Time and Location Differentiated NO_X Control in Competitive Electricity Markets Using Cap-and-Trade Mechanisms*

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Abstract

Due to variations in weather and atmospheric chemistry, the timing and location of nitrogen oxide (NO_X) reductions determine their effectiveness in reducing ground-level ozone, which adversely impacts human health. Interest in using a time- and location-differentiated cap-and-trade program for NO_X emissions to address ozone pollution in the Eastern United States has been growing do to potential improvements in cost-effectiveness compared to un-differentiated cap-and-trade. In order to successfully implement a differentiated cap-and-trade program for stationary sources power plants, which contribute over 95% of NO_X emissions from stationary sources in the Eastern United States, must have the capability to reduce emissions in response to incentives that change in time and by location. We simulate the magnitude of NO_X reductions that can be achieved at various locations and times as a consequence of redispatch of generating units in the "classic" PJM region taking supply-demand balance constraints and network congestion into account. We report simulations using both a zonal model and an optimal power flow model. We also estimate the relationship between the level NO_X emission prices, competitive market responses to different levels of NO_X prices, and the associated reductions in NO_X emissions. The estimated maximum potential reductions, which occur at NO_X prices of about \$125,000/ton, are about 6 tons (15%) hourly in peak electricity demand hours and about 8 tons (30%) in average demand hours. We find that network constraints have little effect on the magnitude of the reductions in NO_X emissions.

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1. Introduction

There is growing interest in implementing a time- and location-differentiated cap-and-trade program to address the impacts of NO_X emissions on ground-level ozone pollution in the Eastern United States. There are four primary reasons for the interest in differentiation. First, states in the Eastern U.S. have found it difficult to attain the National Ambient Air Quality Standards for ground-level ozone – a pollutant that damages public health and welfare (U.S. EPA 2005). Second, scientists studying the atmospheric chemistry of ozone formation have shown that the amount of ozone formed from a given quantity of NO_X emissions can vary considerably due to the timing and location of the emissions (Mauzerall *et al.* 2005, Tong *et al.* 2006, Lehman *et al.* 2004, Ryerson *et al.* 2001, Chameides *et al*. 1988). Third, differentiated regulations offer potential efficiency gains if they can provide the strongest incentives for sources to reduce the most harmful emissions while keeping transaction costs low (Montgomery 1972, Mendelsohn 1986, Krupnick *et al.*2000). Fourth, regulators have used cap-and-trade programs like the 1990 Acid Rain Program and the 2003 NO_X Budget Program to reduce sulfur dioxide (SO_2) and nitrogen oxide (NO_X) emissions from stationary sources at low cost compared to traditional, prescriptive regulations (Ellerman *et al.* 2000, Burtraw *et al.* 2005). The implementation of a differentiated cap-and-trade program would be an incremental improvement building from these successful cap-and-trade programs and the tools, like continuous emissions monitoring, already in place to support them.

One condition that must hold for successful implementation of a differentiated cap-and-trade program that has not been addressed in the literature is that sources must be able to reduce NO_X emissions in response to incentives that change in time or by location.[1] Power plants emit about 97% of the NO_X emissions from the large stationary sources currently regulated under the NO_X Budget Program.[2] Power plant operators in the Eastern U.S. would have two options for abatement in response to differentiated incentives: they could change their level of dispatch (or output) by changing their bids into wholesale power markets or they could alter the plants' emission rates using control

[1] Perhaps in response to allowance exchange rates that varied in time based on forecasts of ozone pollution.
[2] Calculated from EPA Continuous Emissions Monitoring data at http://cfpub.epa.gov/gdm/.

technologies. Although plant operators could use technologies to alter a plant's emission rate on the timescale of a few weeks, it might be less costly for them to respond through redispatch.[3] But technical constraints like full utilization of capacity and network congestion can limit the ability of plant operators to change their level of output to achieve short-term emissions reductions. In particular, ozone formation is most likely on hot, summer days when peak electricity demand and network congestion are also likely. If power plants could not respond to differentiated incentives with NO_X reductions, a differentiated cap-and-trade program would only result in increased electricity prices.

In order to address the question of whether power plants could respond to differentiated incentives, we report simulations of the *potential* magnitude of reductions in NO_X emissions in the "Classic" PJM[4] area that can be achieved at various locations at critical times as a consequence of redispatch of generating units while meeting electricity demand and transmission network constraints with available generating capacity. The simulations used recent historical data on generation, network congestion and NO_X emissions for fossil-fueled generators located in this area. We used both a simplified zonal model and a detailed security-constrained optimal power flow (SCOPF) model of the Classic PJM network. We found that there are significant physical opportunities to reduce NO_X emissions without violating transmission network constraints or the constraint that supply and demand are balanced in real time.

There are reasons to consider applying a differentiated cap-and-trade program to power plants beyond their capability to respond. Power plant operators in the Eastern U.S. have experience with cap-and-trade programs. They also make day-ahead and real-time operational decisions based on sophisticated models of electricity and fuel prices, demand, and weather forecasting: differentiated incentives to reduce NO_X would not greatly alter this decision process. But the abatement costs for power plants should be compared to those for other sources. Mobile sources emit about 59% of the annual NO_X emissions in the Eastern United States while large stationary sources (predominantly

[3] It must be remembered that when emission controls, such as low-NO_X-burners, are adopted under cap-and-trade systems, plant operators are not required to utilize them at all times. Observation of historical compliance with the seasonal cap-and-trade programs suggests that power plant operators can alter the NO_X rates of some units – especially those employing combustion-altering technologies – on the time scale of a few weeks.

[4] We define "Classic" PJM as generating units located primarily in Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia. The PJM system operator also refers to this area as PJM-East and Mid-Atlantic PJM. In the last few years PJM's footprint has expanded to include portions of West Virginia, Virginia, Ohio and Illinois.

power plants) only emit about 22% (U.S. EPA 2006b). A recent study suggests that the marginal costs of NO_X abatement from mobile sources are less than those from stationary sources (Fowlie *et al.* 2007). Thus, although power plant operators have experience that might aid the implementation of a differentiated cap-and-trade program, the relative costs of reducing NO_X from mobile sources and the impacts of NO_X emissions from mobile sources on ozone pollution should be considered as well.

We present order-of-magnitude estimates of the level of NO_X emissions prices that would be needed to induce redispatch to achieve various levels of NO_X reduction within the physically feasible set, assuming that NO_X prices are incorporated into generators' bids. These estimates rely on simplified marginal generation cost-curves for all the fossil fuel generating units in Classic PJM. We provide a brief discussion of the potential for long run investment responses to NO_X prices of these magnitudes and the potential for using time and location differentiated NO_X prices to improve linkages between regulation governing stationary sources and market-based approaches to controlling NO_X emissions from mobile sources.

The remainder of this paper proceeds as follows. In Section 2 we briefly summarize background information on the ozone problem and policies that the Eastern U.S. states and the EPA have used to address it. Section 3 describes the methods we used to simulate the potential reductions in NO_X emissions from redispatch. Section 4 discusses the results of the simulations and some implications for potential long run investment incentives for NO_X control equipment. The final section contains concluding comments.

2. Policy background and description of the ozone problem

The Clean Air Act (CAA) of 1970 mandated that the Environmental Protection Agency (EPA) set health-based National Ambient Air Quality Standards (NAAQS) for criteria pollutants and that the states develop State Implementation Plans (SIPs) to control source-specific emissions at levels that would ensure attainment of the NAAQS.[5] The EPA first set the standard for ozone in 1971 and revised it in 1997.[6]

Summertime cap-and-trade programs for stationary sources have been the primary mechanism policymakers have relied upon to achieve significant NO_X reductions in the Eastern United States since the late 1990s.[7] The first of these programs was the Ozone Transport Commission (OTC) NO_X Budget Program, which began in 1999 and included eleven Northeastern states and the District of Columbia.[8] In 2004, the EPA extended this program to an additional ten Eastern and Midwestern states and it is now called the NO_X Budget Trading Program.[9] In being regional and seasonal,[10] these cap-and-trade programs have made some recognition of the spatial and temporal variability in the effect of NO_X precursor emissions on ozone formation, but the differentiation is very coarse. The extended NO_X Budget Program has brought two-thirds of the previously non-attainment areas in the Eastern U.S. into attainment with the ozone NAAQS; however, the remaining third of the Eastern U.S. areas, including the most densely populated ones, still are not in compliance with the ozone NAAQS during one or more days each year.[11] Moreover, the recent Clean Air Interstate Rule (CAIR), which will significantly reduce

[5] CAA §108(a)(2) states: "Air quality criteria for an air pollutant shall accurately reflect the latest scientific knowledge useful in indicating the kind and extent of all identifiable effects on public health or welfare which may be expected from the presence of such pollutant in the ambient air, in varying quantities."

[6] The original ozone standard was that ozone concentrations could not exceed a 24-hour average of 0.12 parts per million more than once per year. The new ozone standard, set in 1997, is that the 3-year average of the fourth-highest daily maximum 8-hour average ozone concentrations each year must not exceed 0.08 parts per million.

