Are high penetrations of commercial cogeneration good for society?

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Abstract

Low natural gas prices, market reports and evidence from New York State suggest that the number of commercial combined heat and power (CHP) installations in the United States will increase by 7-9% annually over the next decade. We investigate how increasing commercial CHP penetrations may affect net emissions, the distribution network, and total system energy costs. We constructed an integrated planning and operations model that maximizes owner profit through sizing and operation of CHP on a realistic distribution feeder in New York. We find that a greater penetration of CHP reduces both total system energy costs and network congestion. Commercial buildings often have low and inconsistent heat loads, which can cause low fuel utilization efficiencies, low CHP rates-of-return and diminishing avoided emissions as CHP penetration increases. Low emission CHP installations can be encouraged with incentives that promote CHP operation only during times of high heat loads. Time-varying rates are one option. In contrast, natural gas rate discounts, a common incentive for industrial CHP in some states, can encourage CHP operation during low heat loads and thus increase emissions. Policies aimed at reducing emissions should encourage small commercial CHP operation only during times of high heat loads.

1. Introduction

Combined heat and power (CHP) systems can achieve higher fuel utilization efficiencies than conventional power plants. CHP contributes approximately 7% of US generation capacity with 97% of this capacity found in the electrical power and industrial sectors [1]. Low natural gas prices may encourage more commercial CHP in commercial and institutional settings. Schools, hospitals, nursing homes, laundromats, prisons, and other buildings with hot water needs are likely to benefit from commercial CHP [2, 3]. Already, the majority of CHP sizes in New York are less than 1 MW [4] (Supplementary Material, Figure S8) and US market forecasts predict annual growth rates of between 7-9% or about 70 GW over the next five years [5, 6]. If these forecasts are accurate, CHP may have a large effect on the environment, and on electric distribution grids.

Research on high penetrations of CHP in commercial buildings is limited. There is considerable research examining the economic feasibility and optimal sizing of CHP [7, 8, 9], but this work often focuses on universities and hospitals rather than on small commercial buildings such as apartments. Studying these smaller commercial buildings is important because they tend to have large daytime heat loads only in the winter and low heat loads during other times, but CHP could still be attractive for these customers at low natural gas prices. Inconstant commercial building heat loads may lead to wasted heat and low fuel utilization efficiencies if the CHP is operated during times of low heat loads [10, 11, 12]. To mitigate this problem, Smith *et al* [11] recommend oversizing water tanks (where space permits) to allow more heat storage and consequent emission reductions. Mago *et al* [12] suggest operating CHP at small offices only during office hours. These authors did not, however, assess the capability of commercial CHP to reduce regional emissions in high penetration scenarios. Even though the overall fuel efficiency for heat and power can be high, small CHP have electrical efficiencies as low as 25%, so CHP placed at buildings with low heat loads could produce higher emissions than the bulk power grid. Finally, we are not aware of any research that examines the effect of commercial CHP on the local distribution network. Commercial CHP operation is dependent on building heat loads and will have a unique effect on the network losses, congestion and power flows. We examine stakeholder costs and benefits, emissions, and network effects of high penetrations of commercial CHP. Because the details and emission consequences of how commercial CHP is operated may also be dependent on who owns the CHP, we compare utility and customer ownership.

We have constructed an integrated planning and operations model that maximizes owner profit through sizing and operation of commercial CHP on a realistic distribution feeder in New York. In the following section we describe our model. Customer and utility ownership models are used to explore how the benefits of CHP vary. We then discuss results that show CHP in commercial buildings reduces electric distribution system costs but that policies aimed at reducing emissions should encourage CHP operation only during times of high heat loads.

2. Combined heat and power model

Our model compares the CHP benefits accrued when operated by a utility and by a customer. These ownership models reflect current opposing viewpoints on who should own distributed energy resources (DER). For example, the American Council for an Energy Efficient Economy (ACEEE) has recently reported on the benefits of utility owned CHP [13] while the New York Reforming Energy Vision (REV) process currently prohibits utility ownership of DER [14].

An overview of the model is shown in Figure 1 and details are in Section A of the Supplementary Material. A radial distribution feeder is modeled with hourly time-varying electrical and heat loads; these are derived from the GridLab-D feeder taxonomy [15] and the US Department of Energy (DOE) commercial reference building model [16, 17], respectively. CHP that are installed at commercial buildings on the feeder can be used to supplement grid power and heat from pre-existing boilers (Supplementary Material Figure S1) and thus avoid energy costs, but at the expense of additional capital and operations & maintenance (O&M) costs. So, the model places CHP in commercial buildings only if the resulting cash flow yields a rate-of-return greater than 10%. The units are sized to maximize the net present value (Supplementary Material Figure S2). Next, the CHP are operated for one year (using observed heat loads and power prices) and the economic, environmental, and network benefits are computed. The primary difference between the owners is that the customer-owners are subject to a flat rate tariff (prices do not vary with hour or season) and a demand charge. The utility is an investor owned deregulated utility that that does not own generation and buys power on the wholesale market at time-varying locational marginal prices (LMPs). Additionally, the utility must offer the customer a power purchase agreement (PPA) to compensate for the opportunity cost foregone by not renting the space the CHP occupies; the utility can afford to do this because CHP reduces the utility's wholesale power purchase costs. We define a PPA similarly to the SolarCity PPA, where the customer earns a fixed rate for each kWh produced by the CHP. All modeling parameters were based on representative values from the northeastern United States (Supplementary Material, Section C).

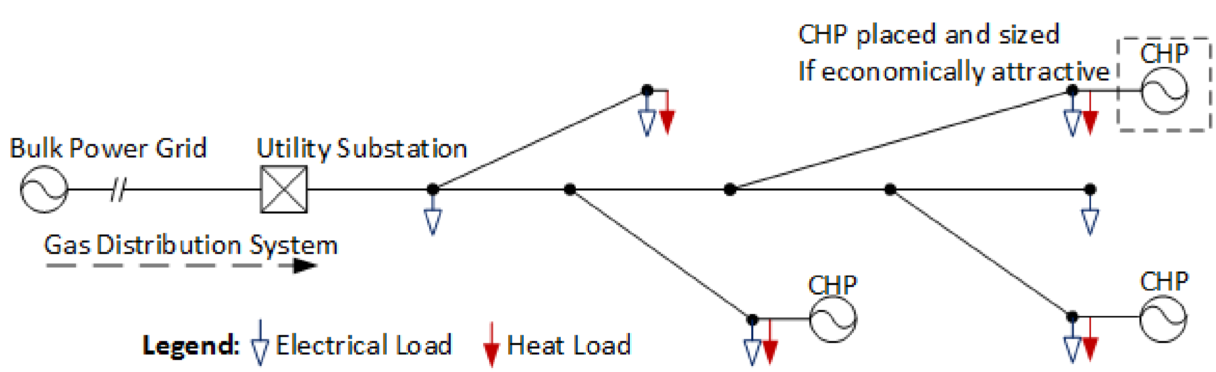

Figure 1. A simplified version of the integrated planning and operations model is shown.

Economically attractive CHP are placed on a distribution feeder with time varying electrical and heating loads. The CHP are operated by a customer, subject to a flat tariff, and a utility subject to time varying locational marginal prices. The effect of each owner's planning and operating strategy on the CHP economics, environmental benefits and network benefits are recorded and compared. Statistics for the full model are shown in Table S7 of the Supplementary Material. The full model has over 700 nodes and a lower penetration of CHP than shown here.

Annual metrics for the distribution network effects, relative CHP emissions, and allocation of economic benefits were collected. Distribution network effects were examined through the loading on all the network components such as transformers. We used regional marginal emission factors (MEFs) for the bulk power generation grid to compare the CHP emissions with marginal emissions on the bulk power grid. The MEFs estimate the emissions of the power plants that the CHP are most likely to replace at the time of day and year the CHP is producing power. We used three metrics for the allocation of economic benefits: System savings compare the cost of energy (i.e. LMP) and transmission & distribution (T&D) costs needed to deliver power to the loads against the cost of delivering that power with CHP (including fuel, O&M, and capital expenses). Customer savings depend on the ownership model and describes the final reduction in the customers' bills accounting for tariff structure (e.g. the energy charge and demand charges), capital costs, O&M costs, and power purchase agreement. Utility savings also depend on the ownership model, and compares avoided LMP costs, with loss of revenue through PPA costs, reduced demand charges, capital costs, O&M costs, and lost sales. Details are in Section B of the Supplementary Material.

3. Results

We find that the benefits of commercial CHP depend on the penetration level and how the CHP fleets are operated. Customer ownership leads to higher CHP penetration, which has benefits for the grid. However, lower CHP penetration and less CHP operation at night and in the summer leads to lower relative CO_2 and NO_x emissions in the utility ownership scenario.

We first discuss in what kinds of buildings CHP is profitable under the two ownership models. In our model, customer CHP owners install more CHP than utility owners on a greater variety of buildings (Table 1). The reason for the difference is that customers benefit from reduced demand charges under both ownership models and utilities must share revenue through a PPA.

Table 1. Planning Results. Customer CHP owners install more CHP on a greater number and variety of buildings.

Owner	Commercial Buildings																	Penetration	Total (kW)
		Large Office	Supermarket	Primary School	Secondary School	Strip Mall	Warehouse	Quick Service Rest.	Stand-Alone Retail	Small Office	Hospital	Medium Office	Full Service Rest.	Small Hotel	Midrise Apt	Outpatient	Large Hotel		
Customer	Total [kW]	513	76	62	600	69	85	0	94	7	425	2	0	30	15	50	250	13.4%	2278
Utility	Total [kW]	10	25	0	20	0	45	0	0	0	135	0	0	20	0	85	250	3.4%	590

In many cases it is not necessary for the utility to offer a PPA, because the customer's avoided demand charges are greater than the opportunity cost foregone by not renting the space the CHP occupies. Figure S14 of the Supplementary Material shows the range of PPAs that the utility could offer to the host customer of each load.

We next discuss network energy losses, thermal violations (i.e. equipment overloading) and voltage violations (e.g. over voltages) for each ownership model (Supplementary Material Section B). Resistive energy losses in the distribution network equipment account for approximately 1% of network demand without CHP and were reduced to 0.9% and 0.8% under utility and customer ownership, respectively. If these losses are monetized using the New York 2014 LMPs, savings would be $6-8/kW-year, a small amount relative to CHP capital costs (~2%). The distribution network in this analysis is representative of many Northeastern feeders and is loaded to 60% of its capacity. It is likely that greater value could be obtained from reduced losses through CHP placed on more heavily loaded feeders.

System benefits can also be produced by CHP that defers capital investments needed for the distribution network infrastructure. On networks with more congestion or high load growth, customer ownership would be more effective than utility ownership in deferring capacity investments (Supplementary Material Figure S15). We did not observe thermal violations or voltage violations that were caused or reduced by the commercial CHP.

A potential challenge with using commercial CHP to defer capacity investments for electrical distribution networks is that congestion will be shifted from the electricity network to the gas distribution network. Commercial CHP increased the yearly natural gas consumption for the sum of the buildings on the feeder by 46% and 400% under the utility and customer ownership scenario, respectively. Thus, high penetration commercial CHP scenarios are likely to require investments in natural gas distribution infrastructure. These investments, however, may not raise natural gas distribution costs since the CHP fleets increased natural gas load factors from 11% to 15% and 36% under customer and utility ownership, respectively.

4. Emissions

The relative CO_2, SO_2 and NO_x emissions of each CHP owner compared to the NPCC bulk power grid are shown in Figure 2. CHP decreases CO_2 and SO_2 emissions, but NO_x emissions increase. We find that utility owned CHP CO_2 and NO_x emissions are lower than those of customer owned CHP, despite having less installed CHP capacity. There are two reasons that the customer owned fleet of CHP has higher emissions. First, the customer owner is subject to a flat electricity tariff and operates the CHP more than the utility owner does during the night when heat loads are low and excess heat is wasted. This behavior is illustrated in Figure 3 for a supermarket. The utility sees lower LMPs at night, so will turn the CHP off at night and waste less heat. For similar reasons, the customer owner will operate the CHP more during the summer when heat loads are low. Buildings that have consistent heat loads, like hospitals, are less sensitive to time-varying rates and show less variation in emissions between owners.

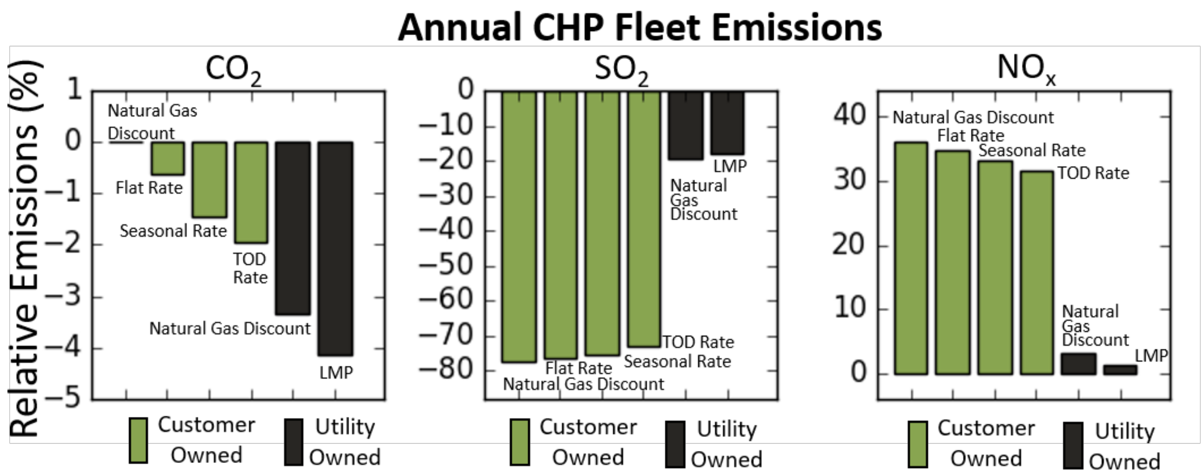

Figure 2. Utility and customer CHP emissions relative to the NPCC bulk power grid. Utility owned CHP reduces CO_2 and NO_x emissions more than customer owned CHP despite having less installed CHP capacity. Customer owned CHP emissions are higher because the customer's flat rate incentivizes continuous operation even when heat loads are low, and because the customer fleet contains more CHP with higher emissions. Time-varying rates, shown in the Time-of-Day (TOD) and Seasonal Rate scenario, reduce customer emissions by incentivizing the owner to reduce CHP operation during times of high heat loads. In contrast, a natural gas discount will encourage more operation of the CHP and increases emissions

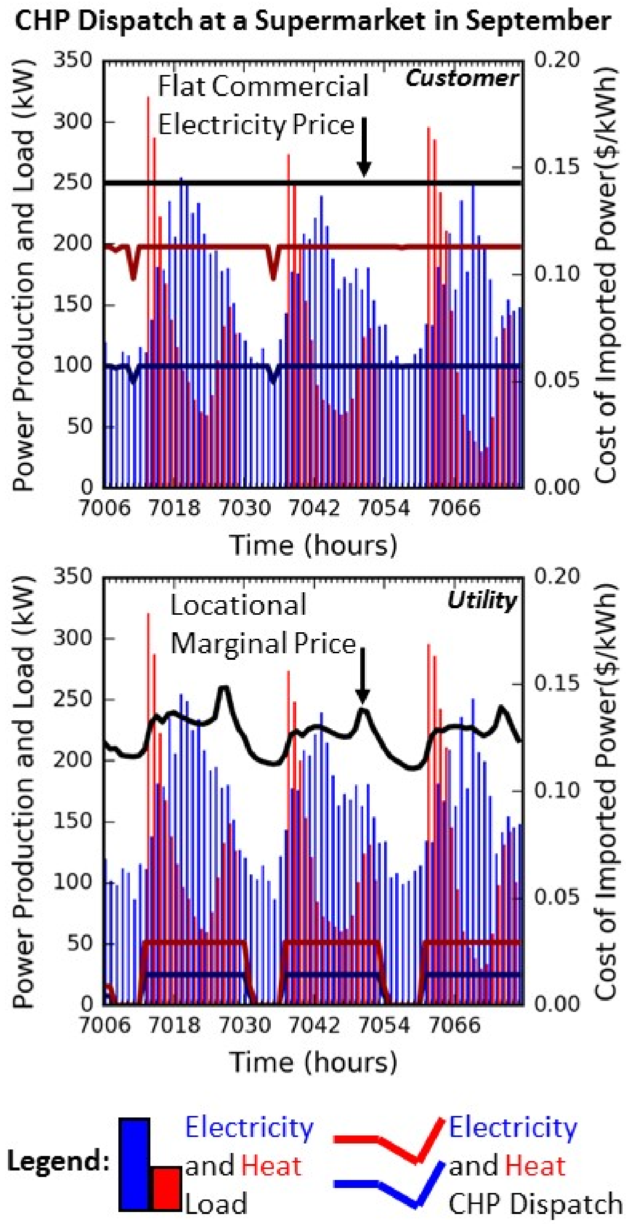

Figure 3. Utility and customer CHP dispatch. A supermarket has large heat loads in the day and very low heat loads during the night. The customer owner will continue to operate the CHP at night, but the utility which sees lower LMPs at night, will turn the CHP off. This results in lower overall emissions from the utility. Generally, dispatch is very sensitive to the heat load and price. Because time-varying rates tend to be small when loads are small, the utility dispatches CHP in a manner that follows the heat load more often.

The second reason that customer CHP ownership produces higher relative emissions is that the customer owned fleet has both larger and more CHP at buildings with higher relative emissions. Large offices with CHP produce more emissions than if powered from the bulk power grid (Figure 4), and more commercial CHP capacity is profitable at large offices in the customer ownership scenario (Table 1). Taken together, this suggests that higher penetrations of commercial CHP may yield higher relative emissions as CHP is placed at more buildings with inconstant heat loads. We examine this possiblity further in the sensitivity analysis.

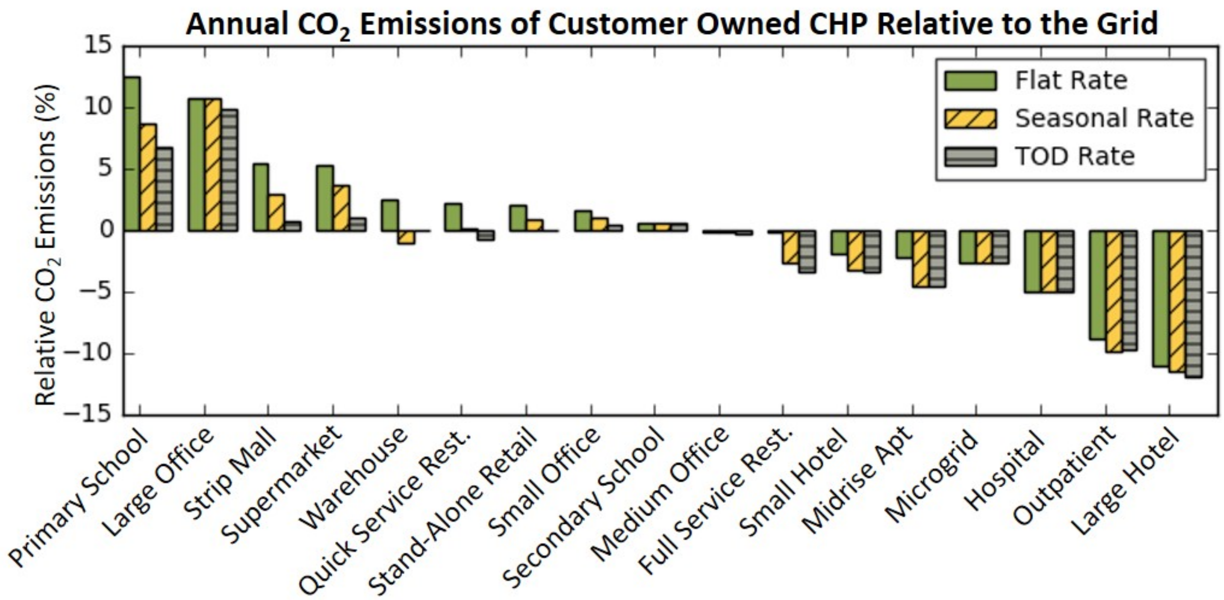

Figure 4. Customer owned CHP CO_2 emissions for representative buildings. Seasonal and Time-of-day (TOD) rates reduce customer CO_2 emissions. CO2, SO_2 and NO_x building level emissions are shown for the full fleet in the Supplementary Material, Figure S16. The microgrid is composed of one warehouse and one secondary school.

A more general way to assess the potential of CHP to reduce emissions is by directly comparing marginal emission factors and CHP emissions (Supplementary Material Figure S11, where marginal emission factors are shown for the NPCC reliability region in the summer, winter, and shoulder months). CHP emissions are also shown, but have a range that depends on how much boiler heating is avoided. Commercial CHP, for example, can reduce CO_2 emissions if heat is not wasted. SO_2 reductions are certain, because natural gas contains very little sulphur. NO_x

emissions depend greatly on both the CHP and boiler emission technology. In our analysis, we assume a best-case scenario for CHP with low NO_x CHP operation and boilers that do not control NO_x emissions. Despite this assumption, NO_x emissions from uncontrolled boilers are still about ¼ the magnitude of low-NO_x CHP. Because boiler NO_x emissions are relatively low, heat generated from CHP is less effective at reducing NO_x emissions (Figure 2).

Figure S11 of the Supplementary Material can be used to estimate the ability of CHP to reduce emissions in locations other than New York. Regions with high percentages of coal powered generation, such as MRO, will benefit from high penetrations of commercial CHP.

5. Potential emission reduction policies

As previously discussed, CHP is profitable for some commercial buildings with inconstant heat loads; in such installations some emissions can increase. Emission controls placed on commercial CHP and boilers would have a large effect on the relative NO_x emissons. Selective Catalytic Reduction (SCR) can reduce CHP NO_x emissions by 95% [3] and would ensure NO_x reductions similar to that of SO_2 for commercial CHP. However, SCR would add about \$150-\$700/kW to the CHP capital cost (approximately 6-27%, respectively) [3]. On the other hand, improved emission controls can reduce heating system boiler emissions by approximately 70% [18], but would significantly reduce the ability of commercial CHP to avoid NOx emissions. We find it is unlikely that commercial CHP owners would install these emission controls because yearly emissions do not qualify most buildings for EPA regulation (e.g. as a ‘major source’ of emissions).

We examine the possibility of using time-of-day rates and seasonal rates to reduce CHP emissions. We constructed hypothetic rates centered on the NYSEG commercial customer rate and designed the rates to discourage CHP operation during times of low heat loads. A time-of-day tariff of $0.121/kWh during the night and $0.165 during the day and a seasonal summer rate of $0.128/kWh and a winter rate of $0.158/kWh were used. Figure 2 and Figure 4 show that emission reductions are achieved for the CHP fleet and for individual buildings when customers are subject to time-varying rates. The emission reductions are achieved because the time-of-day rate discourages CHP operation and therefore, wasted heat during the night when commercial buildings have low heat loads. Similarly, the seasonal rate avoids wasted heat during the summer.

We found that time-varying rates can achieve emission reductions without reducing the economic value of customer-owned CHP, but customer-owned CHP can also lead to high utility losses and possible rate increases for ratepayers. Figure 5 shows that the system, customer, and utility savings remain similar if the customer has time-varying rates. However, utility losses are also high under all customer ownership scenarios because the utility loses revenue from reduced demand charges and reduced energy sales that embody the sunk costs of the distribution system infrastructure. In some regions, policies may be necessary to ensure that commercial CHP installations do not both increases customer rates and increase regional emissions.

