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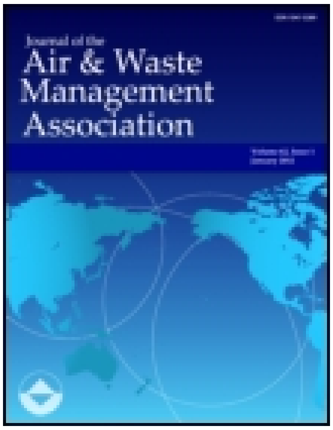

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Air Quality Impacts of Distributed Energy Resources Implemented in the Northeastern United States

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ABSTRACT
Emissions from the potential installation of distributed energy resources (DER) in the place of current utility-scale power generators have been introduced into an emissions inventory of the northeastern United States. A methodology for predicting future market penetration of DER that considers economics and emission factors was used to estimate the most likely implementation of DER. The methodology results in spatially and temporally resolved emission profiles of criteria pollutants that are subsequently introduced into a detailed atmospheric chemistry and transport model of the region. The DER technology determined by the methodology includes 62% reciprocating engines, 34% gas turbines, and 4% fuel cells and other emerging technologies. The introduction of DER leads to retirement of 2625 MW of existing power plants for which emissions are removed from the inventory. The air quality model predicts maximum differences in air pollutant concentrations that are located downwind from the central power plants that were removed from the domain. Maximum decreases in hourly peak ozone concentrations due to DER use are 10 ppb and are located over the state of New Jersey. Maximum decreases in 24-hr average fine particulate matter ($PM_{2.5}$) concentrations reach 3 $\mu g/m^3$ and are located off the coast of New Jersey and New York. The main contribution to decreased $PM_{2.5}$ is the reduction of sulfate levels due to significant reductions in direct emissions of sulfur oxides (SO_x) from the DER compared with the central power plants removed. The scenario presented here represents an accelerated DER penetration case with aggressive emission reductions due to removal of highly emitting power plants. Such scenario provides an upper bound for air quality benefits of DER implementation scenarios.

IMPLICATIONS
Electricity generation is a major contributor to air pollutant emissions. Distributed energy resources provide an alternative means for electricity production or storage and they could be used to reduce total air pollutant and CO_2 emissions from the electricity sector. This study quantifies the potential benefits to air quality due to DER deployment in the northeastern United States, which is likely to meet a significant portion of its electricity production by using DER.

INTRODUCTION
Distributed energy resources (DER) have the potential of substituting part of the conventional central power capacity for electricity production, as well as providing an alternative to power generation to meet the increasing electricity demands in the years to come. DER encompass distributed generation (DG), energy storage, and other interconnection and energy-service-providing technologies. Areas such as California and the northeastern states of the United States have appropriate characteristics in terms of market deregulation, natural gas prices, and grid capacity limitations that provide favorable conditions for DER deployment. Shifting from central generation to a DER-based grid reduces transmission losses and potentially increases energy efficiency, although it may introduce challenges regarding system stability. In addition, deployment of DER introduces new emission sources near the place of use, generally near populated areas, and hence, air quality impacts due to DER need to be assessed before their widespread deployment.

Tomashefsky and Marks[1] suggested that 20% of the increased demand from 2000 to 2020 in California would be met by DER. Later estimates reduced these expectations of DER penetration to approximately 15% of the increased demand—which corresponds to approximately 2000 MW in the state of California—due to a slower start in the commercialization and use of DER.[2] Recent reports have estimated that the potential market penetration of DG in New Jersey and New York combined by 2012 is approximately 1200 MW, and that as much as 3900 MW of DER could be installed if market conditions would favor accelerated deployment of DG.[3,4]

Iannuci et al.[5] estimated emissions from a variety of DG technologies. The study compared emissions from DG with emissions from central generation and concluded that no cost-effective DG technology would reduce emissions with respect to the existing mix of power generation in California. Allison and Lents[6] compared emissions resulting from the use of different DG types and fuels, and concluded that only low-emitting technologies, such as fuel cells, would be marginally competitive with central gas turbine combined cycle power generation. Ianucci et al. reported carbon dioxide (CO_2) emissions from central generation and some DG technologies. The national average CO_2 emissions rate from central generation is as high as that of the highest DG emitter, whereas the California average CO_2 emissions rate is lower than the rate for most DG technologies. On the other hand, Allison and Lents report CO_2 emissions rates from DG, and the benefits from using combined heating and power (CHP). In particular, they suggest that only if heat utilization by CHP is 50% or higher could DG use result in a net decrease in CO_2 emissions compared with central generation in California. These two studies only focused on emissions of primary pollutants and CO_2, but did not consider atmospheric chemistry, transport, or impacts on secondary pollutants. Heath et al.[7] suggested that DG would increase human exposure to pollutants in the Bay Area when compared with central generation. However, they used a simplified nonreactive plume model. Finally, Rodriguez et al.[8] assessed the air quality impacts of DG implementation scenarios in the South Coast Air Basin of California for the year 2010, using a methodology for generating realistic scenarios developed by Medrano et al.[9] The methodology considered information from DG market studies, spatial distribution of economic sectors, and emission regulations, among other factors. Rodriguez at al. used a three-dimensional air quality model to assess the impacts of DG on ozone (O_3) and secondary particulate matter (PM) formation. They concluded that realistic implementation of DG technologies would have a marginal adverse effect on air quality by 2010, compared with the case of zero DG implementation. However, they suggested that increased DG penetration in future years could affect compliance with air quality standards. The study only considered installation of additional power capacity without assuming retirement of existing central generation capacity in the basin.

This work focuses on realistic DER penetration in the northeastern United States in the year 2010. First, this study estimates a DER implementation scenario for 2010. Unlike the work of Rodriguez et al., this study considers a plan for substituting highly polluting old central power plants with DER. Baseline emissions for 2010 and the resulting emissions from the DG implementation scenario are then used as an input for the Community Multiscale Air Quality (CMAQ) model, and impacts on O_3 and PM concentrations are evaluated.

SCENARIO DEVELOPMENT

Assessment of air quality impacts due to DER implementation requires detailed characterization of a DER implementation scenario. Definition of a DER implementation scenario includes a complete set of parameters that determine the location of DER installations, the size and type of DER units, the duty cycle in which DER units are operated, and other parameters that ultimately affect the spatial and temporal distribution of emissions from DER. In addition, this study assumes that existing central power plants are substituted by DER units. Thus, this study selects specific power plants that are retired (emissions removed) in the region of interest simultaneously with DER implementation (emissions introduced).

