Heating Study Project Update: Distribution Network and Tariff Design Impacts

—

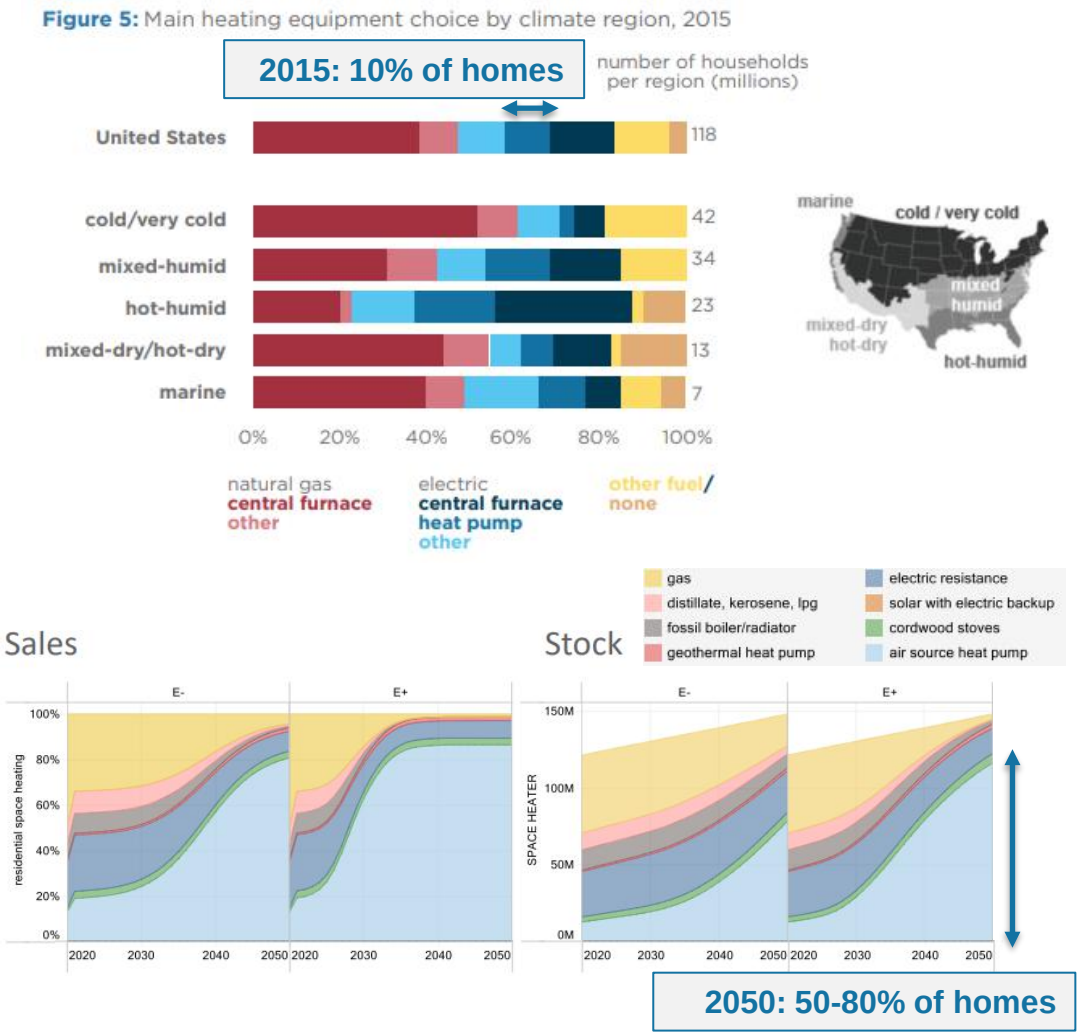
MIT Future Energy Systems Center

May 11, 2022

Tony Lee

Substantial heating electrification is needed to meet state and federal climate goals. Can current electricity delivery systems meet new heat pump electric demands?

- Residential and commercial buildings contribute to 12% of U.S. annual greenhouse gas emissions, mostly in burning fossil fuels for space heating
- With a low-carbon electric grid, (air-source) heat pumps offer an attractive, scalable path to decarbonizing buildings compared to other technologies
- Heat pumps are not new, but have traditionally been deployed in moderate and hot climates where electricity is cheap and heating demands are low
- Decarbonizing heating may require increasing residential heat pumps from 10% of homes in 2015 (EIA) to 50-80% of homes by 2050 (Princeton NZA)
- States like Massachusetts and New York with ambitious climate policies are heavily incentivizing heat pumps (up to $15,000 per home, ~75% cost)
- Colder regions currently rely on fossil delivery capacity (natural gas pipelines and fuel oil deliveries) to meet peak heating needs
- **How will heat pump adoption change electric demand and what challenges will this impose on the electric delivery systems in cold climates?**



Sources: Kaufman et al. 2019 and Evolved Energy Research

Research Questions

- What are the impacts of heat pumps on electricity demand?
- What levels of electrification can current distribution feeders accommodate?
- What are the costs of distribution upgrades at different electrification levels?
- Can rate design shape heating loads to mitigate grid impacts and reduce infrastructure costs?

Methodology

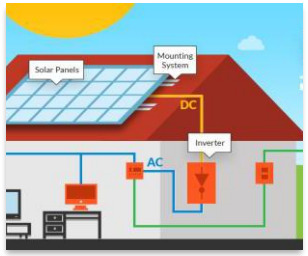
A) Model the impact of heat pumps on demand

B) Model demand impacts on distribution operations

1. Gather input data across sources

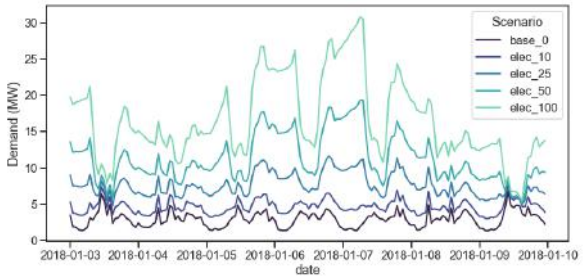
Housing stock characteristics (construction, appliances, building envelopes, orientation) and non-heat end-use demand profiles (water heating, W/D, cooking, plug loads)

