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Current and near-term GHG emissions factors from electricity production for New York State and New York City

B. Howard *, M. Waite, V. Modi

Department of Mechanical Engineering, Columbia University, 500 W 120th St, New York, NY 10027, United States

HIGHLIGHTS

- A multi-regional unit commitment model was developed for New York State.
- The performance parameters of 191 generators were statistically estimated.
- Considered planned and proposed changes to the electricity system up to 2025.
- Average GHG emissions factors could reduce between 9% and 39% from 215 kg CO_2e/MWh.
- Marginal GHG emissions factors may reduce 30% from 540 kg CO_2e/MWh.

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ABSTRACT

This paper reports estimates of average GHG emissions factors for New York State and marginal GHG emissions factors for interventions in New York City. A multi-regional unit commitment model was developed to simulate the behavior of the grid. The parameters defining the system operation were gathered from several publicly available data sources including historical hourly electricity production and fuel consumption from over one hundred power plants. Factors were estimated for a baseline year of 2011 and subsequently for the year 2025 considering planned power plant additions and retirements. Future scenarios are also developed considering different wind turbine installation growth rates and policies affecting the cost of generation from coal power plants. The work finds marginal GHG emissions factors for New York City could reduce between 30% and 36% from 540 kg CO_2e/MWh in 2011 for all future scenarios considered. Average GHG emissions factors for New York State could reduce 9–39% from 215 kg CO_2e/MWh depending on the wind growth rate and price burden on coal power plants.

1. Introduction

New York State and New York City are amongst many regions pledging to reduce greenhouse gas (GHG) emissions by significant proportions over the coming decades [1,2]. In response, policy makers have developed plans promoting the integration of renewable energy sources and implementation of demand-side interventions [3,4].

The impacts of demand-side measures, such as distributed generation or building energy efficiency retrofits, are typically quantified through an avoided burden approach. Under this framework, an intervention is deemed to reduce GHG emissions if it generates less GHG emissions than the current system. The current system for providing electricity is the power grid, therefore one requires an estimate of the GHG emissions produced throughout its operation.

Standard practice, proposed by many governing bodies and institutions [5,6], is to use GHG emissions rates, or factors, that quantify the GHG emissions produced per unit of electricity production from the grid. These factors are meant to provide a simplified measure of the GHG emissions from an entire electricity system. They are region specific, reflecting the generation technologies locally prevalent and can include the cumulative GHG emissions over the entire life span of the power plant, from resource extraction to decommissioning [7,8].

Direct GHG emissions, or those produced during the operation of the power plants, can be described by average and marginal GHG emissions factors. Average GHG emissions factors represent the amount of GHG emissions produced per unit of electricity production considering all power plants within a region of interest. Marginal GHG emission factors, in contrast, are meant to represent

* Corresponding author.
E-mail address: bnh2111@columbia.edu (B. Howard).

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Nomenclature

Decision variables

f	electricity flow along an arc
p	generator power output
μ	generator on/off (commitment) status
h	generator fuel input
s	generator spinning reserve
z	generator start up indicator

Sets

$\mathcal{A}$	set of all transmission arcs
$\mathcal{F}$	set of the set of arcs with aggregate flow constraints
$\mathcal{G}$	set of all generators
$\mathcal{T}$	number of hours in the year
$\mathcal{Z}$	is the set of modeled zones in New York State

Subsets

G^{nys}	set of generators in New York State
G^{RE}	set of generators defined by a reservoir constraint
A^s	individual set of arcs in $\mathcal{F}$ with aggregate constraints
A^+	set of incoming directional arcs
A^-	set of outgoing directional arcs
G^{ak}	set of generators capable of providing spinning reserve in zones A through K
G^{fk}	set of generators capable of providing spinning reserve in zones A through K

Parameters

D	power demand
F	maximum flow on an arc
F^{A^s}	maximum aggregate power flow of arcs in the set A^s
P^+	maximum generator power output
P^-	minimum generator output
P^1	thermal energy used per unit electricity production
P^0	thermal energy used during start up
R^+	generator maximum positive ramp rate
R^-	generator maximum negative ramp rate
UT	generator minimum up time
DT	generator minimum down time
RE	maximum energy produced by a generator during a specified time period
Y	number of days in the year
I	normalized and scaled hourly cost of imports
l	local based marginal price for import region
S^{ak}	minimum spinning reserve to be provided by generators in zones A through K
S^{fk}	minimum spinning reserve to be provided by generators in zones F through K
c	cost of fuel used during the start-up period
r	spinning reserve cost of generator g
CP	clearing price for spinning reserve
yf	future year, 2025
yc	current year, 2011
gr	annual demand growth rate

Parameters for wind turbine output

w	wind speed
$P(w)$	power output of a wind turbine at wind speed w
w^{ci}	cut-in wind speed
w^{co}	cut-out wind speed
w^r	rated capacity wind speed,
$p(w)$	wind turbine power output as a function of wind speed w
ρ	density of air
SA	wind turbine swept area
C^p	power coefficient
w^{ah}	wind speed at the desired height, ah,
h^{ah}	wind turbine hub height,
h^{mh}	height of the measured wind speed
w^{mh}	wind speed at the measured height

Subscripts

g	generator
t	time step
z	network zone
a	transmission arc
s	season, for demand growth estimate
i	import region
d	day

Acronyms

CCGT	combined cycle power plant
GT	gas turbine
ICE	internal combustion engine
ST	steam turbine
JE	jet engine

the GHG emissions that would result from a small change in electricity demand. Marginal GHG emissions factors consider the stratification of power plant dispatch, resolving that small changes in demand will not affect the output of all power plants. Throughout the literature, average and marginal GHG emissions factors have be developed with varied methodologies and data sources.

Average and marginal GHG emission factors for various regions in the United States are estimated annually by the environmental protection agency (EPA) in the Emissions & Generation Resources Integrated Database (eGRID) [9]. The eGRID methodology estimates regional average and non-baseload GHG emissions from historical CO_2 emissions and fuel consumption provided by each power plant. Leveraging hourly production data from power plants, researchers have also estimated marginal GHG emissions factors for different times of the year and sectoral end-use through regression based approaches [10,11].

These data-driven approaches provide insight on historical GHG emissions rates, however the aim of policy makers is to project the potential impacts while also considering changes to the electricity supply itself. A model-based approaches can simulate the behavior of the generators that constitute the power network allowing one to examine how these factors may change under various future scenarios. Several modeling frameworks of varied complexity and data requirements, have been used to estimate changes to GHG emissions in electricity systems.

A merit order dispatch model decides which generators meet demands based solely on the cost of the generators with minimal consideration of the physical limitations and other economic constraints governing there operations. These models have been used by researchers to estimate average and marginal GHG emissions considering changes to supply and from the implementation of electric vehicles [12,13].

Unit commitment (UC) models are used by power systems operators to determine which generators should be used to meet the projected demand. For a set of generators, their technological constraints, and a power demand to be met, the UC model determines the set of generators to bring online that will minimize the total operational cost. These models have been used by several researchers to estimate average and marginal GHG emissions factors for various future scenarios [14–17]. The UC model formulations vary in their description of the technological constraints, which mainly describe the limits on generator output and power flows between regions.

Additionally, energy systems models have been used to evaluate long-term changes to GHG emissions from future supply and demand changes [18–21]. Energy system models take into account the technical and economic constraints to determine optimal configuration and operation of energy system. These tools use fixed model structures, with a precise system defined by specifying the large set of technological and economic parameters [22]. In the techno-economic energy systems model, both the generation system and future power demands are determined endogenously.

Overall there are many and varied approaches for estimating GHG emissions factors for electricity production that range in scope and data requirements. The aim of this analysis is to estimate average and marginal GHG emissions factors for New York State and New York City considering near-term changes to the electric supply. Given the desire to evaluate future scenarios, a model-based approach was selected. Further the New York State Independent System Operator (NYISO) and the Regional Greenhouse Gas Initiative (RGGI) provide information on the transmission network, current and projected power demands, planned generator additions and retirements as well as data on the hourly operation of each power plant. With the large amount of data available to define the system operation, a multi-region unit commitment model was developed to simulate the behavior of the power grid under 2011 and 2025 scenarios. The ultimate aim of the work is to investigate how GHG emissions factors may change over the coming decades considering planned changes to the electricity grid, with the intent to aid policy makers and analysts in evaluating alternatives.

The remainder of this paper is organized as follows: Section 2 describes the current state of the New York State Power Grid operations; Section 3 describes the modeling methodology including the multi-regional unit commitment model and methods used for estimating average and marginal GHG emissions factors from direct power plant operations; Section 4 describes the model validation and estimates of GHG emissions factors; Section 5 presents general conclusions.

2. Description of New York State power grid

Electricity production and transmission in New York State is overseen by the New York Independent System Operator (NYISO). NYISO divides New York State into 11 zones (labeled A through K) for the purposes of scheduling dispatch as illustrated in Fig. 1a. Zones J and K represent New York City and Long Island, respectively and in 2011 these demand centers contributed 47% of the annual electricity demand [23].

There are over 700 power plants in New York State included in the markets organized by NYISO. By national standards electricity production in New York State is relatively low carbon with 51% of annual electricity being provided by hydro and nuclear power plants, 37% from natural gas (or dual fuel) sources and 7% from coal in 2011. A very small percentage (2%) of electricity generation comes from renewable energy sources (primarily wind turbines).

In 2011, 33% of New York States annual energy demand was from New York City however only 14% produced was produced within the City's boundary. Therefore a significant amount of electricity is generated in the northern part of the state (upstate) and transmitted to the southern part of the state (downstate). New York State also imports and exports electricity from 4 surrounding regions: PJM, the New England Independent System Operator (NEISO), Ontario's Independent Electricity System Operator (IESO), and Hydro Quebec. In 2011, imports from these regions provided 15% of the New York States electricity supply. The annual energy demand and generation by zone is depicted in Fig. 1b. Mismatches in supply and demand as well as the significant amount of energy imported from external regions makes the transmission lines and their respective limits an integral aspect of power grid operation.

3. Modeling methodology

The following sections describe the multi-region unit commitment model used to simulate current grid operation, the methods used to estimate average and marginal GHG emissions factors, as well as the assumptions made for the 2025 scenarios.

3.1. Multi-region unit commitment model description

A multi-region unit commitment (MRUC) model was developed to estimate the GHG emissions produced from electricity generation. A unit commitment model is an optimization problem that determines the output of each power plant, or generator, within a system to minimize the overall cost of supplying demand. A MRUC model considers multiple connected regions. The connections represent transmission between each region, typically applying constraints reflecting power flow limits at the interface. The output of the model is the fuel consumption of the generators used to supply demand as well as the electricity flows between regions. The MRUC developed in this work does not consider the automatic dispatch of power generators for maintaining frequency and considers transmission across arcs as energy flows. With respect to the time granularity considered, the commitment model uses methods similar to those used in the day ahead market.

