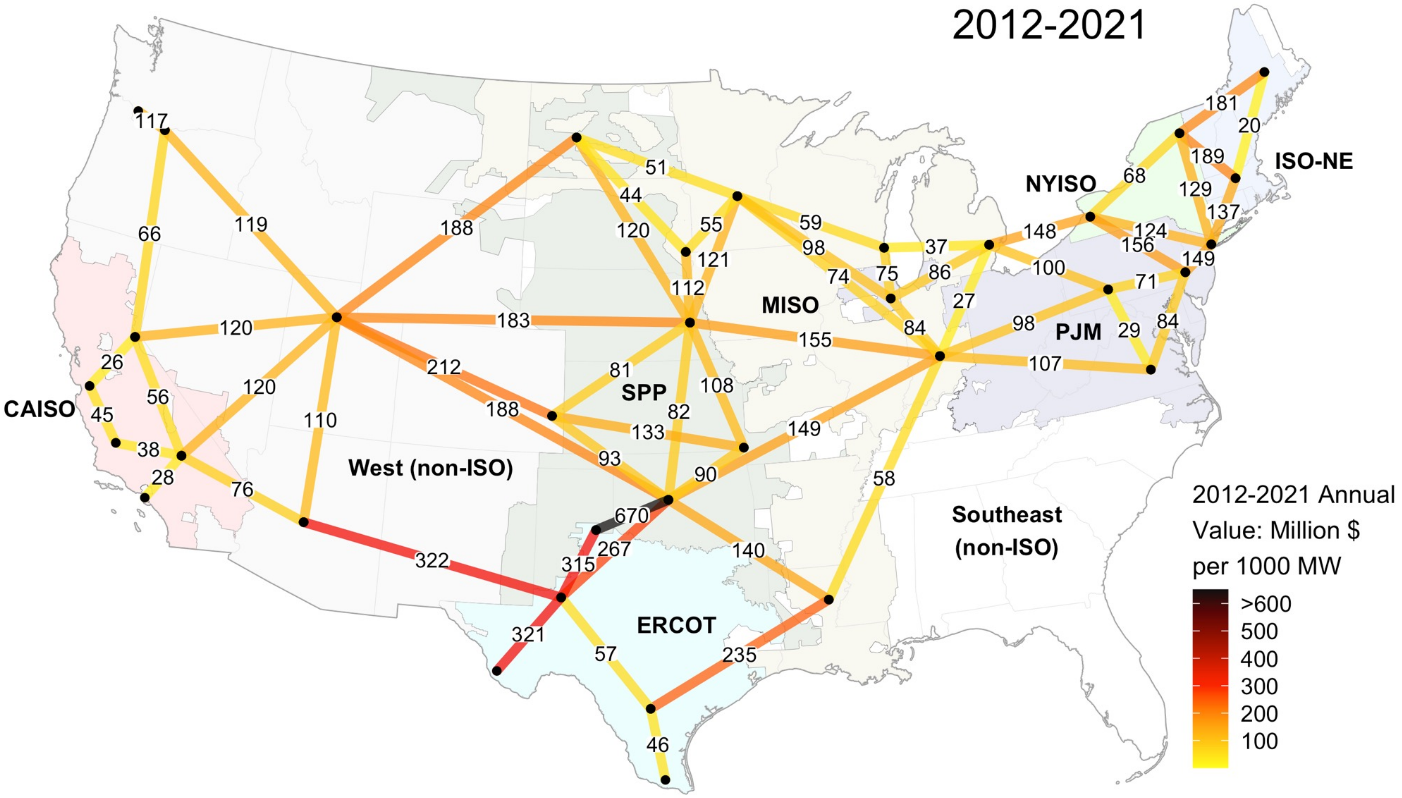
Marginal value of transmission in relieving congestion in 2012-2021 (in $/MWh Units)



$2/MWh to $77/MWh

- Relatively high value links are found in many regions
- High value links to the Texas panhandle and Texas Big Bend region are valuable due to unusually high values found in 2018 and 2019 at these locations
- Extreme events are discussed more generally in the next section

Marginal value of transmission in relieving congestion in 2012-2021 (in $/1000 MW-year units)