Baseline Scenario

Before determining the contribution of DER to total emissions, there is the need for developing a baseline emissions inventory for the year 2010. In addition, as some emission sources depend on meteorological conditions, the emissions inventory must be developed in conjunction with a meteorological episode. This study uses meteorological conditions and emissions from July 11–25, 1999. Emissions for the 2010 base case were obtained from the U.S. Environmental Protection Agency (EPA) Clean Air Interstate Rule modeling; these emissions were developed using 1999 emissions from the National Emissions Inventory (NEI) and average emissions growth factors for each state from 1999 to 2010.

Retirement of Existing Power Plants

The accelerated deployment scenario developed in this study (discussed in Scenario Development) estimates that over 2500 MW of electric generation could be produced with DER. Because details of the energy/economic modeling used for development of the base-case emissions inventory by EPA are not readily available, the generation capacity in the modeling domain was estimated from the actual generation reported on Form EIA-767 to the U.S. Department of Energy (DOE) during the years 2001–2003. Estimates were calculated for the entirety of six states in the northeastern United States: Connecticut, Delaware, Maryland, New York, New Jersey, and Pennsylvania.

Generation data were available for 131 of 180 electric generation point sources in the six states. Units smaller than 5 MW, all of which are natural gas reciprocating engines and turbines and thereby fall under the category of DG, and 49 point sources for which generation data were not available constituted less than approximately 18% of total nitrogen oxides (NO_x) emissions and approximately 5% of total sulfur dioxide (SO_2) emissions due to electricity generation in the six-state region. Of these 131 point sources, 111 point sources correspond to coal-fired units located in all 6 states and 20 point sources correspond to natural gas-fired units located only in New York. A summary of the emissions and generation capacity of these point sources is given in Table 1. The table does not include electricity generation from nuclear or hydroelectric units.

This study selected the generation units to be displaced based on the highest emissions intensity for NO_x and SO_2 in the six-state domain. The process consisted of

Table 1. Summary of point-source electric generation units (EGUs) that are displaced by DER in this study (emissions in t/day).

Type of Unit	MW	VOC	NO_x	CO	SO_2	PM_{10}
20 Natural gas-fired units	3,238	1.27	26.63	7.68	0.00	0.08
111 Coal-fired units	23,295	6.47	483.91	53.73	3,701.28	61.66
49 Units[a]		0.66	72.72	7.19	208.59	10.42
All point-source EGUs		8.40	583.26	68.61	3,909.87	72.17
Area-source EGUs		0.74	40.08	78.25	0.00	1.32
Total		9.13	623.34	146.86	3,909.87	73.48
Retired plants	2,625	1.01	136.63	8.26	845.77	7.84

Notes: [a]No generation data available for these units.

ranking the 131 point-source units in the six-state region on the basis of NO_x emissions per MW and SO_2 emissions per MW to provide a basis for selecting appropriate sources to remove from the inventory. The effect on the emissions totals based on removing the units with the highest emissions intensity is presented in Table 1. Figure 1 shows the locations from which central power generator emissions are removed from the domain. Following the criterion of emissions intensity, two important high-density areas of emissions in upstate New York and Pennsylvania are eliminated that are far upwind from highly populated areas of New York City and much of New Jersey. A third important high-density area of emissions is located in the vicinity of Washington, DC.

Alternative criteria for retiring power plants could include geographical location, age, and energy efficiency. Scenarios based on these alternative criteria could lead to more conservative emission reductions than in the case analyzed in this study.

In addition to criteria pollutant emissions, CO_2 emissions that would be eliminated by removing those power plants are estimated using average U.S. CO_2 emissions from fossil-fuel power plants. According to the Energy Information Agency (EIA),[10] 1999 average CO_2 emissions from fossil-fuel power plants were 1915 lb/MWh. Accounting for the daily electricity produced by 2650 MW of installed capacity leads to a total of 54,724 t of CO_2 per day. This value only includes emissions from electricity generation and does not account for any upstream emissions due to fuel production and delivery, or any life-cycle emissions from construction or dismantling of power plants.

Methodology for Projection of DER Market Penetration

The likely future implementation of DER is governed by a complex set of market constraints and drivers that are expected to significantly affect DER market penetration, technology type, emissions, installation location, duty cycle of operation, etc. First, fuel and electricity prices directly affect the electricity cost savings that DER users could obtain. Second, environmental regulations for both criteria pollutants and greenhouse gases may favor some low-emitting DER technologies, and especially those technologies that use CHP, which improves DER energy utilization. Third, interconnection requirements (including technical, contractual, and tariff issues) and other institutional and rate factors affecting integration of DER into the electricity grid may limit the implementation of DER applications. However, potential DER incentives from utilities and/or authorities could facilitate installation of DER. Finally, DER technology development in terms of

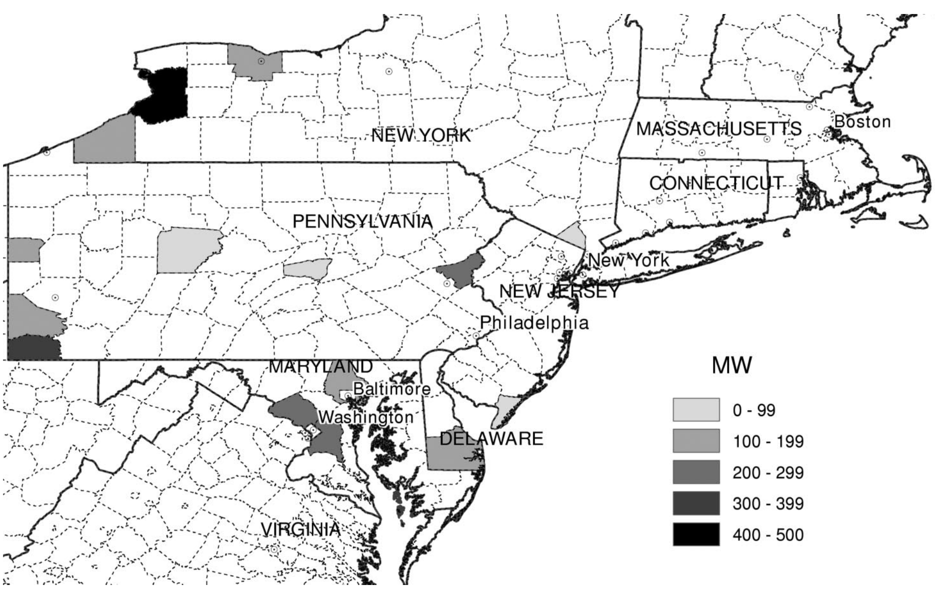

Figure 1. Total capacity of old central generation removed from the domain.

performance, cost, and emissions will change the potential market penetration of DER technologies over the longer term. In addition, as DER sales and service infrastructure develop in the future, customer acceptance will improve, resulting in accelerated DER market penetration. This study attempts to account for much of the complexity of the DER market by consideration of as many published studies, reports, technology demonstrations, DG implementation data, author insights, and other resources as are available.