The MRUC model developed for New York State considers each NYISO control zones and each import connection as a region. The regions are connected by arcs, which represent the aggregate transmission limits between each zone or import connection. The formulation is similar to [24–26]. The resulting mixed-integer linear program (MILP) was solved with CPLEX V12.5 [27] with the MATLAB [28] extension. The following sections will describe the mathematical definitions, data sources, and limiting assumptions for each of the model's components.

3.1.1. Transmission lines

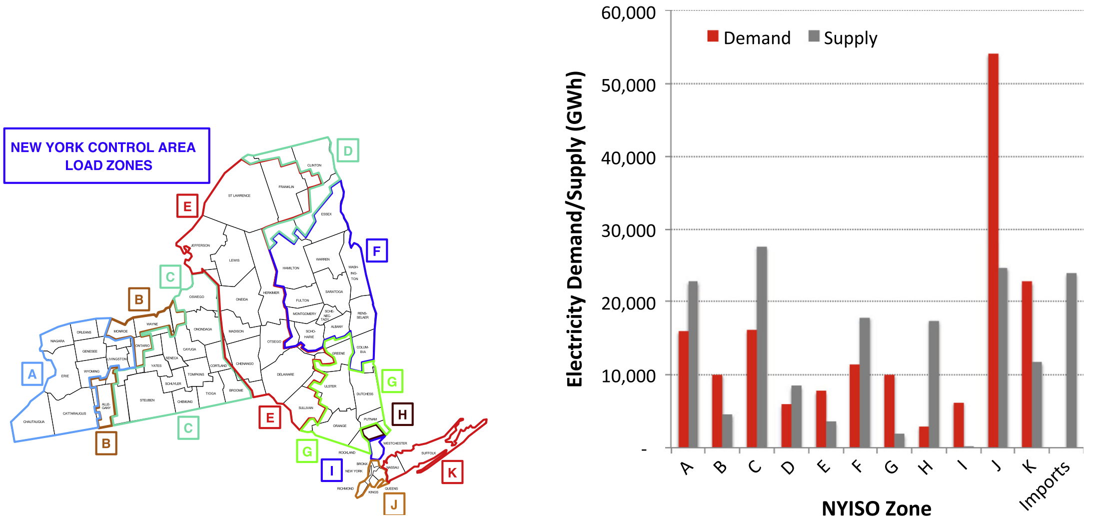
The network connections between each zone include the aggregate transmission limits of all 345 kV lines between each region. The aggregate lines are termed arcs and there is an upper limit on each arc. In addition to limits between regions, there are also limits across various interfaces. Mathematically

$$f_{a,t} \leqslant F_a^+ \quad \forall a \in \mathcal{A},\ t \in \mathcal{T} \tag{1}$$

$$\sum_{a \in A^s} f_{a,t} \leqslant F^{A^s} \quad \forall A^s \in \mathcal{F} \tag{2}$$

where $f_{a,t}$ is the electricity flow on arc a at time t, F_a is the maximum flow on arc, a, $\mathcal{A}$ is the set of all arcs, F^{A^s} is the maximum aggregate power flow of arcs in the set A^s, $\mathcal{T}$ is the simulation time period and $\mathcal{F}$ is the set of arcs with aggregate flow constraints. Eq. (1) describes the capacity limits on each individual arc and Eq. (2) describes aggregate limits for selected sets of arcs.

The network topology as well as the flow limits on arcs between zones and import regions is shown in Fig. 2. The interface limits can be found in Table 1. As illustrated in Fig. 2, the highest limits



(a) New York State Load Control Zones (b) Annual Electricity Demand and Generation

Fig. 1. NYISO control zones and corresponding electricity generation and demand (2011).

on the transmission lines are in the direction of flow towards New York City (Zone J) and Long Island (Zone K).

3.1.2. Generator constraints

In the formulation of the unit commitment model, generators are defined by their limiting characteristics that vary by the underlying power plant technology and environmental factors. However by exploring the data provided by the RGGI, these parameters can be defined uniquely for the majority of generators in New York State. All generators are defined by the following parameters: maximum output, minimum output, part-load heat rate, minimum up time, minimum down time, positive and negative ramp rates, and spinning reserve capability. The following paragraphs describe how these parameters were defined for each generator type. Additional the final parameter values can be found in the Supplementary Materials.

Fossil fuel power plants over 25 MW. Fossil fuel power plants consist of steam turbines (ST), combined cycle gas turbines (CCGT), simple cycle gas turbines (GT), internal combustion engines (ICE), and stationary jet engines (JE) fueled by natural gas, coal and fuel oil.

All fossil fuel power plants above 25 MW are required to report their hourly fuel consumption and power output as part the Regional Greenhouse Gas Initiative (RGGI) [29]. The generators covered in this data set comprise 67% of the New York State's power plant capacity. Hourly data from 2011 was used to defined the minimum output, part-load heat rate, and ramp rates for each generator in the set. An example of the data sets used and the derived parameters are shown in Fig. 3.

Fig. 3(a) depicts the fuel consumption as a function of gross power output for a 387 MW natural gas fueled steam turbine. Also shown in the figure are the derived values for the maximum output, minimum output, linear slope of the heat rate, and intercept value of the heat rate.

The fuel consumption of each generator was defined as a linear function of the gross load as defined in the equation below

$$h_{g,t} = P_g^1 p_{g,t} + P_g^0 \mu_{g,t} \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{3}$$

where $h_{g,t}$ is the fuel input in MWh of thermal energy (quantity of fuel multiplied by the fuel content) for generator g at time t, P_g^1 is the thermal energy used per unit electricity production, and P_g^0 is the thermal energy used during start up.

For the fossil fuel generators with data reported in the RGGI, the coefficients P_g^1 and P_g^0 were found via an ordinary least squares regression using the hourly data heat input and gross load data from [29]. In the literature the generator part-load efficiency is often assumed to be a quadratic function of the load, however from the analysis it was found that a linear approximation provided similar descriptive capabilities with R^2 values for all generators above 0.9. Table 2 reports the average maximum electrical efficiencies and aggregate capacity for each power plant type.

The maximum output for each fossil fuel generator, $P_{g,t}^H$, was defined as the rated capacity listed for each generator listed in the 2012 NYISO annual report [23]. The minimum output of each fossil fuel generator was defined as the lowest 10th percentile of all of the operating points in 2011. Overall the power limits on each generator is defined as

$$P_g^L \mu_{g,t} \leqslant p_{g,t} \leqslant P_{g,t}^H \mu_{g,t} \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{4}$$

where $P_{g,t}^H$ is the maximum power output (MW) of generator g in time t, and $P_{g,t}^L$ is the minimum output of generator g in time t, $p_{g,t}$ is the power produced (MW) by generator g at time t, $\mu_{g,t}$ is the on/off status defined as a binary variable of the generator g in time t, $\mathcal{G}$ is the set of all generators, and T is the number of hours in the year.

The ramp rates define the maximum change a generator can make in a time step. In the MRUC model, two ramp rates are used: the maximum change in power output when increasing the output (positive) and decreasing the output (negative). The positive and negative ramp rates were defined as the maximum change experienced by the generator in a single hour in the respective direction over the annual 2011 data set. For the negative ramp rates, data points were excluded when the next time step was zero to remove the influence of generator shut downs. Fig. 3(b) depicts a histogram of the historical ramps rates for a single generator as well as the evaluated values for the maximum positive and negative ramp rates.

The mathematical constraint is described as

$$p_{g,t} - p_{g,t-1} \leqslant R_g^+ \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{5}$$

$$p_{g,t-1} - p_{g,t} \leqslant R_g^- \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{6}$$

where R_g^+ is the maximum positive ramp rate of generator g, and R_g^- is the maximum negative ramp rate of generator g.

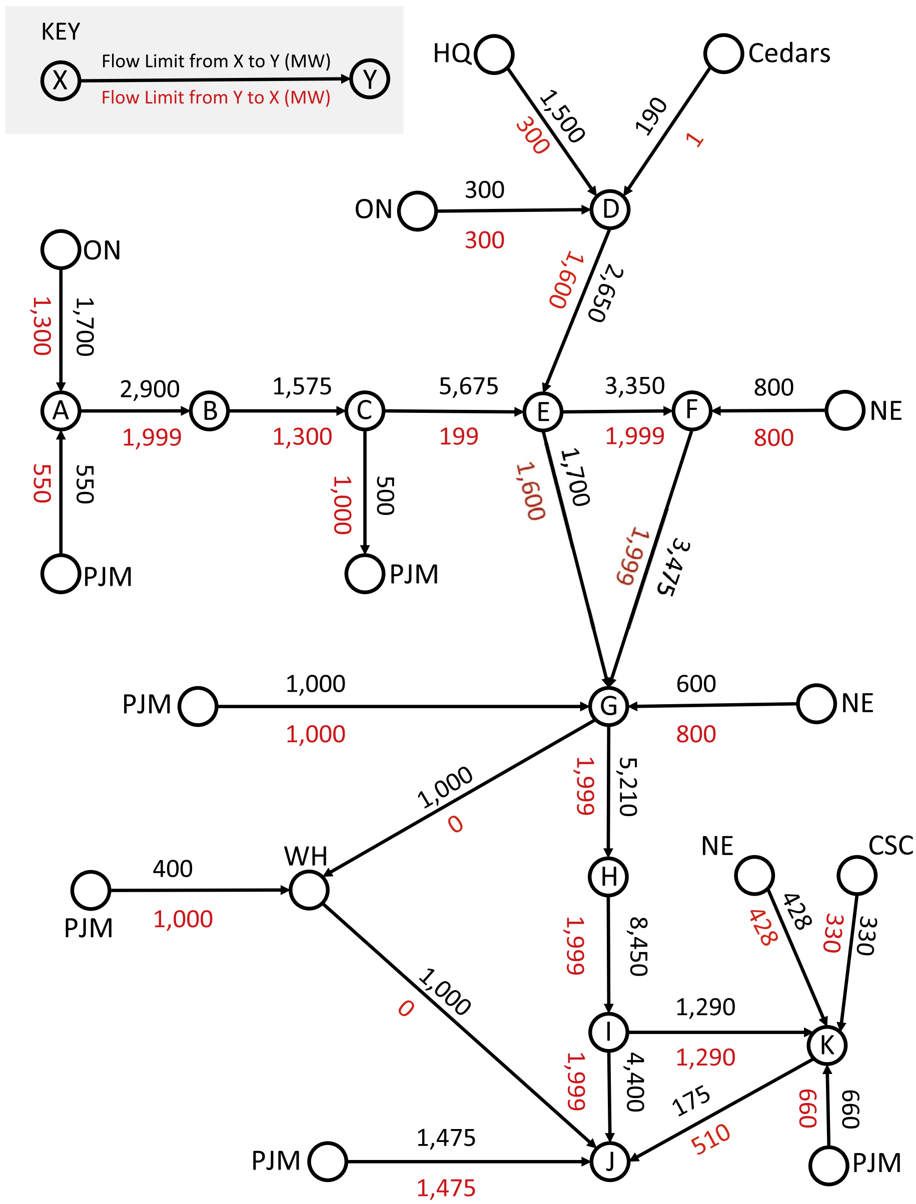


Fig. 2. Transmission network topology with maximum flow limits in (MW) between each zone and import region.