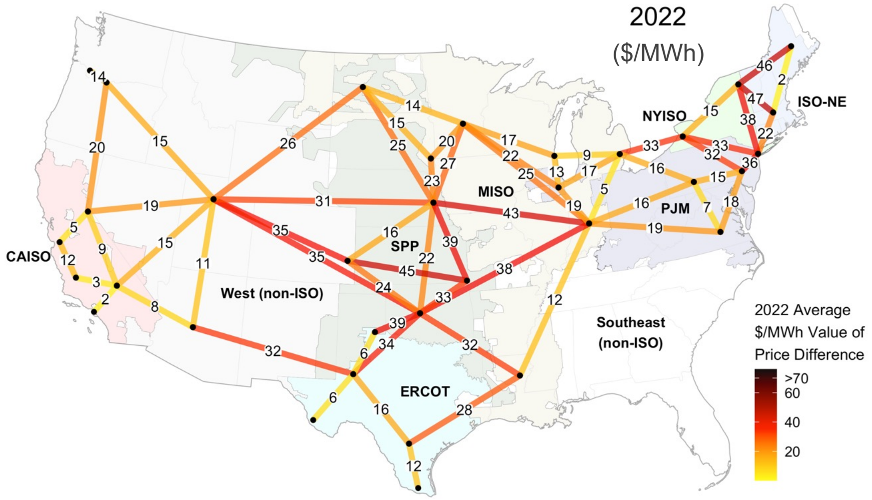


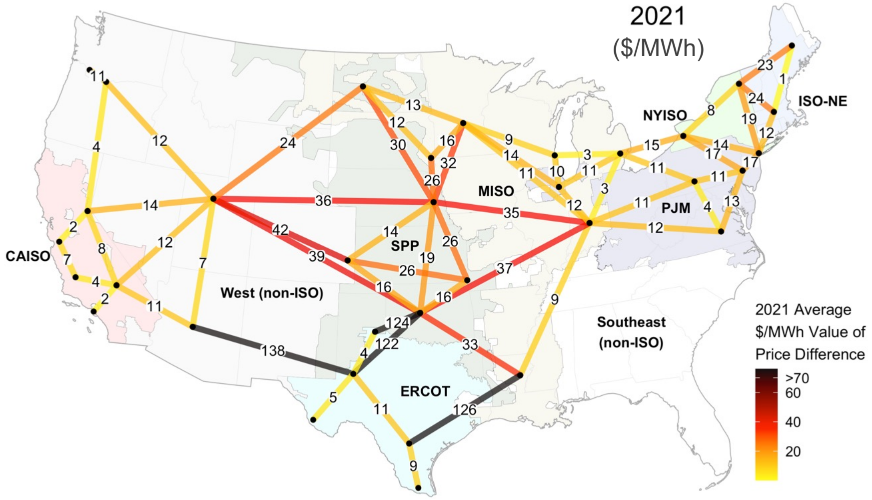
$20 to $670 million/year (for 1000-MW capacity)

- Relatively high value links are found in many regions
- High value links to the Texas panhandle and Texas Big Bend region are valuable due to unusually high values found in 2018 and 2019 at these locations
- Extreme events are discussed more generally in the next section