Weather, heat pump performance parameters, electric rate options, user setpoints

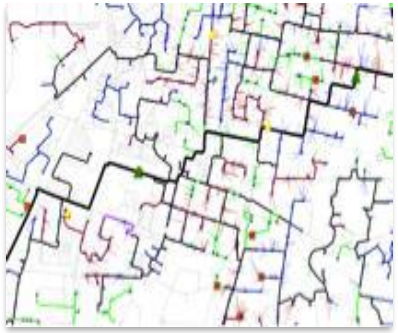


DECARB: economic optimization of investment and operation of building energy resources

2. Generate hourly fossil and electricity demand profiles for different households across rate and electrification scenarios

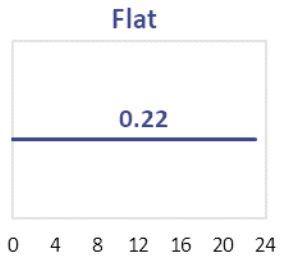
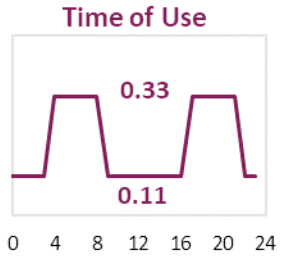
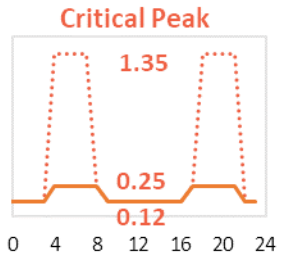


3. Map household demand profiles to loads on a typical residential distribution network



4. Model network operations using AC power flow simulations to identify distribution problems and investment needed

Modeling Scenarios

Scenario	Adoption Rate	HVAC Equipment	Tariff Design	$/kWh
Base	0%	Existing furnace or boiler (natural gas / heating oil), existing electric air conditioner	Flat rate based on MA residential charges for energy and distribution	
Elec	10, 25, 50, 100%	Cold-climate air-source heat pump (22 SEER, 11 HSPF) sized to fully meet heating needs. Heat pump efficiency varies linearly with temperature gradient: 1.8-4.6 heating COP, 3.6-5.8 cooling COP in 2018 AMY simulation Below 100% adoption, heat pumps are first allocated to largest energy consumers		
Elec TOU	100%		Time of Use rate with 3:1 price ratio	
Elec CPP	100%		CPP + TOU rate with 11:2:1 price ratio CP events limited to 100 hours/year for 4-hour event window	

Notes:

22 SEER, 11 HSPF ASHP is the minimum efficiency required for eligibility in Mass Save heat pump rebate program.

Heat pump performance curves estimated based on analysis of manufacturer specifications in NEEP heat pump database.

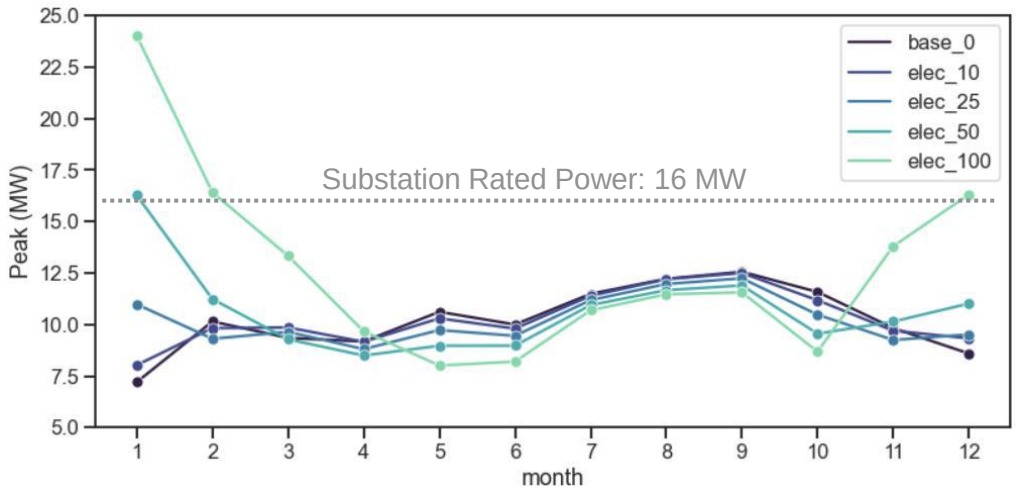
CPP rate based on Hydro Quebec's Rate Flex D option, a full-scale opt-in CPP rate for electric heating customers with a price ratio of 12:2:1.

Effects of heating electrification on distribution peak demand

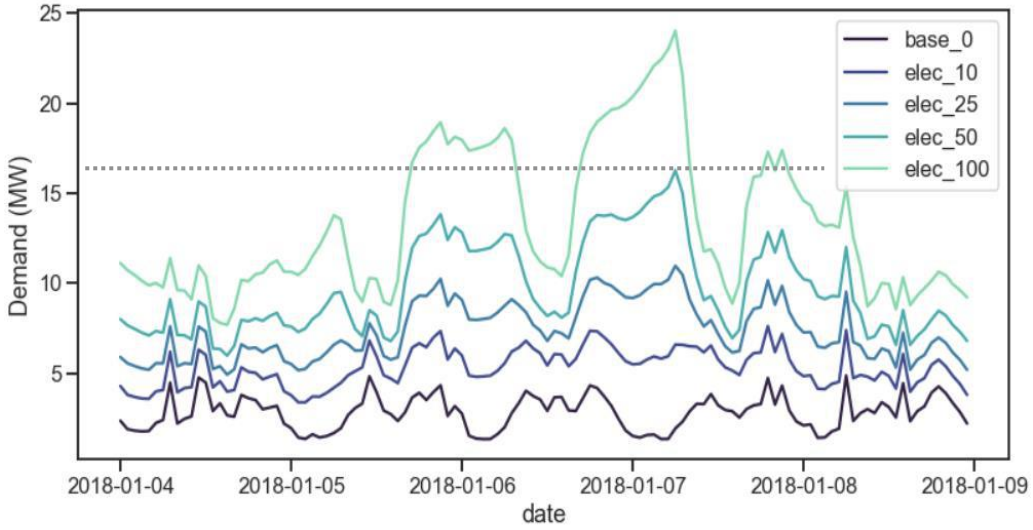
- Heat pumps increase winter peaks and reduce summer peaks, shifting time of peak from afternoon to early morning.
- Potential for beneficial electrification: up to 25% elec., heat pumps decrease peak and increase load factors. System becomes winter peaking at ~30% elec.
- At 50% elec., 30% increase in peak demand results in 13% substation transformer overloading
- At 100% elec., 91% increase in peak demand leads to voltage issues in addition to transformer overloading
- With a flat rate, network can accommodate ~45% heat pump adoption without voltage or capacity issues