Table 1
Interface flows in MW (Key: $f_{X\to Y}$ = flow on arc from Region X to Region Y).

Constraint	Defining equation
1	$f_{PJM\to G} + f_{WH\to J} + f_{PJM\to J} = 2000$
2	$f_{I\to J} + f_{I\to K} = 5210$
3	$f_{E\to F} + f_{E\to G} = 4900$
4	$f_{F\to E} + f_{G\to E} = 350$
5	$f_{NE\to D} + f_{E\to F} + f_{E\to G} + f_{PJM\to G} + f_{PJM\to J} = 6750$
6	$f_{D\to NE_D} + f_{F\to E} + f_{G\to E} + f_{G\to PJM} + f_{J\to PJM} = 1999$
7	$f_{E\to G} + f_{F\to G} + f_{NE\to G} = 5150$
8	$f_{I\to K} - f_{K\to J} = 1465$
9	$f_{K\to I} - f_{J\to K} = 344$
10	$f_{K\to J} - f_{I\to K} - f_{PJM\to K} = 199$
11	$f_{J\to K} - f_{K\to I} - f_{K\to PJM} = 9999$
12	$f_{NE\to D} + f_{NE\to F} + f_{NE\to G} + f_{NE\to K} = 1400$
13	$f_{D\to NE} + f_{F\to NE} + f_{G\to NE} + f_{K\to NE} = 1400$

The spinning reserve capability of a generator defines how quickly its output can increase to respond to an outage. In the event of a forced outage of generators expected to be operating, a sudden drop in electricity from intermittent resources or an unexpected surge in demand, there must be enough generators available to quickly compensate for the loss of power.

For the current model, only the 10-min operating reserve is considered. Any generator currently operating is allowed to provide spinning reserve with the exception of imports and wind turbines. The capability of each generator to provide spinning reserve was defined as 1/6th of the positive ramp rate to reflect the 10-min time frame. The spinning reserve capability is also limited by the current output of the generator. For example if a generator is currently operating at maximum capacity then this generator cannot provide spinning reserve. Therefore the difference between the current operating point and the maximum capacity limits the spinning reserve capacity. The constraints on spinning reserve operation are defined in the following equations

$$s_{g,t} \leqslant R_g^+/_6 \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{7}$$

$$s_{g,t} \leqslant \mu_{g,t} P_g^+ - p_{g,t} \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{8}$$

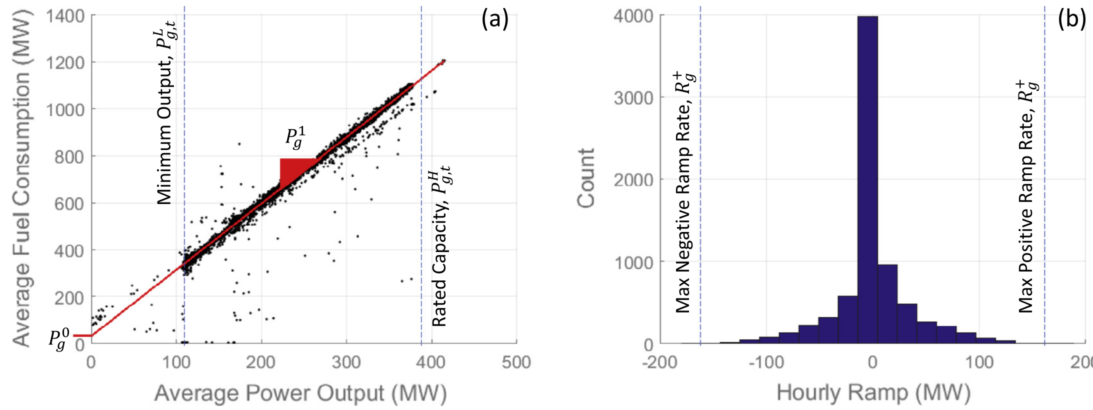


Fig. 3. Description of generator data and derivations of performance parameters for fossil fuel generators. Generator rated capacity: 387 MW, steam turbine fueled by natural gas. (a) Plot of the hourly fuel consumption and power output as reported in the RGGI. Parameters shown for maximum rated capacity, minimum output, and linear heat rate. (b) Histogram of the hourly change in output (excluding changes to 0 MW). Parameters for maximum negative and positive ramp rates shown.

Table 2
Average maximum electrical efficiency and aggregate capacity by power plant type.

Power plant type	Maximum electrical efficiency (%)	Aggregate capacity (GW)
CCGT	45	9.4
ST	34	13.5
GT	31	2.9
JE	25	0.7

where $s_{g,t}$ is the amount of spinning reserve provided by generator g in time t.

The last parameters to be defined are the minimum up and down time. These parameters reflect generator start up times as well as considerations for economic factors not explicitly considered in the model. These constraints prevent the unrealistic behavior of a large power plant from operating for a single hour, shutting off for an hour, and then coming online again. In practice, it would take such a power plant a certain amount of time to come online and the operators of the power plant would bid into the market to ensure operation for a continuous time period. However for the MRUC model formulation, the minimum up and down times for fossil fuel generators, shown in Table 3, was determined based on power plant type and size.

The minimum up and down time were defined by the following equations

$$z_{g,t} \geqslant \mu_{g,t} - \mu_{g,t-1} \quad \forall g \in \mathcal{G},\ t \in \mathcal{T} \tag{9}$$

$$\sum_{q=t-UT_g+1}^{t} z_{g,q} \leqslant \mu_{g,q} \quad \forall g \in \mathcal{G},\ t \geqslant UT_g \tag{10}$$

$$\sum_{q=t+1}^{t+DT_g} z_{g,q} \leqslant 1 - \mu_{g,t} \quad \forall g \in \mathcal{G},\ t \leqslant |T| - DT_g \tag{11}$$

Table 3
Minimum up and down times for fossil fuel generators.

Power plant type	Minimum up time	Minimum down time
CCGT: <100 MW	1	1
CCGT: ⩾100 & <1000 MW	2	2
CCGT: >1000 MW	3	3
ST: <100 MW	1	1
ST: ⩾100 & <500 MW	2	2
ST: >500 MW	5	5
GT, JE, ICE	1	1

where $z_{g,t}$ indicates if the generator g was brought online in time t, UT_g is the minimum up time for generator g and DT_g is the minimum down time for generator g.

For the fossil fuel power plants, the derived parameters are assumed to be constant throughout the year. This means that changes to efficiency or capacity as a function of environmental variables are not captured.

Fossil fuel power plants under 25 MW. Fossil fuel power plants less than 25 MW (i.e. those not in the RGGI dataset) were given default values. These generators, consisting of GT, ICE and ST power plants, represent less than 4% of the system capacity with an average size of 15 MW. Typically these systems are able to provide their full output in less than an hour and are defined by low efficiency. From these assumptions, the minimum output for these generators was set to 0 MW; the positive and negative ramp rates were equal to the maximum output; and the electrical efficiency was a constant 25% (ie. $P^1_g = 4$, $P^0_g = 0$).

Nuclear power plants. There are six nuclear power plant sites in operation in New York State that comprise 13% of its power plant capacity. Nuclear power plants are unique in their operating strategy. Nuclear power plants are capital intensive to build and recoup costs by bidding in a market to run continuously. In practice these power plants annually have capacity factors greater than 90%. The time that the power plants are not operating is typically due to scheduled maintenance.

There is limited data publicly available on the current operation of these nuclear power plants. Therefore several assumptions are made to define the parameters governing their operation. Firstly to mimic the decisions of power plant operators, nuclear power plants are modeled at zero cost (ie. $P^1_g = 0$, $P^0_g = 0$) to ensure operation. However, the monthly output of each generator was modified to reflect the average monthly capacity factor over the past 10 years [30] to reflect typical maintenance schedules. The monthly capacity factors for each nuclear power plant can be found in the Supplementary Materials. As with fossil fuel generators, the maximum capacity was the rated capacity listed in [23]. The minimum output was set to 10% of the maximum capacity and the ramp rates were equal to the maximum capacity of the system.

Nuclear power plants can take a long time to start up depending on how recently it was shut down which can exceed 24 h [31]. As the regional commitment model was solved on the 24-h time scale, the minimum up and down times of these generators was set to 24 h.

Hydroelectric power plants. Hydroelectric power plants, representing 13% of the system capacity, are very flexible resources able to increase or decrease their output to respond to changing demands. They are, however, limited by the availability of the water resource. As limited information was available on the resource availability, the hydroelectric power plants were modeled as energy reservoirs. This means that they can produce as much power at any given point in time, up to the rated capacity, but the amount of energy produced over a given time period is limited; we imposed a daily energy limit. The constraint for generators defined as reservoirs is as follows:

$$\sum_{t=24*(d-1)+1}^{24*d} p_{g,t} \leqslant RE_{g,d} \quad \forall g \in G^{RE},\ d \in Y \tag{12}$$

where RE_{g,st_i} is the maximum amount of energy that can be produced by generator g in the time period st_i, $\bar{h}$ is the number of hours in st_i, G^{RE} is the set of generators defined by a reservoir constraint, and Y is the number of consecutive time periods st_i in the year.

There were 350 hydroelectric power plants in operation in 2011. To reduce the model complexity, these generators were aggregated and modeled as a single generator in each zone containing hydroelectric generators. This resulted in 7 aggregate hydroelectric modeled generators. The maximum output of the aggregate generators is the sum of the individual rated capacities of the generators within the zone.