[7] Mobile sources (cars and trucks) have been subject to a variety of regulations on tailpipe emissions and the composition of gasoline they burn. However, increases in miles driven have largely offset advances in controls affecting mobile sources (U.S. EPA 2003).

[8] These states were CT, DC, DE, MA, MD, ME, NH, NJ, NY, PA, RI, VT. This program was in effect in a summer ozone season (May through September) and it affected fossil fuel fired boilers with a rated heat input capacity of greater than or equal to 250 mmBtu/hour and all electric generating facilities with a rated output of at least 15 MW.

[9] In 1998, the EPA called for revision of NO_X State Implementation Plans (SIPs) in light of the 1997 ozone NAAQS. This SIP Call required 22 states and the District of Columbia to submit revised SIPs to "prohibit specified amounts of emissions of … NO_X – one of the precursors to ozone (smog) pollution – for the purpose of reducing NO_X and ozone transport across State boundaries in the eastern half of the United States." States could choose to comply with the SIP call by participating in the NO_X Budget cap-and-trade program. *Federal Register*, Vol. 63, No. 207, Tuesday, October 27, 1998, or by submitting a plan for source-specific NO_X emission rate limits. The expanded NO_X Budget Program became effective May 31st of 2004 after delays from lawsuits. The additional participating states are: AL, IL, IN, KY, MI, NC, OH, SC, TN, VA, WV. Parts of GA and MO will be included in 2007.

[10] The cap on NO_X applies for the months of May through September – the "ozone" season.

[11] In 2004, the EPA designated 126 areas in the U.S. as non-attainment for the 8-hour ozone standard based on 2001-2003 data. Of these areas, 103 areas were in the eastern U.S. and are home to about 100 million people. Based on data from 2003 through 2005, however, two-thirds of these areas are now in attainment, but problems persist in the remaining third of the areas where about 81 million people live (U.S. EPA 2006b, pg. 23).

the cap on NO_X emissions from stationary sources,[12] is not expected bring all the Northeastern states into full compliance (U.S. EPA 2006b, NESCAUM 2006). This expectation raises the question of whether changes in the current cap-and-trade system that better recognized time and locational variations of the impact of emissions on ozone formation could bring the region closer to compliance with these standards and reduce total compliance costs from stationary sources by reducing the amount of ineffective abatement.

The chemistry of ozone formation suggests that finer spatial and temporal differentiation could improve these programs' cost-effectiveness. Nitrogen oxides are one of the key precursors of ozone pollution but nonlinear interactions of NO_X with reactive volatile organic compounds (VOCs), sunlight, and wind complicate the chemistry of how concentrations of ground-level ozone change over time as a function of NO_X emissions. The amount of ozone formed due to a given amount of NO_X emissions depends on the relative concentrations of VOCs and NO_X ($NO + NO_2$), on the temperature, and on whether or not it is sunny (Ryerson *et. al.* 2001, Chameides *et.al.*1988, CARB 2004). Mauzerall *et. al.* (2005) found that the ozone produced from the same amount of NO_X emissions from stationary sources at different times and locations in the Eastern U.S. can vary by up to a factor of five. The public health impacts of the NO_X also depend on locational variations in demographics that influence exposure (Mauzerall *et. al.* 2005). Tong *et. al*. (2006) used similar techniques to study the ozone-caused NO_X damages around Atlanta and found that ozone formation chemistry causes the marginal damages of NO_X emissions to vary across the Atlanta metropolitan area.

Given the current experience with cap-and-trade programs and with the atmospheric chemistry of ozone pollution, a differentiated regulatory system could be initiated by weather forecasting models that would provide advance warning of the times when meteorological conditions were expected to be conducive to the formation of high ozone concentrations in critical areas (for instance, those in non-attainment).[13] The forecasts could also provide information on the locations or zones of the precursor NO_X

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[12] CAIR will add an annual cap-and-trade program for NO_X in Eastern and Midwestern states in 2010 for the purpose of reducing the contribution of NO_X emissions to fine particulate matter pollution. See Federal Register, Vol. 71, No. 82, Friday, April 28

[13] Ozone air quality forecasting is already utilized by the EPA and the National Oceanic and Atmospheric Administration (NOAA), see Davidson *et al.* 2004.

emissions that would have an impact on ozone formation during those critical times and at the critical receptor areas. Power plant operators could then be notified of the times and locations when a pre-set allowance surrender ratio greater than one-to-one would be imposed on NO_X emissions. Generators would then modify their bids in the day-ahead and real time markets in response to the higher cost of NO_X emissions and engage in further abatement where the capability exists to do so on short notice. The day-ahead and real time markets would then lead to patterns of locational prices that reflect the prevailing NO_X emissions permit exchange rates and result in generator dispatch and abatement that would reduce the relevant NO_X emissions.

Whether operators used control technologies or changes in dispatch to achieve NO_X reductions in the short run, the changes in emissions would result from decentralized, profit-maximizing responses by generators to the higher NO_X price and the resulting higher locational electricity prices in the day-ahead and real-time wholesale electricity markets. In the long run, power plant owners may invest in alternative emissions control technologies. We focus here on the potential magnitude of reductions in NO_X emissions that can be achieved at various locations at critical times in the short run as a consequence of redispatch of generating units while still meeting electricity demand and transmission network constraints. In doing so, we set changes in emission rates resulting from investment in and utilization of alternative emissions control technologies aside in this paper.

3. Methodology

We use two complementary methods to simulate the potential magnitude of reductions in NO_X emissions that can be achieved at various locations and at critical times as a consequence of redispatch while electricity demand and transmission network constraints are still met. Both methods used generating unit-level emission rates and balanced electricity supply and demand. We used a "zonal" method that accurately incorporated generating unit NO_X emission rates and historical load characteristics to demonstrate the physical potential for significant NO_X reductions through redispatch. We also used optimal power flow (OPF) and security constrained optimal power flow (SCOPF) simulations to estimate both the physical feasibility to redispatch generators to reduce NO_X emissions and the levels of NO_X permit prices required to induce various levels of economic redispatch – and therefore NO_X reductions – through wholesale market mechanisms. The second method used PowerWorld Simulator® and more accurately simulated network constraints than did the zonal model. The two methods produced reasonably consistent results. Since there is little evidence of significant market power in PJM today, the NO_X price simulations assumed that generating units engaged in Bertrand competition and bid their marginal costs into the PJM markets.[14]

3.1 Wholesale electricity markets in the Eastern United States

For any given hour, the economic dispatch of generating units to meet electricity demand on a network results in the transfer of electricity between network nodes according to complex but well understood physical laws. On an electric power network with no transmission constraints and no physical losses, economic dispatch would imply that all nodes on the network would have the same price for electricity. In this case, any possible pattern or level of demand could be served by the lowest cost generation available. Additionally, a dispatch of generating units that minimizes generating costs (primarily fuel costs) while also taking into account any price placed on NO_X emissions would be possible for the same levels of demand.

In reality, however, the lowest cost, unconstrained generator dispatch may not be feasible due to network constraints (thermal and contingency). The efficient dispatch of generating capacity must take these constraints into account. In a wholesale electricity market context where generator dispatch decisions are decentralized, this can be accomplished by organizing spot markets around a security constrained bid-based dispatch auction mechanism that yields a compatible set of locational prices for electricity. The wholesale electricity spot markets in the Northeastern and Midwestern states are now based on security-constrained bid-based auction mechanisms that produce a schedule for generator dispatch and set of locational spot prices for electricity that

[14] The independent market monitor for PJM does not believe market power to be a significant problem in PJM, see PJM (2006) pages 59-69 and 83-93. The capabilities of PowerWorld will allow us to explore the implications of market power in future research. For examples of work on the interactions of market power and emissions in PJM see Holland and Mansur (2006) and (2006). Holland and Mansur (2006) found that the exercise of market power in the PJM region leads to lower emissions and that, in this situation, a tradable permit system is superior to a tax in terms of welfare effects. Mansur (2006) also found that electricity restructuring and the accompanying exercises of market power explained about one third of the emissions reductions observed when PJM restructured in 1999 and when the NO_X cap-and-trade program first took effect in the ozone transport region.

reflect generator bids and network constraints simultaneously (Joskow 2006). Prices at different nodes on the network then vary to account for the marginal cost of congestion (and the marginal cost of losses).[15]

Transmission network constraints may limit the physical capability to substitute generation from low-NO_X rate units for generation from high-NO_X rate units while continuing to balance supply and demand at all locations. To assess the physical potential for NO_X reductions through redispatch in Classic PJM, we first used a simplified zonal model to identify portions of the Classic PJM network that were reasonable approximations of areas where the transmission system was capable of handling the exchange of generation between units without causing "trans-zonal" congestion or severely altering network flows between zones. Substitution between zones was assumed to be infeasible if it required increasing generation from one zone to another where network constraints were already binding. In order to capture a richer characterization of network power flows and constraints we used PowerWorld's SCOPF capabilities, parameterized to match the Classic PJM, as a second method to estimate the physical capabilities to reduce NO_X emissions. This model allowed us to take a more refined account of the physical constraints, contingencies and parallel flows on the network.[16]

3.2 The Zonal Model

Publicly available data on the PJM transmission system[17] were used to create a simple network model that mapped the substations of Classic PJM and the lines between them. We then used the substation names and information on voltages and equipment at each substation to match the generators in the EPA's Continuous Emissions Monitoring System (CEMS) to the network model.[18] The CEMS data provide hourly generating unit

[15] The wholesale electricity spot markets in New England and New York include the marginal cost of losses in locational prices. The PJM Interconnection, which we focus on here, started including the marginal cost of losses in its locational pricing mechanism in 2007, we consider the ozone season of 2005 before this change took place.

