# Biomass Reburning – Modeling/Engineering Studies

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Prepared by:

Vladimir Zamansky, Chris Lindsey and Vitali Lissianski

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GE Energy and Environmental Research Corporation

18 Mason, Irvine, CA 92618

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**Abstract**

This project is designed to develop engineering and modeling tools for a family of $NO_x$ control technologies utilizing biomass as a reburning fuel. During the ninth reporting period (September 27 – December 31, 1999), EER prepared a paper *Kinetic Model of Biomass Reburning* and submitted it for publication and presentation at the 28th Symposium (International) on Combustion, University of Edinburgh, Scotland, July 30 – August 4, 2000. Antares Group Inc, under contract to Niagara Mohawk Power Corporation, evaluated the economic feasibility of biomass reburning options for Dunkirk Station. A preliminary report is included in this quarterly report.

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## 1. Project Status and Progress During the Reporting Period

This project is designed to develop engineering and modeling tools for a family of $NO_x$ control technologies utilizing biomass as a reburning fuel. Basic and advanced biomass reburning technologies have the potential to achieve 60-90+% $NO_x$ control in coal fired boilers at a significantly lower cost than SCR. Project participants include: GE Energy and Environmental Research Corporation (EER), NETL R&D group, Niagara Mohawk Power Corporation (NMPC) and Antares, Inc. Project tasks, responsibilities of organizations, and current task status are as follows:

1. Kinetic Modeling of Biomass Reburning (EER) - *completed*
2. Computational Fluid Dynamics (CFD) Modeling (NETL) - *in progress*
3. Physical Modeling (EER) – *in progress*
4. Biomass Preparation Economics (NETL) – *in progress*
5. Evaluation of Slagging and Fouling (NETL) – *in progress*
6. Reburning vs. Cofiring Evaluation (Antares) - *completed*
7. Project Management and Reporting – *in progress*

This NETL project is conducted in close coordination with EER's Phase II SBIR project funded by USDA. The division of tasks between the two projects was thought out to keep process optimization and design tasks within the SBIR project. The FETC project involves modeling activities, economic studies of biomass handling, and experimental evaluation of slagging and fouling.

Tasks No. 1 and 6 are currently completed, and some information on these tasks is presented in this progress report. Tasks No. 2, 3, and 5 are in progress and expected to be completed by NETL R&D group during the next quarter. Task 3 also expected to be completed during the next quarter. After completion of the project, conventional biomass reburning and advanced biomass reburning technologies will be ready for full scale demonstration, although few pre-demonstration pilot scale and modeling studies may be needed to address specific conditions at the target boiler.

During the ninth reporting period (September 27 – December 31, 1999), EER prepared a paper *Kinetic Model of Biomass Reburning* and submitted it for publication and presentation at the 28$^{th}$ Symposium (International) on Combustion, University of Edinburgh, Scotland, July 30 – August 4, 2000. A copy of the paper is presented in Attachment 1. Antares Group Inc. evaluated the economic feasibility of biomass reburning options for Dunkirk Station. A preliminary report is included in this quarterly report as Attachment 2. Results suggest that biomass reburning can add significant value to plants like Dunkirk and that a host for a demonstration project should be pursued.

## 2. Future Work

It is anticipated that major part of Tasks 2, 3, and 5 will be completed by NETL R&D group during the next quarter. EER also plans to conduct cold flow modeling studies. The results will be reported in the next quarterly report.

**Attachment 1**

# Kinetic Model of Biomass Reburning

Vitali V. Lissianski, Vladimir M. Zamansky and Peter M. Maly

*General Electric Energy and Environmental Research Corporation*

*18 Mason, Irvine, CA 92618*

Submitted on December 13, 1999 for publication and presentation at

the 28th Symposium (International) on Combustion

University of Edinburgh, Scotland, July 30 – August 4, 2000

# Kinetic Model of Biomass Reburning

Vitali V. Lissianski, Vladimir M. Zamansky and Peter M. Maly

*General Electric Energy and Environmental Research Corporation*

*18 Mason, Irvine, CA 92618, USA*

## Abstract

This paper presents results of combustion experiments and modeling studies on $NO_x$ reduction in the reburning process with different biomass reburning fuels. Fuels under investigation include furniture pellets, willow wood and walnut shells. Results are compared with natural gas and coal reburning. Experiments were conducted in a 300 kW Boiler Simulator Facility to characterize biomass reburning performance as a function of key process variables. The experiments demonstrated that at small reburning heat inputs some biomass were as effective as natural gas and more effective than coal. The efficiency of biomass is affected by its chemical composition. The model of biomass reburning combines detailed kinetic mechanism of the processes in the gas phase with a one-dimensional representation of mixing. The biomass fuels are represented as gasification products. The most important factors controlling the efficiency of biomass in reburning are low fuel-N content and high content of alkali metals in the ash. The kinetic model agrees with experimental data and can be used for process optimization.

## Introduction

Fossil fuels will continue to play a major role in supplying electricity well into the 21st century. However, combustion of fossil fuels results in pollutant formation. Emissions of greenhouse gases, especially $CO_2$, are of particular concern since their increased concentrations result in greater amounts of heat retained within atmosphere, which leads to an increase in the surface temperature of the earth. Although increasing the efficiency of power generation is a step in the direction of improving the quality of the environment, it is obvious that other approaches have to be implemented in the future to achieve substantial reductions in carbon emissions. The expanded use of renewable fuels, in particular biomass, is one such approach. While combustion of biomass does release $CO_2$ to the atmosphere, its net contribution to atmospheric $CO_2$ is zero, because release the $CO_2$ during biomass combustion is offset by $CO_2$ absorption by plants during photosynthesis. Effective utilization of biomass fuel in the power industry would decrease the dependence on fossil fuels and improve the quality of the environment by reducing net emissions of $CO_2$. Biomass has also lower nitrogen and sulfur content than coal, resulting in lower $NO_x$ and $SO_x$ emissions.

Better utilization of biomass power is the driving force for a variety of technologies currently in various stages of research, development, and commercialization. Cofiring with coal is a promising biomass utilization technology because of the significant fuel consumption in coal-fired boilers. Additionally, it is possible to take advantage of the specific chemical composition of biomass for reducing nitrogen oxide emissions. As an example, biomass can be utilized as a reburning, or secondary, fuel in coal-fired utility boilers. Basic and advanced biomass reburning technologies that utilize biomass as a reburning fuel are currently under development [1]. Advanced biomass reburning is a combination of basic reburning with N-agent injection [2-4]. Biomass, which may include waste wood, straw, agricultural waste, etc., can be inexpensive and may have potential for lower cost $NO_x$ reduction with higher performance than that of gas and coal reburning. This concept presents a means for utilizing both the energy content of biomass and its chemical constituents, which can promote the chemical reactions of $NO_x$ removal from combustion flue gas.

The efficiency of basic reburning depends on biomass chemical composition, the size of biomass particles, location of injection and other factors. Chemical composition is the primary parameter defining reburning efficiency. Since different types of biomass vary significantly in composition, it is advantageous to predict the effect of biomass composition on $NO_x$ reduction before undertaking large scale experimental efforts to optimize the technology. Therefore, development, validation and application of a kinetic model of biomass reburning are important parts of the effort to optimize the technology.

Previous modeling efforts concentrated on the prediction of the composition of biomass gasification products [5-9] and on description of biomass as a primary fuel [10,11]. Detailed modeling of biomass combustion requires combination of gas dynamic equations with particle devolatilization, char oxidation and volatile combustion models [11]. Even the most advanced CFD codes are not yet capable of modeling detailed chemical reaction schemes. As a result, available engineering models [6-12] include global or reduced schemes for the detailed chemistry.

This paper describes experimental and modeling studies conducted to better understand the chemical base for the performance of biomass in reburning. The approach utilized combines a simplified representation of the mixing process in the reburning zone with detailed gas phase chemistry. This approach allows modeling efforts to search for similarities in combustion chemistry of different biomass fuels and to predict the efficiencies of different types of biomass fuels on the basis of their ultimate, proximate and ash analyses.

## Experimental Results

A series of tests was conducted in a 300 kW Boiler Simulator Facility (BSF) to characterize biomass reburning performance as a function of key process variables. The BSF is designed to provide subscale simulation of the flue gas temperatures and compositions found in conventional utility boilers and is described elsewhere [13]. Pelletized furniture waste, willow wood and walnut shells were used as reburning fuels. For comparison, tests were also conducted with natural gas and low rank coal. The composition of biomass fuels is shown in Table 1. Natural gas was used as the primary fuel. Reburning fuel was injected at 1700 K, and overfire air was injected at 1450 K. The initial amount of $NO_x$ in flue gas was kept at 400 ppm by addition of ammonia to the primary natural gas.

Biomass fuels were pulverized for the tests in a hammer mill. The degree to which biomass is pulverized involves trade-offs between improved reburning performance and increased fuel processing cost. Size distribution was varied by installing different screens in the hammer mill and by running samples through the mill multiple times. It was found that the willow wood was fibrous and considerably more difficult to process than furniture pellets. Tests showed that in the range 10 – 27% < 200 mesh furniture pellet performance improved with decreasing particle size. For the range 27 – 48% < 200 mesh efficiency of furniture pellet reburning did not depend on particle size. Willow wood particle size had minimal effect on reburning performance. It is possible that due to the high volatiles content of willow wood (82.29% dry basis, Table 1), the fuel is so highly reactive that finer grinding provides limited benefits. In all subsequent tests the 48% < 200 mesh was used for furniture pellets and 23% < 200 mesh for willow wood. The walnut shells were more brittle than the furniture pellets and provided a finer size distribution. For the walnut shells a grind of 55% < 200 mesh was tested.

