GE Energy Applications and Systems Engineering

Report on:

Assessment of Proposed NOx RACT Regulations on Emissions, Costs of Electricity and Electric System Reliability

Submitted to:

New York Independent System Operator

Issued: February 12, 2010

General Electric International, Inc.
One River Road
Schenectady, NY 12345
USA

Foreword

This document was prepared by General Electric International, Inc. acting through its GE Energy Applications and Systems Engineering (EA&SE) business in Schenectady, NY. It is submitted to the New York Independent System Operator.

Legal Notices

This report was prepared by General Electric International, Inc. (GEII) acting through its GE Energy Applications and Systems Engineering (EA&SE) business, as an account of work sponsored by the New York Independent System Operator (NYISO). Neither NYISO nor GEII, nor any person acting on behalf of either:

1. Makes any warranty or representation, expressed or implied, with respect to the use of any information contained in this report, or that the use of any information, apparatus, method, or process disclosed in the report may not infringe privately owned rights.

2. Assumes any liabilities with respect to the use of or for damage resulting from the use of any information, apparatus, method, or process disclosed in this report.

Table of Contents

1 Introduction

The New York State Department of Environmental Conservation (NYSDEC) has announced its intention to revise 6 NYCRR Subpart 227-2, its regulations to control emissions of Nitrogen Oxides (NOx), to include new emission limitations for coal, oil and gas fired boilers as major facilities, including fossil fueled generating plants. The purposes of NYDEC's revisions are to define presumptive limits and to promulgate procedures for Reasonably Available Control Technology (RACT). Sources subject to the new emission limits must demonstrate compliance by July 1, 2012, unless they choose to utilize the shutdown compliance provision. This rulemaking proposal is a component of the State Implementation Plan (SIP) for New York State and will be part of the SIP that will be submitted with respect to the 2008 ozone national ambient air quality standard. These regulations are known as NOx RACT regulations.

The proposed NOx RACT regulation lowers the emission limits for very large boilers, large boilers, mid-size boilers, and small boilers, and requires a case-by-case RACT analysis for combined cycle/cogeneration combustion turbines. For example, for large boilers that use gas as the fuel, the NOx emission rates are being lowered from 0.20 lb/MMBTU to 0.08 lb/MMBTU. Compliance with the presumptive RACT limits can be achieved by direct application of emission limits on the emission source, the use of flexibility mechanisms such as switching fuels or participation in a system-averaging plan, a commitment to shut down the emission source, or case-by-case RACT determinations. Compliance with the emission limits must be determined on a 24-hour heat input-weighted average basis. Daily, annual, or 30-day caps on emissions are not a compliance option. Additional information about the proposed NOx RACT regulations can be obtained from New York State DEC's website[1].

The proposed NOx RACT regulations will likely result in some generating plants either adding or modifying their emission controls or in the worst case, shutting down in order to comply. This will in turn have an impact on the cost of electricity and the reliability of the New York Electric Power System. The New York Independent System Operator (NYISO), which is responsible for maintaining the reliability of the New York grid and operating the energy markets retained General Electric's Energy Applications and Systems Engineering (EA&SE) to determine the feasibility of applying RACT to NYCA Generating Fleet and a reasonable schedule to implement the emission control retrofits. The findings of this study are discussed in this report.

It should be mentioned at the outset that the purpose of this study is to determine a feasible compliance plan for each generation owner and evaluate the impact of this plan on the reliability of the system under a given set of assumptions. This study does not attempt to capture the investment strategies of generation owners which will be driven by additional evolving regulatory requirements such as Best Available Control Technology (BACT), Maximum Available Control Technology (MACT), 316b, NAAQS, and Ash Classification, nor does it attempt to maximize the investment strategy for a range of future system conditions, such as 30% RPS, 15x15 and lower load growth due to the economic recession. Given these other considerations, it is reasonable to expect some plant owners to choose compliance options that are different from the RACT selections made in this study.

[1] http://www.dec.ny.gov/regulations/propregulations.html

2 Executive Summary

The New York State Department of Environmental Conservation (NYSDEC) has announced its intention to revise 6 NYCRR Subpart 227-2, its regulations to control emissions of Nitrogen Oxides (NOx). The proposed NOx RACT regulations will likely result in some generating plants either adding or modifying their emission controls or in the worst case, shutting down in order to comply. This will in turn have an impact on the cost of electricity and the reliability of the New York Electric Power System. The objective of this study is to determine the feasibility of applying RACT to the NYCA Generating Fleet and a reasonable schedule to implement the emission control retrofits. This study does not attempt to capture the investment strategies of generation owners which will be driven by additional evolving regulatory requirements such as Best Available Control Technology (BACT), Maximum Available Control Technology (MACT), 316b, NAAQS, and Ash Classification, nor does it attempt to maximize the investment strategy for a range of future system conditions, such as 30% RPS, 15x15 and lower load growth due to economic recession.. Given these other considerations, it is reasonable to expect some plant owners to choose compliance options that are different from the RACT selections made in this study.

The GE MAPS™ program was used in this study to simulate the operations of the New York system under future system conditions. The operation of units on the peak-load day, top-25 peak days and the ozone season were analyzed to determine a typical peak-day operation. The 24-hour, heat-input, weighted-average emission rate, and the fuel consumption (MMBTU) for each generator were calculated for the typical peak-day. Since the RACT regulations allow averaging as one of the options for generators to comply, this was factored into the analysis. Generating units that are under the same ownership and in the same nonattainment area classification were allowed to use the averaging option whereby the heat-input, weighted-average daily emission rate of all the generators that are in the same group was checked for compliance.

A generator will be deemed to be in compliance if its peak-day emission rate is below the proposed presumptive RACT limits. If a generator's peak-day emission rate is higher than the limit, it would have the option of retrofitting or upgrading NOx abatement controls or switching to a fuel that will result in lower NOx emission rate. The decision to retrofit will depend on the technical feasibility of implementing an emission control technology and whether or not it passes the economic reasonability test imposed by the NYSDEC. A generator also has the option of shutting down if achieving the RACT limit is not technically feasible, or if the cost of retrofitting is above NYSDEC's reasonability threshold. There is also a provision in the regulation for a case-by-case determination. In addition, generating units that are under the same ownership and in the same nonattainment area classification can use the system averaging option whereby the heat-input, weighted-average daily emission rate of all the units that are in the same group is checked for compliance.

A total of 72 units or 9515 MW of capacity was identified as needing some type of control mechanism or equipment modification to comply with the proposed standard. One or more control mechanisms and/or equipment modification were found to be technically feasible for all 9515 MW of identified capacity. Out of this, only 11 MW of capacity that required some form of emission controls was above NYSDEC's RACT threshold of $5,500/ton of NOx removed. The MAPS analysis showed that the suggested control mechanism or equipment modification would be economically viable for around 8400 MW of capacity. Out of this, nearly 3700 MW is combined cycle gas turbine capacity, 1100 MW simple cycle gas turbines capacity and 3600 MW is steam turbine capacity.

Nearly 4700 MW of capacity will need short duration outages. These outages correspond to the implementation of fuel switching, tuning and optimization of existing controls such as Dry Low NOx, Selective Catalytic Reduction and Water Injection systems. The outage duration for the remaining 3700 MW will be between 30 and 50 days. These outages correspond to the implementation of Low NOx Boilers, Over Fire Air, Reburn and Selective Catalytic Reduction.

These outage durations were assumed to be incremental to the normal course for unit maintenance practices. The incremental outage durations were reviewed by NYISO staff and compared to historical outage schedules. It is believed that the incremental outages could be accommodated within a two-year period without negatively impacting system reliability. This estimate was based on the assumption that no additional unit retirements take place beyond those identified in the 2009 Reliability Needs Assessment. The two-year period for retrofitting was estimated to begin no earlier than 2012 as permitting, engineering, and financing would be required prerequisites to the beginning of construction.

Nearly 3000 MW of capacity that needs emission control mechanisms or equipment modifications is located in New York City. The permitting and preconstruction activities are estimated to require at least 2 years, thus these retrofits will not likely be completed by June 1 2012. Depending on the level of New York City capacity that needs to be retrofitted, and cannot be accomplished prior to July 1, 2012, reliability concerns may arise. The current retrofit compliance deadline is too aggressive, not reasonably practicable, and has the potential to jeopardize grid reliability. A more reasonable compliance schedule for retrofitting is estimated to be June 1, 2014 based on a two year retrofit program beginning no earlier than 2012 as permitting, engineering, and financing would be required prerequisites to the beginning of construction.

Assuming that the nearly 8400 MW of identified generators install the suggested emission control mechanisms and equipment modifications, the NOx emissions in New York will be significantly lower. Simulation results show that the projected peak-day NOx emissions were reduced from 273 tons to 222 tons, nearly a 20% reduction. The reduction in top 25 days, ozone and annual emissions were 22%, 27% and 28% respectively. The energy generated, production cost and wholesale prices in New York were virtually the same under existing and proposed RACT regulations. In general, this is due to the fact that the increase in variable cost of operating the emission controls were offset by the reduction in operating costs associated with the purchasing of NOx emission allowances.

3 Study Methodology

The objective of this study is to determine the possible actions taken by generation owners in response to the proposed NOx RACT regulations and evaluate the impact of those actions on the wholesale prices in New York and reliability of the State's Electric System. A generator will be deemed to be in compliance if its peak-day emission rate[2] is below the proposed presumptive RACT limits. If a generator's peak-day emission rate is higher than the limit, it would have the option of retrofitting or upgrading NOx abatement controls or switching to a fuel that will result in lower NOx emission rate, in order to comply. The decision to retrofit will depend on the technical feasibility of implementing an emission control technology and whether or not it passes the economic reasonability test imposed by the NYSDEC. A generator also has the option to shutdown if achieving the RACT limit is not technically feasible or the retrofit cost is above the NYSDEC's reasonability threshold, or go in for a case-by-case determination. In addition, generating units that are under the same ownership and in the same nonattainment area classification can use the system averaging option whereby the heat-input, weighted-average daily emission rate of all the units that are in the same group is checked for compliance. This study did not attempt to evaluate system averaging across ownership groups which is provided for in the proposed regulation.

The actions that generation owners take in response to the proposed NOx RACT regulation will most likely have an impact on the economics and reliability of the New York Electric System. The retirement of generators for which reduction in emissions is not technically feasible or economically viable, will have an impact on the reliability of the New York Grid. Also, the outage schedule for implementing the compliance plans of generators that have opted to retrofit or upgrade emission controls need to be coordinated to ensure sufficient reserve margin in the system at all times.

The methodology used in this study to determine the compliance plan of generators, evaluate the economic and reliability impacts of their actions and develop a coordinated outage plan is described in this section. The study methodology is also depicted in the flowchart shown in Appendix B.

3.1 Calculation of Peak-Day Emission Rates using GE-MAPS

As mentioned previously, the NOx RACT regulation is based on the 24-hour, heat-input, weighted average emission rate of each generating unit. This weighted average emission rate needs to be less than the presumptive RACT limit for each 24-hour period for a generator to be in compliance. It is most likely that a generator or a group of generators, and the system as a whole, will have the highest emission rate on the peak-load day or at least in the top-25 peak-load days. Therefore, the operation of all the generators on the top-25 peak days, under future system conditions needs to be simulated to study the impacts of the proposed regulation.

The GE MAPS™ program was used in this study to simulate the operations of the New York system under future system conditions. GE MAPS simulates a power system from the point of view of a system operator – performing an N-1 security constrained system dispatch with complete and detailed transmission modeling. A more detailed description about GE MAPS is available from the brochure included as Appendix C. The results of the MAPS simulations were also used to calculate the net energy market revenue for each generator, which is required to evaluate the market viability of retrofitting or upgrading emission controls. This will be discussed in more detail in Section 3.

[2] Peak-day emission rate is defined as the 24-hour, heat-input, weighted-average emission rate on the peak load day

The economic and reliability impacts of the proposed NOx RACT regulation were studied for a Base Case scenario and three additional scenarios, which are described in Section 6. The MAPS database developed for the NYISO Congestion Assessment and Resource Integration Study (CARIS), which is part of the economic planning process in New York, was used as a starting point for this study[3]. Unit-specific NOx emission curves for Ozone and Winter seasons derived from Environmental Protection Agency (EPA) Clean Air Markets Data (CAMD) were used to improve the generator emission model in this database. The process used for deriving these emission curves are given in Section 4.2.

Using the CARIS database with the updated NOx emission curves, the Base Case database was simulated for 6 study years, namely 2010 through 2015. For each study year, the operation of units on the peak-load day, top-25 peak days and the ozone season were analyzed to determine a typical peak-day operation. The 24-hour, heat-input, weighted-average emission rate, and the fuel consumption (MMBTU) for each generator were calculated for the typical peak-day. The emission rates calculated from MAPS were compared with rates obtained from EPA, NYSDEC and other sources as a check. The data gathered from EPA, NYSDEC and other sources are described in detail in Section 4.3 of the report.

3.2 Development of NOx RACT Compliance Plan

The typical peak-day weighted average emission rates obtained from the MAPS simulation were used in determining the compliance plan for the generators in New York. The flowchart in Appendix B shows the overall procedure that was employed in developing the compliance plans. Since generators that are under the same ownership and in the same nonattainment area classification are allowed to use the averaging option, compliance plans for individual generators as well as groups of units were developed.

3.2.1 Grouping of Generators for Averaging

Since the RACT regulations allow averaging as one of the options for generators to comply, this was factored into the analysis. Generating units that are under the same ownership and in the same nonattainment area classification were allowed to use the averaging option whereby the heat-input, weighted-average daily emission rate of all the generators that are in the same group was checked for compliance.

The first step in the NOx RACT compliance plan development process was to identify these groups. Based on ownership and nonattainment area classifications, nine groups were identified. Most of the large owners were allowed to average the emission rates of all their generators. However, those who had generators in two different nonattainment area classifications were allowed to average the generators within each of the nonattainment areas. For each group, the peak-day emission rate was calculated using the heat-input, weighted-average of the individual units' daily emission rates[4].

3 Details regarding the MAPS database can be found in the 2009 CARIS report and in Appendix A.

4 An individual unit's daily emission rate is the 24-hour, heat input weighted average of the hourly emission rates.

3.2.2 Compliance Plan for Individual Generators

Individual generators are generators that do don't have the provision of averaging their emissions with other generators in the system. The process used to determine the compliance plan for individual generators is given below.

3.2.2.1 Verification of Compliance

The peak-day emission rate of each individual generator calculated from the MAPS simulations was compared with its proposed NOx RACT limit. For units that did not have a presumptive NOx RACT limit (i.e. case-by-case determination), the existing NOx RACT limit was used. If a unit's peak-day emission rate was lower than the limit, then the generator was deemed to be in compliance. If not, the technical feasibility, reasonableness[5] and the market viability of various compliance options were explored as detailed in the sections below.

3.2.2.2 Technical feasibility of Compliance Plan

For the individual units that were not in compliance as determined above, the existing emission controls were obtained from the NYSDEC and from other sources such as the EPA. Other pertinent information such as the unit model number (example, 7FA, LM6000 etc.), emission performance guarantees were obtained from internal GE databases and other sources. Section 4.3 contains more information about the data sources. Based on the information gathered, the potential emission control mechanisms or equipment modifications that are technically feasible[6] for each unit were determined.

Before recommending emission controls retrofits, care was taken to examine the capabilities of the existing control technology for each unit. For example, the data gathered from various sources showed that some gas turbines were already equipped with Selective Catalytic Reduction (SCR), and or dry low NOx burner (DLN) and or water injection, and some fossil fuel boilers were already retrofitted with low NOx burners and or over fire air and or SCR. If the existing control technologies were capable of meeting the applicable limit, but were not performing optimally, the recommendation from the analysis was to optimize or tune the existing equipment[7]. For some gas turbine or combined cycle units that had duel fuel capability and their primary fuel was liquid fuel, the recommendation was to switch to natural gas as a most cost-effective emission control method. For the units that needed to add control mechanisms instead of modifications to the existing equipment, such as optimization, tuning and fuel switching, the potential control technologies were identified according to the amount of reduction required.