Target applications for DER implementation are identified based on electric and thermal energy consumption data for various building types and industrial facilities. Data sources include the Energy Information Agency (EIA) Commercial Buildings Energy Consumption Survey (CBECS),[11] the Manufacturing Energy Consumption Survey (MECS),[12] and several industrial and commercial models and databases of Energy and Environmental Analysis, Inc. (EEA).[13] As an example, target commercial/institutional applications for DER that use CHP include such buildings as hospitals, hotels, nursing homes, universities, schools, commercial laundries, car washes, health clubs, correctional facilities, large office buildings, and large multifamily buildings. Target industrial applications include food processing, chemical plants, paper mills, textile mills, and certain fabrication industries such as fabricated metals products and industrial machinery. These applications all have typical thermal and electric profiles that tend to support CHP and these industries and commercial sectors have existing experience with CHP. The information on location of these applications allows estimation of the potential spatial distribution of DER in the region of interest.

Once applications that could technically support DER are identified, they are grouped into size categories on the basis of average electric power demand. Total DER potential is then estimated for each target application on the basis of the number of target facilities in each size category. Finally, the potential is reduced by the current level of market penetration to avoid double counting. This correction is based on a variety of existing public and private databases.[13] The result of this second step is to estimate the power size distribution among DER applications.

After the general potential market penetration of DER is determined, specific market penetration in the northeastern U.S. markets of interest must be determined by considering several factors. These factors include the economic value to the user (based on electric and fuel rates), a maximum achievable growth rate, and the size of the remaining potential market, which are used in the scenario development methodology to determine the rate of DER adoption throughout the region of interest. The market penetration analysis approach has the following features:

- Maximum growth rates are defined that reflect how fast the market can ramp up if the economic value to the customer is at an optimum level.
- Maximum growth rate is modified by an economic acceptance factor that equals 100% for project paybacks of 2 yr or less and declines to zero for paybacks of 8 yr or more.
- As the ratio of remaining market potential to initial market potential declines, the maximum rate of growth declines.
- It is not possible to penetrate 100% of the theoretical market potential because of site restrictions, customer risk preferences, customer diversity in economic value received, or other factors that would inhibit the customer from implementing DER projects. These restrictions become more important the smaller the size of the customer.

The approach allows for rapid early growth rates from historical levels that ultimately are moderated by market saturation as the technical potential is approached. The result of applying these factors is the total DER power penetration.

The approach also weighs different technologies in size and application categories and prorates market penetration on the basis of relative economics. Certain DER technologies meet the needs of certain applications and/or size categories more effectively than other technologies and this is reflected in the relative economics of the various technologies. Ultimately, this step results in a DER technology mix that directly affects the emissions of pollutants released to the area of interest. The factors

Table 2. 2010 accelerated deployment technical specifications of gas turbines considered in the scenario development.

Characterization	Gas Turbine	Gas Turbine with DLN	Gas Turbine with DLN	Gas Turbine with SCR	Gas Turbine with SCR
Capacity (MW)	1	3	10	25	40
Installed costs ($/kW)	1,400	1,100	900	725	675
Heat rate (Btu/kWh)	14,200	12,200	10,500	9,000	8,750
Electric efficiency (%)	24.0	28.0	32.5	37.9	39.0
Power-to-heat ratio	0.66	0.8	0.88	1.08	1.15
Thermal output (Btu/kWh)	5,170	4,265	3,877	3,159	2,967
Operation and maintenance costs ($/kWh)	0.009	0.005	0.005	0.0045	0.004
NO_x emissions (lb/MWh)	0.07	0.04	0.036	0.02	0.02
CO emissions (lb/MWh)	0.59	0.51	0.45	0.05	0.04
VOC emissions (lb/MWh)	0.023	0.023	0.02	0.01	0.01
PM_{10} emissions (lb/MWh)	0.29	0.20	0.18	0.15	0.15
SO_2 emissions (lb/MWh)	0.0083	0.0069	0.0062	0.0053	0.0051
CO_2 emissions (lb/MWh)	1,706	1,405	1,265	1,058	1,035
After treatment cost ($/kW)	200	150	110	75	70

Table 3. 2010 accelerated deployment technical specifications of reciprocating engines considered in the scenario development.

Characterization	RB with TWC	EGR with TWC	EGR with TWC	LB with SCR	LB with SCR
Capacity (kW)	100	300	1000	3000	5000
Installed costs ($/kW)	1,250	1,200	980	900	875
Heat rate, Btu/kWh	10,500	9,750	8,860	8,425	8,025
Electric efficiency (%)	32.5	35.0	38.5	40.5	42.5
Power-to-heat ratio	0.7	0.8	1.07	1.18	1.31
Thermal output (Btu/kWh)	4,874	4,265	3,189	2,892	2,605
Operation and maintenance costs ($/kWh)	0.012	0.0125	0.01	0.008	0.008
NO_x emissions, lb/MWh (with after treatment)	0.15	0.04	0.04	0.124	0.124
CO emissions with after treatment (lb/MWh)	0.20	0.17	0.17	0.31	0.31
VOC emissions with after treatment (lb/MWh)	0.05	0.03	0.03	0.05	0.05
PM_{10} emissions (lb/MWh)	0.11	0.01	0.01	0.01	0.01
SO_2 emissions (lb/MWh)	0.0062	0.0057	0.0052	0.0050	0.0047
CO_2 emissions (lb/MWh)	1,248	1,140	1,036	998	939
After treatment cost ($/kW)	N/A	45	40	120	110

Notes: RB = rich burn, EGR = exhaust gas recirculation, LB = lean burn.

considered in the methodology to determine the DER technology mix are as follows.