Figure 1 shows $NO_x$ control performance for willow wood, furniture pellets, walnut shells, low rank coal and natural gas as a function of reburning heat input. $NO_x$ reduction provided by the furniture pellets was better than that of natural gas at 10% and 15% reburning. For furniture pellets, maximum NO reduction was 66%, achieved at 15% reburning heat input. Willow wood gave a maximum of 61% $NO_x$ reduction at 20% reburning. Performance of willow wood was worse than natural gas at all reburning heat inputs. $NO_x$ reduction provided by walnut shells was similar to natural gas at 10 and 15% reburning and was less than natural gas at higher than 15% reburning.

Thus the test data show that at small heat inputs biomass can be as effective a reburning fuel as natural gas and more effective than coal.

## Modeling

Experimental data demonstrate that $NO_x$ reduction performance of different biomass fuels is quite different. Since test conditions for all fuels were similar, these differences most likely are due to differences in chemical composition. The purpose of kinetic modeling was to identify factors that control the efficiency of biomass as a reburning fuel and predict $NO_x$ reduction based on fuel analysis. The approach taken was to combine detailed kinetic modeling of the processes in the gas phase with a one-dimensional representation of mixing that has proved to provide a realistic description of the reburning process with natural gas [14]. The following sections describe the modeling approach used to represent biomass composition and the model set up.

## Representation of Biomass Composition

Experimental data for furniture pellets and willow wood show that for particles of small size the process efficiency does not depend on particle size. It was assumed that the time scale of biomass gasification under these test conditions was smaller than the characteristic time of the mixing process in the reburning zone. Since the selected biomass fuels all have high volatile content, it was further assumed that the contribution of char combustion to $NO_x$ reduction was less significant than that of gas phase reactions. Thus, in modeling the biomass fuels were represented as gasification products, i.e. it was assumed that fuel gasification is instantaneous and complete. The fuel oxygen was presented in the form of CO. A mixture of $C_2H_6$, $C_2H_4$ and $C_2H_2$ represented the remaining hydrocarbon component. The composition of biomass gasification products corresponds to the ultimate analysis and is shown in Table 2. This approach to represent biomass gasification products has been used previously [9,11] and is often used in CFD [11] modeling where simplification of biomass gasification chemistry is a requirement. The approach assumes that primary products of biomass gasification are highly reactive and at high temperatures quickly decompose to produce less reactive hydrocarbons.

The concentration of N in the tested biomass fuels (about 0.5 % by weight) is less than that usually found in coals (1-2 %). However, this amount of fuel-N can contribute to $NO_x$ production at large heat inputs of the reburning fuel. It was assumed that fuel-N was present in gasification products in the form of $NH_3$. Modeling with representation of fuel-N as HCN showed similar results.

Ash analysis shows that biomass contains many elements (Na, Fe, K, P, S and others) that can affect the reburning process. For example, it is known that alkali metals [2,4] and iron-containing compounds [15] added to the reburning zone can increase $NO_x$ reduction. Comparison of K and Fe content in different biomass fuels (Table 1) shows that they do not differ significantly from fuel to fuel. Also, concentrations of these metals in biomass are similar or lower than that found in coals. Thus, the presence of Fe and K in biomass can not explain differences in the performances of the biomass fuels observed in tests.

The concentration of Na in biomass, however, significantly differs from one fuel to another and can be higher than that found in coals. It was shown [4] that Na–containing additives can improve the efficiency of the reburning process if co-injected with $NH_3$. Since the amount of

Na found in ash of furniture pellets is significant, the presence of Na can affect the performance of this fuel.

Reactions of Na with components of flue gas have been studied [4,13,16] in connection with reduction of NO and $N_2O$ emissions in SNCR and reburning processes. Since the chemistry of NaOH decomposition and reactions with C-H-O-N species at high temperatures is relatively well defined [13], it can be easily incorporated into the kinetic model. Reactions of Na species [13] were added to the reaction mechanism [17] used to describe biomass reburning. The model includes 470 reactions of 69 chemical species.

The important question is in what form Na is present in biomass. The mineral composition of biomass fuel is generally complex and difficult to determine quantitatively. It was found [18] that in straw most alkali metals are present in a water soluble form (in the form of NaCl or ionically linked to the surface) and only small amounts are in a water insoluble form (mostly silicates). However, the distribution between forms of Na may be different for different biomass fuels. Dayton and Milne [19] found that some biomass fuels release alkali metals during combustion in the form of chlorides, while others release significant amounts of alkali vapor in the form of hydroxides and cyanates. Chenevert and Kramlich [20] showed that fuels with high chlorine content release alkali metals to the gas phase in the form of chlorides, while fuels with low chlorine content release metals in the form of sulfates and carbonates. However, the available information does not allow one to identify concentrations of different alkali-containing species released from the biomass studied in this work to the gas phase. Since $Na_2O \cdot Al_2O_3 \cdot (SiO_2)_2$, commonly found in biomass ash, is insoluble and stable at reburning temperatures [18], it was assumed in the current model that most sodium found in ash is present in the form of silicate. The amount of sodium present in the form of silicate was calculated based on the biomass ash analysis (Table 1) and the amount of silicate ($Al_2O_3 \cdot (SiO_2)_2$) present. Remaining sodium was assumed to be present in the form of NaOH since a previous study [13] showed that this form of Na is the most stable at high temperatures and flue gas compositions. The effect of variation in Na concentration in the gas phase during combustion of furniture pellets is discussed later.

## Modeling Setting

The chemical kinetic code ODF [21], for "One Dimensional Flame" was employed to model experimental data. ODF treats a system as a series of one-dimensional reactors. Each reactor may be perfectly mixed (well-stirred) or unmixed (plug flow). Each ODF reactor may be assigned a variety of thermodynamic characteristics, including adiabatic, isothermal, or specified profiles of temperature or heat flux, and/or pressure. Process streams may be added over any interval of the plug flow reactor, with arbitrary mixing profiles along the reactor length. The flexibility in model setup allows for many different chemical processes to be simulated under a wide variety of mixing conditions.

The approach adopted in this work is similar to that used [14] to describe natural gas reburning. The reburning process was treated as series of four reactors. Each reactor described one of the physical and chemical processes occurring in a boiler: addition of the reburning fuel, $NO_x$ reduction as a result of reaction with the reburning fuel, addition of overfire air, and oxidation of partially oxidized products.

The following features of the mixing process were incorporated into the modeling:

- Injected gases are available for reaction over a certain period of time (mixing time) rather than instantaneously.
- Injection of reburning fuel results in mixture stratification such that mixture composition in the mixing area is not uniform.

The mixing time in the reburning zone was an adjustable parameter. For the reburning fuel jet, the mixing time was adopted to be 200 ms for all biomass fuels. The value 200 ms was chosen because it gave the best description of experimental data. This time is considerably longer than the mixing time for natural gas injection (120 ms) estimated using a model of single jet in cross flow [14]. This increase in mixing time was introduced to take into account the longer heating times of biomass particles. Modeling showed that the value of the mixing time has a relatively small effect on the efficiency of $NO_x$ reduction. For example, a twofold increase in mixing time results in about 30% improvement in the reburning efficiency. For the overfire air jet, the mixing time was estimated [14] using a model of single jet in cross flow to be 120 ms.

The mixing process in the reburning zone was described in modeling by addition of flue gas to the stream of biomass gasification products over mixing time (so-called inverse mixing). Mixture stratification in the reburning zone, or existence of local fuel rich zones in which concentration of fuel is higher than average, is an important factor that affects efficiency of the reburning process. Fuel stratification in modeling was introduced by assuming that within the reburning zone there is one zone with 25% larger and one zone with 25% smaller concentration of fuel than average. $NO_x$ reduction was calculated as the average of that for these two zones. This approach has been shown [14] to be effective in describing natural gas reburning.

## Modeling Results

### Willow Wood and Furniture Pellets

Modeling of reburning with willow wood and furniture pellets was conducted after obtaining experimental data. The model was used then to select another biomass fuel with high NOx reduction potential. Walnut shells were selected, and experiments validated model predictions.

Figure 2 shows comparison of modeling predictions with experimental data for willow wood. The model predicts that willow wood is a less effective reburning fuel than natural gas. The model quantitatively agrees with experiments within the scatter of experimental data.

Agreement of modeling predictions with experimental data for furniture pellets is qualitative (Fig. 3). The solid line in Fig. 3 represents calculations with the amount of NaOH in decomposition products calculated as discussed above. These calculations underestimated the efficiency of $NO_x$ reduction by furniture pellets. The dashed line in Fig. 3 represents calculations made under the assumption that all Na found in biomass is present in the gas phase in the form of NaOH. These calculations gave better agreement with experimental data. While the amount of Na present in the gas phase during combustion of biomass is uncertain, modeling clearly shows that minerals present in ash can improve efficiency of biomass as reburning fuel by promoting reactions in the reburning zone. Modeling predicts high efficiency of furniture pellets at low heat inputs of the reburning fuel. A decrease in efficiency at large heat inputs is also predicted.