[16] However, despite this method's ability to model nodal prices, the parameters of the network underlying the model also change in time due to fluctuations in demand and ambient conditions. Any feasible representation of an electric power system will not capture how its electrical properties change in real time with patterns and levels of utilization and with ambient conditions.

[17] The data at PJM, "Transmission Facilities," available at http://www.pjm.com/services/transm-facilities.jsp, which contained data on the name, type and voltage of each bus and the buses to which each connected.

[18] See Environmental Protection Agency's Continuous Emissions Monitoring System (CEMS) (unit generation and heat input data) and data on emissions and characteristics of regulated sources at http://cfpub.epa.gov/gdm/. These data are available for fossil fuel-fired generating units with rated capacities of at least 15 or 25 MW, depending on the state.

operation data for each generator (e.g. heat input, generation, and emissions). Data on the capacities and fuel types of the generating units from the Energy Information Association (EIA) were also matched to the model.[19] Using these publicly available data sources, we matched approximately 49.1 GW (93%) of the fossil fuel-fired capacity to the network model of Classic PJM.[20]

We then used two criteria to create zones in the PJM network within which congestion rarely occurred. In its State of the Market Report, PJM discussed the impact of frequently congested lines on market concentration (PJM 2006). For 2005, it listed thirteen transmission lines and transformers that were congested for over 100 hours in 2005. The State of the Market Report discussed three other lines and one other transformer that were frequently congested in 2004. The first criterion we used to identify zones within PJM was that these 17 lines be located on the borders between zones and not within the zones. The second criterion defined zones with historical hourly locational marginal price (LMP) data and it created smaller zones than the first criterion.[21] The second criterion was that the standard deviation of the LMP's within each zone be less than \$10/MWh for at least 90% of a sample of 144 summertime hours in 2005.[22]

These two criteria created 35 zones with between 117 and 4 nodes in each. We then estimated the potential reductions in NO_X from the redispatch of fossil capacity in Classic PJM while taking account of the constraints caused by the most frequent patterns of network congestion in 2005. That is, we minimized NO_X emissions from fossil fuel generating units in Classic PJM subject to three constraints for each hour of analysis:

1. Total generation and demand were held constant.

[19] See EIA "Form EIA-860 Database: Annual Electric Generator Report," available at http://www.eia.doe.gov/cneaf/electricity/page/eia860.html.

[20] The 2005 PJM State of the Market Report stated that there were about 50.6 GW of fossil capacity in PJM in 2005 (PJM 2006), so our matching process covers about 97% of the fossil capacity in PJM. Of the 49.1 GW capacity in the EIA database, about 96% of it (47.2 GW) reports emission data to the EPA's CEMS database. This gives us detailed data on the emissions from about 93% of the fossil fuel-fired capacity in PJM.

[21] Hourly LMP and zonal demand data for PJM are available on the PJM website and we matched them to the network graph. PJM website "Real Time" energy market data at http://www.pjm.com/markets/energy-market/real-time.html.

[22] This criterion was selected because differences in LMP of less than \$10/MWh rarely indicate congestion. More typically, they indicate other differences in marginal cost between nodes. PJM lists both LMPs and data on "real time constraints" or "transmission limits". The LMPs between nodes often vary up to \$30/MWh without the line between those nodes being listed as a constraint. Additionally, we only required the zonal model to capture frequent patterns of congestion. Many of the identified zones easily met the last criterion. For example, in the largest zone of 117 nodes, the standard deviation of LMPs was less than \$5/MWh in 90% of the hours and less than \$10/MWh in 98% of hours. See "PJM Operational Data" at http://www.pjm.com/pub/account/lmpgen/lmppost.html or "Real Time Transmission Constraints 1998-2005" at http://www.pjm.com/markets/energy-market/real-time.html.

2. The total generation from all the generating units in zones on the high-LMP side of congested lines and transformers could not decrease.
3. The total generation from all the generating units in zones on the low-LMP sides of congested lines and transformers could not increase.

The first constraint is the balancing constraint. The second constraint reflects the fact that a decrease in the net generation from units on the high-LMP side of a constraint would cause an increase in the power flowing over a congested line and therefore would not be possible. Similarly, the third constraint was used because increasing the net share of power from units on the low-LMP side of a constraint would necessitate an increase in the power flowing over the congested line. It is possible, however, to increase the generation from units on the high-LMP side of a congested line while reducing that from the generators on the low-LMP side. This would decrease the flow of power over that line (i.e. create counterflow), thereby relieving congestion.

We estimated the possible NO_X reductions for a 24-hour diurnal period between August 3rd, 2005 at 2pm and August 4th, 2005 at 2pm. We also performed three variations of this analysis to test the impact of the above constraints on our results. First, we relaxed the second and third constraints to estimate the potential NO_X reductions that were possible if network constraints were not a factor; we call this the "unconstrained" case. In the second variation, we de-rated the capacities of generating units by the forced outage rate for PJM in 2005.[23] Last, we assumed that no generators could turn on in the redispatch and therefore used only the unused ("excess") capacity of generating units that were already operating in each hour to estimate potential NO_X reductions.

In the zonal simulations as well as the PowerWorld simulations described in the next section, we designated only combustion turbine units as "fast start" generators. This meant that the dispatch algorithms could turn on combustion turbines, but could only increase or decrease the output of all other units. We constrained the generation from all initially operating units to be at least 20% of their capacity and units could generate up to 100% of their summertime rated capacities. We also held the generation from all units outside Classic PJM and imports and exports constant. The NO_X emission rates for the units were estimated based on each unit's average NO_X rate for the hours between May 1st and September 30th 2005. This assumption is likely to underestimate the potential NO_X

[23] See infra note **Error! Bookmark not defined.**.

reductions because many of the coal units with the highest emission rates have emission rates that decrease with decreasing utilization and, as we discussed above, generators have some flexibility to vary NO_X emissions rates in the short run.

The zonal analysis had three major limitations. First, it did not consider new network overloads that the redispatch of generating units might cause. Second, it did not consider the loop flows at the borders of zones that might require units on the either side of a constraint to increase or decrease their output in order to avoid an increase in the flow over a congested line. Third, it did not consider contingency constraints. The second method using a security constrained optimal power flow (SCOPF) model of the PJM network, described immediately below, helped address these issues.

3.3 Optimal Power Flow Using PowerWorld Simulator®

PowerWorld Simulator® contains a security constrained optimal power flow (SCOPF) analysis package that can solve power flows for large electricity systems while optimally dispatching generators and enforcing transmission limits, interface limits, and contingency constraints.[24] We used PowerWorld to simulate how a range of uniform NO_X permit prices for Classic PJM, incorporated into linear cost curves for generators, changed the security constrained economic dispatch. In doing so we estimated the NO_X prices needed to achieve a range of NO_X reductions up to the maximum level (when further increases in NO_X prices caused little additional reduction). This provided both a measure of the physical capability and of the NO_X prices required to induce different levels of NO_X emissions through redispatch of generating units.

To perform reasonably realistic simulations of the PJM network, we used the information on network elements from two solved load flow cases: the PJM Financial Transmission Rights (FTR) and the North American Electric Reliability Corporation

[24] PowerWorld uses a full Newton-Raphson AC load flow algorithm or a DC approximation to solve the power flow. The optimal power flow capability simulates economic dispatch by iterating between solving the power flow and minimizing total system operating cost, using generator cost-curves, while enforcing system constraints like line and generator operating limits. Thus, the security constrained optimal power flow simulates economic dispatch while enforcing both normal operating limits and ensuring that there are no operating limit violations during specified contingencies (PowerWorld Corporation at http://www.powerworld.com/). For more explanation of the widely used algorithms behind optimal power flow models such as PowerWorld Simulator see, for example, Sun *et. al.* (1984).

(NERC) Multiregional Modeling Working Group (MMWG) cases.[25] The solved, or base-case, load flows included data like the voltages and impedances of lines for most of the elements in the PJM network and predetermined power injections at generator nodes and power withdrawals at load nodes. This information allowed PowerWorld to solve for the power flows across the lines in PJM.