Technology Cost and Performance. Advanced technology cost and performance is based on accelerated development through 2012, as described in the detailed technology characterizations EEA has undertaken for DoE and EPA.[14] These advanced technologies show significant improvement over currently available equipment, especially in the emerging technologies category and smaller sized applications.

DER Incentive Program. An incentive program based on the 2005 New Jersey incentives for DER is assumed to apply to the entire six-state region and for the entire period of the analysis. The New Jersey incentives provide cost reductions for up to 30% of capital costs up to $1000/kW for CHP systems smaller than 1 MW and 40% of capital costs up to $2500/kW for fuel cells.

Gas and Electricity Prices. Regional EEA or DOE EIA long-term forecast prices are used to provide the wholesale price track for gas. The wholesale price track for electricity is estimated based on the cost of power from a combined cycle power plant using the projected natural gas price track. Average retail rates for a representative utility in each state are used to determine the wholesale-to-retail markups by customer size class.

Accelerated Deployment. It is assumed that an aggressive outreach program and a favorable market climate will bring more project developers to the market and thereby accelerate market penetration rates for economically viable projects.

Emissions Regulations. 2005 New Jersey emissions regulations are assumed for the entire region. These are:

- Gas turbine $<$ 150 MMBtu/hr input (12–15 MW): 15 ppm of NO_x achieved with dry low NO_x (DLN) technology;
- Gas turbine $>$ 150 MMBtu/hr input: 2.5 ppm of NO_x, with selective catalytic reduction (SCR); and
- Reciprocating Engine: 0.5 lb NO_x/MWh, which requires aftertreatment—rich burn with three-way catalyst (TWC), exhaust gas recirculation with TWC, or lean burn with SCR.

Table 4. 2010 accelerated deployment technical specifications of fuel cells considered in the scenario development.

Characterization	PEM Fuel Cell	SOFC	MCFC
Capacity (kW)	150	250	2000
Installed costs ($/kW)	2700	2500	2200
Heat rate (Btu/kWh)	9480	7125	7110
Electric efficiency (%)	36.0	47.9	48.0
Power-to-heat ratio	0.98	2.1	2
Thermal output (Btu/kWh)	3482	1625	1706
Operation and maintenance costs ($/kWh)	0.015	0.017	0.018
NO_x emissions (lb/MWh; no after treatment)	0.07	0.05	0.05
CO emissions (lb/MWh)	0.07	0.04	0.03
VOC emissions (lb/MWh)	0.01	0.01	0.01
PM_{10} emissions (lb/MWh)	0.001	0.001	0.001
SO_2 emissions (lb/MWh)	0.0056	0.0042	0.0042
CO_2 emissions (lb/MWh)	1135	853	851

Table 5. 2010 accelerated deployment technical specifications of MTGs considered in the scenario development.

Characterization	Small MTG	Medium MTG	Large MTG
Capacity (kW)	70–100	250	500
Installed costs ($/kW)	1,400	1,300	1,100
Heat rate (Btu/kWh)	11,375	10,825	10,250
Electric efficiency (%)	30.0	31.5	33.3
Power-to-heat ratio	1.1	1.3	1.32
Thermal output (Btu/kWh)	3,102	2,625	2,585
Operation and maintenance costs ($/kWh)	0.015	0.014	0.014
NO_x emissions (lb/MWh) (no after treatment)	0.13	0.13	0.11
CO emissions (lb/MWh)	0.20	0.24	0.24
VOC emissions (lb/MWh)	0.023	0.023	0.023
PM_{10} emissions (lb/MWh)	0.19	0.16	0.0060
SO_2 emissions (lb/MWh)	0.0067	0.0064	0.0055
CO_2 emissions (lb/MWh)	1,333	1,270	1,201
After treatment cost ($/kW)	N/A	90	90

Specifications for DG units

Tables 2–5 contain information on performance and emission factors for the different DG types considered in this study. The values of these tables are adopted from the report, "Distributed Energy Resources Emissions Survey and Technology Characterization" (E2I, 2004).[15] The emission factors for gas turbines and reciprocating engines assume 2005 New Jersey emissions regulations for the entire region. The cost and performance specifications shown in the tables reflect the accelerated technology case assumptions for 2010, that is, higher performance and lower costs than are available today. In addition, the capital costs shown in the table are for generic installations at average U.S. construction prices. The market competition model used in this analysis included site-specific capital cost multipliers that ranged from 104% (DE, MD, northeastern PA) to 140% (New York City and Long Island).

Gas turbines, which involve large investments in capital costs, are typically used in large applications—from 1 to 40 MW. Reciprocating engines, which are available in a wide range of sizes with moderate capital costs, can be typically used in low- to medium-sized applications—from 100 kW to 5 MW of power demand. Fuel cells can also be used in a wide range of applications, although the capital costs are significantly higher than the costs for reciprocating engines. Large applications generally require high-temperature fuel cells—solid-oxide fuel cells (SOFCs) or molten-carbonate fuel cells (MCFCs)—whereas smaller applications use low-temperature fuel cells—polymer electrolyte membrane (PEM) fuel cells. In the smallest size range, microturbine generators (MTGs) are an emerging technology that is generally used in applications that vary from 65 to 500 kW.

DG Installations

The DER market penetration was modeled for the North East Ozone and Particles Study (NE-OPS) 4-km resolution area, which includes eastern Pennsylvania, northern Delaware and Maryland, all of New Jersey, downstate New York, and the extreme southwestern edge of Connecticut. The total capacity of installations that result from the scenario development methodology in each state are presented in Table 6. Figure 2 shows the geographical location of the installed capacity in the region. Approximately 54% of the total capacity corresponds to large gas-turbine installations, larger than 60 MW. Whereas this size of power plant cannot be considered DER, the authors believe the methodology used to determine future power generation installations as presented in Figure 2 and Table 6 is sound. This suggests that DER alone is not likely to meet the expected need for extra capacity to meet electricity demand. The current methodology suggests that the majority (54%) will be supplied by large installations to be economically and environmentally viable. The remaining 46% of the installed capacity corresponds to installations that are smaller than 60 MW, which are considered DER in this study. Nearly 34% of the total capacity of these DER installations corresponds to gas turbines, whereas reciprocating engines account for 62%

Table 6. DER installations in the NE-OPS 4-km resolution domain.