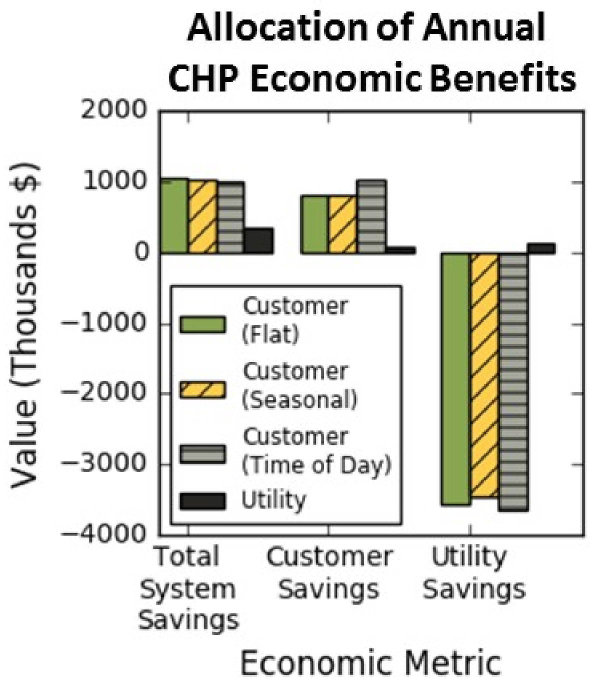

Figure 5. Allocation of CHP Savings for the base case and time-varying rates. Total system savings are positive for both owners indicating that the capital costs and energy costs of delivering power with CHP are cheaper than the grid. The high utility losses reflect lost energy sales and sunk distribution infrastructure costs. Time-varying rates do not have a large effect on customer or utility savings suggesting that time-varying rates can achieve emission reductions without negatively affecting the CHP payback period.

Microgrids are sometimes discussed as another option for reducing emissions [19], but we did not observe consistent emission reductions from microgrids. As shown in Figure 4 and Figure S22 of the Supplementary Material, microgrids composed of a warehouse and secondary school tend to produce lower emissions than if CHP were placed at those loads separately. The opposite is true for microgrids composed of a quick-service restaurant and strip mall. Microgrids may be more effective if emission reductions are included in the CHP sizing objective functions. Also, microgrids composed of many buildings could take advantage of the increasing electrical efficiencies and decreasing heat-to-power ratios of larger sized CHP (Supplementary Material Figure S6). However, despite these improvements, commercial building microgrids will still have a tendency to produce wasted heat because many commercial buildings have highly correlated heat loads (Supplementary Material Figure S23).

In some states, natural gas discounts are used to encourage CHP. New Jersey Natural Gas, for example, offers natural gas discounts of up to 50% to residential and commercial customers that install CHP [20]. We applied a natural gas discount of $2/MCF to the CHP fleet in Table 1 and examined the effect of this discount on the CHP fleet emissions, shown in Figure 2. The natural gas discount increases CO_2 and NO_x emissions because it encourages operation of the CHP even during times of low-heat loads. This result is further discussed in the following section.

6. Sensitivity analysis

We examined the robustness of the ability of time-varying rates to reduce emissions. In Figure 2 and Figure 4, we showed that time-varying rates cause utility owned CHP to turn off when heat loads are low, resulting in higher overall fuel utilization efficiencies. An important question is to what extent time-varying rates will be effective at reducing emissions in states that have different electricity and natural gas prices. For example, we also showed in Figure 2 that a natural gas discount would increase both customer and utility CHP fleet emissions, thus reducing the ability of time-varying rates to reduce emissions.

Figure 6 can be used to predict how effective time-varying rates will be in achieving emission reduction. It shows dispatch regions for a 10 kW CHP over a range of natural gas and electricity prices. These regions approximate how electricity and gas prices affect CHP dispatch under different loading scenarios. CHP units are not dispatched in the black region. In the green regions, CHP are dispatched only if a heat and electric load are present. In the yellow region, CHP are dispatched even when only the electric load is present. The customer owner's dispatch behavior, presented earlier for New York State with electricity and natural gas at $0.143/kWh [21] and $8.3/MCF [22], falls in the yellow region. The average utility electricity and natural gas prices also fall within the yellow region, but it is subject to a time varying LMP and thus often falls within the green region. Also, low LMPs tend to occur when commercial heat loads are low, so utilities fall within the green region when it is possible to achieve higher efficiencies. In contrast, the customers in the New York State have a flat rate, so they are consistently in the yellow dispatch region, and operate the CHP less efficiently. CHP larger than 10kW have smaller green regions, and will be less sensitive to time-varying rates, as shown in Figure 6 for a 500 kW CHP.

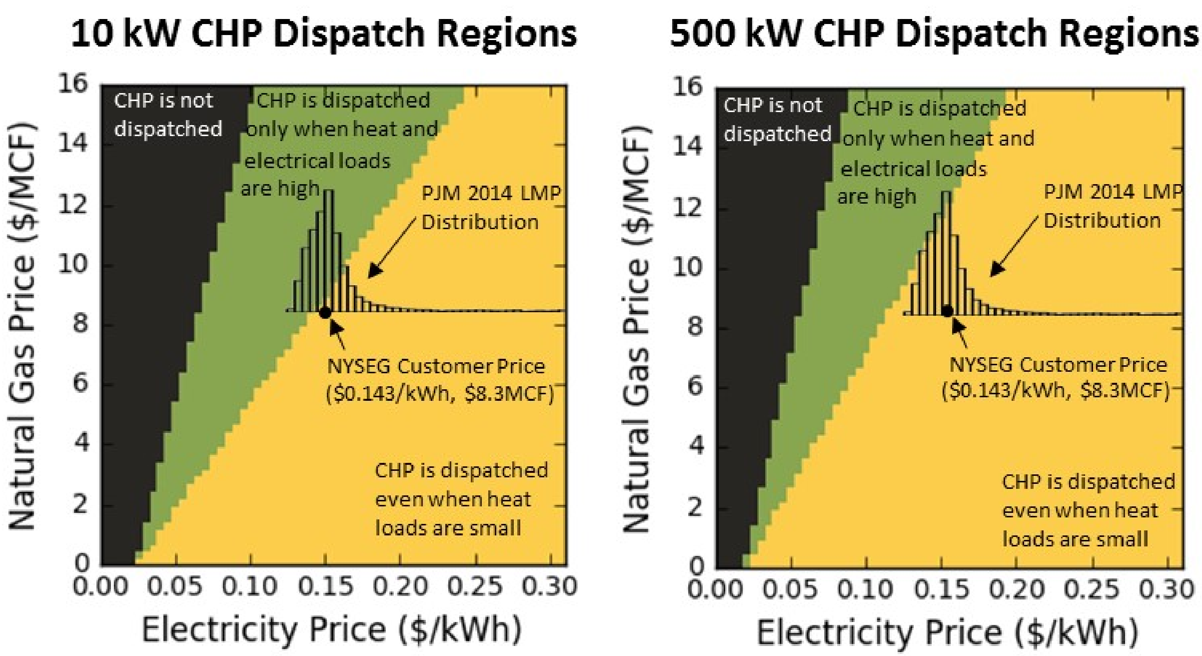

Figure 6. Sensitivity of dispatch of a 10kW and 500kW CHP to natural gas and electricity prices. CHP are not turned on in the black region. In the green region, CHP are only turned on if a heat and electric load is present. In the yellow region, CHP are dispatched at times even when only electric load is present. Dispatch in the green zone is likely to reduce emissions. Dispatch in the yellow zone may not reduce emissions if CHP heat production does not offset building heat load. For small CHP the customer owner's dispatch behavior, presented earlier, with electricity and natural gas at $0.143/kWh and $8.3/MCF falls in the yellow region. And, the utility is subject to a time varying LMP and so, it often falls within the green region, leading to lower utility emissions. Larger CHP becomes less sensitive to these effects, so time-varying rates will not be effective at reducing large CHP emissions.

As the penetration of commercial CHP increases, the emission benefits associated with CHP diminish. Figure 2 shows that the smaller utility owned fleet of CHP produces fewer relative emissions than the larger customer owned fleet. The larger customer fleet has more emissions because it has more CHP at buildings with higher relative emissions. This relationship is further examined in Figure 7. A range of CHP penetration scenarios for small CHP (<100 kW) was created by varying the capital cost and discount rate of the CHP investments. As the economic conditions became more favorable to the commercial CHP, penetrations increased, but the relative emissions also increased. Time-varying rates caused the utility owned fleet to produce lower emissions than the customer owned fleet for similar penetration levels. In contrast, the owner emissions of larger CHP (>100kW) are unaffected by penetration level and time-varying rates (see Figure 7).

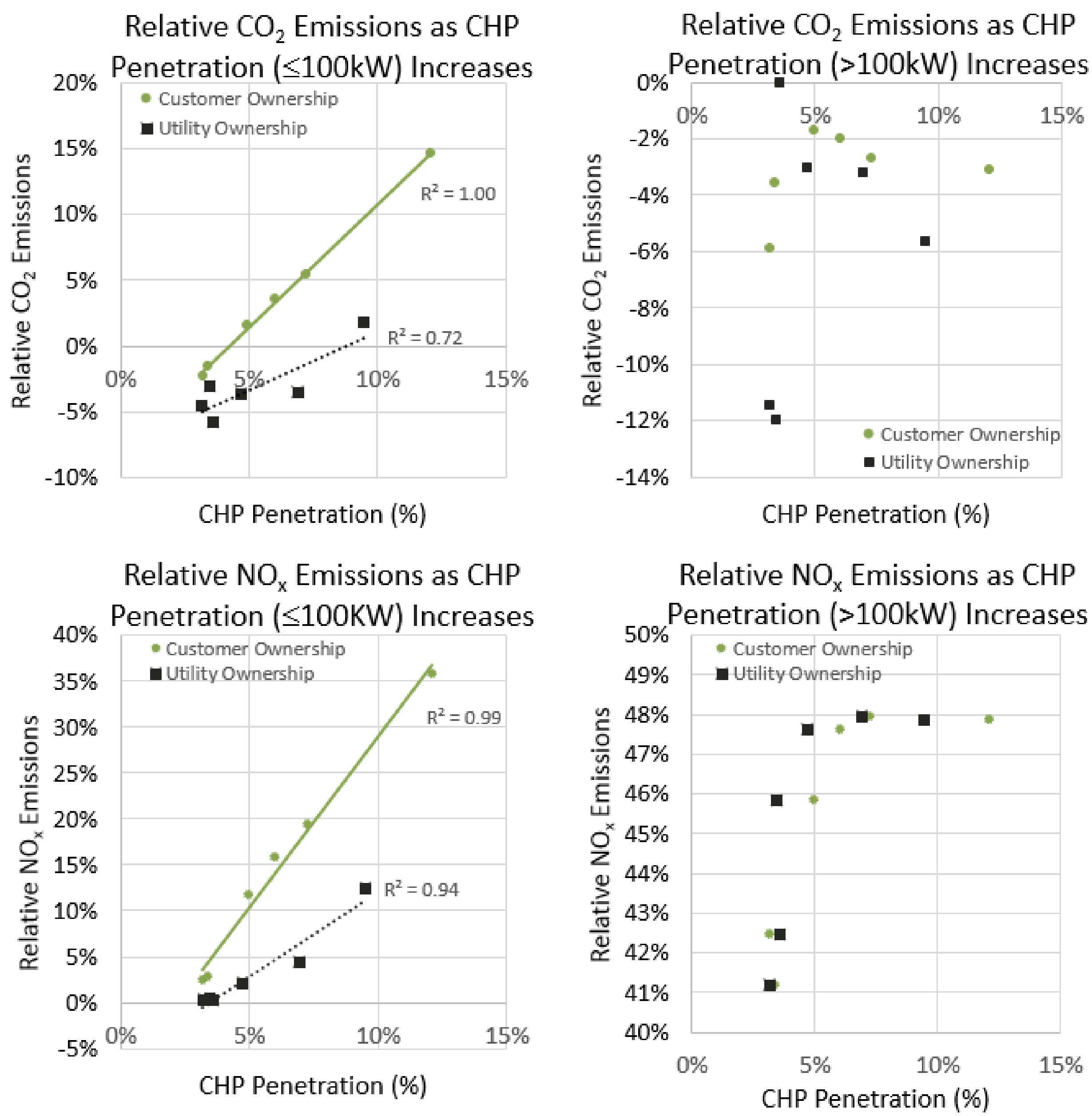

Figure 7. Emissions as the penetration of small CHP (<100 kW) and large CHP (>100kW) increases. Emissions increase as the penetration of small CHP increase but time-varying rates are effective at reducing these emissions. Emissions do not increase for large CHP and time-varying rates are ineffective at reducing emissions. The CHP fleet penetration correspond to the following scenarios moving from left to right: 30% Increase in CHP Capital Costs, 30% Increase in Discount Rate, Base Case, 30% Decrease in Discount Rate, 30% Decrease in CHP Capital Costs, 50% Decrease in Capital Costs and Discount Rate.

The emission and economic benefits of CHP were simulated for the years 2010 through 2014 to determine if the corresponding natural gas prices, electricity prices and marginal emission factors would affect the relative emissions or economic benefits of CHP fleets. The results are shown in Figure S17 and Figure S21 of the Supplementary Material, and are consistent with the 2014 results. Customer CHP fleet emissions are generally higher than utility emissions, and the economic benefits are allocated similarly for most years.

7. Conclusion and policy implications

We constructed an integrated planning and operations model that maximizes owner profit through optimal sizing and operation of commercial CHP on a realistic distribution feeder in New York. Using customer and utility ownership models we found that a greater penetration of CHP reduces network congestion and total system costs. Commercial CHP, however, will not always reduce emissions. Based on these results we summarize the following considerations to help policy makers maximize the benefits of CHP in commercial buildings.

Commercial CHP will reduce system costs. The capital, O&M, and energy costs of commercial CHP are lower than the lower than the capital, O&M, and energy costs of the grid. Overall, this will produce system savings, but there is likely to be a debate over who should be able to own commercial CHP and benefit from these savings. In particular, customer ownership leads to lost revenue for the utility.

Commercial CHP will reduce distribution network congestion and losses. On highly congested networks, commercial CHP may be an effective way to defer capacity investments.

Commercial CHP will reduce emissions less as penetrations increase. Commercial buildings vary in the quantity and consistency of their heat loads. Favorable economic conditions, such as a natural gas discount or a high electricity price relative to that of natural gas, may result in CHP at these buildings. SO_2 emissions decrease when CHP is installed, but CO_2 emissions rates depend on the head load of the building. In our New York model, we found large emission reductions for some buildings that have consistent heat loads, such as large hotels. However, the emission of some other building types, such as large offices, are sometimes larger than the bulk power grid emissions in the northeast because their inconsistent heat loads do not take advantage of the potential reductions due to CHP. A consequence of this finding is that high incentives for commercial CHP can have diminishing environmental benefits. In short, while commercial CHP are likely to be effective at reducing emissions in emission intensive regions, such as the Midwest, high penetrations of commercial CHP may not be effective at reducing emission in the northeast.

Policies aimed at reducing emissions should encourage small commercial CHP operation only during times of high heat loads. Time varying rates can be used to encourage CHP dispatch only when heat loads are high. We showed that time-of-day rates reduce customer owned CHP emissions and do not reduce customer rates-of-return. Incentives that reduce capital costs, such as accelerated depreciation, are also an option where regional grid emissions are high. Reduced capital costs will neither encourage nor discourage CHP dispatch during times of high heat loads. In contrast, natural gas rate discounts, a common incentive for industrial CHP in some states, can encourage CHP operation during low heat loads and increase relative emissions. Similarly, a production tax credit will cause most commercial CHP to produce higher relative emissions.

Acknowledgements

This work was supported in part by the Carnegie Mellon Electric Industry Center. Additionally, J.A. received partial support from the Carnegie Mellon Climate and Energy Decision Making Center (CEDM), formed through a cooperative agreement between the National Science Foundation and CMU (SES-0949710). We thank Inês Azevedo for providing marginal emission factors in digital form. Technical advice provided by Jason Fuller (of PNNL), David Pinney (of NRECA and the OMF), and the DER-CAM team was invaluable.

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[18] *Compilation of Air Pollutant Emission Factors (AP 42), Fifth Edition, Volume I (Chapter 1.4, Natural Gas Combustion);* U.S. Environmental Protection Agency: Research Triangle Park, *NC*, 1998. https://www3.epa.gov/ttn/chief/ap42/ch01/final/c01s04.pdf .

[19] *Summary Report: 2012 DOE Microgrid Workshop;* United States Department of Energy Office of Electricity Delivery and Energy Reliability: Smart Grid R&D Program: Chicago, IL, 2012. http://energy.gov/sites/prod/files/2012%20Microgrid%20Workshop%20Report%2009102012.pdf .

[20] *Save Energy & Money: Distributed Generation;* http://www.njng.com/save-energy-money/distrGen/index.asp.

[21] *U.S. Utility Rate Database*; http://en.openei.org/wiki/Utility_Rate_Database.

[22] *Natural Gas Prices;* United States Energy Information Agency, Washington, DC, 2016. http://www.eia.gov/dnav/ng/ng_pri_sum_a_EPG0_PCS_DMcf_a.htm.

Supplementary Data
for
Are high penetrations of commercial cogeneration good for society?

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Section A: Modeling

Network Model

We used Pacific Northwest National Laboratory's (PNNL) Gridlab-D solver and distribution feeder taxonomy for representative distribution feeder models and for all distribution powerflow simulations. Gridlab-D is a distribution time-series AC powerflow solver produced by PNNL. [1] The feeder taxonomy, created by Schneider et. al., [2] is a set of 24 prototype non-urban, radial feeder models from varying climate and demographic regions with residential and commercial static loads. To develop the feeder taxonomy, hierarchical clustering was performed by Schneider et. al. on a set of 575 feeders[*] to determine common feeder features. [2] The feeder taxonomy prototypes were based on these common features. [2]

In our model, the static load sources in the feeder taxonomy models were replaced with time-varying heat and electric loads. Time-varying electrical loads were first produced by Hoke et. al. [3] [†] to study the maximum penetration of solar photovoltaics on distribution feeders[‡]. To include heating loads, some time-varying electrical loads were replaced with commercial building electrical and heat loads. The electrical and heat loads were originally created as part of the *Commercial Reference Building Model of National Building Stock* for different regions in the United States. [4] [§] These heat loads are shown for each building type in the summer and winter in Figure S3 and Figure S4. The commercial building loads were scaled to ensure that peak loading

[*] The feeders were provided by 17 investor owned (IOU), rural electric authority (REA), public utility districts (PUD) and municipality utilities.

[†] To create the dynamic load dataset, a commercial and residential load dataset was acquired from a utility in geographic regions corresponding to the taxonomy regions. These were then scaled by transformer capacity and a feeder wide factor that kept power flows within violation ranges. Finally, some guassian noise was added to the loads.

[‡] The electrical loads are available at https://catalog.data.gov/dataset/randomized-hourly-load-data-for-use-with-taxonomy-distribution-feeders-88065

[§] The commercial building loads are available at https://catalog.data.gov/dataset/commercial-and-residential-hourly-load-profiles-for-all-tmy3-locations-in-the-united-state-1d21c conditions remained the same as the Gridlab-D feeder taxonomy. These buildings represent approximately two-third of the US commercial building stock. The percentage of each building type is based on the 2003 Commercial Building Energy Consumption survey. [5]

Table S1 shows each commercial building type and the approximate proportion assumed to be on each feeder. Building loads were placed on pre-existing loads that minimized the norm of the difference between the electrical peak load, minimum load, and load factor. The final heat and electrical power load is scaled so that the total electrical energy consumption over the year remains the same. Figure S5 shows one example of each building's matched load, the scaled load, and the original time varying Gridlabd-D taxonomy load. The American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) climate region 6 was used. Climate region 6 has a cold climate and is typical of the northeastern and north central portions of the US. [6]

CHP Model

We use natural gas fired reciprocating engine CHP in our model. According to Flin, [7] CHP systems are generally cost effective when there is a need to upgrade an existing heating system, and can be used to supplement a boiler. Diesel-fired CHP are not used in our model because diesel's higher emissions typically limit its operating hours to backup applications, [8] and because natural gas is the most common form of fuel for CHP. [9] The full combined heat and power system is shown in Figure S1. The commercial building can purchase power from the distribution network or can produce its own power. Heat can be produced by the boiler or the CHP.

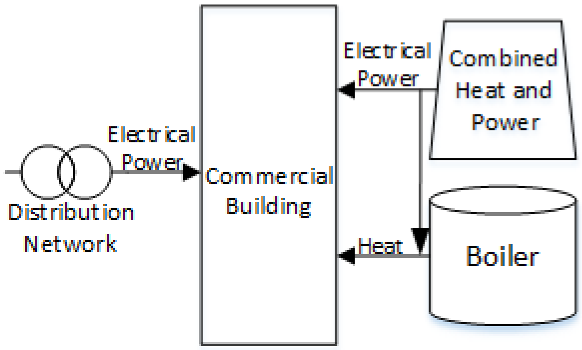


Figure S1: Energy options for the commercial building. Electrical power comes from the grid or from the CHP. Heat can come from the boiler or the CHP. The lowest cost source of heat and electrical power is used to meet demand at each hour. CHP dispatch decisions also have environmental and network consequences, but these are not considered in the dispatch objective function.

CHP Type, Sizing and Placement

Natural gas, reciprocating engine CHP are placed on a load if they earn a rate-of-return greater than 10% and if their payback period is less than the equipment lifetime. If multiple CHP sizes meet this criteria, the CHP size with the maximum NPV is used. Revenues are based on one year of loading conditions and each owner's tariff structure. The CHP selection objective function is shown in Figure S2.

CHP Selection Objective Function

For all commercial loads, select the size that will,

Minimize:

NPV (Grid Costs +
Boiler Energy Costs +
CHP Energy Costs +
CHP capital costs +
Annual O&M costs)

Subject to:

Energy purchased, generated = demand
CHP stays within operational limits
Rate of return > 10%
Payback period is within CHP lifetime

Figure S2: CHP selection objective function. The CHP size with the lowest capital costs, O&M costs, and energy costs is used. CHP are not placed on the commercial load if the rates-of-return are less than 10%. Take out. Add text to body

CHP are considered in sizes of 1 kW and higher. According to the EPA, 8 CHP are available in sizes ranging from 10kW to over 18 MW, but we have found CHP as low as 1 kW. [10] Reciprocating engines are used because they are well suited for optimized dispatch. In comparison to microtubines and fuel cells, they are better at following load, have faster startup capabilities and have been used for peak shaving. [7, 8] CHP parameters were extrapolated from DER-CAM, a software tool produced by Lawrence Berkeley National Lab and from the EPA's 2015 CHP Characterization. [8] Both sets of parameters are determined with an industry expert survey. Capital costs include engineering fees and labor. A fixed linear efficiency is used for each CHP. The DER-CAM CHP parameters are shown in Table S2 for a 1121 kW, 250 kW and 75 kW CHP. The extrapolated CHP capital costs, O&M, efficiencies, and heat-to-power ratios are shown in Figure S6.

The CHP sizes used in our model range from 1kW to 1000kW, but the most common size was less than 75 kW, and, less than the CHP sizes characterized by DER-CAM or the EPA. Our main concern was that we were underestimating the capital costs for small commercial CHP and overestimating penetration levels. To the best of our knowledge, industry surveys do not exist for small CHP, but we were able to obtain a quote on the internet site Alibaba. The quote was for a 10kW natural gas CHP generator. The capital cost quoted was $1000/kW, and slightly less than the capital cost for a 100kW given by the EPA [8] at $1400/kW. From this, we conclude that our linear extrapolating capital costs for small CHP is reasonable.