As hydroelectric plants are flexible in their operation, the aggregate power plants were allowed to ramp to their full capacity and the minimum up and down times were 1 h. As with nuclear power plants, hydroelectric plants typically bid in the market at low prices, therefore the plants were modeled with zero cost (ie. $P_g^1 = 0, P_g^0 = 0$). The aggregate daily energy reservoir values, RE_{g,st_i}, were derived from the reported monthly output of the hydroelectric power plants within the zone by the EIA [30] and full list of the daily constraints can be found in the Supplementary Materials. The spinning reserve capability was defined the same as fossil fuel generators.

Wind turbines. Wind turbines comprise of 3% the system capacity. The wind output of the wind sites was modeled using wind resource estimates made by NREL and estimated power curves for the wind turbines installed at the wind sites. The following paragraphs describe the methodology used to estimate the power output of the 17 existing wind sites.

For each existing site data on location, number of wind turbines at each site, wind turbine manufacturer, rated capacity power curves, hub height, and swept area were collected and collated from [32].

The power curve is a function that describes the power output of a wind turbine given a specific wind speed. The curve is piecewise consisting of 4 regions defined by the following equation:

$$P(w) = \begin{cases} 0, & \text{if } w \leqslant w^{ci} & (13) \\ p(w), & \text{if } w > w^{ci} \ \&\ w \leqslant w^{r} & (14) \\ P^{+}, & \text{if } w > w^{r} \ \&\ w < w^{co} & (15) \\ 0, & \text{if } w \geqslant w^{co} & (16) \end{cases}$$

where $P(w)$ is the power output of a wind turbine at wind speed w, w^{ci} is the cut-in wind speed, w^r is the rated capacity wind speed, $p(w)$ is the function defining the nonlinear relation between the power output and the wind speed, P^+ is the wind turbine rated capacity and w^{co} is the cut-out wind speed.

Key to defining power output of a wind turbine is defining the curve $p(w)$. Carrillo et al. [33] tested various approximations for developing continuous power curves and found that the cubic and exponential approximations provide the best fit in terms of energy density. Therefore for the current analysis, the cubic power curve approximation was deemed sufficient. The cubic approximation defines the power output of a wind turbine as

$$p(w) = \frac{1}{2}\rho(SA)C^p w^3 \tag{17}$$

where ρ is the density of air, SA is wind turbine swept area, C^p is a constant equivalent to the power coefficient, and w is the wind speed.

For each wind turbine type, five data points from the manufacturers power curves, the reported swept area, and a constant air density of 1.225 kg/m^3 were used to estimate the value of C^p. This allowed for a continuous estimate of the power output. The parameters defining the wind turbine output, i.e. rate capacity, estimated power coefficients, the hub heights, blade diameters, and defining wind speeds, can be found in the Supplementary Materials.

The wind resource in each location was estimated using NREL's Wind Integration Tool Kit [34]. The kit provides estimates the wind resource at various sites across the Untied States including New York from 2007 to 2013. The selected sites are those sites that have the potential to produce the most annual energy, considering typical wind turbine power curves and buildable land area. More details on the methodology of the NREL toolkit can be found in [34].

A single wind resource time series (from the year 2011) was used for each existing wind turbine site (17 sites). The annual wind resource chosen for each site was the NREL toolkit site with the closest latitude and longitude to that of the existing wind site. The NREL model estimates winds at 100-meter hub heights however the hub heights of the existing turbines were mostly at 80 or 60 m. A general hub height adjustment equation

$$w^{ah} = w^{mh}\left(\frac{h^{ah}}{h^{mh}}\right)^{1/7} \tag{18}$$

was used to adjust the wind speeds for the correct hub height. In the above equation, w^{ah} is the wind speed at the desired height, ah, h^{ah} is the wind turbine hub height, h^{mh} is the height of the measured (in this case modeled) wind speed, and w^{mh} is the wind speed at the measured (in this case model) height. These wind speeds in conjunction with the site-specific wind power curves were used to estimate the electricity produce from each wind site. The wind speeds estimated in the NREL toolkit are estimated at 5-min intervals therefore the power estimates were also at 5-min intervals. The 5-min data were averaged to develop average hour power outputs. The resulting aggregate power output of the 17 wind turbine sites is shown in Fig. 4.

The hourly power output estimates for the wind turbines were used in the regional unit commitment model to set the maximum power output of the wind turbines for each hour, $P^+_{g,t}$. The other parameters were set as follows: the ramp rates for the wind turbines were set to $P^+_{g,t}$ for each hour; The heat rate was equal to 0 (ie. $P_g^1 = 0$, $P_g^0 = 0$); the minimum up and down times were set to 1; and no spinning reserve variable was modeled for wind turbine power plants.

Explicitly modeling the wind turbine power plants as generators, as opposed to assuming all wind is utilized, allows the model to curtail the wind generation if deemed advantageous to the system i.e. reduce the overall cost of providing electricity.

Solid waste and solar power plants. There is a small amount of electricity generated from solid waste facilities and solar power plants throughout the state. These power plants were not explicitly modeled and their output is assumed constant, equal to the historical monthly electricity generation.

Imports from neighboring regions. The imports from neighboring regions were modeled as generators with fluctuating price to allow the model to determine the optimal import levels. The import power plants were modeled as energy reservoirs limited to the monthly net imports from each region as reported by the NYISO [23]. The maximum capacity of the generators was the

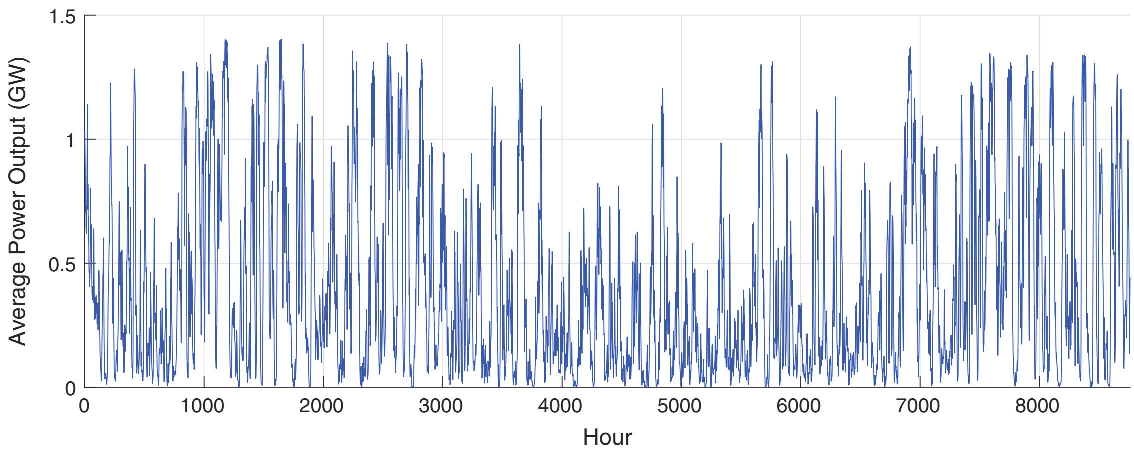


Fig. 4. Aggregate hourly power output of wind turbine sites. Total capacity: 1.4 GW.

transmission limit of the specific import region. The minimum output was set to zero, the ramp rates were set equal to the maximum capacity and the minimum up down times were 1 h. This leads to an extremely flexible resource however the hourly prices of imports specifically shapes when imports are utilized.

Imports from neighboring regions are used to balance the system only when the price is advantageous. The price for imports, or electricity from any region, can be defined by the local based marginal price. The LBMP is the highest price paid for electricity for a particular location, in this case those of the import regions. There are daily patterns, seasonal patterns, and spikes in the price that most likely reflect the constraints of the external systems and effects of supply and demand. As the current model does not consist of a module reflecting the economics, the prices themselves were used as basis to signal when imports should be allowed to provide electricity.

However the LBMP for these regions are the *price* of electricity whereas the other generator types are modeled to reflect the *cost* of providing electricity. Therefore an adjustment was made to ensure the imports would be competitive.

The LBMP's for each region were normalized with the logistic sigmoid function and rescaled between the minimum and median LBMP prices as described in the following equations

$$I_{i,t} = \frac{e^{\hat{l}_{i,t}}}{1+e^{\hat{l}_{i,t}}} * (\text{med}(l_i) - \min(l_i)) + \min(l_i) \quad \forall i \in \mathcal{Z},\ t \in \mathcal{T} \tag{19}$$

where $I_{i,t}$ is the normalized and scaled hourly cost of imports from region i in hour t, l_i is the vector the hourly LBMP for import region i in 2011, $\text{med}(l_i)$ is the median hourly LBMP price for import region i in 2011, $\min(l_i)$ is the minimum hourly LBMP for import region i in 2011 and $\hat{l}_{i,t}$ is

$$\hat{l}_{i,t} = \frac{l_{i,t} - \bar{l}_i}{std(l_i)} \tag{20}$$

where $std(l_i)$ is the standard deviation of the hourly LBMP for import region i in 2011 and $\bar{l}_i$ is the mean hourly LBMP for import region i in 2011.

This normalization and rescaling retains the fluctuation in the cost based in the availably of generators in the other regions.

3.1.3. System wide constraints

There are two system wide constraints. The first constraint dictates that for each zone, the total generator output, imported and exported electricity must equal the demand in each hour, ensuring supply meets demand at all times. This is described mathematically with the following equation

$$\sum_{g=1}^{G_z} p_{g,t} - D_{z,t} + \sum_{a=1}^{A_z^+} f_{a,t} - \sum_{a=1}^{A_z^-} f_{a,t} = 0 \quad \forall z \in \mathcal{Z},\ t \in \mathcal{T} \tag{21}$$

where $D_{z,t}$ is the demand in zone z at time t, G_z is the set of generators in zone z, A_z^+ is set of the arcs that follow into zone z, A_z^- is the set of arcs that follow out of zone z, and $\mathcal{Z}$ is the set of modeled zones in New York State. The hourly electricity demand for each zone, $D_{z,t}$, was calculated as the time-weighted average power reported for approximate 5-min intervals by the NYISO. The aggregate hourly demand for New York State is depicted in Fig. 5.

The second system wide constraint defines the requirements for spinning reserve. Spinning reserve, also termed operating reserve, is a reliability requirement of the NYISO to protect against unplanned outages. In the event of an outage, there must be generators available to quickly compensate for the loss of power. The spinning reserve requirement considered in the model is the 10-min operating reserve. The NYISO defines two aggregate spinning reserve requirements: one for Zones F-K of 330 MW and one for all zones (A-K) of 655 MW. This requirement is modeled as follows:

$$\sum_{g=1}^{G^{ak}} s_{g,t} \geqslant S^{ak} \quad \forall t \in \mathcal{T} \tag{22}$$

$$\sum_{g=1}^{G^{fk}} s_{g,t} \geqslant S^{fk} \quad \forall t \in \mathcal{T} \tag{23}$$

where S^{ak} is the minimum spinning reserve to be provided by generators in zones A through K, G^{ak} is the set of generators capable of providing spinning reserve in zones A through K, S^{fk} is the minimum spinning reserve to be provided by generators in zones F through K, and G^{fk} is the set of generators capable of providing spinning reserve in zones A through K.