For gas turbine units, three technologies were considered as retrofit options. They are selective catalytic reduction (SCR), dry low NOx (DLN) and water/steam injection (WI/SI). A brief description of the three technologies, along with their capital and operation costs, can be found in Appendix D. SCRs are usually capable of providing 90% NOx reduction. However, the application of SCR requires

---

[5] Reasonableness here implies the economic analysis used by the NYSDEC to determine if a control technology is RACT or not. RACT by definition is the lowest emission limit that a particular source is capable of meeting by application of control mechanism that is reasonably available, considering technological and economic feasibility.

[6] Technical feasibility does not take into account physical limitation or other local constraints that may make the retrofit infeasible.

[7] Tuning and optimization, in general, refer to the following: Online data collection and analysis, performance diagnostics, hardware maintenance and upgrade, control software upgrade, and fuel/air/reagent flow balancing, etc.

the ammonia injection into flue gas in a temperature range of 600-750 °F. Meanwhile, the application generates ammonia slip and waste catalyst. The applicability of an SCR system is therefore, different from site to site. DLN is a design of the combustor that stages combustion. Depending on the type of unit, DLN can achieve NOx emissions anywhere between 9 ppm and 25 ppm. Water injection technology injects water or steam into flame to reduce flame temperature and therefore, thermal NOx. WI can achieve 42 ppm NOx emission. However, injecting water or steam into flue gas will result in a heat rate penalty. The potential technology recommendations are only based on achievable NOx reduction efficiencies of each technology.

For steam turbine units, deNOx technologies include combustion modifications, such as low NOx burners (LNB), over fire air (OFA), and reburn, and post-combustion retrofits, such as selective non-catalytic reaction (SNCR) and selective catalytic reduction (SCR). In general, combustion modifications have lower capital and operating costs, while post combustion retrofits requires higher capital and operating costs. Low NOx burners are often considered as the first step of deNOx retrofit, which can bring about a 40 to 50% NOx reduction depending on the type of fuel, boiler design and initial NOx. OFA stages the air from the burner zone and results in another 30 to 50% reduction. Reburning uses a portion of fossil fuel as reagent to react with NOx. Together with OFA to complete combustion, the technology can achieve about 50 to 60% reduction. SNCR is a trim technology and technically challenging when applied in utility boilers since it is only effective in a narrow temperature window. SNCR can achieve about 30% reduction. SCR is the most effective NOx control technology and can remove 90% of NOx. However, its application is often limited by the requirement of space and high maintenance of the catalyst bed for high efficiency removal.

Appendix C contains more detailed description of the NOx emission control technologies and their capital and operating costs.

3.2.2.3 Reasonability Test of Compliance Plan

As a part of any RACT determination, an economic analysis needs to be performed to determine if the proposed control mechanism or equipment modification pass the reasonability test. NYDEC's Air Guide 20[8] details the economic analysis procedure used to calculate the total cost of controls per ton of NOx removed. Appendix E contains a sample economic analysis sheet from the Air Guide. The NYSDEC has established the upper economic limit for NOx RACT to be $5,500 per ton of NOx removed[9]. A facility will not be required to implement any emission reduction or control technique that is more costly than these limits.

For each one of the control mechanisms or equipment modifications identified in the technical analysis, the total cost per ton of NOx removed was calculated. Appendix D gives the capital and variable cost assumptions for each control mechanism or equipment modification used in the calculation of the total annual cost.

The control mechanism or equipment modification with the lowest cost per ton of NOx removed was chosen as the potential compliance plan for each generator. Generators for which the cost per ton of emissions removed is greater than the NYSDEC threshold of $5,500/ton were also identified as a part of the process. These units would be subject to a case-by-case RACT determination or required to retire.

[8] Air Guide for the Economic and Technical Analysis for Reasonably Available Control Technology.

[9] This figure was obtained from the NYSDEC.

3.2.2.4 Market Viability of Compliance Plan

While the reasonability test discussed above identifies which control mechanism or equipment modification is considered RACT, it does not necessarily mean that generator owner will implement that control mechanism. NYSDEC economic analysis is based on the potential of a particular generator to emit. As such, procedure outlined in the guide assumes that a generator operates all hours of the year (8760 hours) in calculating the cost of tons of NOx removed, where as, in actual operations, the generator may not run enough hours to justify the investment.

For the compliance plans that were identified to be technically feasible and reasonable by NYSDEC's definition, a market viability test was performed using the results of the MAPS simulations. The ability of the each generator to absorb the cost of the compliance plan was determined. For each study year, the annualized total cost of the emission control mechanism or equipment modification was subtracted from the annual net energy margin[10]. A positive value indicates that a generator, in the absence of other considerations, will earn sufficient net margin to be incented to continue to operate. In this calculation, it is implicitly assumed that the addition of the control mechanism or equipment modification does not alter the operation of the plant. Another MAPS simulation was performed with all the compliance plans modeled to verify that net energy sales margins remained positive.

A generator that passes the test will possibly implement the identified control mechanism or equipment modification. A generator that does not pass the test will need look for other avenues to comply. The market viability test described above is meant to indicate which generators can possibly retrofit. It does not attempt to forecast all the sources of revenue for a generation owner. For example, a generator might derive most of its revenue from the capacity market and may be able to absorb the retrofit costs even if the net energy margin after including the costs of emission control mechanism is negative. Conversely, a generator may not derive enough revenues from the capacity market and may be leaning on profits from the energy market to be made whole. In this instance, a positive number for the net energy margin (minus the costs of emission control mechanism) may not indicate the generator's capacity to absorb the costs associated with the emission control mechanism.

This study does not attempt to capture the investment strategies of generation owners which will be driven by additional evolving regulatory requirements such as Best Available Control Technology (BACT), Maximum Available Control Technology (MACT), 316b, NAAQS, and Ash Classification, nor does it attempt to maximize the investment strategy for a range of future system conditions, such as 30% RPS, 15x15 and lower load growth due to economic recession. Given these other considerations, it is reasonable to expect some plant owners to choose compliance options that are different from the RACT selections made in this study.

3.2.3 Compliance Plan for Averaging Groups

As mentioned before, generating units that are under the same ownership and in the same nonattainment area classification were allowed to use the averaging option whereby the heat-input, weighted-average daily emission rate of all the units that are in the same group was checked for compliance. The process used to determine the compliance plan for averaging groups is given below.

---

[10] The net energy margin is the revenue made by a unit in the energy market minus all its variable costs of operation.

For each group that was identified in Section 3.2.1, the peak-day emission rate was calculated using the heat-input, weighted-average of the individual units' daily emission rates. The NOx RACT limit for the group was calculated using the heat-input, weighted-average of the individual units' RACT limits. If a group's weighted-average emission rate was lower than the its weighted-average limit, then the group as a whole was deemed to be in compliance. If not, the technical, economic feasibility and the market viability of various compliance options were explored as detailed below.

There are two broad strategies for a group of units to comply with the proposed NOx RACT regulations. Each generator that is above the limit can be dealt with in isolation, i.e., as in the individual generator's case, the technical and economic feasibility of implementing a control mechanism or equipment modification for each generator in the group can be investigated in isolation. The other strategy is to add control mechanisms or equipment modifications to the generators that have the most impact on the weighted-average emission rate of the group, in order to bring the group into compliance. This could mean achieving over-compliance on one or more large units within the group in order for the group to be within its system average RACT limit. As in the case of the individual units, the technical feasibility of implementing the desired control mechanism or equipment modification to one or more units in the group needs to be verified.

An owner of a fleet of generators may choose the averaging option if it is financially a better option than attempting to bring each unit into compliance. The market viability of the two strategies was evaluated by comparing the net energy market revenue minus the costs associated with the implementation of desired control mechanisms or equipment modifications for the group under the two strategies. The compliance plan associated with the strategy that resulted in a higher value was chosen. As before, the market viability is meant to indicate generators for which a retrofit is possible. It does not attempt to forecast all the sources of revenue for a generation owner.

It should also be noted that the compliance plan determined for groups does not take into account the impact of forced outages. In other words, the group's average rate will be below the RACT limit only if all the units are online, particularly the large, over-complied units that help in bringing the group average down. In reality, generation owners will need understand the impact of outages under the proposed regulations and plan for this contingency in coming up with their averaging plan.

3.3 Evaluation of Reliability Impact of Planned Outages

This study also evaluated the impact of potential early retirements for the proposed regulation on grid reliability. The NYISO currently allows outages to be scheduled on a first come first serve basis, via the market access portal on its website. These outages are typically scheduled in the shoulder months, which occur during the spring and fall periods. Planned outages of the nature required to retrofit environmental control technology are generally precluded from taking place during the peak Summer Capability period. The NYISO outage-scheduling process is implemented so that a sufficient reserve margin is ensured at all times.

Outage durations were estimated for units identified as potential candidates for retrofit technology. These outage durations were assumed to be incremental to the normal course for unit maintenance practices. The incremental outage durations were reviewed by NYISO staff and compared to historical outage schedules. It is believed that the incremental outages could be accommodated within a two-year period without negatively impacting system reliability. This estimate was based on the assumption that no additional unit retirements take place beyond those identified in the 2009 RNA. The two-year period for retrofitting was estimated to begin no earlier than 2012 as permitting, engineering, and financing would be required prerequisites to the beginning of construction.

4 Baseline System Inputs

This section describes the MAPS database and the sources for other data used in the study. Section 4.1 describes the MAPS database used in the study. Section 4.2 details the changes to the emission modeling in the MAPS database. Section 4.3 describes the sources for the other data used in the study.

4.1 CARIS MAPS database

The MAPS database developed for the NYISO CARIS study was used as a starting point for the NOx RACT analysis. Table 4.1 shows the assumptions and the basis for the assumptions for all the input categories of the MAPS database. Additional details regarding the MAPS database can be found in Appendix A.

Table 4.1: CARIS MAPS Database Assumptions

Parameter	**Modeling for CARIS- NOx RACT Base Cases**	**Basis for Recommended Assumptions for CARIS-NOx RACT**
Peak Load	Forecast as per 2009 RNA Base. Scenarios for other forecasts.	Based on CRP Peak Forecast Use 2009 Base Case Energy Forecast
Load Shape Model Energy Forecast	2002 Load Shape, constant over ten-year period. 2009 RNA Base Case Forecast	2002 load shape is an appropriate representation for this analysis. For base year, use 2002 Load Shape. Adjusted for Energy Forecast if needed. Evaluate alternative in future
Load Uncertainty Model	Statewide and zonal model updated to reflect current data, constant over ten year period	Base Level Forecast will be used. Other load uncertainty levels not evaluated.
Generating Unit Capacities	Same as CRP - Per 2009 CRP, updated DMNC test values plus units	Any changes in CRP capacities through time to be represented in CARIS.
New Units	As per the CRP and scaled back according to procedure (Tariff Attachment Y: Section 11.3.b)	N/A
Wind Resource Modeling	Existing units derived from hourly wind data with average Summer Peak Hour capacity factor of approximately 11 %. New units from wind shapes from wind study.	Typical shape for location as per MARS and wind studies.
Non-NYPA Hydro Capacity Modeling	Pondage Run of River (Hourly)	N/A
Special Case Resources	Those sold for the program, discounted to historic availability and distributed	N/A

	according to zonal performance. Assume 15% growth rate for all zones. Modify load SCR/EOP to proportion available SCR by load amount by zone. See SCR determinations in Attachment G.	
EDRP Resources	Those registered for the program, discounted to historic availability (45 % overall). July & August values calculated from 2009 July and August registrations.	Need to define costs associated, firm modifiers vs. price responsive.
External Capacity – Purchases	Based on NYISO forecast. Sensitivity performed to remove contracts and see the effect on LCR-IRM curve. Results should not impinge on IRM. Sensitivity with 20 MW MISO wheel through Ontario to Zone A).	N/A
Retirements	2009 Gold Book over ten-year period.	As per the CRP.
Planned Outages	Per 2009 CRP, based on schedules received by NYISO & adjusted for history. Constant over ten-year period.	As per the CRP.
Outage Scheduling	Continue with approximately 150 MW after reviewing last year's data…	As per the maintenance schedules in long term adequacy studies.
Gas Turbines Ambient Derate	Continue with approximately 150 MW after reviewing last year's data, constant over ten-year period.	Reflected only in summer/winter ratings.
Environmental Modeling Externalities Allowances	Included in the Base Case and modified in the scenarios Built into the development of cost curves of resources. Optimization is cost driven.	Any impacts assumed in CRP carried forward. Limits on emissions done through allowances, not hard limits. Allowance cost from Chicago Climate Futures Exchange.
Commitment and Dispatch Options Operating Reserves	Each Balancing Authority Commits separately Hurdle Rates are employed for commitment and dispatch… Operating Reserves as per NYCA requirements.	N/A
Fuel Price Forecast	EIA data obtained quarterly, adjusted for seasonality on monthly basis, monthly volatility based on historical patterns.	NYISO to calibrate forecast based on public information and historical data.
Cost Curve Development	Developed from Heat Rate Curve, Fuel Price forecast, environmental adders, penalty factors.	Allowances from Chicago Climate Futures Exchange, Heat Rate development under discussion. Unit specific heat rates are confidential and not disclosed.
Heat Rates NYCA External Systems	Developed from vendor supplied data and fuel input data matched with MWh data for NYCA.	

Local Reliability Rules	List and develop appropriate nomograms.	Fuel burn restrictions, operating restrictions and exceptions, commitment/dispatch limits.
Energy Storage Gilboa PSH Lewiston PSH	Gilboa and Lewiston scheduled against NYCA.	N/A
Transmission System		
Power Flow Cases	As per CRP.	N/A
Interface Limits Monitored/contingency pairs Nomograms Joint, Grouping Unit Sensitive Voltage	Transfer limit analysis done in RNA/CRP for critical interfaces. External system limits from input from neighboring systems.	Based on historical congestion, planning study results, NERC book of flowgates, PROBE/SCUC list of active/potential constraints, Special Protections Systems including Athens SPS in 2009 and 2010.
New Transmission Capability	As per CRP.	N/A
Internal Controllable Lines (PARs, DC, VFT)	Optimized in simulation.	N/A
Neighboring Systems		
Outside World Area Models Fuel Forecast	Power flow data from CRP, "production" data developed by NYISO with vendor and neighbor input. Linked with NYCA forecast.	N/A
External Capacity Load Forecast	Firm and grandfathered are included. Neighboring systems data reviewed and held at required reserve margin.	Neighboring systems modeled consistent with reserve margins in the RNA/CRP analysis.
System representation in Simulation	HQ modeled as load/generation pair. Full Representation/Participation - NYISO - NE-ISO - IESO - PJM Classic & Full Representation: NYISO, NEISO, IESO, PJM (PJM Classic, AP, AEP, CE, DLCO, DAY, VP) Proxy Bus: HQ-NYISO, HQ-NEISO Transmission Only/Zeroed Out: MECS, FE, SPP, MAR, NIPS, OVEC, TVA, FRCC, SERC, ERCOT, WECC	N/A
External Controllable Lines (PARs, DC, VFT, Radial lines)	A,B,C and J,K "wheel" Both sets set at 600 min, 1200 max, imbalance monitored Norwalk +/- 100 MW L33,34 - +/- 300 MW PV20 – 130, 0 MW Neptune and CSC as per CRP firm X 24 hrs, economy remainder	N/A

4.2 Emission Rate Curves for New York Generators

The GE MAPS database allows the user to model seasonal emission curves for each generator. Separate emission curves for NOx, SO_2, CO_2 and other emissions can be modeled. The emission curve for each generator is modeled using the average emissions (in lb/MWh) at each defined power point. This section describes how generator specific emission curves (in lb/MMBTU) were obtained by the NYISO using the Environmental Protection Agency (EPA) Clean Air Markets Data (CAMD).

Emission rates were calculated for each fossil fuel unit on an individual basis. To begin, hourly Clean Air Markets Data (CAMD) for NOx emissions provided by the Environmental Protection Agency (EPA) was divided by thermal input yielding a value in terms of lb/MMBTU. These emission rates were plotted against net generation from the NYISO's Pi database. Linear and quadratic regressions were fit to the data for each generating unit. The reduced R-Squared value for each regression was determined, and the best-fit regression was selected as the emission rate curve to represent the operations of the unit. In several instances sufficient data was not available to form a regression. In these situations the rate curve from a unit with similar characteristics was applied to the new unit.

