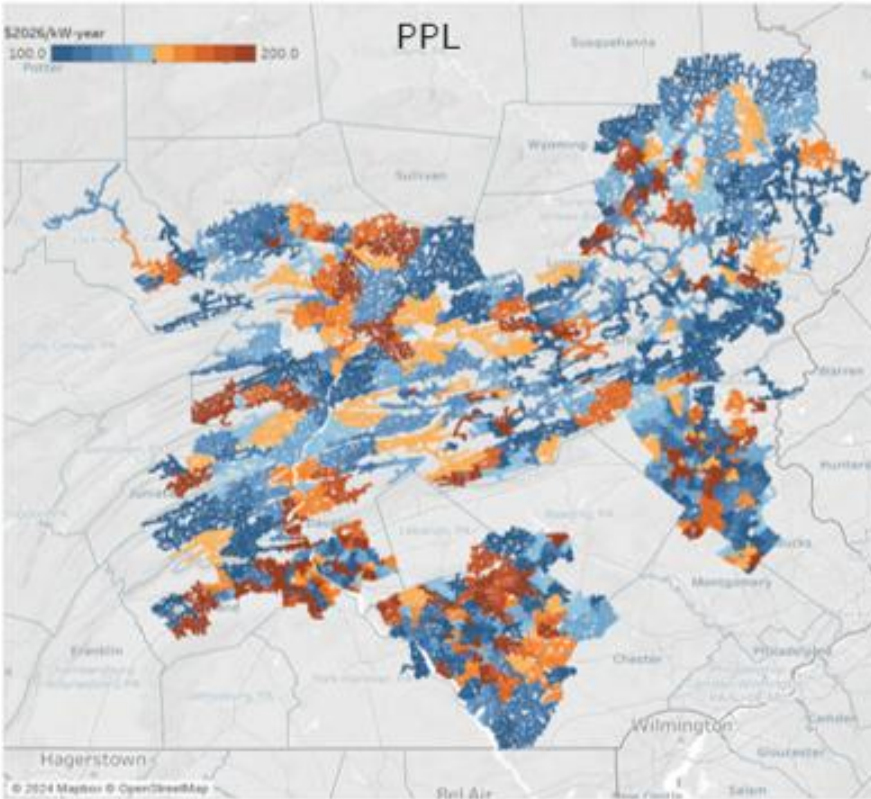
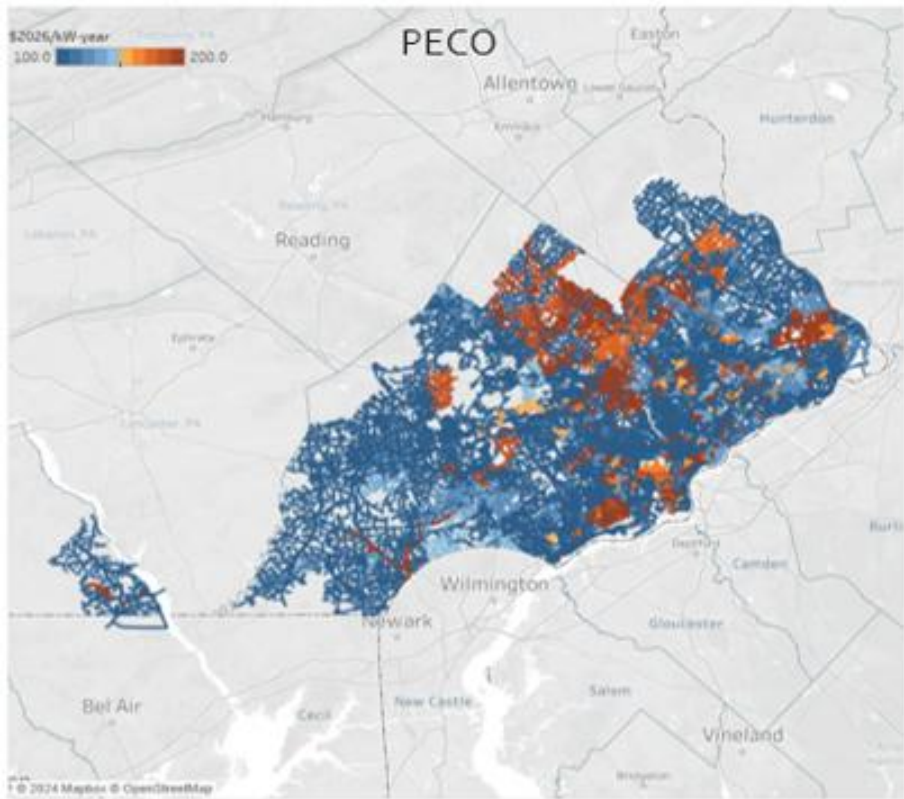


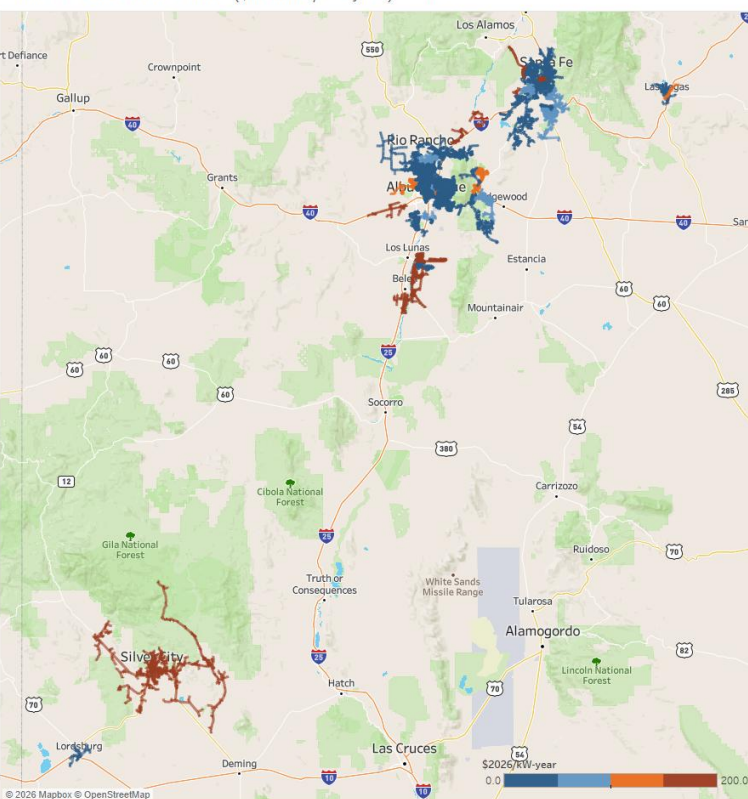
# GRANULAR AVOIDED T&D COST STUDIES



## AEIC WLRA SPRING 2026 LOAD RESEARCH & ANALYTICS CONFERENCE



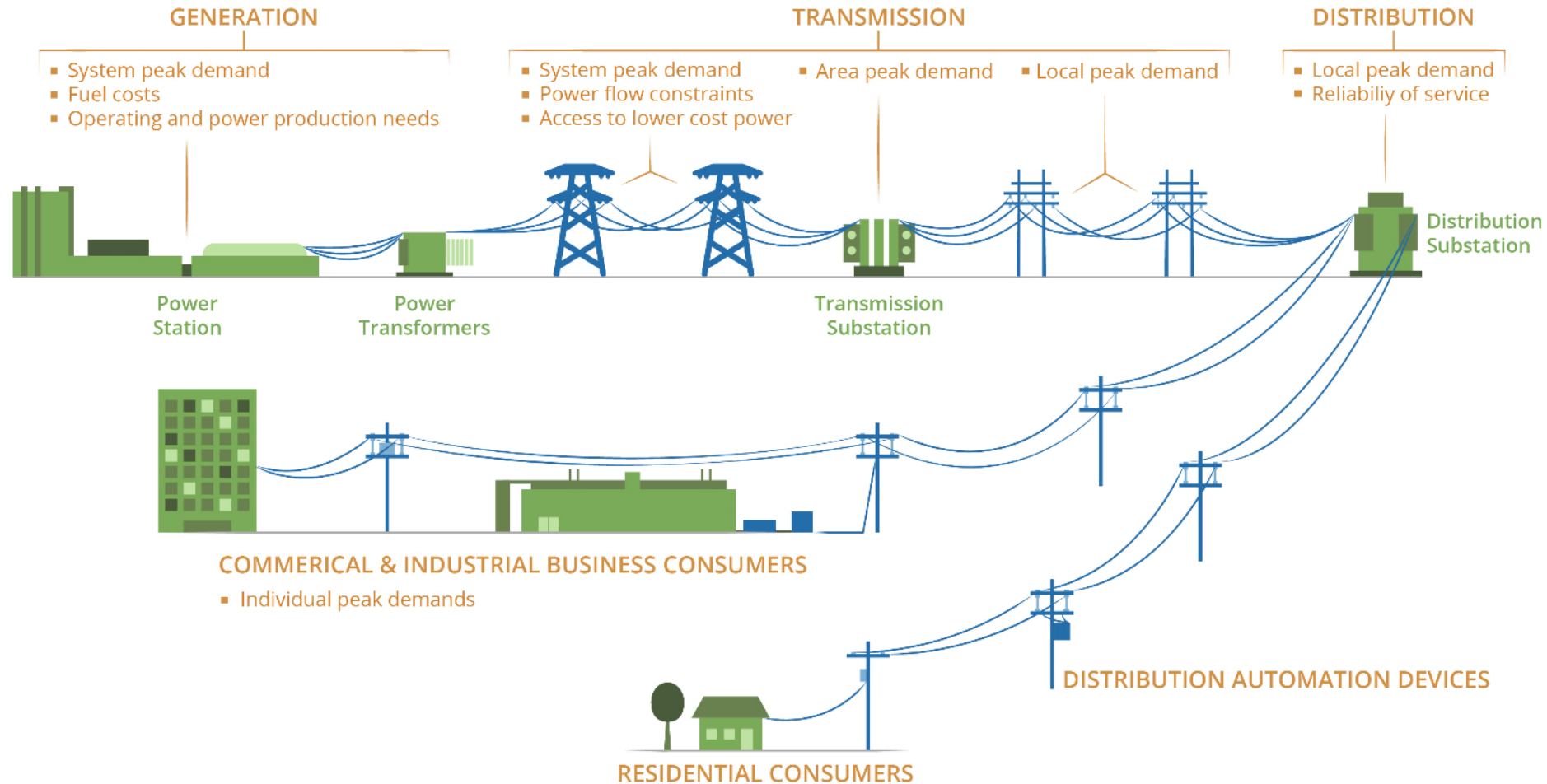
Transmission Deferral Value (\$nominal/kW-year) - 2035