3.1.4. Objective function

The objective function of the multi-region unit commitment model is to minimize the cost of operations, which includes the cost of fuel for each generator for both operation, and start up, as well as the cost for each generator to provide the spinning reserve requirement. Formally,

$$\min \sum_{g=1}^{\mathcal{G}} \sum_{t=1}^{\mathcal{T}} (f_{g,t} h_{g,t} + c_g z_{g,t} + r_g s_{g,t}) \tag{24}$$

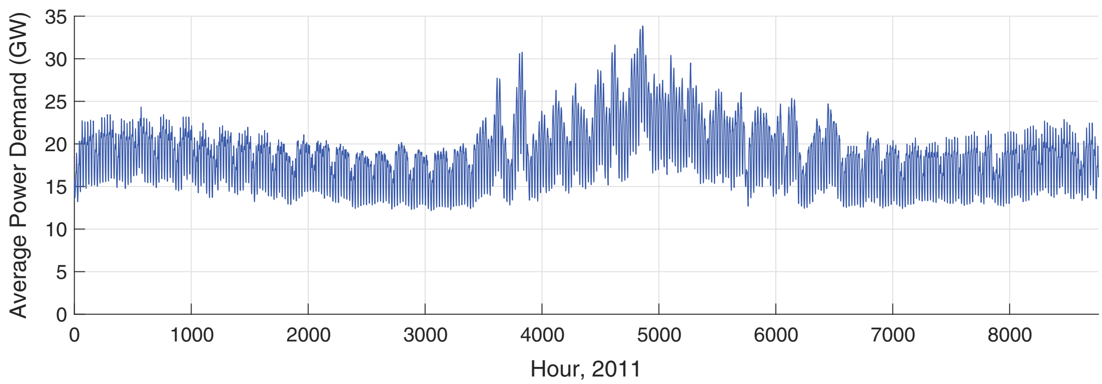


Fig. 5. Hourly average power demand for New York State, 2011.

where $f_{g,t}$ is the fuel cost for generator g in time t, $h_{g,t}$ is the fuel consumption of generator g in time t as described in Eq. (4), c_g is the cost of fuel used during the start-up period, and r_g is the spinning reserve cost of generator g.

The cost of each type of fossil fuel was the 2011 average annual price for the power sector for the middle Atlantic region as reported by the EIA [35] and shown in Table 4. Nuclear power plants, hydroelectric power plants, and wind turbines were modeled at zero price.

The start-up costs were meant to reflect the fuel consumed during the warm up period to produce power at minimum capacity. Given the minimum down time is used to reflect the time required for a generator to come on-line, the start-up fuel costs were defined as follows

$$s_g = \frac{1}{2} DT_g f_{g,t}(P_g^1 P_g^L + P_g^0) \tag{25}$$

Eq. (25) assumes a linear progression of the fuel consumption to the minimum output of the generator.

The spinning reserve cost was defined as the lost revenue from not selling energy in the market. In a simplified example of NYISO market operations, all generators report the price at which they will provide a specified amount of electricity. After all generators have submitted their bids, the NYISO sums the offered capacity, least cost first, to meet demand. The last generator selected to satisfy the demand sets the clearing price. The clearing price is then paid to all selected generators.

For the current model, the revenue an individual generator would lose by providing spinning reserve would be the difference between the clearing price and their bid price. In the model, the bid price is fuel cost for that generator at maximum capacity and the clearing price is the cost of providing generation by a simple cycle gas turbine, therefore defining the spinning reserve price. Mathematically

$$r_g = \max\left[CP - f_{g,t}(P_g^1 P_g^H + P_g^0), 0\right] \tag{26}$$

where CP is the clearing price equal to \$67/MWh, i.e. the price of a gas turbine of 25% electrical efficiency providing electricity. With this assumption, there is no additional cost to providing spinning reserve with fuel oil based generators. The only cost would be the cost of fuel required to maintain the minimum output of the generator.

Table 4
2011 average fuel price [35].

Fuel type	Fuel price (2011 \$/MWh)
Distillate fuel oil	63.7
Heavy fuel oil	40.4
Kerosene	63.7
LPG	58.8
Coal	12.5
Natural gas	16.8

3.2. Methodology for estimating GHG emissions factors

Three greenhouse gases are created from the combustion of fuel to produce electricity: carbon dioxide CO_2, methane CH_4, and nitrous oxide N_2O. Carbon dioxide is the dominant species produced during combustion and can be accurately accounted for based on the chemical combustion formulation. The other species depend greatly on the unit utilized for combustion. The fuel analysis approach was utilized to estimate the GHG emissions produced from electricity production. This method assigns a carbon content to the fuel combusted to estimate CO_2 emissions. This approach is also utilized for the other species given typical production based on the fuel and unit type.

The greenhouse gases emitted from fuel combusted in power plants are estimated using typical emission factors from stationary units as reported by the US EPA in the document Compilation of Air Pollutant Emissions Factors [36]. Carbon dioxide equivalents utilized to represent the aggregate GHG emissions and were calculated utilizing the global warming potential equivalents provided by the IPCC [37]. The carbon dioxide equivalents used by relevant fuel and power plant type are shown in Table 5.

Two aggregate metrics of GHG emissions produced from electricity are considered in this work: average GHG emissions factor for New York State and marginal GHG emissions factors for New York City.

The average GHG emissions factor is defined by the following equations

$$e_{avg} = \frac{E}{P} \tag{27}$$

where

$$E = \sum_{g=1}^{G^{nys}} \sum_{t=1}^{\mathcal{T}} e_g * h_{g,t} \tag{28}$$

and

$$P = \sum_{g=1}^{G^{nys}} \sum_{t=1}^{\mathcal{T}} \overline{p_{g,t}} \tag{29}$$

In the equations above, E are the total annual GHG emissions produced, P is the total annual energy demand, e_g is the GHG emissions factor for generator g, $h_{g,t}$ is the fuel consumed by generator,g, at time t, $\overline{p_{g,t}}$ is the energy produced in by generator g, in time t, and G^{nys} is the set of generators in New York State. This definition

Table 5
Carbon dioxide equivalent factors by fuel and power plant type [36].

Fuel type	Power plant type	Carbon dioxide equivalent ($kg\ CO_2e/MWh_{fuel\ input}$)
Natural gas	GT, CCGT, JE	172
	ICE	219
	ST	183
Fuel oil # 2	GT	243
	ICE	259
Kerosene	GT, JE	243
Fuel oil # 6	ST	260
Coal	ST	360

of the average GHG emissions excludes the GHG emissions produced from the imported regions. This allows for a direct comparison with values previously reported in the literature.

The marginal GHG emissions factor is defined as the unit change in GHG emissions over a unit change in demand, i.e. the local derivative or rate of change of annual GHG emissions as a function of demand. However the definition of a unit change in the context of marginal GHG emissions is not clearly defined. For model based approaches in the literature, a unit demand change has been defined as a fixed MW value or a percent change applied to each simulated time step [17,16,12]. In other instances time varying profiles were used to reflect changes in demand due to specific interventions [13].

The aim of the current analysis was to evaluate the change in GHG emissions for considering both increases and decreases in demand to reflect the implementation of energy efficiency and distributed generation measures. Therefore we estimated annual GHG emissions for incremental 1% changes in the hourly demand of up to ±10% from the respectively baseline demand scenario.

As the model is not defined as a continuous function, the local slopes are estimated from the least-squares line through the simulated points. The marginal GHG emissions factor, e_{mar}, is the value that

$$\min\left[\sum_{\delta=-10}^{10}\left(E_\delta-(e_{mar}*P_\delta+\beta)\right)^2\right] \tag{30}$$

where P_δ is the total annual energy considering a change in demand of $(1+0.01*\delta)$, E_δ is the total annual GHG emissions resulting in a change in demand of $(1+0.01*\delta)$, β is the fixed GHG emissions of the local estimation.

It is important to note that the GHG emissions from imported electricity are not explicitly modeled in this work. However due to the definition of the GHG emissions factors and limitations on the amount of energy imported from neighboring regions, the GHG emissions from imported electricity do not affect the resulting average and marginal GHG emissions factors. Specifically the average GHG emissions factors are calculated excluding electricity from neighboring regions and imports do not contribute to the marginal GHG emissions factors as their annual values are held constant through all scenarios.

3.3. Projecting changes to the grid in 2025

To estimate the GHG emissions factors for 2025, assumptions were made about the change in demand, fuel prices, and composition of power plants to meet reliability requirements. Specifically the 2025 hourly power demands were projected from 2011 demands, the cost of fuel and electricity from import regions was adjusted for projected future prices, and scenarios were developed for changes to the generation mix and policies influencing coal power plants. The details of these assumptions are described in the following sections.

3.3.1. Demand growth

The NYISO use econometric models to estimate and report annual growth rates that are used project future energy consumption and peak power demands for New York State. Specifically the operator provides annual growth rates for total energy consumption, summer peak demand, and winter peak demand for the next 10 years. These growth rates [23] were used to estimate the 2025 demand from the historical 2011 hourly demand.

The summer peak rates were assumed to apply over the months June, July, and August and the winter peak growth rates were assumed to apply in November, December, January, and February. The growth rates for the remaining seasons (Swing) were taken to be the value required to satisfy the annual growth rate. The final growth rates utilized were: Summer 0.85%, Winter 0.43% and Swing 0.51%. The projected future demand for each zone was determined utilizing the following equation

$$d_{s,h,yf}=d_{s,h,yc}*(1+gr_s)^{yf-yc}\quad\forall s,h \tag{31}$$

where $d_{s,h,yf}$ is the hourly demand in season, s, in the future year, yf, $d_{s,h,yc}$ is the hourly demand in season, s, and current year yc, and gr_s is the annual demand growth rate in season s.

The aggregate statewide hourly demand under the 2011 and 2025 scenario for January 15th, April 15th, and July 15th are shown in Fig. 6. The maximum increase in hourly power demand for these days are 1.3, 1.4 and 3.3 GW for the winter, spring and summer periods respectively.

3.3.2. Change in fuel prices

The fuel prices of natural gas, coal, and fuel oil were modified using annual growth rates reported by the EIA in the Annual Energy Outlook [35]. As the EIA reports fuel costs for different types of users, the annual growth rates specific to the electric power industry were used. To obtain future projections of the price of imports annual growth rates for electricity prices in the respective regions were used.

