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IMPACTS ON NEW YORK GHG EMISSIONS FROM DISTRIBUTED COMBINED HEAT AND POWER

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ABSTRACT

As cities have begun to implement greenhouse gas initiatives, one technology that has become of interest is building level combined heat and power (CHP). In New York City, over two thirds of greenhouse gas emissions are attributed to buildings. As space heating is the major end use of building energy consumption in the Northeast, building level CHP systems have the potential to significantly reduce greenhouse gas emissions especially since many buildings utilize fuel oil to fire boilers for space heating.

While distributed CHP has potential to reduce energy consumption and greenhouse gas emissions, this statement is quite dependent on the current types and efficiencies of generators used to supply electricity. In New York State, approximately 50% of electricity is produced from nuclear and hydro power plants with the majority of the remainder supplied by simple and combined cycle gas turbines. Only 1% of electricity is supplied by less efficient oil power plants.

In the current work we seek to determine how the emissions benefits of distributed generation change with increasing penetration of CHP systems (up to 1.58 GW of aggregated capacity) considering the current mix of electricity generation capacity in New York State. The analysis indicates while there are emissions reductions for all scenarios the impact reduces on the order of 400 metric tons per MWe.

NOMENCLATURE

Decision Variables
$p_{g,t}$ electricity produced by generator g in hour t
$\mu_{g,t}$ commitment of generator g in hour t
$z_{g,t}$ start up of generator g in hour t
$f_{a,t}$ flow on arc a at time t
Sets
G set of all generators
T set of time periods
G_z set of generators in zone z
A_z^+ set of arcs flowing into zone z
A_z^- set of arcs flowing out of zone z
A set of all arcs
Z set of Zones in the NYISO
Parameters
$d_{z,t}$ demand in zone z at time t
P_g^- minimum output of generator g
P_g^+ maximum output of generator g
R_g^- minimum ramp rate of generator g
R_g^+ maximum ramp rate of generator g
UT_g minimum up time of generator g
DT_g minimum down time of generator g
C_g^1 linear fuel cost coefficient of generator g
C_g^0 fuel cost of minimum generation of generator g
$MaxOp_g$ maximum monthly energy of generator g

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INTRODUCTION

With national, state, and regional objectives to reduce greenhouse gas (GHG) emissions, many strategies and technologies have been proposed to achieve these objectives. One technology that has been utilized to achieve this goal is combined heat and power systems (CHP). CHP systems generate electricity and utilize the heat produced during the process for a useful purpose. While these systems have been utilized at the district scale for many decades, recently CHP systems have been utilized at the building level. These systems create electricity and utilize the excess heat for space heating or domestic hot water applications. As a sustainability solution distributed CHP has become popular. In New York City, the sustainability document, PlaNYC [1], explicitly calls for distributed generation including CHP systems. Building level CHP systems have been also supported in New York State through financial incentives.

CHP systems are in essence an energy efficiency technology as they still utilize fossil fuels to supply electricity and thermal energy. The emissions benefits of this technology are due to the simultaneous production of electricity and heat instead of using two independent processes to produce electricity and thermal energy. If one considers a gas turbine producing electricity from natural gas at 40% efficiency and a boiler converting energy at 90% efficiency, for a CHP system to be more efficient it must produce electricity and usable thermal energy at an efficiency of at least 65%. Current building level CHP systems can produce electricity and usable thermal energy at 85% efficiency meaning as a technical solution CHP is valid [2]. A nuance of the energy efficiency and GHG emission benefits of CHP systems is that in many instances there isn't a concurrent demand for electricity and space heating. For instance, in the summer there is an electricity demand but not heating demand. Through absorption cooling systems this thermal energy could be utilized to meet the cooling demand but this would require additional capital investment. Even with a demand for thermal energy in the summer there are also the swing seasons, spring and fall, which have minimal thermal demands.

Assuming that the demand exists for both electric and thermal energy, one must determine the capacity or size of the system as well as the operating strategy. If one wanted to completely meet both the thermal and electrical demands of a building one would choose a much larger system than if the system were operated to just meet the electric base load (electricity demand available throughout the year). The former situation of attempting to completely satisfy the building energy demands requires a CHP system to meet a range of demands meaning the system would not be used at its optimal operating point for many hours of the year. There are ways to aggregate smaller systems to maintain higher efficiencies over a range of loads but again this require additional investments. To satisfy the base load energy demands, the CHP system would be utilized at it's optimal (or full load) operating point throughout the year but would satisfy less of the buildings energy demands.