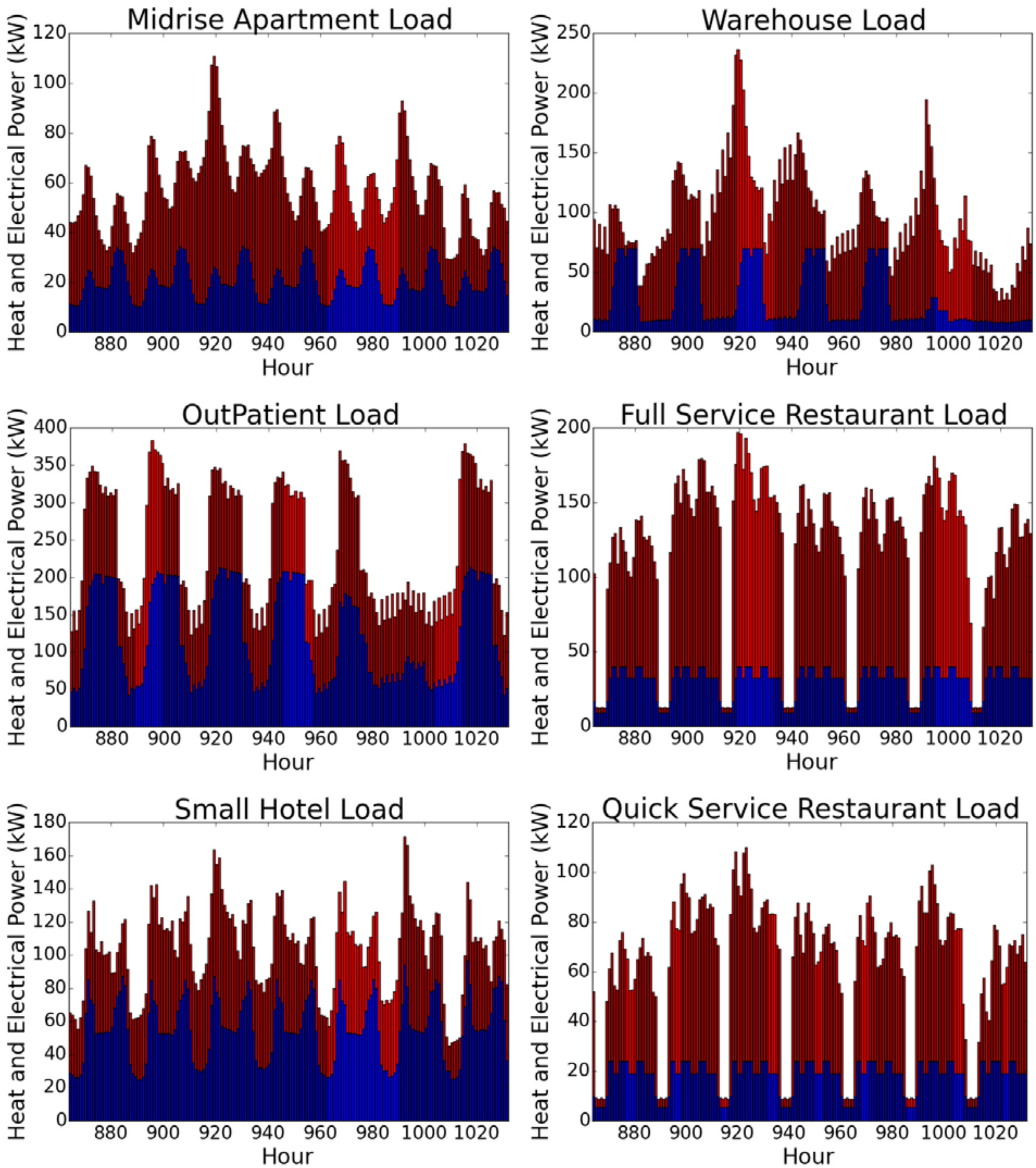
Ownership Model

In recent years, a debate has emerged over who should own distributed energy resources (DER), such as CHP, and profit from their benefits. Utilities argue that market participation will allow them to fulfill their traditional obligations in serving unserved customers. [11] NYSERDA [12] adds that utility ownership may be beneficial because utilities can readily access customer information and technical information, avoid duplicative services, and improve customer service quality through differentiated service options associated with DER. The Edison Electric Institute (EEI, the trade group for investor-owned electric utilities) has argued for a “level playing field” for utilities and new DER market entrants, and it warns of potential grid safety, reliability, and customer cross-subsidies-to the disadvantage of low-income customers- without sufficient involvement from utilities. [13] In a series of white papers, the American Council for an Energy-Efficient Economy (ACEEE) argues that there are societal benefits of utility CHP ownership. [14] They say that utilities may be better equipped to capture the environmental benefits of CHP, to participate in ancillary markets, and to manage long term investments. [14] However, third parties, fearful of utility market advantages, argue that utility involvement will inhibit competition, [12, 11] and we will lose an opportunity to invigorate a stagnate industry. [15]

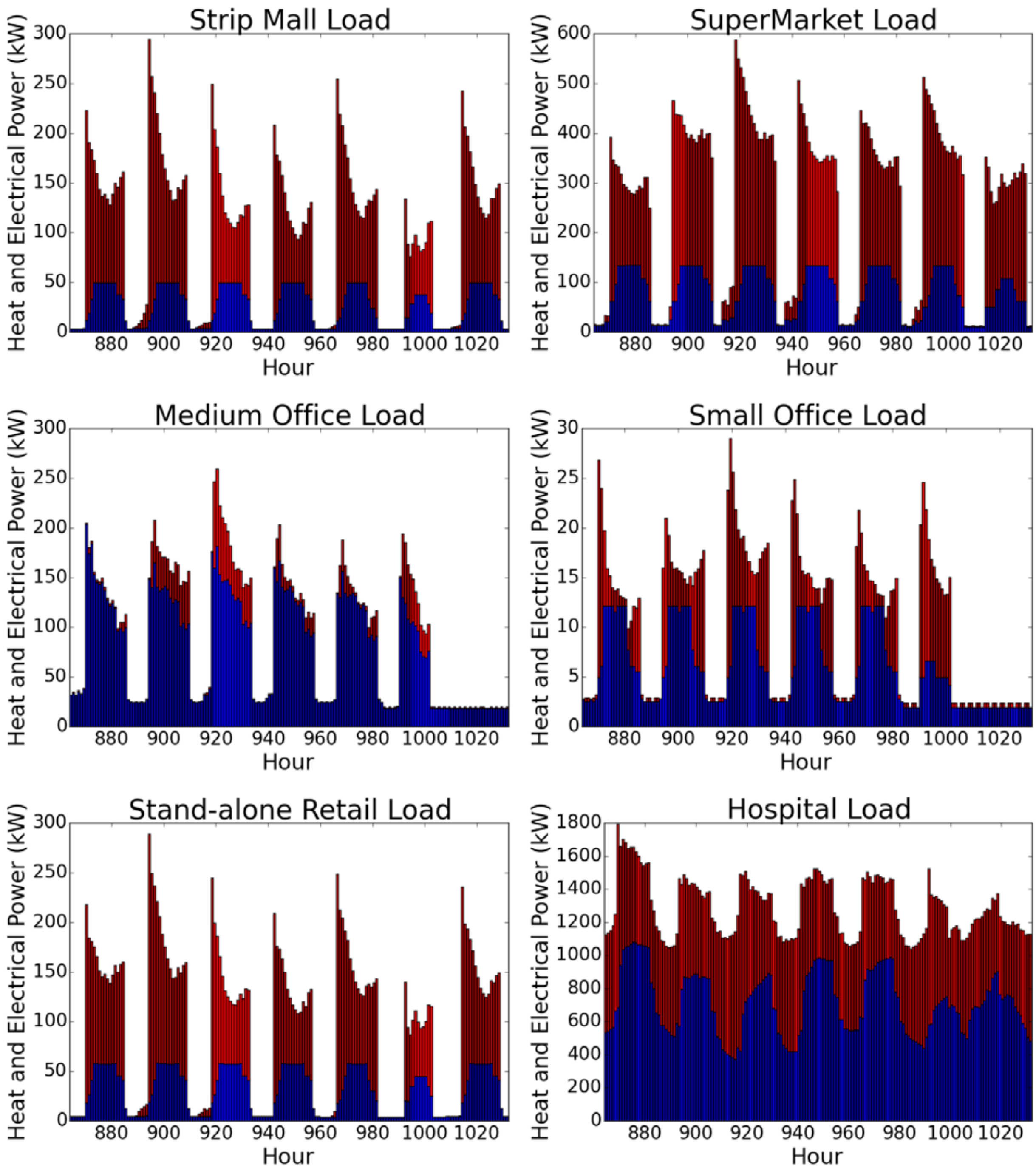
Private customer and utility owned CHP operating strategies are both modeled. In the private customer ownership model, the owner is assumed to be a customer of the utility with a flat rate that does not vary hourly or seasonally**. The customer operators attempt to minimize their costs over the year by producing power when grid costs exceed generation costs. In this model, it is assumed that each customer operates independently. The objective function for the private customer ownership model is shown in Table S3. The first term describes customer payments to the utility for power demand less generated power. The second term describes the cost of power production less the reduced heating bill from offset boiler demand. The objective function is constrained by the generation operational limits. Scenarios were created where power exports are not permitted and where power is exported and compensated the retail rate.

In the utility ownership model, the utility attempts to maximize its profit. The objective function is shown in Table S4. The first term describes revenue earned by the utility from dispatching CHP at customer sites. The revenue is based on the standard utility tariff less the value of the customer's PPA when CHP is dispatched. In the second term, heat revenue is earned at the customer's avoided heating cost. The third term describes the utility's cost of buying power from the wholesale market and of generating power. Scenarios were created where power exports are not permitted and where power is exported and compensated at the wholesale rate (including transmission costs). Demand charges are not included in the objective function but are considered indirectly during the planning stage. Additionally, the utility must offer a power purchase agreement (PPA) to the customer to compensate for the opportunity cost foregone by not renting the space the CHP occupies. We assume that the PPA will be different and based on the economics of each CHP location. Each customer is offered the smallest PPA that overcomes their opportunity cost.

** Generally, small residential and commercial customers prefer static rates.[35] Discussions between the authors and industry stakeholders have suggested that this also appears to be true for commercial customers with CHP.



Midrise Apartment Load
Warehouse Load
OutPatient Load
Full Service Restaurant Load
Small Hotel Load
Quick Service Restaurant Load
Heat and Electrical Power (kW)
Hour


Strip Mall Load
SuperMarket Load
Medium Office Load
Small Office Load
Stand-alone Retail Load
Hospital Load
Heat and Electrical Power (kW)
Hour

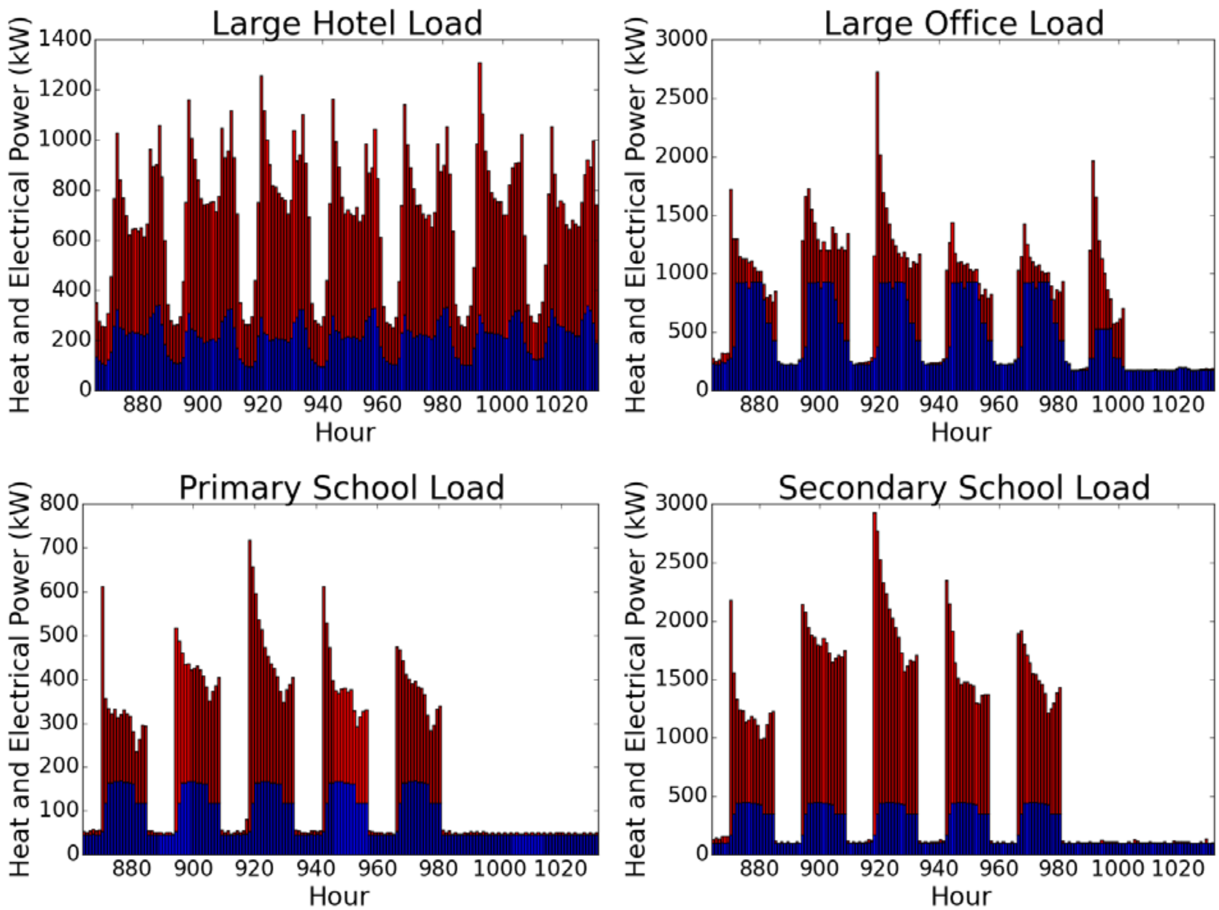
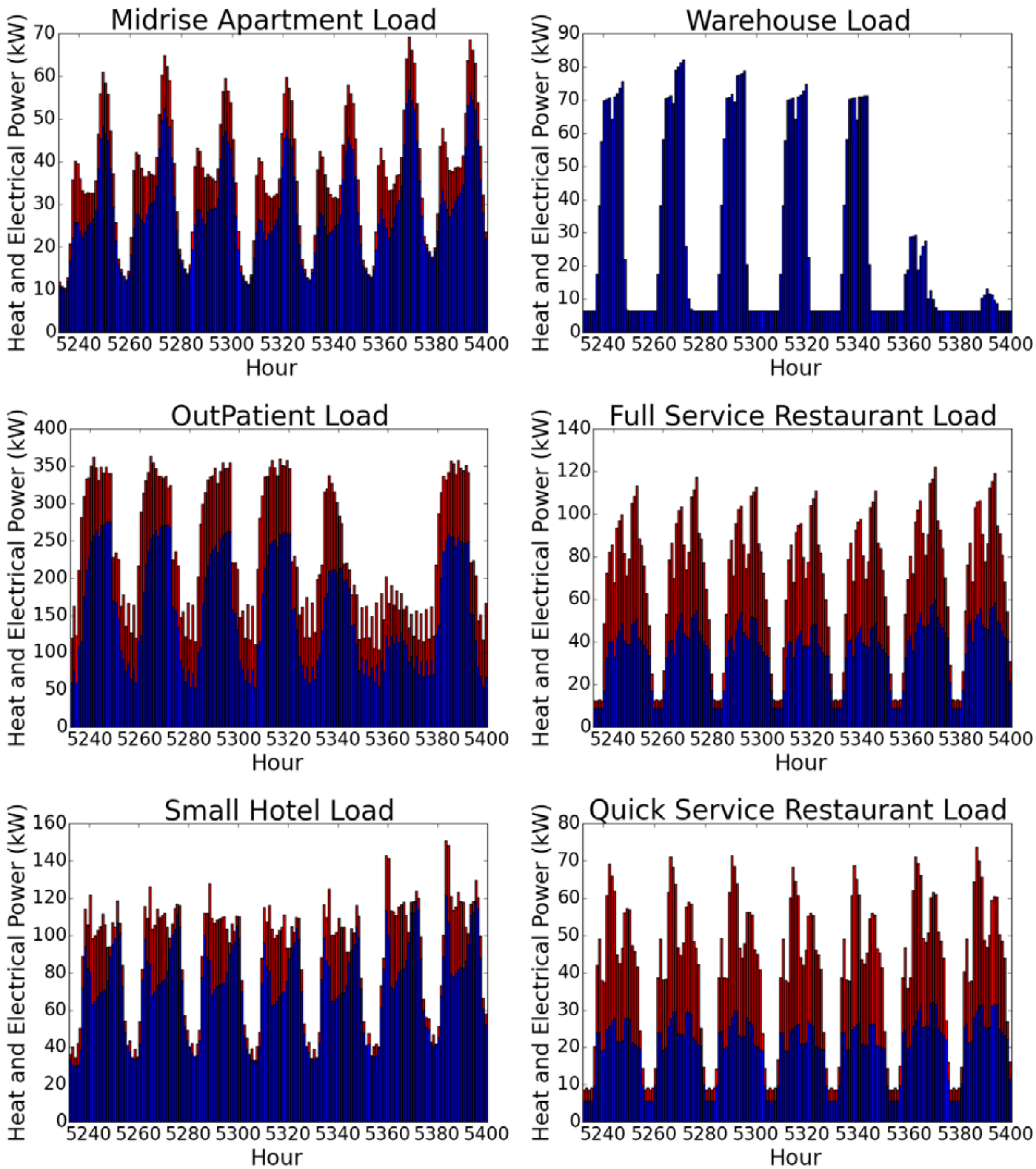
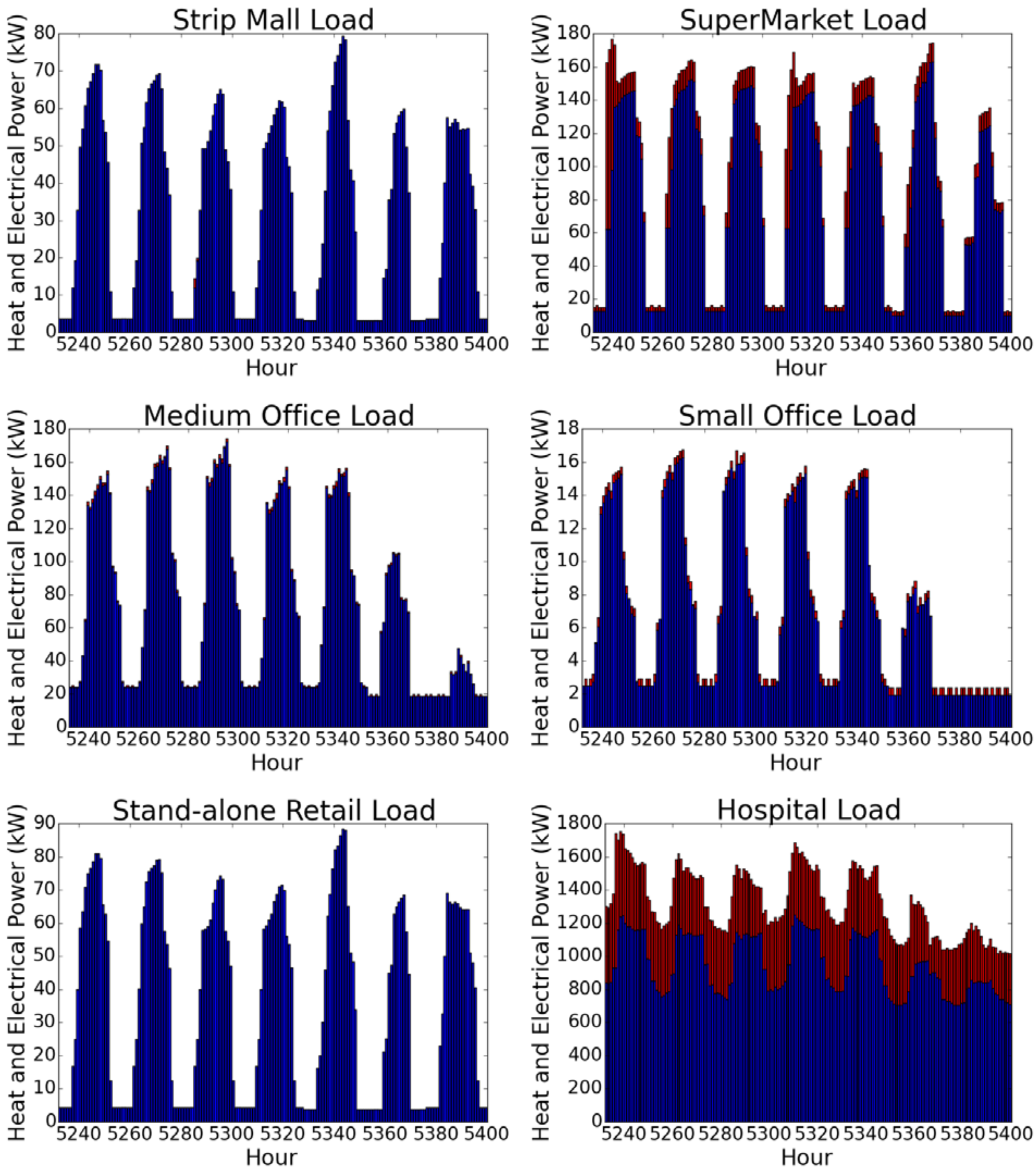


Figure S3: Building heat and electric loads during the winter. One week in February is shown.