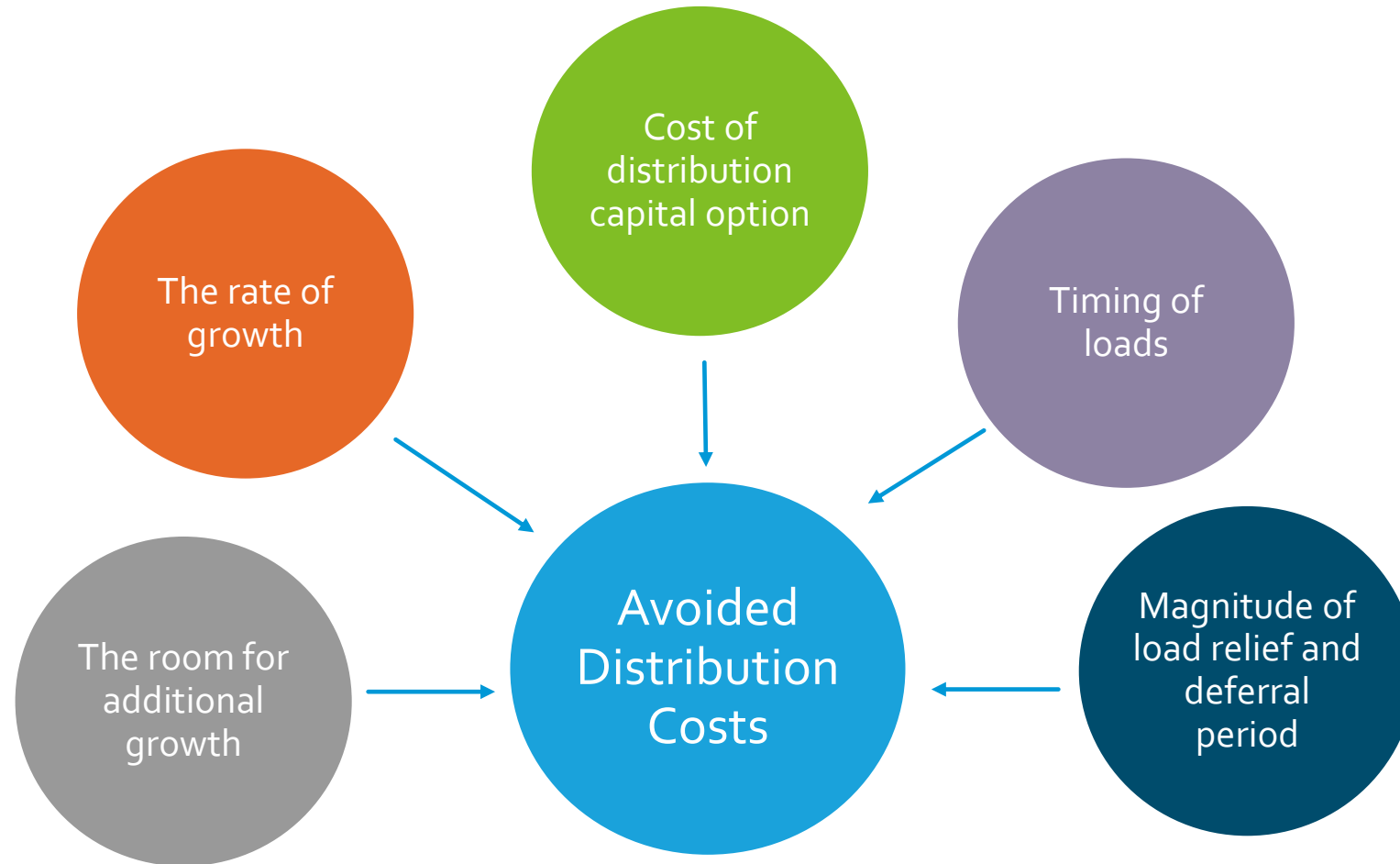
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# What do T&D avoided costs have to do with load analytics?