After the curves were completed, NYISO staff analyzed each plant individually to verify their validity. Power points and corresponding heat rates for each unit were extracted from the NYISO CARIS database. At each power point the curve was evaluated and multiplied by the heat rate resulting in a generation based emission rate (lb/MWh).

It should be noted that the EPA data is reported on a gross generation basis while NYISO Pi data is based on net generation. Because of this discrepancy some regressions were initially found to be slightly higher than expected. This was caused by hours when the unit was starting up but not generating power. These hours contained NOx emissions that were higher than typical operating conditions. In units where this skewed the data beyond a reasonable margin of error, data below the minimum generation was excluded, and the regressions were recalculated.

4.3 RACT Limits and Existing Control Technology Data

The data required for conducting this study was obtained from a number of sources including NYSDEC, NYISO, EPA, Energy Velocity, and GE as listed below.

- Primary and secondary fuel, if applicable, for each generator was obtained from the NYISO Gold book and verified using the data provided by the NYSDEC.
- Current and future NOx RACT limit for each generator was provided by the NYSDEC
- Historical annual and ozone season NOx emission rates (for available generators) were obtained from NYSDEC, EPA and Energy Velocity. These were compared against the peak-day emission rates obtained from the MAPS simulation.
- Existing emission control technology for each unit was provided by the NYSDEC and verified using data obtained from the EPA.
- Make and model of gas turbine were obtained from GE databases.

5 Findings

The findings of this study are discussed in this section. Section 5.1 discusses the capacity by zone that will need emission control mechanisms or equipment modifications. Section 5.2 details the coordinated outage plan for implementing the retrofits. Section 5.3 summarizes the impact of the proposed regulation on the NOx emissions, energy generation and production cost of the New York Electric System.

5.1 Capacity by Zone that Need Emission Retrofits

Section 3 described the process used to determine the control mechanisms and equipment modifications that are necessary to meet the proposed RACT standards. Table 5.1 shows the capacity[11] requiring control mechanisms or equipment modifications by zone. A total of 72 units or 9515 MW of capacity was identified as need some type of control mechanism or equipment modification to comply with the proposed standard. This is shown in column A of Table 5.1. One or more control mechanisms and/or equipment modification were found to be technically feasible for all 9515 MW of identified capacity as shown in column B. Out of this, only 11 MW of capacity that required some form of emission controls was above NYSDEC's RACT threshold as shown in column C. The MAPS analysis showed that the suggested control mechanism or equipment modification would be viable for around 8400 MW of capacity.

Out of the 8400 MW of capacity that will most likely implement a control mechanism or equipment modification, nearly 3700 MW is combined cycle gas turbine capacity, 1100 MW simple cycle gas turbines capacity and 3600 MW is steam turbine capacity.

The suggested control mechanisms or equipment modifications fall in four main categories as shown below. The capacity associated with each category is also given.

- Fuel Switching – 500 MW
- Tuning and optimization of existing controls such as DLN, SCR, WI system – 4250 MW
- Low NOx Burner (LNB), Over Fire Air (OFA), Reburn – 3000 MW
- Selective Catalytic Reduction (SCR) – 650 MW

Table 2 shows the outage duration required to implement the viable control mechanisms and equipment modifications by zones. The outage duration for nearly MWs of capacity will be relativley short. These outages corresponding to the implementation of fuel switching, tuning and optimization of existing controls such as DLN, SCR and WI systems. The outage duration for the remaining 3700 MW will be between 30 and 50 days. These outages correspond to the implementation of LNB, OFA, Reburn and SCR.

[11] The Capacity values shown here are the Summer Capacity values from the 2009 NYISO Gold Book.

Table 5.1: Capacity Requiring Control Mechanisms or Modifications by Super-Zones

Zone	Capacity Requiring Control Mechanisms or Equipment Modifications (A)	Technically Feasible Control Mechanisms or Equipment Modifications (B)	RACT Eligible Control Mechanisms or Equipment Modifications (C)	Market Viable Control Mechanisms or Equipment Modifications (D)
ABC	4,035	4,035	4,024	3,050
DEF	1,039	1,039	1,039	932
GHI	1,363	1,363	1,363	1,363
JK	3,078	3,078	3,078	3,078
NYISO	9,515	9,515	9,504	8,423

Table 5.2: Capacity by and outage duration by Super-Zones

Zone	Short Outage Duration (MWs)	Outage Duration 30-50 days (MWs)
ABC	1,172	1,879
DEF	876	56
GHI	35	1,328
JK	2,651	428
NYISO	4,733	3,690

5.2 Reliability Impact of Outages due to Emission Retrofits

Outage durations were estimated for units identified as potential candidates for retrofit technology. These outage durations were assumed to be incremental to the normal course for unit maintenance practices. The incremental outage durations were reviewed by NYISO and compared to historical outage schedules. It was estimated that the incremental outages could be accommodated within a two-year period without negatively impacting system reliability provided there are no remarkable circumstances. This estimate was based on the assumption that no additional unit retirements take place beyond those identified in the 2009 RNA. The two-year period for retrofitting was estimated to begin no earlier than 2012 as permitting, engineering, and financing would be required prerequisites to the beginning of construction.

Based on the analysis performed, 9515 MWs of generation capacity in New York needs to be retrofitted; nearly 3000 MWs of this capacity is located in NYC. The permitting and preconstruction activities are estimated to require at least 2 years, thus these retrofits will not likely be completed by June 1 2012. If this occurs, reliability concerns will arise. Previous NYISO studies have shown that the loss of 2000 MWs of generation in New York City alone will severely impact the reliability of the entire system. The current retrofit compliance deadline is not practicable and has the potential to jeopardize grid reliability throughout New York.

5.3 Impact of Retrofits on the New York Grid

This section summarizes the impact of the proposed regulation on the NOx emissions and the production cost of the New York Electric System.

5.3.1 Emission Impact

Assuming that the nearly 8500 MW of identified generators install the suggested emission control mechanisms and equipment modifications, the NOx emissions in New York will be significantly lower. Table 5.3 shows the peak-day NOx emissions and the peak-day NOx emission rates under the existing and proposed regulations. The peak-day NOx emissions are reduced from 273 tons to 222 tons, nearly a 20% reduction. The peak-day emissions even under the existing regulations are lower than historical peak-day emissions due to a number of key transmission and generation additions such as Linden VFT, Neptune HVDC, M29, Caithness combined cycle and upstate wind generation and the retirement of Poletti, assumed in the simulations. The peak-day emission rate is correspondingly lower- 0.085 lb/MMBTU, compared to 0.105 lb/MMBTU under the current standards. The results shown in Table 5.3 are for the year 2013, the first full year after the proposed NOx RACT regulations are expected to come into effect. Detailed results by zone for all the study years can be found in Appendix F, Table F1.

Table 5.3: Peak-Day Emissions and Emission Rates

	Under Existing Regulations	Under Proposed RACT
New York Peak-Day NOx Emissions (tons)	273	222
New York Peak-Day NOx Emission Rate (lbs/MMBTU)	0.105	0.085

Table 5.4 shows the top 25 days, ozone and annual emissions under existing and proposed RACT regulations for the year 2013. The reduction in top 25 days, ozone and annual emissions are 22%, 27% and 28% respectively. Detailed results by zone for all the study years can be found in Appendix F, Table F1.

Table 5.4: Top 25 Days, Ozone and Annual NOx Emissions

	Under Existing Regulations	Under Proposed RACT
New York Top 25 Peak-Day NOx Emissions (Tons)	5,707	4,463
New York Ozone Season NOx Emissions (Tons)	26,312	19,155
New York Annual NOx Emissions (Tons)	45,406	32,501

5.3.2 Electricity Production Cost Impact

Table 5.5 shows the impact of the proposed regulations on the energy generated in New York, production cost and the average spot price, for the year 2013. The energy generated, production cost and prices are virtually the same under existing and proposed RACT regulations. In general, this is due to the fact that the increase in variable cost of operating the emission controls is offset by the reduction in operating costs associated with the purchasing of NOx emission allowances. Detailed production cost results by NYISO zones, for all study years can be found in Table F2 of Appendix F.

Table 5.5 - Generation, Production Cost and Average Electricity Price for NYISO

	Under Existing Regulations	Under Proposed RACT
Energy Produced (GWh)	160,299	160,261
Production Cost (Mil. $)	6,079	6,076
Average Spot Price ($/MWh)	67.39	66.83

6 Scenarios

In addition to the Base Case Scenario, the impacts of the proposed NOx RACT regulation under three other scenarios were also studied. The assumptions for the three scenarios are given in Appendix G. The NYISO staff performed the MAPS simulations for these scenarios. It should be noted that the compliance plans for generators were determined assuming the Base Case forecast discussed before. The scenarios were simulated to determine how these compliance plans will impact the system under various possible future system conditions.

6.1 Base case using the 2009 NYISO 15x15 forecast

In this scenario, the zonal peak load and energy forecast used in the NYISO 2009 Reliability Needs Assessment (RNA) 15x15 forecast was used. Table G.1 in Appendix G gives the annual peak load and energy assumptions for this scenario. Table 6.1 shows the impact of the retrofits on the 15x15 case. When compared to the Base Case results shown in Tables 5.4 and 5.5, it can be observed that the energy produced and as result the production cost, LBMP and annual NOx are all lower due to the destruction in demand under the 15x15 scenario.

Table 6.1: Impact of the Retrofits on the 15x15 case

	15x15 (2014)	
	Under Existing Regulations	**Under Proposed RACT**
Energy Produced (GWh)	149,532	149,530
Production Cost (Mil. $)	$5,163	$5,164
Average Spot Price ($/MWh)	$66.48	$66.33
NYISO Annual NOx (tons)	39,456	26,990

6.2 New York Renewable Portfolio Standard at 30%

In this scenario, a 30% RPS by 2015 was modeled. Table G.2 in Appendix G shows the zonal wind generation additions for the 30% RPS case. Table 6.2 below shows the results of the simulation for the year 2014. It can be observed that more energy is produced in New York due to the increase in renewable generation. However, the annual NOx emissions are lower than the Base Case.

Table 6.2: Impact of the Retrofits on the 30% RPS case

	RPS (2014)	
	Under Existing Regulations	**Under Proposed RACT**
Energy Produced (GWh)	164,120	163,584
Production Cost (Mil. $)	$5,894	$5,885
Average Spot Price ($/MWh)	$68.09	$68.29
NYISO Annual NOx (tons)	43,711	30,779

6.3 Retirement of Indian Point Generation Station

In this scenario, Indian Point nuclear Unit 2 was retired in September 2013. Table 6.3 shows the impact of the emission retrofits under this scenario. In this scenario, New York imports more from its neighbors as compared to the Base Case. Production cost, LBMP and emissions are higher since the generation from Indian Point generator has to be replaced with more expensive generators within New York and outside that have more NOx emissions.

Table 6.3: Impact of the Retrofits on the Indian Point Retirement case

	IP Retirement (2014)	
	Under Existing Regulations	**Under Proposed RACT**
Energy Produced (GWh)	159,001	158,676
Production Cost (Mil. $)	$6,983	$6,972
Average Spot Price ($/MWh)	$71.97	$71.50
NYISO Annual NOx (tons)	50,106	36,683

A. CARIS MAPS Database

Below are descriptions of key data in more detail. The data was developed based on the Tariff and in collaboration with stakeholders.

Base Case Load Forecast

Table C-2 present CARIS Base Case load forecasts from 2009 through 2015 used from the 2009 RNA/CRP. For zonal peak demand refer to Table 3-2 of the RNA.

Table C-2: Annual Zonal Energy (GWh)

Zone	2009	2010	2011	2012	2013	2014	2015
West	16,011	16,143	16,189	16,211	16,287	16,375	16,436
Genesee	10,067	10,162	10,154	10,157	10,210	10,323	10,410
Central	16,881	16,975	17,039	17,035	17,102	17,219	17,311
North	7,014	7,102	7,147	7,153	7,178	7,192	7,176
Mohawk Valley	8,020	8,066	8,109	8,117	8,127	8,171	8,202
Capital	11,907	11,919	11,988	12,074	12,160	12,257	12,355
Hudson Valley	11,007	11,146	11,263	11,302	11,382	11,496	11,566
Millwood	2,748	2,786	2,817	2,830	2,871	2,884	2,903
Dunwoodie	6,478	6,541	6,572	6,564	6,593	6,586	6,595
NY City	54,987	55,905	56,661	57,503	58,358	59,430	60,353
Long Island	23,008	23,002	23,015	22,981	22,888	22,866	22,870
NYCA Total	**168,128**	**169,747**	**170,954**	**171,927**	**173,156**	**174,800**	**176,177**

Power Flow Data

The CARIS uses the network topology, system impedance and transmission line ratings that were developed from the 2009 CRP power flows. The following power flow cases were developed for the CARIS from the 2008 FERC Form 715 filing Base Cases:

- Summer 2009 Peak Load
- Summer 2013 Peak Load
- Winter 2013/2014 Peak Load

For the intermediate years between 2010 and 2015, the power flow cases were based on data provided in the FERC Form 715 2013 Summer Peak Load case. PJM system changes modeled in PJM's 2012 Regional Transmission Expansion Plan (RTEP) Study and NYISO system changes described in the 2009 CRP Study required changes to these power flow cases, such as additional generators and transmission lines, to capture the sequencing of these additional resources. The winter transmission line ratings from the FERC Form 715 Winter 2013/2014 Peak Load case were used for all years assessed in the CARIS.

Transmission Model

New York Control Area Model

Figure C-1 below displays the bulk power system for NYCA, which generally consists of facilities 230 kV and above, but also includes certain 138 kV facilities and a small number of 115 kV facilities. The balance of the facilities 138 kV and lower voltage are considered non-bulk or sub-transmission facilities for purposes of this study. The figure also displays key transmission interfaces for New York.

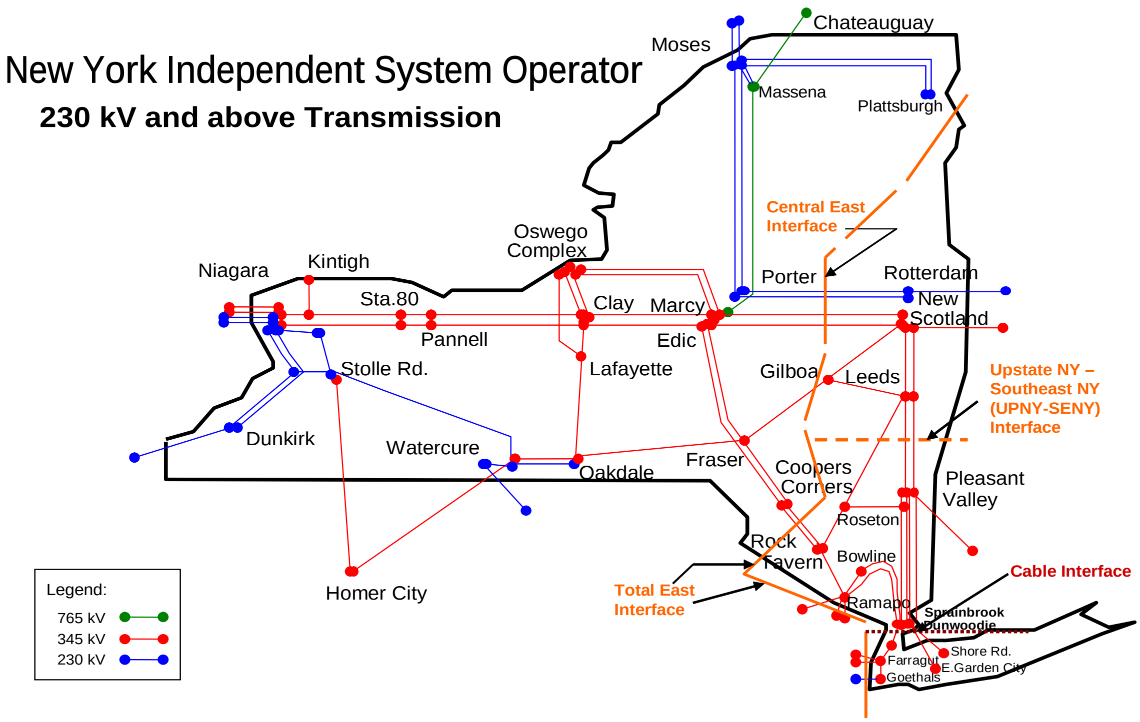


Figure C-1: NYISO 230 kV and above Transmission Map

New York Control Area Changes, Upgrades and Resource Additions

The highlights of year on year model changes are as follows:

a. Caithness Long Island – new 310 MW, Combined Cycle, LIPA, Suffolk, NY, Commercial Operation – 4/2009;

b. BesiCorp – new 660 MW, Combined Cycle, National Grid, Rensselear, NY, proposed Commercial Operation 2/2010;

c. Polleti – 890.7 MW, retirement expected 2/2010;

d. M29 – 345 kV cable from an existing station in Yonkers, NY to a new substation in NYC, with normal, LTE and STE ratings of 521 MW, 748 MW and 1195 MW respectively. Expected in-service date is Summer 2011;

f. Linden VFT – the VFT facility was set to control flow between 245 MW and 295 MW, not to exceed 300 MW. The VFT facility commenced commercial operation November 1, 2009.