PowerWorld uses generator cost information to perform optimal power flow simulations, which minimize total operating cost subject to network and generator capacity constraints. We created constant marginal cost curves for the Classic PJM generating units and imported them into PowerWorld in order to simulate security-constrained economic dispatch.[26] The cost curves were defined simply by:

$$c_i\ (\$/\text{MWh}) = H_i(p_{fi} + p_{ni}N_i) + O\&M_i$$

where, for each generating unit *i*, H_i is its heat rate (mmBTU/MWh), p_{fi} is the price of fuel ($/mmBTU), p_{ni} is the price of NO_X permits ($/ton), N_i is the unit's NO_X emission rate in (tons/mmBTU), and $O\&M_i$ is the unit's variable O&M costs in ($/MWh). For each level of demand in question, the units were "dispatched" in order of least cost according to these cost curves. The NO_X price was applied uniformly to all units in PJM and was varied between $2000/ton and $125,000/ton.[27]

To generate the cost curves, we utilized data on the average delivered cost of fuel for natural gas, coal, petroleum products, and petroleum coke to the electricity sector from the EIA's Electric Power Monthly for August 2005.[28] We matched these data to the generating units by state and primary fuel type. The variable O&M data were from the EIA's Annual Energy Outlook for 2006 matched to the generators by technology type and fuel.[29] We used EPA CEMS data to generate average 2005 ozone-season heat rates and NO_X emission rates for each unit.

[25] See PJM, "FTR Model Information," at http://www.pjm.com/markets/ftr/model-info.html and NERC, "Multiregional Modeling Working Group" at http://www.nerc.com/~pc/mmwg.html. We obtained the former with the help of PJM and the latter through a Freedom of Information Act, Critical Energy Infrastructure Information request through FERC.
[26] The generation and load in areas of PJM outside the Classic PJM footprint were held constant between the base case and the "redispatched" cases. The generation and load in the areas surrounding the larger PJM were zero in the base case and subsequent cases; thus imports and exports to and from PJM as a whole were assumed to be zero.
[27] In August of 2005 these prices were around $2500/ton. Prices are currently about $1000/ton.
[28] EIA's *Electric Power Monthly*, Tables 4-10 through 4-13, available at http://www.eia.doe.gov/cneaf/electricity/epm/epm_ex_bkis.html.
[29] (EIA 2006) Table 38, page 77.

As in the zonal model, we compared the NO_X emissions resulting from three cases: 1) an "unconstrained" case where the generation from units in Classic PJM was dispatched economically without enforcing network constraints, 2) the constrained case (optimal power flow "OPF") in which the network constraints, like line limits, were enforced, and 3) the security constrained case in which both network and contingency limits[30] were enforced (security constrained optimal power flow "SCOPF"). In this way, the PowerWorld analysis complemented the zonal analysis, which did not address contingency constraints or whether redispatch created new congestion.

The FTR base-case load flows simulated hours with average levels of total electricity demand, around 38 GW in Classic PJM.[31] The electricity demand in nighttime and early morning hours was typically about this level in Classic PJM during the summer of 2005. NO_X reductions in the nighttime summer hours may be important for ozone formation because winds can transport nighttime emissions to highly populated areas where ozone can form during the day.

Daytime electricity demand is typically higher than nighttime demand. In a peak hour of August 4th at 2 pm, electricity demand reached about 59 GW in Classic PJM in 2005. In order to simulate high demand conditions we scaled the FTR base case from 38 GW to 59 GW of demand in Classic PJM. We developed three scaled cases that had similar levels of total demand as well as similar levels of fossil generation and NO_X emissions as those observed on August 4th, at 2pm (the Classic PJM fossil units generated 35 GW and produced 38 tons of NO_X emissions in this hour). The first scaled case mimicked the historical LMP patterns observed on August 4th at 2pm ("Matched LMPs"). In the second case, we altered the nodal load data until there were 9 initially binding constraints, four of which PJM reported as active on August 4th at 2 pm ("Constraints"). In both the Matched LMP and Constraints cases the generation from the Classic PJM fossil units was 34 GW and NO_X emissions were 38 tons. In the third scaled case the Classic PJM fossil units generated 37 GW and emitted 39 tons of NO_X emissions and there were six initially binding constraints ("High Utilization"). The High Utilization case

[30] Contingency, or security, constraints require that the network be operated such that if a statistically likely contingent scenario occurred (like the outage of a plant or transmission line) overflows would not occur on certain other lines. For example, an n-1 criterion would generally require that any transmission or generation outage not disrupt the stable and secure operation of the network.

[31] For the analyses reported in this paper, we used the Monthly FTR load flow case that PJM posted in July 2007.

provided the most conservative estimate of potential NO_X reductions because it required more generation from the fossil units, which left less under-utilized generation available for redispatch.

The MMWG cases were designed to be representative of the network during various conditions (peak and otherwise).[32] The MMWG cases contained information on the entire Eastern Interconnection including the power systems of New York and New England. PowerWorld was used to build an "equivalent" network that contained only the Classic PJM and "electrically equivalent" but simpler approximations of the surrounding systems (see Overbye *et al.* 2004 for another example of using an "equivalenced" system). The imports and exports to and from Classic PJM and the approximated adjoining systems were held constant. In the Summer MMWG case the total electricity demand in Classic PJM was about 59 GW, similar to that on August 4th at 2pm 2005. In the Fall and Spring cases Classic PJM demand was about 41 GW and 40 GW respectively and in the "Low load" case it was about 24 GW.[33]

For all the PowerWorld simulations we used the DC approximation to the AC load flow. Both the AC and DC methods solve for the power flows over the network, but the former does not consider reactive power flows or line losses.[34] The literature suggests that DC SCOPF is sufficient for most economic analyses of electricity networks. Schweppe *et al.* (1988) proposed the DC load flow as a tool for economic analysis. Overbye *et al.* (2004) analyzed the accuracy-tractability trade off between using the full AC load flow and the DC SCOPF for LMP studies for the 13,000-bus model of the Midwest U.S. transmission grid. They found that DC SCOPF performed reasonably well: although the power flows were not identical, the DC method identified very similar patterns of constraints and the average LMP only differed by about $2.40/MWh (lower in the DC case). The DC approximation found that some lines were only about 99% loaded while the AC load flow found them to be congested, causing the observed difference in LMPs. Given this finding, any inaccuracies resulting from the use of a DC approximation

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[32] NERC, "Multiregional Modeling Working Group" at http://www.nerc.com/~pc/mmwg.html.

[33] The MMWG cases did not include information on contingencies and used different bus numbers and a slightly different network aggregation (or network topology) compared to the FTR cases. Minghai Liu from CRAI provided us with some valuable assistance in mapping the contingency constraints from the FTR to the MMWG cases.

[34] According to Overbye *et al.* 2004, the major simplifications of the DC power flow are that it 1) ignores the reactive power balance equations, 2) assumes identical voltage magnitudes of one per unit, 3) ignores line losses, and 4) ignores tap dependence in the transformer reactances.

are likely overshadowed by our use of linear cost curves, our choice only to model Classic PJM and not the entirety of the PJM network, and the necessity of scaling the FTR cases to better represent peak demand conditions.

4. Results and Discussion

Three characteristics of a power system create the potential for flexibility to reduce NO_X emissions (or emissions generally) through redispatch. First, for redispatch to be possible at all requires the existence of under- or unutilized generating capacity. Second, NO_X reductions may be possible if some of the underutilized capacity burns natural gas because natural gas units tend to have lower NO_X emission rates than coal and oil units. Third, if the NO_X rates of generators within the same fuel category differ and the low NO_X generation is underutilized then the redispatch of these units could reduce NO_X emissions. The characteristics of capacity, generation, and NO_X emissions in Classic PJM suggest the potential for flexibility to reduce NO_X through redispatch; the simulations were designed to test whether network constraints limit this potential.

In this section, we discuss the relevant background characteristics of Classic PJM and present the results of our estimates of the maximum technical potential for NO_X reductions by redispatch. We present our examination of the magnitude of the NO_X prices needed to achieve various levels of NO_X reduction up to the maximum.

4.1 NO_X Emission Characteristics of Classic PJM

Both demand and fossil fuel-fired generation in PJM and in Classic PJM are highest during the ozone season (May through September). Table 1 displays the average and maximum hourly demand in PJM in 2005 during the ozone season and during the non-ozone season months. The table also shows the average and maximum hourly generation and NO_X emissions from the fossil-fired generating units in Classic PJM that we used in our simulations (371 units).[35] The average hourly NO_X emissions from the units in Classic PJM in 2005 were about 20 tons per hour and the peak NO_X emissions were about 45 tons (see Table 1).

[35] Our simulations do not model the further possibilities of exchanging hydro or nuclear power for fossil generation – although for nuclear we would expect the possibilities to be small as most nuclear plants are typically run near their full capacity in most hours.

Table 1 Average and Maximum demand in PJM and Classic PJM and Fossil Fuel-Fired Generation and Emissions in Classic PJM.