The fact that the model agrees with experimental data suggests that contribution of heterogeneous reactions to $NO_x$ reduction is not significant and $NO_x$ reduction at the test conditions is mainly determined by reactions in the gas phase.

## Walnut Shells

The model developed in this work makes it possible to select effective biomass fuels based on their chemical composition and predict their performances relative to other fuels. Modeling shows that there are several factors that determine the reburning efficiency of biomass. At low heat inputs, fuels with a higher concentration of minerals show $NO_x$ reduction efficiencies similar or better than that of natural gas. At high heat inputs, fuels with high fuel-N content show degradation in the reburning efficiency.

These conclusions can be used to estimate efficiencies of different types of biomass as potential reburning fuels. To demonstrate this, a number of biomass fuels with known composition were considered. Walnut shells were selected as a promising reburning fuel. As shown in Table 1, walnut shells have low fuel-N and high Na in ash content. Modeling predicts that performance of walnut shells as a reburning fuel is comparable with that of natural gas.

To verify this prediction, the performance of walnut shells was tested in BSF at the same conditions as for furniture pellets and willow wood (Fig. 1). Tests confirmed modeling predictions that walnut shells are an effective reburning fuel. Their performance was slightly better than that of natural gas at lower reburning heat inputs, and worse than natural gas at higher reburning heat inputs. The walnut shells provided a maximum of 65% NO reduction at 20% reburning. Figure 4 shows comparison of modeling predictions with experimental data for walnut shells.

## Conclusions

It is demonstrated that the model developed in this work can be used to predict the efficiencies of different biomass fuels. Modeling predictions and experimental data confirm that some biomass fuels can be as effective for reburning as natural gas and coal. The most important factors that provide high efficiency of biomass in reburning are low fuel-N content and high content of alkali metals in ash. Modeling predicts that walnut shells are as effective for reburning as natural gas at low heat inputs. Pilot-scale tests in a 300 kW combustor validated modeling predictions and confirmed the high efficiency of walnut shells. Agreement of experimental and modeling results strongly suggests that the developed model of biomass reburning has predictive ability.

**Acknowledgment**

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Table 1. Test fuel analytical properties. Units are mass %.

| Parameter | Furniture pellets | Willow wood | Walnut shells | Parameter | Furniture pellets | Willow wood | Walnut shells |
|---|---|---|---|---|---|---|---|
| Proximate analysis | | | | Ash analysis | | | |
| Ash | 1.31 | 1.60 | 1.93 | $SiO_2$ | 13.86 | 2.65 | 34.98 |
| Volatiles | 79.06 | 82.29 | 72.02 | $Al_2O_3$ | 3.29 | 0.41 | 6.09 |
| Fixed Carbon | 19.63 | 16.11 | 26.05 | $TiO_2$ | 6.72 | 0.50 | 0.21 |
| Moisture | 6.37 | 1.97 | 12.43 | $Fe_2O_3$ | 8.25 | 2.42 | 10.71 |
| Ultimate analysis | | | | CaO | 24.10 | 41.80 | 23.25 |
| Carbon | 53.91 | 50.48 | 51.00 | MgO | 3.00 | 4.80 | 3.16 |
| Hydrogen | 6.07 | 5.98 | 5.72 | $K_2O$ | 7.50 | 14.00 | 11.15 |
| Nitrogen | 0.56 | 0.53 | 0.32 | $Na_2O$ | 11.16 | 0.24 | 6.64 |
| Sulfur | 0.03 | 0.04 | 0.00 | $SO_3$ | 6.73 | 1.80 | 1.59 |
| Oxygen | 38.12 | 41.37 | 41.03 | $P_2O_5$ | 2.20 | 9.50 | 1.92 |
| Ash | 1.31 | 1.60 | 1.93 | SrO | 0.13 | 0.34 | 0.02 |
| Chlorine | 0.190 | 0.040 | 0.130 | BaO | 3.83 | 0.06 | 0.08 |
| Heating Value (kJ/kg dry) | 20,500 | 19,800 | 20,000 | $Mn_3O_4$ | 1.75 | 0.18 | 0.10 |
| | | | | Undetermined | 7.48 | 21.30 | 0.10 |

Table 2. Composition of biomass fuels (vol. %).

| Component | Furniture pellets | Willow wood | Walnut Shells |
|---|---|---|---|
| $CO$ | 68.86 | 74.8 | 74.54 |
| $C_2H_6$ | 27.40 | – | – |
| $C_2H_4$ | 2.60 | 15.0 | 23.20 |
| $C_2H_2$ | – | 9.0 | 1.50 |
| $NH_3$ | 1.10 | 1.2 | 0.70 |
| $NaOH$ | 0.14 | – | 0.06 |

## Figure Captions

Figure 1. Performance comparison of different reburning fuels. ● natural gas, ■ low rank coal, □ willow wood, Δ furniture pellets, ○ walnut shells.

Figure 2. Performance of willow wood reburning. Symbols are experiments, line represents calculations.

Figure 3. Performance of furniture pellets reburning. Symbols are experiments. Solid line represents calculations with biomass composition from Table 2, dashed line represents calculations assuming all Na is present in the form of NaOH.

Figure 4. Performance of walnut shells reburning. Symbols are experiments, line represents calculations.

*Figures*

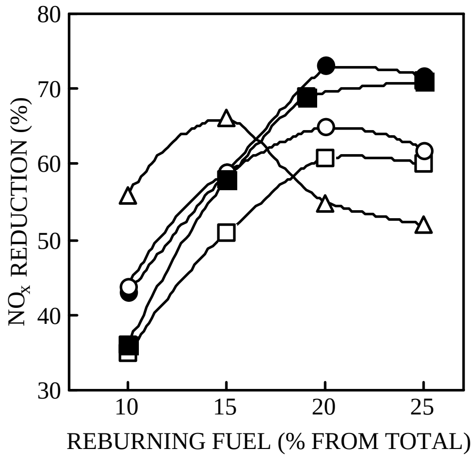


Figure 1

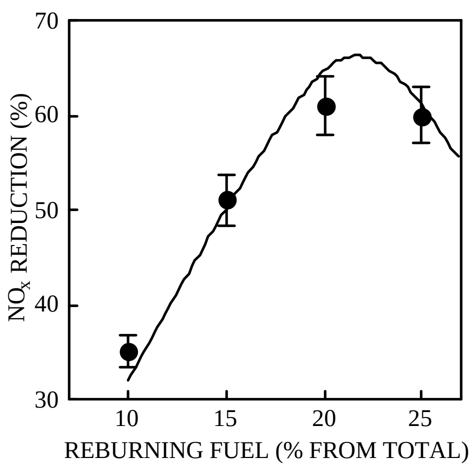


Figure 2

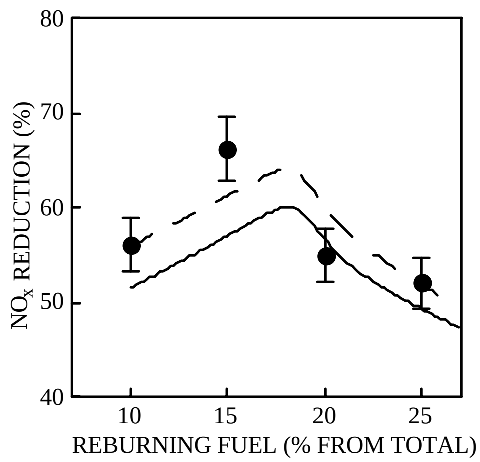


Figure 3

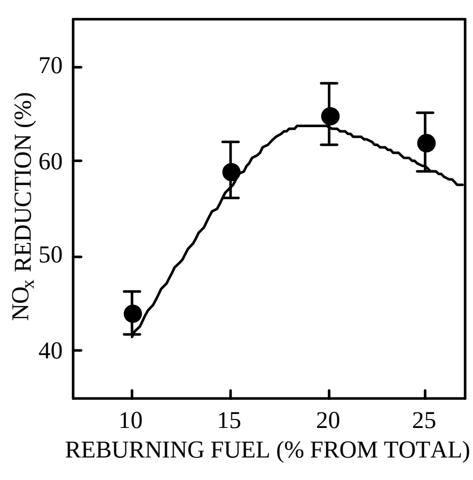


Figure 4

**Attachment 2**

# Pre-feasibility Study of Reburn Options for Dunkirk Power Plant

**Prepared for:**

**Dr. Edward F. Neuhauser**
**Niagara Mohawk Research & Development**

**Prepared by:**

**Antares Group Incorporated**
**4351 Garden City Drive Ste. 301**
**Landover, Maryland 20785**

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# EXECUTIVE SUMMARY

Existing legislation and pending regulations are applying considerable pressure on power generators to reduce air born emissions. This includes $NO_X$ which has emerged as a very hot issue especially in New York where Ozone transport issues are being highlighted by recent gubernatorial rhetoric. The net effect is that coal-fueled power plants are looking for technologies that will help them comply with a varying landscape of emission limitations. Reburn is emerging as a choice with considerable technical and economic merit especially if a low cost reburn fuel can be used. Given Dunkirk station's ongoing retrofit to cofire biomass fuels, this technology should be of special interest.