External Area Model

The external areas immediately adjacent to the NYCA are also modeled at full representation, except for Hydro Quebec (HQ). Those areas include ISO-NE, IESO, and PJM (PJM Classic, AP, AEP, CE, DLCO, DAY and VP). Since HQ is asynchronously tied to the bulk system, proxy buses representing the direct ties from HQ to NYISO and HQ to ISO-NE are modeled. The HQ capacity modeled is 1300 MW. External areas surrounding the above areas are only modeled to capture the impact of loop flows. Table C-3 illustrates the external transmission limits used in the CARIS Study.

Table C-3: External Area Transmission Transfer Limits

Area	Interface	2009	2010	2011	2012	2013	2014-2015
IESO	IMO EXPORT	2500	2500	2500	2500	2500	2500
IESO	IMO-MISO	1	1	1	1	1	1
IESO	IMO-NYISO	2000	2000	2000	2000	2000	2000
ISO-NE	Boston	4900	4900	4900	4900	4900	4900
ISO-NE	Connecticut-Export	2200	2200	2200	2200	2200	3600
ISO-NE	East-West (NE-NY)	2100	2100	2100	2100	2100	2100
ISO-NE	ISO-NE EXPORT	4000	4000	4000	4000	4000	4000
ISO-NE	ISO-NE-NYISO	1400	1400	1400	1400	1400	1400
ISO-NE	LI – ISO-NE	450	450	450	450	450	450
ISO-NE	ME – NH	1400	1400	1400	1400	1400	1500
ISO-NE	NB – NEPOOL	500	500	500	500	500	500
ISO-NE	North – South	2700	2700	2700	2700	2700	2700
ISO-NE	Norwalk-Stamford	1300	1300	1300	1300	1300	1300
ISO-NE	Orrington South	1050	1050	1050	1050	1050	1050
ISO-NE	SEMA	1450	1450	1450	1450	1450	1450
ISO-NE	SEMA/RI	2200	2200	2200	2200	2200	2200
ISO-NE	South West CT	2350	2350	2350	2350	2350	3650
ISO-NE	Surowiec South	1150	1150	1150	1150	1150	1150
NYISO	NYISO-HQ	1050	1050	1050	1050	1050	1050
NYISO	NYISO-IESO	2500	2500	2500	2500	2500	2500
NYISO	NYISO-PJM	2500	2500	2500	2500	2500	2500
PJM	APSOUTH	3250	3250	3250	3250	3250	3250
PJM	Central Interface	5200	5200	5200	5200	5200	5200

PJM	Eastern Interface	7000	7000	7000	7000	7000	7000
PJM	PJM East – NYISO	2500	2500	2500	2500	2500	2500
PJM	PJM EXPORT	6000	6000	6000	6000	6000	6000
PJM	PJM West – NYISO	2000	2000	2000	2000	2000	2000
PJM	PJM_Extension Export	1500	1500	1500	1500	1500	1500
PJM	PJM_Homer Cty	531	531	531	531	531	531
PJM	PJM-VAP	500	500	500	500	500	500
PJM	Western Interface	6250	6250	6250	6250	6250	6250

Two major transmission additions in the PJM area are included in the Base Case. The first addition is the TrAIL Line, which is located in PJM and is scheduled to enter commercial operation in 2010. The second addition is the Susquehanna-Roseland 500 kV addition, which is located in PJM and is scheduled to enter commercial operation in 2013. These substantial upgrades to the PJM system will provide additional transfer capability and a lower impedance path from western PJM to eastern PJM. This may allow for cheaper resources to be delivered to eastern PJM by bypassing potential constraints. As a result, these upgrades may impact prices in eastern PJM and New York. With the network impedance change, there will be an impact on the shift factor calculations that may increase or decrease congestion in PJM and New York.

Hurdle Rates and Interchange Models

Hurdle rates set the conditions in which economic interchange can be transacted between neighboring markets/control areas. They represent a minimum savings level that needs to be achieved before energy will flow across the interchange. Hurdle rates serve two purposes in the CARIS model. First, they are used when preparing the Base Case to help calibrate the production-cost simulation so that it replicates the historical pattern of internal NYCA generation and imports. . Second, they are used to find a different (and usually lower-cost) combination of generation resources to meet loads aggregated from the Base Case.

Two independent hurdle rates are used in the CARIS, one for the commitment of generation and a separate one for the dispatch of generation. The commitment hurdle rate sets the level that a unit commitment change will be made and the dispatch hurdle rate sets a level that will allow economic dispatch to be changed to allow scheduled energy to flow between market areas. Hurdle rates are held constant throughout the 2009-2015 study period. Hurdle rates on several closed and open interfaces were used to model regional power imports, exports and wheel-through transactions. These hurdle rates are frequently used in conducting multi-pool production cost simulations and they are used to represent several phenomena such as complex market pricing at the boundary buses, cost mark-ups and market inefficiency. The hurdle rate values in the CARIS databases are consistent with previous NYISO and consultant studies, and are considered standard industry practice. In addition, the annual NYISO imports are consistent with historic import levels, confirming that NYISO's hurdle rate assumptions are reasonable.

Only energy transactions associated with Unforced Capacity Deliverability Rights (UDRs) granted on controllable tie lines were specifically modeled, namely on the NYISO DC tie-lines (Neptune and Cross Sound Cable (CSC)). Flows on those facilities were not subject to hurdle rates and the required firm commitment was modeled in the associated neighboring system. The flow on the CSC line was modeled to allow bi-directional flow (i.e., flow both from and toward ISO-NE) but the Neptune flows was restricted to no more than 660 MW in one direction into Long Island from PJM. The reverse flow toward PJM was not allowed to occur in the simulation because exports from Long Island to PJM are not presently permitted operationally on Neptune line.

The hourly interchange flow for each interface connecting the NYISO with neighboring control areas was priced at the LBMP of its corresponding proxy-bus. The summation of all 8,760 hours determined the annual cost of the energy for each interface. Table C-4 lists the proxy bus location for each interface.

Table C-4: Interchange LBMP Proxy Bus

Interface	Proxy-Bus
PJM	Keystone
Ontario	Beck
Quebec	Chateauguay
Neptune	Atlantic 230 kV
New England	Sandy Pd
Cross Sound Cable	New Haven Harbor

Production Cost Model

Production cost models require input data to develop cost curves for the resources that the model will commit and dispatch to serve the load subject to the constraints given in the model. In conducting the CARIS production cost analysis, the NYISO used two simulation tools: ABB's GridView software and GE's MAPS software. These tools came with their own data sets, which the NYISO checked and verified.

This section discusses how the "production cost data" is identified and quantified. The model simulations are driven by incremental production costs of generators. The incremental cost of generation is the product of the incremental heat rate multiplied by the sum of fuel cost, emissions cost, and variable operation and maintenance expenses.

Heat Rates

Fuel costs represent the largest incremental expense for fossil fueled generating units. Fuel costs are the product of fuel prices and incremental heat rates. Thus, it is critically important to the quality of the CARIS results that individual generating unit heat rates used in the simulations be an accurate representation of reality. Individual unit heat rates are important competitive information and thus are not widely available from generator owners. Both the GridView and MAPS simulation models have databases that represent the model providers' best estimates of heat rates. When the heat rates from the two models were compared, it was apparent that significant differences existed.

In order to gain additional insight as to which, if either, data set was an accurate representation of actual unit performance, publicly available information reporting heat input was matched with net generator production from NYISO market data to calculate hourly heat rates for 2008. One vendor has substituted a dataset for which the NYISO did not have a direct license agreement, thus removing that data set from further consideration. Unit heat input data is available from the U.S. Environmental Protection Agency's (EPA) Clean Air Market Data. Accordingly, this data set was used to calculate unit heat rates and incremental heat rates across each unit's operating range through

the use of regression analysis techniques. First, second, and third order polynomials were developed. Generally, third order polynomials resulted in the best fit. A small number of data points were eliminated for a few units to improve curve fit. The eliminated data could be the result of errors in reporting or represent limited operation within a specific hour. These calculated heat rates were compared to the remaining simulation model data for each fossil fueled unit in the NYCA and one heat rate curve was selected for each unit. Several plants have significant steam supply contracts. The steam sales revenues are not captured in the simulation models. In order to simulate the operation of these units, some of them were simulated as must run units.
Consideration was given to using this approach across all of the units in the simulation. However, the relative smaller impact of heat rate inaccuracies for non-NYCA units and the magnitude of the effort to correct heat rates for all units in the simulation lead to the conclusion that vendor-supplied heat rate information should be used for all non-NYCA units.

CARIS simulation models employ power points, which are points in each unit's operating range where specific data such as heat rate is tied to the power point. In general there are minimum and maximum points where the unit can be simulated to operate on a sustained basis. There may also be additional intermediary points. Each of these points was tied to a point on the heat rate curve and the incremental heat rate was determined for each unit.

A review of the actual operating performance of NYCA units revealed that the vendor supplied data sets did not accurately capture the point of minimum operation for units that have emission control systems that are sensitive to flue gas exit temperatures for the control of NO_X emissions. The minimum operating points for units with these permit conditions were increased to reflect these operating limits.

Heat Rates of marginal units in all zones display the expected seasonal patterns with summer months having the highest values. Also, there is a progression by which the monthly averages are the lowest in Zone A. The further east a zone is located in the NYCA, the higher is the implied heat rate. The relative magnitudes of differences across zones are consistent with the differences in the generation fuel-mixes as depicted in Figure C-2.

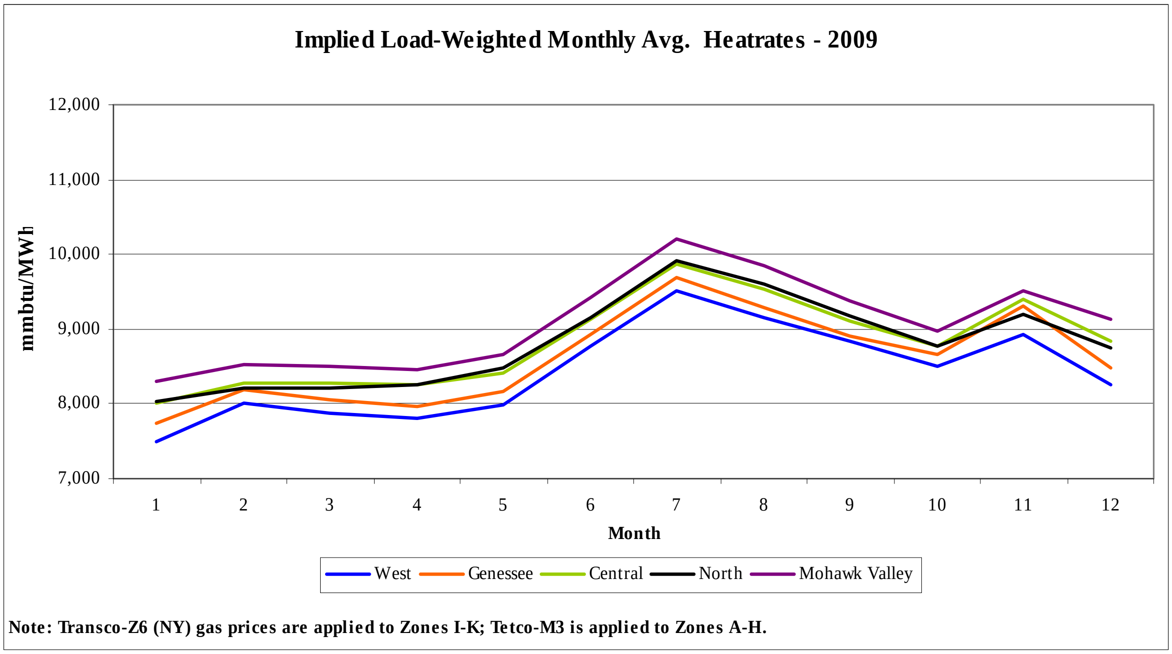


Figure C-2: Implied Load-Weighted Monthly Average Heat Rates for Upstate NY (nom. $)

The implied heat rates for all downstate zones, depicted in Figure C-3, display the expected seasonal patterns. The heat rates of marginal units are highest for Millwood (Zone H), Hudson Valley (Zone G), and Long Island (Zone K). With respect to Zones G and J, the difference in assumed gas prices explains the relative heat rate parity during non-winter months, and the divergence during the winter months.

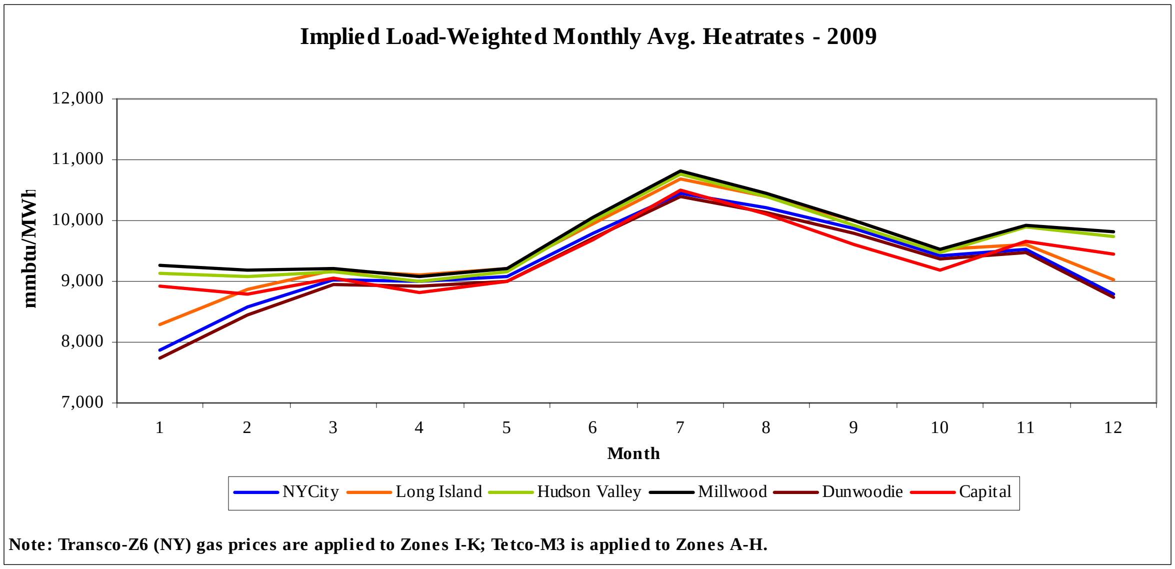


Figure C-3: Implied Load-Weighted Monthly Ave. Heat Rates for Downstate NY (nom. $)

Fuel forecast

Figures C-4 and C-5 illustrate forecasted oil and natural gas fuel prices for external areas.