Case	Peak Hour	Peak (MW)	Load Factor (%)	Subst. XF Load (%)	Max Line Load (%)	Min Voltage (p.u.)
base_0	9/5/2018 14:00	12.56	27.86	85.31	32.52	0.974
elec_10	9/3/2018 12:00	12.50	32.27	84.95	33.63	0.973
elec_25	9/3/2018 12:00	12.24	36.25	83.06	32.74	0.974
elec_50	1/7/2018 6:00	16.27	29.96	113.56	51.32	0.971
elec_100	1/7/2018 6:00	24.02	23.14	182.53	73.51	0.949

Monthly Substation Peak Demand



Hourly Demand During Coldest Winter Week

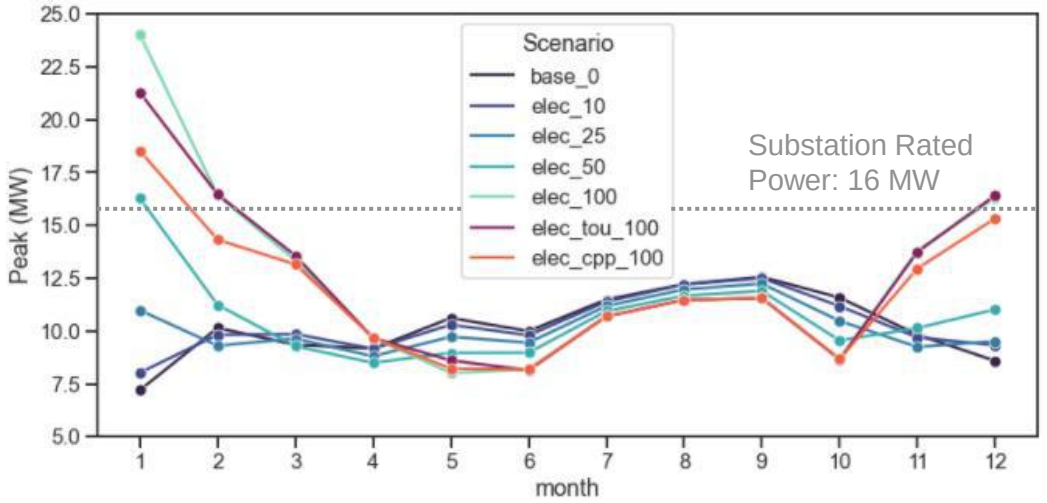


Time-varying rates can reduce distribution impacts and increase heating electrification under current system constraints

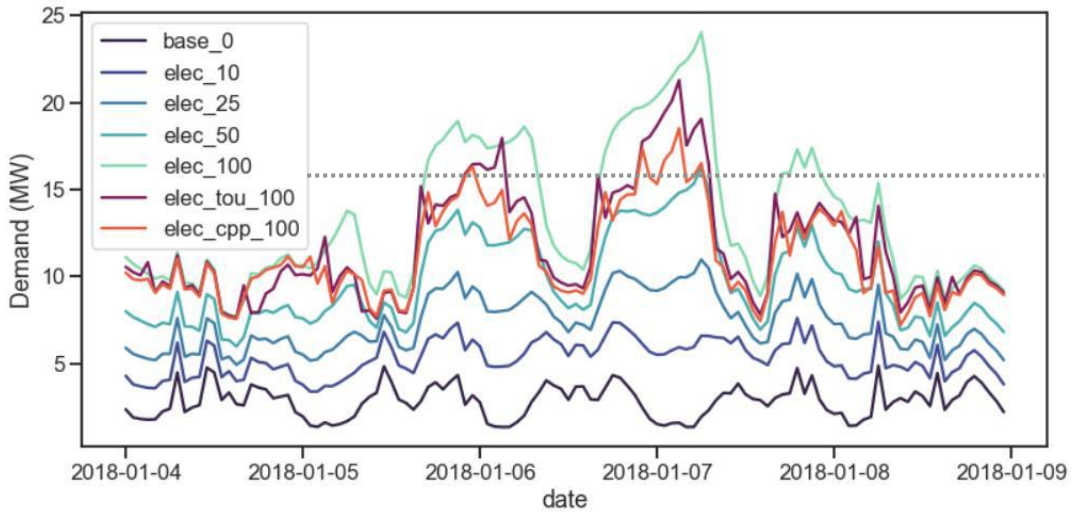
- At 100% electrification, optimal consumer response to TOU rate would lower peak by 2.7 MW (11%)
- CPP rate would lower peak by 5.5 MW (23%)
- Transformer overloading is reduced 14% and 28%
- Rate designs that enable demand flexibility can increase heat pump adoption that the current network accommodates from ~45% to ~50% under TOU rates and ~60% under CPP rates

Case	Peak Hour	Peak (MW)	Load Factor (%)	Subst. XF Load (%)	Max Line Load (%)	Min Voltage (p.u.)
base_0	9/5/2018 14:00	12.56	27.86	85.31	32.52	0.974
elec_10	9/3/2018 12:00	12.50	32.27	84.95	33.63	0.973
elec_25	9/3/2018 12:00	12.24	36.25	83.06	32.74	0.974
elec_50	1/7/2018 6:00	16.27	29.96	113.56	51.32	0.971
elec_100	1/7/2018 6:00	24.02	23.14	182.53	73.51	0.949
elec_tou_100	1/7/2018 3:00	21.29	25.83	156.21	63.76	0.953
elec_cpp_100	1/7/2018 3:00	18.52	29.64	131.84	50.67	0.958