The previous caveats to the benefits of CHP systems dealt with the system response to variation in the energy demands. However one must also consider the current efficiency of electricity generation. There are many different generators with different operational characteristics used to supply electricity demand in any given hour. If one were to offset a coal-fired power plant, the GHG emissions benefits would increase (assuming the CHP system is utilizing natural gas as fuel source). However if one were to offset a highly efficient combined cycle power plant, the efficiency requirements of the CHP system would be higher. If one were to offset a renewable source of electricity, the CHP system would have negative emissions benefits.

The current work considers many of these issues to determine the GHG emissions benefits of various magnitudes of distributed building CHP systems located in New York City. In previous works we've estimated the magnitude of building level CHP systems considering different building uses as well as various sizing and operational strategies. For the current analysis we've considered building level CHP systems utilizing an electric load following strategy. To estimate the GHG emissions impacts of these systems we've created a simplified model of electricity dispatch in New York State. The following sections will describe these aspects in detail.

ESTIMATES OF DISTRIBUTED CHP CAPACITY

There are two aspects of estimating the capacity of distributed CHP systems: an estimate of the thermal and electrical building demands and the sizing/operating strategy for the CHP system. In this analysis we considered each building in New York City utilizing its size and usage type as primary indicators of building energy consumption. Utilizing publicly available data on annual energy consumption and simulations of building energy, we've estimated hourly electricity and thermal demand profiles for each building in New York City. Using these profiles as well as assumptions for sizing and operational strategies of CHP systems, we estimate the capacity as well as utilization of building CHP systems. The foundations of this analysis have been done in previous works. We will briefly review the methodology in the following sections but for a full understanding of the analysis methods see [3].

Building Energy Consumption

Initially estimates of annual building energy intensities were made utilizing zipcode level building energy consumption [4]. The estimates were created using building floor area of different building usage types or functions as independent variables to predict electricity and local fossil fuel based energy consumption. Through robust general regression analysis we estimated the coefficients of the statistical model leading to estimates of energy consumption per square meter of building floor area. Subsequent analysis divided the energy consumption into different end uses of space heating, space cooling, water heating, and non-cooling (base) electricity demands.

From the annual estimates of energy consumption per square foot, hourly estimates were developed utilizing profiles from the DOE commercial reference buildings [5]. These models were made to estimate the energy consumption of a typical building given its location in the United States and its building function. Hourly heating and electricity profiles from each of these buildings was scaled per square foot to match the annual energy consumption estimated from the previous New York City specific analyses.

CHP Sizing and Operating Strategies

Once estimates of the thermal and electrical profiles were created the next step was to estimate the capacity of each system under a certain sizing and operational strategy.

There are many strategies for how to best operate and size a CHP system such as maximizing revenue, maximizing system efficiency, and minimizing the carbon footprint of the system. Each of the objectives would result in utilization of different types of CHP technologies, numbers of generators used to meet the loads, uses of additional heat recovery systems, as well as operational strategies.

Researchers have developed methods to determine the optimal operating strategies and system components for CHP systems depending on the desired outcome and load profiles (time of use energy demands) of the buildings to be sized. These methods typically deploy mixed-integer linear or non-linear programs [6–9] to determine system size and optimal operational strategies. However simpler heuristics are also utilized.

Two of the simplest methodologies for operating a CHP system are to meet either the thermal or electric base load. For these methods, the CHP system is operated year round, satisfying the minimum constant electric or thermal demand. This method ensures that the system is sized in such a way to always run at peak load and efficiency. Two additional sizing methodologies are electric and thermal load following strategies also called electric and thermal demand management [10] and electricity- and heat-led [7]. These methods size the system to follow either the electric or thermal loads for the majority of the year and require the CHP system to increase or decrease its supply based on demand. Typically CHP systems used to deploy these strategies have high part load efficiencies. The part load efficiency is a measure of how well the system operates when not running at full load. Internal combustion engines have high part load efficiencies with minimal reduction in efficiency until 60% of the peak load [11].