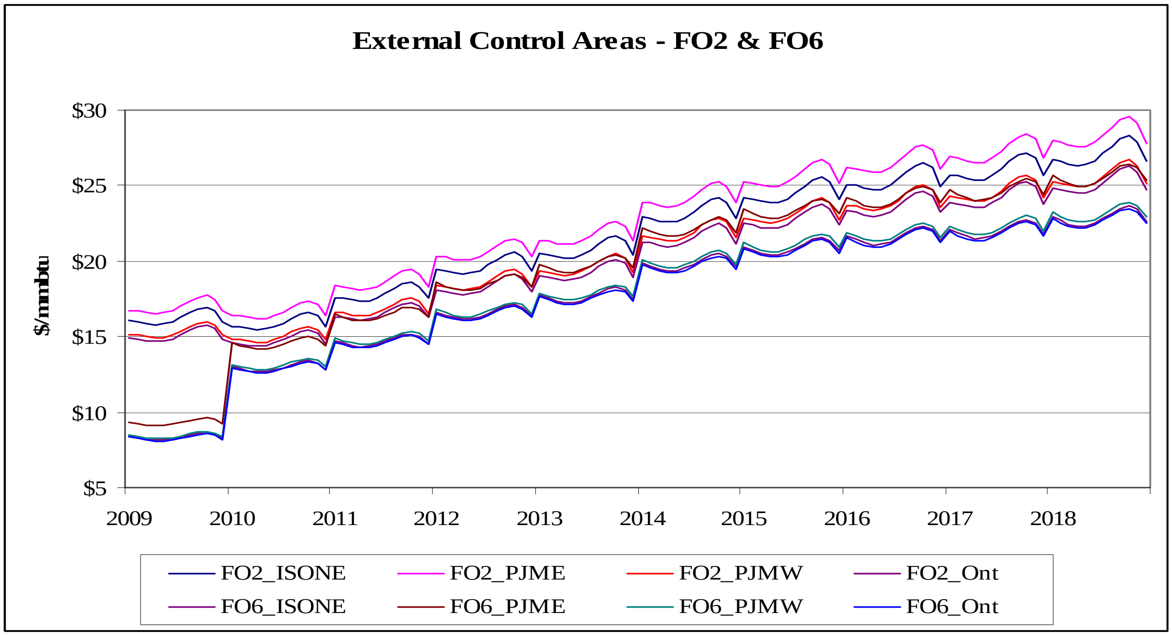


Figure C-4: Forecasted oil fuel prices for ISO-NE, PJM, & Ontario (nominal $)

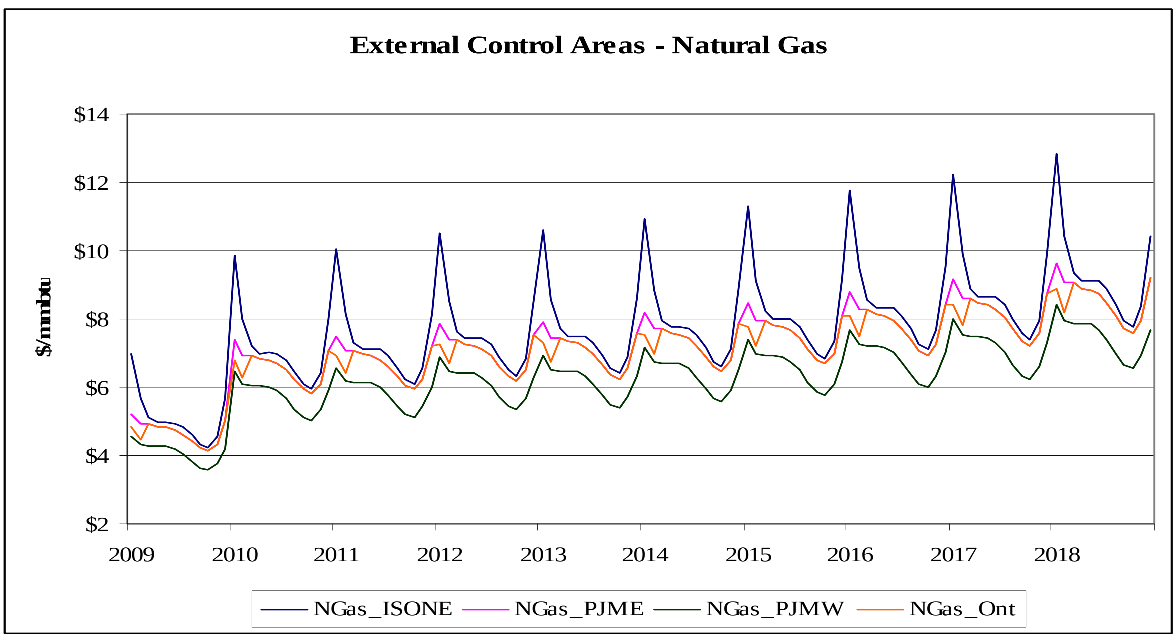


Figure C-5: Forecasted natural gas prices for ISO-NE, PJM, & Ontario (nominal $)

Fuel Switching

Fuel switching capability is widespread within NYCA. In the NYCA, 37% of the 2009 generating capacity, or 14,470 MW, has the ability to burn either oil or gas. There are three reasons that generating facilities would exercise the capability to burn oil: the first reason is that oil would be the economic fuel of choice, the second reason would be to satisfy reliability rules, and the third reason would be an interruption of the gas supply. Historically, significant quantities of oil have been used at the prices illustrated in Figure C-6.[12]

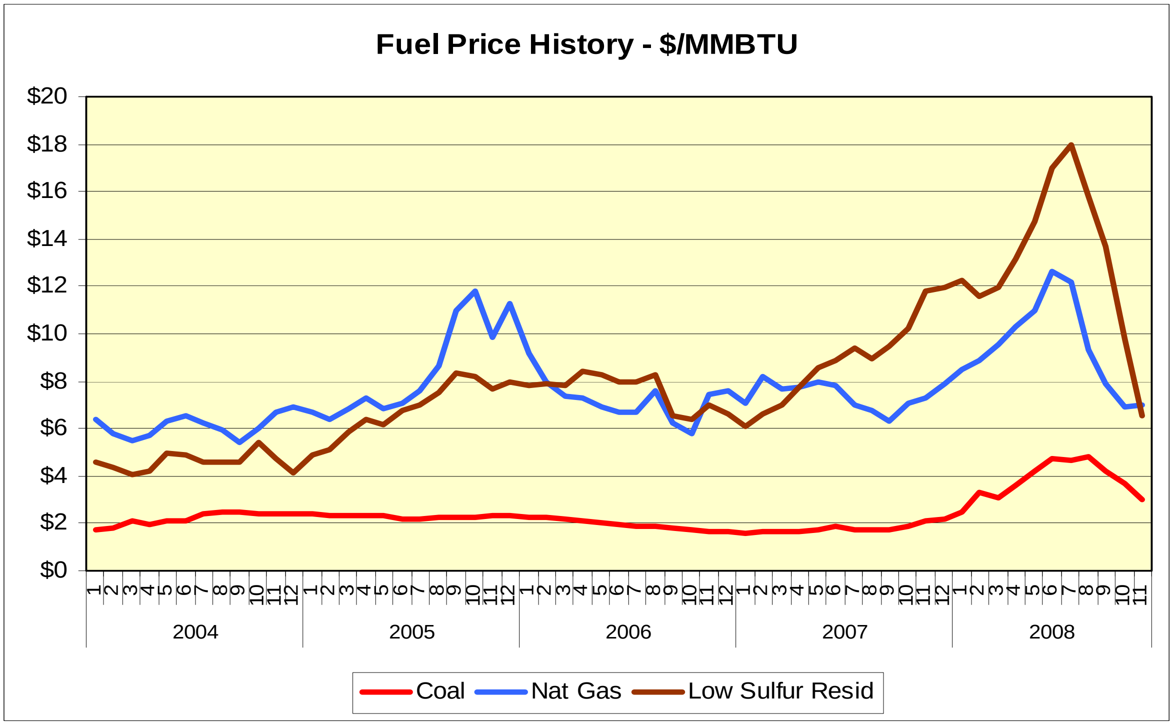


Figure C-6: Historical fuel prices of coal, natural gas, and low sulfur coal (nominal $)

Both simulation models can select the economic fuel based on monthly production costs for units with duel fuel capability. For the planning horizon, the fuel price forecast does not show that low sulfur residual fuel oil will be an economic choice on a monthly basis.

The New York State Reliability Council (NYSRC) establishes rules for the reliable operation of the New York Bulk Power System. Two of those rules guard against the loss of electric load because of the loss of gas supply. Rule I-R3 states "The New York State bulk power system shall be operated so that the loss of a single gas facility does not result in the loss of electric load within the New York City zone." Rule I-R5 similarly states "The New York State bulk power system shall be operated so that the loss of a single gas facility will not result in the uncontrolled loss of electricity within the Long Island zone." To satisfy these criteria, annual studies are performed that update the configurations of the electricity and gas systems and simulate the loss of a various gas supply facilities. The loss of these

12 The data source for the fuel price history for natural gas is USEIA Sourcekey N3045US3, and for residual fuel oil the data source is USEIA Sourcekey RFO1LNYH5, and NYMEX Central Appalachian. The delivery points of these fuel costs are: Natural Gas NYC; RFO NYH; and Coal Ohio River.

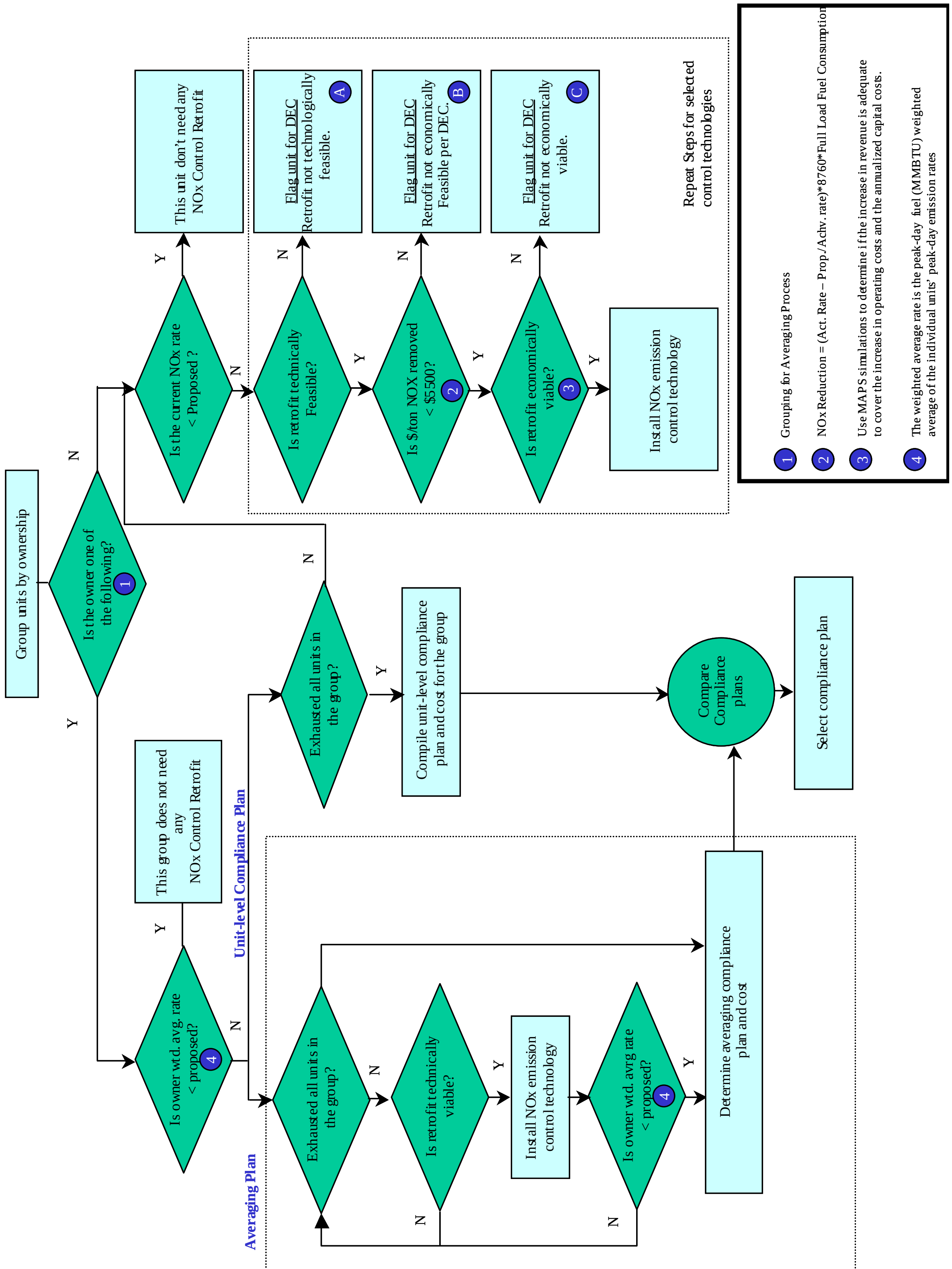
gas facilities leads to the loss of some generating units. This loss becomes critical because it may result in voltage collapse when load levels are high enough. Therefore, criteria are established whereby certain units that are capable of doing so are required to switch to minimum oil burn levels so that in the event of the worst gas system contingency these units stay on-line at minimum generation levels and support system voltage. This MW deficiency must be made up first through the increased use of imports until oil burning units are able to ramp up their output over a longer timeframe. Some new combined cycle gas turbine units in these zones have the ability to "switch-on-the-fly" from gas-burn to oil-burn with a limited loss of output that can be quickly recovered. However, there is the risk that this live switching may not be successful and the unit may trip. Therefore, in many cases, such units are required to switch to burning oil at lower load levels so there is the ability of recovering from an unsuccessful switching. As the generator fleet in these zones has experienced a shift to increased use of combined cycle units with switch-on-the-fly capability, the amount of oil used in steam units to satisfy minimum oil burn criteria has decreased. In order to simulate the use of oil in steam units to satisfy these reliability criteria, Northport #4 is modeled to burn oil throughout its operating range during the Summer capability period. Ravenswood #3 is modeled to burn oil up to its second dispatch point of 608 MW throughout the year. For the balance of the year for Northport #4 and for the balance of the operating range for Ravenswood #3, the most economic fuel was selected.

Generation Maintenance

Levels (MW) of generation unavailability were developed based on historic 2007 and 2008 generation unavailability reported in FERC Form 714, which reports 2 types of monthly unavailability: Planned (maintenance outages) and Unplanned (forced outages). Each generating unit was then assigned an unavailability period for each type. Planned or maintenance outage durations are based on established maintenance durations by generating unit technology (i.e. nuclear refueling, steam unit major overhauls, gas turbine inspection). Unplanned or forced outage durations were determined for each generating units based on its most recent 5-year average forced outage rate (EFORd).

Both unavailability periods were then scheduled throughout a calendar year in such a way that the level of unavailability (MW) for each type of outage at the hour of the monthly peak is consistent with the 2007 and 2008 monthly levels of unavailability. The outage duration periods were fixed for each of the study years 2009 through 2015.

B. Compliance Plan Process Flowchart



C. GE-MAPS Description

(PDF Goes Here)

D. Emission Control Technology Description

D.1 Gas Turbine Units NOx Emission Control Technologies

The three most widely used NOx control technologies are considered in this study. They are dry low NOx combustor (DLN), water/steam injection (WI) and selective non-catalytic reduction (SCR). A brief description of the three technologies is provided in this section.

D.1.1 Dry Low NOx (DLN) Technology

DLN technology achieves low NOx emissions by staging fuel in a lean premixed combustion mode at designed flame temperatures. For a heavy-duty gas turbine, a DLN combustor usually consists of four major components: fuel injection system, liner, venture and cap/center body assembly. The components form two stages in the combustor. In the premixed mode, the first stage thoroughly mixes the fuel and air and delivers a uniform, lean, unburned fuel-air mixture to the second stage. Figure D-1a illustrates a schematic of heavy-duty turbine DLN combustor.

For aeroderivative gas turbines, a Dry Low NOx Emissions Combustor (DLE) is also available. The technology consists of a premixed combustion configuration to achieve uniform mixing of fuel and air producing a reduced heating value gas, which will then burn at lower flame temperatures. Figure D-1b shows an illustration of DLE combustor.

The minimum achievable NOx emissions by DLN are about 9 ppm to 65ppm @ 15% O_2. The achievable NOx level is different for the type of unit and the type of fuel fired and should be determined case by case from the technology providers.