	Total Power (MW)	Gas Turbine (>60 MW)	Gas Turbine (<60 MW)	Reciprocating Engine (MW)	Microturbine (MW)	Fuel Cell (MW)
Connecticut	12.30	0.00	0.43	11.81	0.00	0.06
Delaware	503.08	503.08	0.00	0.00	0.00	0.00
Maryland	109.48	109.48	0.00	0.00	0.00	0.00
New Jersey	303.12	0.00	159.04	143.22	0.04	0.82
New York	1204.92	480.51	188.23	491.63	33.36	11.19
Pennsylvania	402.41	286.02	40.11	76.08	0.00	0.20
Total	2535.30	1379.09	387.81	722.74	33.40	12.26

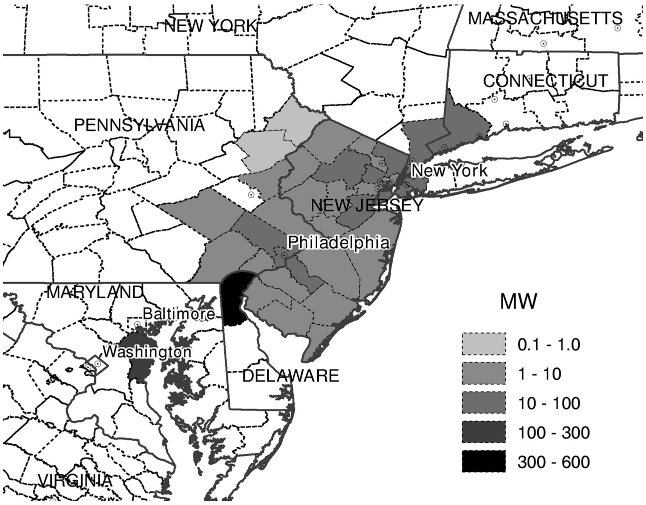

Figure 2. Power generation added to the system in the NE-OPS 4-km resolution domain.

of the installed DER power. The remaining 4% of the power capacity is met by MTGs and fuel cells, which are mostly installed in the state of New York. The state of New York is also the state in which the largest DER capacity is installed, in particular around New York City. Delaware is the state with the second highest installed power capacity. However, 100% of the power is met by a single installation of large gas turbines, and hence cannot be considered DER. Likewise, the capacity installed in Maryland is exclusively met by a large gas turbine. Therefore, on the basis of the methodology applied for the development of DER scenarios, the states of Delaware and Maryland are not expected to adopt DER in the time frame before 2010. Recently, the state of Delaware has ordered the installation of a 200- to 300-MW offshore wind farm in conjunction with a 150- to 200-MW synchronous condenser combined-cycle gas turbine.[16] Moreover, a study by Kempton et al.[17] suggests that there is a strong potential for wind power generation off the coast of Delaware and neighboring states. The potential wind resources in the area could, in theory, supply the entire power demand in those states, and hence reduce the emissions from power generation further than the emission reductions presented in this scenario. However, a wind-power case study for Denmark by Østergaard[18] suggests that employing wind power for a high percentage of electricity generation could lead to system instabilities, and that CHP installations could be used as load-balancing units. Pennsylvania and New Jersey are expected to install a large capacity of installations with reciprocating engines and gas turbines, locating DER installations near the major metropolitan areas of Philadelphia, Atlantic City, and Newark. Finally, Connecticut is the state with the lowest new installed capacity in the region, and most installations use reciprocating engines.

Emissions resulting from DER implementation are shown in Table 7. NO_x and sulfur oxides (SO_x) emissions from DER units correspond to 1.51 and 0.02% of the total NO_x and SO_x emissions, respectively, from the old power plants that were removed in the current scenario. As a result, implementation of DER produces important emission reductions of precursors for O_3 and secondary PM formation. Alternatively, emissions from the power plants considered for retirement could be limited with stricter emission standards. The lowest achievable emissions rates (LAERs)[19] of coal-fired power plants for NO_x and SO_x are 0.239 and 0.341 lb/MWh, respectively. Using LAER emission limits for the power plants considered for removal would lead to emission reductions of 95 and 98.9% for NO_x and SO_x, respectively, which would represent more moderate emission reductions than in the case of DER implementation. Table 7 also shows CO_2 emissions from DER, which add up to 28,520 t/day, 48% lower than the estimated total emissions from the central power plants removed. As a result, CO_2 emissions from electricity generation are reduced because of DER implementation.

Finally, implementation of DER allows the use of excess heat for CHP, which reduces the need for consuming fuel in a boiler or heater. As shown in Table 7, the maximum excess heat that could be used from DER, which is calculated based on the thermal output of the DER units, adds up to 143,101 million Btu per day. In general, the use of CHP increases the efficiency of DER installations considerably, reducing the need for fuel that would otherwise be required for heating. In addition, CHP eliminates the potential air pollutants and CO_2 emissions that would be emitted by a boiler or heater. Using nominal emission factors for boilers reported by Ianucci et al.[5] (0.147 lb/MMBtu for NO_x and 118 lb/MMBtu for CO_2) the potential maximum reductions in NO_x and CO_2 emissions due to CHP could add up to 9 and 7666 t/day, respectively.

SIMULATION CONDITIONS

Air Quality Model Specifications

This study uses the CMAQ model, version 4.3. The model includes advective and diffusive transport, gas-phase

Table 7. Daily emissions from DER resulting from the installation of 2535 MW of DER power following the DG mix and spatial distribution shown in Table 6 and Figure 2.

	VOC (t/day)	NO_x (t/day)	CO (t/day)	SO_2 (t/day)	PM_{10} (t/day)	CO_2 (kt/day)	Avoided Boiler Fuel (MMBtu/day)
Connecticut	0.01	0.02	0.04	0.00	0.00	0.14	736.12
Delaware	0.05	0.10	0.25	0.03	0.77	5.62	23,172.86
Maryland	0.01	0.02	0.05	0.01	0.17	1.22	5,043.02
New Jersey	0.09	0.36	0.70	0.02	0.27	3.41	21,665.40
New York	0.30	1.28	2.30	0.06	1.18	13.63	70,444.75
Pennsylvania	0.07	0.21	0.44	0.02	0.51	4.51	22,039.19
Total	0.54	1.99	3.79	0.13	2.90	28.52	143,101.34

chemistry, aerosol and cloud dynamics, and dry and wet deposition equations to predict air quality. The chemical mechanism selected for the current simulations is CB4.[20,21] The simulations are performed using a one-way nested-grid modeling system that includes the eastern part of the United States and two smaller subdomains. The cell sizes in the nested domains are 36, 12, and 4 km, respectively.