For the current analysis an electric load following approach was utilized considering base electric and space heating end uses as electric and thermal demands, respectively. The CHP systems were allowed to operate at up to 60% part load depending on the magnitude of the electric demand. If the electric demand was less than 60% of the capacity of the CHP system, then the system was not operated. The system capacities in the load following strategies utilized an algorithm that first uses the electric demand to estimate the range of possible system sizes. These system sizes were between the maximum and minimum hourly electric demand. Then for each possible capacity in 1 kW intervals, the system efficiency, electric, and thermal output at each hour was calculated. The largest system with at least 60% annual efficiency was selected as the system for the building.

TABLE 1. Characteristics of CHP Systems

Electrical Capacity	Prime Mover	Electric Efficiency	Thermal Efficiency
<100 kW	Microturbine	25%	47%
100 – 500 kW	Internal Combustion Engine	36%	45%
500 – 1,000 kW	Internal Combustion Engine	38%	49%
>1 MW	Internal Combustion Engine	45%	42%

For the current analysis, only internal combustion engines and microturbines were considered as these technologies are typically dispersed in sizes for distributed generation, from 30 kW to 5 MW, and are compatible with existing infrastructure, as they can be fuelled by natural gas. Four different technologies were used to represent different capacity ranges. There characteristics are shown in Tab. 1.

To illustrate the sizing methodology, Figure 1 and 2 on the following page depict the electric and thermal demands for a single building comprised of residential (27,088 sq. m) and store (738 sq. m) building types. Also illustrated in the figures is the electric and thermal output of a CHP system sized based on the electric load following methodology previously discussed. Utilizing the described sizing methodology for this mix of building types with their respective building floor areas, the estimated electrical capacity of the CHP system is 151 kW. The system operates at peak load for most hours of the year requiring rejection (or waste) of thermal energy over the summer and swing seasons. The annual CHP efficiency for this system was 60%.

Utilizing these methods, the potential capacity and system utilization were estimated for each tax lot (building) in New York City. At the building level, the electric load following methodology previously discussed identified 2,348 potential CHP systems

FIGURE 1. Example of system sizing, Electric Demand/Production

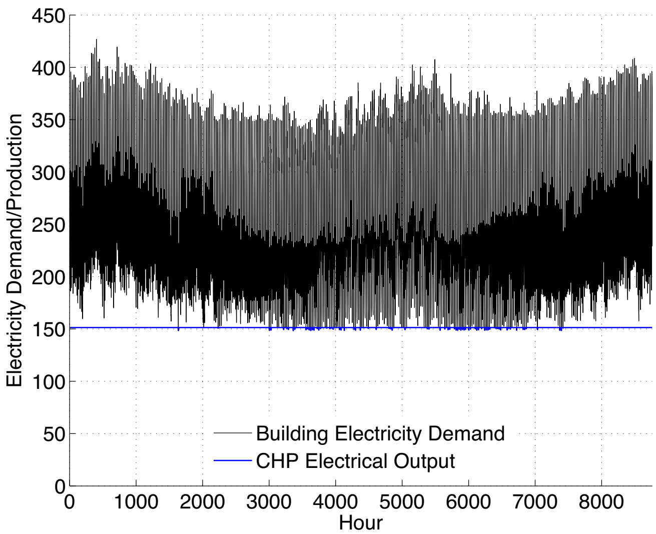
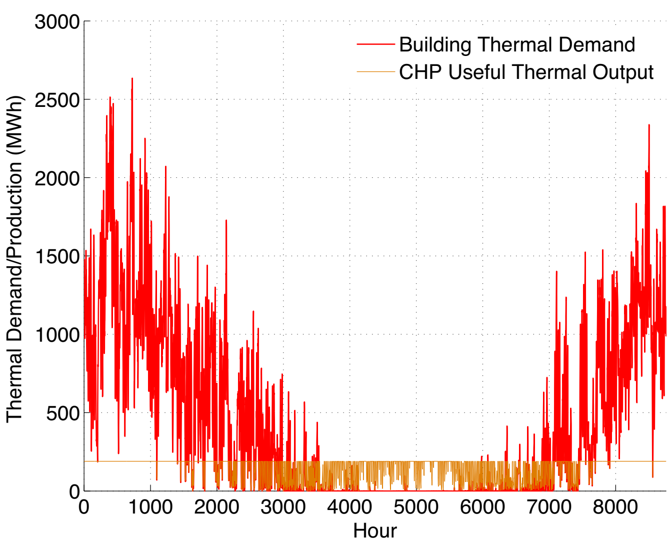