Table D-2 shows examples of annual cost and operating cost for the application of DLN technology. The information was obtained mainly from public references, GE's experience and the consideration of inflation. The capital recovery is calculated based on 10 years.

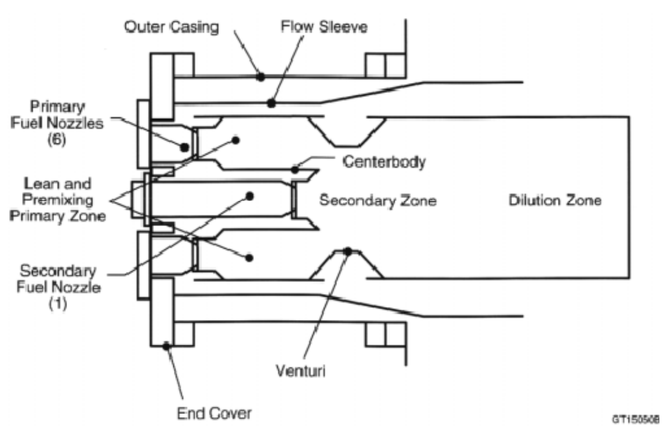


Figure D-1a. Heavy-duty DLN combustor.

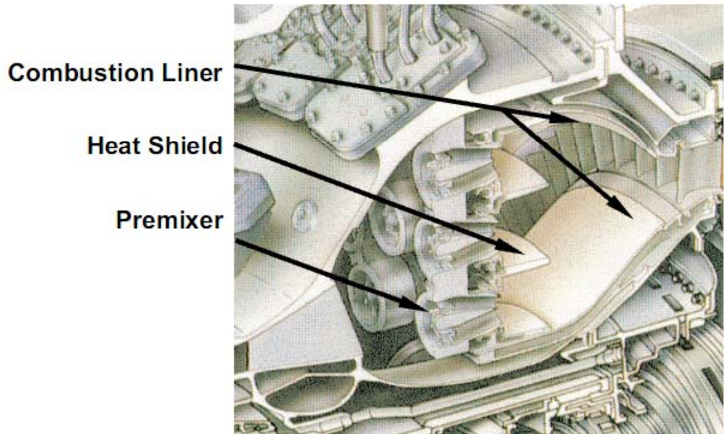


Figure D-1b. Aeroderivative DLE combustor.

Table D-1. Cost Analysis for DLN Technology

Potential Emission Control Technology		Unit	Dry Low NOx			
			5 MW	25 MW	150+ MW	> 250 MW notional scaling
Sample Model			Allison 501-KB7	GE LM2500	GE Frame 7EA	
Cost						
1	**Equipment Cost Including Installation**	$	25,853	1,034,103	5,816,827	8,215,857
2	**Capital Recovery Factor***		0.12	0.12	0.12	0.12
3	**Annual Equipment Cost (item 1 x item 2)**	$	3,187	127,495	717,162	1,012,941
4	**Annual Operating Costs**	$	41,364	155,115	155,115	155,115
	A. Electricity	$	included	included	included	included
	B. Natural Gas	$	included	included	included	included
	C. Catalyst Replacement	$	included	included	included	included
	D. Carbon Replacement/Ammonia Injection	$	included	included	included	included
	E. Maintenance**	$	included	included	included	included
5	**Total Annual Costs (item 3 + item 4)**	$	44,551	282,611	872,277	1,168,056

D.1.2 Water/Steam Injection (WI) Technology

Since NOx emissions increase significantly with combustion zone flame temperature, injecting water or steam to combustor can effectively reduce flame temperature and therefore, NOx emissions. The water injection system usually consists of a water pump and filter, water flow meters, and water flow control valves. The water injection at the combustion chamber is achieved through passages in the fuel nozzle assembly. Figure D-2 shows an example of water injection fuel nozzle assembly.

A penalty in overall efficiency must be paid for additional fuel required to heat the water to combustor temperature. However, gas turbine output is enhanced because of the additional mass flow through the turbine. The injected water must be of boiler feed water quality to prevent deposits and corrosion in the hot turbine gas path area downstream of the combustor. Steam can also be used. However, steam injection for NOx reduction is not as effective as water in reducing thermal NOx. Since the high latent heat of water acts as a strong thermal sink in reducing the flame temperature. In general, for a given NOx reduction, approximately 1.6 times as much steam as water on a mass basis is required for control.

Some side effects from water/steam injection should be aware of, such as: (1) impact on dynamic pressure activity within the combustor, (2) increase of CO emissions, (3) reduction on combustion stability and (3) flame blow out when increasing water/steam injection, etc.

The minimum achievable NOx emissions by water/steam injection are about 25 ppm to 42 ppm @ 15% O_2. The achievable NOx level is different for the type of unit and the type of fuel fired and should be determined case by case from the technology providers.

Table D-2 shows examples of annual cost and operating cost for the application of WI technology. The information was mainly obtained from public references posted early years, GE's experience and the consideration of inflation. The capital recovery is calculated based on 10 years.

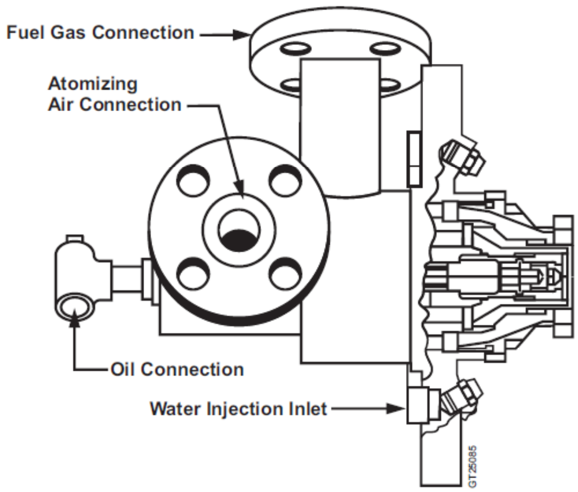


Figure D-2. Water injection fuel nozzle assembly for GE heavy-duty gas turbines.

Table D-2. Cost Analysis for WI Technology

Potential Emission Control Technology		Unit	Water/Steam Injection			
			5 MW	25 MW	150+ MW	> 250 MW
Sample Model			Solar Centaur 50	GE LM2500	GE MS7001F	notional scaling
Cost						
1	**Equipment Cost Including Installation**	$	523,773	1,400,142	6,249,560	8,827,062
2	**Capital Recovery Factor**		0.12	0.12	0.12	0.12
3	**Annual Equipment Cost (item 1 x item 2)**	$	64,576	172,625	770,514	1,088,297
4	**Annual Operating Costs**	$	88,716	309,771	1,325,587	1,872,298
	A. Electricity	$	354	1,788	23,987	33,879
	B. Natural Gas	$	35,000	177,000	677,000	956,215
	C. Catalyst Replacement	$	0	0	0	0
	D. Carbon Replacement/Ammonia Injection	$	5,525	27,926	374,618	529,121
	E. Maintenance	$	47,838	103,057	249,983	353,083
5	**Total Annual Costs (item 3 + item 4)**	$	153,293	482,396	2,096,101	2,960,595

D.1.3 Selective Catalytic Reduction (SCR) Technology

SCR technology converts NO and NO_2 in the gas turbine exhaust stream to molecular nitrogen and oxygen by reacting the NOx with ammonia in the presence of catalyst. Conventional SCR technology requires that the temperature of the exhaust stream remain in a narrow range (550°F to 750°F or 288°C to 399 °C) and is restricted to applications with a heat recovery system installed in the exhaust. New high-temperature SCR technology is being developed that may allow SCRs to be used for applications without heat recovery boilers.

SCR systems are sensitive to fuels containing more than 1000 ppm of sulfur, since sulfur poisons the catalyst being used in SCRs and react with ammonia to form ammonium bisulfate, which is extremely corrosive, particularly near the discharge of a heat recovery boiler. Another byproduct from the SCR systems is the ammonia slip. Ammonia slip may increase when the catalyst bed is plugged forming non-uniform distribution of the ammonia flow.

Table D-3 shows examples of annual cost and operating cost for the application of SCR technology. The information was mainly obtained from public references posted early years, GE's experience and the consideration of inflation. The capital recovery is calculated based on 10 years.

Table D-3. Cost Analysis for SCR Technology

Potential Emission Control Technology			Conventional SCR				Simple Cycle SCR			
							Lo/Med Temp SCR		Hi - Temp SCR	
		Unit	5 MW	25 MW	150+ MW	> 250 MW notional scaling	5 MW	25 MW	150+ MW	> 250 MW notional scaling
Sample Model			Solar Centaur 50	GE LM2500	GE Frame 7FA		Solar Centaur 50	GE LM2500	GE Frame 7FA	
Cost										
1	**Equipment Cost Including Installation**	$	534,234	1,481,904	4,596,405	6,492,097	534,234	1,481,904	18,385,619	25,968,388
2	**Capital Recovery Factor***		0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
3	**Annual Equipment Cost (item 1 x item 2)**	$	65,866	182,705	566,695	800,417	65,866	182,705	2,266,780	3,201,667
4	**Annual Operating Costs**	$	91,745	231,605	1,273,847	1,777,178	91,745	231,605	1,273,847	1,777,178
	A. Electricity	$	16,511	90,418	632,923	893,959	16,511	90,418	632,923	893,959
	B. Natural Gas	$	0	0	0	0	0	0	0	0
	C. Catalyst Replacement	$	10,740	58,816	411,714	581,517	10,740	58,816	411,714	581,517
	D. Carbon Replacement/Ammonia Injection	$	11,052	28,929	175,768	248,259	11,052	28,929	175,768	248,259
	E. Maintenance**	$	53,442	53,442	53,442	53,442	53,442	53,442	53,442	53,442
5	**Total Annual Costs (item 3 + item 4)**	$	157,612	414,310	1,840,542	2,577,595	157,612	414,310	3,540,628	4,978,845

D.2 Steam Turbine Units NOx Emission Control Technologies

NOx emission controls for the steam turbine units are mainly achieved by boiler combustion modifications such as low NOx burners (LNB), overfire air (OFA), and reburn, and post-combustion technology including selective non-catalytic reduction (SNCR) and selective catalytic reduction (SCR). In general, combustion modification technologies require lower capital and operating cost than the post-combustion technology. Figure D-3 illustrates the concept of these control technologies. Figure D-4 shows the estimated achievable NOx reductions. However, the real reduction efficiency in the application is different case by case and often is constrained by the capability of controlling combustible emissions. Table D-4 summarizes the cost analysis for the control technology. The information was mainly from public references, GE's experience and the consideration of inflation. The capital recovery is calculated based on 10 years.

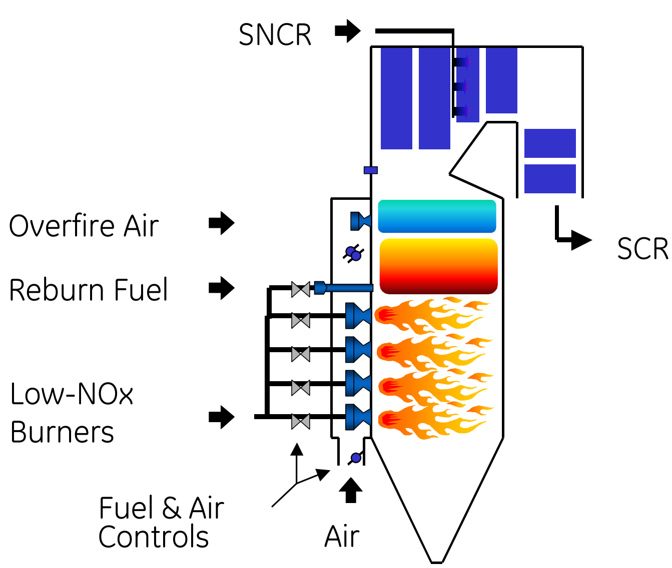


Figure D-3. NOx control technologies for steam turbine boilers.

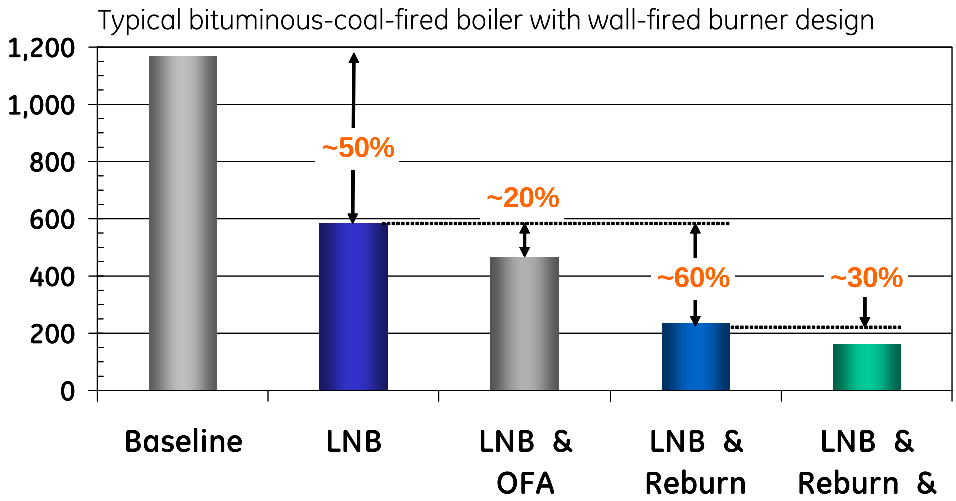


Figure D-4. Achievable NOx reductions.

Table D-4. Cost Analysis for Steam Turbine DeNOx Technologies

	Potential Emission Control Technology		LNB		SNCR		OFA		Coal Reburn		SCR	
		Unit	200 MW	550 MW	200 MW	550 MW	200 MW	550 MW	200 MW	550 MW	200 MW	550 MW
Cost												
1	**Equipment Cost Including Installation**	$	2,470,000	4,800,000	1,290,000	1,455,000	1,225,000	2,240,000	2,690,000	3,480,000	10,288,000	21,481,000
2	**Capital Recovery Factor***		0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.12
3	**Annual Equipment Cost (item 1 x item 2)**	$	304,529	591,797	159,045	179,388	151,031	276,172	331,653	429,052	1,268,417	2,648,413
4	**Annual Operating Costs**	$	0	0	323,550	837,369	13,272	26,600	22,677	30,730	824,807	2,127,150
	A. Electricity	$	0	0	13,000	35,694	3,472	8,680	1,157	2,890	280,724	772,000
	B. Natural Gas	$	0	0	0	0	0	0	0	0	0	0
	C. Catalyst Replacement	$	0	0	0	0	0	0	0	0	134,127	369,000
	D. Carbon Replacement/Ammonia Injection	$	0	0	278,300	765,300	0	0	0	0	197,000	541,500
	E. Maintenance**	$	0	0	32,250	36,375	9,800	17,920	21,520	27,840	212,956	444,650
5	**Total Annual Costs (item 3 + item 4)**	$	304,529	591,797	482,595	1,016,757	164,303	302,772	354,330	459,782	2,093,224	4,775,563

D.2.1 Low NOx Burner

All low-NOx burners offered commercially for application to coal-fired boilers control the formation and emission of NOx through some form of staged combustion. In this process, the mixing of the fuel and the air by the burner is controlled in such a way that ignition and initial combustion of the coal takes place under oxygen deficient conditions. Mixing of some portion of the combustion air is then delayed along the length of the flame. The objective of this process is to drive the fuel-bound nitrogen out of the coal as quickly as possible, under conditions where no oxygen is present, and where it will be forced to form molecular nitrogen, rather than be oxidized to NOx. Any nitrogen escaping the initial fuel-rich region has a greater opportunity to be converted to NOx as the combustion process is completed.

In practice, there are many factors that tend to influence the ability to reduce NOx in any given (wall-fired) utility boiler application, without significantly impacting unit performance. Many of these stem from the need to delay fuel/air mixing, and to expand the volume occupied by the combustion process, in order to adequately control NOx. Key factors are of course, the design of the low-NOx burner itself, and the characteristics (nitrogen content, volatility, and char reactivity) of the coal fired. However, there are also a number of key boiler design parameters that combine to affect NOx reduction potential. These include: available firing depth; cross sectional area; burner-burner spacing; and the size of existing wall penetrations.