Meteorological Conditions

The meteorological episode selected for this study is July 11–25, 1999, which occurred during the NE-OPS, a comprehensive campaign that collected meteorological and air quality data in the northeastern United States during the summers of 1998, 1999, and 2001. During this particular period, O_3 concentrations in Philadelphia reached the highest levels in 1999. Peak O_3 concentrations in Philadelphia and Baltimore were higher than 120 ppb for 4 consecutive days (July 16–19). Meteorological conditions during the episode were characterized by weak westerly to southwesterly winds and stagnation that favored the accumulation of pollutants. In addition, overnight transport of pollutants from the Ohio River Valley contributed to maintaining O_3 levels at 20–30 ppb during the night in urban areas. The presence of a Bermuda high-pressure system created a convergence airflow zone on the coast of Maryland and New Jersey that transported air masses from southwest to northeast parallel to the shoreline. On July 19, there were 17 stations that exceeded hourly O_3 concentrations of 120 ppb. On July 23 and 24, another period of air recirculation followed by weak southwest winds led to warm temperatures and high O_3 concentrations in the area. A storm approaching the area on July 24 ended the period of high O_3 concentration.[22]

Model Performance

The 1999 case study is used to evaluate the model performance. Two air quality datasets have been included to assess model bias and error compared with measured data: (1) Air Quality System (AQS) for gas species such as O_3, nitrogen dioxide (NO_2), and SO_2; and (2) Interagency Monitoring of Protected Visual Environments (IMPROVE) for fine PM ($PM_{2.5}$) concentrations. Tables 8–10 present statistical metrics of the model performance for predicting the 1999 baseline conditions in the 36-, 12-, and 4-km domains, respectively. In general, the model well reproduces the general trends of O_3 and PM. In the case of O_3, the model demonstrates good agreement with O_3 peaks.

Table 8. Model performance for the 36-km model domain simulation of the 1999 baseline conditions.

Statistical Measure	O_3	NO_2	SO_2	$PM_{2.5}$
Number of sites	676	44	436	17
Maximum observed	178 ppb	83 ppb	549 ppb	52 $\mu g/m^3$
Maximum simulated	184 ppb	74 ppb	24 ppb	17 $\mu g/m^3$
Average observed	75 ppb	15 ppb	6 ppb	18 $\mu g/m^3$
Average simulated	58 ppb	12 ppb	2 ppb	8 $\mu g/m^3$
Mean normalized gross error (%)	24.7	78.3	83.3	45.3
Mean normalized bias (%)	−21.4	15.0	−35.4	−42.0

Table 9. Model performance for the 12-km model domain simulation of the 1999 baseline conditions.

Statistical Measure	O_3	NO_2	SO_2	$PM_{2.5}$
Number of sites	165	9	145	5
Maximum observed	178 ppb	71 ppb	310 ppb	52 $\mu g/m^3$
Maximum simulated	150 ppb	108 ppb	87 ppb	19 $\mu g/m^3$
Average observed	80 ppb	18 ppb	7 ppb	19 $\mu g/m^3$
Average simulated	59 ppb	14 ppb	3 ppb	8 $\mu g/m^3$
Mean normalized gross error (%)	27.9	67.0	103.8	51.1
Mean normalized bias (%)	−25.9	1.3	−0.1	−35.5

AIR QUALITY IMPACTS OF DER

2010 Baseline O_3 and PM Concentrations

Air quality impacts of DER are evaluated by subtracting baseline 2010 concentrations from concentrations resulting from the simulation of the DER scenario. Air quality impacts depend strongly on meteorological conditions. The episode used in this study includes several days with warm temperatures and stagnant conditions that favor secondary pollutant formation. On the other hand, the episode also includes several days in which wind circulation and temperatures are moderate, conditions that preclude pollutants from accumulating. As a result, this episode allows for evaluation of air quality impacts of DER under different meteorological conditions in the northeastern United States.

O_3 and PM concentrations reach the highest levels during the period of July 16–19. Figure 3 shows peak O_3 concentrations in the 12-km domain on July 16 and July 19, and Figure 4 shows 24-hr average $PM_{2.5}$ concentrations in the area during the same days. Results in the 36- and 4-km domains show trends that are identical to the results obtained for the 12-km domain. However, the peak values are slightly sensitive to model domain resolution. Peak O_3 occurs on July 16, and it reaches 148 and 150 ppb in the 12- and 4-km domains, respectively. The peak 24-hr average $PM_{2.5}$ occurs on July 19, reaching 74 and 67 $\mu g/m^3$ in the 12- and 4-km domains, respectively. On July 16, high O_3 concentrations occur in large portions of the 12-km domain, near Pittsburgh, and along a strip of land parallel to the coast that goes from Washington DC, Baltimore, across the states of New Jersey and Connecticut, and along Long Island. These conditions persist from July 17 to 18. A cold front from the west and northwest that arrives on July 19 is the cause of a significant decrease in O_3 concentration in most of Pennsylvania and upstate New York. As a result, an area of elevated

Table 10. Model performance for the 4-km model domain simulation of the 1999 baseline conditions.