Midrise Apartment Load
Warehouse Load
OutPatient Load
Full Service Restaurant Load
Small Hotel Load
Quick Service Restaurant Load
Heat and Electrical Power (kW)
Hour
5240 5260 5280 5300 5320 5340 5360 5380 5400


Strip Mall Load
Heat and Electrical Power (kW)
Hour
SuperMarket Load
Heat and Electrical Power (kW)
Hour
Medium Office Load
Heat and Electrical Power (kW)
Hour
Small Office Load
Heat and Electrical Power (kW)
Hour
Stand-alone Retail Load
Heat and Electrical Power (kW)
Hour
Hospital Load
Heat and Electrical Power (kW)
Hour

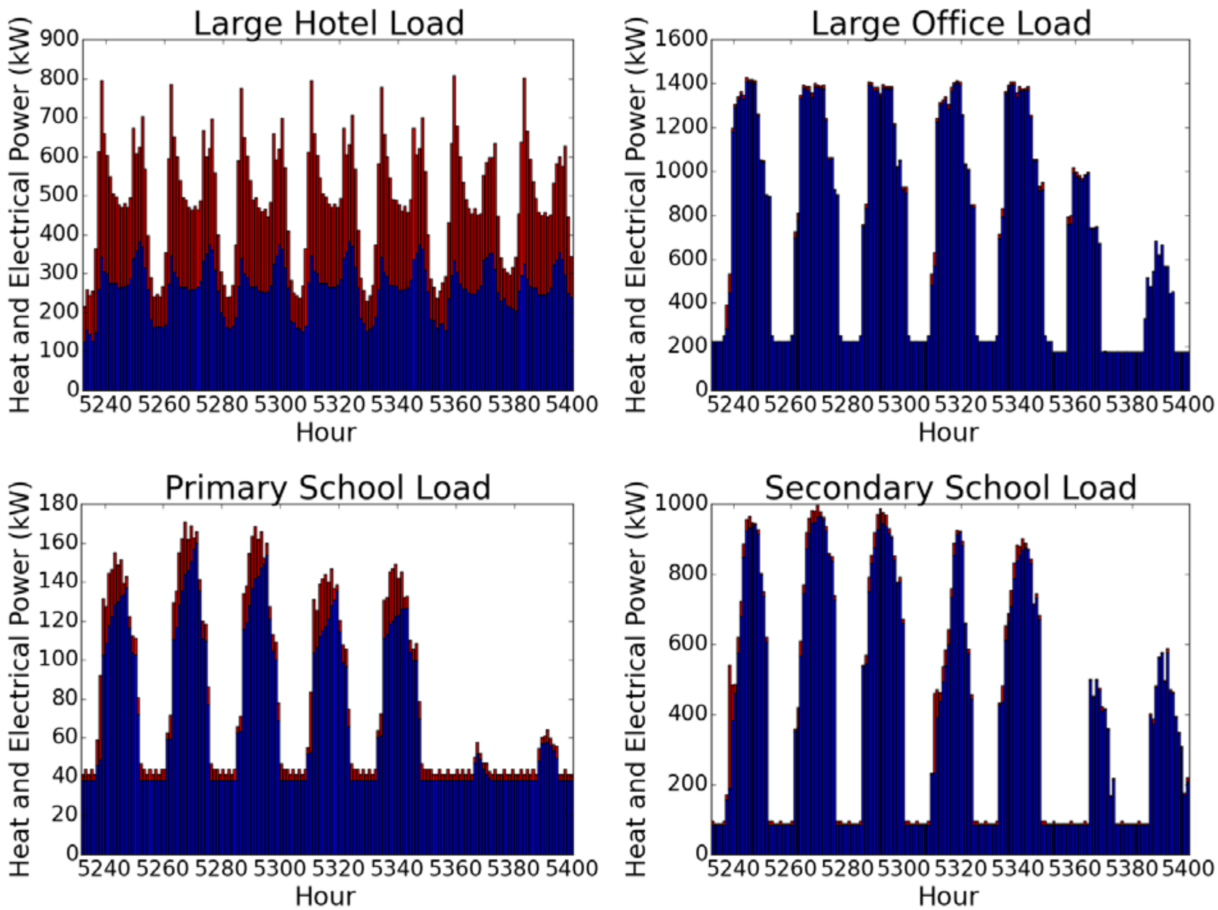
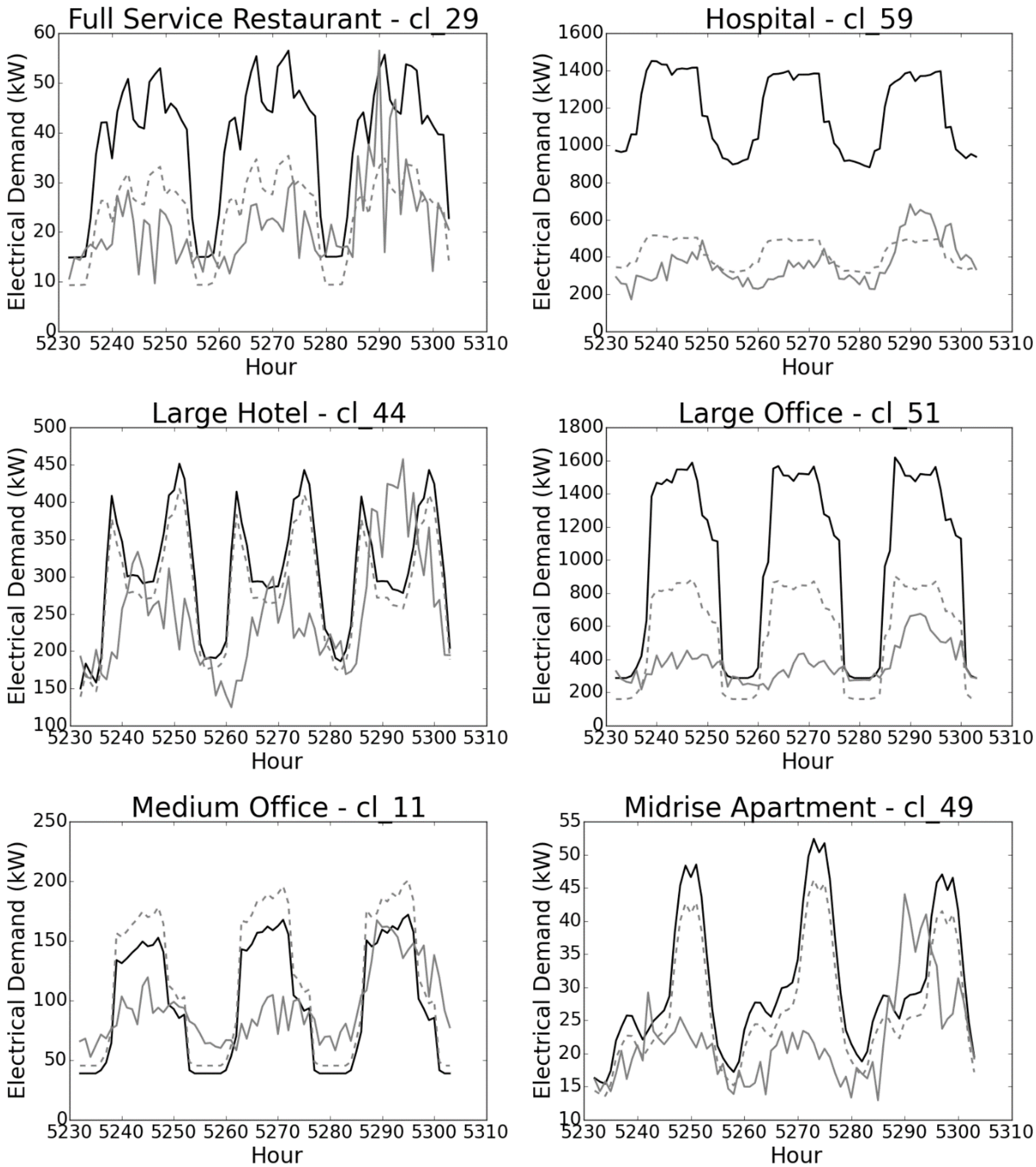


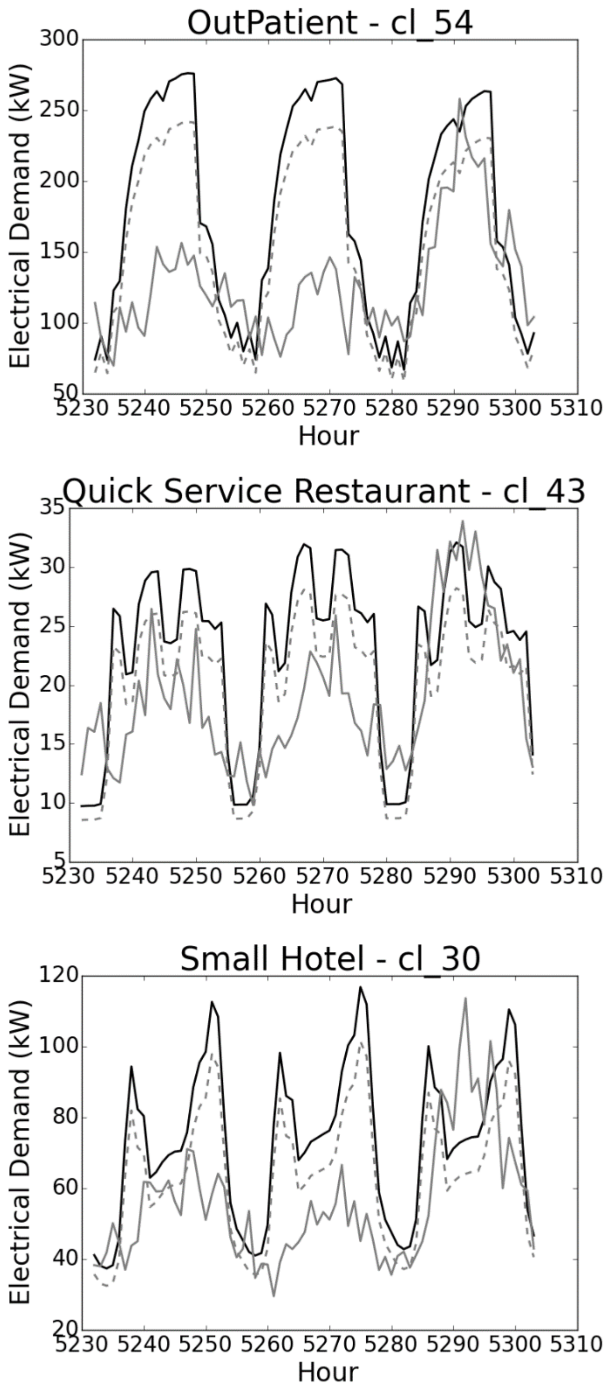
Figure S4: Building heat and electric loads during the summer. One week in July is shown.

Table S1: Commercial building types and quantity. The commercial buildings shown represent approximately two-thirds of the US commercial building stock and are used to determine heat and electrical loads for the feeder, as provided by NREL [4]. The percent quantity found on each feeder is based off of the DOE's 2003 commercial building energy survey. [5]

Commercial Building Type	Feeder Quantity (%)
Small Office	9
Warehouse	9
Stand-Alone Retail	7
Strip Mall	7
Medium Office	6
Primary School	6
Large Office	4
Hospital	4
Outpatient Healthcare	3
Secondary School	2
Full Service Restaurant	2
Small Hotel	2

Large Hotel	2
Midrise Apartment	1
Quick Service Restaurant	1
Supermarket	1




OutPatient - cl_54
Primary School - cl_53
Quick Service Restaurant - cl_43
Secondary School - cl_36
Small Hotel - cl_30
Small Office - cl_39
Electrical Demand (kW)
Hour

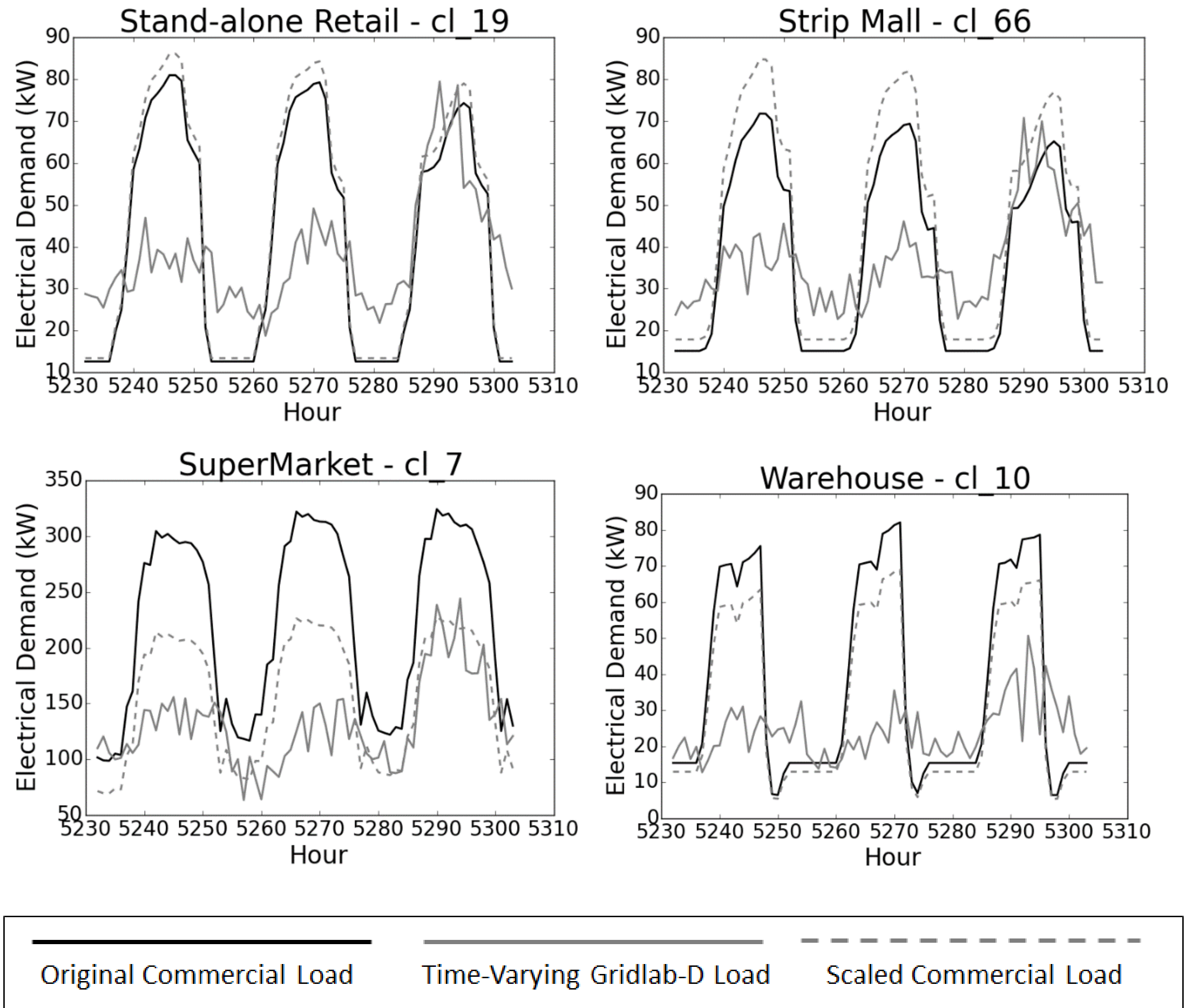


Figure S5: Matched electrical loads are shown for the three days in July. The electrical commercial building loads are matched to the Gridlabd-D loads and used to replace these Gridlab-D loads so that commercial building heat loads can be introduced to the model. The matching algorithm uses the set of loads with the minimum norm of the difference between peak load, minimum load, and load factor. The building loads were then scaled so that the total yearly energy consumption was the same as the Gridlab-D load. Large discrepancies between the scaled commercial load and Gridlabd-D load are by seasonal differences in the load profiles and the limited number of commercial Gridlab-D loads to match.

Table S2: DER-CAM CHP Technology Options LBNL [16] and the EPA. [8] Internal Combustion Engines with Heat Exchangers for collecting hot water are considered for placement on the commercial loads. CHP parameters are extrapolated from these values.

CHP Technology Options					
Max Power (kW)	Lifetime (years)	Capital Cost ($/kW)	Variable O&M ($/kWh)	Full Load Efficiency	Heat to Power Ratio
75	15	2880	0.0255	0.26	2.0
250	15	2614	0.025	0.27	1.82
1121	15	2366	0.019	0.368	1.12

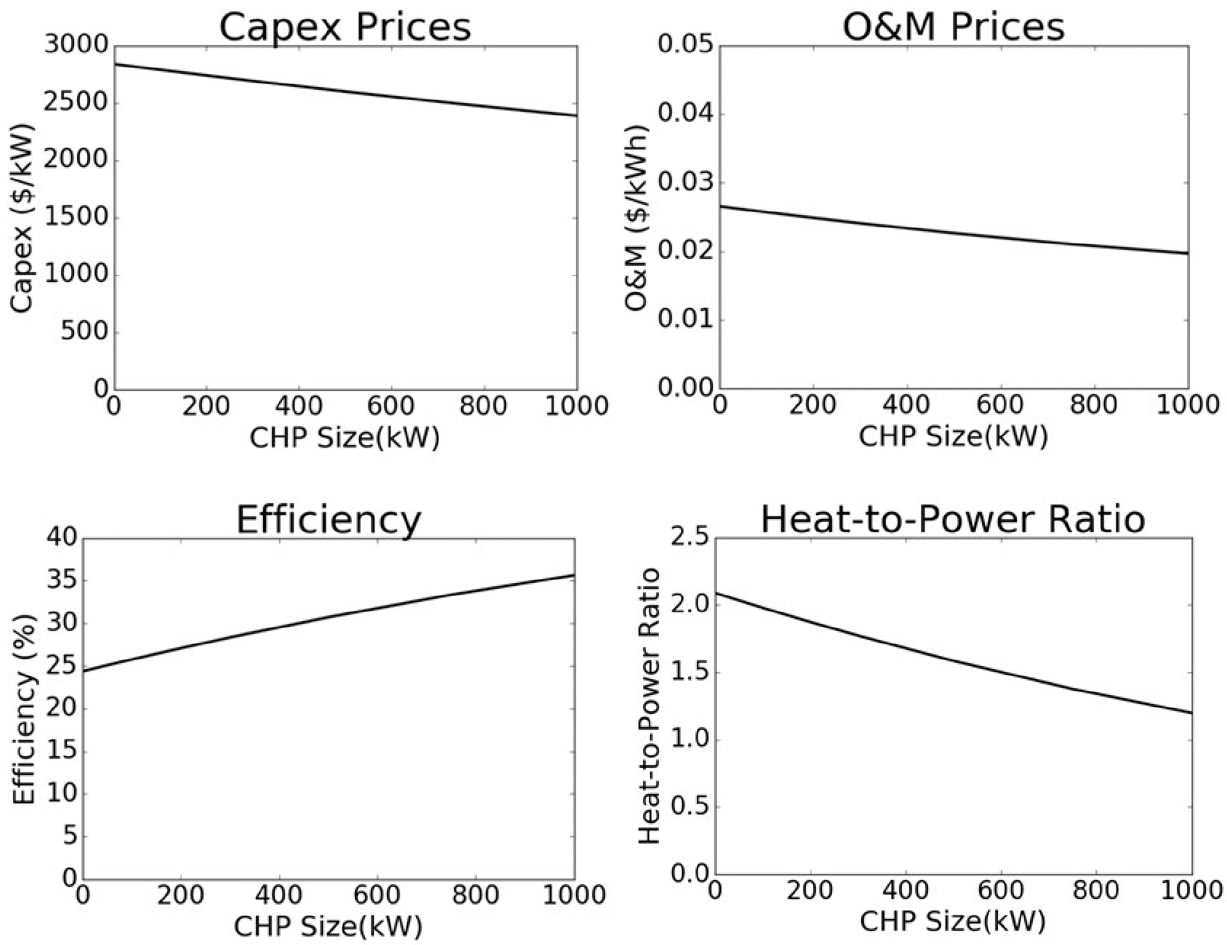


Figure S6: CHP Capital prices, O&M prices, and efficiency as a function of CHP Size.

Table S3: Private Customer Ownership Hourly Dispatch Model. The first term describes customer payments to the utility for power demand less generated power and shed load. The second term describes the cost of power production less the reduced heating bill from offset boiler demand. The objective function is constrained by the generation operational limits. Demand charges are not included in the objective function but are considered indirectly during the planning stage.

Objective	Owner	Market	Input	Control Variable
Minimize Cost over all hours(t)	<u>Private Operation</u> Prosumer with one generator	Deregulated	α=heat to power ratio of CHP plant η_{boiler} = efficiency of the boiler $\eta_e(S_{e,t})$=efficiency of fuel conversion to electrical power as a function of the electrical power delivered D_{max} = Customer's maximum demand in a month $L_{e,t}$ = Hourly Metered Electrical Load $L_{h,t}$ = Hourly Metered Heat Load P_d = The utility demand charge $P_{e,retail}$ = Retail utility price per kWh. P_{ng}=price of natural gas in $/ MMBtu $S_{h,t}$ = The heat power delivered by the generator (depends on $S_{e,t}$)	$S_{e,t}$ = The complex electrical power delivered by the generator

$$\min_{\forall\, hours,t} \; \left[P_{e,retail} * \left(L_{e,t} - S_{e,t}\right)\right] + \left[\frac{S_{e,t}}{\eta_e\left(S_{e,t}\right)} * P_{ng} - \min\begin{cases} S_{e,t} * \alpha * \dfrac{P_{ng}}{\eta_{boiler}}, & S_{e,t} * \alpha \le L_{h,t} \\[2ex] L_{h,t} * \dfrac{P_{ng}}{\eta_{boiler}}, & S_{e,t} * \alpha > L_{h,t} \end{cases}\right]$$

$$s.t. \quad S_{e,min} \le S_{e,t} \le S_{e,max}$$

Minimize the cost of buying power from the utility.

Minimize the cost of natural gas needed to run the CHP and the boiler. The CHP does not offset natural gas costs if heat demand is already met.

Each generator must operate within its limits.

Table S4: Utility Ownership hourly dispatch Model. The first term describes revenue earned by the utility from dispatching CHP at customer sites. The revenue is based on the standard utility tariff less the value of the customer's PPA when CHP is dispatched. The second term describes heat revenue earned at the customer's avoided heating cost. The third term describes the utility's cost of buying power from the wholesale market and of generating power. Power exports at the customer level are not permitted. Demand charges are not included in the objective function but are considered indirectly during the planning stage. Additionally, the utility must offer a power purchase to agreement to compensate for the opportunity cost foregone by not renting the space the CHP occupies**.**

Objective	**Owner**	**Market**	**Input**	**Control Variable**
Maximize profit over all hours(t)	<u>Utility Operation</u> i Customers with CHP	Deregulated	$P_{e,retail}$ = Utility retail price per kWh of electricity/heat. $P_{e,PPA}$ = the agreed PPA for electricity/heat P_{ng}=price of natural gas in \$/ MMBtu $P_{m,t}$ = locational marginal price (modified) $L_{e/h,i,t}$ = Hourly metered electrical/heat Load P_d = The utility demand charge D_{max} = Customer's maximum demand in a month $\eta_e(S_{e,t})$=efficiency of fuel conversion to electrical power as a function of the electrical power delivered $S_{h,t}$ = The heat power delivered by the generator (depends on $S_{e,t}$)	$S_{e,t}$ = The complex electrical power delivered by the generator

$$
\max_{\forall\, hours,t}
\begin{aligned}
&\left[\sum_i \left(\left(P_{e,retail} - P_{e,PPA}\right) * \left(S_{e,i,t}\right) + \ P_{e,retail} * \left(L_{e,i,t} - S_{e,i,t}\right)\right)\right] \\
&+\left[\sum_i \min \begin{cases} S_{e,i,t} * \alpha * \dfrac{P_{ng}}{\eta_{boiler}}, \ S_{e,i,t} * \alpha \leq L_{h,i,t} \\ L_{h,i,t} * \dfrac{P_{ng}}{\eta_{boiler}}, \ S_{e,t} * \alpha > L_{h,t} \end{cases}\right] \\
&-\left[\sum_i \left(\left(L_{i,t} - S_{e,t}\right) * P_{m,t} + \frac{S_{e,t}}{\eta_e\left(S_{e,t}\right)} * P_{ng} \right)\right] \\
&\qquad s.t. \quad S_{e,min} \leq S_{e,t} \leq S_{e,max} \\
&\qquad\qquad \sum_i S_{i,t} \leq feeder\ demand
\end{aligned}
$$

Maximize profit from CHP and retail electrical power sold to the customer. The CHP power is discounted in accordance with a PPA.

Maximize profit from CHP and heat power sold to the customer. The CHP does not offset natural gas costs if heat demand is already met.

Minimize wholesale costs for any load that has not been offset by the CHP, and minimize natural gas costs for running the CHP.

Each generator must operate within its limits.

Section B: Metrics

The operational strategy of each owner affects when the CHP are dispatched and therefore, will affect the network, economic, and environmental benefits associated with the CHP.