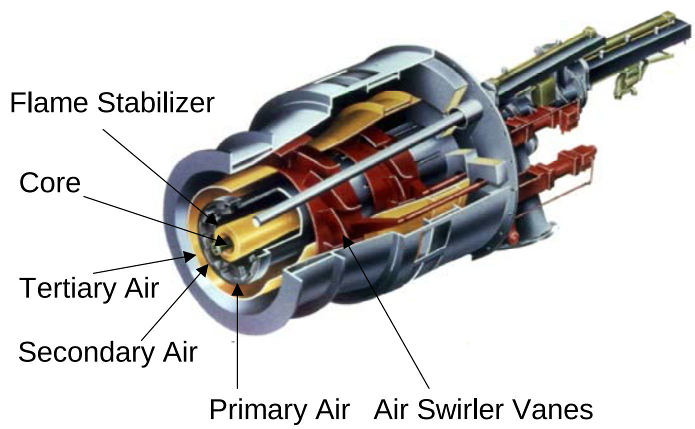


Figure D-5. NOx control technologies for steam turbine boilers.

D.2.2 Overfire Air

Overfire air technology consists of staging the combustion air added to the furnace. In this technology, combustion air is diverted from the burners and injected into the furnace above the main flame zone. Overfire air reduces the amount of oxygen available in the combustion zone and results in lower thermal NOx and fuel NOx emissions. For coal-fired boilers equipped with low-NOx burners, overfire air is a very effective technique for reducing NOx emissions as it enhances the staged combustion processes already in place.

Overfire air can impact boiler performance due to changes in the furnace heat absorption profile. The impacts of overfire air on boiler performance are site specific and depend upon the boiler design and operating characteristics, the fuels fired, and the levels of staging that must be employed to reach an emissions reduction target. In general, overfire air has a minimal impact on boiler steam generation and temperatures provided that the unit is operating with fuels similar to the design fuel and with some level of main steam attemperation. Overfire air can also increase the level of carbon in fly ash and emissions of carbon monoxide. Any increase in carbon in ash can be minimized by maintaining good burner flame stability and good mill fineness.

D.2.3 Reburning

Reburning is a combustion modification technique that removes NOx from combustion products by using fuel as a reducing reagent. The fundamental principles of reburning - that fuel fragments can react with NO to form molecular nitrogen - was first demonstrated as a viable NOx control technique more than thirty years ago. Since that time, the process has been demonstrated and applied successfully to a wide range of different utility boiler systems firing a range of solid, liquid and gaseous fuels.

The application of reburning to a typical utility boiler furnace is shown conceptually in Figure D-6. Here, reburning fuel, representing a proportion of the total thermal input to the system, is injected into the furnace at a location above the main combustion zone. This provides a slightly fuel rich environment, or reburning zone, which reduces nitrogen oxides formed in the main combustion process to molecular nitrogen. Following the reburn zone, additional combustion air (or overfire air) is introduced to complete the combustion process by oxidizing carbon monoxide and any residual fuel fragments exiting the reburn zone.

Natural gas has been the reburning fuel of choice for many of the reburn system applications to date. This is largely because natural gas is highly reactive; it does not contain fuel-nitrogen species or sulfur, and is therefore readily incorporated into most retrofit situations where space and access may be limited. Reburning can however be achieved with any hydrocarbon fuel, and the use of coal and heavy fuel oils in the reburning process has been successfully commercialized. With coal and heavy oil as the reburning fuel, boiler applications have typically yielded NOx reduction levels on the order of 50% relative to pre-retrofit emissions, while with natural gas NOx reduction levels have routinely been in excess of 60%.

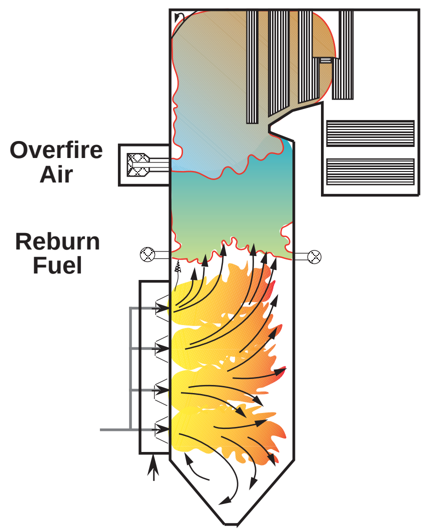


Figure D-6. Schematic of reburn application.

D.2.4 Selective Non-Catalytic Reduction (SNCR) Technology

Selective non-catalytic reduction is a flue gas treatment process in which an amine containing agent, such as ammonia (NH_3) or urea ($CO(NH_2)_2$), is injected into combustion gases to react with and reduce NOx formed during the combustion process. At the proper temperature window, NH_2, generated from decomposition of the injected reagent, reacts directly with NO to form N_2. The experimental temperature sensitivity of ammonia and urea is illustrated in Figure D-7 for long residence time and isothermal conditions. Although the optimum temperature depends on the agent and furnace thermal characteristics, the accepted window for SNCR application is generally at a temperature between 1,600 to 1,800°F (900 to 1000°C).

The performance of SNCR on coal-fired boilers depends upon the reagent used, the quantity of reagent injected, and the furnace design and operating characteristics. For maximum performance, the injection system must be designed to provide effective mixing of the reagent within the optimal temperature window. In addition, the furnace design must provide adequate residence time at the proper temperature window.

The SNCR system mainly consists of a reagent supply and control system and a reagent injection system. The main byproduct from the SNCR process is the ammonia slip. Depending on the process conditions, as the flue gases cool, ammonia slip can react with sulfur trioxide (SO_3) and water vapor to form ammonium bisulfate ($(NH_4)HSO_4$) and ammonium sulfate ($(NH_4)_2SO_4$). Ammonium bisulfate is a sticky corrosive liquid that can deposit on and foul heat transfer surfaces. Ammonium sulfate is a dry solid and forms as solid particles, which may increase particulate emissions.

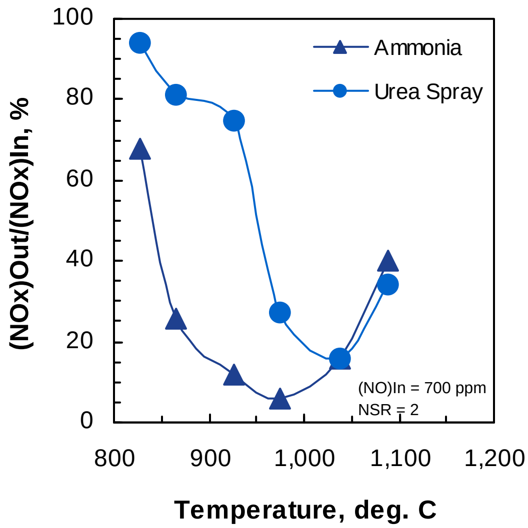


Figure D-7. Impact of injection temperature on SNCR process.

D.2.5 Selective Catalytic Reduction (SCR) Technology

SCR is a process that involves post-combustion removal of NOx from flue gas with a catalytic reactor. In the SCR process, ammonia injected into the exhaust gas reacts with NOx and O_2 to for nitrogen and water. The reactions take place on the surface of a catalyst. The NOx removal efficiency relates to the catalyst reactor design, optimum operating temperature, sulfur content of the fuel, and design of the ammonia injection system.

The SCR system is comprised of a number components: the SCR reactor, ammonia injection system, and ammonia storage and delivery system. From the economizer outlet, the flue gas will first pass through a low-pressure ammonia/air injection grid. The ammonia treated flue gas will then flow through the catalyst bed and exit the air heater. Figure D-8 shows a schematic of the ammonia distribution in the SCR system.

Sulfur content of the fuel can be a concern for the system. Catalyst systems promote partial oxidation of SO_2 to SO_3, which combines with water to form sulfuric acid. At typical SCR operating temperature, SO_3 and sulfuric acid react with excess ammonia to form ammonium salts, which may condense as the flue gases are cooled leading to increased particulate matter emissions. Fouling may eventually lead to decreased NOx reduction performance.

An optimum SCR system can result in a 90% reduction. However, the application of a SCR system is subject to the economic feasibility and space availability.

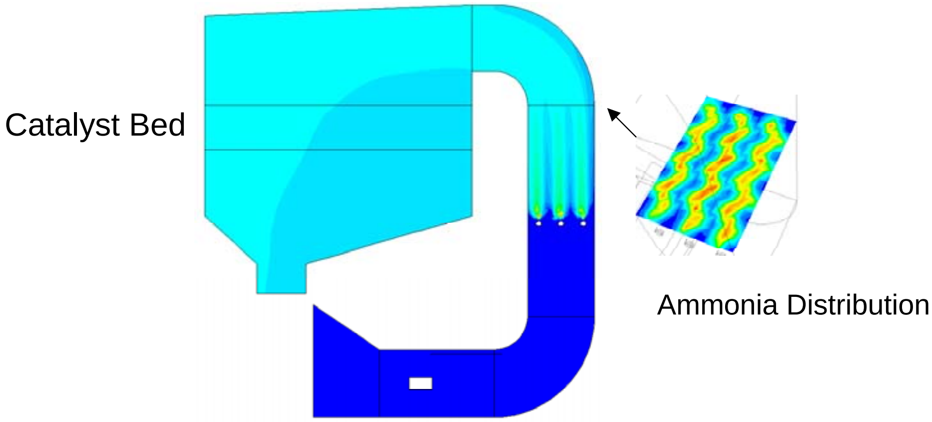


Figure D-7. SCR ammonia distribution study.

E. NYSDEC Economic Analysis - Air Emissions Control Equipment

- 8 -

Table I

Economic Analysis - Air Emissions Control Equipment

FACILITY NAME AND ADDRESS: ______________________________

FACILITY ID AND EMISSION POINT ______________________________
CONTROL TYPE ______________________________

1.	COST OF EMISSIONS CONTROL EQUIPMENT INCLUDING INSTALLATION	$______________	(1)
2.	CALCULATE CAPITAL RECOVERY FACTOR (*) RECOVERY FACTOR(*)	______________	(2)
3.	CALCULATE ANNUAL EQUIPMENT COST (MULTIPLY ITEM 1 BY ITEM 2)	$______________	(3)
4.	ANNUAL OPERATING COSTS		
A.	ELECTRICITY(**)	$______________	(4A)
B.	NATURAL GAS(**)	$______________	(4B)
C.	CATALYST REPLACEMENT	$______________	(4C)
D.	CARBON REPLACEMENT	$______________	(4D)
E.	MAINTENANCE	$______________	(4E)
5.	TOTAL ANNUAL COSTS [ADD ITEMS 3 AND 4 (A TO E)]	$______________	(5)

---

6. CALCULATE ANNUAL VOC OR NOx TONNAGE REDUCTION

A.	VOC OR NOx ACTUAL ANNUAL EMISSIONS	__________	(6A)
B.	PERCENT CAPTURE AND CONTROL (OR PERCENT REDUCTION) ACHIEVED	__________	(6B)
C.	TONS REDUCED (MULTIPLY ITEM 6A BY ITEM 6B)	__________	(6C)

TOTAL COST OF CONTROLS PER TON REDUCED $__________
(DIVIDE ITEM 5 BY ITEM 6C)

---

*CRF = CAPITAL RECOVERY FACTOR

$$= \frac{I(1+I)^n}{(1+I)^n - 1}$$

WHERE I = ANNUAL INTEREST RATE
n = EQUIPMENT OR REPLACEMENT PARTS LIFE, IN YEARS (n=10)

** Energy costs should be the added costs of operating the control equipment minus any cost that will no longer continue to incur as a result of the equipment installation and operation, not the total energy costs of running the process to be controlled.

AIR GUIDE 20 Revised: January 24, 1996

F. Additional Base Case Results

The tables in this Appendix show the peak-day, top-25 days, ozone season and annual NOx emissions by zone under existing and proposed RACT regulations. These emissions under the proposed regulations are shown for the years 2010 through 2012 for comparison purposes only.

Table F1: Peak-Day, Top-25, Ozone and Annual Emissions by Zone

Year 2010

	Peak-Day emissions		Top 25 day emissions		Ozone season emissions		Annual emissions	
Zone	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
CAPITAL	5	5	112	101	672	602	1,276	1,141
CENTRAL	35	21	958	546	6,064	3,171	11,464	6,027
GENESSEE	1	1	8	8	14	14	22	22
HUDSONVA	39	28	813	570	3,495	2,254	6,079	3,892
LONGISLA	36	33	685	650	2,604	2,510	3,776	3,654
MILLWOOD	0	0	0	0	0	0	0	0
MOHAWKVA	2	2	55	43	272	180	501	334
NORTH	1	1	22	22	126	127	269	270
NYCITY	100	93	1,618	1,514	5,050	4,803	7,373	6,953
WEST	40	28	972	663	6,553	4,301	12,483	8,369
NYISO	258	211	5,244	4,117	24,850	17,961	43,242	30,662

Year 2011

	Peak-Day emissions		Top 25 day emissions		Ozone season emissions		Annual emissions	
Zone	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
CAPITAL	5	5	114	104	672	602	1,282	1,146
CENTRAL	35	21	943	523	6,057	3,139	11,538	6,063
GENESSEE	1	1	8	8	14	14	24	24
HUDSONVA	39	29	810	566	3,619	2,346	6,324	4,068
LONGISLA	39	38	729	697	2,796	2,709	4,127	4,017
MILLWOOD	0	0	0	0	0	0	0	0
MOHAWKVA	2	2	55	43	274	183	513	348
NORTH	1	1	21	21	128	128	279	280
NYCITY	99	89	1,762	1,606	5,247	4,895	7,563	7,049
WEST	40	28	975	663	6,577	4,328	12,562	8,448
NYISO	261	213	5,417	4,231	25,385	18,346	44,214	31,443

Year 2012

	Peak-Day emissions		Top 25 day emissions		Ozone season emissions		Annual emissions	
Zone	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
CAPITAL	5	5	114	104	675	602	1,288	1,149
CENTRAL	35	21	939	522	6,070	3,151	11,571	6,082
GENESSEE	1	1	9	9	13	13	21	21
HUDSONVA	40	29	829	580	3,673	2,388	6,390	4,112
LONGISLA	38	37	735	703	2,778	2,697	4,129	4,018
MILLWOOD	0	0	0	0	0	0	0	0
MOHAWKVA	2	2	56	43	276	185	519	353
NORTH	1	1	22	22	133	132	294	293
NYCITY	104	93	1,827	1,652	5,307	4,959	7,662	7,154
WEST	40	28	976	666	6,591	4,339	12,581	8,463
NYISO	267	216	5,506	4,301	25,517	18,466	44,455	31,646

Table F1: Peak-Day, Top-25, Ozone and Annual Emissions by Zone (contd.)