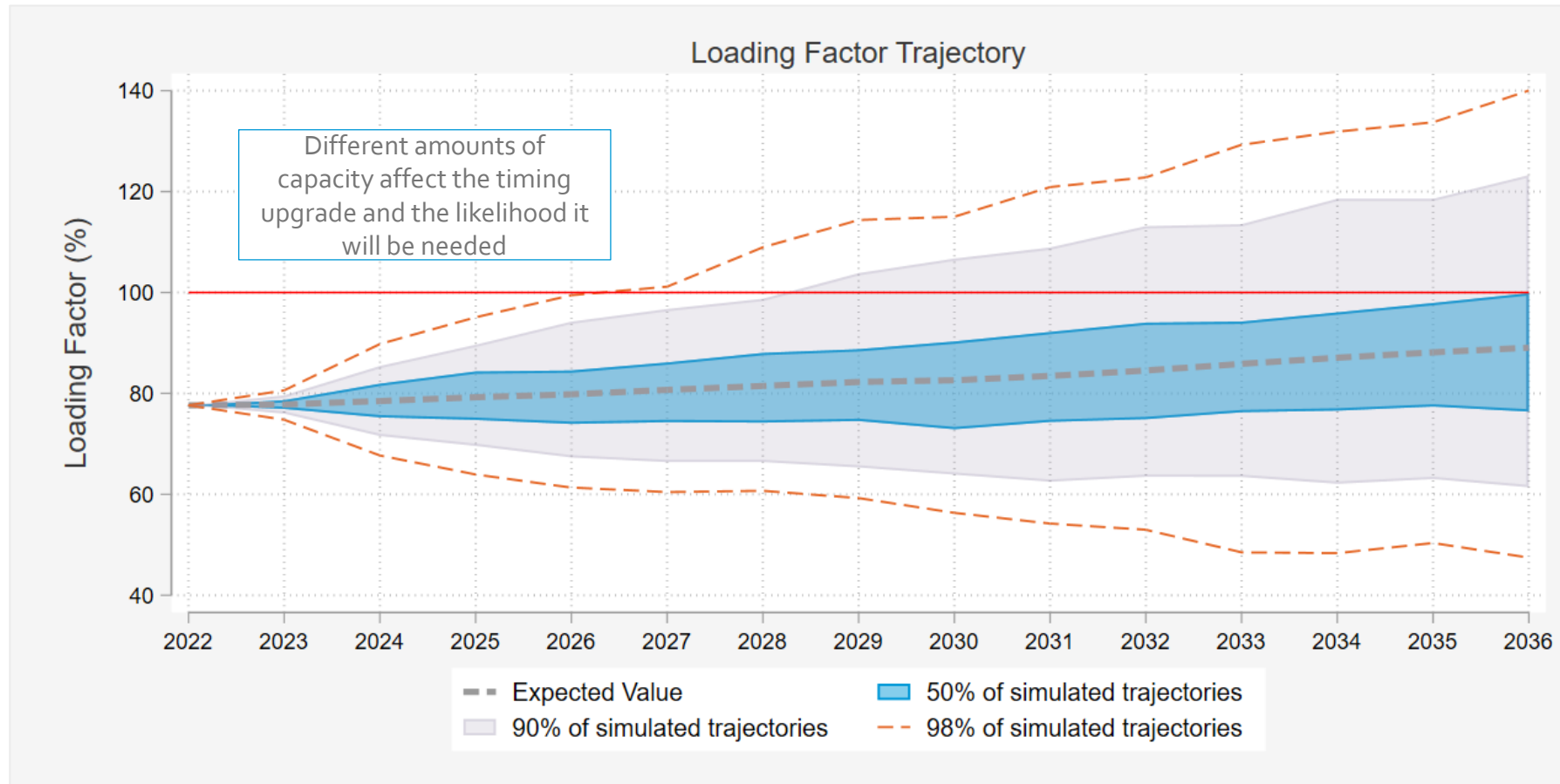
# CONCEPT #1: T&D PLANNING IS TIED TO PEAK LOADS



## CONCEPT #2: SEVERAL FACTORS AFFECT AVOIDED DISTRIBUTION VALUE

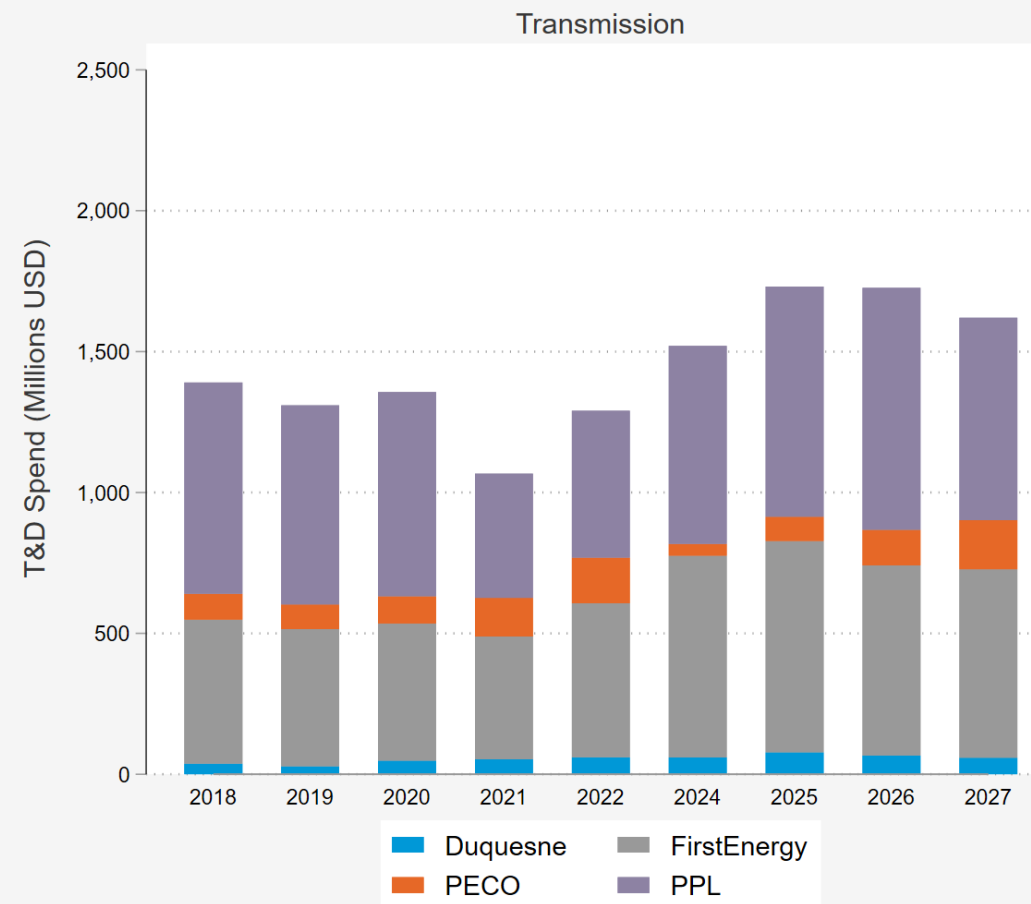
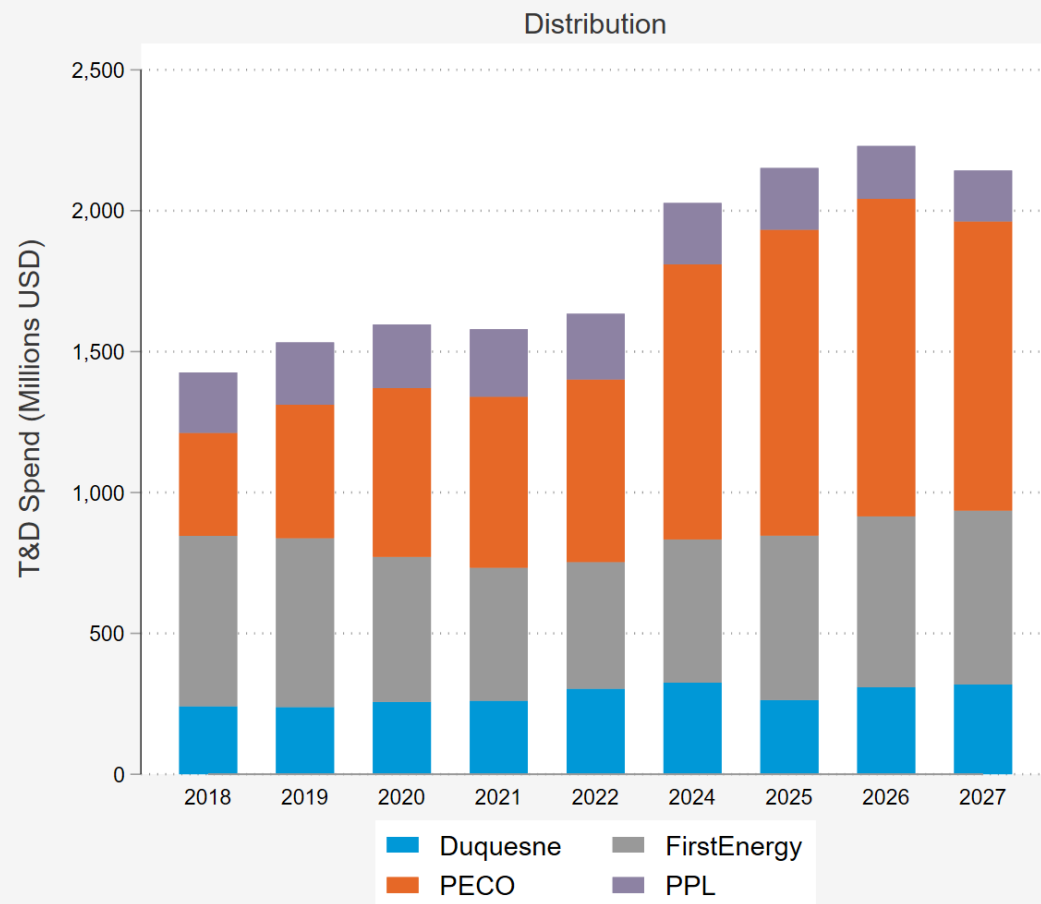


## CONCEPT #3: INSUFFICIENT CAPACITY IS A KEY DRIVER OF LOCATION VALUE



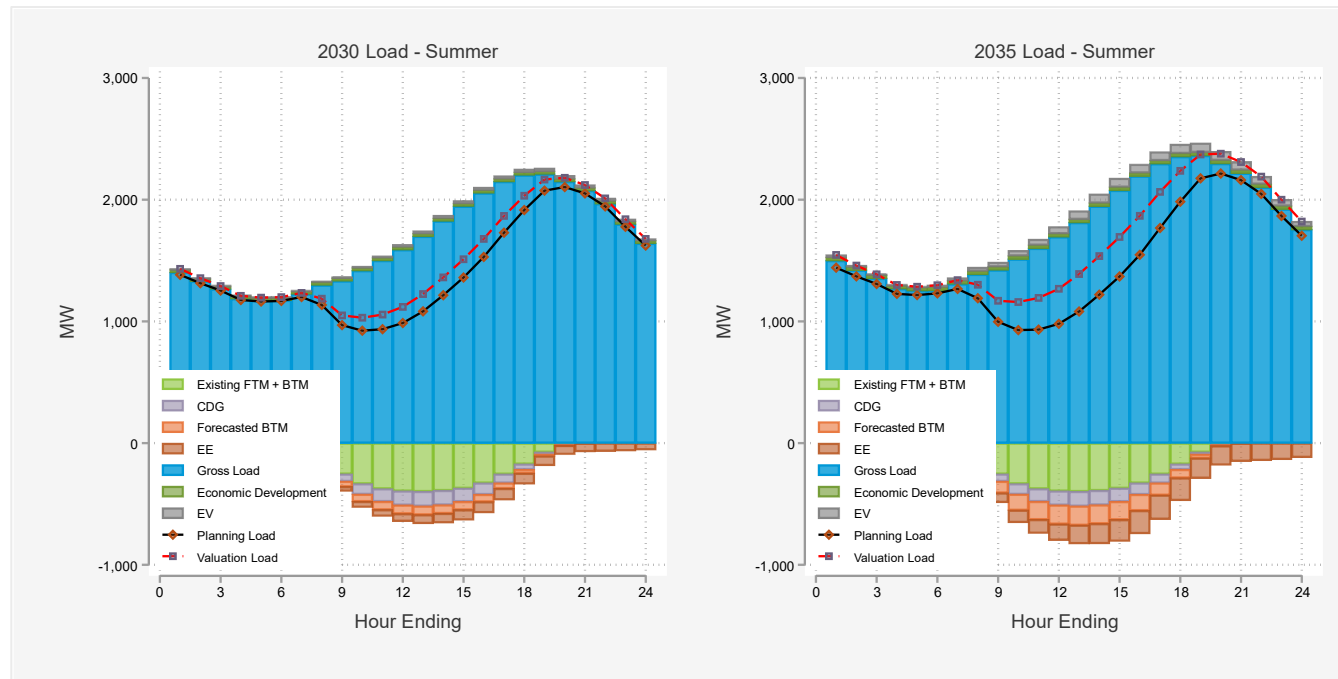
- Investments driven by local peak demand
- If a resource helps reduce local peak demand, it free up room for additional loads or defer, or reduce investments  
Not all T&D costs are avoidable

## CONCEPT #4: A LOT OF CAPITAL IS SPENT ON T&D CAPITAL INVESTMENTS EACH YEAR





## CONCEPT #5: LOADS ARE EVOLVING QUICKLY



- Planning load includes everything
- “Valuation load”:
  - Does NOT include load relief resources that have not yet been built (e.g. incremental solar, EE)
  - DOES include added load (e.g. EVs)

# OBJECTIVES OF GRANULAR AVOIDED T&D COSTS STUDIES



Analyze load patterns, excess capacity, load growth rates, change in load patterns, and the magnitude of expected infrastructure investments at a local level



Model location-specific forecasts of growth with uncertainty



Quantify the probability of potential need for infrastructure upgrades at specific locations



Calculate local avoided distribution costs by year and location



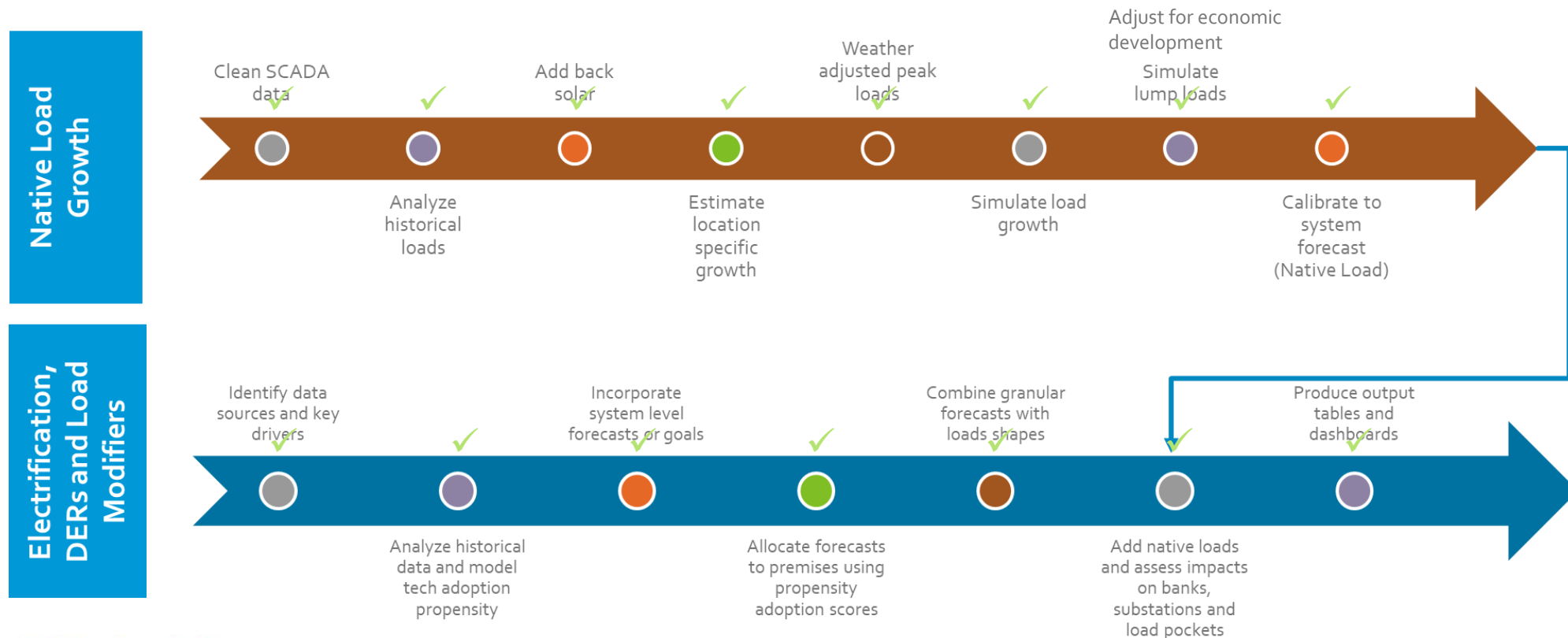
Identify beneficial locations for load relief