Statistical Measure	O_3	NO_2	SO_2	$PM_{2.5}$
Number of sites	56	2	46	1
Max observed	171 ppb	65 ppb	110 ppb	18 $\mu g/m^3$
Max simulated	142 ppb	72 ppb	192 ppb	4 $\mu g/m^3$
Average observed	86 ppb	17 ppb	6 ppb	9 $\mu g/m^3$
Average simulated	59 ppb	14 ppb	7 ppb	3 $\mu g/m^3$
Mean normalized gross error (%)	31.8	72.6	146.9	53.1
Mean normalized bias (%)	−30.2	5.5	88.0	−53.1

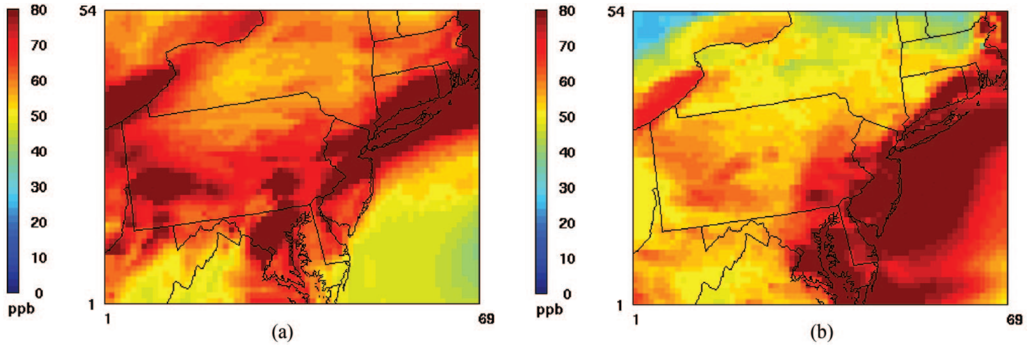

Figure 3. Baseline 2010 peak O_3 concentrations (in ppb) in the 12-km domain for (a) July 16 and (b) July 19.

O_3 concentration accumulates over the coasts of New Jersey, Connecticut, and New York. With respect to particles, there are four areas that exhibit high $PM_{2.5}$ concentrations located near Pittsburg, Buffalo, New York City, and Albany. In addition, $PM_{2.5}$ concentrations on July 16 and 17 reach values of 40 $\mu g/m^3$ over a large portion of Pennsylvania and New York. On July 19, because of the presence of a westerly cold front, PM concentrations decrease in the inland part of the domain. Wind circulation transports particles and their precursors toward the New Jersey coast, and strong accumulation of $PM_{2.5}$ develops over New Jersey, Delaware, Maryland, and in particular, over New York City.

Air Quality Impacts of DER

As mentioned above, the DER scenario assumes the retirement of 22 power plants. Five power plants are located in upstate New York, near the Great Lakes; five plants are in Pennsylvania, near the border with Ohio and West Virginia; six plants are located around the Chesapeake and Delaware bays; three power plants are located upwind from New York City; and two plants are located in central Pennsylvania. The emissions from these power plants are orders of magnitude higher than the emissions due to DER implementation. As a result, the emissions contained in the DER scenario are lower than those of the 2010 baseline.

The meteorological conditions on July 16–19 are representative of a high-O_3 production episode, and this particular event is used to analyze the air quality impacts of DER. In fact, the strongest impacts of DER on O_3 and $PM_{2.5}$ occur on July 16 and 19. Also, July 23–24 is another period with high concentrations of O_3 and $PM_{2.5}$, which presents similar air quality impacts to those shown for July 16–19. Colder temperatures and less stagnant conditions during the other days of the 15-day episode lead to lower photochemical activity and lower concentrations of secondary pollutants. Consequently, the impacts of DER occurring on July 16 and 19 represent a relative upper bound of air quality impacts corresponding to the most challenging meteorological conditions.

In general, concentrations of O_3 in the DER scenario are lower than in the 2010 baseline. Reductions in O_3 concentrations are localized downwind from the location of the power plants that were removed (see Figure 5). These power plants emit NO_x at high rates, and their elimination leads to an overall reduction of peak O_3 concentration in locations near the plants. The biggest reduction in O_3 peak concentration (10 ppb) occurs on July 19, over Delaware, downwind from the power plants removed from that state and from Maryland. In addition, important reductions in peak O_3 occur in New Jersey. More moderate reductions also occur in upstate New York and Pennsylvania, near the location of the plants removed in those states.

Similarly, concentrations of $PM_{2.5}$ in the DER scenario are lower than those of the 2010 baseline. Reductions in $PM_{2.5}$ concentrations occur near the power plants. However, impacts on $PM_{2.5}$ are evaluated using 24-hr average concentrations, and hence these impacts are more diffuse than the impacts observed in hourly O_3 concentrations (see Figure 6). Maximum reductions in $PM_{2.5}$ in the DER scenario compared with the 2010 base case are 3 $\mu g/m^3$, which occur predominantly over New Jersey and off the coast of Delaware, New Jersey, and New York. Smaller reductions also occur over a vast area in the

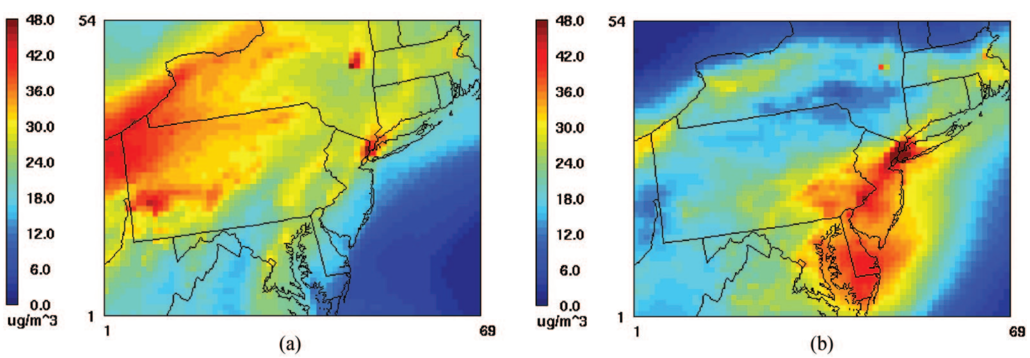

Figure 4. Baseline 2010 24-hr average $PM_{2.5}$ concentrations (in $\mu g/m^3$) in the 12-km domain for (a) July 16 and (b) July 19.