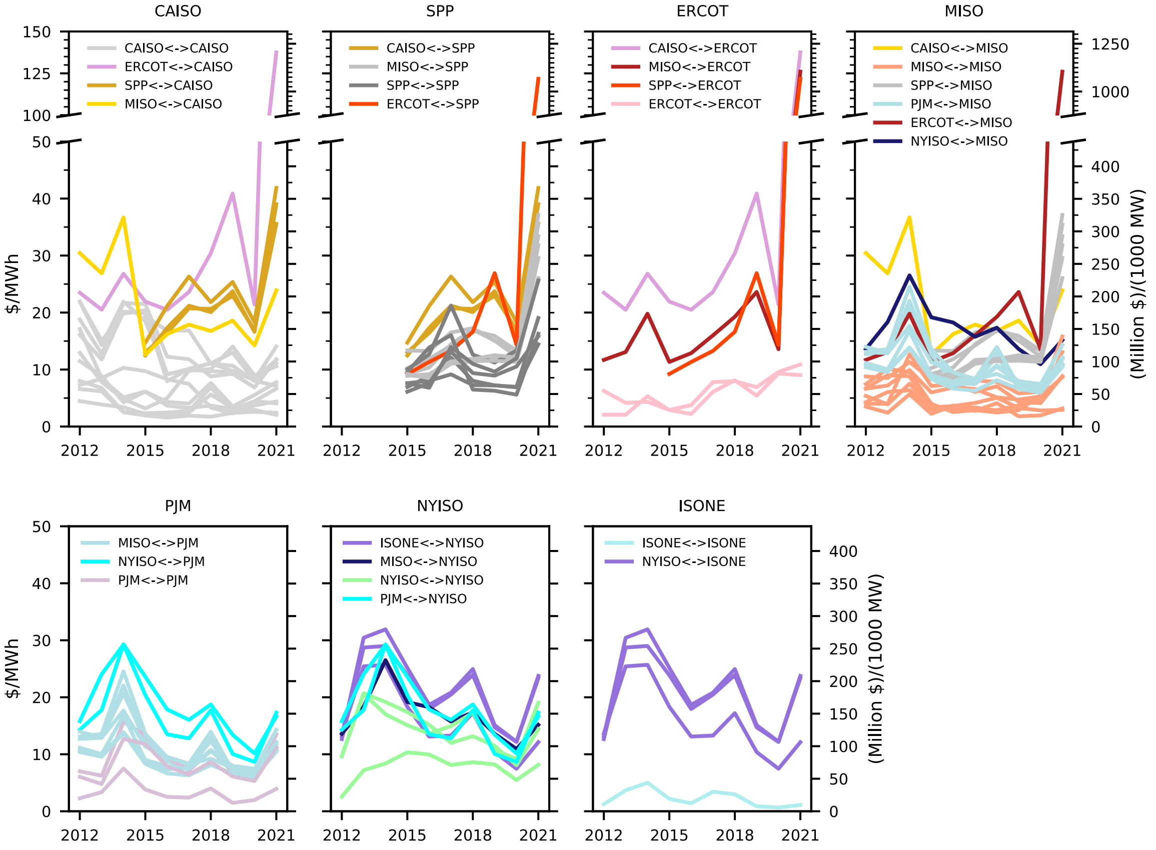
Transmission values high in 2021 and the first half of 2022

- YTD 2022 transmission values are similar or higher to 2021 even without similarly extreme weather events
- The exception are interregional links into ERCOT. These links have lower value in 2022 than in 2021, links into and within SPP have maintained high values into 2022
- Links in the northeast and northwest of the U.S. also have high values in the first half of 2022





High value links occur in different regions in different years



- A number of links in ERCOT and SPP show an upward trend that begins prior to 2021
- Values tend to be correlated with overall wholesale prices
- Overall the unpredictable variation in wholesale prices and extreme conditions makes it challenging to pick out trends in the value of transmission links

Analysis of Transmission Value During Extreme Events and High Value Hours

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Identifying extreme conditions: Two approaches

1. Identify a list of specific events that are known to have impact the electricity grid through literature review and NERC reports
2. At each link, find a subset of hours with the highest values (i.e., the top 10%, 5%, and 1% of all hours)

- These approaches identify a somewhat overlapping set of hours, and we take care to prevent double counting where relevant

Designated events

- Weather events identified in the literature: Named storms, heatwaves, polar vortex, etc.
- Periods of ‘grid stress’ identified in NERC reports