Hourly Data, 2005		**Ozone-Season**	**Off-Season**	**Annual**	
PJM Demand^	avg	74	68	71	*(GW)*
	max	116	97	116	
Classic PJM Demand	avg	36	32	33	*(GW)*
	max	59	46	59	
Classic PJM Fossil	avg	19	16	18	*(GW)*
	max*	36	26	35	
Classic PJM NOx Emissions	avg	19.6	30.0	25.7	*(Tons)*
	max*	44.7	46.2	46.2	

^Does not include the DUQ control area that joined PJM May 1, 2005
*Max from the highest demand hour in Classic PJM in 2005 in the ozone season (7/27/05 16:00) and non-ozone season (1/18/05 19:00) respectively

An important feature of Classic PJM (and of nearly all electricity control areas) is that even during the hours of the highest peaks in demand, there is generating capacity that is in some form of reserve status and not actually generating. This is the first reason to expect potential NO_X reductions from redispatch. Table 2 shows the capacity of the 371 fossil fuel-fired generating units that were used in our redispatch simulations. The total capacity of these units was about 46 GW (or 42 GW if de-rated by the annual forced outage rate for PJM in 2005).[36] The maximum hourly generation from these units during 2005 was about 36 GW, leaving about 6 to 10 GW of capacity that was not generating electricity. Some of this remaining capacity was providing spinning, non-spinning, and supplemental reserve margins for reliability purposes. We assume that units with higher NO_X emission rates that were generating electricity during the peak hours could be exchanged for lower NO_X units in these reserves, at least for short periods of time.

[36] Since the annual forced outage rate may be too restrictive, as noted earlier (infra note **Error! Bookmark not defined.**), the range is presented in Table 2.

Table 2 Capacity and generation by fuel-type in Classic PJM during the 2005 ozone season.

Hourly Data, Ozone Season 2005		Coal	Natural Gas	Oil	TOTAL	
Capacity	rated	21	15	10	46	*(GW)*
	unforced^	19	14	9	42	
Generation	avg	15	3.0	1.6	19	*(GW)*
	max*	18	10	8.2	36	
NOx Emissions	avg	15.8	1.2	2.6	19.6	*(Tons)*
	max*	20.2	6.9	17.6	44.7	
NOx Emission Rates	avg	2.15	0.78	3.19	2.02	*(lbs/ MWh)*
	max*	2.24	1.37	4.29	2.46	

Fuel Category Designations from the EPA's Clean Air Markets Database
*Max from the highest demand hour in Classic PJM in 2005 in the ozone season (7/27/05 16:00)
^Derated by the equivalent demand forced outage rate for PJM in 2005 (7.3%) (PJM 2006)

Table 2 also shows that natural gas generation had the lowest average NO_X rate, about half the average for coal-fired generation. The second reason to expect that redispatch might cause NO_X reductions is that natural gas-fired capacity represented the largest portion of the unutilized capacity (for both peak and average hours). This occurred because the bid-based, security constrained economic dispatch utilized the highest marginal cost units last and natural gas-fired units tend to have the highest marginal costs due to natural gas prices (which were particularly high in 2005). For all fuel-types, the generation dispatched to fill peak demand had a higher NO_X rate than that dispatched to fill average demand. This was expected since there is no differentiation in NO_X pricing between peak and other summer hours and the units pressed into service during peak hours are typically those of all fuel types with lower efficiency (higher heat rates).

The third reason to expect potential NO_X reductions from redispatch was that some of the coal-fired generating units in Classic PJM that were underutilized had a lower NO_X rate than those generating. For example, the average NO_X emission rate for the generation from coal power plants on August 4th, 2005 at 2 pm was 2.2 lbs/MWh and 34% of the undispatched coal capacity had a lower NO_X rate.

4.2 Zonal Model Simulations of Potential NO_X Reductions in Classic PJM

The timing of NO_X emission reductions is important because meteorological conditions affect ozone formation. Although ozone formation is most likely in hot, sunny conditions, NO_X emissions in other hours can impact downwind formation of ozone. Table 3 reports the generation, emissions, simulated NO_X "reductions" using the zonal model for Classic PJM the 24 hours preceding a peak hour (every four hours). The potential NO_X reductions from redispatch vary in time because the total demand for electricity varies diurnally and according to the weather.[37]

Table 3 Results of simulation of potential reductions in NOX emissions from redispatch in Classic PJM using the zonal model.

Zonal Model Simulations of Maximum Potential NOx Reductions

	Base Case		*Unconstrained*		*Transmission*		*Unforced Capacity^*		*Only "ON" Units*	
Date	**Generation**	**NOx**	**Reduction**	**%**	**Reduction**	**%**	**Reduction**	**%**	**Reduction**	**%**
8/3/05 14:00	33	35	7.0	20	6.6	19	6.5	18	6.0	17
8/3/05 18:00	33	35	9.2	26	6.1	17	7.4	21	6.1	17
8/3/05 22:00	26	26	10.8	42	6.9	27	9.2	36	6.5	25
8/4/05 2:00	19	19	7.8	42	7.6	41	9.8	52	3.9	21
8/4/05 6:00	23	23	8.6	37	8.4	36	9.3	40	4.5	19
8/4/05 10:00	31	28	7.2	25	6.9	24	6.7	24	4.5	16
8/4/05 14:00	35	38	8.2	21	8.0	21	7.5	20	7.1	19
	(GW)	*(Tons)*	*(Tons)*	*(%)*	*(Tons)*	*(%)*	*(Tons)*	*(%)*	*(Tons)*	*(%)*

^ Capacities were derated by the 2005 demand equivalent forced outage rate for PJM of 7.3% (PJM 2006).

The range of total hourly generation for the units we considered in Classic PJM was from about 19 GW per hour, which occurred during the middle of the night, to 35 GW on August 4th at 2pm. The range of initial hourly NO_X emissions was between about 19 and 38 tons. The NO_X reductions ranged from about 6.1 tons (17%) during the day to 8.4 tons (about 35%) in early morning and late night hours for the transmission constrained estimates (labeled "Transmission").[38] Larger reductions should be possible at night because the network is typically less constrained and less capacity is utilized during the lower demand hours.

[37] There will also be some variation due to planned maintenance of facilities which will be scheduled primarily for other than the peak summer demand season.

[38] Since natural gas prices were high during the summer of 2005, observed emissions, and therefore the simulated reductions, might have been higher than in a more normal year. For comparison, we looked at a peak demand hour of 2001 when natural gas prices were much lower. During this hour, there were about 31 GW of fossil generation in Classic PJM (vice 35 during the peak-hour in 2005) and 51 tons of NO_X emissions (vice 38 tons). The potential unconstrained NO_X reductions were about 16 tons or 32%. Both the initial emissions and NO_X reductions were higher in the 2001 peak-hour than in the near-peak hour in 2005 with the same level of fossil generation (e.g. 8/3/05 20:00); however, the percent reduction was about the same.

Two additional simulations are reported in Table 3 in the columns labeled "unforced capacity" and "Only 'ON' units," both of which were intended to represent plausible restrictions on the potential to switch generating units, additional to transmission constraints. In the former, the summertime rated capacities of all generating units were multiplied by a factor of one minus the forced outage rate of PJM in 2005 to represent the possibility that all capacity may not be available at a level of 100% in all hours.[39] The last column represents the case where the low NO_X-emitting units that could substitute for higher NO_X emitting units were limited to those providing spinning reserve services. Of these two further limitations, restricting the pool of exchangeable units to operating units with unused capacity in spinning reserves had the greater effect. Moreover, this effect was significantly greater during non-peak hours than in peak hours. Or, stated differently, most of the NO_X-reducing substitution capability during peak hours came from units in spinning reserve while most of that during non-peak hours was from units that were not generating at those times.

Recent actions taken in the OTC States suggests that this magnitude of potential NO_X reductions from redispatch is nontrivial. A recent OTC Memorandum of Understanding (MOU) signals an intention by the signatory states to reduce emissions on high electricity demand days.[40] Four of the signatory states are in the Classic PJM region and the MOU requires these states to make total daily NO_X reductions of about 72 tons on high electricity demand days, which is an average of 3 tons per hour over a 24-hour period.[41] Given that 6 tons of reductions are available from redispatch even in the highest demand hours, the potential reductions from redispatch are about twice the targets for reducing NO_X emissions.

[39] PJM (2006), page 244, states that the forced outage rate for PJM in 2005 was 7.3% for all generating units. This rate does vary by type of generating unit (steam units have the highest outage rate and combined cycles the lowest of the fossil-fuel fired units). In this analysis, the capacities of all generating units were scaled by a factor of 0.927.

[40] The states agreed to make the reductions beginning in 2009 and no later than 2012. See, OTC's "Memorandum of Understanding Among the States of the Ozone Transport Commission Concerning the Incorporation of High Electrical Demand Day Emission Reduction Strategies into Ozone Attainment State Implementation Planning," March 2, 2007. The MOU does not fully define a high electricity demand day, but some related analysis suggests that these are the days on which the high demand requires peaking units that typically generate in less that 10% of annual hours to generate power (NESCAUM 2006)

[41] The four signatory states that are in the Classic PJM area are DE, MD, NJ, and PA. The other signatory states are CT and NY.