Year 2013

	Peak-Day emissions		Top 25 day emissions		Ozone season emissions		Annual emissions	
Zone	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
CAPITAL	5	5	117	106	700	624	1,333	1,190
CENTRAL	35	21	931	519	6,070	3,169	11,563	6,108
GENESSEE	1	1	8	8	12	12	19	19
HUDSONVA	40	29	854	603	3,815	2,495	6,598	4,277
LONGISLA	41	39	787	751	3,013	2,919	4,386	4,260
MILLWOOD	0	0	0	0	0	0	0	0
MOHAWKVA	2	2	58	46	285	193	550	384
NORTH	1	1	23	23	142	142	310	309
NYCITY	108	96	1,961	1,751	5,729	5,302	8,124	7,541
WEST	40	27	967	657	6,547	4,299	12,525	8,414
NYISO	273	222	5,707	4,463	26,312	19,155	45,406	32,501

Year 2014

	Peak-Day emissions		Top 25 day emissions		Ozone season emissions		Annual emissions	
Zone	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
CAPITAL	5	5	117	107	708	631	1,347	1,203
CENTRAL	35	21	939	522	6,122	3,205	11,741	6,261
GENESSEE	1	1	9	9	17	17	32	32
HUDSONVA	40	29	866	610	3,915	2,573	6,813	4,455
LONGISLA	43	41	819	784	3,126	3,029	4,559	4,438
MILLWOOD	0	0	0	0	0	0	0	0
MOHAWKVA	2	2	60	48	304	213	585	420
NORTH	1	1	24	24	153	153	329	329
NYCITY	116	105	2,038	1,819	5,973	5,540	8,433	7,843
WEST	41	28	983	674	6,632	4,382	12,719	8,603
NYISO	285	233	5,857	4,596	26,950	19,743	46,559	33,582

Year 2015

	Peak-Day emissions		Top 25 day emissions		Ozone season emissions		Annual emissions	
Zone	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
CAPITAL	5	5	116	101	706	631	1,341	1,199
CENTRAL	37	23	960	502	6,151	3,231	11,723	6,239
GENESSEE	1	1	9	6	16	16	26	26
HUDSONVA	39	29	860	563	3,879	2,544	6,723	4,382
LONGISLA	39	37	815	695	3,099	3,012	4,479	4,363
MILLWOOD	0	0	0	0	0	0	0	0
MOHAWKVA	2	2	60	43	308	217	586	420
NORTH	1	1	24	24	159	159	341	341
NYCITY	114	104	2,072	1,553	6,158	5,747	8,675	8,099
WEST	41	28	984	657	6,614	4,366	12,635	8,523
NYISO	280	230	5,900	4,145	27,091	19,925	46,529	33,592

Table F2: Generation and Average LBMP by Zone

Year 2010

Zone	Generation (GWh) Under Existing Regulations	Generation (GWh) Under Proposed RACT	Average LBMP ($/MWh) Under Existing Regulations	Average LBMP ($/MWh) Under Proposed RACT
WEST	28,141	28,133	$56.43	$56.41
GENESSEE	4,768	4,766	$58.89	$58.90
CENTRAL	34,111	34,118	$59.03	$59.04
NORTH	9,955	9,956	$57.88	$57.85
MOHAWKVA	3,475	3,474	$60.53	$60.55
CAPITAL	21,791	21,792	$62.86	$62.89
HUDSONVA	5,298	5,350	$64.86	$64.88
MILLWOOD	17,154	17,154	$66.29	$66.30
DUNWOODI	6	6	$66.11	$66.10
NYCITY	23,219	23,233	$68.12	$67.95
LONGISLA	9,535	9,511	$66.51	$66.51
NYISO	157,453	157,493	$62.50	$62.49

Year 2011

Zone	Generation (GWh) Under Existing Regulations	Generation (GWh) Under Proposed RACT	Average LBMP ($/MWh) Under Existing Regulations	Average LBMP ($/MWh) Under Proposed RACT
WEST	28,252	28,249	$57.44	$57.46
GENESSEE	4,770	4,769	$59.77	$59.78
CENTRAL	34,113	34,097	$59.70	$59.72
NORTH	9,966	9,968	$58.54	$58.57
MOHAWKVA	3,490	3,490	$61.10	$61.11
CAPITAL	21,801	21,821	$63.32	$63.33
HUDSONVA	5,531	5,549	$66.52	$66.54
MILLWOOD	17,154	17,154	$68.33	$68.35
DUNWOODI	6	6	$68.03	$68.05
NYCITY	23,200	23,178	$68.79	$68.80
LONGISLA	9,975	9,980	$68.21	$68.21
NYISO	158,260	158,261	$63.61	$63.63

Year 2012

Zone	Generation (GWh) Under Existing Regulations	Generation (GWh) Under Proposed RACT	Average LBMP ($/MWh) Under Existing Regulations	Average LBMP ($/MWh) Under Proposed RACT
WEST	28,257	28,256	$59.50	$59.51
GENESSEE	4,775	4,774	$61.91	$61.92
CENTRAL	34,199	34,193	$61.87	$61.90
NORTH	9,985	9,984	$60.63	$60.64
MOHAWKVA	3,500	3,500	$63.35	$63.38
CAPITAL	21,873	21,869	$65.80	$65.93
HUDSONVA	5,589	5,602	$69.06	$69.17
MILLWOOD	17,206	17,206	$70.89	$70.99
DUNWOODI	6	6	$70.63	$70.74
NYCITY	23,202	23,209	$71.56	$71.59
LONGISLA	9,955	9,956	$70.81	$70.92
NYISO	158,546	158,554	$66.00	$66.06

Table F2: Generation and Average LBMP by Zone (contd.)

Year 2013

Zone	Generation (GWh)		Average LBMP ($/MWh)	
	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
WEST	28,163	28,160	$58.97	$58.22
GENESSEE	4,748	4,747	$61.42	$60.67
CENTRAL	34,191	34,195	$63.03	$62.48
NORTH	10,024	10,023	$62.01	$61.50
MOHAWKVA	3,540	3,540	$64.75	$64.22
CAPITAL	22,229	22,224	$67.02	$66.59
HUDSONVA	5,802	5,804	$70.99	$70.51
MILLWOOD	17,155	17,155	$73.10	$72.61
DUNWOODI	6	6	$72.86	$72.32
NYCITY	24,074	24,042	$74.06	$73.47
LONGISLA	10,367	10,366	$73.05	$72.56
NYISO	160,299	160,261	$67.39	$66.83

Year 2014

Zone	Generation (GWh)		Average LBMP ($/MWh)	
	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
WEST	28,491	28,494	$63.37	$62.66
GENESSEE	4,806	4,806	$65.79	$65.10
CENTRAL	34,361	34,363	$67.23	$66.72
NORTH	10,034	10,033	$66.05	$65.59
MOHAWKVA	3,583	3,584	$68.88	$68.41
CAPITAL	22,331	22,322	$71.06	$70.70
HUDSONVA	6,007	6,019	$75.86	$75.48
MILLWOOD	17,155	17,155	$78.26	$77.88
DUNWOODI	6	6	$78.04	$77.62
NYCITY	24,347	24,360	$78.95	$78.44
LONGISLA	10,650	10,657	$78.22	$77.84
NYISO	161,771	161,797	$71.97	$71.50

Year 2015

Zone	Generation (GWh)		Average LBMP ($/MWh)	
	Under Existing Regulations	Under Proposed RACT	Under Existing Regulations	Under Proposed RACT
WEST	28,341	28,345	$65.36	$64.50
GENESSEE	4,774	4,774	$68.03	$67.18
CENTRAL	34,355	34,349	$69.58	$68.90
NORTH	10,051	10,051	$68.40	$67.79
MOHAWKVA	3,572	3,573	$71.42	$70.76
CAPITAL	22,310	22,311	$73.73	$73.17
HUDSONVA	5,921	5,930	$78.68	$78.07
MILLWOOD	17,155	17,155	$81.09	$80.52
DUNWOODI	6	6	$80.90	$80.25
NYCITY	24,715	24,742	$82.03	$81.33
LONGISLA	10,498	10,512	$81.11	$80.50
NYISO	161,698	161,748	$74.58	$73.90

G. Scenario Assumptions

Table G.1a Zonal Energy (GWh) in the 15x15 Scenario

Zone	2010	2011	2012	2013	2014	2015
West	15,811	15,669	15,420	15,209	15,025	14,812
Genesee	9,952	9,826	9,657	9,530	9,470	9,384
Central	16,625	16,492	16,203	15,968	15,798	15,602
North	6,957	6,920	6,807	6,707	6,602	6,467
Mohawk Valley	7,900	7,850	7,722	7,589	7,498	7,393
Capital	11,670	11,599	11,481	11,354	11,245	11,139
Hudson Valley	10,913	10,900	10,750	10,629	10,553	10,432
Millwood	2,728	2,727	2,693	2,685	2,650	2,621
Dunwoodie	6,308	6,201	5,997	5,819	5,611	5,419
NY City	54,497	54,418	54,091	53,710	53,582	53,305
Long Island	22,563	22,327	21,950	21,513	21,147	20,808
NYCA Total	**165,923**	**164,929**	**162,772**	**160,712**	**159,182**	**157,382**

Table G.1b Zonal Coincident Peak Load in the 15x15 Scenario

Zone	2010	2011	2012	2013	2014	2015
West	2,611	2,588	2,547	2,512	2,482	2,446
Genesee	1,908	1,884	1,852	1,827	1,816	1,799
Central	2,813	2,791	2,742	2,702	2,674	2,640
North	830	825	812	800	788	771
Mohawk Valley	1,365	1,356	1,334	1,311	1,295	1,277
Capital	2,252	2,239	2,216	2,191	2,171	2,150
Hudson Valley	2,325	2,323	2,291	2,265	2,249	2,223
Millwood	638	637	630	625	614	605
Dunwoodie	1,505	1,480	1,431	1,383	1,325	1,275
NY City	11,948	11,869	11,707	11,526	11,361	11,165
Long Island	5,292	5,241	5,161	5,054	4,966	4,874
NYCA Total	**33,489**	**33,234**	**32,722**	**32,197**	**31,739**	**31,227**

Table 6.4 Zonal Wind Additions for RPS Scenario

Zone	Wind (MW)
West	440
Genesee	83
Central	686
North	694
Mohawk Valley	1,252
Capital	-
Hudson Valley	1
Millwood	-
Dunwoodie	-
NY City	-
Long Island	-
NYCA Total	**3,156**

H. Resumes

SUNDAR VENKATARAMAN

Director
Energy Applications and Systems Engineering
GE Energy

EDUCATION

M.S. Electrical Engineering, Iowa State University, 1994

MBA, Union College, New York, 2007

EXPERIENCE

Sundar Venkataraman is a Director with GE Energy Applications and Systems Engineering. In this capacity, he primarily advises GE Energy and GE Energy Financial Services on generation and transmission related investments. His expertise is in the area of economic evaluation of generation and transmission assets in regulated, as well as deregulated markets in the U.S. He has also teaches various GE seminars on how the U.S. Power Industry is organized and how energy markets operate. Mr. Venkataraman started his career with GE in 1994 as an Application Engineer and has over 15 years of experience in providing advisory services related to electricity markets, utility economics, power systems operation, and power plant engineering.

Between 2004 and 2006, Mr. Venkataraman worked for ABB as the Manager of their Energy Market Consulting practice. At ABB, Mr. Venkataraman's primary responsibility was to develop and manage a consulting practice that aimed at providing services related to the planning and operation of generation and transmission assets.

AFFILIATIONS, PATENTS, PUBLICATIONS

Mr. Venkataraman has authored several papers and taught courses on production simulation, energy price forecasting and power plant controls. He is an Instructor for two GE Power Systems and Energy courses – "U.S. Electric Power Industry", and "Power Plant Financial Modeling and Evaluation". Mr. Venkataraman is a member of CIGRE WG C5.03 – "Investments and Financing of New generation and Transmission Projects in a deregulated Environment", and a frequently invited Panelist in IEEE.

ROBERT WOODFIELD

Application Engineer
Power Economics
GE Energy Applications and Systems Engineering

EDUCATION

B.S. Mechanical Engineering, Rensselaer Polytechnic Institute, 2007
B.S. Economics, Rensselaer Polytechnic Institute, 2007
Pursuing M.B.A. at Union Graduate College

EXPERIENCE

Mr. Woodfield joined GE Energy Applications and Systems Engineering in December 2007 as an application engineer working on the power economics team. He has led the development of an automated proforma creation tool for power plant financial evaluations using GE MAPS. Mr. Woodfield has also participated in the development of models to project capacity prices for New York's ICAP, PJM's RPM and ISONE's FCM auctions and conducted studies using GE MAPS in support of GE's Energy Financial services as well as GE sales teams and new technology introduction efforts.

Prior to joining GE EA&SE Mr. Woodfield had a series of internships with the Accessories Engineering team within the GE Energy Engineering Division in Schenectady, NY. His main project work there included cost and cycle impact estimates for non standard customer requests related to accessories systems for the GT, ST and generator product lines as well as working toward standardizing these offerings in order to reduce cost and cycle impacts to the customer.

DAVID MOYEDA
GE Environmental Services
Manager, Boiler Combustion Engineering

EDUCATION
Bachelor of Science, Chemical Engineering, University of Utah, 1984 Bachelor of Science, Fuels Engineering, University of Utah, 1984
Masters of Science, Mechanical Eng., University of California, 1995

SUMMARY
25 Years – Boiler Combustion Engineering Manager, Principal Engineer, Systems Engineering Manager, Project Manager, Group Leader, Field Test Director, Research Engineer.

Development, evaluation, and application of emissions control technologies; emission control system design; field test data evaluation and interpretation; combustion system and control technology aerodynamic studies.

EXPERIENCE
As Manager, Boiler Combustion Engineering, Mr. Moyeda is responsible for directing activities related to the application of emissions control technologies to a wide variety of combustion systems firing both conventional fossil fuels and industrial and hazardous waste fuels. The Boiler Combustion Engineering team is responsible for technical and economic evaluation, selection, and design of NOx, SO_2, mercury, and air toxics (PCDD/PCDF, metals, etc.) emissions control technologies for industrial, utility, and municipal waste combustion systems, and for providing coordination and engineering analysis and testing support for commercial programs. The Boiler Combustion Engineering team is also active in development of new and innovative technologies for air pollutant emissions control.

Mr. Moyeda is also responsible for supervising the experimental activities of GE Environmental Services' combustion test facility, aerodynamics facility, and other modeling capabilities, such as computational fluid dynamics and boiler performance modeling tools. The aerodynamics facility is involved in the investigation of the aerodynamics of fossil fuel-fired and waste-fired combustion systems and in the design of in-furnace acid gas (SO_2 and NOx) and air toxics emissions control technologies for these types of combustion systems. Mr. Moyeda has many years of experience in combustion and emissions control research and development programs.

Mr. Moyeda has managed numerous projects to develop and apply advanced pollutant control technologies for reduction of NOx emissions from industrial processes, such as glass furnaces and other high temperature processes, and to evaluate the potential for full-scale application of the coal reburning process to utility boilers. Mr. Moyeda has been involved in a number of full-scale studies where he has been responsible for the design and scale up of pollutant control processes and for optimization and evaluation of the full-scale performance and results. These projects have involved developing process designs and layouts for pollution control equipment for industrial, utility, and municipal processes. These studies include projects for application of sorbent injection for SO_2 control from coal fired boilers, gas reburning for NOx control from coal fired boilers and municipal waste incinerators, gas cofiring for PCDD/PCDF pollutant emission reduction from a municipal waste combustor, and oil reburning for NOx control from an industrial boiler. As part of the start up of these projects, Mr. Moyeda was involved in acquisition and analysis of the test emissions data.

WEI ZHOU, Ph.D.
GE Environmental Services
Manager, Systems Engineering

EDUCATION
Bachelor of Science, Tsinghua University, Beijing, 1991
Doctor of Philosophy, Combustion, Princeton University, NJ, 1998

SUMMARY
10 Years – Systems Engineering Manager, Sr. Process Engineer, Research Engineer, CFD Engineer.

Design, development and evaluation of emission control technologies. CFD combustion modeling of over thirty utility and refinery boilers. Chemical kinetics. Turbulent reacting flow. Multiphase reacting flow. Coal combustion. NOx emissions simulation. Mercury reduction modeling, SNCR technology.

EXPERIENCE
As a Systems Engineering Manager, Dr. Zhou is responsible for leading systems engineering effort to support commercial emission control projects as well as technology development. Dr. Zhou has been involved in worldwide low NOx, low SOx, and mercury control projects. Meanwhile, as a Senior Process Engineer, Dr. Zhou is also responsible for CFD modeling activities at GE to support process design and new technology development. Dr. Zhou has successfully completed numerous CFD studies to provide insight to various low emissions technology applications. Dr. Zhou also has expertise in gas-phase and coal combustion modeling. She is experienced in solving complicated problems, such as turbulent multiphase reacting flows.

Prior to joining GE, Dr. Zhou was a CFD engineer and consultant of Fluent Inc. She supported over than twenty companies in the chemical and petrochemical industries in the application of CFD to solve complex problems in reacting flows. She also lead the effort in modeling multiphase reacting flows, such as polymerization, crystallization, fluidized bed combustion, etc.

After graduating from Tsinghua University with a Bachelors degree, Dr. Zhou entered the Ph.D. program in combustion at Princeton. Her Ph. D. work was on modeling boron particle combustion including consideration of detailed surface and gas-phase chemistry. Her work has been published at the 26th International Combustion Symposium and several other journals.