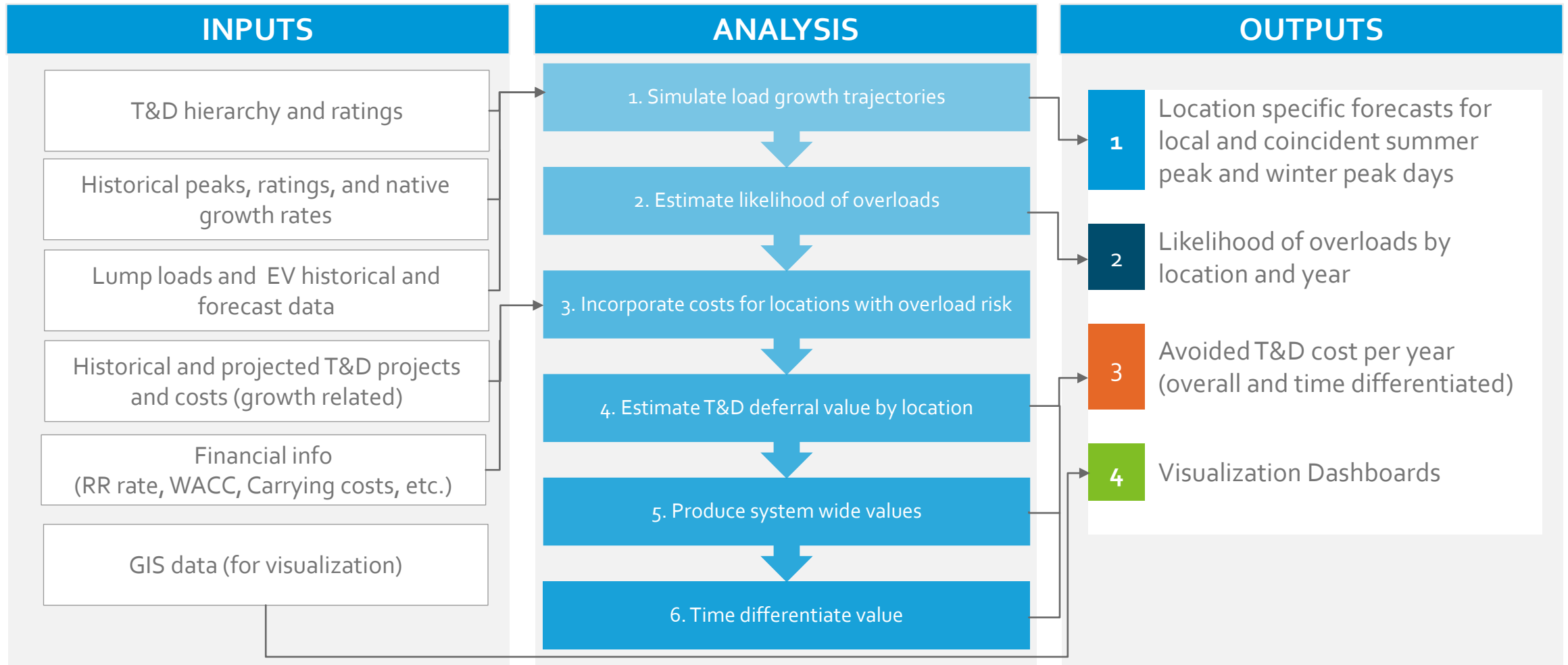


# GRANULAR FORECASTS ARE CRITICAL

- To understand the impact of load modifiers at the feeder or substation level, granular forecasts are required. We dispersed the system load modifier forecasts and combined with calibrated, granular native load forecasts



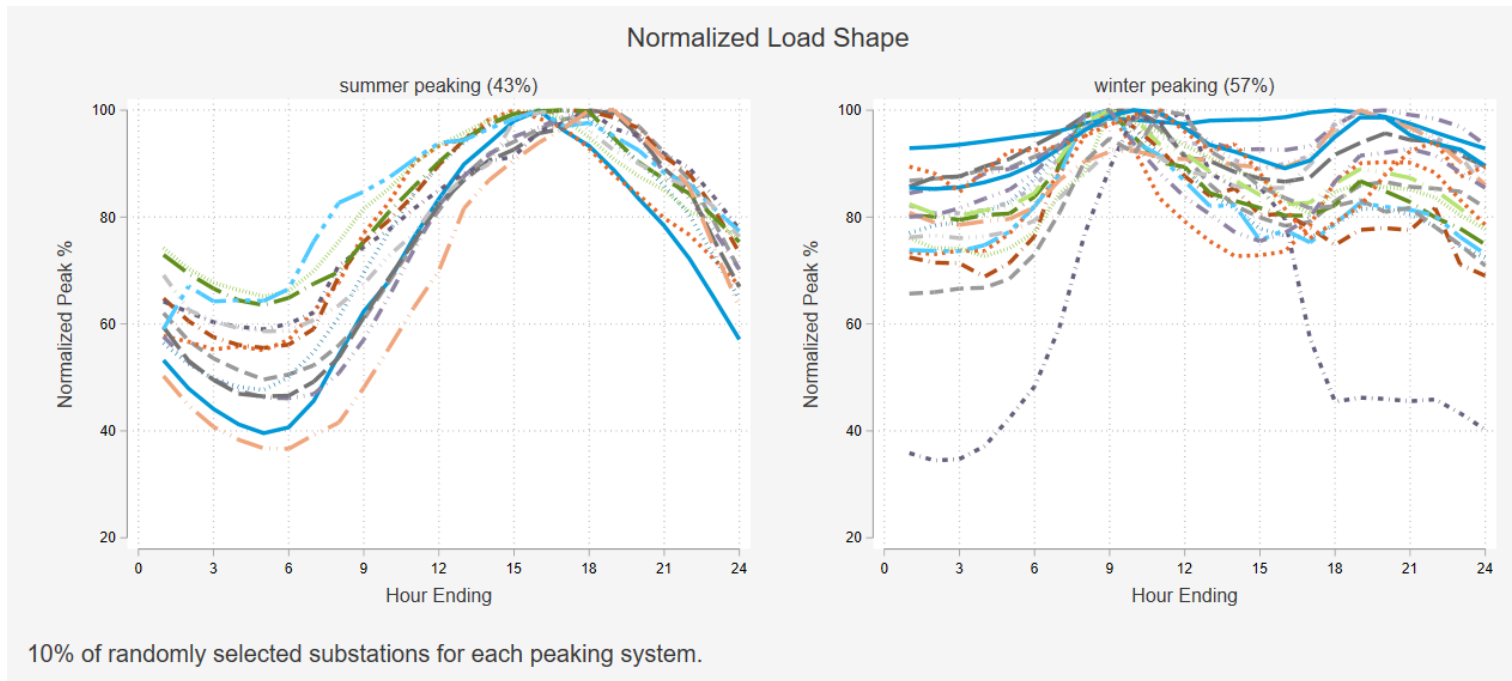
# T&D AVOIDED COSTS ANALYSIS OVERVIEW



FINDINGS – USING EXAMPLE UTILITY



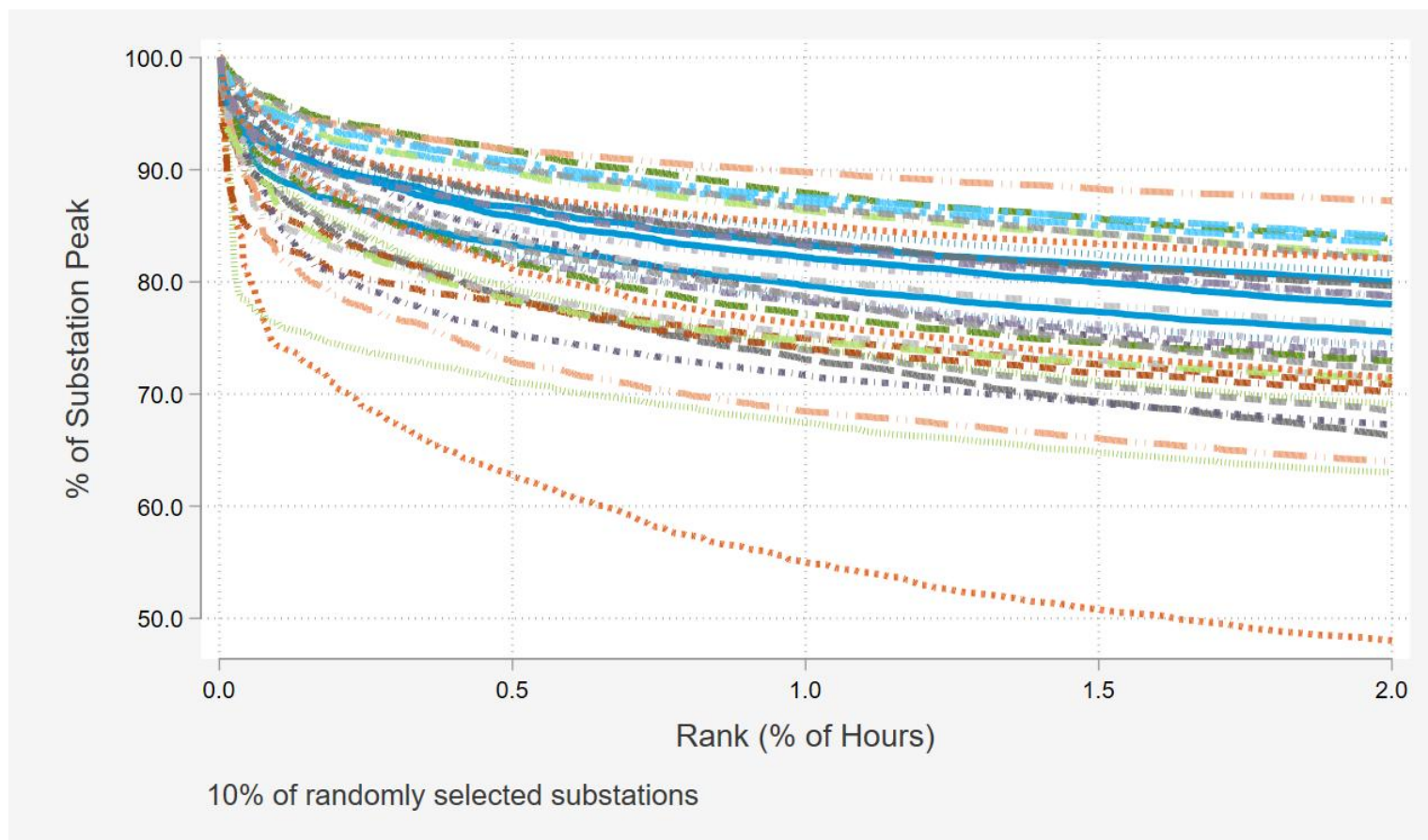
# ABOUT 50/50 SUMMER PEAKING AND WINTER PEAKING



- For summer peaking systems, the greatest usage on peak days occurs between 5 PM and 8 PM
- For winter peaking systems, it occurs between 8AM and 9AM and between 7 PM and 9 PM