The reburning process is accomplished by routing part of the boiler's fuel, approximately 10-20%, to a point above the primary combustion zone. When properly designed and implemented, this technology can offer significant reductions in boiler $NO_X$ emissions (up to 85%).

Reburn fuels demonstrated on a utility scale include natural gas, coal, and orimulsion. Other fuels, including biomass have been demonstrated as effective for reburn on a pilot scale.

Biomass is an attractive choice for several reasons. It is a renewable fuel, low in sulfur, and can be obtained at a significant discount to coal or other fossil fuels. In addition, pilot scale reburn tests have indicated that under certain conditions it can outperform other fuels (including natural gas) in providing $NO_X$ reductions.

Beyond its potential for low cost, biomass may have other economic benefits. Several legislative initiatives have been undertaken to allow power providers using biomass as fuel to earn tax credits. In addition, green power markets may add value to power generated renewably, adding even more incentive for biomass-based generation.

The results of the economic analysis suggest that biomass reburn is economically attractive and can provide deep $NO_X$ control at while adding value to the plant's bottom line. The results also suggest that biomass reburn could be more economically attractive than biomass cofiring.

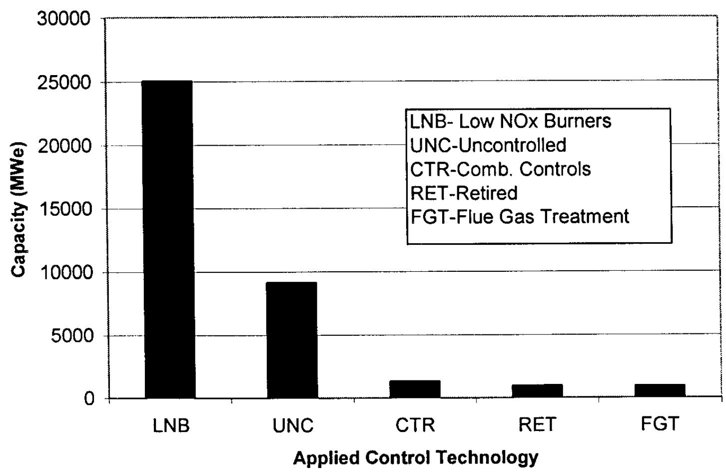
Based on the research and analysis documented in this report, Dunkirk Station is well positioned to capitalize on the opportunities presented by biomass reburn technology. The plant is already undergoing retrofits to cofire biomass, and much of the equipment needed to explore reburn is already on-site. Certainly, more in-depth analysis is required, but a biomass reburn demonstration project at Dunkirk should be seriously considered by the plant's management. The approach for a demonstration would include confirming $NO_X$ reductions experienced under current plans to cofire, detailed planning of retrofit requirements, and implementation of a testing protocol.

## 1.0 INTRODUCTION

Recently, many strategies have been adopted within the Ozone Transport Region (OTR) to meet the Clean Air Act (CAA) Title I and Title IV Phase II compliance orders. These technologies include low-$NO_X$ burners, flue gas treatment, selective catalytic and non-catalytic reduction, combustion controls, and repowering. Exhibit 1-1 outlines the application of these technologies for coal-fired boilers in the OTR. Low-$NO_X$ burners are unquestionably the most popular choice. Using this technology $NO_X$ can be reduced approximately 30-50% below uncontrolled emissions levels.

However, natural gas reburn is emerging as an important technologies for $NO_X$ reduction. Originally designed for cyclone boilers, reburn technologies is being applied to an expanding range of boilers including stokers and utility pulverized-coal units. Developers of reburn technology have received substantial assistance to demonstrate reburn systems at various energy production sites through the Clean Coal Technology Demonstration Program sponsored by the U.S. Department of Energy (DOE).

**Exhibit 1-1:**
OTR Utility Coal-Fired Boiler
Capacity by Applied Control Technology




*Taken from Status Report on NOX Control Technologies and Cost Effectiveness for Utility Boilers, NESCAUM, June 98.*

Reburning technology uses hydrocarbon radicals to convert nitric oxide (NO) to nitrogen ($N_2$) and carbon monoxide (CO). In the boiler's primary combustion region, fuel is burned with lower than usual excess air. The reburning process is accomplished by routing part of the boiler's fuel, approximately 10-20%, to a point above the primary combustion zone, where it is injected to produce a slightly fuel-rich "reburn zone." The remaining combustion air is then injected to ensure that all the reburn fuel and other combustibles completely burn out. In order to obtain the best results for $NO_X$ reduction, injection of the reburn fuel should be able to penetrate completely across the furnace and mix thoroughly with furnace gases. Reductions in $NO_X$ without the use of an injected reagent (advanced reburn) typically range between 58-77%.

As noted previously, low-$NO_X$ burners are the major retrofit used to comply with Phase I, Title IV obligations of the CAA Amendments of 1990. Although reburn technology can be applied to boilers already outfitted with low-NOx burners, it can also be applied to boilers that are not able to use standard low-$NO_X$ combustion modification techniques because of the need for high furnace temperatures - such as wet bottom boilers.

Currently, natural gas is the preferred reburn fuel because, in general, it generates the greatest $NO_X$ reduction per heat unit of injected fuel. Natural gas also produces negligible quantities of ash and sulfur, and requires no preparation. Micronized coal has also been used as a reburn fuel at some power facilities either by itself or blended with biomass. Micronized biomass, the focus of this report, is also being explored and tested as a reburn fuel on a pilot scale.

This report focuses on evaluating the economic feasibility of using micronized biomass as a reburn fuel at a tangentially fired pulverized coal facility like Dunkirk Steam Station. Reburn and advanced reburn options are discussed. Technical and economic performance data are based on information provided by the reburn project team. Specifically, Niagara Mohawk provided data on Dunkirk Station operations and cofiring retrofit costs; EER and the Federal Energy Technology Center (FETC) in Pittsburgh provided reburn performance data, MESA Reduction Engineering and Processing – a developer of biomass processing technologies – provided costs and performance data on micronizing biomass.

## 2.0 PILOT STUDY AND PRELIMINARY DATA

### 2.1 Description of Reburn and Advanced Reburn Systems

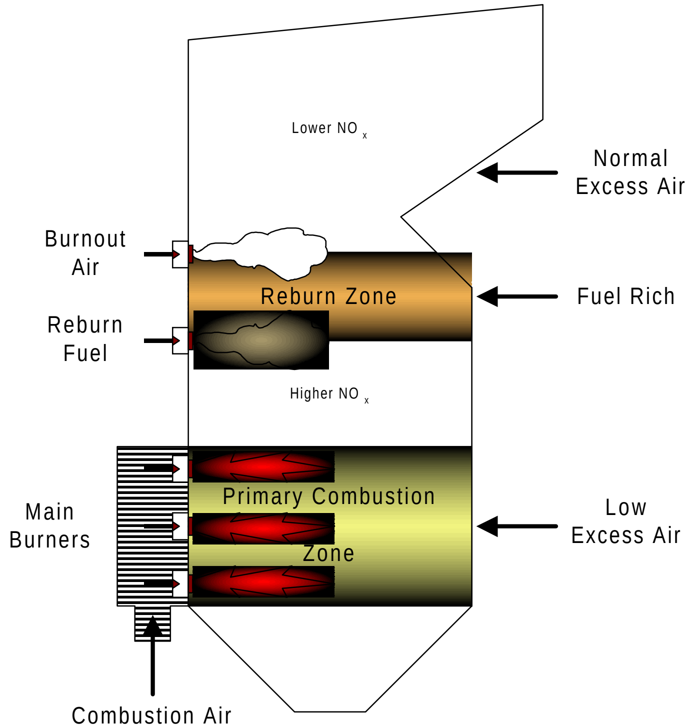
Low-$NO_X$ burners have dominated as the technology of choice for power plant operators to meet the Phase-I, Title IV $NO_X$ requirements of the Clean Air Act Amendments. However, the looming deadline for Phase-II/III reductions and the failure of low-$NO_X$ burners to live up to performance expectations at some sites has forced plant operators to look elsewhere. Reburn technologies are emerging as the potentially lowest cost choice for NOx controls in boilers with emission levels less than 0.6 lb/MMBtu. These technologies offer substantial $NO_X$ reductions (potentially in excess of 85% using advanced reburn) and can even help boilers with other underperforming $NO_X$ control technologies.

#### *2.1.1 Reburn Systems*

Exhibit 2-1 shows a schematic of a conventional reburn system. In the lower primary combustion zone, the main fuel (coal for the purposes of this report) is burned with lower than usual excess air. Combustion by-products including $NO_X$, then move to the reburn zone. In the reburn zone, a hydrocarbon fuel is injected to produce a slightly fuel-rich mixture. In the upper part of the boiler, overfire air is added to ensure complete burnout of the reburn fuel and other combustibles. Reductions in $NO_X$ using conventional reburning technologies typically range between 58-77%.

No physical change to the main burners is required, but the burners are typically operated at the lowest excess air that maintains flame stability and with acceptable carbon losses, slag tapping, and ash deposition. Maximum $NO_X$ reduction is usually achieved with the reburn zone operating in the range of 90% theoretical air.