FIGURE 2. Example of system sizing, Thermal Demand/Production

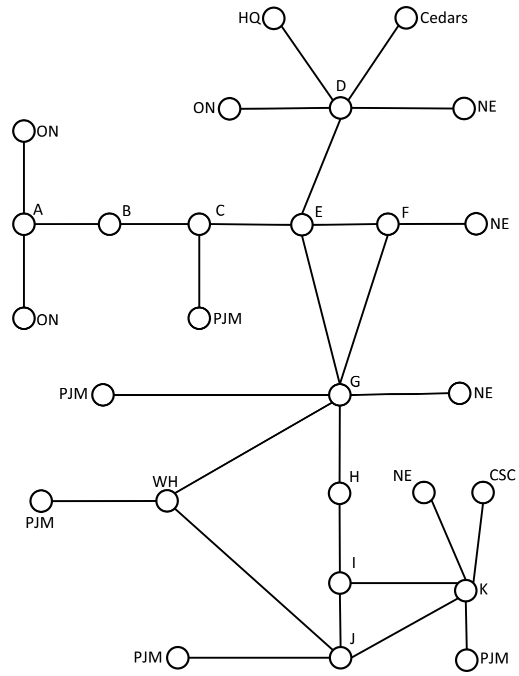


with an aggregate electrical capacity of 1,579MW. The system sizes spanned the entire range of allowed systems capacities with the largest number of systems ranging between 100 and 250 kW.

GHG EMISSIONS FROM TRADITIONAL SOURCES

The emissions reductions from a CHP system are from two aspects: energy from electricity production and fuel burned for space heating applications. As electricity is provided from a slew of generators across the state and the order of commitment changes with demand and transmission constraints, it was nec-

FIGURE 3. Network Topology of the NYISO (Zone J= New York City)



essary to model these aspects of the system. In New York, 50% of electricity is produced from Nuclear and Hydro sources, 40% by natural gas based generators, 8% coal fired generators and 1% fuel oil. To understand which generators would not be utilized with the introduction of distributed generation in New York City, we created a simplified unit commitment model of electricity generation and flows in New York described in the next section.

GHG Emissions from Grid Electricity

The hourly greenhouse gas emissions from electricity generation in New York State were estimated through a simplified unit commitment model. The commitment model considered each of the 11 zones in New York State connected by various transmission lines as well as the interfaces with the other independent system operators, Ontario, New England and PJM. The network topology is shown in Fig. 3. In each zone there is an electricity demand as well as a set of generators with varying characteristics. The use of a simplified model was facilitated by the currently available data on the New York State power system including, hourly generator output for fossil fuel burning generators greater than 25MW from the EPA [12], monthly net electricity production and fuel consumption for each generator from the EIA [12], transmission line locations and capacity limits from the NYISO [13], and hourly electricity demand for each zone from the NYISO.

The unit commitment network flow problem was modeled as a mixed-integer linear program whose objective was to minimize the cost of generation subject to various constraints. The formulation is similar to [14–16]. Our model does not incorporate spinning or non-spinning reserves and forced outage rates. Also it should be noted that the model is not a power model in that line susceptances and voltage angles are not explicitly modeled. A mathematical description of the general model is given below.

Objective Function : Minimize the cost of generation

$$\min \sum_{g,T} C_g^1 p_{g,t} + C_g^0 \mu_{g,t} + S_g z_{g,t} \tag{1}$$

Subject to the Following Constraints

$$\sum_{g\in G_z} p_{g,t} + d_{z,t} + \sum_{a\in A_z^+} f_{a,t} + \sum_{a\in A_z^-} f_{a,t}, \forall z \in Z, \forall t \in T \tag{2}$$

$$P_g^- \mu_{g,t} \leq p_{g,t} \leq P_g^+ \mu_{g,t}, \forall g \in G, \forall t \in T \tag{3}$$