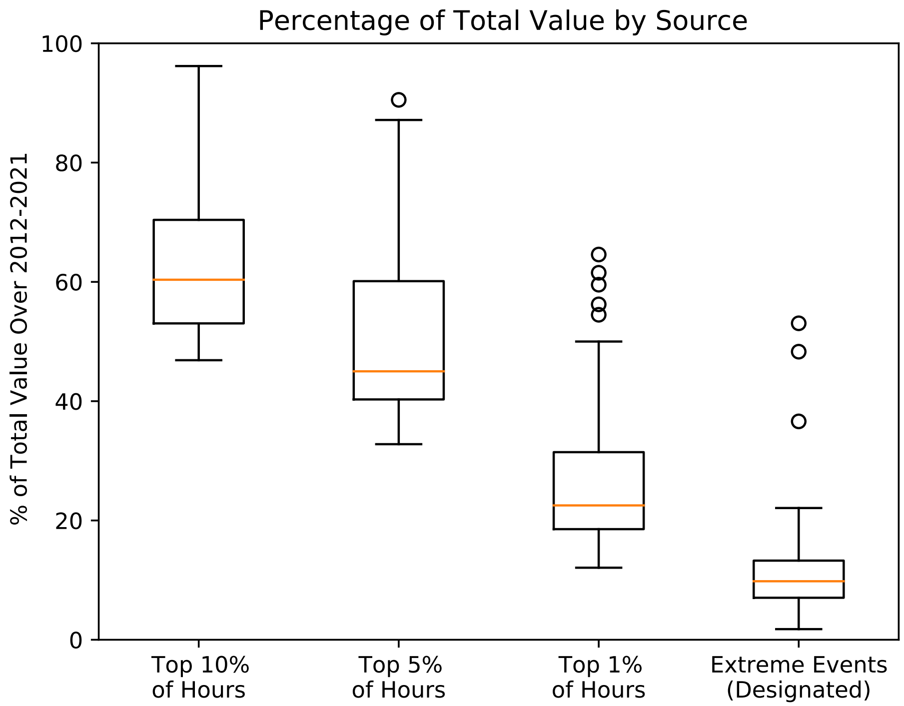
Top X%

- Hours identified by unusually large differences in prices between locations
- Specifically, the top 1%, 5%, 10% of price differences between locations over a specified time period.
- These hours may or may not overlap with the ‘designated’ events.

NERC: “North American Electric Reliability Corporation”