Network Metrics

The metrics used for quantifying the network benefits are network losses, equipment capacity utilization, and network violations. Network losses are the I^2R losses and are multiplied by the wholesale cost to determine the network system costs. Capacity utilization is the ratio of the maximum observed electrical power (or electrical current) to the equipment rating. Reductions in capacity utilization can be quantified in terms of their potential for capital expenditure deferrals. Similarly, a reduction in network violations also has value to the utility. Voltage violations, which we define as any deviation in voltages outside the ANSI standard (114-126 volts) [17], may require adjustments to under load tap changing transformers (ULTCs), investments in capacitors, or reconductoring distribution lines. Thermal violations (i.e. equipment overloading) may require investments in new transformers or new distribution lines. The cost of capacity for different distribution components are shown in Table S5.

Table S5: Cost of distribution components. Each ownership operating strategy will affect the network differently and may increase or reduce future network investment costs. Figure adapted from Knapp et. al. [18] Original data is from Willis et. al. [19] and Burke. [20] The number of significant figures have been preserved from the original sources.

Equipment Type	**Cost Example**		
Lines	▪ $50k/mile (46 kV wooden pole subtransmission)		
Feeder	▪ $10-15 per kW-mile (12.47 kV overhead) ▪ $30-50 per kW-mile (12.47 kV underground)		
Laterals	▪ $5-15 per kW-mile (low voltage overhead) ▪ $5-15 per kW-mile (low voltage underground-direct buried) ▪ $30-100 per kW-mile (low voltage underground-ducted)		
Single Phase Padmount Transformers	*Capacity*	*12.5 kV*	*34.5 kV*
	20 kVA	$2552	$3119
	50 kVA	$2986	$3931
	75 kVA	$3591	$4725

	100 kVA	$4972	$5728
Three Phase Padmount Transformers	*Capacity*	*12.5 kV*	*34.5 kV*
	75 kVA	$7,749	$10,584
	150 kVA	$9,450	$11,605
	300 kVA	$11,718	$15,574
	500 kVA	$13,608	$20,034
	750 kVA	$21,357	$21,377
	1000 kVA	$25,515	$28,824
	1500 kVA	-	$40,824
	2500 kVA	-	$50,841
Substation	▪ $3,348,000 (115/13.2 kV, 20/37.3 MVA, 4 feeder) ▪ $1,026,000 (35/12.5kV, 12/16/20 MVA, 2 feeder) ▪ $4,050,000 (115/35kV,60/112 MVA, 5 feeder) ▪ $23/kW (rural 69 kV 5MVA single transformer) ▪ $25-33/kW (138/12.47kV 80 MVA)		

Economic Metrics

The system savings, private customer savings, and utility savings were assessed for one year of operation. They are summarized below and in Figure S7. The system savings is identically defined for all ownership models. The private customer and utility savings change for each ownership model.

System Savings

The system savings include all savings associated with meeting end-user heat and electrical energy demand, but excludes any costs associated with reselling power. Savings include, the wholesale power purchase reductions, generation cost reductions, heating cost reductions, and T&D cost reductions. The system savings is,

$$System\ Savings = System\ Costs\ without\ CHP - System\ Costs\ with\ CHP$$

$$System\ Cost = \sum_{\forall CHP} \sum_{\forall Hours} \begin{array}{l} Net\ Load_{CHP,hour} * Modified\ LMP_{hour} \\ \quad +Generation\ Cost_{CHP,hour} \\ \quad +Heating\ Cost_{CHP,hour} \end{array}$$

The LMP is increased (modified) to equal the average commercial price of electricity, as given by the EIA, so it includes transmission and distribution costs. The net load is the original load less generation and the generation cost is defined by,

$$Generation\ Cost = \frac{Real\ Power}{Efficiency} * Cost\ of\ Natural\ Gas + O\&M\ Costs + Capex$$

Private Customer Ownership Model

When the CHP are operated by a private customer, the utility sells less power, so savings are negative. The utility loses revenue for each unit of CHP energy (less the pass-through transmission and energy costs) that is produced. Customer savings are created from avoided retail power costs less the generation cost. The customer saves money if the retail value of this power is greater than the generation cost.

$$Utility\ Savings = \left(-\sum_{\forall CHP}\sum_{\forall Hours} Power_{CHP,hour} * (Retail\ Price_{hour} - Transmission\ Cost - LMP_{hour})\right) - \sum_{\forall CHP}(Max\ Load - Max\ Net\ Load) * Demand\ Charge$$

$$
\begin{aligned}
&\mathit{Customer\ Savings} \\
&= \sum_{\forall CHP} \sum_{\forall Hours} \begin{matrix} Power_{CHP,hour} * Retail\ Price_{hour} \\ -Generation\ Cost_{CHP,hour} \end{matrix} \\
&+ \sum_{\forall CHP} (Max\ Load - Max\ Net\ Load) * Demand\ Charge
\end{aligned}
$$

Utility Ownership Model

When the utility operates the CHP, customer and utility savings are dependent on the PPA. The PPA is the $/kWh rate paid to customers by the utility to compensate for the opportunity cost foregone by not renting the space the CHP occupies. The utility savings are defined as the difference between load acquired entirely through the wholesale market (i.e. LMP and transmission costs) and load acquired through a combination of market purchases, PPA purchases, and generation costs. The customer savings increase according to the PPA for each unit of CHP power produced and for demand charge reductions.

Utility savings are defined with a modified LMP that includes transmission costs as,

$$
\begin{aligned}
&\mathit{Utility\ Savings}\\
&\quad = \sum_{\forall CHP}\sum_{\forall Hours} Load_{CHP,hour} * Modified\ LMP_{hour}\\
&\quad - \left[\sum_{\forall CHP}\sum_{\forall Hours} Net\ Load_{CHP,hour} * Modified\ LMP_{hour}\right.\\
&\quad + \sum_{\forall CHP}\sum_{\forall Hours} Power_{CHP,hour} * PPA + \sum_{\forall CHP}\sum_{\forall Hours} Generation\ Cost_{CHP,hour}\\
&\quad - \sum_{\forall CHP}\sum_{\forall Hours} Heat\ Costs_{\ CHP,hour}\\
&\quad \left. - \sum\nolimits_{\forall CHP} (Max\ Load - Max\ Net\ Load) * Demand\ Charge \right]
\end{aligned}
$$

The customer savings are defined as,

$$
\begin{aligned}
&\mathit{Customer\ Savings}\\
&\quad = \sum_{\forall CHP}\sum_{\forall Hours} Power_{CHP,hour} * PPA\\
&\quad + \sum\nolimits_{\forall CHP} (Max\ Load - Max\ Net\ Load) * Demand\ Charge
\end{aligned}
$$

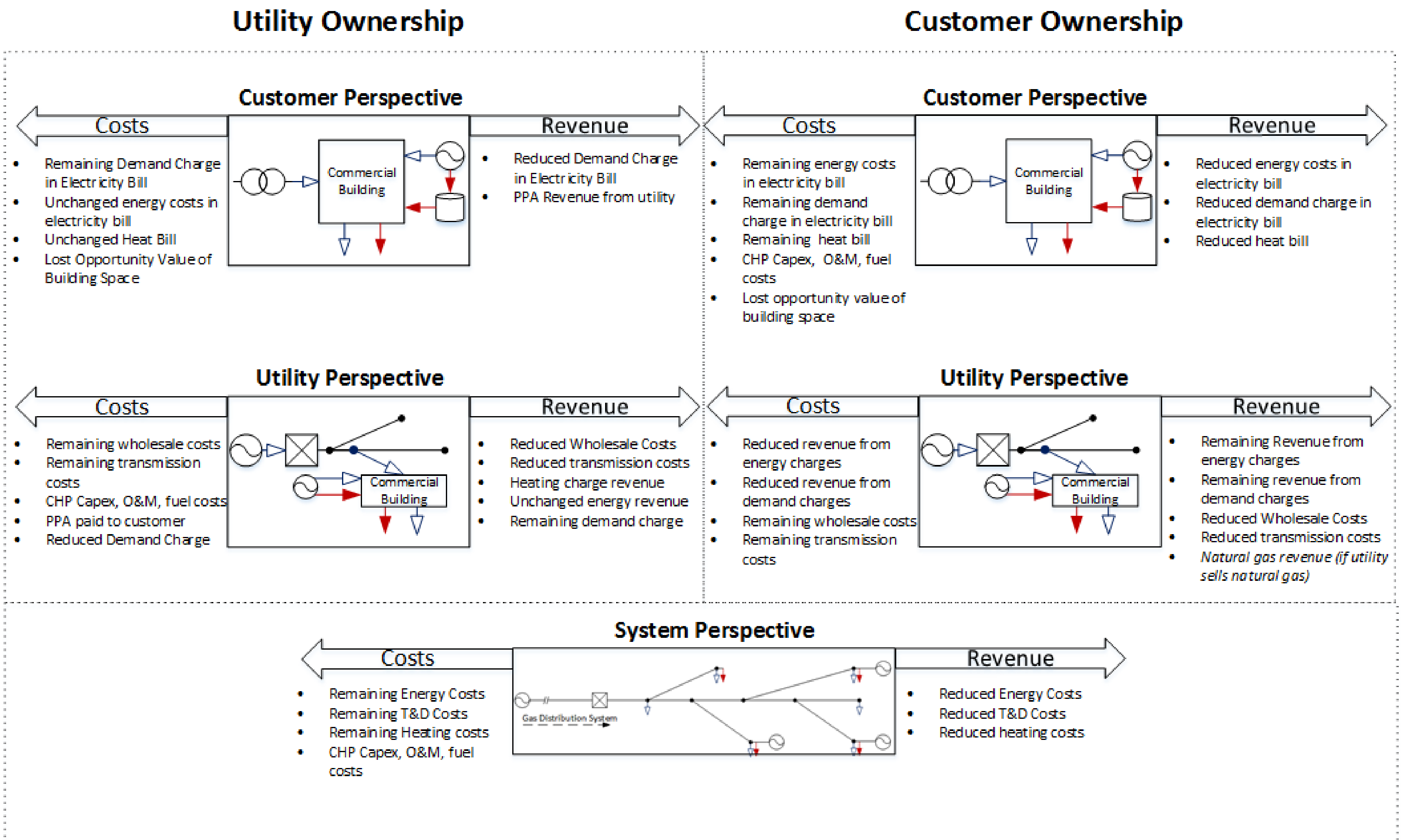


Figure S7: System, customer and utility costs and revenues associated with CHP. For example, under customer ownership, the utility will see reduced revenue from energy charges and demand charges. Wholesale and transmission costs will be reduced but will still remain. Revenue will still come from remaining energy sales and demand charges not met by the CHP. The utility will also see lower wholesale and transmission costs. Overall, the utility will experience losses from this arrangement, but it is possible that the utility will benefit on occasion when wholesales costs are above the retail electricity price. Utility losses will also be mitigated if the utility sells natural gas.

Environmental Metrics

The avoided CO_2 , SO_2 and NO_x emissions are used to evaluate the environmental impact of each model. Avoided emissions are aggregated over one year of operation for each owner. To calculate the avoided emissions, the emissions of each owner are compared with and without the CHP. Marginal emissions were used for the bulk power grid from Siler-Evans et. al. [21], but was updated by the authors [21] for more recent years. Low NO_x CHP emissions and uncontrolled boiler emissions were assumed.

Section C: Input

The benefits of CHP for each ownership model were based on New York and Northeastern input parameters. Tariffs were taken from NYSEG and NYISO. Heat loads are based on ASHRAE climate region 6. Otherwise, data is from the northeast. All data input and their source is summarized in Table S6. The distribution network statistics are shown in Table S7 and the network feeder is shown in Figure S10. Emissions produced by the bulk power system and CHP are shown in Figure S11 and Table S8, respectively. The distribution of utility bulk power prices are shown in Figure S12. The distribution of these prices for the years 2010-2014 are shown in Figure S13.

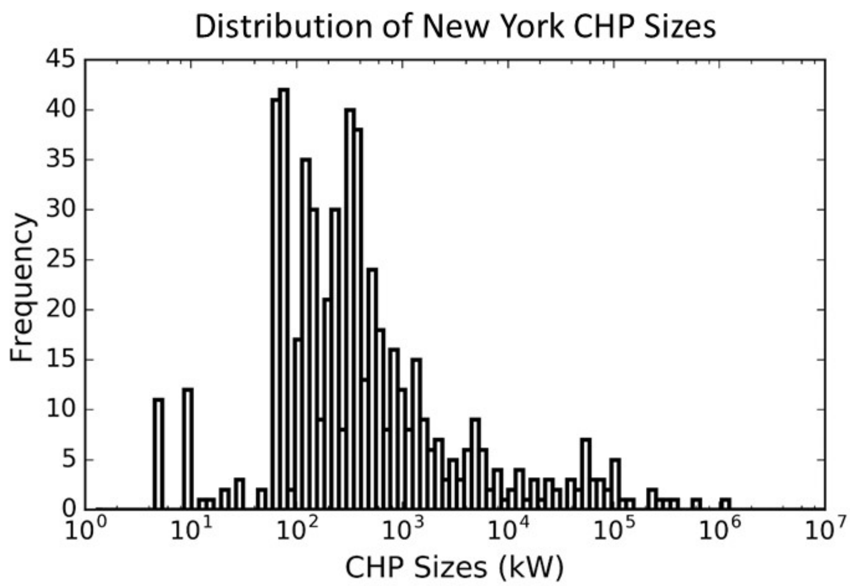


Figure S8: Distribution of CHP Sizes in New York.[22] The majority of CHP in New York are less than 1 MW.

Table S6: Model input values.

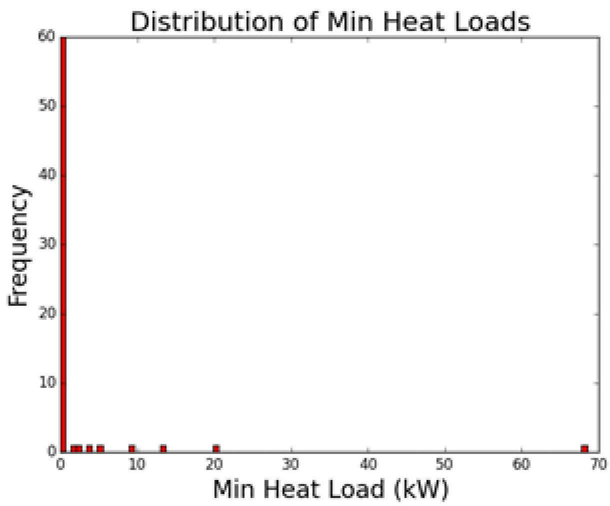
Data	Description	Value	Source(s)
Building Heating and Electric Loads	Loads are based on the DOE Commercial Reference Building Models and EnergyPlus simulation software	See Figure S3 and Figure S4	23, 4
NYISO Wholesale Prices	Day-Ahead Locational Marginal Prices	Average $0.143/kWh See Figure S12 for distribution.	24
Commercial Electricity Prices	Flat Energy Charge and Demand Charge	$0.143/kWh $8/kW	25
US State EIA Commercial Electricity Prices	Average Commercial rate	$0.162/kWh	26
Commercial Natural Gas Prices	Monthly $/MCF cost of Natural Gas in New York for commercial customers	$6-12/MCF	27
Time Varying Electrical Loads	Hourly electric loads matched to PNNL Feeder Taxonomy	Figure S5	3
Number of each building type	Proportion of each building type that are placed on the network.	See Table S1	5
CHP Parameters	Capex, O&M, linear efficiencies for 75, 250, and 1121 kW natural gas reciprocating	See Table S2	16 *Sandbox Version 8

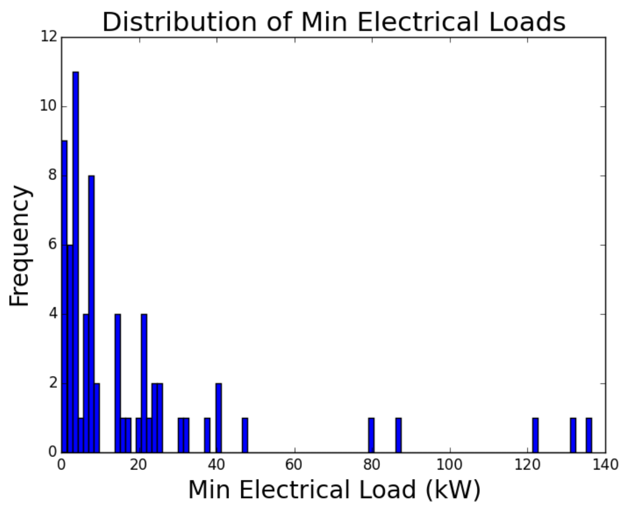
	engines.		
Marginal Emission Factors	NPCC marginal emission for CO2, NOx, and SO2	Figure S11	21
CHP Emissions	NOx, CO2 and SO2 emissions	Table S8	8
Cost of Building Space	The value of building space is needed to calculate CHP host opportunity cost.	\$25.4/ft^2 per year Class A surburban	28
Boiler Efficiency	The Annual Fuel Utilization Efficiency (AFUE) minimum requirement stated by ASHRAE 90.1-2004. This the highest efficiency used by der-cam. Decade old, but probably more representative of actual boiler stock.	0.8	6
Boiler Emissions	CO_2, SO_2, and NOx emission of uncontrolled boilers	Table S8	29
Effective Tax Rate	The effective tax rate is used to calculate	20%	30
Depreciation	MACRS	15 Year	31

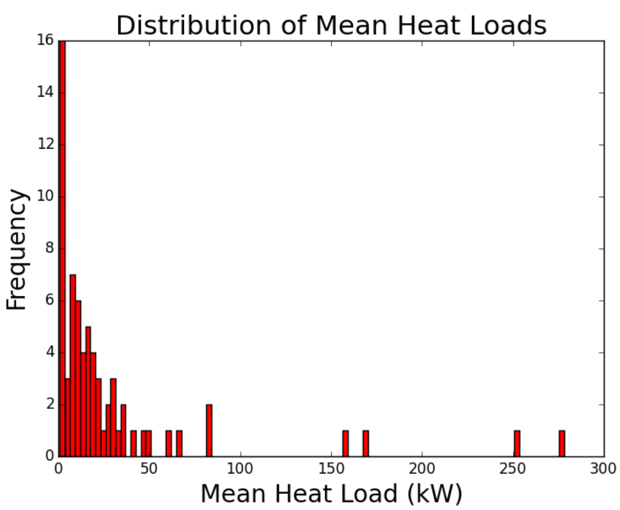
Table S7: Feeder Statistics for Feeder R2-25.00-1.

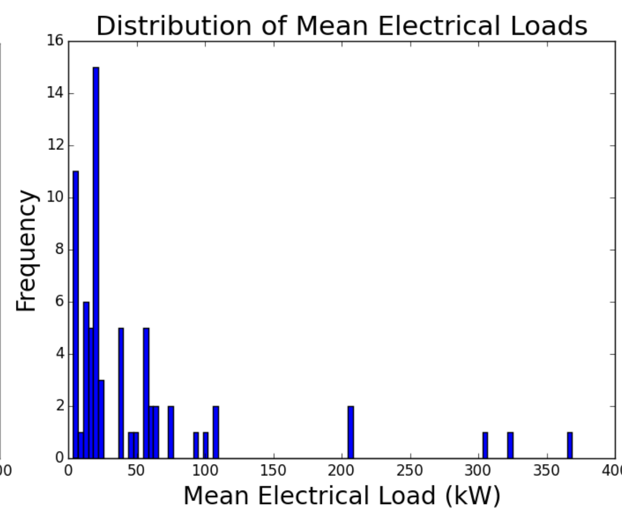
Feeder Statistics			
Description	Representative north eastern feeder situated in a moderately populated suburban area with light and moderate loading.		
Components	**Number of Components**		
Nodes	728		
Loads	274		
Regulator	1		
Transformer	274		
Switch	39		
Capacitor	5		
Fuse	57		
Overhead Line	146		
Triplex Line	202		
Underground Line	81		
Loading Condition	**Min**	**Mean**	**Max**