$$p_{g,t} - p_{g,t-1} \leq R_g^+, \forall g \in G, \forall t \in T \tag{4}$$

$$p_{g,t-1} - p_{g,t} \leq R_g^-, \forall g \in G, \forall t \in T \tag{5}$$

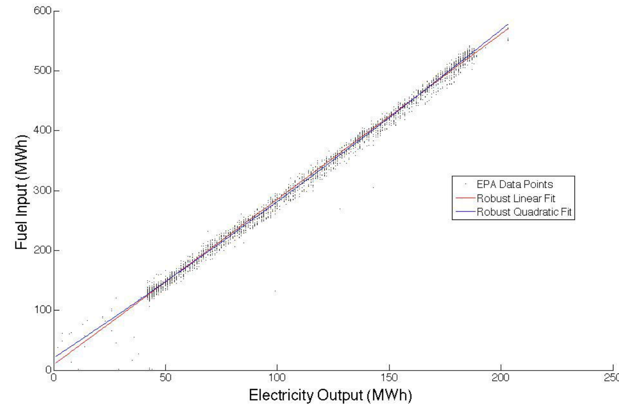
$$f_{a,t} \leq F_a^+, \forall a \in A, \forall t \in T \tag{6}$$

$$z_{g,t} \geq \mu_{g,t} - \mu_{g,t-1}, \forall g \in G, \forall t \in T \tag{7}$$

$$\sum_{q=t-UT_g+1}^{t} z_{g,q} \leq \mu_{g,q}, \forall g \in G, t \geq UT_g \tag{8}$$

$$\sum_{q=t+1}^{t+DT_g} z_{g,q} \leq 1 - \mu_{g,t}, \forall g \in G, t \leq |T| - DT_g \tag{9}$$

FIGURE 4. Linear and Quadratic fit of Generator Cost Function



$$p_{g,t}, f_{a,t}, z_{g,t} \geq 0, u_{g,t} \in \{0,1\}, \forall g \in G, a \in A, t \in T \tag{10}$$

Equation (1) describes the objective function that minimizes the sum of the linear generator cost function as well as a startup cost for each generator and time period. Equation (2) describes the load balance for each zone ensuring that supply equals demand. We have assumed a lossless transmission model. Equation (3) describes the minimum and maximum output for each generator. If a generator is not committed its output is set to zero. Equations (4) and (5) describe the positive and negative ramping limits (or how quickly a generator can change its output) for each generator. Equation (6) describes the capacity limits on each arc. Equation (7) defines the start up variable. Equations (8) and (9) describe the minimum up and down time requirements for each generator. Equation (10) describes the nonnegative and integrality constraints for each respective variable. The system of equations was solved at the hourly time scale one month at a time.

As shown in Equ. (1) the cost function for each generator was given linear behavior. Utilizing the hourly electricity production data from the EPA on every generator above 25MW, we found that a linear model closely approximated the fuel usage versus electricity production. The linear fuel cost for each generator in the data set was derived from a robust linear regression on the hourly heat input and electricity data. Figure 4 depicts an example of the linear and quadratic fit for a generator in the EPA data set. Some of the generators in the EPA set had unreliable efficiency data (efficiencies greater than 1 or higher than record). For these generators cost functions were utilized from comparable generators with the same unit type (ie combined cycle or gas turbine) and fuel type. Generators less than 25MW were assumed to have 25% electrical efficiency. The efficiencies were converted to cost by multiplying the fuel cost for each fuel type. Table 2 on the following page shows the price of each fuel type. The cost of the imports was modeled from the local based marginal price of each zone. This price, LBMP, indicates the

TABLE 2. Fuel Price by Fuel Type

Fuel Type	US dollars/MWh
Light Fuel Oil	64
Heavy Fuel Oil	40
Kerosene	64
LPG	59
Coal	12
Natual Gas	17

TABLE 3. Minimum Up and Down Times by Generator Type and Capacity.

Unit Type	System Capacity	Minimum Up	Minimum Down
CC	< 100 MW	1	1
CC	100 - 500 MW	2	2
CC	> 500 MW	3	3
GT	< 100 MW	1	1
IC	< 6.4 MW	1	1
JE	< 60 MW	1	1
Nuclear	> 500 MW	25	25
ST	< 100 MW	1	1
ST	100 - 500 MW	2	2
ST	> 500 MW	5	5
Coal	Any size	5	5

cost of the next MW in that area meaning its a maximum price of generation. Since this reflects pricing of generators in the zones as opposed to the cost as well as other market factors, the hourly LBMP was reduced to the average price of generation at that hour and all hourly LBMP values less than this in the NYISO dataset for imports from the respective control area.