For Canadian regions Ontario and Hydro Quebec, projections for prices of electricity exports are estimated to the year 2035 in [38]. The price estimates were converted to equivalent annual growth rates. For the domestic regions PJM and NE, annual growth rates were determined from the projected growth in electricity prices for the Middle Atlantic and New England regions respectively. The growth rates are shown in Table 6.

3.3.3. System generation capacity

The set of power plants available to provide power are modified under two premises. Initially, power plants are removed or added to the system based on the planned power plant additions or retirements until 2019 as indicated by the NYISO. Beyond 2019, more power plants must be added to meet the minimum installed capacity requirement (ICR) ensuring sufficient and reliable supply. It is through the latter that various scenarios are explored.

Scheduled additions and retirements until 2019. The planned power plant additions listed by the NYISO consist of approximately 3 GW of CCGT and 2.2 GW of wind turbine capacity. The retirements were a mixture of coal-fired power plants, gas turbines and steam turbines with an aggregate capacity of approximately 3.3 GW. Table 7 depicts the capacity changes by generator and fuel type.

Performance characteristics of the new CCGT and GT power plants were derived from the most efficient New York State power plants with similar configurations. Given the new wind sites have not yet been built, simulated power outputs from the proposed sites from the NREL wind data tool kit were used to define the maximum hourly power output. The simulated power plants use the best rated technology at 100 m hub heights to estimate the

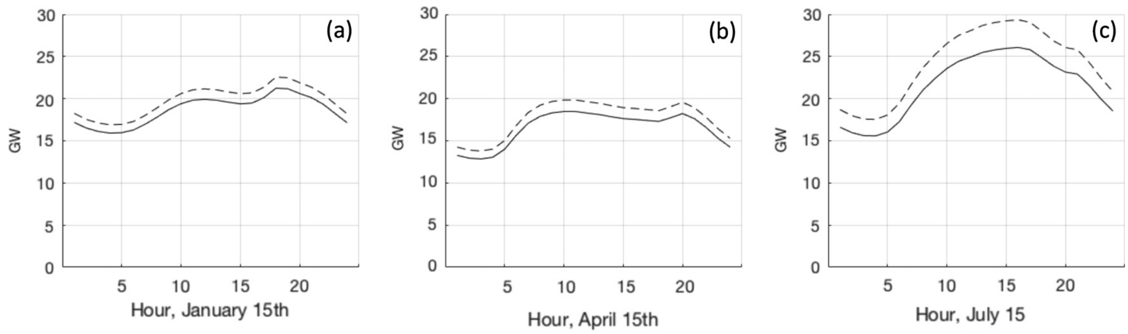


Fig. 6. Hourly New York State Demand from 2011 (Solid) and projected for 2025 (Dotted). (a) January 15, Winter Period (b) April 15th, Swing Period (c) July 15th, Summer Period.

Table 6
Annual fuel and electricity price growth rates.

Fuel type	Annual growth rate
Natural gas	0.032
Coal	0.01
Distillate fuel oil/kerosene	0.006
Heavy fuel oil	−0.005
Import region	
Cedars/Hydro Quebec	−0.001
New England	0.002
Ontario	0.016
PJM	0.016

power output for the generators. Each site contained at most 8, 2 MW turbines depending on the available land. The NREL sites closest to proposed new wind sites were used to define the wind resource and power output, considering data from 2011. However each site has a rated capacity of at most 16 MW. Therefore the hourly estimated power output of each site was scaled to match the listed rated capacity for each planned site.

As the simulated power output uses the best technology, the capacity factors for these turbines increases relative to the 2011 wind sites.

Capacity added beyond 2019. Additional capacity is added to the system to meet the ICR defined by the NYISO as the projected peak demand plus the installed reserve margin (17%). For the analysis we consider the new capacity to possibly be comprised of wind turbines, CCGT, and GT power plants. The first two power plant types are considered as it continues the current trend for power plant additions. The additional GT were considered to determine if there would be a significant change in GHG emissions if the new generation capacity was composed of the fast ramping but less efficient gas turbines. Also it is important to note that only 10% of the rate capacity of wind turbines can contribute to the ICR.

Table 7
Planned power plant additions (positive) and retirements (negative) between 2011 and 2019 [23].

Power plant type	Change in capacity (GW)
ST: Coal	−1.45
Natural gas	
GT	−0.55
ST	−0.72
CCGT	3.03
Fuel oil (all types)	−0.56
Hydro	0
Nuclear	0
Wind turbine	2.23
Imports	0

The installed reserve margin required for the 2025 projected demand is 44.6 GW. After the power plant additions, there is only 39.5 GW that can contribute to meeting the ICR. Therefore there is an additional 5.1 GW of generation capacity that must be added to the system. The composition of this additional capacity is determined by initially defining the wind turbine growth scenario and then adding either CCGT or GT power plants to meet the final ICR. Specifically sets of 200 MW CCGT or 50 MW GT power plants with maximum electrical efficiencies of 50% and 40%, respectively, were add to the system to meet the full requirement.

Two wind growth scenarios were considered:“current growth rate” and “accelerated growth rate”. The current growth rate was derived from the historical wind addition rate from 2006 to 2014. A linear regression yielded a growth rate of 92 MW per year with an R^2 equal to 0.9.

The accelerated growth rate is meant to represent a high penetration of wind turbine technologies. It was defined as 10 times the current growth rate resulting in approximately 7.5 GW of additional wind turbine capacity. This value is similar to that of the reference high penetration wind scenario explored in the Eastern Wind Integration and Transmission Study performed by NREL [39]. With the required capacity defined, it is necessary to determine where the new capacity will be located in New York State.

The simulated data from the NREL toolkit was used to define the maximum power output of the future wind sites as well. While wind resources at specific sites change year-to-year, meteorological models for 2025 were not available; therefore the 2011 wind resource profiles were used. To meet the new capacity indicated by the respective growth rates, the sites in New York State with the highest capacity factors were selected until the desired capacity was met.

The wind scenarios and additional capacity requirements led to four different 2025 scenarios: Current Wind Growth with CCGT make up generation, current wind growth with GT make up generation, accelerated wind growth with CCGT make up generation, and accelerated wind growth with GT make up generation.

3.3.4. Policy changes

The US EPA currently has a highly debated proposed plan to have emissions standards that would require significant retrofitting of coal power plants. This would result in a higher generation costs for these plants to recover capital costs for the retrofits for carbon capture and storage [40].

To explore the affect of additional costs on the operation of coal power plants, \$5/MWh were incrementally added to the price of each coal generator. Given the current model formulation, coal power plants are virtually not operated after a price of \$15/MWh. As some reports [40] indicate additional prices of at least \$35/MWh, for future assessment of GHG emissions an additional scenario of a coal price of $35/MWh was utilized to provide insight to a scenario where there is a cost burden on coal power plants.

3.3.5. Transmission upgrades

The aim of this analysis is to evaluate the impacts of near term changes on the GHG emissions from electricity production. Transmission lines represent a defining characteristics of the electricity system. However according to the NYISO [23], there are no significant planned upgrades to the transmission lines in the coming years. Therefore for the future scenarios, the transmissions constraints remain the same as in the 2011 case.

4. Results and discussion

In the following sections, the validation of the MRUC model, 2011 marginal GHG emissions factors, and GHG emissions factors for 2025 scenarios are discussed.

4.1. Model validation

A comparison of monthly electricity generation by fuel type as estimated by the model and reported by the EIA is shown in Fig. 7. Hydroelectric and solid waste power plants are not depicted as their output is the defined by monthly generation. Annual electricity generation from natural gas, coal, and nuclear power plants, which represent 76% of electricity production, where each estimated within 5%.

Considering the monthly comparison there are a few discrepancies. The model assumes more generation from natural gas fueled generators in the beginning of the year and more from coal fueled generators during the later months. In addition fuel oil generators are not committed in the model due to their high cost.

The model structure is similar to the day ahead market in that generator commitments are made hourly for a single day. To understand the commitments of fuel oil generators, the modeled costs were compared to the electricity prices in the day-ahead market. Indeed there are only a few times of the year when the local based marginal price for New York City is high enough to warrant commitment. This indicates that these generators may typically be dispatched in the real-time market where the ability of these generators to quickly ramp is more valued. As the model is reflective of the day-ahead market, it is reasonable that these generators, producing less than 1% of annual generation, are not dispatched.

In model based approaches, discrepancies in commitment are to be expected. In an analogous study, Gilbraith and Powers [41] modeled nitrogen oxide and particulate matter production from generators in New York State using one of the most prominent commercial electricity generation platforms (GE MAPS) and proprietary databases of generator performance characteristics. Their models also reported increased generation by combined cycle power plants and low usage of fuel oil generators.

The aim of this work, however, is to estimate GHG emissions factors; therefore a monthly comparison between the calculated GHG emissions factors from the modeled generation and reported electricity consumption is shown in Fig. 8.

The annual GHG emissions rate produced by the model is 14% lower than that computed by the EIA. We have not analyzed the causes of month-to-month variation in differences between model-predicted and actual GHG emissions as this requires detailed information about grid operations that are not publicly available; however, we have identified a few possible reasons.

The models objective function is to minimize cost requiring in the most efficient generators using the lowest cost fuels to always be selected. This results in CCGT power plants being selected over ST generators and the average fleet efficiency of CCGTs to be higher. This does not occur in the market due to several reasons including how individual generators place their bids, bilateral contracts and the availability of generators throughout the year.

The over-prediction of CCGT use appears to have the biggest effect in the cold months of January and February. Conversely, the model assumes the efficiency of gas turbines is solely load-dependent; however, gas turbines are less efficient when intake air is higher temperature, which may explain the discrepancy in GHG emissions rate during warmer months despite the accuracy of monthly fuel use for electricity generation at those times. Plant-specific effects may also be exacerbated by the use of gross electricity generation to establish the generator efficiency profiles whereas the electricity exported to the grid will be slightly less.