4.3 Optimal Powerflow Simulations (PowerWorld) of NO_X Reductions in Classic PJM

The available load flow cases restricted the PowerWorld simulations to "generic" hours with different demand, generation, and congestion characteristics (rather than for a series of hours). The results agreed reasonably well with those from the zonal model, although the zonal simulations tended to be slightly optimistic compared to the PowerWorld simulations. Table 4 shows optimal power flow (OPF) simulation results for high NO_X prices of $125,000/ton for solved load-flow cases with varying levels of demand and generation. NO_X prices above $100,000/ton caused only small additional reductions in NO_X emissions (see Table 5). In Table 4 the base case was the result of OPF dispatch with assumed NO_X prices of $2000/ton (indicated by "2k") to roughly represent the observed NO_X prices of between 2000 and 3000 $/ton in the summer of 2005. (The SCOPF simulations did not alter the magnitude of potential reductions but did cause 2 additional tons of base-case NO_X emissions, Table 5.)

Table 4 Potential reductions in NO_X emissions from redispatch in Classic PJM using PowerWorld optimal power flow simulations.

PowerWorld Simulations of Maximum Potential NOx Reductions

		Base Case		*Unconstrained*		*OPF*	
		Generation	NOx	Reduction	%	Reduction	%
Peak Demand	Matched LMP	34	35	8.2	*23*	8.0	*23*
	Constraints	34	35	7.4	*21*	7.2	*21*
	High Fossil Gen	37	39	7.5	*19*	6.4	*16*
	MMWG Summer	37	43	5.9	*14*	5.8	*13*
Average and Low Demand	Avg Demand	19	20	12	*60*	12	*60*
	MMWG Low Demand	14	16	6.9	*43*	6.9	*43*
	MMWG Spring	24	28	7.5	*27*	7.5	*27*
	MMWG Fall	23	26	7.7	*30*	7.7	*30*

The maximum physical reductions depended on the initial levels and patterns of demand and were between about 6 and 8 tons hourly (13% and 30%, see Table 4). The MMWG cases produced the most conservative estimates of the potential NO_X reductions (about 6 tons per hour in the peak demand, "summer" hour). The potential reductions for the security-constrained (SCOPF) simulations using the MMWG summer case were also about 6 tons (Table 5).

A major difference between the FTR and MMWG solved load-flow cases was the pattern of the loads on the network. The locations of the loads on the network partially determine which generators are dispatched because of network characteristics, including transmission constraints. Even though the overall magnitude of the demand was the same and the same set of fossil units generated 37 GW in the "High Fossil Gen" FTR case and in the MMWG Summer case, the NO_X emissions in the "High Fossil Gen" base case were 39 tons compared to 43 tons in the MMWG Summer case. Because each unit had the same NO_X emission rates in both cases, this reflects the fact that different units were initially dispatched to fill demand in each case due to differences in the patterns of demand on the network. The resulting redispatch and potential NO_X reductions were also different as a result. The scaling process provided, at best, a rough approximation of nodal peak load patterns in the FTR cases so the MMWG summer case is likely more representative of peak demand conditions in Classic PJM. Notably, more lines were congested in the FTR High Fossil Gen case (6 lines) compared to the MMWG Summer case (only 2 lines). The potential reductions were greater in the former suggesting that "congestion" *per se* did not limit the flexibility to reduce emissions through redispatch and that the nodal pattern of demand relative to the locations of the generators had a greater effect.

4.4 Locational variation in potential NO_X reductions

The location, in addition to the time, of NO_X reductions affects their impact on ozone formation. One of the first criticisms of the cap-and-trade approach was that "hotspots" could result because these programs have not traditionally captured time and locational variations of the impacts of emissions on air quality standards. These hotspots, which have not been shown to occur in any of the currently implemented cap-and-trade programs, would occur when sources in an environmentally sensitive area chose to buy permits for their pollution, rather than taking actions that resulted in abatement.[42] This motivates the question of whether the redispatch of units to reduce NO_X is accompanied by substantial increases in NO_X emissions in some geographic areas.

It is certainly true that on the level of individual plants, some locations will produce more and some less NO_X as a consequence of redispatch. But at a higher level of aggregation it is not necessarily true that the redispatch, which results in a net reduction of NO_X, will result in areas with significantly higher NO_X emissions. Table 5 shows the

[42] For a summary of analyses of these issues see Swift (2004).

observed NO_X emissions by county for August 4th at 2 pm and the base case NO_X emissions in the MMWG Summer case. It also shows the changes in NO_X and generation due to redispatch subject to network transmission constraints in the zonal model and the reductions in the MMWG summer case with NO_X prices of $100,000/ton. The magnitudes of any increases in NO_X were generally small. Emissions increased more than 200 lbs in only 5 counties in the MMWG Summer case and in 3 counties in the August 4th, 2 pm zonal simulation. In both simulations, the redispatch increased emissions in 19 of the 57 total counties. The table shows only the counties in which redispatch changed NO_X emissions by at least 200 lbs.

Table 5 Original emissions and changes in at the county-level for simulated redispatch subject to network constraints for the MMWG Summer OPF simulation in PowerWorld and on August 4th, 2005 at 2 pm in the zonal model. The chart shows counties that had a net change in NO_X of at least 200 lbs.

		PowerWorld MMWG Summer		Zonal August 4th, 2 pm	
State	County	NOx	Change in NOx	NOx	Change in NOx
NJ	Burlington	4580	-4234	2553	-1557
PA	Bucks	3012	-2240	335	-257
NJ	Hudson	5624	-1808	5370	-3258
MD	Harford	1841	-1035	1146	-749
MD	Talbot	1017	-1017	0	0
NJ	Essex	1044	-963	719	-337
PA	Philadelphia	1628	-898	546	32
PA	Clearfield	2206	-674	1464	-967
NJ	Cape May	1969	-488	1752	-1134
MD	Prince Georges	6375	-357	5283	-715
PA	Northampton	3452	-208	6304	-1754
DC	DC	1470	0	613	1011
PA	Venango	27	89	81	213
PA	Delaware	3185	126	3141	257
NJ	Gloucester	463	202	427	-3
MD	Baltimore	2050	206	2605	-1451
PA	Union	0	223	0	0
MD	Dorchester	311	558	744	-595
NJ	Middlesex	3034	1782	4651	-1716
			lbs		

In the MMWG summer case, emissions increased the most in Middlesex County, New Jersey as a consequence of the increased output of one generating unit. The same unit reduced its output as a consequence of redispatch in the zonal model of August 4th at 2 pm, so emissions in Middlesex County decreased in the zonal simulation. Emissions increased the most in the August 4th, 2pm zonal simulation in the District of Columbia. Again this increase occurred because of the increased utilization of one generating unit. In the MMWG summer case the redispatch caused the unit to generate less, decreasing emissions in DC. The air quality consequences of these changes would ultimately depend on the meteorology and atmospheric chemistry conditions at the times they occurred. Atmospheric chemistry and meteorological modeling will also be necessary to identify which reductions and increases in NO_X are important for mitigating the formation of ozone in targeted areas.

4.5 Comparison of Zonal and Optimal Power Flow Simulations

The results of the zonal and PowerWorld simulations were comparable but the zonal simulations were slightly optimistic compared to the PowerWorld simulations. Comparable zonal and PowerWorld cases for peak demand hours are the MMWG Summer case and the zonal model simulation of August 4th at 2pm. Comparable average demand cases are the MMWG Fall case and the zonal simulation of August 4th at 6am. The generation from Classic PJM fossil units in the two peak cases was slightly different (37 GW in the MMWG Summer case compared to 35 GW on August 4th at 2pm). The potential reductions in the MWMG case were only about 6 tons (from 43 tons) compared to 8 tons in the zonal model simulations (from 38 tons). The NO_X reductions represented a change in average emission rate by 13% (from 2.3 to about 2.0 lbs/MWh) in the MMWG Summer case and by about 18% (from 2.2 to about 1.8 lbs/MWh) in the zonal simulation of August 4th at 2pm. The generation in both the average cases (MMWG Fall case and August 4th at 6am) was 23 GW. The zonal simulation reduced NO_X emissions by 8.4 tons (from 23 tons) compared to 7.7 tons in the MMWG Fall case (from 26 tons initially). The reduction in initial average NO_X emission rate was 35% in the zonal simulation (from 2.0 to 1.3 lbs/MWh) and 30% in the MMWG Fall simulation (from 2.3 to 1.6 lbs/MWh).

As Table 5 suggests, the initial emissions and the changes from redispatch were different in the PowerWorld and zonal models. The nodal load data for historical hours, such as August 4th at 2pm, were not available. This made simulating historical hours with PowerWorld difficult and made it a challenge to determine whether the differences in the zonal model and PowerWorld simulations were more a result of the simulation method or of initial conditions. The differences between the PowerWorld FTR and MMWG simulations suggested that initial load patterns influenced the potential NO_X reductions from redispatch. But a comparison of the changes in generation from units in the

PowerWorld MMWG Summer case and the zonal August 4th, 2pm case show that the zonal simulations allowed many more substitutions than the PowerWorld simulations.