**Exhibit 2-1:** Reburn System




For best results, the reburn fuel injectors should be located close to the upper firing elevation to allow enough space above the main burners to complete the primary combustion process. The reburn fuel injectors are designed for rapid mixing and to allow the fuel to penetrate across the boiler depth.

The reburn fuel can be any hydrocarbon and site-specific economics will dictate the best choice. Natural gas, oil, micronized coal, orimulsion, and micronized biomass have all been shown to be effective reburn fuels. However, natural gas remains the preferred fuel for several reasons including: 1) it produces the greatest $NO_X$ reduction per heat unit of injected fuel over the greatest range of heat input; 2) it has no ash or sulfur; and 3) it requires no fuel preparation. However, on a $/MMBtu basis, natural gas remains a premium fuel.

Significant savings in fuel costs are part of the attraction that biomass fuels may offer to power plants pursuing biomass reburn. Biomass supplies can be obtained at prices as low as $0.50/MMBtu, or about a fifth of the delivered cost of natural gas. Some additional processing will be required in most cases, but this provides the potential for substantial savings in fuel costs. Additionally, relative to natural gas, biomass may also offer some $NO_X$ reduction benefits at lower heat input percentages. This advantage is discussed further in section 2.2.

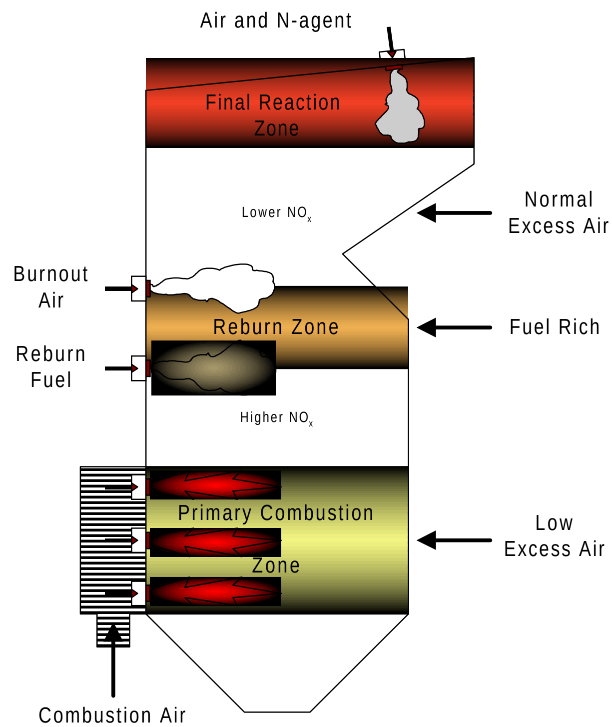
### *2.1.2 Advanced Reburn Systems*

Exhibit 2-2 shows a schematic of an advanced reburn configuration. The advanced reburn (AR) option uses a nitrogen-rich compound or N-agent to provide even more $NO_X$ control than conventional reburn systems. To date, most of the advanced reburn research has focused on using natural gas as the reburn fuel. Provided that demonstrations of biomass reburn technologies are successful, advanced reburn technologies may be pursued for this feedstock as well.

There are two approaches to advanced reburn configuration in coal boilers; synergistic and non-synergistic. For non-synergistic configurations, the N-agent is added downstream of the reburn system. This essentially represents a combination of reburn and selective non-catalytic reduction. For these configurations $NO_X$ reductions are expected to be on the order of 56-70% for a 10% heat input of natural gas.

For synergistic advanced reburn configurations, the N-agent is injected with the overfire air above the reburn zone. In this case combustion dynamics are customized to provide $NO_X$ control of up to 85% for 10% heat input of natural gas. Although limited in application by some boiler configurations, this approach allows greater flexibility in flue gas temperature resulting in better load following characteristics.

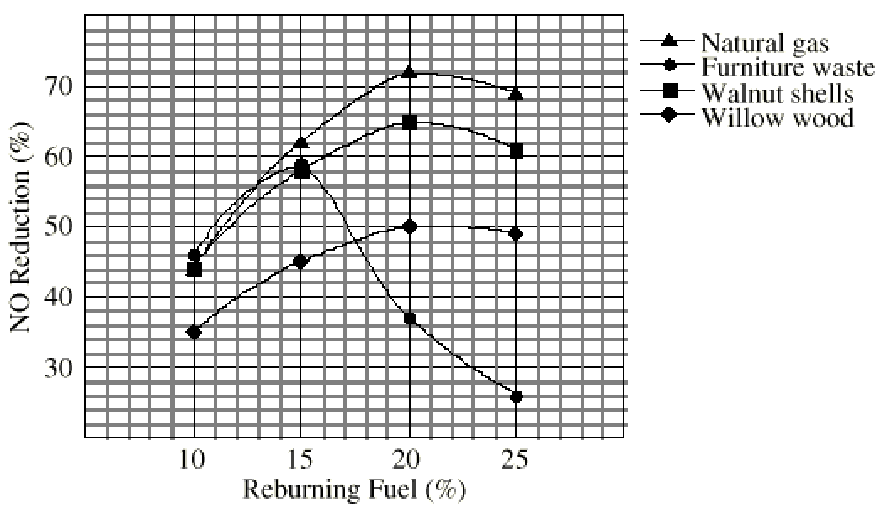
**Exhibit 2-2:** Advanced Reburn System




## 2.2 Results of EER Biomass Reburn Studies

Energy and Environmental Research Corporation (EER) has initiated a Small Business Innovation Research (SBIR) multi-phase development and demonstration program, funded by the U.S. Department of Agriculture. Phase-I of the program involved feasibility studies on

**EXHIBIT 2-3:** Pilot Scale Reburn Test Results



reburning and advanced reburning technologies using biomass as the reburn fuel. EER has also completed Phase-II of the program, which involved further development and optimization of these technologies. Results from pilot-scale demonstrations have been very promising.

For example, pilot-scale experimental testing has shown that furniture waste can yield comparable $NO_X$ reduction performance to natural gas at reburn heat input rates up to 15%. Exhibit 2-3 shows some of these results for biomass reburn. This is a significant development since biomass can often be obtained much less expensively than natural gas. EER has also developed an advanced biomass reburning technology that utilizes additives and has achieved 70-90% $NO_X$ control in pilot scale experiments.

### 2.3 List of EER Reburn Projects

GE/EER will have completed 10 reburn projects by the Fall of 1999. A list of projects is shown in Exhibit 2-4. The choice of reburn fuel for these projects has depended on site specific conditions and includes, coal, orimulsion, and natural gas. Although GE/EER is not the only vendor for reburn technologies retrofits, this list is sufficient to demonstrate the interest and the power sector's commitment in this technology.

**Exhibit 2-4:** List of GE/EER Reburn Projects

| **Utility Name** | **Plant** | **(MWe)** | **Configuration** | **Status** |
|---|---|---|---|---|
| Illinois Power | Hennepin 1 | 71 | Tan | Complete |
| City Water, Light & Power | Lakeside 7 | 33 | Cyc | Complete |
| P.S. Company of Colorado | Cherokee 3 | 158 | FW | Complete |
| New York State E&G | Greenidge 4 | 104 | Tan | Complete |
| Ukraine | Ladyzhin | 300 | Opp | Complete |
| Eastman Kodak | Kodak Park 15 | 50 | Cyc | Complete |
| Tennessee Valley Authority | Allen 1 | 330 | Cyc | Complete |
| Baltimore Gas & Electric | Crane 1 | 205 | Cyc | Complete |
| Baltimore Gas & Electric | Crane 2 | 205 | Cyc | Complete |
| Conectiv | Edge Moor 4 | 160 | Tan | Complete |
| Tennessee Valley Authority | Allen 2 | 330 | Cyc | Summer '99 |
| Tennessee Valley Authority | Allen 3 | 330 | Cyc | Install Fall '99 |
| Allegheny Power | Hatfield 2 | 595 | Opp | Install Fall '99 |
| Potomac Electric | Chalk Point 1 | 355 | Opp | Install Spring '00 |
| Potomac Electric | Chalk Point 2 | 355 | Opp | Install Spring '00 |