# THE HIGHEST LOADING CONDITIONS OCCUR IN ONLY A SMALL FRACTION OF PERIODS FOR THESE SUBSTATIONS



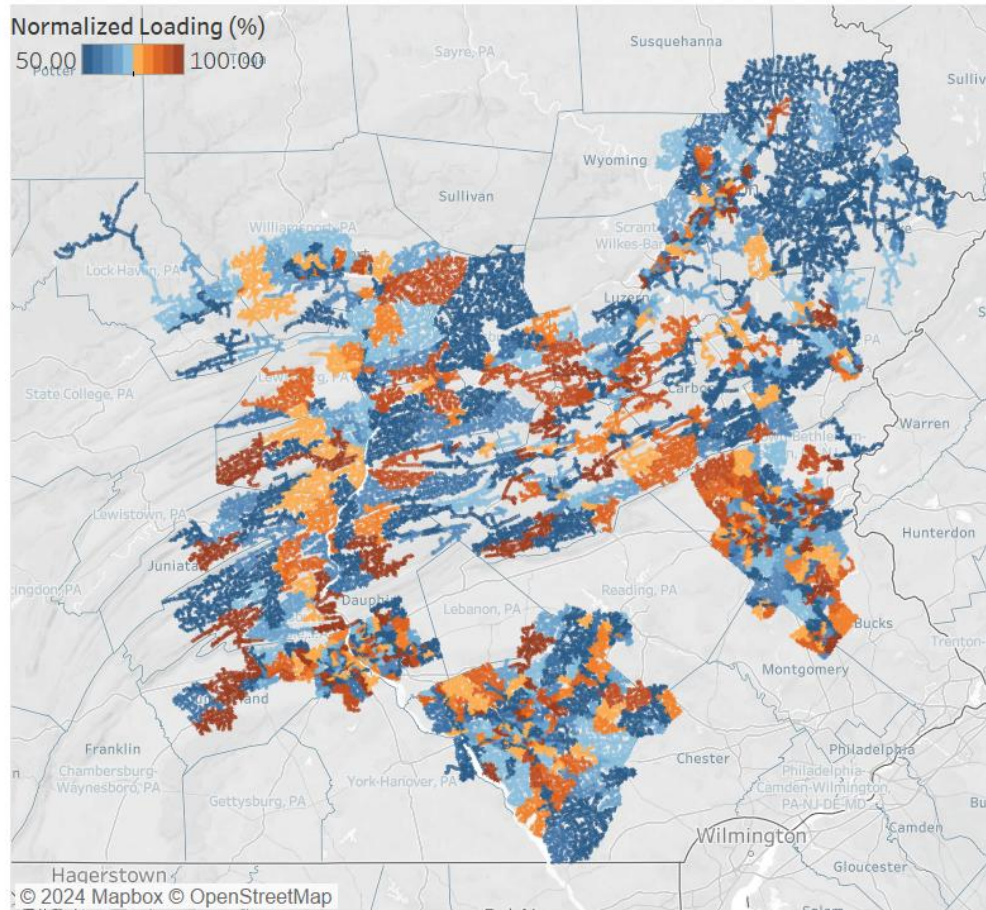
- All loads within 10% of the peak occur in less than 2% of the periods over five years
- In some locations, all loads within 20% of the peak occur in less than 1% of the periods over five years
- These substations may be good candidates for dispatchable demand response or NWA projects



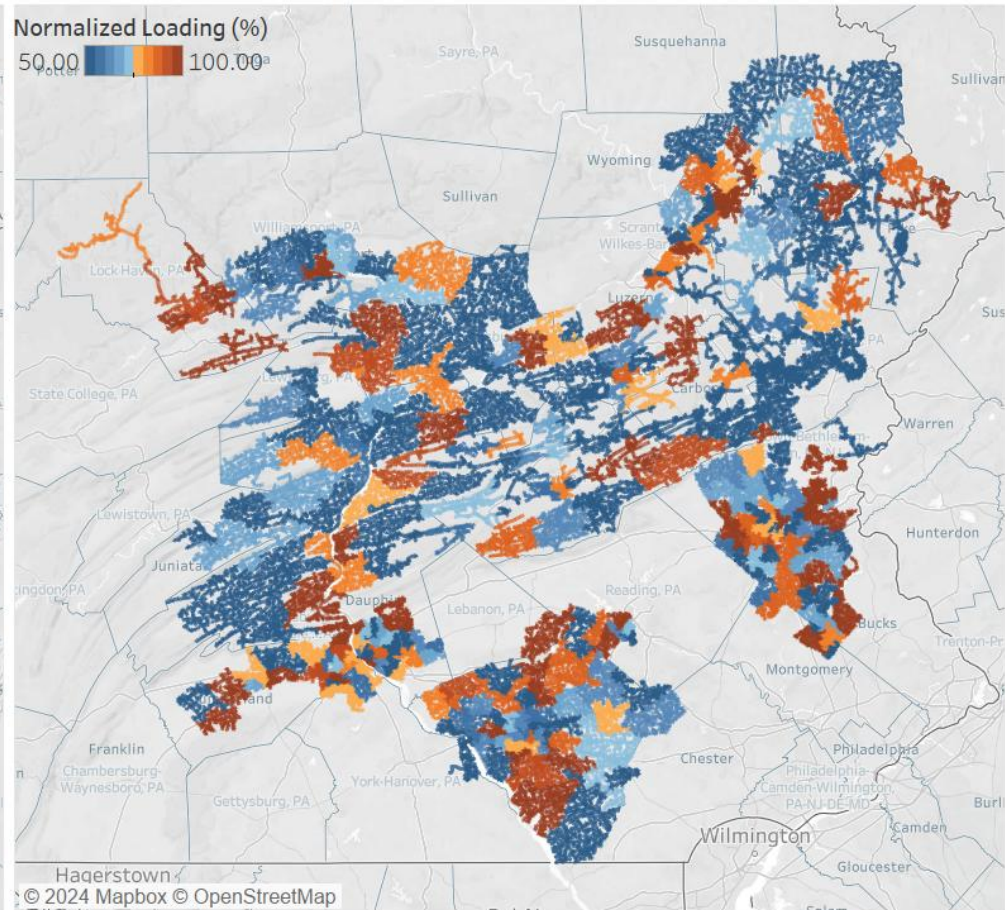


# SOME PARTS OF THE TERRITORY ARE MORE HIGHLY LOADED

Normalized Loading - Feeder - 2022



Normalized Loading - Substation - 2022

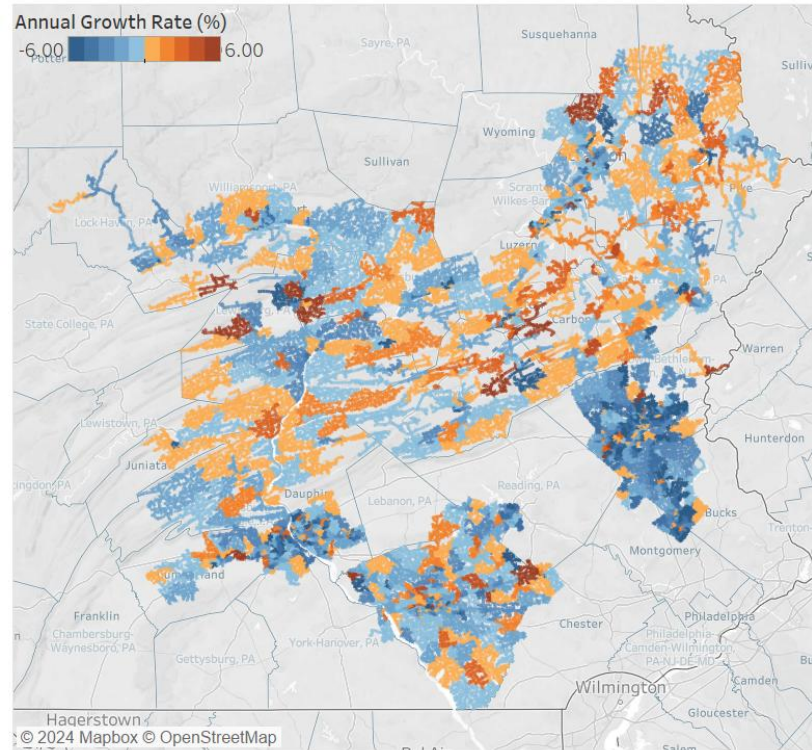




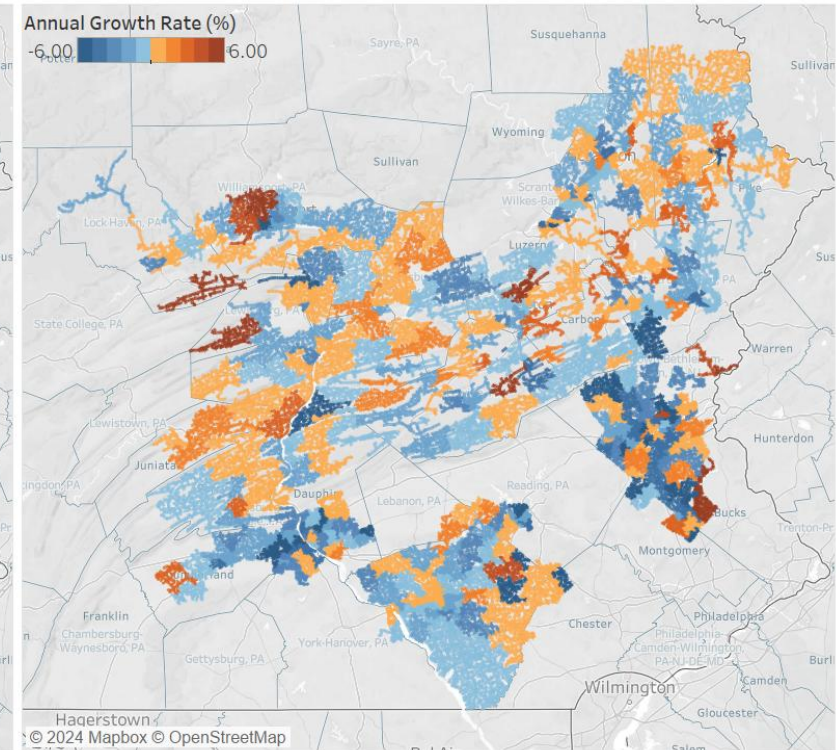
# SOME AREAS ARE EXPERIENCING GROWTH OTHERS ARE EXPERIENCE LOAD DECLINES

- They account for native growth – lump loads are included as an explanatory variable
- Based on 2018-2022 hourly loads