Coincident Load (kW)	5.7	10.1	16.2
Losses	0.7%	1.0%	1.1%
Load Factor	-	64%	-









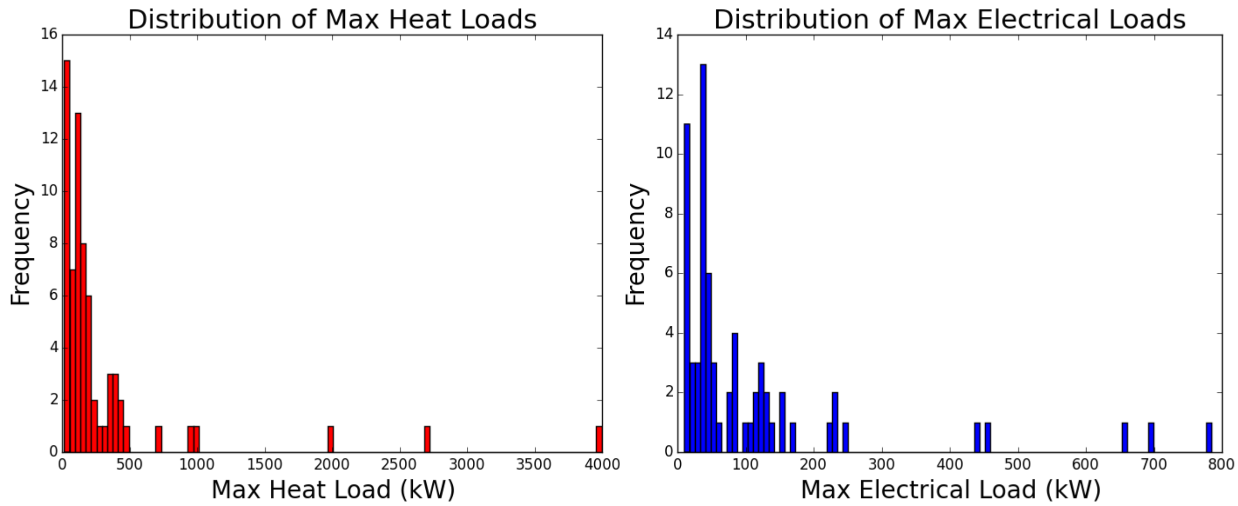
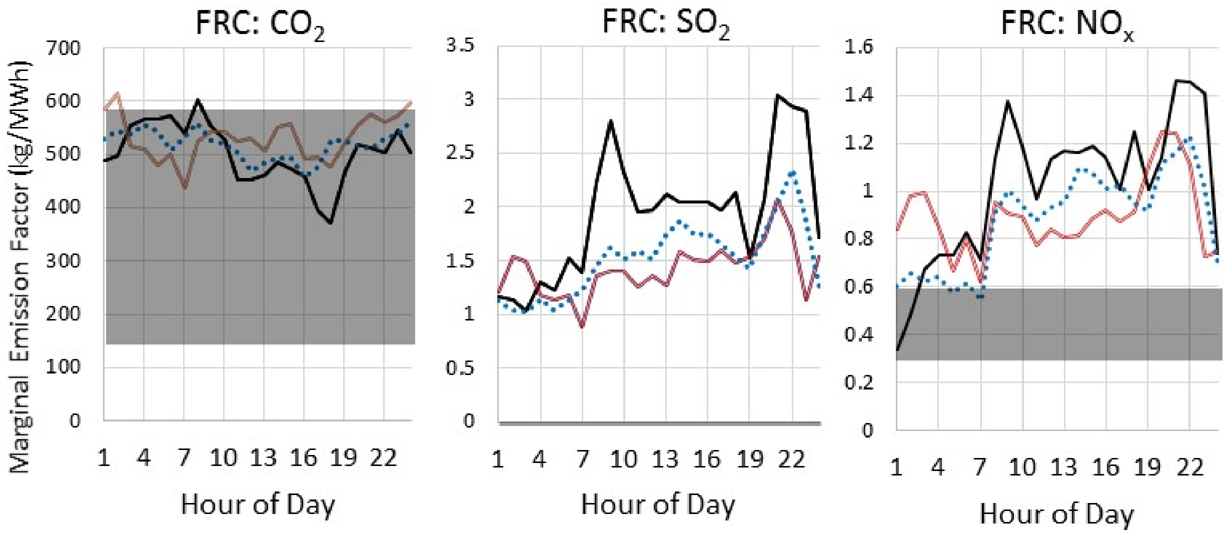
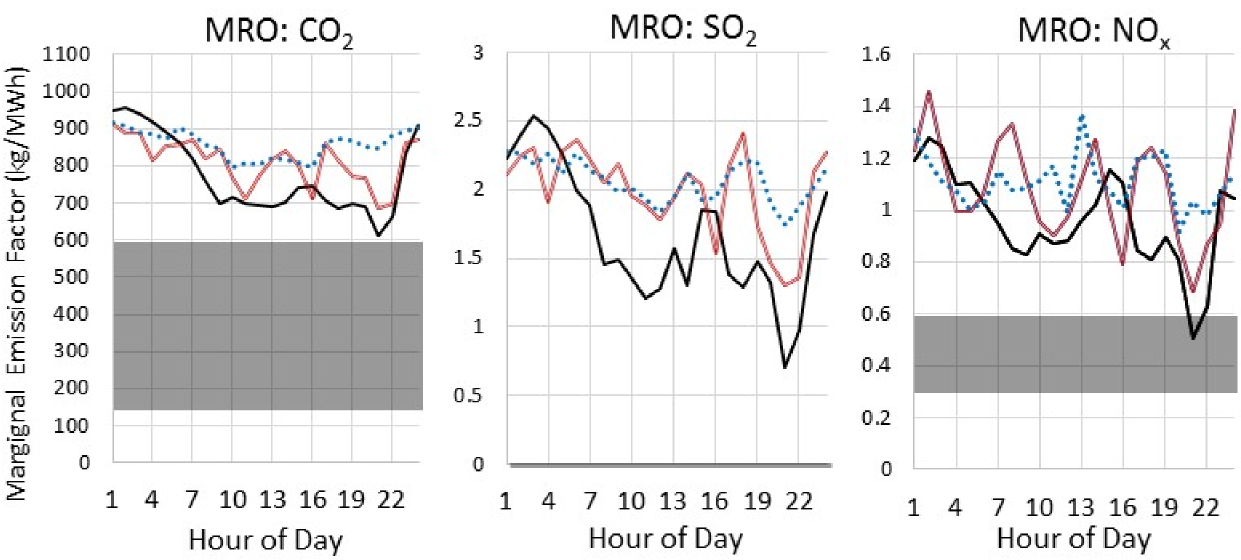
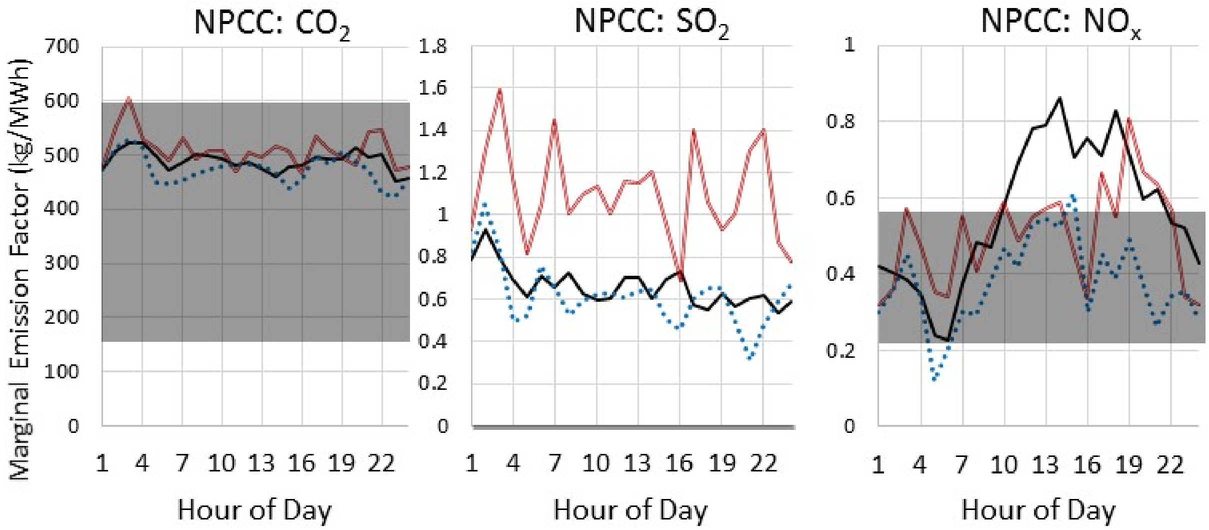


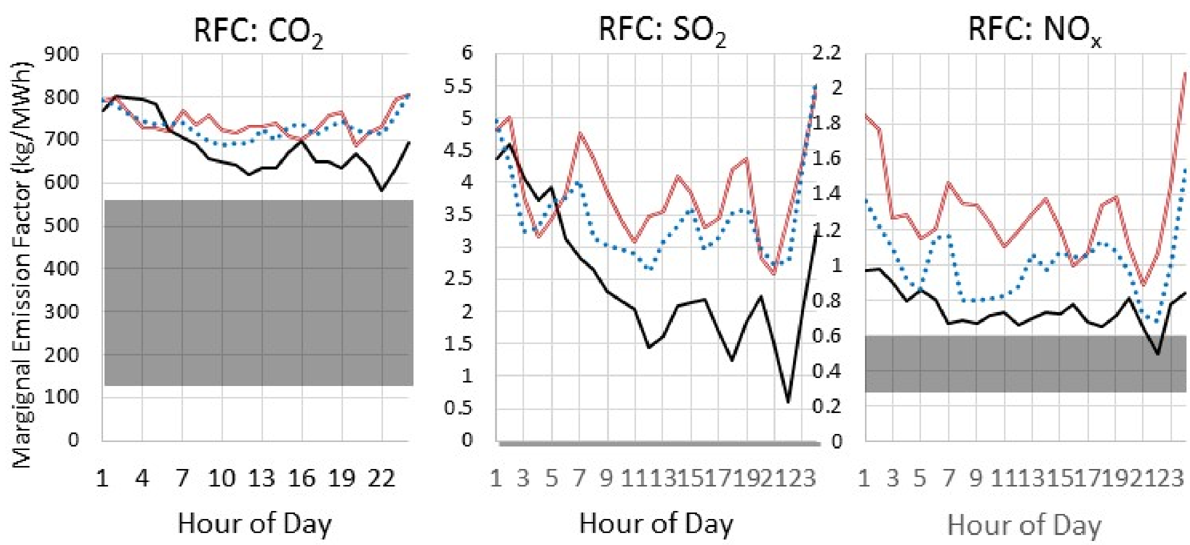
Figure S9: Minimum, mean, and maximum heat and electrical loads. The minimum and mean electrical loads are generally larger than the minimum and mean heat loads. CHP sizing will be constrained by the heat loads.

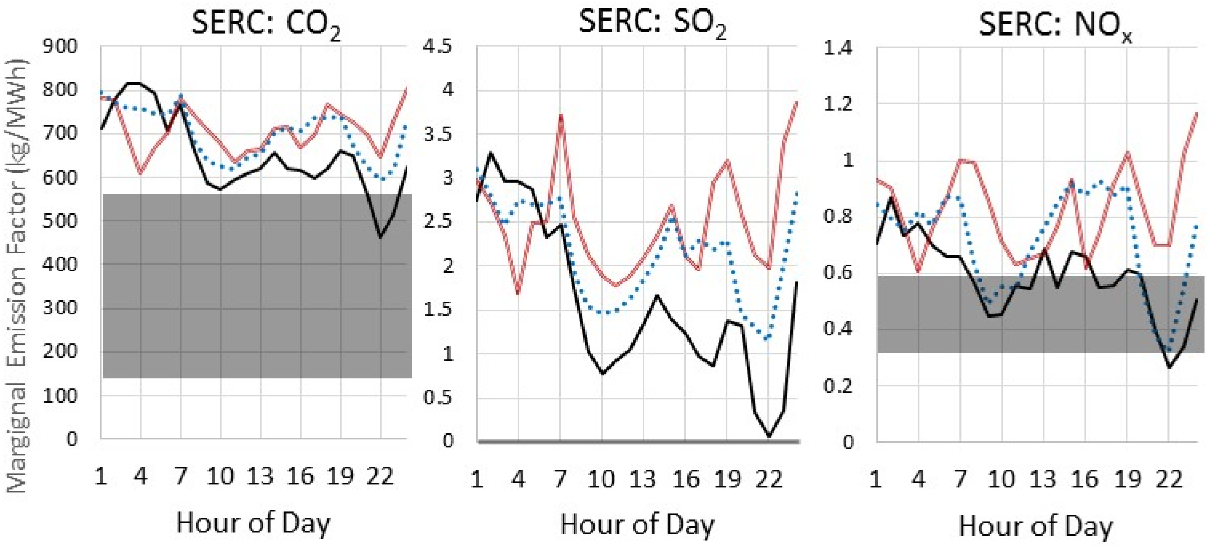
Figure S10: Distribution Network Feeder Model. Feeder R2-25.00-1 is shown from the PNNL feeder taxonomy. The feeder is representative of Northeastern feeders with light and moderate loading.

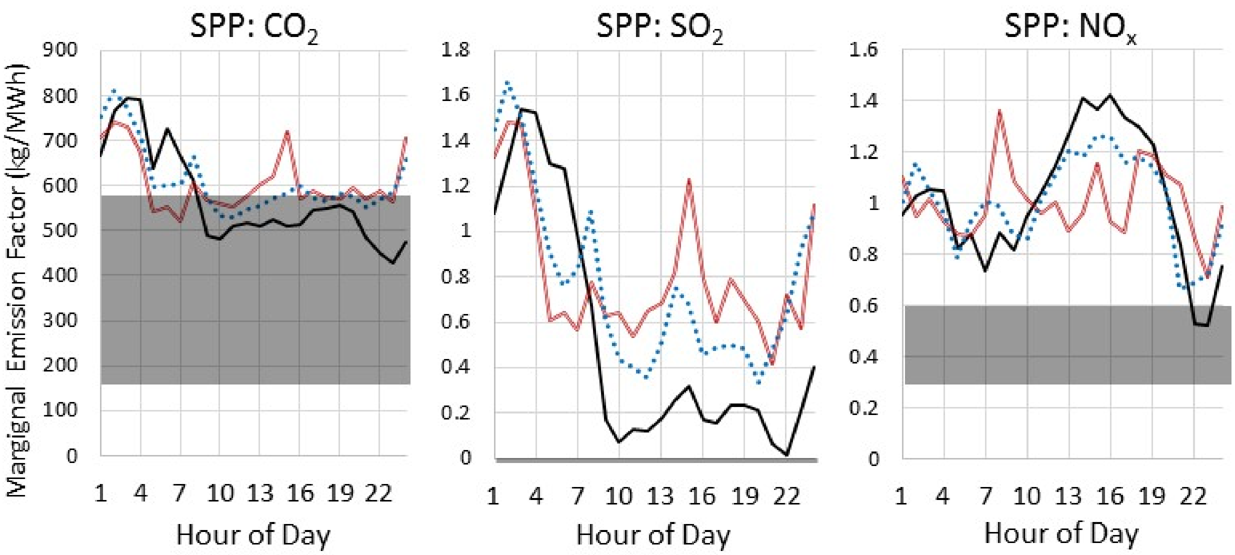

FRC: CO_2
FRC: SO_2
FRC: NO_x
Marginal Emission Factor (kg/MWh)
Hour of Day
Hour of Day
Hour of Day


MRO: CO_2
MRO: SO_2
MRO: NO_x
Marginal Emission Factor (kg/MWh)
Hour of Day
Hour of Day
Hour of Day


NPCC: CO_2
NPCC: SO_2
NPCC: NO_x
Marginal Emission Factor (kg/MWh)
Hour of Day
Hour of Day
Hour of Day


RFC: CO_2
RFC: SO_2
RFC: NO_x
Margignal Emission Factor (kg/MWh)
Hour of Day
Hour of Day
Hour of Day


SERC: CO_2
SERC: SO_2
SERC: NO_x
Margignal Emission Factor (kg/MWh)
900
800
700
600
500
400
300
200
100
0
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1 4 7 10 13 16 19 22
Hour of Day


SPP: CO_2
SPP: SO_2
SPP: NO_x
Margignal Emission Factor (kg/MWh)
900
800
700
600
500
400
300
200
100
0
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1 4 7 10 13 16 19 22
Hour of Day

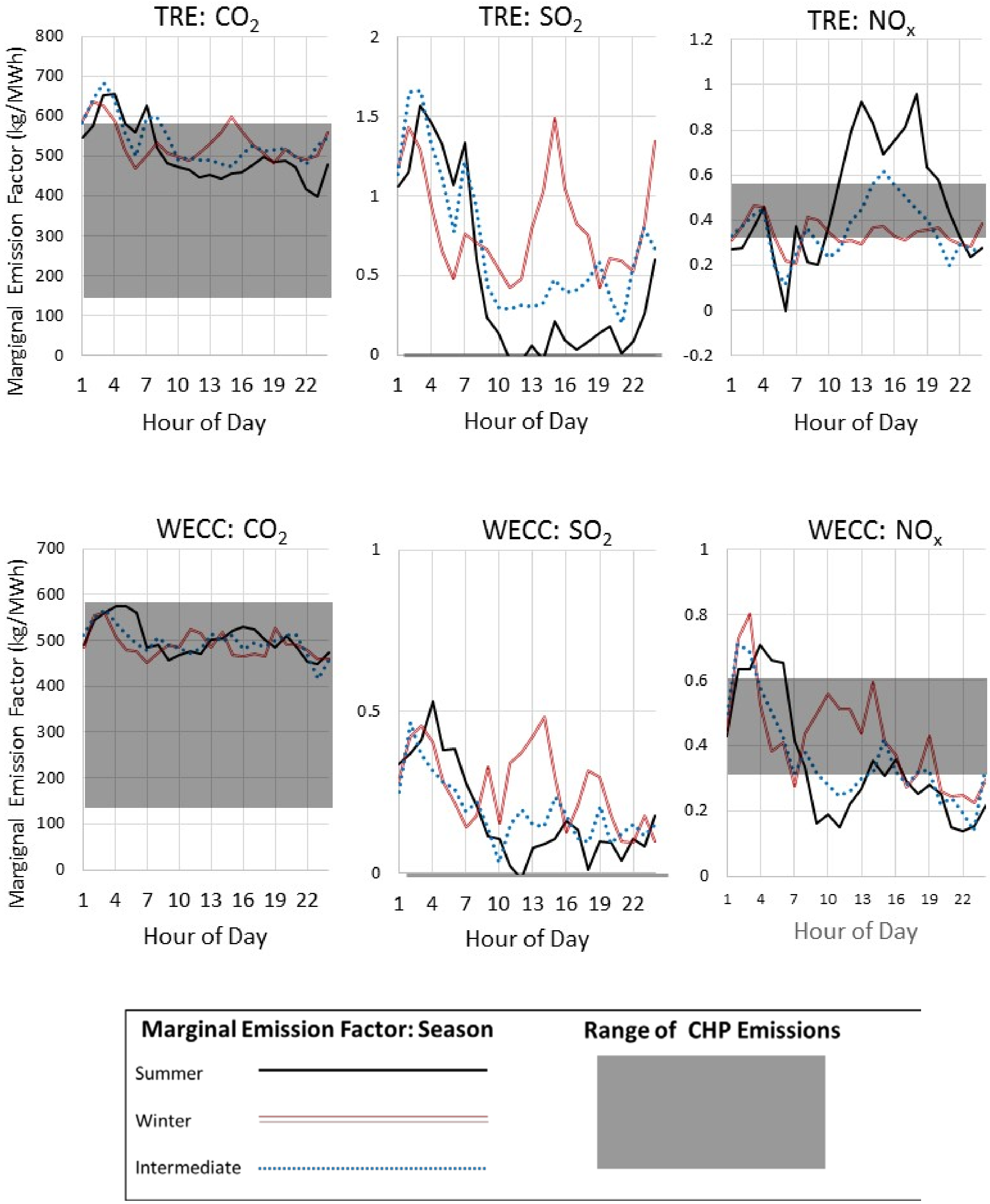


Figure S11: Comparison of Bulk Power Grid Marginal Emission Factors [21] with the range of potential CHP emissions. The marginal emission factors are shown for each reliability region, season and hour of the day. The range of CHP CO_2, SO_2, and NOx emissions is shown in the grey boxes (SO_2 emission are zero). The CHP emissions depends on how much heat load is offset. If all of the CHP heat is wasted it produces the equivalent of 600 kg CO_2/MWh, 0 kg SO_2/MWh, and 0.6 kg NOx/MWh.

If all of the CHP heat is used it produces the equivalent of 150 kg CO_2/MWh, 0 kg SO_2/MWh, and 0.3 kg NOx/MWh. CHP emission are based on a 30% electrical efficiency, heat-to-power ratio of 2, and a boiler without NOx controls.

Table S8: CHP and Boiler Emissions.

Pollutant	CHP Emissions (kg/MWh-e)	Boiler Emissions (kg/MWh-th)
CO_2	600	225
SO_2	0.0	0.0
NO_X	0.628	0.15

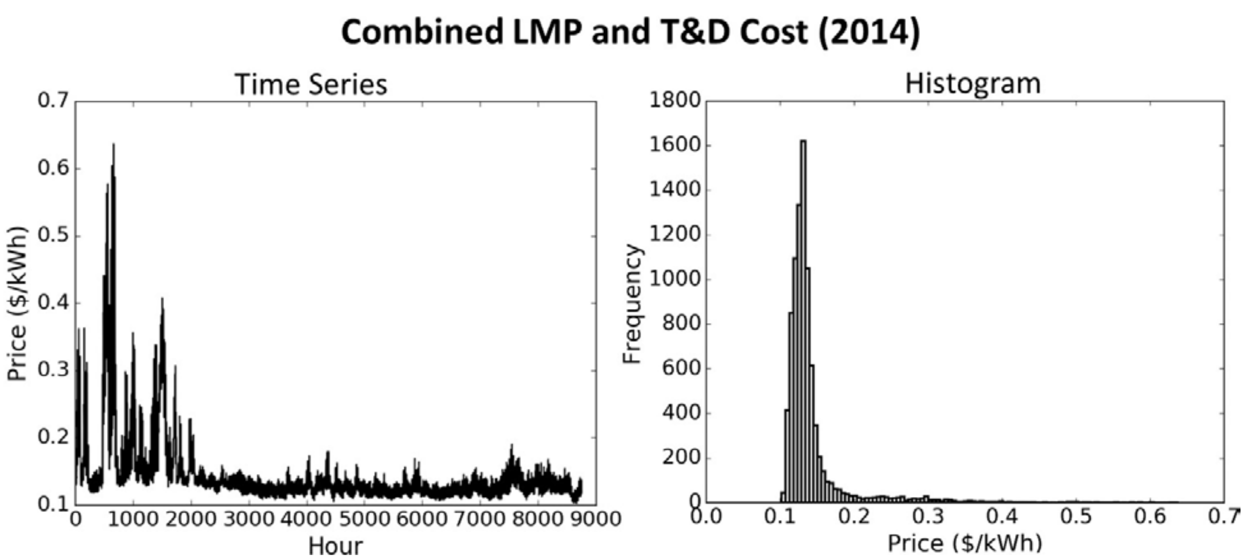


Figure S12: Utility cost of electricity. The time varying costs and cost histogram are shown for the year 2014.

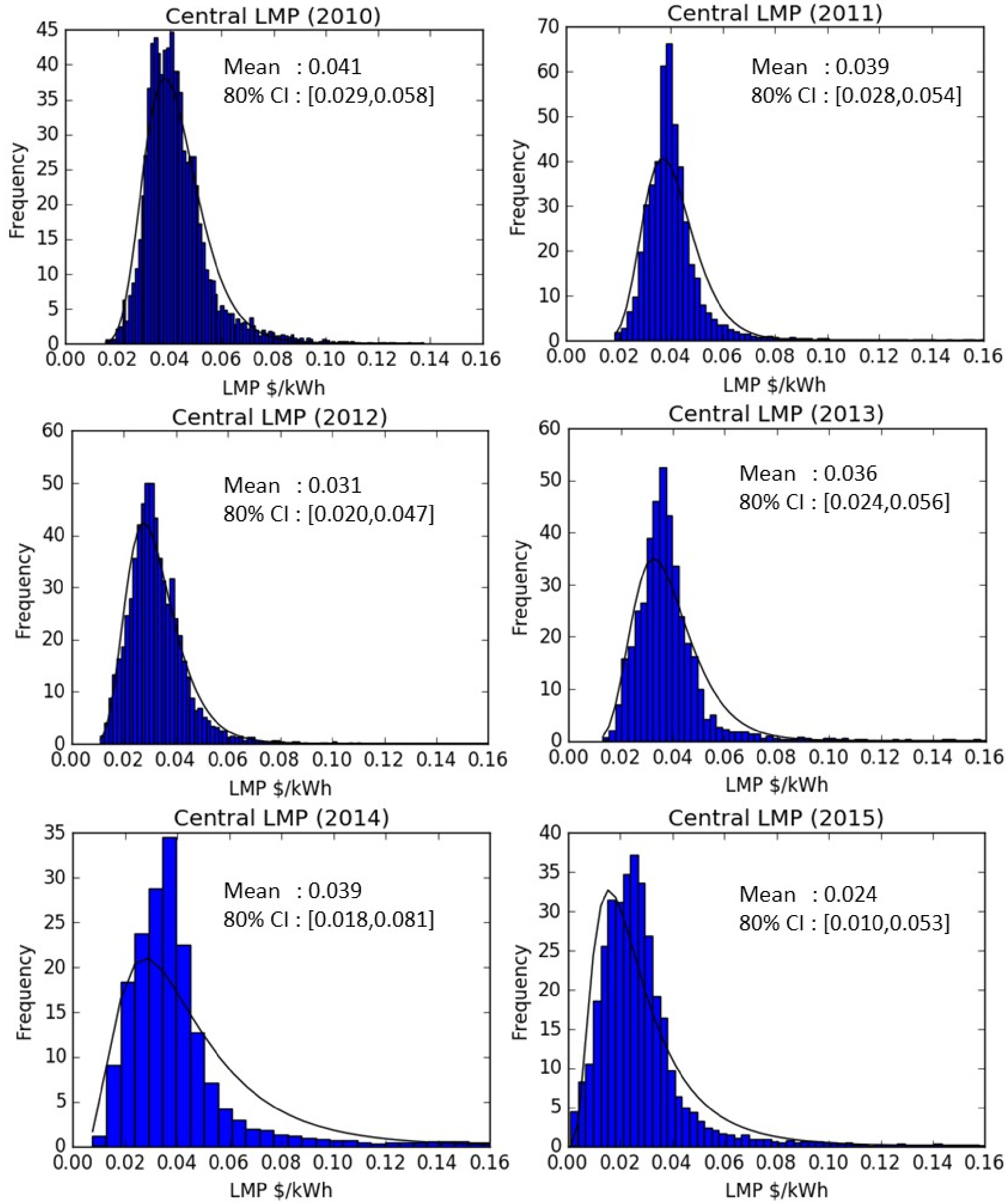


Figure S13: New York LMPs 2010-2015.