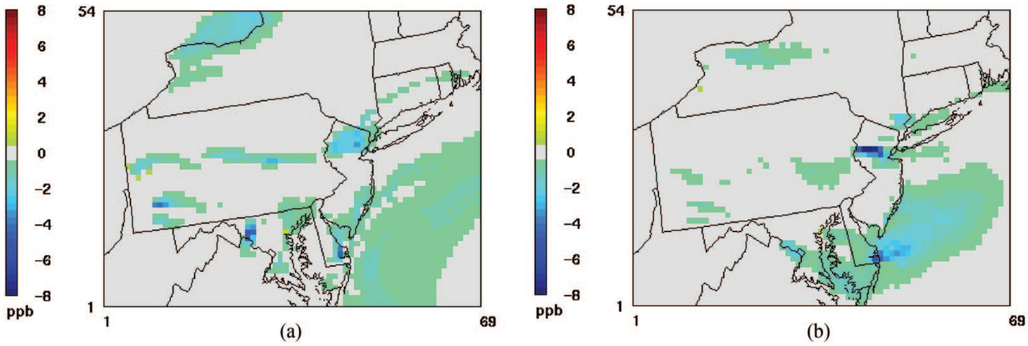

Figure 5. Difference in peak O_3 concentrations (in ppb) between the DER scenario and the 2010 baseline in the 12-km domain for (a) July 16 and (b) July 19.

inland portion of the domain. On July 19, because of the movement of a westerly cold front, O_3 and PM concentrations decrease significantly in Pennsylvania and upstate New York. Similarly, reductions in pollutant concentrations in those areas also decrease because of precursor dilution and lower photochemical activity. Reduction of $PM_{2.5}$ concentrations is caused by the decrease of PM and SO_x emissions, attributable to removal of the power plants. The main contributor to lower levels of $PM_{2.5}$ is the decrease in sulfate aerosol. Sulfate aerosol is emitted directly from power plants or is formed via oxidation of SO_x in the presence of ammonia in the atmosphere. Removal of the power plants leads to a decrease in PM and SO_x emissions from point sources of 10.6 and 21.6%, respectively. As a result, $PM_{2.5}$ concentrations decrease by up to 10% in some areas of New Jersey.

Although domain-wide O_3 and $PM_{2.5}$ peak concentrations do not decrease significantly, removal of emissions from point sources leads to important decreases in pollutant concentrations in some areas of the domain. In general, O_3 concentrations are not affected as much as $PM_{2.5}$ concentrations. Nonetheless, removal of NO_x and volatile organic compound emissions from point sources leads to significant localized reductions of O_3. On the other hand, $PM_{2.5}$ concentrations are reduced over a large area of the domain because of the reduction of SO_x and PM from power plants. As a result, installation of DER in place of old existing power plants could reduce particulate concentrations significantly.

CONCLUSIONS

This article presents a methodology to predict future market penetration, emissions, and potential air quality impacts of DER in the northeastern United States. The methodology considers economic and emission factors to estimate the most likely implementation of DER. As a result, spatial distributions and a mix of DG technology types are obtained for six states of the northeastern United States, resulting in spatially and temporally resolved emission profiles of criteria pollutants.

The technology mix obtained using the methodology results in a large penetration of gas turbines that are larger than 60 MW, which cannot be considered as DER. This result suggests that DER cannot be used exclusively to meet new power demands without considering the use of central generation if all market drivers are taken into account. Among DER installations, reciprocating engines predominate installations, with a 62% share of the total DER capacity, whereas gas turbines smaller than 60 MW account for 34% of the total DER capacity. Installations with novel technologies such as MTGs and fuel cells only meet 4% of the total DER capacity and are primarily located in the state of New York.

This study assumes that the generation capacity due to introduction of DER leads to retirement of some existing power plants. The criterion used for removing the existing plants was to eliminate the installations with the highest NO_x and SO_x emissions in the region of interest. The total capacity removed from the domain is 2625 MW.

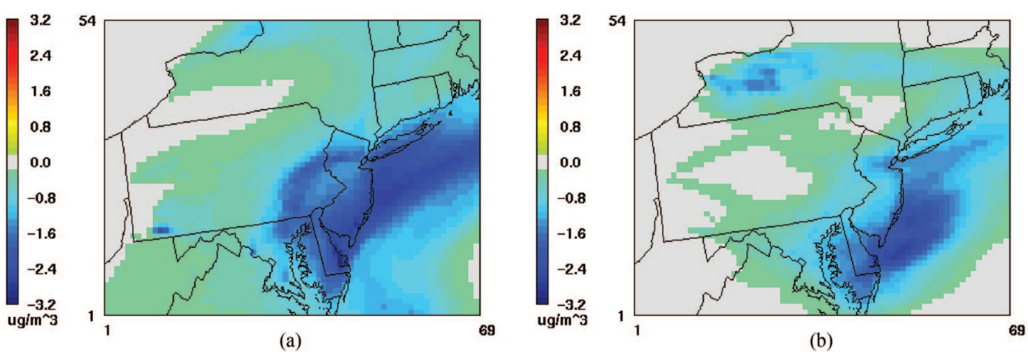

Figure 6. Difference in 24-hr average concentrations of $PM_{2.5}$ (in $\mu g/m^3$) between the DER scenario and the 2010 baseline in the 12-km domain for (a) July 16 and (b) July 19.

The total emissions from the central power plants removed from the area are 2–4 orders of magnitude higher than the total emissions introduced by DER installations. As a result, introduction of DER in place of high-emitting power plants leads to a domainwide decrease in NO_x and SO_x emissions of approximately 20%.

Air quality modeling of the 2010 baseline and DER cases predicts maximum differences in air pollutant concentrations are located downwind from the central power plants removed from the domain. Maximum decreases in hourly peak O_3 concentrations are on the order of 10 ppb and are located over the state of New Jersey. Maximum decreases in 24-hr average $PM_{2.5}$ concentrations reach approximately 3 $\mu g/m^3$ and are located off the coast of New Jersey and New York. The main contributor to decreases in $PM_{2.5}$ concentrations is the reduction of sulfate levels due to elimination of direct emissions and secondary particulate formation via oxidation of SO_x. Overall, deployment of DER in substitution of existing power plants may lead to localized reductions in O_3 concentrations and significant reductions of $PM_{2.5}$ over large areas of the northeastern United States. Because the CMAQ model tends to underpredict $PM_{2.5}$ and SO_x concentrations, air quality benefits of using DER may be even greater than the current simulation results.

In general, simulation results suggest that air quality benefits from DER implementation are mainly attributable to substitution of high-emitting power plants by DER. The criteria used in this study to select candidate plants to be substituted by DER might not correspond to the most realistic scenario. In addition, no consideration has been made to account for grid stability or connectivity. Hence, the resulting emissions reductions due to power plant removal represent an aggressive emission reduction that could represent an upper bound for air quality benefits of DER implementation scenarios. On the other hand, alternative DER scenarios could adopt higher penetration of low-emitting, though more expensive, technologies, such as fuel cells, that could lead to more significant emission reductions from power generation.

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