Other parameters were derived from the EPA data as well. For a specific generator, the positive and negative ramp rates were calculated for each consecutive hour operating at non-zero conditions. The minimum and maximum values of this set were taken as the negative and positive ramps rates (R_g^- and R_g^+), respectively. The minimum generator output, P_g^-, was taken as the first quartile of generator electricity production. Generators less than 25 MW were assumed to have no limits on their ramp rates as well as 0 MW minimum output. The maximum capacity and list of generators was taken from the NYISO goldbook utilizing the rated capacity for each generator [13]. The minimum up and down times for each generator (UT_g , DT_G) were specified by generator size and unit type as shown in Tab. 3.

To provide realistic values additional constraints were added to the model. The main additional constraint is on the maximum amount of energy a generator can produce.

$$\sum_{t \in T} p_{g,t} \leq MaxOp_g, \forall g \in G \tag{11}$$

TABLE 4. GHG Emissions Coefficients by Fuel Type and Import Location

Fuel Type / Import Location	GHG Emissions (kg CO_2e/MWh)
Light Fuel Oil	228
Heavy Fuel Oil	262
Kerosene	231
LPG	235
Coal	317
Natural Gas	179
Cedars	0
Hydro Quebec	0
New England	422
Ontario	164
PJM	495

For conventional power plants (fossil fuel and nuclear), $MaxOp_g$ was set to the energy produced at full output, P_g^+, for the entire time period meaning this constraint had no effect. For hydro power plants, this limit was set to the historical monthly energy consumption for each generator. For electricity from imported regions, $MaxOp_g$ was set to the historical monthly electricity imports of that region. The flow of electricity from neighboring systems is governed by complex economic dispatch as well as contracts that the current model would not be able to capture. To ensure that imports were not used in excess a monthly limit was utilized.

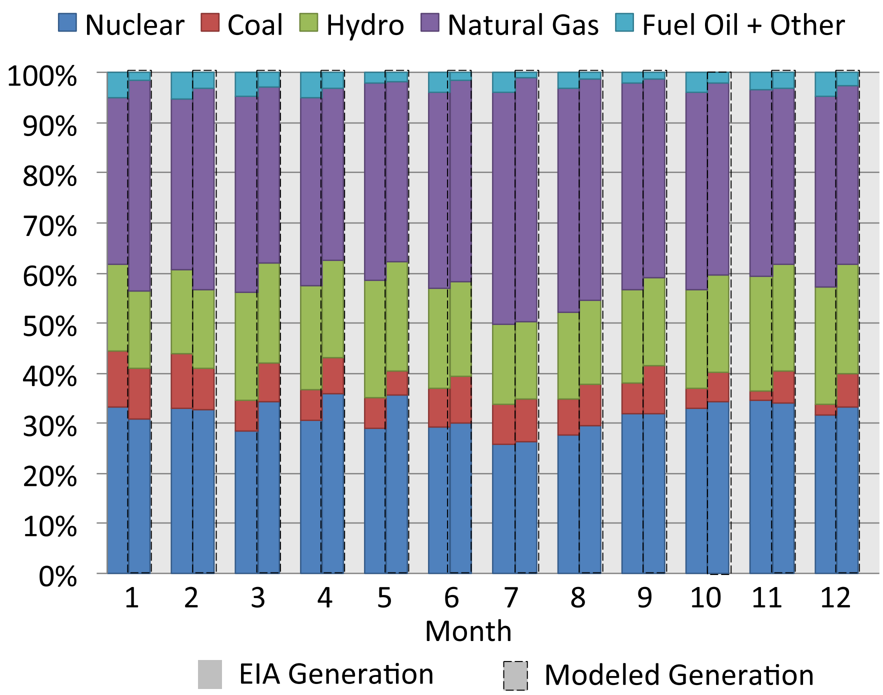
Also since there were many small hydro power plants in the NYISO generation set to reduce run times, the hydro plants were aggregated by zone. The maximum output in any hour of the aggregate hydro plant was equal to the sum of the individual outputs. The same was done for the maximum monthly output. While this formulation of the aggregate hydro power plants is not the same as the individual power plants, we observed little difference in the model operation from this aggregation.