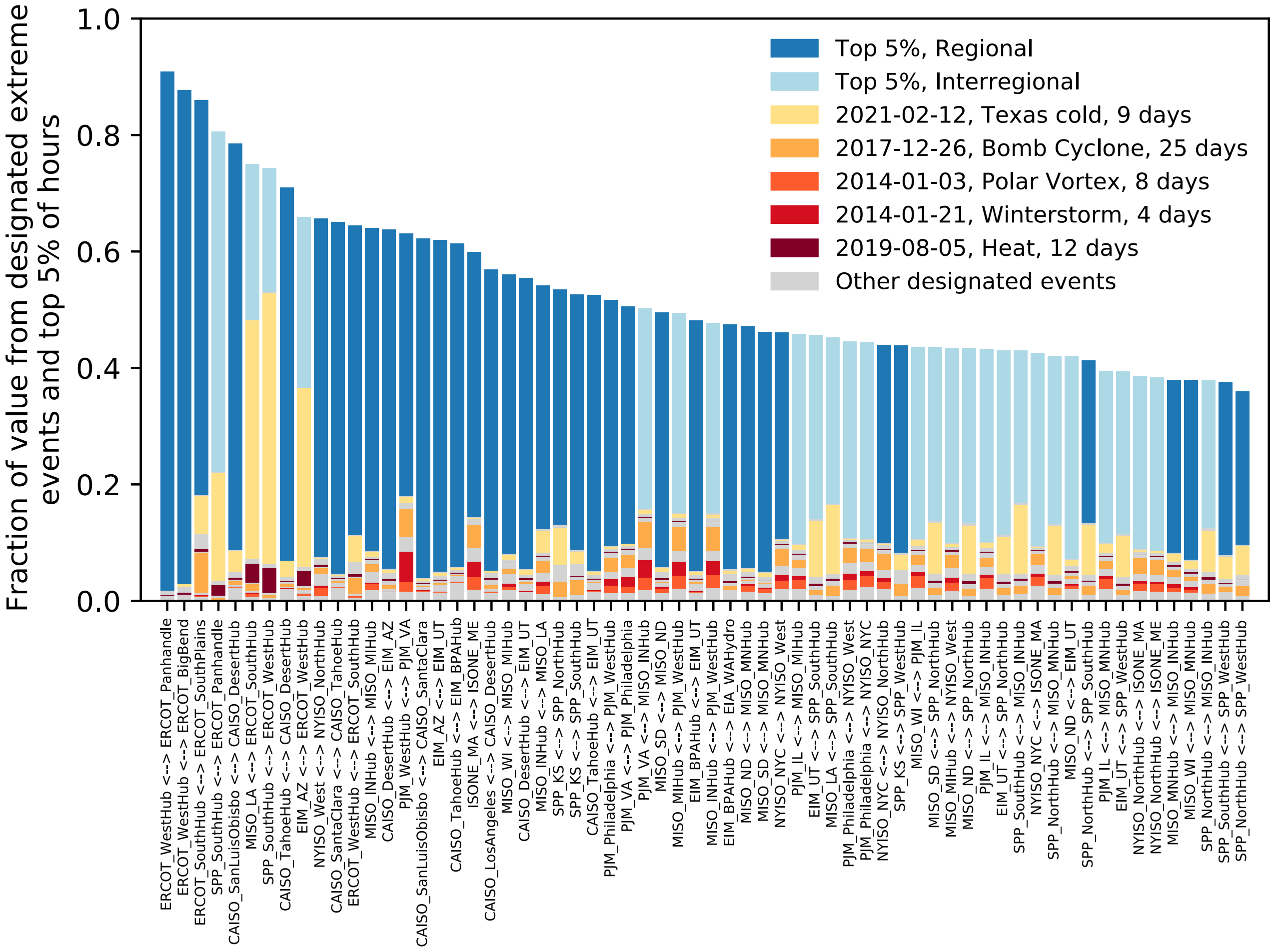
Extreme conditions and value

- In the median case, the top 10% and 5% of hours accounts for ~60% and ~50% of value, respectively
- The top 1% of hours account of 20 to 30% of total value
- Designated extreme events produce 10% to 20% of value (account for ~5% of total hours)
- This indicates that 'extreme' conditions that fall outside our extreme event designation process account for the majority of transmission value



Value during extreme conditions, 2012 – 2021

- Only a few of the many designated events included provide substantial value
- Only a few interregional links to ERCOT have >20% of value due to designated events
- At most links, value derives from infrequent high value hours outside of designated weather or grid stress events



Can models realistically represent the complexity inherent in the values of transmission?

Key challenges to modeling transmission value:

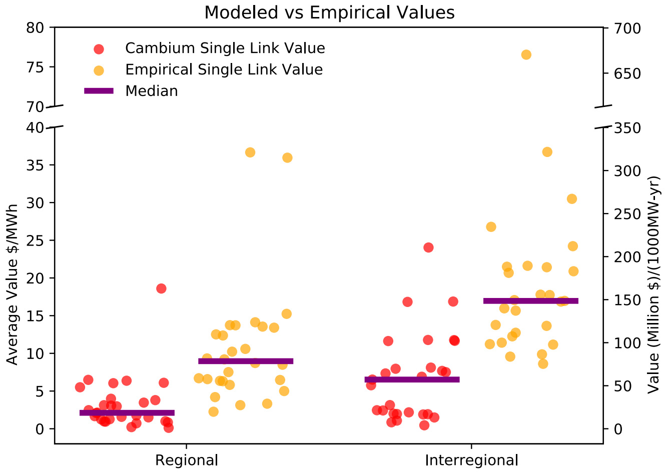
- Lack of a 'multi-value' focus and prioritization of only a subset of benefits (i.e., reliability)
- Normalized or average weather profiles
- Limited representation of infrastructure outages
  - Lack of correlated outages across multiple generators or existing transmission lines
- Deterministic simulations with limited or no representation of uncertainty in real-time conditions

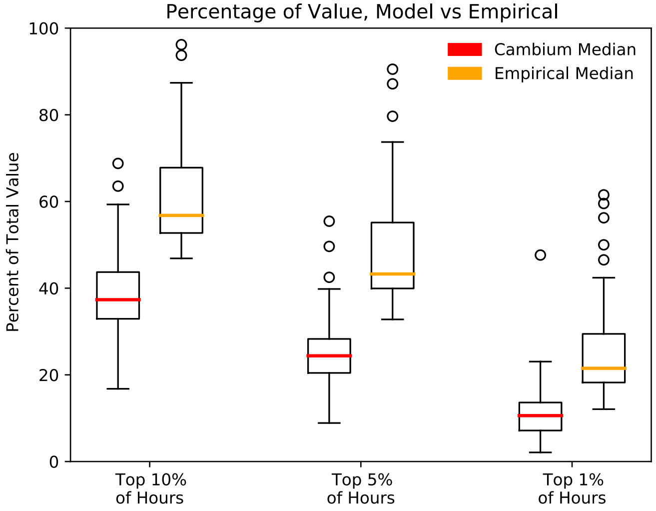
References:

1. Pfeifenberger et al. (2021) "Transmission Planning for the 21st Century: Proven Practices that Increase Value and Reduce Costs" The Brattle Group/Grid Strategies, https://www.brattle.com/insights-events/publications/brattle-economists-identify-transmission-needs-and-discuss-solutions-to-improve-transmission-planning-in-a-new-report-coauthored-with-grid-strategies/
2. Horn et al. (2020) "The Value of Diversifying Uncertain Renewable Generation through the Transmission System" Boston University Institute for Sustainable Energy. https://hdl.handle.net/2144/41451
3. Pfeifenberger et al., (2021) "Initial Report on the New York Power Grid Study" NYSERDA, https://beta.documentcloud.org/documents/20463209-nypowergridstudy

Model example: Value underestimated by ~3X

- Cambium-based national Standard Scenario modeling (*Ref 1*)
  - Note: This model is *not* used in a regulatory context and the modeling system has explicit limitations in representing transmission value, including, but not limited to, a zonal rather than nodal market representation
  - The comparison is based on the average 2012 – 2021 empirical values versus a modeled year of 2022
- This demonstrates the consequences of not explicitly representing extreme conditions, extreme events, fuel-price volatility, generation and load uncertainty, and geographic market resolution in estimating transmission value
- One likely cause for this discrepancy in value is that a much smaller portion of total modeled value is due to extreme events or high value hours compared to the empirical analysis
  - For example, the top 5% of hours account for ~50% of value empirically, but only 25% in the modeled system





1. Cole et al. (2021) "2021 Standard Scenarios Report: A U.S. Electricity Sector Outlook" National Renewable Energy Laboratory (NREL). NREL/TP-6A40-80641. https://www.nrel.gov/docs/fy22osti/80641.pdf

Conclusions

Key conclusions

1. Wholesale power prices exhibit stark geographic differences that, in many cases, are stable over time.
2. Many regional and interregional transmission links have significant potential economic value from reducing congestion and expanding opportunities for trade.
3. The value of transmission is correlated with overall energy prices and varies by region and year. At many links, the transmission value in 2021 and the beginning of 2022 was substantially larger than the 2012 – 2020 average.
4. Extreme conditions and high-value periods play an outsized role in the value of transmission, with 50% of transmission's congestion value coming from only 5% of hours.
5. Transmission planners run the risk of understating the benefits of regional and interregional transmission if extreme conditions and high-value periods are not adequately considered.

Interpretation of transmission value

- **Avoided cost:** The congestion value of transmission calculated here is derived from the value of allowing a lower cost set of generators to meet load and by increasing operational flexibility through reduced congestion and increased interregional trade. Thus, value can also be thought of as the potential to reduce system cost through reducing congestion. In other words, properly accounting for the full suite of values that derive from transmission is critical toward building a least-cost electricity system.

- **Insurance value:** The fact that so few hours (5%) account for such a large portion of transmission value, and that a small number of extreme events (1 – 3 over ten years) can contribute meaningfully to the total 10-year value of a particular link, indicates that one lens with which to view transmission value is that of 'insurance' against the high costs of faced during extreme grid conditions, extreme events, or other factors (such as unexpected deviations from forecasted conditions).

- With insurance, as with some other benefits, attribution of value between different stakeholders is challenging because each stakeholder's potential benefits depend on the characteristics of future extreme grid conditions or weather events that are unpredictable. The attribution of this complex value is another challenge that faces transmission planners as they strive to weigh the costs and benefits of transmission expansion projects.

Key limitations

1. The transmission value analyzed only represents the value in reducing energy market congestion. It does not include value from capacity markets, reliability value, or other value streams described in the introduction.
2. The transmission value analyzed represents a marginal value and thus would be subject to saturation effects. We did not explore the capacity of transmission that could be installed at each location prior to substantial decline in marginal value.
3. Historical values do not necessarily reflect values under changing or future market conditions.
4. Some differences in pricing between regions is due to wheeling charges and differences in market rules and market structure rather than transmission constraints.
5. We did not investigate the costs of transmission, which vary greatly by location, distance, and many circumstantial factors.