Section D: Results

Planning

The utility must offer the customer a power purchase agreement (PPA) to compensate for the opportunity cost foregone by not renting the space the CHP occupies; the utility can afford to do this because CHP reduces the utility's wholesale power purchase costs. We define a PPA similarly to the SolarCity PPA, where the customer earns a fixed rate for each kWh produced by the CHP. In many cases it is not necessary for the utility to offer a PPA, because the customer's avoided demand charges are greater than the opportunity cost foregone by not renting the space the CHP occupies. Figure S14 shows the range of PPAs that the utility could offer to the host customer of each load.

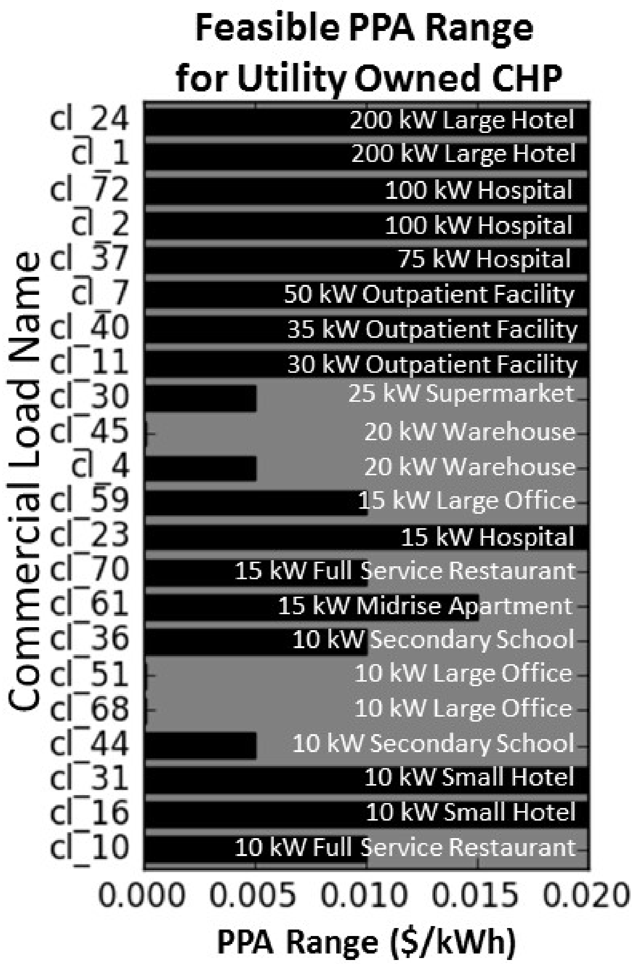


Figure S14: Feasible power purchase agreement range for each commercial load. Utilities could offer individual PPAs ranging from $0.0/kWh to $0.02/kWh to compensate for the opportunity cost foregone by not renting the space the CHP occupies. $0.0/kWh PPAs are possible when the CHP reduces customer demand charges enough to compensate for the opportunity cost.

Network

The capacity utilization histograms are shown in Figure S15. The distribution transformers, underground lines, and overhead lines all show reduced congestion when CHP are placed on the network. The commercial CHP installations do not reduce congestion on the triplex lines, which only feed residential customers.

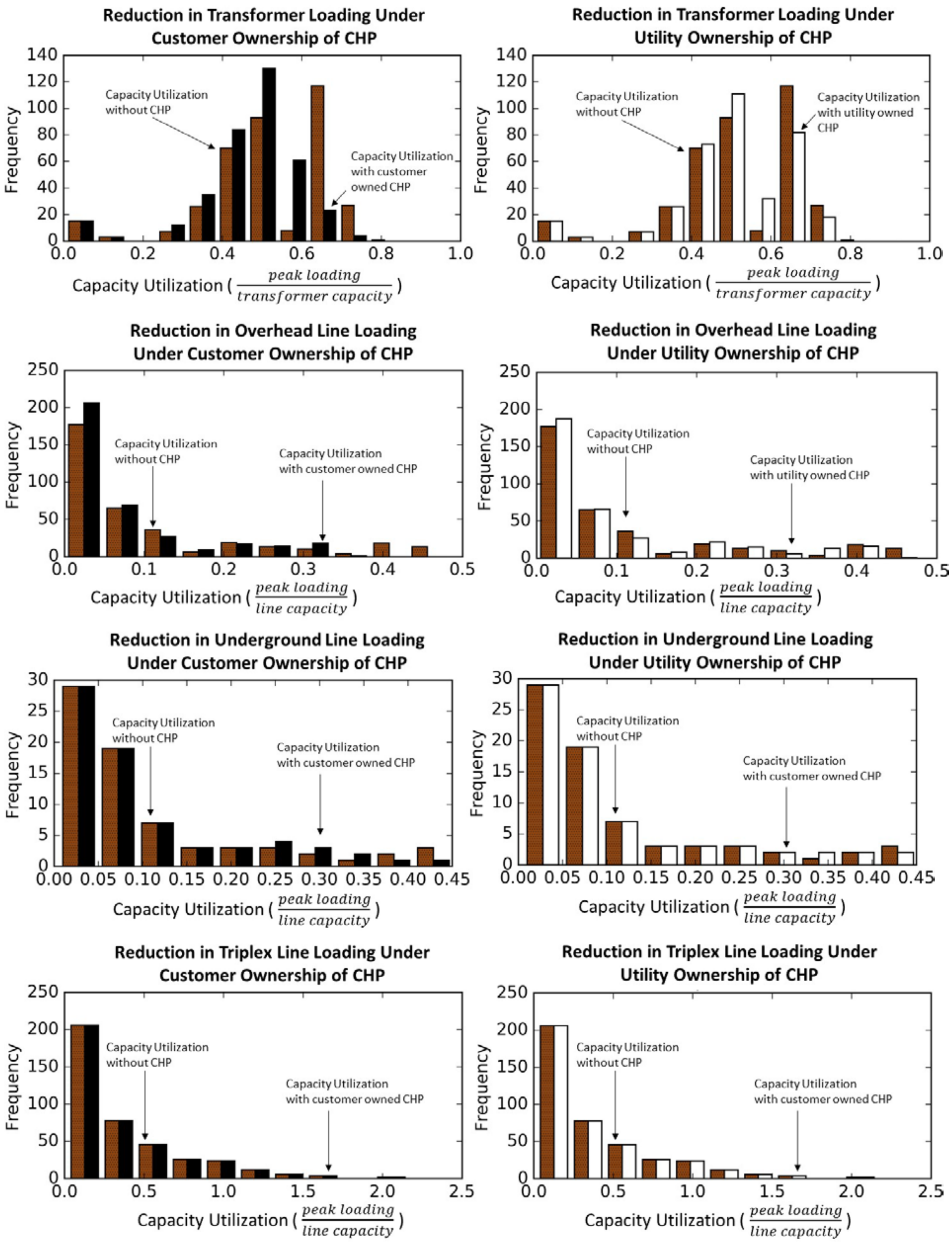
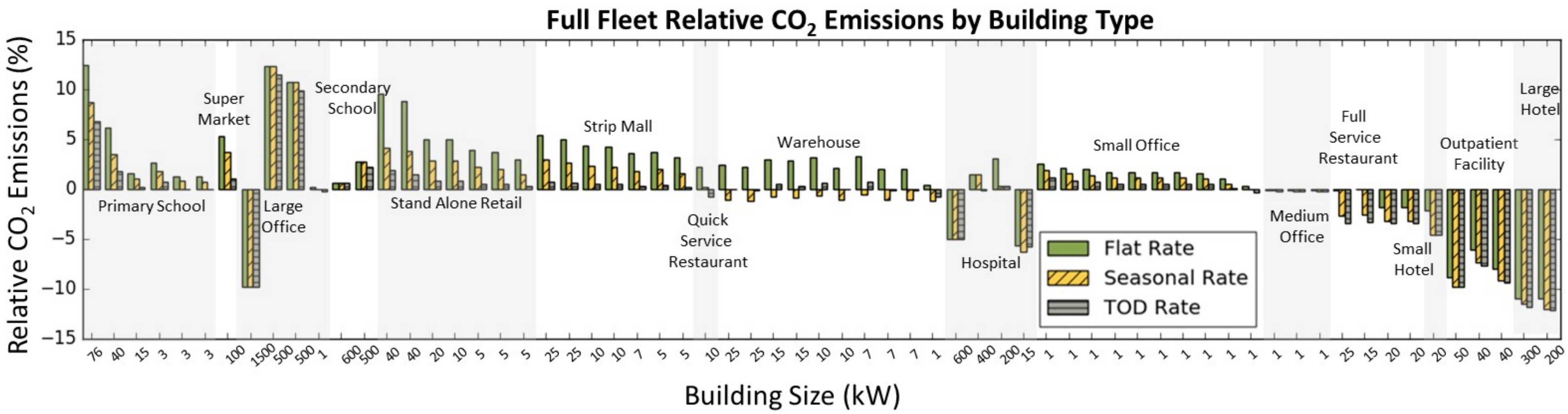
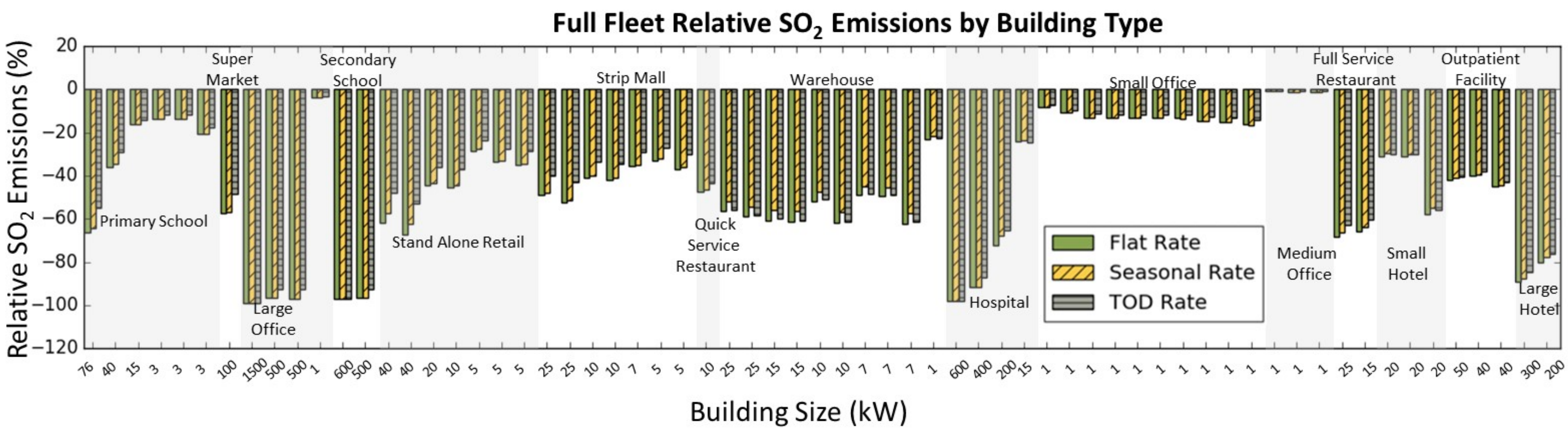


Figure S15: Network equipment capacity utilization histograms. The capacity utilization (the ratio of a components maximum observed load to its rating) of overhead lines, and underground lines are similar for both CHP ownership scenarios. The larger number of customer owned CHP shifts the transformer capacity utilization histogram further to the left, suggesting that the higher quantity of customer owned CHP is more effective at deferring network capacity investments.

Emissions

Figure S16 shows the annual relative CO_2, SO_2 and NO_x for the fleet of CHP. Each building displays different relative emissions, and Figure 6 (main text) shows that higher emitting buildings will be installed more as penetrations increase. The higher penetration of higher emitting buildings and time-varying rates leads to large differences in emission between customer and utility owned CHP fleets, as shown in Figure 2 (main text) and Figure S17. Figure S17 also shows this relationship is consistent for different years with different LMPs and natural gas prices.


Full Fleet Relative CO_2 Emissions by Building Type
Relative CO_2 Emissions (%)
Building Size (kW)
Primary School
Super Market
Large Office
Secondary School
Stand Alone Retail
Strip Mall
Quick Service Restaurant
Warehouse
Hospital
Small Office
Medium Office
Full Service Restaurant
Small Hotel
Outpatient Facility
Large Hotel
Flat Rate
Seasonal Rate
TOD Rate


Full Fleet Relative SO_2 Emissions by Building Type
Relative SO_2 Emissions (%)
Building Size (kW)
Primary School
Super Market
Large Office
Secondary School
Stand Alone Retail
Strip Mall
Quick Service Restaurant
Warehouse
Hospital
Small Office
Medium Office
Full Service Restaurant
Small Hotel
Outpatient Facility
Large Hotel
Flat Rate
Seasonal Rate
TOD Rate

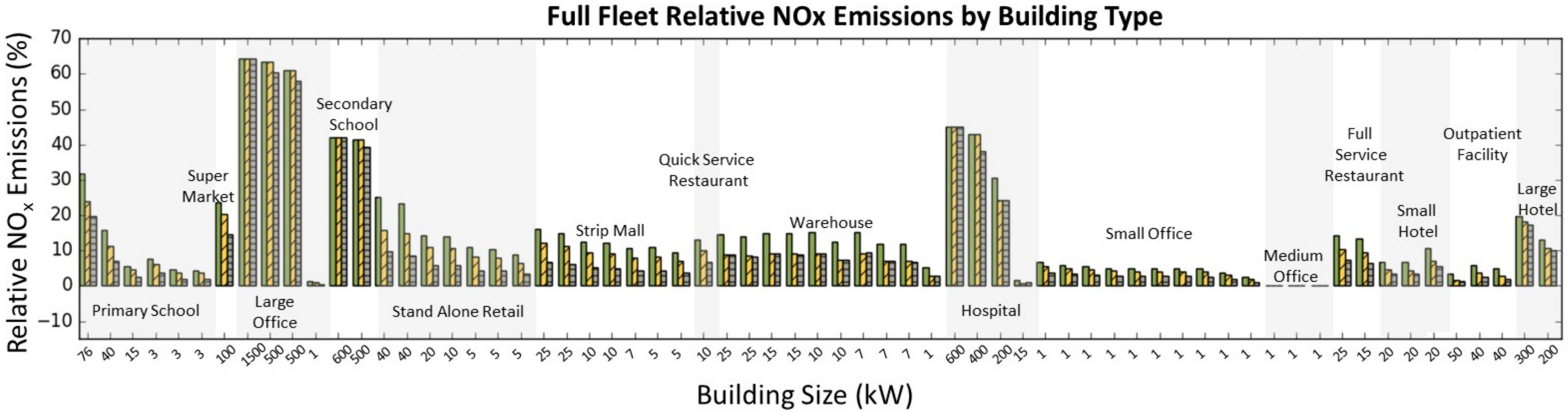


Figure S16: Relative CO_2, SO_2, and NO_x building level emissions. Each building type has identical heat and electrical load shapes, but the magnitudes of the loads vary. This causes the optimal CHP size and relative emissions to vary. For buildings with small CHP, seasonal and time-of-day rates are effective at reducing CO_2 and NO_x emissions.

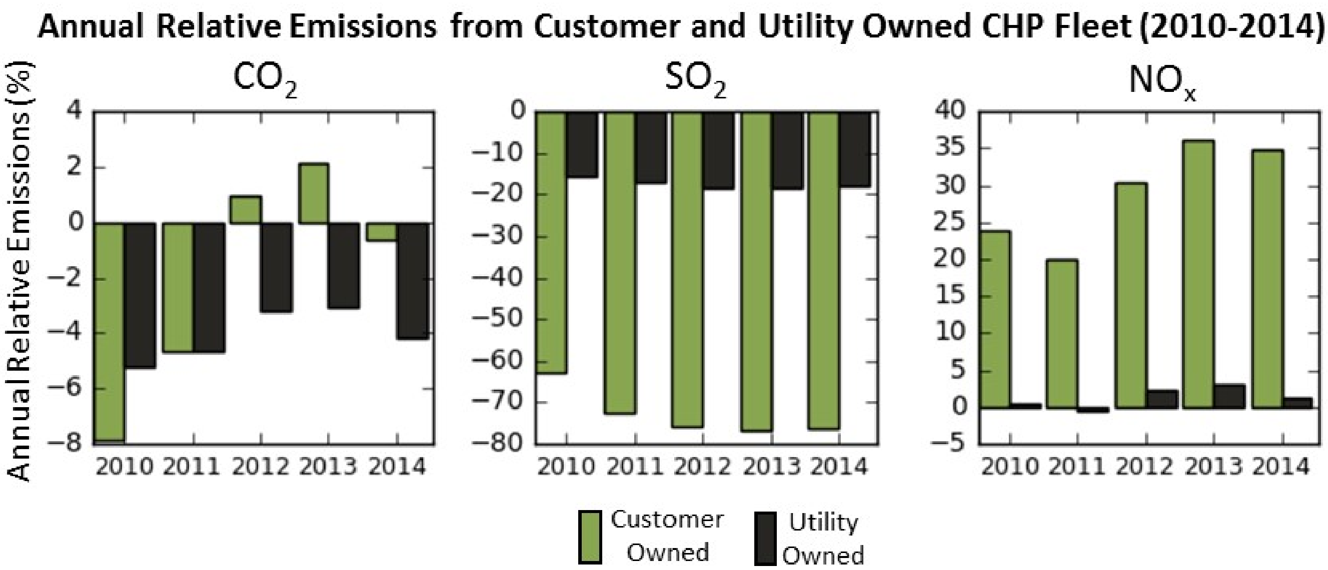


Figure S17: Relative CO_2, SO_2, and NO_x CHP Fleet emissions 2010-2014. The relative emissions are generally consistent with 2014. The year 2010 is an exception. High natural gas prices reduced customer owned CHP emissions but also led to unprofitable operating conditions.

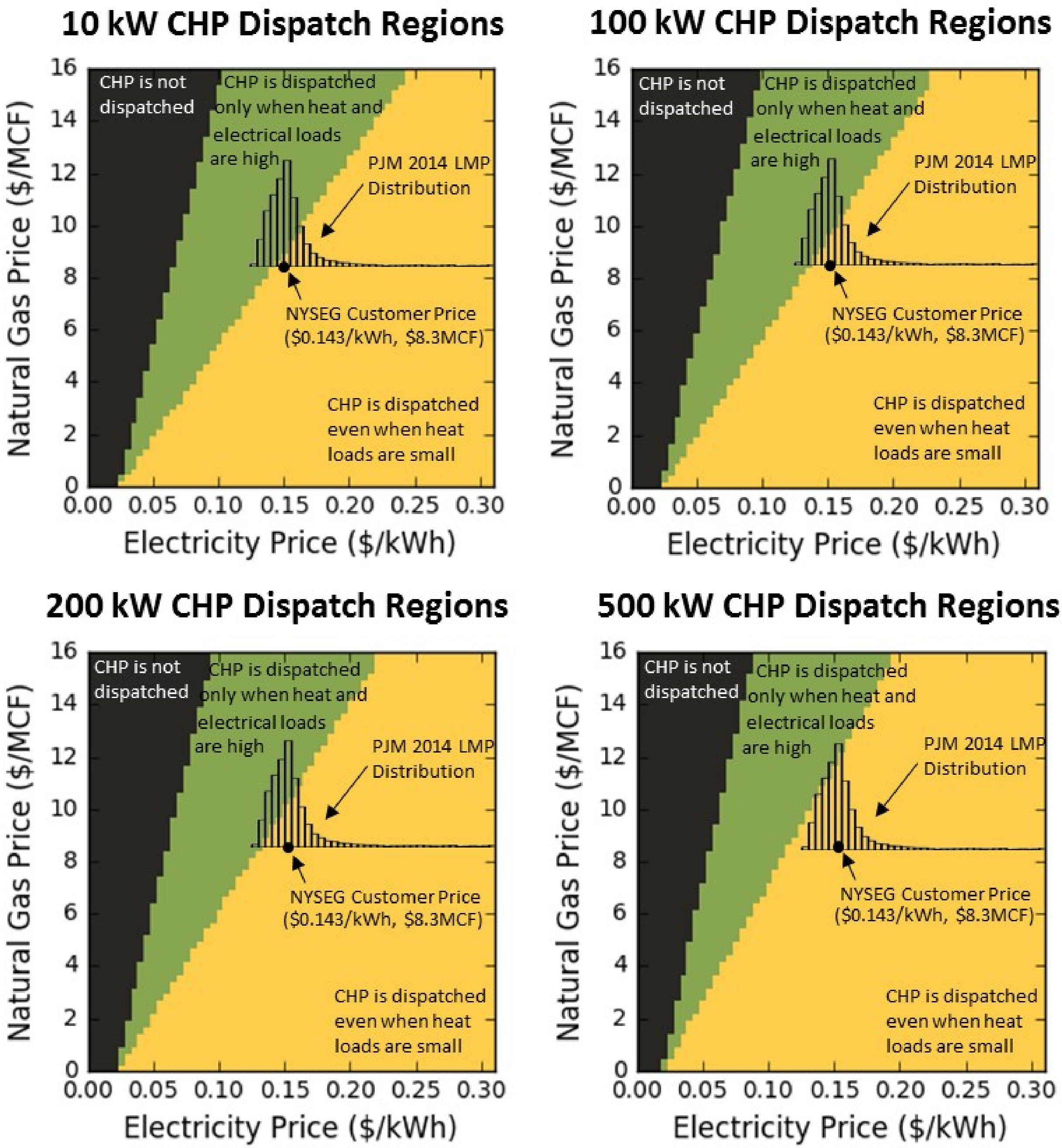


Figure S18: Sensitivity of dispatch of a 10kW, 100kw, 200kW and 500kW CHP to natural gas and electricity prices. CHP are not turned on in the black region. In the green region, CHP are only turned on if a heat and electric load is present. In the yellow region, CHP are dispatched at times even when only electric load is present. Dispatch in the green zone is likely to reduce emissions. Dispatch in the yellow zone may not reduce emissions if CHP heat production does not offset building heat load. For small CHP the customer owner's dispatch behavior, presented earlier, with electricity and natural gas at $0.143/kWh and $8.3/MCF falls in the yellow region. And, the utility is subject to a time varying LMP and so, it often falls within the green region**,** leading to lower utility emissions. Larger CHP becomes less sensitive to these effects, so time-varying rates will not be effective at reducing large CHP emissions.