In addition to the maximum monthly energy constraints, additional constraints on the flow across various power lines were added according to limits posed by the NYISO. For example the flow from the neighboring PJM regions to Zone J, New York City, was limited to 2,000 MW although the capacity on the individual lines would allow more flow than that.

Once the estimates of generator output and fuel consumption were made from the optimization model, the GHG emissions in kg CO_2e were calculated utilizing the coefficients in Tab 4 .

A comparison of monthly generation by fuel type from the model versus data provide by the EIA are shown in Fig. 5. In general the comparison by fuel type is fairly good for each of the months. However, fuel oil based generation is systemically under estimated by the model. Since fuel oil accounts for only

FIGURE 5. Comparison of Modeled Generation to EIA Data



1% of electricity generation in New York State and we are considering large reductions in electricity demand, the discrepancy was considered acceptable. Also in November and December coal generation is significantly higher in the model and in January and February more natural gas based generation is higher in the model. Since the model does not incorporate forced outage rates coal generation is fairly consistent through out the year whereas in reality the coal production reduces in November and December presumably from maintenance. Due to market forces natural gas prices peak in January reducing their utilization in these months.

In addition, a comparison to the monthly net generation and fuel consumption reported by the EIA indicate that natural gas and coal based generation systems operate 10% and 4% more efficiently. As the EIA reports net generation and aggregate fuel consumption, the efficiency differences in reality are not as extreme as shown above but this must be noted. The higher natural gas based efficiency is due to the large number of combined cycle plants utilized in the model since these systems are the lowest cost option.

Other researchers have attempted to model generator output for the NYISO as well. Gilbraith and Powers [17] modeled power flows and generation for New York State to assess the emissions impacts of residential demand repsonse programs utilizing the commerical software MAPS and data on the generation system from a proprietary database. The MAPS modeling platform includes additional constraints in their model formulation including spinning reserves, non-spinning reserves, and probabilitistic forced outage rates. Utilizing this software and databases, their model yielded similar inconsistencies with reported generation including an over production of electricity from coal generators as well as the majority of natural gas based electricity generation coming from combined cycle power plants. This illustrates that there are many aspects of the power system that are difficult for a unit commitment economic dispatch model to capture even when including additional constraints. Since a relatively large amount of demand reductions considered in the paper, the model results are satisfactory for our purposes.

GHG Emissions from Space Heating

The emissions from space heating require knowledge of the types of system as well as the operation and maintenance for every building in New York City. Since this information is not available we have assumed that space heating for each building in provided by a boiler operating 85% utilizing the average mix of fuels used to supply building energy usage. This mix is primarily natural gas with 30% attributed to fuel oil.

GHG EMISSIONS REDUCTIONS FROM CHP

The change in the source of electricity production from the introduction of a fleet of building combined heat an power sys-

TABLE 5. Change in Electricity Generation (MWh) by fuel type and Aggregate CHP Capacity (MW)

Generator Fuel Type	236 MW	462 MW	688 MW	914 MW	1,142 MW	1,367 MW	1,579 MW
Fuel Oil	1	-2	1	-1	0	0	-2
Imports	71	191	177	153	136	118	102
Natural Gas	1,061	1,933	3,348	4,301	5,577	6,656	7,434
Coal	343	741	732	1,226	1,266	1,422	1,742
Total	1,476	2,864	4,258	5,679	6,978	8,196	9,276

FIGURE 6. GHG Emissions Reductions per MWe CHP capacity

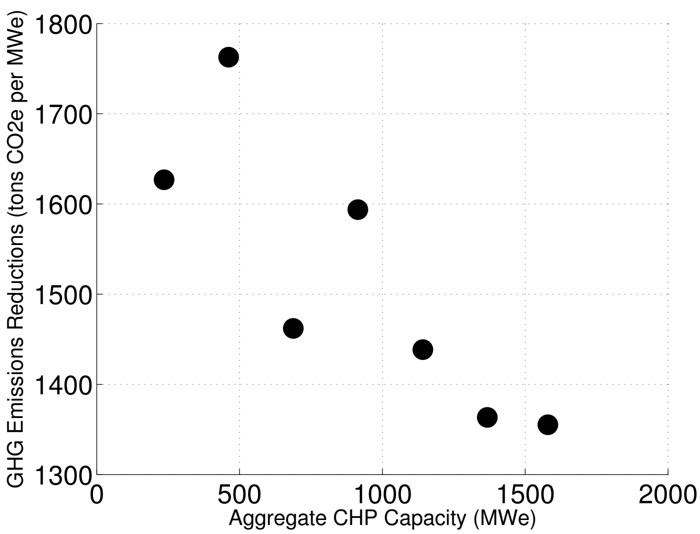


TABLE 6. GHG Emissions Reductions from Distributed CHP

Aggregate CHP Capacity (MW)	GHG Reductions (Metric tons,CO2e)
236	383,877
462	814,215
688	1,006,472
914	1,456,831
1,142	1,642,346
1,367	1,864,268
1,579	2,140,598