Historical Growth Rates - Feeder

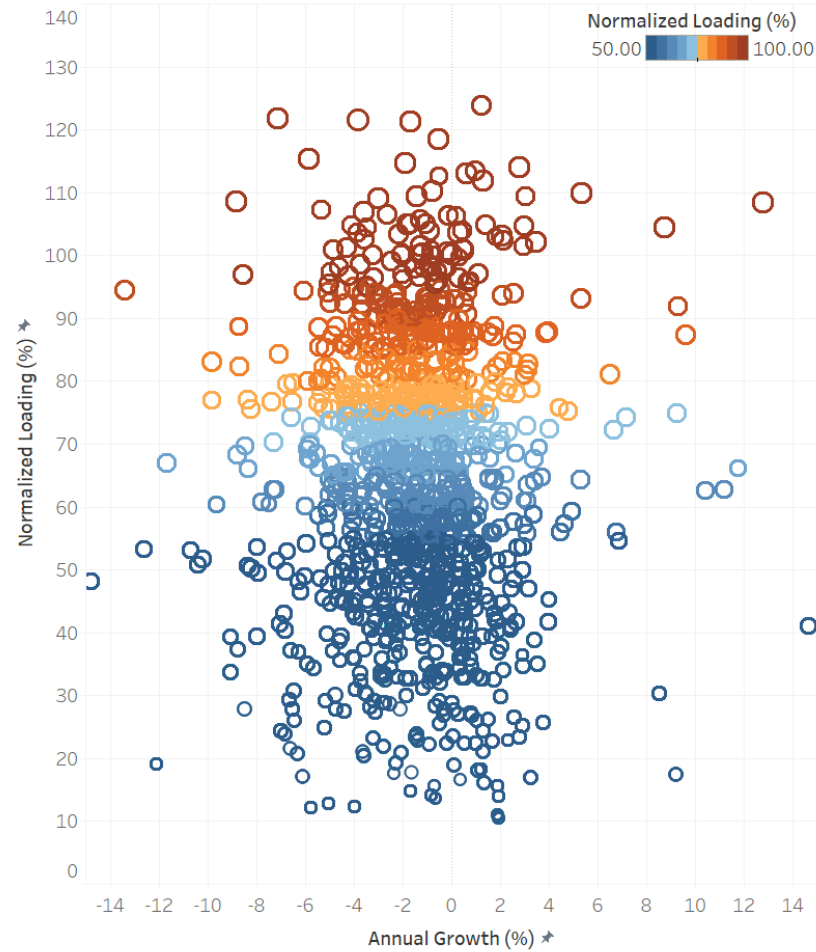


Historical Growth Rates - Substation

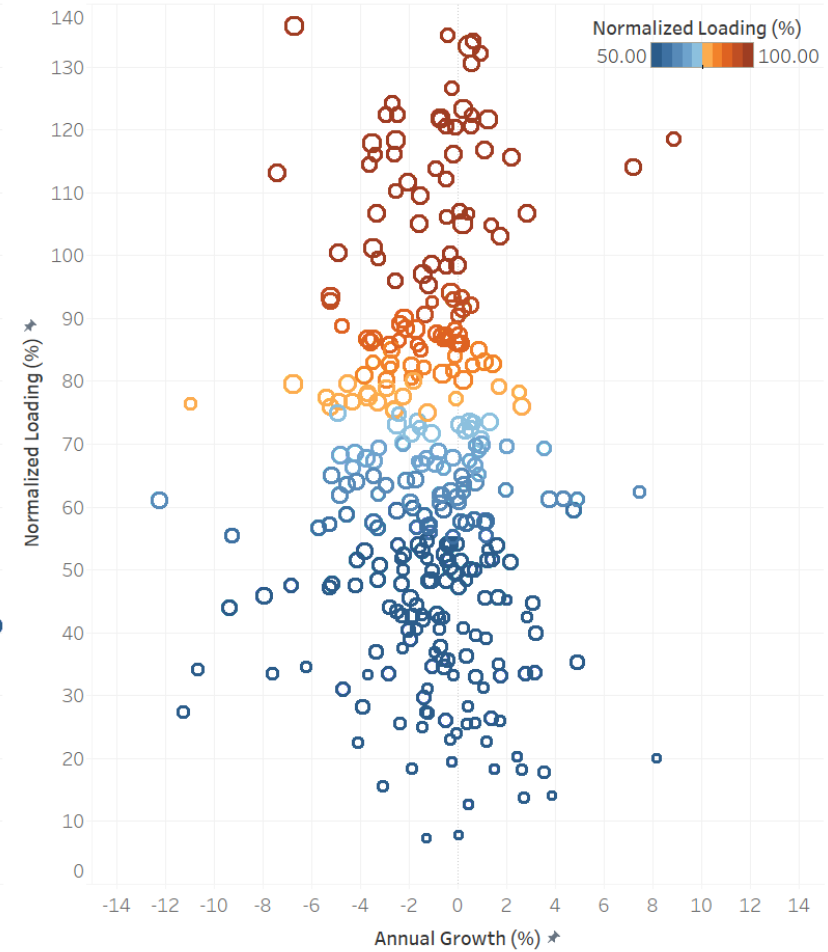


# SEVERAL LOCAL SYSTEMS ARE BOTH HIGH LOADED AND GROWING

Loading vs Growth - Feeder



Loading vs Growth - Substation



Bubble size is proportional to the annual peak MW with weather normalization of the site. The color reflect the overall loading for each site. The data is filtered on year, which keeps 2022.

# LUMP LOADS SIMULATION USING LOG-NORMAL DISTRIBUTION

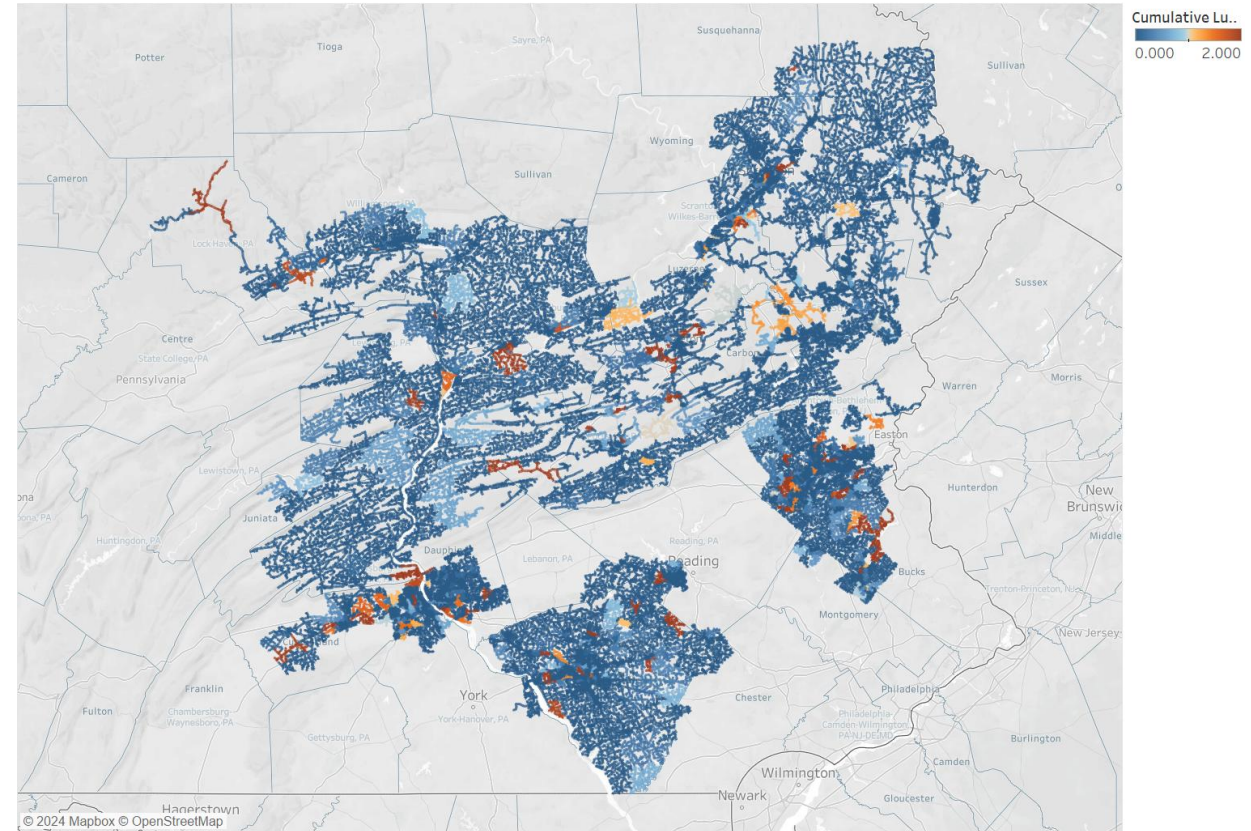
## ■ Simulation Parameters

- pr: The probability of a lump load for any given year
- ln\_mean: The expected size of a lump load logged. We use log because  $\ln(\text{lump\_loads})$  is roughly normal
- ln\_sd: Input the from the lump load analysis
- rr: Realization rate of lump loads. Peak coincident.

## ■ Outputs

- Projected lump load
- Actual lump load: projected lump load times rate
- Cumulative planning lump load: cumulative actual lump loads plus cumulative lump loads projected in next five years

Cumulative Lump Loads - 2022

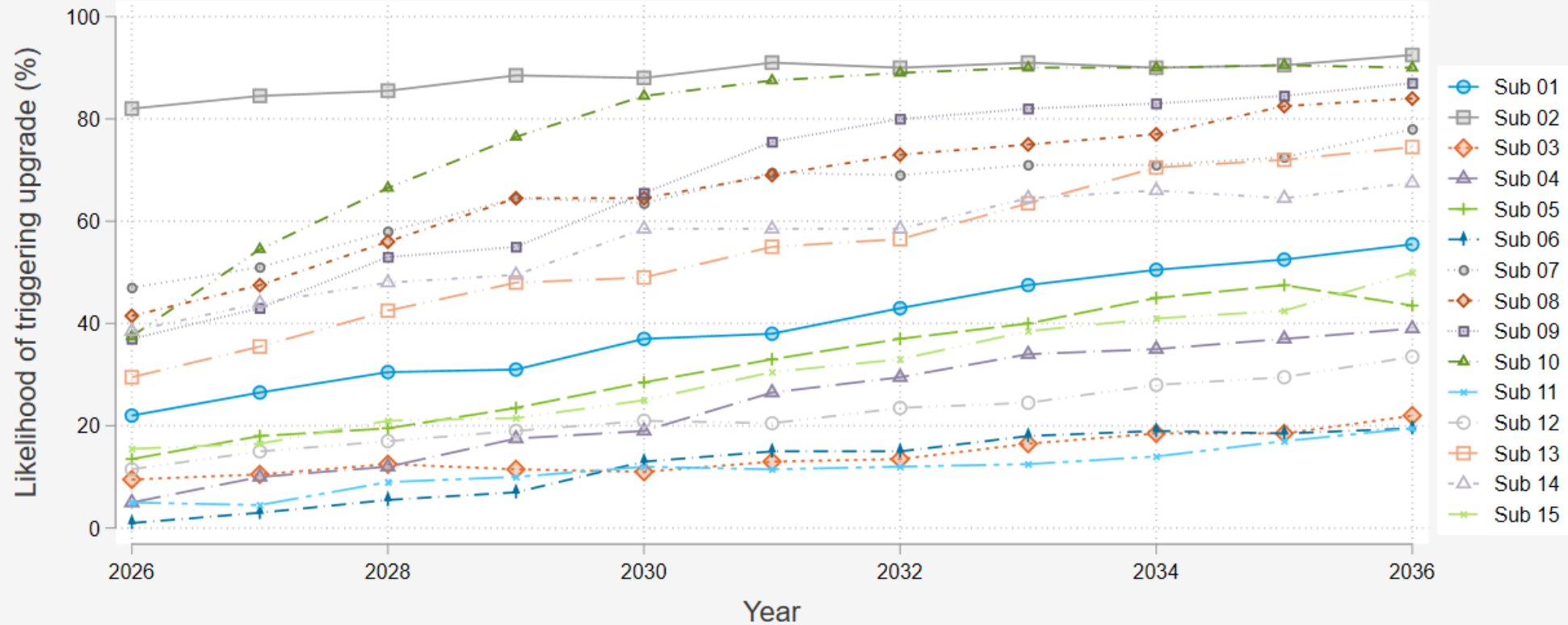


This map only includes lump loads (>100 kVA) at feeder level. There also larger transmission level lump loads that do no connect to feeders.