Monthly Substation Peak Demand

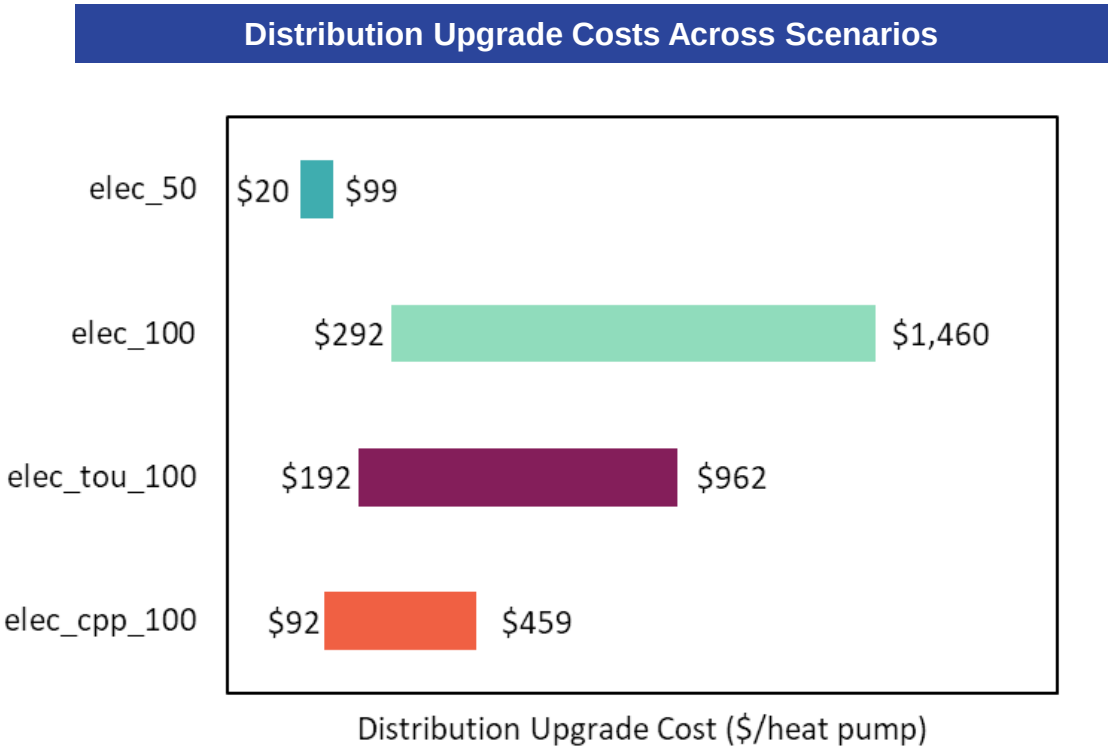


Hourly Demand During Coldest Winter Week



Distribution upgrade costs related to heat electrification for the network studied

- Distribution capacity costs vary greatly across sources, locations and estimation approaches
- To translate load impacts into infrastructure costs, we conservatively assume a range of **$100–$500/kW of substation capacity exceeded**
- 100% electrification under flat rates requires distribution capacity costs of **$292-1,460 per customer**
- TOU and CPP rates can reduce electrification integration costs



Research Findings and Future Work

- Deployments of residential heat pumps required to meet state and federal climate objectives will fundamentally reshape how households use electricity in cold regions like New England
  - Heat pumps both increase winter loads and reduce summer loads
  - The tested distribution system becomes winter peaking at ~30% adoption

- On the network studied, we see various distribution issues above 50% heat pump adoption
  - MV transformers at substations are the most immediate and costly investment need
  - Voltage quality (and line congestion) become issues close to full electrification

- Rate design can reduce peaks but its effectiveness depends on building envelopes and participation enabled through automation
  - TOU rates can increase heat pump adoption on this constrained network from 45% to 50%
  - CPP rates can further increase adoption to 60%

- Future work could include:
  - Analyzing power flow metrics in non-peak hours (e.g. % of heating season with distribution issues)
  - Modeling the effects of distributed solar and distributed storage on transformer and voltage issues
  - Extending analysis to additional networks using real feeder data in regions of interest

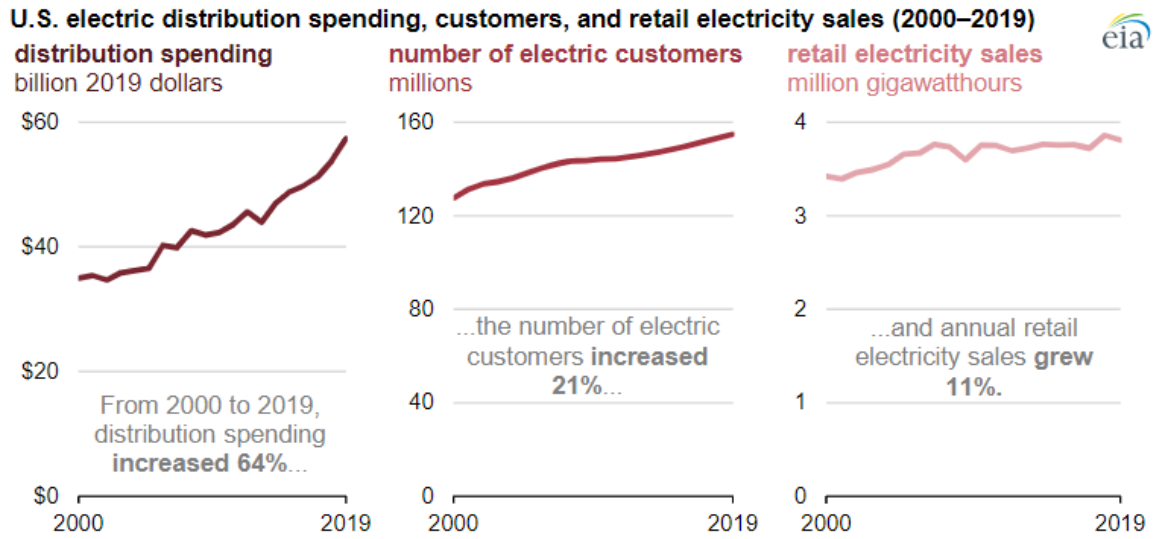
Thank you!