Lastly, the generator types modeled as reservoirs, i.e. hydroelectric power plants and the imports, leads to a very flexible resource. Fig. 9 depicts the modeled hourly generation by generator and fuel type for winter, summer and summer weeks. Generally the base-load generation is provided by nuclear, coal-fueled, and combined cycle power plants. The load following is provided by the hydroelectric power plants and imported electricity. In the summer periods, load following is also provided by natural gas fueled steam and gas turbines. While it is possible for the aggregate hydroelectric

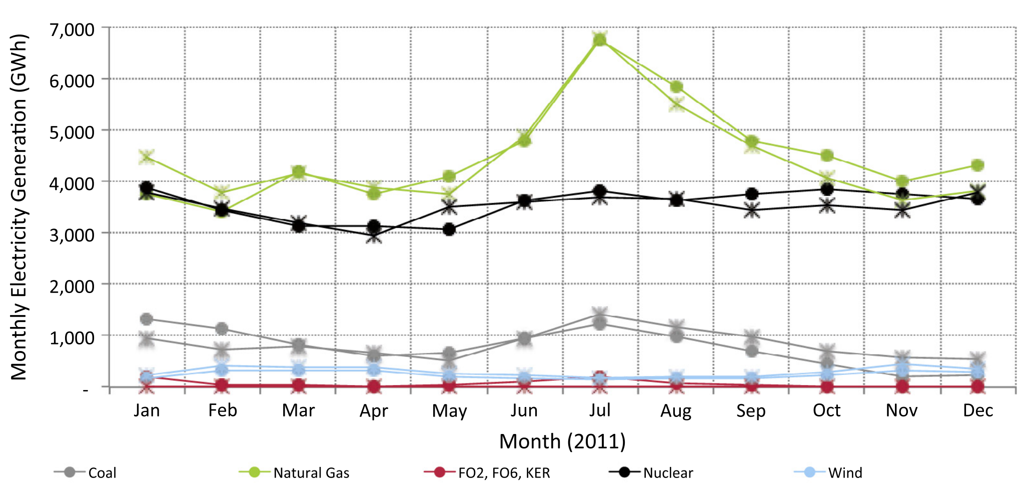
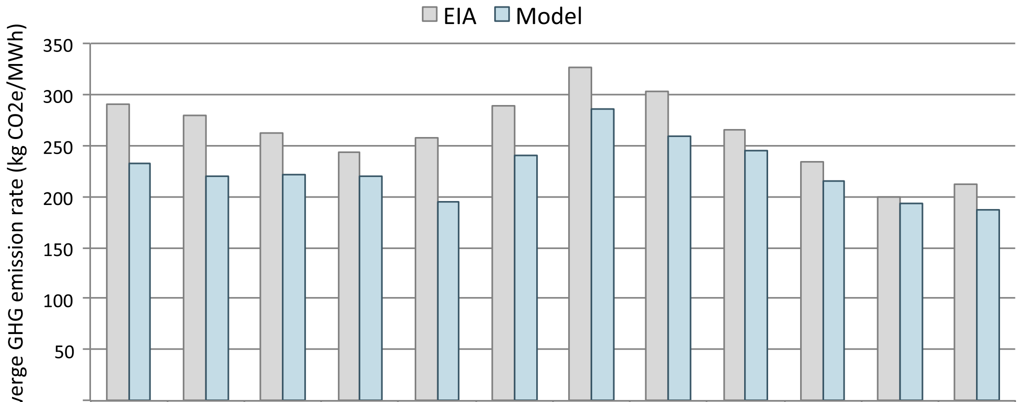


Fig. 7. Comparison of monthly modeled electricity generation and reported electricity generation by fuel type.



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
EIA	290	280	262	243	257	288	327	303	265	234	199	211
Model	232	220	221	219	194	240	286	259	246	215	193	188

Fig. 8. Comparison of modeled GHG emissions and emissions calculated by EIA.

plant to provide a flexible resources, in reality the imports typically do not respond to demand changes as rapidly as they are governed by the generator constraints of the neighboring regions. This could be reducing the amount of generation coming from fast acting but less efficient GT and ICE generation.

In summary the modeled results underestimate the GHG emissions produced from electricity by 14% potentially due to mismatches in natural gas fueled and coal fueled generators, more efficient uses of CCGT power plants, and displacement of fast acting generators by flexible imports.

4.2. Average and marginal emissions factors: 2011

The average and marginal GHG emissions factors were calculated with the methodology described in Section 3.2 and are depicted in Table 8. For the 2011 scenario, average and marginal GHG emissions factors were estimated to be 215 kg CO_2e/MWh and 540 kg CO_2e/MWh, respectively. The average factor is a function the types of generators used to provide power, mainly CCGT, nuclear, and hydro power plants.

The marginal GHG emissions factor results from a change in the generators used to provide demand. In calculating the marginal GHG emissions factor we used a least squares regression, however reviewing the generators that contribute to local scope change provides insights into the types of generators that contribute to marginal GHG emissions factors. A 1% increase in the baseline demand is met 24% by an increase in coal power plants and 62% by an increase in combined cycle power plants. The remainder is simple cycle gas turbines and natural gas based steam turbines.

The average and marginal GHG emissions factors are similar to those reported by other sources for similar time frames. The eGRID reports an average GHG emissions factor for New York State of 288 kg CO_2e/MWh and a non-baseload GHG emissions factor of 514 kg CO_2e/MWh for 2010. Differences in the emissions factors are most likely due to the model's increased efficiency and varied methodologies.

4.3. Grid composition, operation, and GHG emissions factors in 2025 scenarios

Fig. 10 shows the generation capacity composition for the 2025 scenarios in comparison to the current capacity in 2011. In 2011 the aggregate generation capacity is 41 GW. In 2025 projection under the current wind growth scenario and accelerated wind growth scenarios the aggregate capacity is 48 and 52 GW respectively. The difference in capacity is due to wind generation only being able to contribute 10% to the ICR. Other notable changes are the retirement of 1 GW of coal based power plants, and the 3–4 GW change in the CCGT and GT capacity depending on the make up generation scenario.

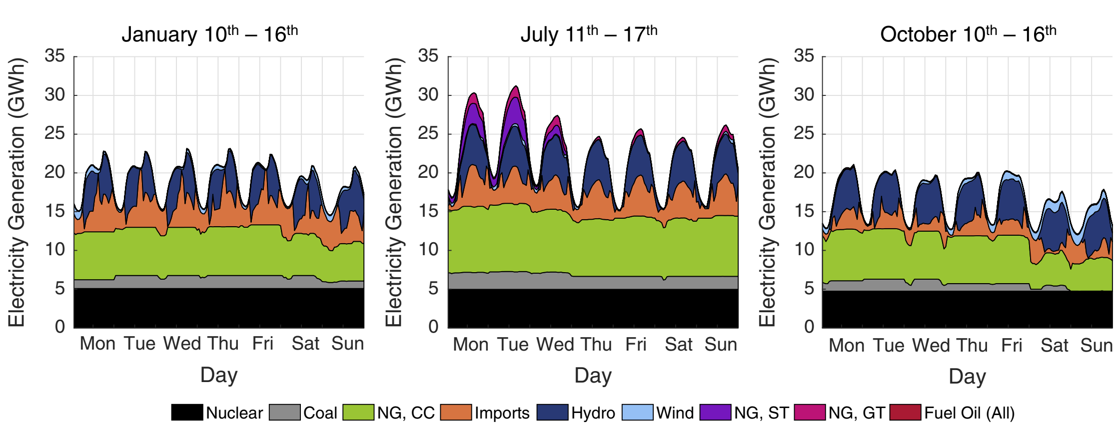


Fig. 9. Hourly modeled generation by generator and fuel type, 2011.

Table 8
Estimated average and marginal GHG emissions factors for New York State and New York City, respectively, 2011.

Average GHG emissions factor (New York State)	Marginal GHG emissions factor (New York City)
215 kg CO_2e/MWh	540 kg CO_2e/MWh

The operational changes are best illustrated by the fleet capacity factors as illustrated in Fig. 11. The most significant change affecting the GHG emissions is the operation of the coal power plants. For coal-based power plants the capacity factor increases to 90% for the 2025 current wind growth scenarios. This difference in operation is due to the difference in the annual growth rates for coal and natural gas resources. With the projected fuel prices, electricity generated by coal power plants becomes the lowest cost fossil fuel based generators making them base-loaded generators for the power system.

Under the accelerated wind growth scenario the capacity factors of coal based power plants reduce to 54%. This is caused by network constraints on the power system. As mentioned previously, the majority of power plants are located in upstate New York while the main demand is in downstate New York. When the major transmission lines for transferring electricity downstate reach their limits, the state is effectively separated into two regions. At that point the upstate power plants, primarily nuclear, hydro, wind turbines and coal power plants, are competing to meet the upstate demand. Of this mix of power plants during times of high wind resource and low demand, the coal power plants are not utilized.

Fig. 12 illustrates the dispatch for a low demand, high wind week in October. Coal power plants are only dispatched 1 day of the week. In this accelerated wind growth scenario, the outputs of the nuclear

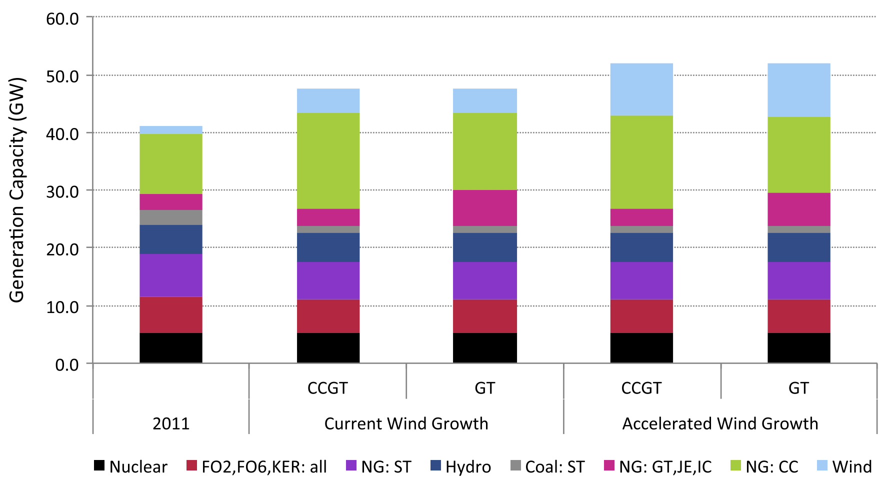


Fig. 10. Total New York State generation capacity under all generation scenarios. Generation capacity is indicated by fuel type and unit type.