For example, there were 191 units that generated in both the August 4th, 2pm observed data and the MMWG Summer base case. Of these 191 units, 95 units had similar levels of initial generation in both base cases.[43] Although the extent to which the simulations could redispatch the 95 units depended on the initial states of other generating units and on the patterns and magnitudes of nodal loads, it is telling to compare the changes in generation of these units between the two simulation methods. In the PowerWorld MMWG Summer base case, the 95 units generated about 19.1 GW and in the zonal base case they generated about 19.2 GW. After redispatch, this set of units generated 19.4 GW in the MMWG Summer case and 19.1 GW in the zonal case (other units turned on to make up the difference). The redispatch changed only 3 units' output by more than 20% in the MMWG Summer simulation, while it changed 23 units' output by more than 20% in the zonal simulation. This suggests that the constraints limiting the exchange of generation from units in the PowerWorld simulations were more stringent than those in the zonal simulations and that the PowerWorld simulations provide a more conservative estimate of the potential NO_X reductions from redispatch.

4.6 Security-constrained Simulations of NO_X Reductions at Varying NO_X Prices

Table 5 shows the relationship between NO_X prices and potential reductions in NO_X emissions for PowerWorld simulations. All simulations economically dispatched the generators in Classic PJM (minimized total operating costs) for ranges of NO_X prices in the MMWG Fall and Summer cases using the cost curves discussed in Section 3.

[43] We define similar in this case as units with generation that differed by less than 11.5 percent between the two base cases; the median difference in the 191 units' generation levels between the two cases was 11.5 percent.

Table 6 Results of the PowerWorld simulations for a range of assumed NO_X permit prices. Reductions (absolute and percentages) are calculated from the $2000/ton (2k) NO_X price case.

MMWG Summer									
NOx	Unconstrained			OPF			SCOPF		
Price	NOx	Reduction		NOx	Reduction		NOx	Reduction	
2k	43	--	--	43	--	--	45	--	--
10k	40	3.0	*7*	40	3.0	*7*	41	3.7	*8*
20k	38	4.5	*11*	38	4.5	*10*	40	4.6	*10*
50k	37	5.4	*13*	38	5.2	*12*	39	5.3	*12*
100k	37	5.8	*14*	37	5.6	*13*	39	5.4	*12*
125k	37	5.9	*14*	37	5.8	*14*	39	5.6	*13*
$/ton	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*

MMWG Fall									
NOx	Unconstrained			OPF			SCOPF		
Price	NOx	Reduction		NOx	Reduction		NOx	Reduction	
2k	26	--	--	26	--	--	26	--	--
10k	24	1.8	*7*	24	1.8	*7*	24	1.7	*7*
20k	23	2.9	*12*	23	3.0	*12*	22	3.1	*12*
50k	19	6.2	*24*	19	6.1	*24*	20	5.8	*23*
100k	18	7.4	*29*	18	7.5	*29*	18	7.4	*29*
125k	18	7.7	*30*	18	7.7	*30*	18	7.7	*30*
$/ton	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*	*Tons*	*Tons*	*%*

The SCOPF simulations used a set of 144 contingency constraints in Classic PJM.[44] Especially in the MMWG Fall case, the inclusion of contingency constraints did not dramatically change the results. The contingency constraints were not binding in the Fall case, but in the MMWG Summer case there were two to three binding constraints depending on the level of assumed NO_X price. The contingency constraints increased the base-case NO_X emissions in the Summer case by about 2 tons, but did not cause large changes the potential reductions (resulting in higher emissions each price).

Even in the average demand hour simulated in the Fall case, NO_X prices of about $50,000/ton were be necessary to obtain substantial reductions (5 or 6 tons in both the Summer and Fall cases).[45] This occurred because a NO_X price of about $50,000/ton was required to reverse the merit order of typical coal and gas generating units given summer of 2005 fuel prices.[46] The particular price did vary for individual units, decreasing with

[44] It is possible that the consideration of this set of contingency constraints is overly restrictive. The base case emissions and in the OPF cases match the observed for similar levels of generation better than the SCOPF base cases. Other uncertainties (e.g. in the cost curves) could also contribute to this discrepancy. But PJM reports on its website that they do not always enforce all contingency constraints and their operating procedures allow for the system operators to use their judgment with regard to whether lines can be overloaded. See PJM's information on Contingencies at http://www.pjm.com/markets/energy-market/lmp-contingencies.html.

[45] If the NO_X emission rate of the marginal generating unit were 3 lbs/MWh then a $20,000/ton NO_X price would add (roughly) $30/MWh to the locational price for electricity. If the marginal generating unit had a NO_X rate of only 0.5 lbs/MWh, the NO_X price would only add about $5/MWh to the locational price for electricity.

[46] The exact NO_X price for particular plants depended on heat rates, NO_X rates, and fuel prices. For example, a coal unit with a NO_X rate of 0.4 lbs/mmBTU and a heat rate of 10 mmBTU/MWh and a natural gas with a NO_X rate of 0.15 lbs/mmBTU and heat rate of 10 mmBTU/MWh would generate one megawatt of electricity for the same cost if NO_X prices were $52,000/ton, coal prices were $2.5/mmBTU, and natural gas prices were $9/mmBTU.

increases in the coal unit's NO_X rate or in the natural gas unit's heat rate. NO_X prices of \$20,000/ton did not cause a change in coal generation in the MMWG Summer simulation, but natural gas generation did replace oil generation at this price (Table 6). Some substitution of natural gas generation for coal occurred in the MMWG Summer case at NO_X prices of \$50,000/ton and more at higher prices. A small amount of coal to natural gas substitution occurred at prices below \$50,000/ton in the lower demand MMWG Fall simulation and much more substitution occurred at the higher prices. In the Fall case, NO_X prices above \$50,000/ton caused further reductions by increasing generation from natural gas. In the peak demand case, these natural gas units were already generating so there was less excess capacity to exchange.

Table 7 Changes in generation from coal, oil, natural gas and municipal solid waste (MSW) caused by NO_X prices of \$20,000/ton (20k), \$50,000/ton (50k), and \$100,000/ton (100k) compared to the base case generation (\$2000/ton NO_X prices).

	Base Case	Change in Generation		
MMWG Summer	**Generation**	**20k**	**50k**	**100k**
Coal	17996	0	-196	-425
Oil	7185	-182	-128	-104
Natural Gas	10377	198	409	670
MSW	225	0	-60	-115
MMWG Fall				
Coal	16461	-132	-1900	-2965
Oil	2217	-142	393	844
Natural Gas	4130	284	1548	2233
MSW	143	-10	-40	-112
		MW		

The substitution between fuels does not explain all of the simulated NO_X reductions – within-fuel substitutions also caused NO_X reductions. For example in the \$100,000/ton MMWG Fall simulation, the sum of reductions in generation from coal generating units was 3487 MW. But the net change in coal generation was a decrease of 2965 MW (Table 6) meaning that some coal units increased their output as well – by a total of about 522 MW. There was about 1000 MW of substitution within the natural gas generating units in the same simulation.

The average costs of NO_X abatement from redispatch were calculated by dividing the total change in fuel and O&M costs by the NO_X reductions between the higher-NO_X-price simulations and the \$2000/ton base case. Table 7 shows the average abatement costs for the MMWG Summer and Fall OPF simulations. The average costs of abatement at NO_X prices below about $20,000/ton were roughly half or less than half of the NO_X prices.[47] Figure 2 shows the marginal and average abatement cost curves for the same simulations. Especially in the MMWG Summer case, the costs increased steeply as the simulations approach the maximum potential NO_X reductions. The costs were also similar for the MMWG Summer and Fall cases for abatement up to about 10%, at which point the costs increased more quickly in the higher demand MMWG Summer case.

Table 8 NO_X emissions, abatement, and average abatement costs for NO_X prices between $2000/ton and $100,000/ton in the MMWG Summer and Fall simulations.

MMWG Summer Case **NOx Price**	**NOx**	**Abatement**	**Percent Abatement**	**Average Cost of Abatement**
2k	42.7	--	--	--
10k	39.8	3.0	7	5741
15k	39.2	3.6	8	6635
20k	38.3	4.5	10	9203
25k	38.1	4.6	11	9397
30k	38.0	4.7	11	9778
50k	37.5	5.2	12	15061
100k	37.2	5.6	13	21414
$/Ton		*Tons*	*%*	*$/Ton*

MMWG Fall Case **NOx Price**	**NOx**	**Abatement**	**Percent Abatement**	**Average Cost of Abatement**
2k	25.6	--	--	--
10k	23.8	1.8	7	5792
15k	23.1	2.5	10	7524
20k	22.6	3.0	12	10844
25k	22.0	3.6	14	14911
30k	21.3	4.3	17	18964
50k	19.5	6.1	24	32913
100k	18.1	7.5	29	44218
$/Ton		*Tons*	*%*	*$/Ton*

[47] Personal conversations with industry representatives suggested that this was expected.