## 3.0 DESCRIPTION OF MODELED SYSTEM

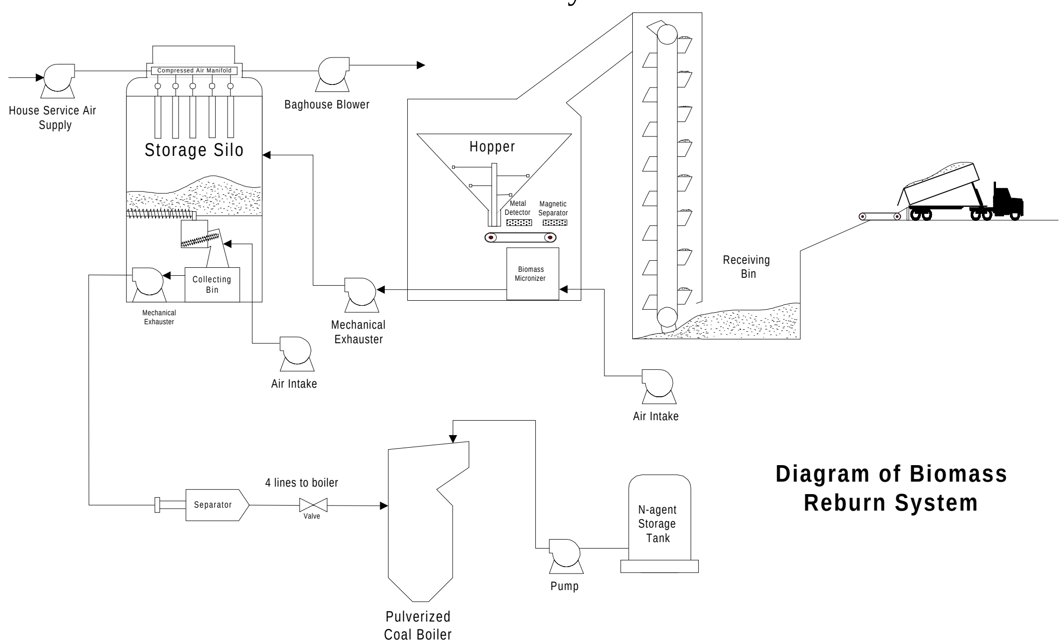
Dunkirk Station, a pulverized coal plant representative of the target market for reburn, is equipped with two 200 MW and two 100 MW Combustion Engineering tangentially fired boilers, circa 1950. The later units (Unit #1, #2) currently burn eastern bituminous coals and have been retrofitted with low-$NO_X$ burners and upgraded combustion control systems. Unit #1 has 16 burners located at four levels in the corners of the furnace. Coal is supplied to each level by a Raymond bowl mill and the unit has been retrofitted with a low-$NO_X$ burner system which incorporates a close-coupled overfire air system. This unit is currently undergoing retrofits to cofire biomass at heat input rates of up to 20 percent. Besides the addition of biomass handling and processing equipment, the boiler has already been modified to inject processed biomass through ports located between the second- and third-level coal nozzles.

Since Dunkirk Station is already undergoing retrofit for biomass combustion, the modifications required to use biomass as a reburn fuel are minimal. Newly installed receiving, primary handling, processing, and storage facilities are all adequate to handle the material for a reburn application. Modifications required beyond those considered for the cofiring retrofit will include:

1) Use of biomass micronizing equipment for secondary processing
2) Change in biomass flow for delivery to the boiler
3) Addition of injection ports in reburn zone
4) Urea injection and storage - *Advanced Reburn Option*

Exhibit 3-1 shows a possible configuration for conducting reburn and advanced reburn operations at Dunkirk.

**Exhibit 3-1:** Reburn System Schematic



Although a substantial portion of Dunkirk's biomass processing train is useable in reburn application there are some fuel sizing requirements that need to be addressed. The current cofiring system is designed for a final biomass fuel particle sizes of 1/8" minus. This will allow complete burnout of the fuel when introduced into the boiler's primary combustion zone. However, based on discussions with various combustion and processing experts, a particle size of 1/16" minus may be required for reburn applications. Larger particle sizes may be acceptable, but this aspect of biomass reburn can only be quantified in full scale tests.

## 4.0 ECONOMIC MODEL

As part of its efforts to evaluate renewable energy technologies, ANTARES has developed a number of specialized models. These include models for determining the economic and technical feasibility of different cofiring and reburn technologies. The model used in this efforts is composed of two main modules: power plant performance; and financial performance.

### 4.1 Model Description

#### *4.1.1 Power Plant Performance Module*

This module uses inputs based on typical values for utility-scale power plant operations to estimate net plant generation, emissions, and fuel requirements. Input parameters include gross plant power output, parasitic loads, gross plant efficiency, cofiring/reburn heat input, emissions profiles (lb/MMBtu), and operating schedules. These parameters are also used to estimate the required equipment sizes and staffing requirements. For this effort, many of the input parameters have been tailored to model the performance of Dunkirk Station while using biomass reburn.

#### *4.1.2 Financial Performance Module*

This part of the model is used to calculate the production cost effects of cofiring/reburning based on the plant performance results. Inputs include the delivered cost of fuels (biomass and coal); the value of emission credits; tax incentives, green marketing incentives; and capital costs. The output of the module is the production cost effect on the plant for cofiring/reburning.

### 4.2 Key Input Data

Input data used in the analysis was collected from the project partners. This included estimates of retrofit costs, boiler performance data, increased O&M data, and pilot- scale $NO_X$ reduction data.

#### *4.2.1 Retrofit Costs*

Retrofit costs were based on estimates provided by Niagara Mohawk for biomass handling/processing equipment that is being secured to retrofit the station for cofiring. These requirements have been scaled, where appropriate, to accommodate the different heat input levels for biomass reburn. Costs that are exclusive to the reburn or advanced reburn systems modeled were derived from estimates provided by EER. These included urea storage and injection system costs.

Specialty processing equipment (biomass micronizing train) costs were provided by an outside vendor. There are several vendors of such technology and most are similar to those used to finely process coal. Mesa Reduction Engineering and Processing has developed a milling technology that has been designed and tested on biomass feedstocks. For this reason, the specifications of this equipment have been used for this analysis. This technology reportedly has the ability to process incoming biomass feedstocks to the appropriate parameters in one pass, rather than requiring multiple hammer mills and feedback loops for oversized material. However, before specifying equipment for project deployment, additional analysis to determine the most economic deployment of processing technologies should be performed.

Although much of the handling equipment for retrofitting Dunkirk is already purchased, this report compares the economics of cofiring, reburn, and advanced reburn on a turnkey basis and all prior investments in equipment and installation are included.

### *4.2.2 Changes in Plant Efficiency*

Plant heat rate increases have been experienced in cofiring operations and they are an inevitable cost associated with new processing and handling systems. Based on past, published experiences with biomass cofiring systems, the boiler is also expected to experience a slight decrease in efficiency due to the high moisture content of biomass.

*Parasitic Load Changes*
Based on ANTARES estimates using data supplied by the plant and equipment vendors, a net increase in plant parasitic load of 180-530 kW will be experienced as a result of the cofiring/reburn retrofits relative to coal-only operations. A summary of these changes is presented below in Exhibit 4-1.

**Exhibit 4-1:** Increase Plant in Parasitic Load

| | **Load Change (kW)** | | |
|---|---|---|---|
| **Load Source** | **Cofiring** | **Reburn** | **Adv. Reburn** |
| Coal Processing | (354) | (354) | (354) |
| Biomass Processing | 537 | 737 | 881 |
| ***Net Parasitic Load Change*** | ***183*** | ***383*** | ***527*** |

*Changes in Boiler Efficiency*

The plant is also likely to experience a slight decrement in boiler efficiency because biomass has a higher moisture content than coal. This loss, although difficult to measure, is estimated in this analysis to reduce boiler efficiency 1.13% from (88.8% to 87.7%.) This decrement is based on estimates derived from an independent biomass power model developed by EPRI. This decrement assumes that biomass provides 15% of the heat input into the boiler.

### 4.2.3 Operation and Maintenance Costs (excluding fuel)

The additional operation and maintenance costs associated with the biomass reburn retrofit consist of maintenance on new equipment, additional operating personnel, and for the advanced reburn case, urea injection.

Repairs and maintenance for new equipment is estimated to be 5 percent of the investment cost per year. This figure is for engineering estimates only and may need to be revised based on the system's performance.

The requirement for additional operating personnel to oversee receipt, processing, and injection of biomass at a coal-fired station is still a subject of debate. It has been suggested that these responsibilities could be delegated to current plant personnel. However, it was the opinion of various biomass handling experts and the ANTARES group that one additional operator would be required to oversee these functions adequately and ensure steady operation.

Urea requirements for the advanced reburn option were estimated based on a study commissioned by the EPA to study $NO_X$ control technologies for the Northeast and Mid-Atlantic regions of the United States. This data, where possible, was cross referenced with information provided by GE/EER. Based on these sources, urea is estimated to cost $385/ton. Urea usage is estimated based on a Normalized Stoichiometric Ratio (NSR) of 1.5. This factor describes the amount of urea required relative to the amount of $NO_X$ reduction experienced[1].

### 4.2.4 Emissions Reductions and Value

*$SO_2$ Benefits*

Title IV of the 1990 Clean Air Act Amendments (CAAA) established marketable $SO_2$ allowances or credits, each equivalent to one ton of $SO_2$. Exhibit 4-2 shows recent activity in this market as reported by Fieldston Publications.

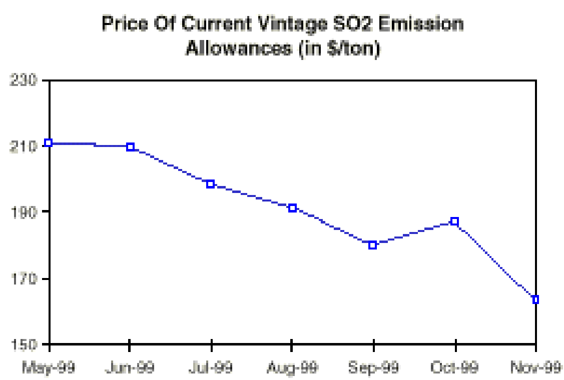



**Exhibit 4-2**

Fieldston Publications, *Clean Air Compliance Review*, 12/1/99

[1] *Reagent utilization is very difficult to generalize and 1.5 represents a rule of thumb. A more rigorous analysis is required before an SNCR system is installed.*

The value of $SO_2$ allowances has an important impact on the economics of biomass reburn, since most biomass sources contain only small amounts of sulfur even when compared to low-sulfur coals. This means that Btu for Btu, biomass fuels avoid nearly 100% of the $SO_2$ that would have been emitted by coal combustion. For the purposes of this analysis, $SO_2$ allowances have been assigned a value of $150/ton over the life of the project.