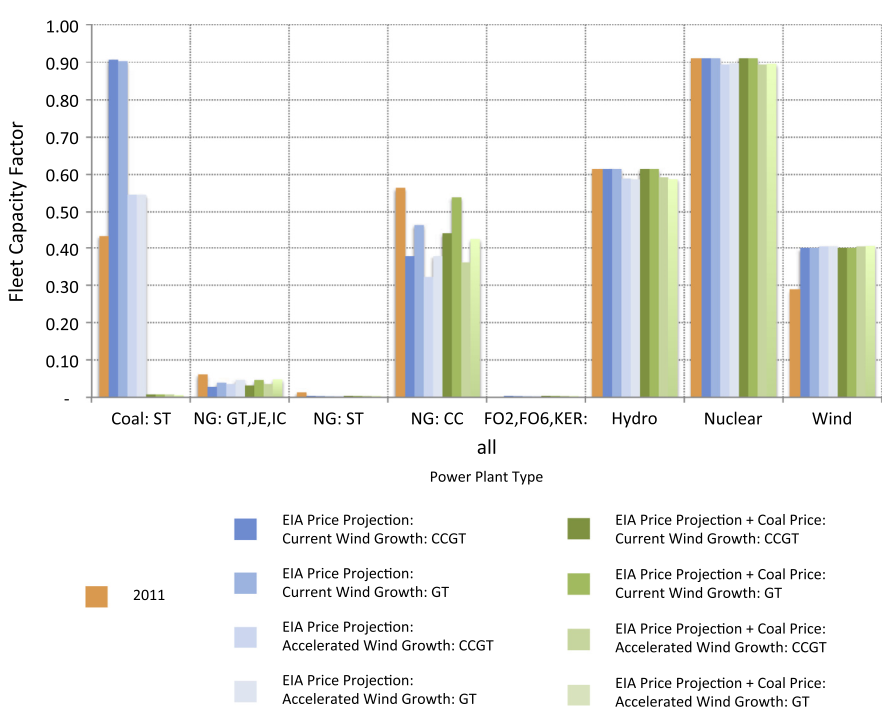


Fig. 11. Annual fleet capacity factors by generation type for wind growth, makeup generation, and coal price scenarios.

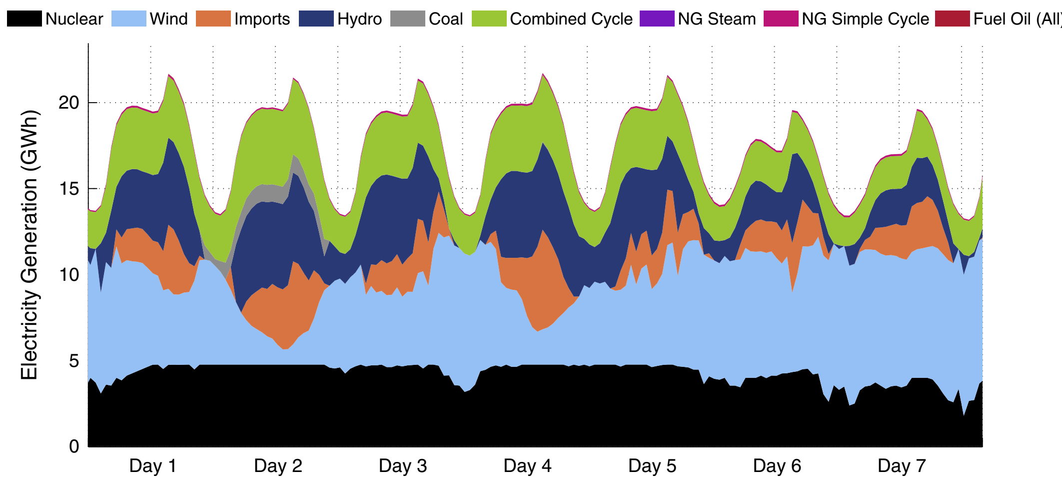


Fig. 12. Modeled electricity generation for a week in October by generation type.

and hydro power plants are reduced as well, leading to the slight decrease in the annual capacity factors for these resources.

Lastly for the scenarios with an additional coal price the capacity factor drops to 1%. The additional price leads to them being dispatched to only provide spinning reserve.

Small natural gas based power plants (GT, JE, ICE) have low capacity factors with slightly higher capacity factors for the scenarios where the make up generation is provided by GTs. These systems are primarily operated to provide spinning reserve.

The capacity factors of the CCGT are affected by a few different factors. Firstly under the scenarios with no additional coal price, the capacity factors are lower than the 2011 values due the new position in the dispatch order for these power plants. With coal power plants becoming firm base-loaded plants, the CCGT plants are required to handle more of the variability leading to lower utilization. Under the scenarios with and additional coal price, the CCGT are performing both duties providing some base-load and some load following capabilities increasing their capacity factor. With respect to the make up generation scenarios, CCGT has higher capacity factors when the make up is composed of GT. When there are more GT on the system, this is similar to there being less capacity available as these generators are not selected to perform base-load operations. Therefore CCGT's are operated more intensely to cover the lost capacity. With respect to the wind growth scenarios, CCGT are utilized less in the accelerated wind growth scenarios as the wind generation displaces some CCGT generation.

These changes in operation lead to differences in the average and marginal GHG emissions factors. The average and marginal GHG emissions factors for 2011 and the 2025 scenarios are shown in Figs. 13 and 14.

The average GHG emissions factors reduce from 9% to 39% depending on the scenario. Without an additional coal price and makeup generation by CCGT power plants, the average GHG emissions factor reduces by 9% and 30% for the current and accelerated wind growth scenarios, respectively. If there is an additional price for coal significantly reducing the power output from these plants, the average GHG emissions factors reduce by 24% and 39% for the current and accelerated wind growth scenarios, respectively. When GTs are utilized for make up generation the average GHG emissions are slightly higher. These results are consistent with the high GHG emissions impact of replacing electricity with renewable wind turbine and not utilizing high emitting coal power plants.

The marginal GHG emissions factors reduce between 30% and 36% in all future grid scenarios considered. In 2011 scenario

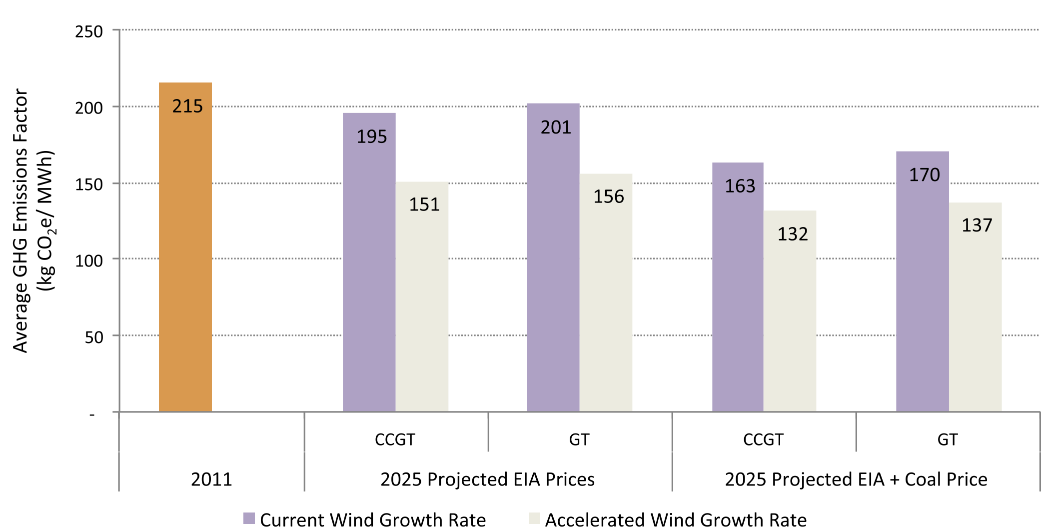


Fig. 13. Average GHG emissions factors for 2011 and 2025.

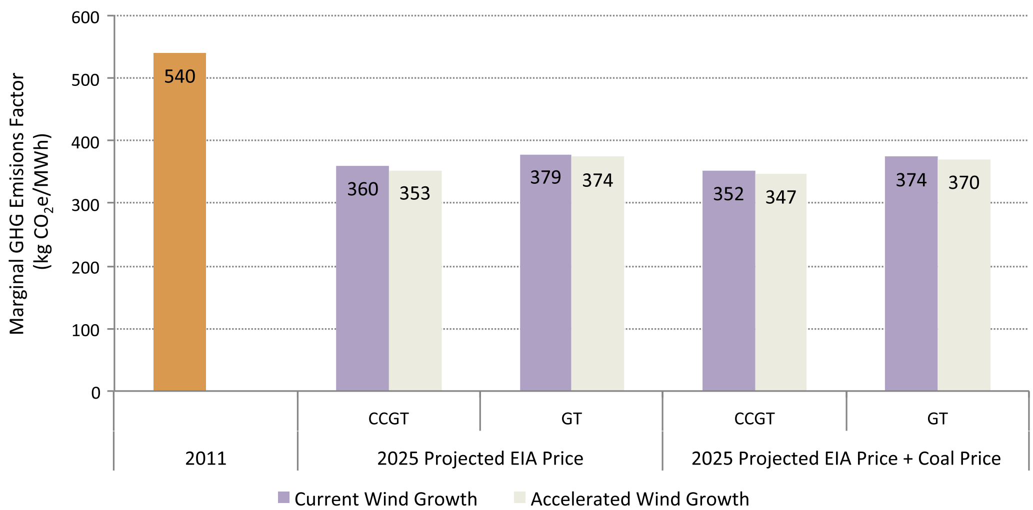


Fig. 14. Marginal GHG emissions factors for New York City in 2025.

electricity generated by coal power plants contributed to the marginal GHG emissions. In the 2025 scenarios with no additional coal price, the coal power plants are base-loaded and are not impacted by changes in demand. With a coal price, coal power plants are not dispatched to meet energy demands, only spinning reserve requirements in extreme cases. Therefore the only generator types contributing to the marginal GHG emissions factors are the natural gas-based CCGT and GT power plants.

5. Conclusion

In this work average GHG emissions factors for New York State and marginal GHG emissions factors for New York City were estimated for 2011 and projected to future 2025 scenarios. The values of the GHG emissions factors are necessary for calculating the impacts of demand-side energy efficiency measures. The analysis indicates that GHG emissions factors are set to decrease given the current projections for fuel prices and wind turbine growth rates. For current wind growth rates, average GHG emissions factors could reduce by 9–24%, the latter occurring if the additional price burden for retrofitting coal power plants results in low utilized. For an accelerated wind growth case, the average GHG emissions factors could reduce by 39%. The marginal GHG emissions factors are significantly reduced in all scenarios to approximately 365 kg CO_2e/MWh from the current marginal emissions rate of 540 kg CO_2e/MWh. The results of this study make a strong case for including considerations of the future mix of electricity generators in evaluating energy efficiency measures and related policy decisions.

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Appendix A. Supplementary material

Supplementary data associated with this article can be found, in the online version, at http://dx.doi.org/10.1016/j.apenergy.2016.11.061.

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