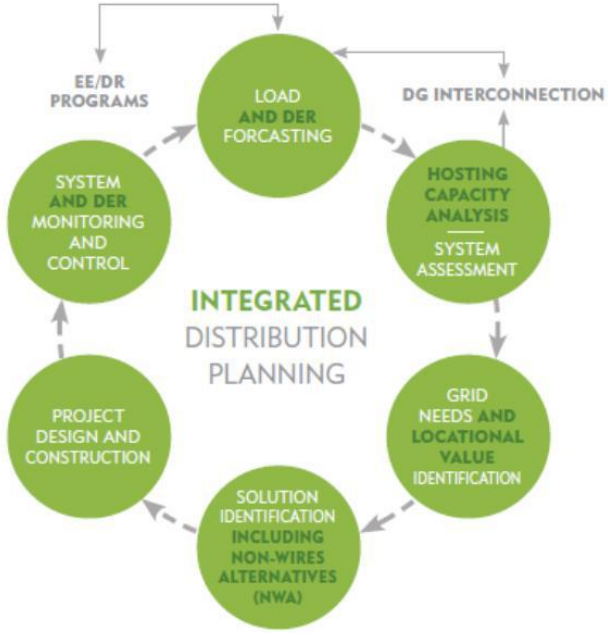
Tony Lee

MIT Future Energy Systems Center

May 11, 2022

Distribution costs have been rising even before widespread electrification





- 5.5 million miles of distribution lines deliver the “last mile” of electricity to residential and commercial customers
- Distribution systems are owned/operated by utilities who generally face state-level, cost-of-service regulation
- Transmission and distribution costs account for over 40% of delivered cost of electricity in 2020
- Utility spending on electric distribution has outpaced customer/demand growth due to aging infrastructure
- Emergence of rooftop solar, smart thermostats, and other distributed energy resources with capabilities to provide value to the grid has revealed the need for *integrated* distribution planning that considers non-wires alternatives

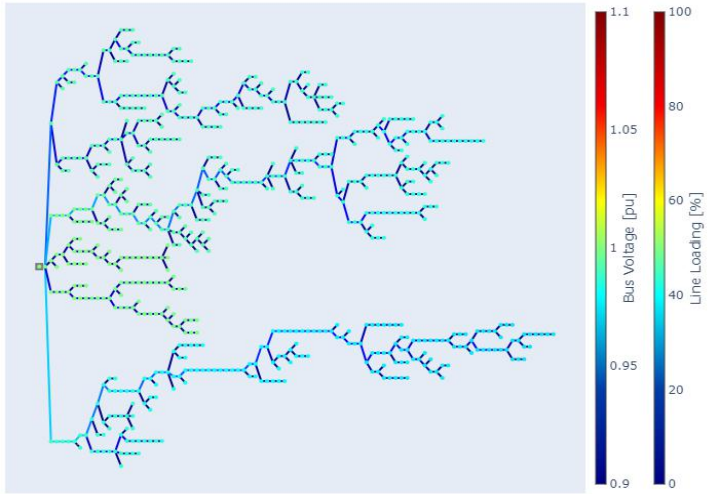
Sources: EIA, Today in Energy; GridLab.

Network and Customer Characteristics

Distribution Network Characteristics

- Synthetic network illustrative of a suburban distribution system with mostly residential customers
- 16 MW rated substation capacity, 54 km of 12.47 kV lines, 85% transformer loading
- 12.6 MW system peak from 2,826 customers

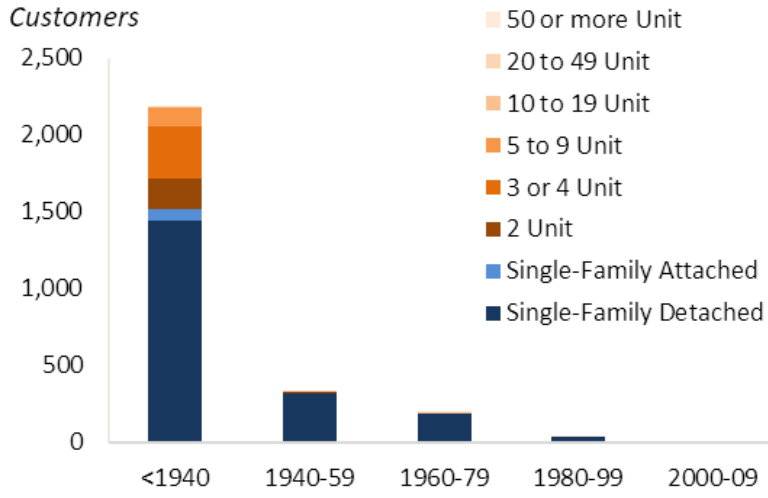
	Residential	Commercial
Customers	2,747	79
Peak	11.82 MW	0.74 MW
Avg. Customer Peak	4.30 kW	9.34 kW



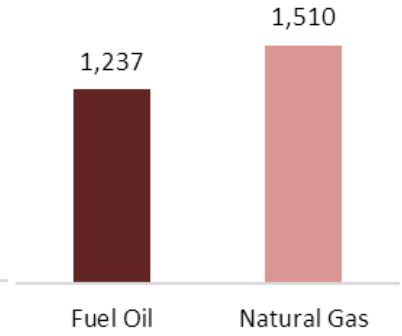
Customer Characteristics

- We only model heat pump adoption by residential customers which represent majority of initial network demand
- Assume that all customers have fossil heat and ACs in base
- 67 customer archetypes are assigned to network loads by based on closest ResStock peak demand
- Customer selection produces a realistic range of single-family and multi-family building units, construction vintages, baseline heating sources for New England