tems is depicted in Tab. 5. The major changes are seen in natural gas and coal fired power plants, comprising from 95% to 99% of the total reductions. The change is observed in these generators because electricity from hydro and nuclear power plants are not assigned a cost in the model driving them be utilized in all scenarios.

The changes in imports indicate a change in the region that the imports were supplied from. As shown in Tab. 4 GHG emissions from PJM are less than from Cedars or Hydro Quebec. Imports from Hydro Quebec and Cedars are also lower cost than PJM at various times through the year. Therefore by reducing electricity demand in Zone J more imports are allowed from Hydro Quebec and Cedars leading to small emissions reductions. This may or may not be the case in reality but the effect of this change is small and does not significantly affect the overall emission reductions.

In addition there is an increase in the amount of fuel oil utilized in some scenarios. Since there are only a few profiles of building electricity utilized in the model the load reductions from CHP occur at the same time creating times of rapid demand changes. This results in an increase in small natural gas and fuel oil generators to adjust to the rapid changes in demands. While this is an artifact of the methods for modeling building CHP systems the effects are small.

Since the GHG emissions reductions are primarily from natural gas and coal, the ratio of their production affects the emissions benefits. Figure 6 depicts the emissions reductions per MW_e vs the aggregate capacity of installed CHP systems. One can observe the decrease on the order of 400 tons per MW_e in the emission benefits of distributed CHP systems. The plot does not show a smooth decline in emissions. This is effect was created by the change in coal being less gradual than the change in natural gas. Since generation from coal-fired power plants have longer minimum up and down times leading to more costly start up costs, it takes a significant amount of CHP generation to offset a coal generator. Therefore the emissions reductions from coal are about the same from 462 MW to 688 MW as well as from 914MW to 1,142 MW. This leads to the variable emissions reductions seen in Fig. 6.

The aggregate emissions reduction for each aggregate capacity of building systems introduced is shown in Tab. 6. In the smallest scenario considered, comprising of 236 MW of building level distributed generation, the GHG emission were reduced by 0.3 million metric tons. In the largest scenario of incorporating 1.58 GW of distributed CHP results in a reduction of 2.1 million metric tons CO_2e. The total GHG emissions for New York City in 2011 was 53 million metric tons [18].For the smallest scenario considered, the electricity generation is 2.7% of NYC's electricity demands while reducing emissions citywide emissions 1%. In the largest scenario, the electricity generated by the CHP systems is 17% of electricity consumption in New York City and the emissions reductions only account for 4% of GHG emissions.

CONCLUSIONS AND FUTURE WORK

The current work estimated the GHG emissions impacts from various penetrations of building level CHP systems. These systems were operated utilizing base electric and space heating as electric and thermal demands for the CHP systems. Each system was modeled to operate at 60% annual CHP efficiency. As the emissions benefits from the introduction of CHP systems depends on the generators used to supply electricity from conventional generators at a given time, a unit commitment model was created for electricity generation and transmission across New York State. Utilizing this model, we found that there were decreasing benefits to increasing penetration of distributed CHP systems. The benefits reduce from about 1,750 metric tons per MWe considering 236 MWe of CHP capacity to 1,350 metric tons per MWe when considering 1.58 GW of CHP capacity. These results indicate that policy makers will need to consider the magnitude of the impacts they would expect to see from distributed CHP systems. In addition for the largest scenario considered, the 1.58 GW of distributed CHP systems would lead to 4% reduction in GHG emissions.

The current work evaluates 235 MW aggregations of distributed CHP systems considering an electric load following operational methodology on base electric and space heating demands. Future work will investigate the GHG emissions impacts of smaller aggregation units, different electric and thermal demands as well as different CHP operational strategies.

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