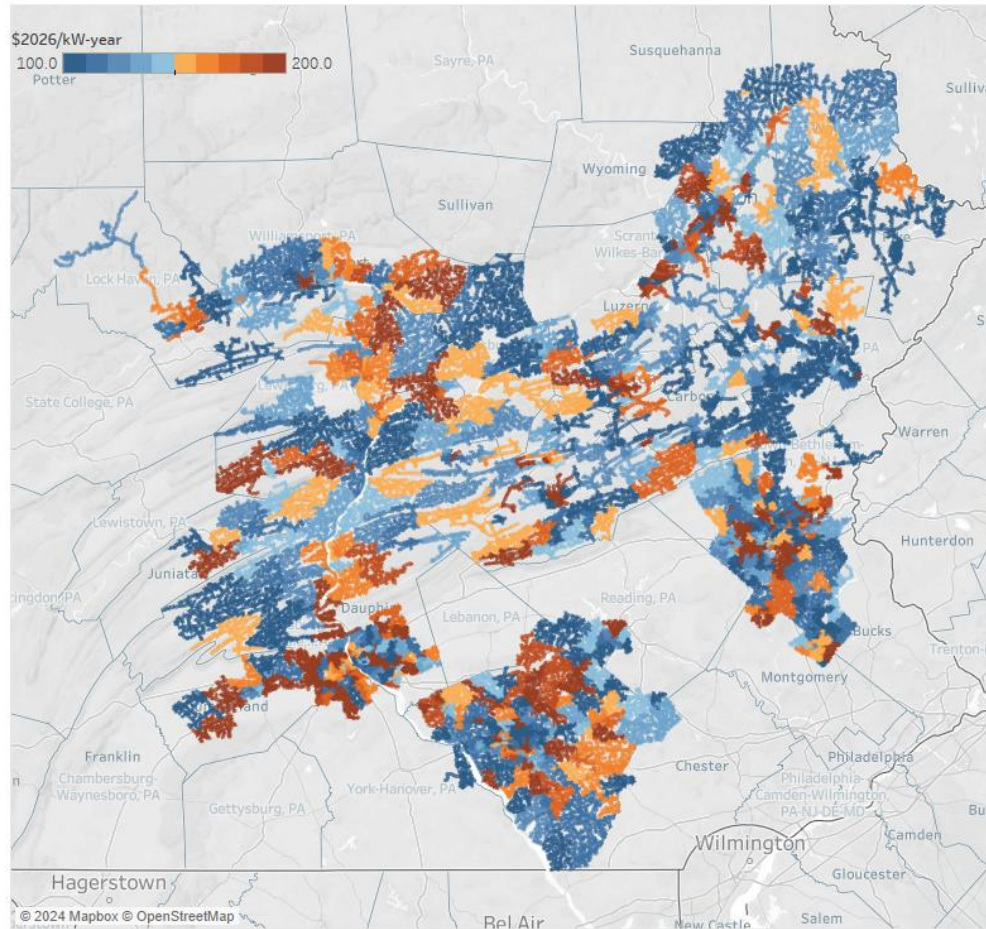
# LIKELIHOOD OF EXCEEDING OPERATIONAL LIMITS



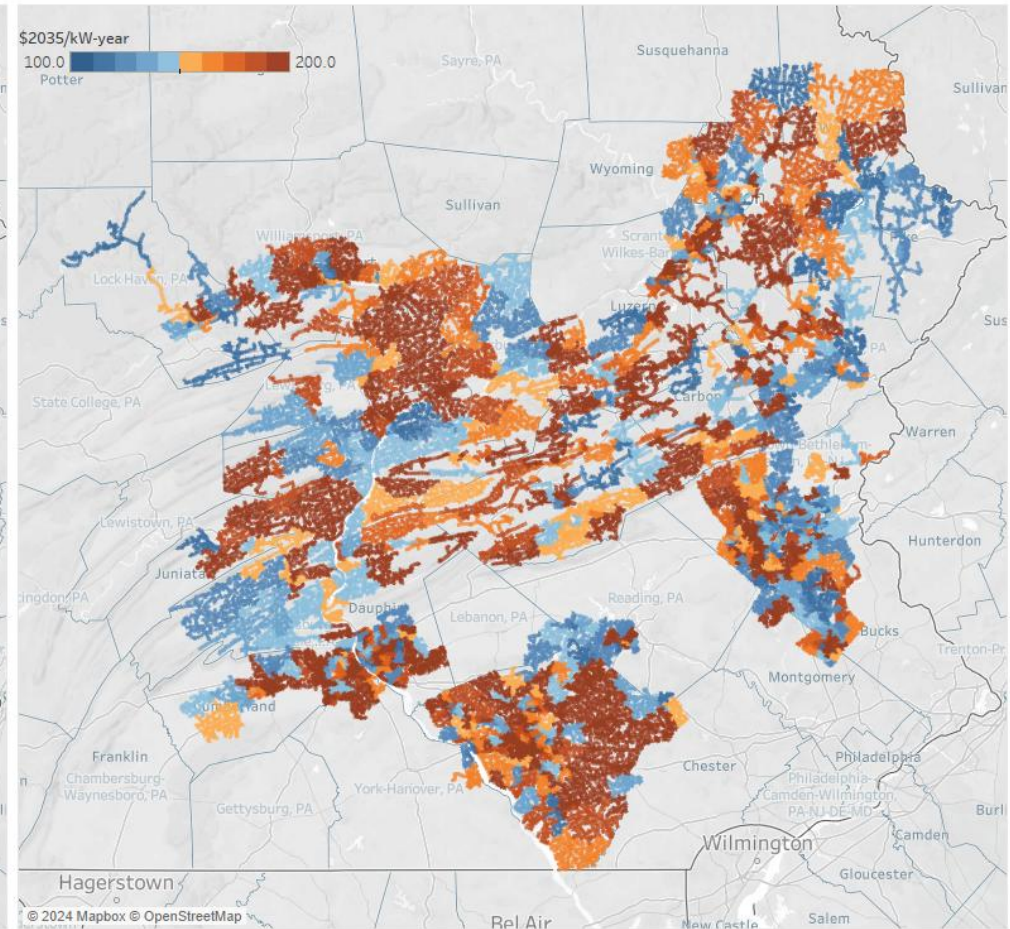
Randomly selected substations with likelihood greater than 10% of triggering upgrades by 2030.

# TRANSMISSION + DISTRIBUTION AVOIDED COST (NOMINAL \$/KW-YEAR)

Avoided Cost (nominal \$/kW-year) - 2026



Avoided Cost (nominal \$/kW-year) - 2035



## KEY TAKEAWAYS

# KEY TAKEAWAYS

1

Local peak loads drive T&D infrastructure needs

2

Granular forecasting is a key need for T&D planning

3

Load growth varies by location. Some pockets are experiencing load growth, and some are experiencing load decreases.

4

Value is concentrated at locations that are more heavily loaded. Not all locations have value.

5

Individual locations are generally winter or summer peaking, not both

6

Resources that deliver load relief at the right location, in the right season, and at the right hours are more valuable.

7

Lump loads are a key driver of distribution upgrades

8

The components of T&D need to be stacked to capture the full value: secondary transformers, feeder, bank, substation, transmission



# QUESTIONS?



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# THREE DISTINCT APPROACHES

## Deferral Value

$$\text{T\&D Avoided Cost (\$/kW)} = \frac{\text{Deferral Value}}{\text{kW needed to attain deferral}}$$

- Value of load relief
- Estimate effect of flattening, reducing or shifting peak loads on timing of T&D investment
- More complex to implement and goes out more than 5 years
- Can be used to produce location specific or system wide values

USED for Distribution

## Marginal Cost of Service

$$\text{Marginal Cost (\$/kW)} = \frac{\text{NPV(Net Cost)}}{\text{NPV(Capacity Increase)}}$$

Net Cost = Investment Cost – Replaced Asset Residual Value  
Capacity Increase = Capacity Increase at Contingency Ratings

- Cost of increasing T&D capacity (\$/kW)
- Does not factor in actual demand
- May or may not reflect avoidable costs
- Produces stable values

USED for Transmission

## Simplified System Wide Value

$$\text{T\&D Avoided Cost (\$/kW)} = \frac{\text{Growth related T\&D costs}}{\text{load growth kW}}$$

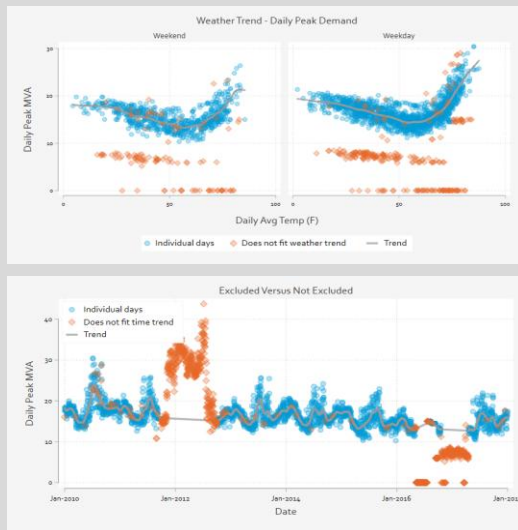
- Approach does not work with low or no load growth
- May be possible to modify it to account for location specific growth (only count load growth from areas that are growing)
- T&D equipment ages and cannot be avoided indefinitely