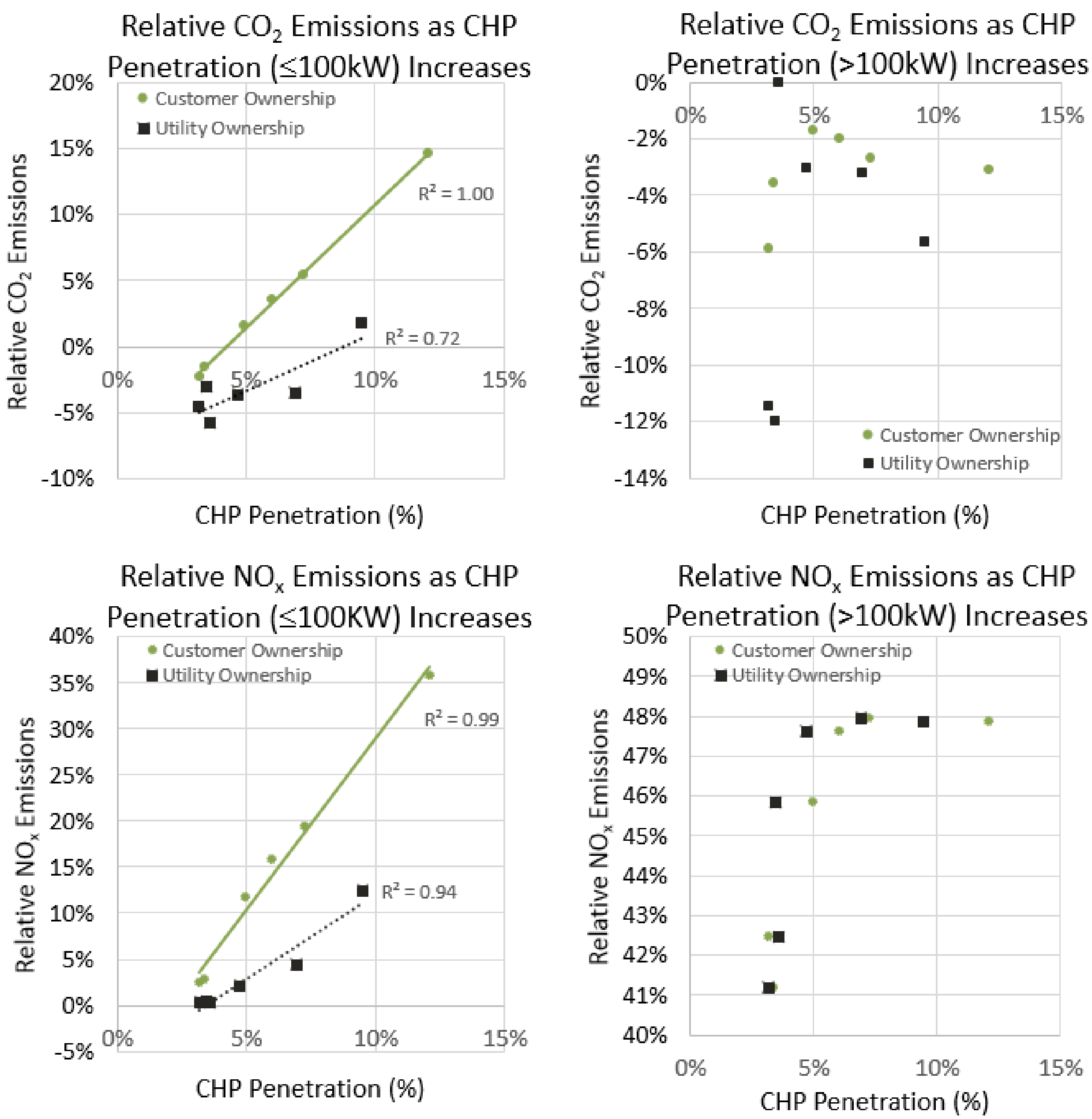


Figure S19: Emissions as the penetration of small CHP (<100 kW) and large CHP (>100kW) increases. Emissions increase as the penetration of small CHP increase but time-varying rates are effective at reducing these emissions. Emissions do not increase for large CHP and time-varying rates are ineffective at reducing emissions. The CHP fleet penetration correspond to the following scenarios moving from left to right: 30% Increase in CHP Capital Costs, 30% Increase in Discount Rate, Base Case, 30% Decrease in Discount Rate, 30% Decrease in CHP Capital Costs, 50% Decrease in Capital Costs and Discount Rate.

Economics

Total system savings are positive for both ownership scenarios indicating that the capital costs and energy costs of delivering power with CHP are lower than the alternative grid and wholesale energy costs (Figure S20). System savings are higher under the customer ownership scenario because customers installed more CHP capacity. Customer savings are low under the utility ownership scenario because the customer benefits only from PPA revenue and a reduced demand charge. Utility losses are also consistently high under customer ownership because the utility loses revenue from reduced demand charges and reduced energy sales that embody the sunk costs of the distribution system infrastructure. These utility losses would be reduced by about 30% if the utility sold natural gas.

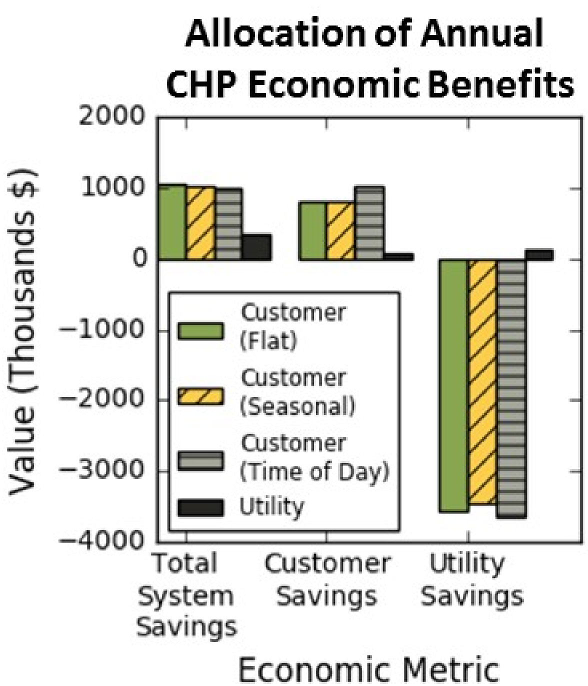
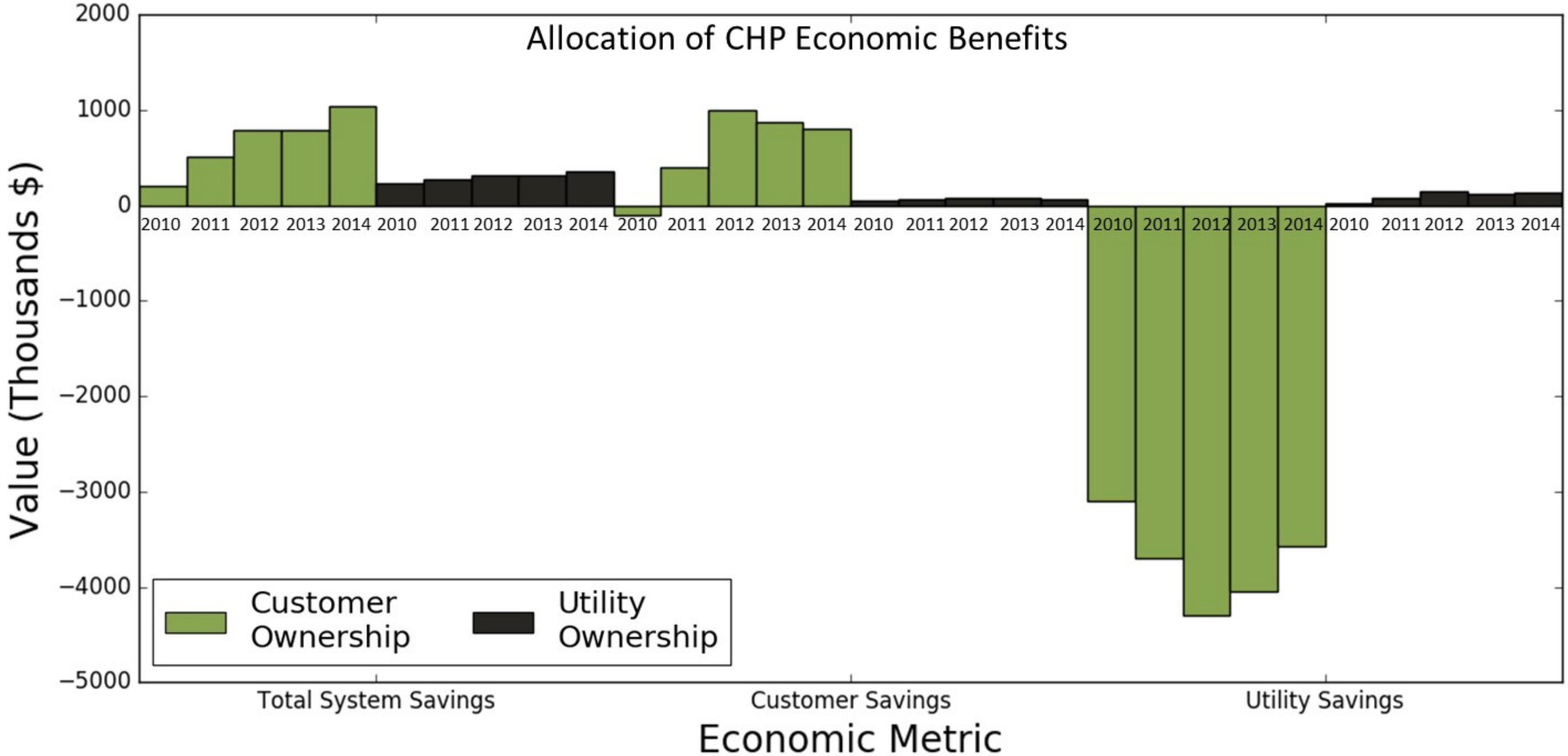


Figure S20: Allocation of CHP Savings for the base case and time-varying rates. Total system savings are positive for both owners indicating that the capital costs and energy costs of delivering power with CHP are cheaper than the grid. The high utility losses reflect lost energy sales and sunk distribution infrastructure costs. Time-varying rates do not have a large effect on customer or utility savings suggesting that time-varying rates can achieve emission reductions without negatively affecting the CHP payback period.



222 **Figure S21:** CHP Economic Benefits 2010-2014. System savings, customer savings, and utility savings were calculated for the years 2010-2014. Some variation is caused by high natural gas prices in 2010 and 2011.

Options for Reducing Wasted Heat

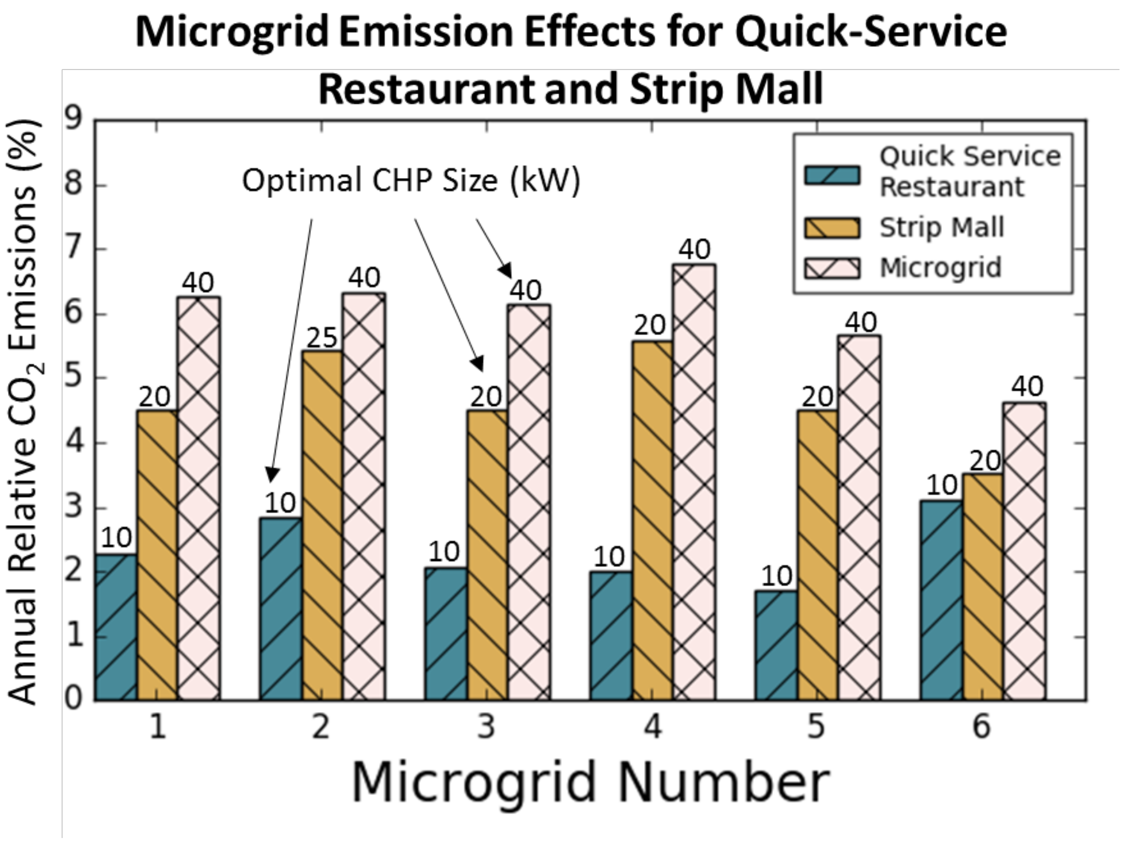
Although commercial CHP installations have the potential to have high fuel utilization efficiencies, inconstant heat loads and wasted heat can limit these efficiencies and result in higher emissions than the bulk electric grid. In our section on Emissions, we suggested using time-varying rates to limit heat production during times of low heat loads, but other options exist.

Microgrids

Microgrids are an electrical power system that connect multiple loads and can operate independently of the local distribution network. By connecting multiple heat loads, they may create more uniform heating and reduce wasted heat. Additionally, larger CHP sizes have higher electrical efficiencies and lower heat-to-power ratios, which will also reduce wasted heat.

Despite the apparent advantages of microgrids, we did not observe consistent emission reductions from microgrids, as shown in Figure S22. Microgrids composed of a warehouse and secondary school tend to produce lower emissions than if CHP were placed at those loads separately. The opposite is true for microgrids composed of a quick-service restaurant and strip mall.

There are two factors reducing the ability of microgrids to reduce emissions. First, the microgrid CHP sizes in our analysis were found by maximizing net present value (NPV), and do not account for emissions. Second, the heat loads of many commercial buildings are highly correlated. This correlation is apparent in Figure S3 and Figure S4, and it is calculated in Figure S23. Most commercial buildings are service oriented and their heat loads are highest during regular business hours. Thus, any combination of commercial buildings will still have low heat loads at night and the CHP will waste heat.


Microgrid Emission Effects for Quick-Service Restaurant and Strip Mall
Annual Relative CO_2 Emissions (%)
Microgrid Number
Optimal CHP Size (kW)
Quick Service Restaurant
Strip Mall
Microgrid
0
1
2
3
4
5
6
7
8
9
1
2
3
4
5
6
10
20
40
10
25
40
10
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20
40

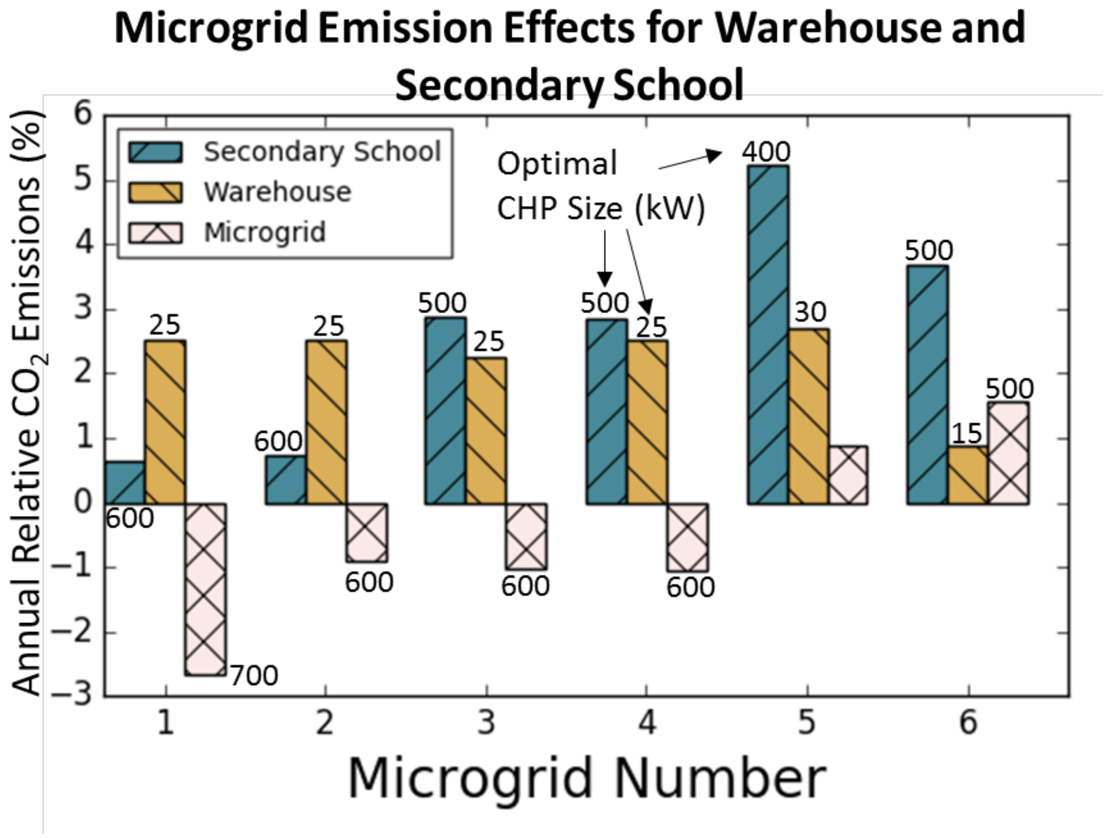

Figure S22: Microgrid emission effects for different sets of commercial buildings. Microgrids created from primary and secondary schools reduce overall emissions. Microgrids created quick-service restaurants and strip malls tend to increase emissions. Microgrids may reduce emissions because larger CHP have higher electrical efficiencies and lower heat-to-power ratios. Combining loads may also even out the heat load and reduce wasted heat. However, optimally sizing CHP by maximizing net present value (NPV) may eliminate these effects.

Correlation Matrix for Commercial Building Heat Loads

	Large Office	Primary School	Sec. School	Large Hotel	Hosp.	Small Office	Medium Office	retail Retail	Strip Mall	Super Market	Quick Service Rest.	Full Service Rest.	Small Hotel	Out Patient	Ware-house	Mid Apt
Large Office	***1.00***	0.79	0.78	0.63	0.42	0.94	0.97	0.72	0.71	0.74	0.65	0.64	0.59	0.40	0.61	0.67
Primary School	0.79	***1.00***	0.99	0.56	0.34	0.77	0.82	0.74	0.73	0.72	0.60	0.61	0.55	0.46	0.51	0.61
Secondary School	0.78	0.99	***1.00***	0.58	0.32	0.75	0.82	0.73	0.73	0.73	0.60	0.61	0.55	0.46	0.48	0.60
Large Hotel	0.63	0.56	0.58	***1.00***	0.40	0.64	0.67	0.66	0.66	0.77	0.74	0.78	0.68	0.41	0.56	0.69
Hospital	0.42	0.34	0.32	0.40	***1.00***	0.39	0.43	0.36	0.36	0.40	0.60	0.56	0.68	0.58	0.77	0.68
Small Office	0.94	0.77	0.75	0.64	0.39	***1.00***	0.97	0.71	0.70	0.73	0.65	0.64	0.58	0.35	0.60	0.65
Medium Office	0.97	0.82	0.82	0.67	0.43	0.97	***1.00***	0.75	0.74	0.78	0.68	0.68	0.63	0.41	0.62	0.70
Stand-alone Retail	0.72	0.74	0.73	0.66	0.36	0.71	0.75	***1.00***	1.00	0.82	0.62	0.65	0.60	0.54	0.54	0.65
Strip Mall	0.71	0.73	0.73	0.66	0.36	0.70	0.74	1.00	***1.00***	0.82	0.61	0.64	0.59	0.55	0.52	0.63
SuperMarket	0.74	0.72	0.73	0.77	0.40	0.73	0.78	0.82	0.82	***1.00***	0.71	0.76	0.67	0.51	0.57	0.71
Quick Service Restaurant	0.65	0.60	0.60	0.74	0.60	0.65	0.68	0.62	0.61	0.71	***1.00***	0.98	0.77	0.49	0.76	0.81
Full Service Restaurant	0.64	0.61	0.61	0.78	0.56	0.64	0.68	0.65	0.64	0.76	0.98	***1.00***	0.76	0.49	0.71	0.78
Small Hotel	0.59	0.55	0.55	0.68	0.68	0.58	0.63	0.60	0.59	0.67	0.77	0.76	***1.00***	0.56	0.87	0.92
OutPatient	0.40	0.46	0.46	0.41	0.58	0.35	0.41	0.54	0.55	0.51	0.49	0.49	0.56	***1.00***	0.50	0.55
Warehouse	0.61	0.51	0.48	0.56	0.77	0.60	0.62	0.54	0.52	0.57	0.76	0.71	0.87	0.50	***1.00***	0.92
Midrise Apartment	0.67	0.61	0.60	0.69	0.68	0.65	0.70	0.65	0.63	0.71	0.81	0.78	0.92	0.55	0.92	***1.00***
Mean	**0.70**	**0.67**	**0.67**	**0.65**	**0.52**	**0.69**	**0.73**	**0.69**	**0.69**	**0.71**	**0.70**	**0.71**	**0.69**	**0.52**	**0.66**	**0.72**

Figure S23: Commercial building heat load correlation matrix. Commercial building heating loads are highly correlated.

Heat Storage

Heat storage can act to smooth daily fluctuations in a buildings heat load. This option is best described by Barbieri et. al.[32] Higher capacity hot water tanks are a relatively low cost storage option and were shown to reduce emissions[32] Their main limitation occurs during times of consistently low heat loads, such as during the summer months. During these times, heat storage may be most effective when used with seasonal rates or absorption chillers.

Absorption Chiller

Hot water absorption chillers use heat energy to cool buildings. During summer months, they could use heat from CHP generation to cool commercial buildings, and reduce emissions. We believe more research is needed on absorption chillers, but were skeptical that they are ready for widespread adoption now. Although, large absorptions chillers are commonly found in industry, academic interest in commercial building sized chillers (e.g. about 10kW) are relatively recent.[33] Also, hot water absorption chillers are on the market but options and sizes are limited. Our own economic assessment is preliminary but a number of challenges exist:

- The only quote we were able to receive was on the internet site Alibaba. An 11.5kW-th hot water absorption chiller was quoted at $1,300/kW-th. Thus, the capital cost is only slightly less than a CHP generator but is more limited in its ability to avoid energy costs.
- Hot water absorption chillers, like CHP, will be most economical in buildings with consistent cooling loads. Unfortunately, these buildings are also likely to have consistent heat loads and are less likely to have excess heat to use in an absorption chiller.
- Absorption chillers have relatively low coefficients of performance, around 0.6,[34] whereas electric chillers have coefficients of performance of 3 or higher. Both of these factors limit the ability of hot water absorption chillers to reduce energy costs.

CHP Generation that Produces Less Heat

In our analysis we focuses on reciprocating engine CHP because it has the low capital costs and load following capabilities. However, we have also considered the possibility that different CHP generation type may have higher electrical efficiencies and produce less heat. Unfortunately, microturbines are more expensive and would similar heat output than reciprocating engines. Fuel cells would reduce heat production but are currently uneconomical in most commercial settings.

Table S9: Comparison of CHP Generation Types and Operating Characteristics[8].

CHP Type	**Size** (kW)	**Capital Cost** ($/kW)	**Electrical Efficiency** (HHV)	**Heat to Power Ratio**
Reciprocating	100	$2,900	27.0%	1.96

Engine				
Microturbine	65	$3,220	23.8%	1.96
	200	$3,150	26.7%	1.36
Fuel Cell	300	$10,000*	47%	1.0
*The Fuel Cell capital cost includes only the package cost and not additional installation and engineering fees.				

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