Vintage

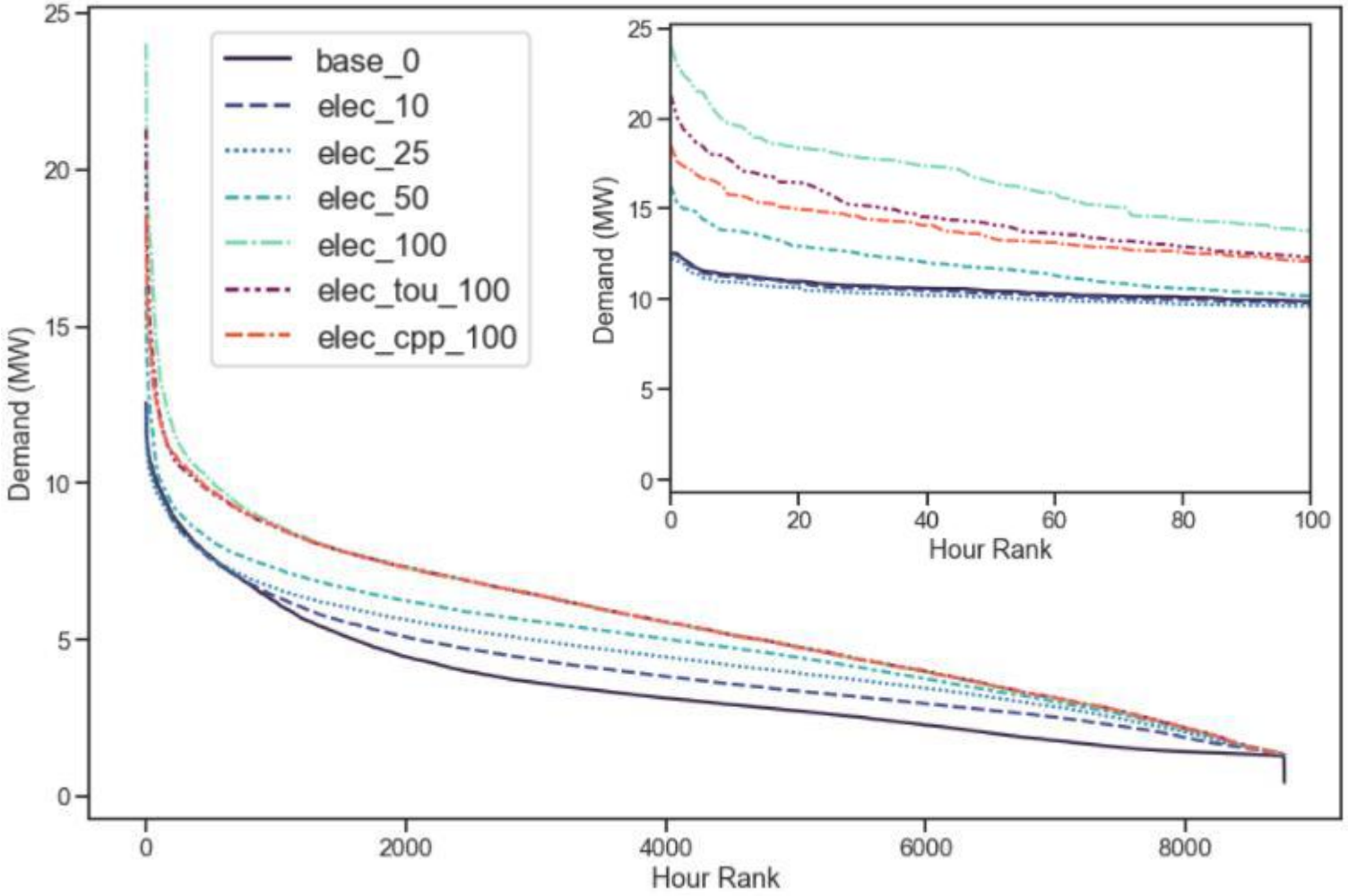


Baseline Heating Source

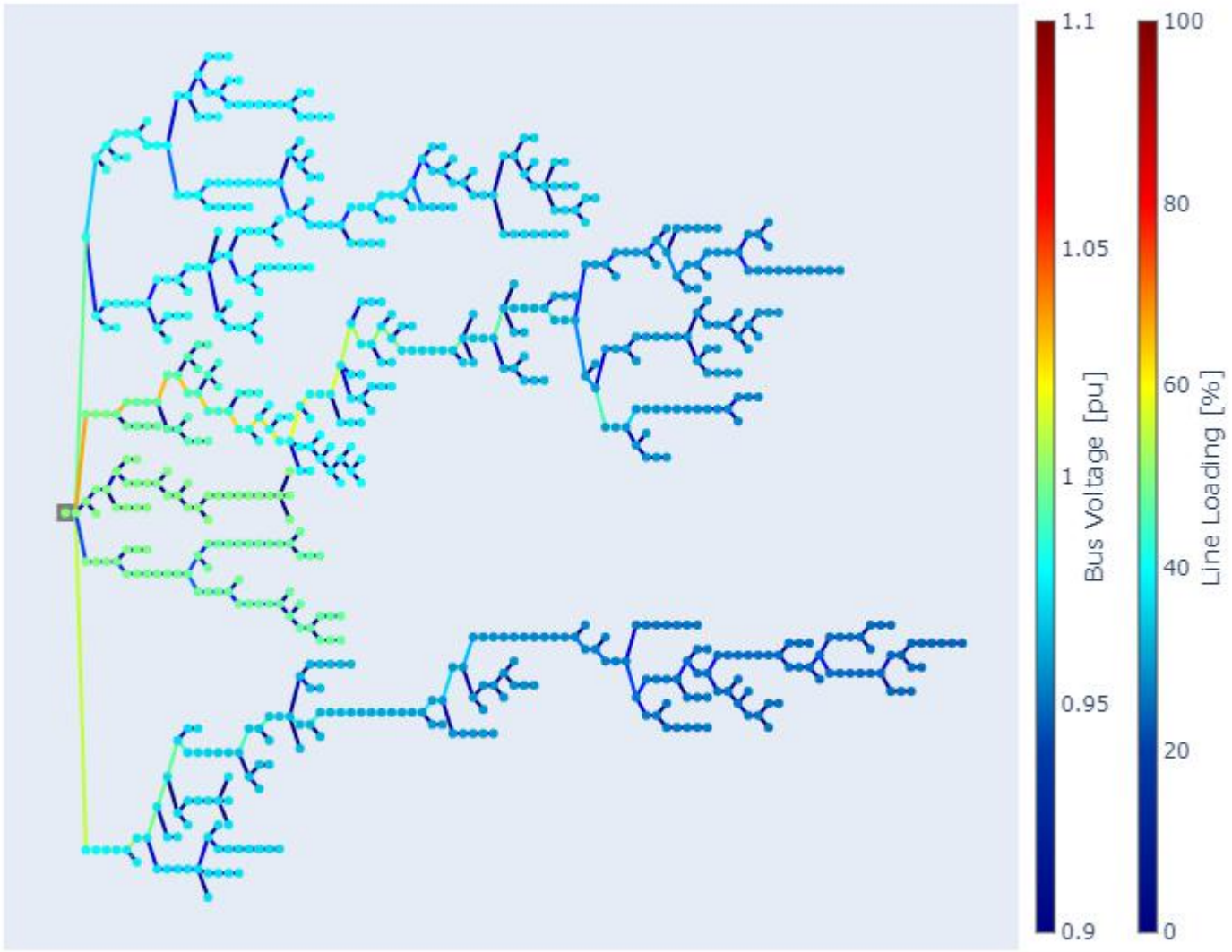


Load Duration Curves