*$NO_X$ Benefits*
Based on guidelines provided in the CAAA, Congress established the Ozone Transport Commission (OTC) to address the region-wide transport of ozone and its precursor gases including $NO_X$. Early in 1999 the OTC announced the beginning of a new emission trading program for $NO_X$. This cap and trade system allows purchasers to buy offsets, and deals on $NO_X$ reductions have already been negotiated. Exhibit 4-3 lists recent OTC price trends for $NO_X$ credits.

**Exhibit 4-3**: Estimate of OTC $NO_X$ allowance prices

| Vintage | Price ($/ton) |
|---|---|
| 1999 | $1,700 |
| 2000 | $2,200 |
| 2001 | $2,100 |
| 2002 | $1,800 |

***July 1999 Price Index - Air Daily, Fieldston Publications, Vol 6, No. 136***

The value of $NO_X$ credits is very important to calculating the economic benefits of biomass reburn. For this analysis, a price of $1,700/ton has been assigned to $NO_X$ credits over the life of the project. Credits are generated only during the ozone season per CAAA Title I requirements. However, based on provisions in Title IV, it is also possible that in the future $NO_X$ credits could be generated during the Non-Ozone season. Recent evidence of this can be found in Governor Pataki's (NY) announcement that he intends to order New York power plants to cut their annual of $NO_X$ emissions levels to the levels slated for summer only in 2003. As part of this plan, $SO_2$ emission levels would be cut to less than half of the federal requirements.

*$CO_2$ Benefits*
Although examples are few, carbon has been traded internally within large companies and externally among a few innovators. Values range from $1.20 to $15.00 per ton of carbon dioxide emitted, indicative of the instability of an infant market. However, because an official policy driver does not exist for $CO_2$ reductions at this time, this analysis does not assign any value to carbon emission reductions resulting from substituting biomass for coal.

### *4.2.5 Ash Sales and Disposal costs*

Cofiring biomass and coal may also adversely affect existing revenue streams from coal ash sales. The ASTM standard for flyash sales (ASTM C 618) restricts the use of coal-and-biomass derived ash sales. In this analysis, it was assumed that 70% of the ash generated from baseline coal operations is sold into markets with an average ash value of $2.00/ton (this figure is typical of current ash markets). By introducing biomass into the fuel mix it was assumed that this entire revenue stream is converted to a liability of $10.00/ton. This is probably a conservative assumption since many coal-fired generators using mixed fuels have reported finding alternative markets for their ash. This assumption has been used in all of the cases evaluated.

### *4.2.6 Biomass Production Tax Credit*

Section 45 of the 1986 Internal Revenue Code allows an inflation adjusted tax credit of 1.7 cents per kWh for renewable electricity production for closed-loop biomass (energy crops) facilities.[2] In order to qualify, the facility must be owned by the taxpayer and have been originally placed in service after December 31, 1992 and before July 1, 1999. The 1.7 cent credit received by a qualified closed-loop biomass facility may be reduced if that facility uses grants, tax-exempt bonds, subsidized energy financing, or other tax credits.

To date, no biomass facility has been able to take advantage of this credit because of its narrow definition for biomass. As a result, several new pieces of Federal legislation were introduced to modify the current law and attempt to provide a practical incentive for increasing biomass power capacity in the United States. Although too numerous to explore in depth in this report, many "opened the loop" to include biomass residues and provided a credit for electricity generated through biomass cofiring. Only the portion of the electricity generated via biomass heat input is eligible. For comparative purposes, this report presents cases that include and exclude a 1.7 c/kWh tax credit.

## 4.3 Modeling Results

### *4.3.1 Summary of Inputs*

Exhibit 4-4 summarizes the key inputs for this analysis. For all cases, common input assumptions include:

- gross plant electric output of 96 MW
- gross plant efficiency (coal only) of 36%
- plant capacity factor of 72%
- plant operating 24 hours/day, 7 days/week
- cofiring/reburning fuel on 24 hours/day, 7 days/week
- biomass delivery 10 hours/day, 5 days/week
- coal is eastern bituminous, HHV of 12,997 Btu/lb, $1.37/MMBtu

[2] *The code also provides a tax credit for wind facilities but only the biomass portion is treated in this report.*

- biomass is mill waste, HHV of 7,359 Btu/lb, $0.75/MMBtu
- biomass heat input is 15%
- baseline plant emissions (lb/MMBtu) are 3.66 for $SO_2$, 0.42 for $NO_X$, 238 for $CO_2$
- 70% of ash generated currently sold @ $2.00/ton
- disposal cost of ash $10.00/ton
- cofiring/reburn cases assume an additional operator is required to manage biomass system at a fully loaded rate of $17.00/hour. Time in excess of 2,000 hours/year is charged at $25.50/hour
- ozone transport season is 5 months long
- emission credit values ($/ton): $NO_X$ ($1,700), $SO_2$ ($150), $CO_2$ (None)
- $CO_2$ emission reductions assume that biomass is $CO_2$ neutral.

**Exhibit 4-4:** Summary of Input Variables

| Case Input Variable | Cofiring | Reburn | Adv. Reburn |
|---|---|---|---|
| $/kW-biomass | $244 | $362 | $404 |
| $/kW-total plant | $34 | $51 | $56 |
| Net Plant Heat Rate | 10,285 | 10,308 | 10,325 |
| $NO_X$ Reduction (%) | 8% | 59% | 83% |
| Reagent (tons/year) | 0 | 0 | 430 |
| Incr. O&M ($/year) | $196,079 | $241,584 | $428,869 |

### *4.3.2 Discussion of Analytical Methods*

Results of this analysis could be presented on two different bases. These viewpoints reflect differences in the way power providers are evaluating operational cost improvements and emission control technology options.

Cofiring is primarily a fuel cost reduction strategy. The benefits of cofiring are primarily measured based on the incremental benefit the plant experiences by substituting a lower cost fuel for coal. Ancillary benefits like emission credits are usually rolled into the incremental economics by assuming that either new credits will be generated or by assuming the plant will have a reduced requirement to purchase credits. The sum of these benefits less new liabilities (e.g. increased O&M, decreased ash sales) is used to calculate a return on the retrofit investment.

This type of analysis is very useful for considering cofiring opportunities against other operational improvements which use "business as usual" as the baseline. However, since it does not consider the need for plants to meet current or future environmental regulations it is not as useful in comparing technologies targeted toward deep emission controls.

In contrast, reburn technology is usually viewed as an emission control strategy. Therefore, its benefits are expressed in terms of the investment required to move from a baseline $NO_X$ emission level to a new, lower $NO_X$ emission level. Since reburn applications often use natural gas, a premium fuel, there are no fuel cost savings to offset the investment[3]. The result is a net cost/ton of $NO_X$ removed. This number can readily be compared to other $NO_X$ control technology choices such as SCR. However, when using a discounted fuel such as biomass, a positive incremental benefit may be experienced and the net cost/ton of $NO_X$ removed can be a negative number.

Since the goal of this analysis is to compare biomass cofiring and reburn options (admittedly an apples and oranges comparison) a new comparison criterion was developed. Instead of comparing the benefits of cofiring and reburn on an incremental emissions benefit basis, an absolute basis was adopted.

Under this type of comparison, assumptions are made about the regulatory conditions which the plant must meet. These conditions must be obtained either through purchasing emission credits or reducing emissions. The total cost to comply with these regulations are then used as the basis of comparison. This is more representative of how power plant operators will consider their choices in an environment where emission regulations are as much a concern as lowering production costs. An example helps illustrate this point.

> A plant operator currently exceeds the Title IV $SO_2$ emission cap and is purchasing credits from another operator to comply with Federal regulations. He has several options including installing an FGD emissions system which will bring his plant into compliance or biomass cofiring. Although the FGD will cost less, the benefits used to offset the costs of the system are limited to reducing the cost of purchasing $SO_2$ allowances. On the other hand, a more expensive biomass system will reduce his $SO_2$ emissions and can reduce fuel costs. However, some allowances will still need to be purchased since cofiring alone will not bring the plant into compliance. Therefore the total cost to comply must be considered. An absolute analysis that considers the regulatory compliance point must be used to determine the most economic option.

An analysis of the retrofit options for Dunkirk was completed using both an incremental and absolute analysis viewpoints. The results of the absolute analysis are presented based on the cost of regulatory compliance ($/ton of pollutant emitted) and separated among the three air pollutants evaluated. The incremental analysis results are presented using more traditional project finance criteria such as return on investment and payback period.

For reference, both analyses will rely on forecasts regarding current baseline emissions, future compliance points and emission reductions resulting from the application of cofiring and reburn technologies. The cost to achieve reductions or total compliance can then be calculated from the capital and ongoing maintenance requirements for each technology. The results of this analysis are presented below.