Contact and acknowledgements

Contact: Dev Millstein (dmillstein@lbl.gov)

Full Report: https://emp.lbl.gov/publications/empirical-estimates-transmission

More Information: https://emp.lbl.gov

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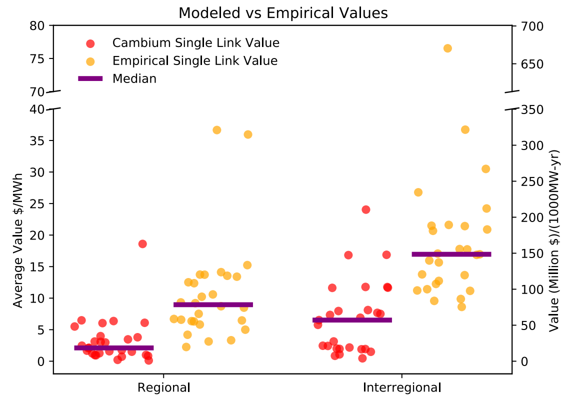
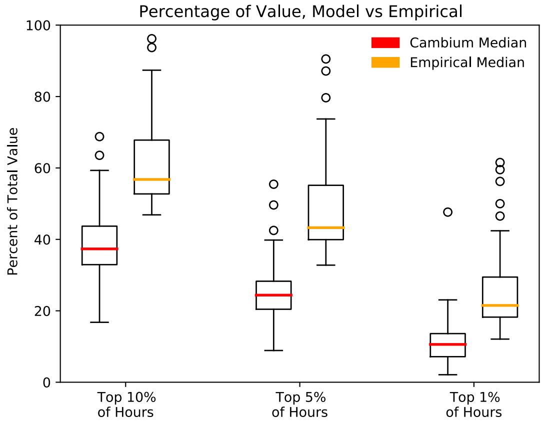
Appendix

Identifying extreme conditions: Designated events

- We identified 171 extreme event days (with many events covering multiple consecutive days) between 2012 and 2021.
- We identified these extreme events based on specific events listed in:
  1. Goggin M. (2021) “Transmission Makes the Power System Resilient to Extreme Weather”, Grid Strategies. https://acore.org/transmission-makes-the-power-system-resilient-to-extreme-weather/#:~:text=The%20analysis%20finds%20that%20each,Uri%20in%20February%20of%202021
  2. Novacheck et al. (2021) “The Evolving Role of Extreme Weather Events in the US Power System with High Levels of Variable Renewable Energy” National Renewable Energy Lab. (NREL), NREL/TP-6A20-78394. https://doi.org/10.2172/1837959
- We also identified the top-10 NERC high grid stress days (using the severity risk index) as designated by NERC in their Annual State of Reliability reports. These can be found at https://www.nerc.com/pa/RAPA/PA/Pages/default.aspx
- These events covered various weather events, such as heatwaves, cold snaps, hurricanes, polar vortices, bomb cyclones, wind storms, winter storms, and other extreme weather events.
- The events also included non-weather related stressors, such as coincidental generator outages.

Methods for the comparison to modeled transmission value





- Here we examined the NREL Standard Scenarios which were created with a combination of the capacity-expansion model ReEDS and the dispatch model Plexos.
- We examined value in the model year 2022, using the 2021 model version, and specifically used the ‘mid-case’ scenario. See https://scenarioviewer.nrel.gov for more information.
- We matched model balancing areas to the empirical nodes and compared price time series between balancing areas to determine value in a similar manner to how value was determined in the empirical analysis. 9 of 64 links were not able to be recreated as both ends were contained within a single modeled BA. Of those 9, 4 were located in CAISO, 2 in NYISO, 2 in PJM, and one in ERCOT. All interregion links were replicated.
- We compared value to the average empirical value across 2012 – 2021. Empirical values were on average larger in 2021 and the beginning of 2022, meaning that the comparison to only recent data would show a larger discrepancy between modeled and empirical transmission value.
- Modeled average wholesale prices were similar to average empirical prices over the 2012 – 2021 period, though modeled prices were overall ~10% lower than observed prices. This difference in overall wholesale prices likely accounts for a small portion of the difference in modeled to empirical value of transmission. It would not account for the difference in the portion of transmission value contained in the top 5% of hours.