# KEY STEPS IN BOTTOM UP DEFERRAL VALUE PROCESS (1/3)

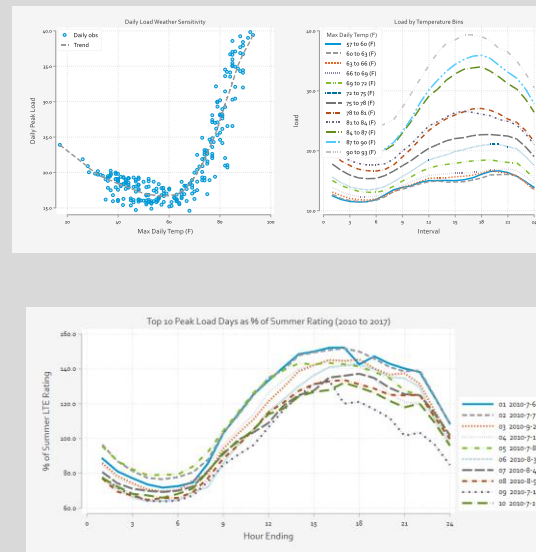
## 1. CLEAN SCADA DATA

- Identify load transfers
- Remove outages and meter recording issues
- Avoid mixing data issues such as load transfers with load growth/declines



## 2. ANALYZE HISTORICAL DATA

- Plot top 10 peak load days
- Plot load duration curves
- Sensitivity of loads to weather



## 3. ESTIMATE LOCATION SPECIFIC GROWTH RATES

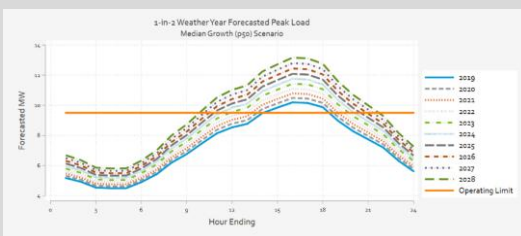
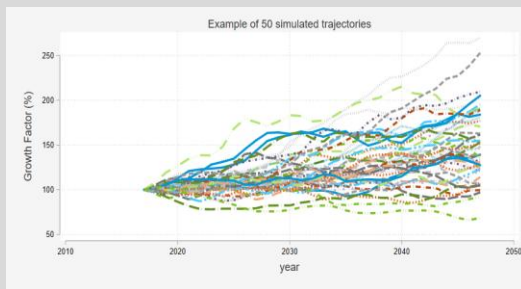
- Goal is to produce location specific peak growth rates absent incremental load modifiers (otherwise beneficial load modifiers are undervalued)
- Growth rates produced for each substation and transmission area.
- Add back historical solar production based on location specific installed resources over time
- Estimate models using most recent 5 years of loads. Goal is to isolate the annual % change in peak load (vs. weather, etc.).
- Use model to predict loads under planning conditions (normal weather years)



# KEY STEPS IN BOTTOM UP DEFERRAL VALUE PROCESS (2/3)

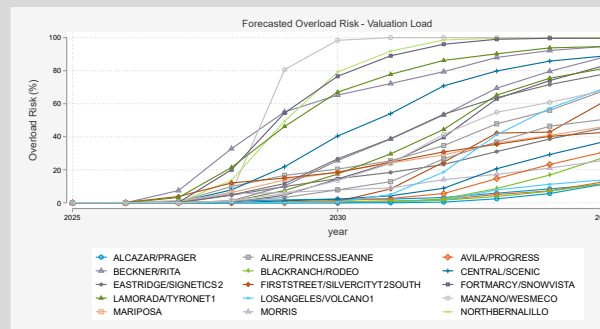
## 4. SIMULATE GROWTH TRAJECTORIES

- Use Monte Carlo simulation to reflect greater uncertainty in future years
- Factor in growth trend, uncertainty, and auto-correlation (random-walk)
- Forecasts do not include beneficial load modifiers that have not yet been built (otherwise undervalued)



## 5. ESTIMATE THE LIKELIHOOD OF OVERLOADS BY YEAR AND LOCATION

- Estimate the likelihood of upgrades given uncertainty in growth and weather
- Record likelihood of upgrades due to normal and emergency overloads
- Identify the subset that are potentially deferrable



## 6. GATHER COST DATA FOR LOCATIONS WITH OVERLOAD RISK

- For locations with an overload risk, gather data on:
  - T&D solution
  - Capital costs
  - O&M costs (are we including this?)
  - Fixed charge rates
  - Useful life and book life
  - Deferral limits
    - year of deferral: 10 years
    - max load reduction: 20% of peak

But we only count deferral value during the study period



# KEY STEPS IN BOTTOM UP DEFERRAL VALUE PROCESS (3/3)

## 7. ESTIMATE VALUE OF INCREMENTAL RESOURCES

- For each site and simulated load growth trajectory, assess:
  - If an upgrade is triggered
  - When the upgrade is needed
  - The magnitude of resources required to attain deferral
  - The deferral period
  - The costs with and without deferral.
- Calculate
  - Deferral value
  - kVA needed to defer
  - $\$/\text{kVA} = \text{Deferral value} / \text{Demand Reduction needed to attain deferral}$
  - $\$/\text{kVA-year} = \$/\text{kVA annualized}$

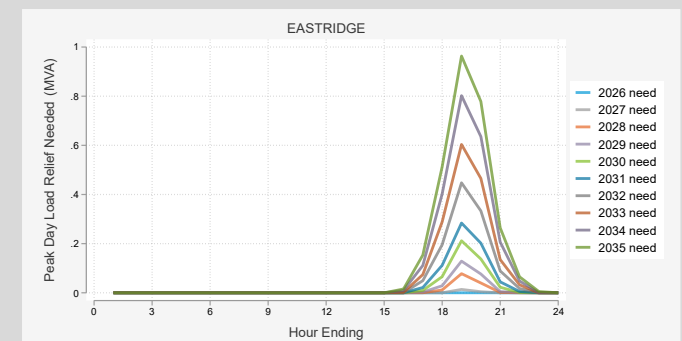
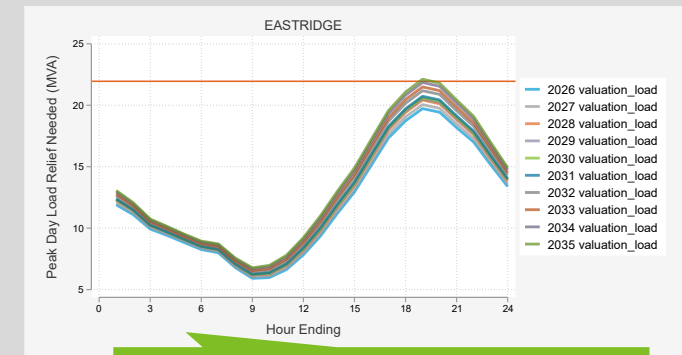
## 8. PRODUCE 10-YEAR LEVELIZED VALUE AND SYSTEM VALUE

- Expected deferral value by year and location (\$/kVA-year)
- Calculate 10-year levelized value
- For system value, calculate the load-weighted value. Factors in the reality that load relief does not lead to avoided costs for a large share of territory

Year	System	ALCAZAR	ALIRE	AVILA
2026	\$0.00	\$0.00	\$0.00	\$0.00
2027	\$0.58	\$0.00	\$7.99	\$0.00
2028	\$3.99	\$2.99	\$320.76	\$0.00
2029	\$7.45	\$4.46	\$372.70	\$0.00
2030	\$9.08	\$5.89	\$402.25	\$0.00
2031	\$10.11	\$6.68	\$428.69	\$1.43
2032	\$12.01	\$8.71	\$471.41	\$4.12
2033	\$14.50	\$11.99	\$530.81	\$10.33
2034	\$16.13	\$16.04	\$566.01	\$15.37
2035	\$17.75	\$20.41	\$614.11	\$33.48
10-year levelized value	\$11.83	\$37.10	\$341.82	\$37.10

## 9. TIME-DIFFERENTIATE VALUE

- Allocate value by hour of day based on the load relief need



## LUMP LOAD MODEL – WHAT PERCENT OF THE PROJECTED LOAD SHOWS UP

- Panel data model with feeder and region-by-year fixed effects:

$$\text{Feeder } MW_{ft} = \rho \text{Lump Load } MW_{ft} + \alpha_f + \delta_{ry} + X_{ft}\theta' + \varepsilon_{ft}$$

With

- $\text{Feeder } MW_{ft}$  = Daily peak load for feeder  $f$  on top 10 peak day hours of years 2018 through 2022  $t$ 
  - (for each feeder we restrict to the peak hour on each day of year, then keep the top 10 hours for each year)
- $\rho$  = estimated realization rate
- $\text{Lump Load } MW_{ft}$  = Cumulative lump load MW on feeder  $f$  on top 10 peak day hours of years 2018 through 2022  $t$
- $\alpha_f$  = feeder fixed effects, absorbing time invariant features of the feeder
- $\delta_{ry}$  = region-by-year effects, which absorb variation in load in each region over time that is common across feeders in that region
- $X_{ft}$  = controls for month, day of week, hour-by-weekend, 10-degree temperature bins at the substation level

Identification:

- Changes in lump load are exogenous conditional on fixed effects and controls





# LUMP LOAD RESULTS AND (MAJOR) CAVEATS

	(1) Feeder Daily Peak Load (MW)
Cumulative Lump Load MW	0.143*** (0.0347)
Observations	62,336
R-squared	0.991
Feeders	250

Note: \*\*\*  $p < 0.01$ , \*\*  $p < 0.05$ , \*  $p < 0.1$ . This table reports coefficient estimates and standard errors from an OLS regression of daily peak load (MW) on cumulative lump load (MW). The model is estimated using feeder-by-hour observations for 2018 through 2022. The sample is restricted to the daily peak hour for the top 10 load days in a year for each feeder. Standard errors are clustered at the feeder level. The specification includes fixed effects for feeder, region-by-year, and control variables for month, day-of-week, hour-by-weekend, and temperature bins at the substation level; we do not report coefficients on controls.

- Realization rate: a 1 MW increase in lump load yields a .143 MW increase in daily peak feeder load on the top 10 load days of the year, on average
- Major threats to identification:
  - Unobserved changes to feeder load that are correlated with changes in lump load e.g. feeders with more economic growth have more lump load, feeders with more lump load also have more (unobserved) loads dropping off
  - Unclear still what exactly the lump load variable on the RHS is measuring. Is it lump load that is coincident with the daily peak on that feeder? If it is non-coincident, so just the peak for that lump load, then the correlation (or lack of) with the timing of the daily peak load on the feeder will lower the estimated realization rate
  - Any measurement error in lump load on RHS attenuates the realization rate
  - Unknown timing of lump load realization. Here we encoded it as coming online in the middle of the year. A thorough exposition would encode lump load as coming online at the beginning and end also and see how results changed