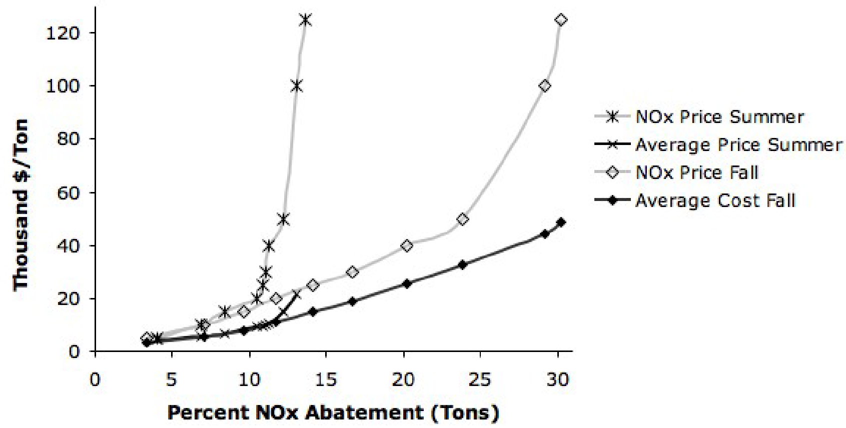

Figure 1 Marginal and average abatement cost curves for the MMWG Summer and Fall OPF simulations.

The recent OTC MOU again provides a point of comparison. The MOU did not require specific actions to reduce the peak demand day NO_X emissions and it noted that the reductions could come from controls on peaking units or through other measures like energy efficiency or demand response. As an example action that states could take to control emissions from power plants on peak electricity demand days, the EPA calculated that the average abatement costs of installing water injection NO_X control technology on peaking units in the Northeastern U.S. would be about $158,000/ton to reduce NO_X by about 0.23 tons per day over a 12-day, high-electricity-demand period for each unit that installed the technology.[48]

Redispatch appears preferable on a cost per ton basis to controlling NO_X emissions from infrequently used peaking units, although other control options may also be available. One of the benefits of time varying NO_X prices is that the control decisions could be made through decentralized market incentives rather than by regulatory fiat. Another related benefit is that, with the incorporation of air quality forecasting, these costly reductions could come during the times and locations that would most likely impact ozone formation in critical areas – rather than from a specific, predefined set of generating units. For comparison to these cost examples, Mauzerall *et. al.* (2005)

[48] EPA Clean Air Markets Division presentation by Chitra Kumar, "High Electricity Demand Day Attainment Strategies for the OTC," December 6, 2006. The same EPA analysis estimated average costs of installing SNCRs on uncontrolled coal plants of $18,000/ton to reduce NO_X by about 2.2 tons per day per unit over the same 12-day period.

estimated the damages of ozone per incremental ton of additional NO_X emissions to be between about $13,000 and $64,000 per ton.[49]

While the focus here, and the primary focus of regulators, has been on reducing NO_X emissions from electric generators, another option is to tighten controls on NO_X emissions from mobile sources. Accordingly, another potential benefit of a transparent time varying NO_X pricing system is that it will also make the need to undertake potentially economic opportunities to reduce NO_X emissions from mobile sources more transparent. Although this option is not typically discussed as a targeted action, it could be. For example, the variable cost of using selective-catalytic reduction (SCR) on diesel trucks is high due to the cost of urea. The use of these controls could be mandated only in locations and at times when the NO_X reductions would reduce the formation of ozone in highly populated areas. A pricing system could also be used to deter driving during specific periods and in highly populated areas where the resulting reductions in NO_X emissions would reduce the likelihood of high ozone concentrations. Because controlling NO_X emissions from vehicles has not been thoroughly analyzed as an option to target ozone episodes, it is difficult to find cost information to compare to the above estimates of short-term reductions in NO_X from stationary sources. But, because little has been done to reduce NO_X from mobile sources, especially in comparison to the number and stringency of NO_X regulations on stationary sources, it is possible that the reductions would be less expensive than further reductions from stationary sources.[50]

4.7 The Impact of Network Constraints on Potential NO_X Reductions

The most striking feature of the results reported in Tables 4 and 5 is that transmission constraints did not significantly reduce potential NO_X emissions reductions from redispatch in Classic PJM. There were three primary reasons for this result. The first was related to the spatial heterogeneity in the low and high NO_X generating units in PJM. High NO_X units were not mostly in one area of PJM and low NO_X units in another; they tended to be located together *within* the zones created by transmission constraints. This

[49] Mauzerall *et. al.* (2005) page 2863. Estimates converted from 1995 to 2005 dollars with a Consumer Price Index conversion factor of 0.78.

[50] In a general, non-targeted sense, the cost effectiveness of retrofitting heavy-duty on-road vehicles with SCRs is about $5,000/ton over the lifetime of the equipment. EPA, "NO_X Mobile Measures", available at www.epa.gov/air/ozonepollution/SIPToolkit/documents/nox_mobile_measures.pdf.

was particularly important in high demand hours. In these hours congestion was less of a problem because local generation predominantly filled local demand

The second reason for the small effect of transmission constraints was that, to the extent low-NO_X generation was located at one end of a congested line, it tends to be on the high-LMP side of the constraint. For example, the capacity-weighted average NO_X emission rate of the units on the low-LMP side of the frequently constrained 10THST to OST line was 3.1 lbs/MWh in the summer of 2005, while that on the high-LMP side was 1.8 lbs/MWh. On August 4th, 2005 at 2 pm, the generation on the low-LMP side of this constraint had an average NO_X rate of 2.6 lbs/MWh and that on the high-LMP side an average NO_X rate of 1.7 lbs/MWh. Anything that increased the use of unused low-NO_X generation on the high-LMP side of the constraint in place of the higher-NO_X generation on the low-LMP side relieved the transmission constraint. Here again, the transmission constraint was not a problem because the NO_X-reducing exchange creates a flow in the opposite direction.

The third and final reason was that NO_X reducing substitutions involved small amounts of generation, especially in the peak hour. In peak demand hours in PowerWorld and the Zonal Model, the simulations exchanged about 4.5 GW of generation to reduce emissions to the physical limit, within a set of units contributing about 35 GW total. In the average demand hour, the simulations exchanged about 8.5 GW of generation out of about 20 GW total generation from the same set of units.

Section 5. Conclusion

Ozone episodes are a problem in some highly populated areas of the Eastern United States and are expected to continue to be a problem despite aggressive regulatory measures to reduce precursor NO_X emissions. The problem may lie in the mismatch between the relatively uniform incentives to reduce NO_X provided by existing regulatory systems and the highly variant temporal and locational impact of NO_X emissions on ozone formation. For these reasons, there is growing interest in the whether a time- and location-differentiated cap-and-trade program could help the states in the Eastern U.S. reduce the likelihood of peak ozone episodes more cost-effectively than further reductions in the seasonal caps on NO_X from stationary sources. A differentiated cap-and-trade program could be implemented using ozone forecasting to alter NO_X emission permit exchange ratios in a wholesale electricity market that uses bid-based, security-constrained economic dispatch. But in order for such a program to be effective, power plants must be able to respond in the short-term to incentives for NO_X reductions that changed in time and by location.

We simulated the potential magnitude of NO_X reductions from the redispatch of generating units in the area of Classic PJM, while taking transmission constraints into account. We used two methods to perform the simulations and found that hourly reductions of about 6 tons (or 15%) were possible on the highest demand days of 2005 in Classic PJM and about 8 tons (or 30%) on average demand days. The magnitudes of potential hourly reductions depend on the time of day and the corresponding level of electricity demand. These region-wide net reductions are not accompanied by "hotspots" – large increases in NO_X in subareas of Classic PJM. In addition, redispatch is only one way that power plants can reduce emissions in the short term. Some control technologies can be used to alter emission rates on the timescale of a few weeks. In the longer term, high NO_X prices would also provide incentives for power plants to invest in NO_X control technologies.

Future work will link the estimates of potential reductions from power plants to weather forecasting and atmospheric chemistry models in order to determine if the simulated NO_X reductions are of the necessary magnitude to reduce the likelihood of ozone episodes. [51] The redispatch analysis reported here involves a significant amount of substitution of relatively low-NO_X rate natural gas units for relatively high-NO_X rate coal units. Given the large differences between coal and natural gas prices in 2005, we will not be surprised if we continue to find that high NO_X permit prices are required to induce significant changes in redispatch mediated through wholesale power markets and higher spot prices for electricity when and where ozone formation conditions trigger high surrender values for NO_X permits.

[51] Mobile sources also emit a large portion of NO_X emissions (about 60% of annual NO_X emissions in the Eastern U.S.) and may also be important for reducing ozone. Mobile source emissions are higher in urban areas and during the day and their impacts on ozone, which could be positive or negative, will be a factor in determining where and when hourly NO_X reductions of about 10 tons from power plants could reduce peak ozone concentrations.

Ozone is an episodic problem and numerous conditions, including wind, sunlight, and concentrations of VOCs, determine whether a reduction of NO_X at a given time and location will lead to reductions of ozone in a target area. Advances in liberalized wholesale electricity markets, weather forecasting, and cap-and-trade mechanisms provide an opportunity to address the ozone problem in a more cost-effective manner by matching NO_X reductions to when and where they will help reduce ozone formation. Although much work remains, our initial result is encouraging because it suggests that an important pre-condition for the implementation of a time and location differentiated regulatory system is satisfied, namely, the existence of significant flexibility to reduce NO_X precursor emissions through the redispatch of power plants on hot summer days when ozone formation is most likely and the electricity system is most likely to be constrained.

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