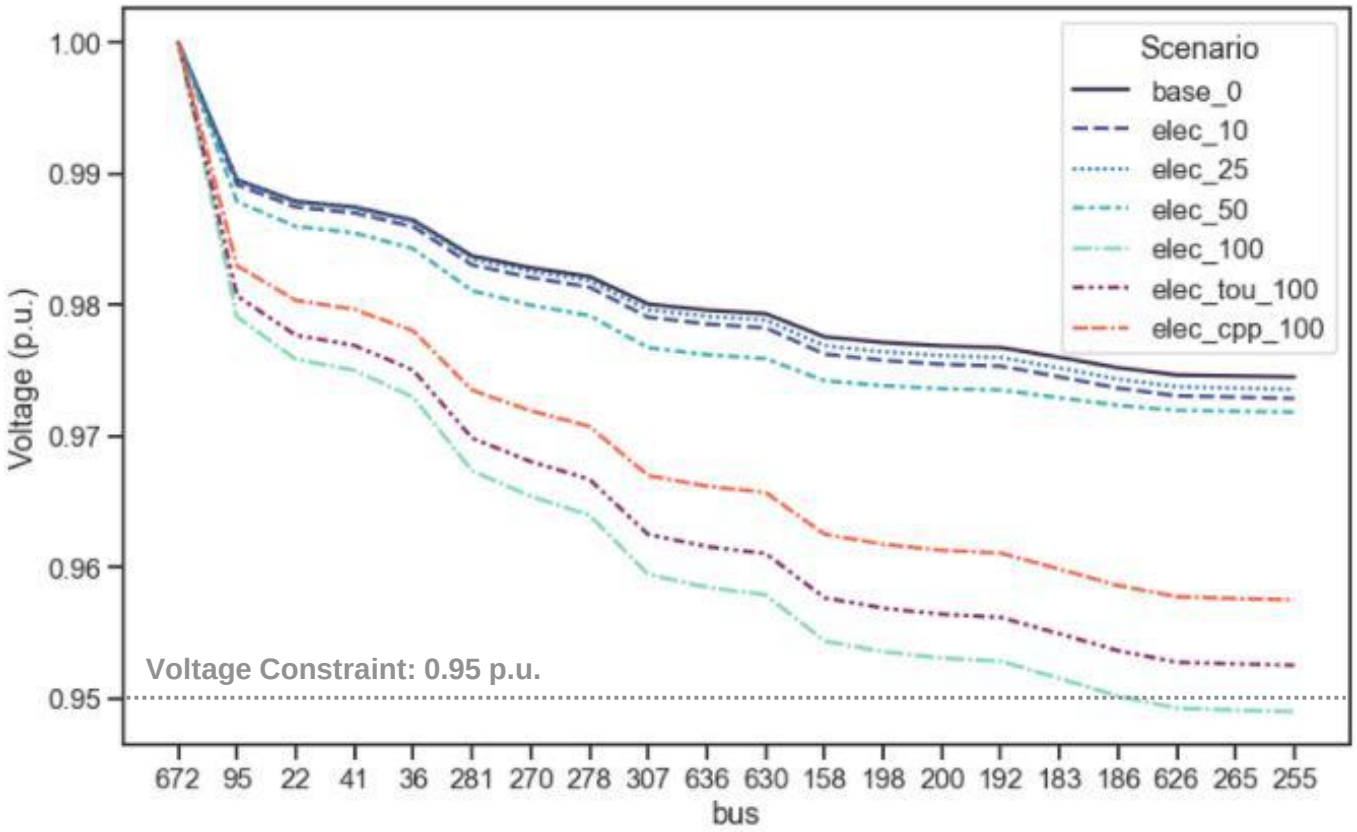
- Load duration curves shift up under electrification as higher winter loads displace summer loads at the top ranked hours



Power Flow Results – 100% Electrification Case



Power Flow Results – Voltage Across Longest Network Branch

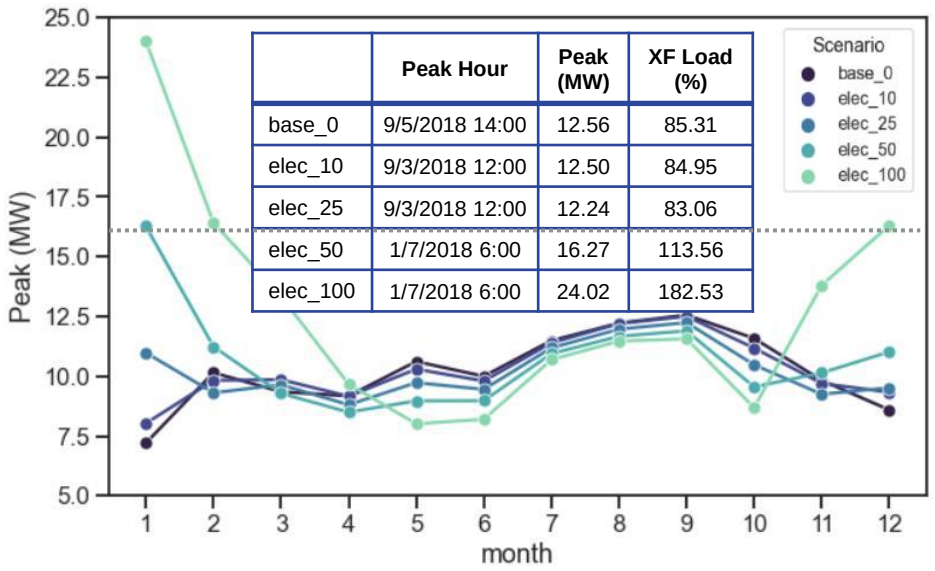


Effects of heating electrification on distribution peak demand

- Before electrification, substation demand peaks on a hot summer day at 12.6 MW, well below transformer rated power of 16 MW
- Heat pumps increase winter peaks and reduce summer peaks, so system is **winter peaking at 25% elec**.
- At 50% elec., peak demand exceeds rated power and transformer is overloaded by 13%
- At 100% elec., demand exceeds rated power in 57 hours

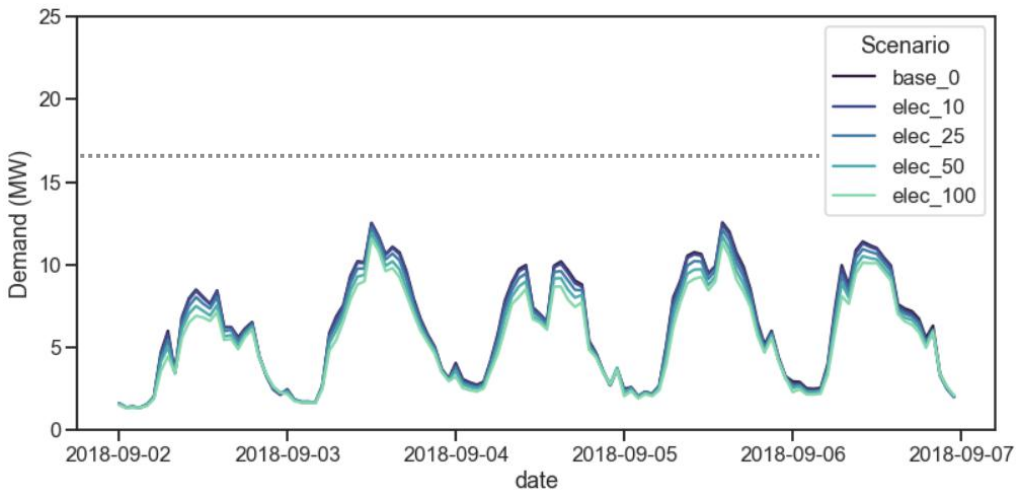
Monthly Substation Peak Demand

	Peak Hour	Peak (MW)	XF Load (%)
base_0	9/5/2018 14:00	12.56	85.31
elec_10	9/3/2018 12:00	12.50	84.95
elec_25	9/3/2018 12:00	12.24	83.06
elec_50	1/7/2018 6:00	16.27	113.56
elec_100	1/7/2018 6:00	24.02	182.53

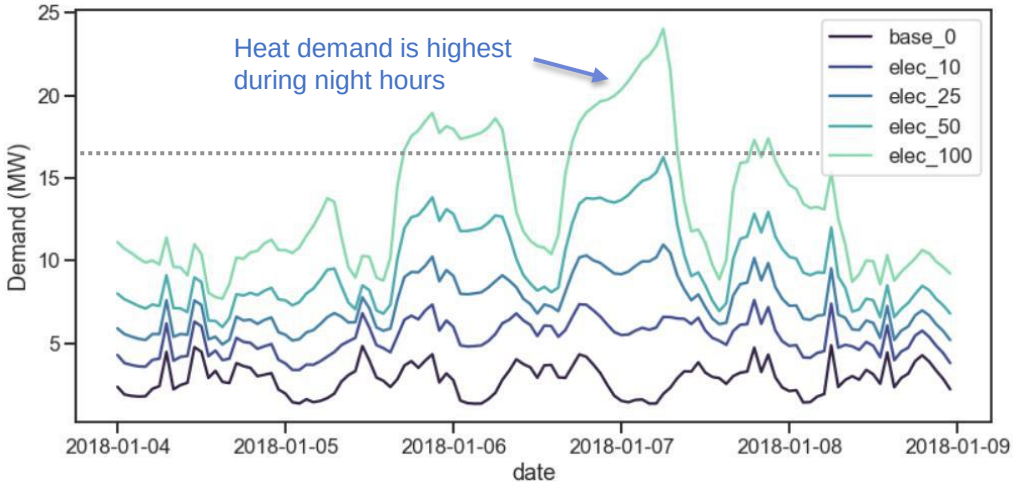


Substation Rated Power: 16 MW

Hourly Demand During Hottest Summer Week



Hourly Demand During Coldest Winter Week



Distribution upgrade costs related to heat electrification

Distribution capacity costs vary greatly across sources, locations and estimation approaches

- Bottom-up transformer upgrade costs range from **$67–$332/kVA**
  - 2019 NREL cost database estimates transformer installed costs of $95–261/kVA
  - Eversource typical substation transformer upgrade is $4m for 60 MVA unit, or $67/kVA, excludes expansion/rebuilding costs
  - In 2020 100% Residential Electrification Impact Study, City of Palo Alto estimates transformer costs of $194-332/kVA
- Top-down estimates range from **$150-1,500/kW** in marginal cost studies, **$100-200/kW** in avoided cost studies
  - Marginal costs are highly location-specific: Cutter et al. (2021) show a range from $148/kW in PG&E Mission and $186/kW in Eversource to $1,520/kW in SCE, and assume $400/kW
  - Avoided cost studies for MA DSM programs use $103/kW for National Grid and $198/kW for Eversource
  - Fares and King (2016) estimate that average distribution costs of $40/kW-yr (~$400/kW)

To translate load impacts into infrastructure costs, we conservatively assume a range of **$100–$500/kW**