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[3] *Although $NO_X$ credits are factored into the equation, the current ozone season does not afford sufficient credits to result in a positive incremental benefit.*

### *4.3.3 Results*

Exhibit 4-5 lists the emission reductions benefits estimated in this analysis relative to baseline emission levels. Exhibit 4-6 and 4-7 summarize the results of the absolute economic comparison, while Exhibit 4-8 and 4-9 summarize the incremental economic comparison.

**Exhibit 4-6:** Summary of Absolute Analysis without Production Tax Credit

| Case Output Variable | Cofiring | Reburn | Adv. Reburn |
|---|---|---|---|
| Cost to control (\$/ton $SO_2$) before tax | \$810 | \$654 | \$610 |
| Cost to control (\$/ton $SO_2$) after tax | \$501 | \$412 | \$388 |
| Cost to control (\$/ton $NO_X$) before tax | \$9,171 | \$1,347 | \$1,078 |
| Cost to control (\$/ton $NO_X$) after tax | \$5,672 | \$848 | \$684 |
| Cost to control (\$/ton $CO_2$) before tax | \$12 | \$10 | \$9 |
| Cost to control (\$/ton $CO_2$) after tax | \$8 | \$6 | \$6 |

*Cost to control equals the total emissions reduction over the life of the project divided by the total cash flow on a before/after tax basis.*

**Exhibit 4-5:** Summary of Emission Reductions (tons)

| | TECHNOLOGY DESCRIPTION | | |
|---|---|---|---|
| | Cofiring | Reburn | Adv. Reburn |
| **Baseline Emission Levels - Coal Only** | | | |
| SO2 | 10,515 | 10,515 | 10,515 |
| NOX | 1,200 | 1,200 | 1,200 |
| CO2 | 683,991 | 683,991 | 683,991 |
| **Maximum Legal Emission Levels** | | | |
| SO2 | 3,491 | 3,491 | 3,491 |
| NOX | 861 | 861 | 861 |
| CO2 | N/A | N/A | N/A |
| **Required Reductions** | | | |
| SO2 | 7,024 | 7,024 | 7,024 |
| NOX | 340 | 340 | 340 |
| CO2 | - | - | - |
| **Reductions Achieved** | | | |
| SO2 | 1,459 | 1,459 | 1,459 |
| NOX | 129 | 708 | 826 |
| CO2 | 95,088 | 95,088 | 95,088 |
| **Reduction Shortfall*** | | | |
| SO2 | 5,565 | 5,565 | 5,565 |
| NOX | 211 | (369) | (487) |
| CO2 | (95,088) | (95,088) | (95,088) |

**Negative values indicate reductions requirements exceeded*
*N/A - Not applicable for this case*

**Exhibit 4-7:** Summary of Absolute Analysis with Production Tax Credit (1.7 c/kWh)

| Case Output Variable | Cofiring | Reburn | Adv. Reburn |
|---|---|---|---|
| Cost to control (\$/ton $SO_2$) before tax | \$810 | \$654 | \$610 |

| | | | |
|---|---|---|---|
| Cost to control (\$/ton $SO_2$) after tax | (\$488) | (\$575) | (\$598) |
| Cost to control (\$/ton $NO_X$) before tax | \$9,171 | \$1,347 | \$1,078 |
| Cost to control (\$/ton $NO_X$) after tax | (\$5,518) | (\$1,184) | (\$1,057) |
| Cost to control (\$/ton $CO_2$) before tax | \$12 | \$10 | \$9 |
| Cost to control (\$/ton $CO_2$) after tax | (\$7) | (\$9) | (\$9) |

*Cost to control equals the total emissions reduction over the life of the project divided by the total cash flow on a before/after tax basis. Numbers in "( )" indicate net revenues*

**Exhibit 4-8:** Summary of Incremental Analysis without Production Tax Credit

| Case Output Variable | Cofiring | Reburn | Adv. Reburn |
|---|---|---|---|
| Before Tax Annual Revenue Impact | \$631,392 | \$964,700 | \$1,064,767 |
| Before tax ROR | 22% | 24% | 23% |
| After tax ROR | 17% | 17% | 17% |
| Before tax payback period (years) | 5.2 | 5.0 | 5.1 |
| After tax payback period (years) | 5.9 | 5.7 | 5.7 |

**Exhibit 4-9:** Summary of Incremental Analysis with Production Tax Credit (1.7 c/kWh)

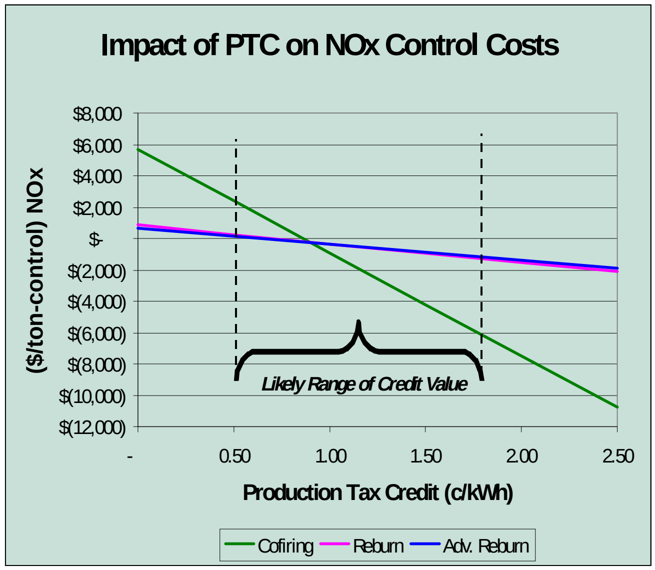
| Case Output Variable | Cofiring | Reburn | Adv. Reburn |
|---|---|---|---|
| Before tax ROR | 22% | 24% | 23% |
| After tax ROR | 188% | 101% | 88% |
| Before tax payback period (years) | 5.2 | 5.0 | 5.1 |
| After tax payback period (years) | 1.5 | 1.9 | 2.1 |

### *4.3.4 Discussion of Results*

The results of this analysis demonstrate the stark differences between these technologies in their ability to control $NO_X$ emissions and the corresponding economics. It is apparent from these exhibits that cofiring is not in the same class of $NO_X$ emission control as reburn. Exhibit 4-5 lists $NO_X$ reductions for the reburn technologies that are roughly an order of magnitude better than those for the cofiring case. In Exhibit 4-6, the cost to control $NO_X$ emissions shows a similar result. Although a reburn or advanced reburn technology is more expensive to implement, deeper $NO_X$ control is obtained. Other emissions benefits remain fairly flat across the cases. Note that the annual reduction of $SO_2$ and $CO_2$ emissions is the same for all three cases since biomass was used in the same quantities for all three cases.

Exhibit 4-7 lists the results for the cases that include a renewable production tax credit. Under these circumstances the after-tax value for each scenario was positive which resulted in a negative cost to control. This suggests that the plant can comply with the emission standards used in the analysis and still have a positive cash flow. In the cofiring case, the benefit of this credit is such that it overwhelms any requirement to buy emission allowances to meet regulations. In other words, firing biomass under this tax credit scenario has more value than making the additional investment in reburn technologies to control $NO_X$ emissions. However, a moderate reduction in the tax credit (PTC) of just a few mills/kWh dramatically changes this result and the reburn cases become the more attractive alternatives for controlling emissions. This is illustrated in Exhibit 4-10. Recently, congress has passed an extension of the existing closed-loop biomass tax credit. The new provision includes poultry litter but would still exclude cofiring and reburn technologies. Although it is very likely that this issues will be addressed again next year, there is significant financial risk in relying on the tax credits for economic justification of a project.

**Exhibit 4-10:** PTC v. Control Costs




Exhibits 4-8 and 4-9 represent an incremental economics analysis. The production cost benefits (lower fuel costs and emission credits) are used to offset the investment in the capital equipment. The results of this analysis are consistent with those shown in the absolute analysis. The scenarios without tax credits favor the reburn technologies, while the tax credit cases favor a combination of cofiring and purchasing emission allowances. However, the real value in presenting these cases is to point out a fundamental difference between biomass and natural gas reburn options. This analysis suggests that biomass reburn can pay for itself while providing deep $NO_X$ control. Although a detailed analysis of natural gas reburn options was not performed, a sample economic analysis provides a useful baseline.

| | | |
|---|---|---|
| Price of natural gas - | $2.76/MMBtu | |
| Price of coal - | $1.37/MMBtu | |
| Price differential - | $1.39/MMBtu | |
| | | |
| $NO_X$ allowances | $1,700/ton | |
| $SO_X$ allowances | $150/ton | |
| | | |
| Heat rate - | | 10,000 Btu/kWh |
| Natural gas cofire rate - | | 15% |
| Capacity factor - | | 72% *during ozone season* |
| $NO_X$ reductions (tons/ozone season) - | | 295 |
| $SO_2$ reductions - | | 608 |
| | | |
| Annual increase in fuel cost - | | $0.53M *assumes natural gas used only during ozone season* |
| Value of annual emissions offset - | | $0.59M |
| ***Net Benefit not including capital or O&M -*** | | ***$0.06M*** |

The natural gas case (which does not include capital or operational costs) results in a slight decrease in annual production costs of $0.06M per year. When all other things are considered, this benefit would be insufficient to generate a positive return on the investment required for the reburn upgrade. Further, natural gas reburn would not benefit from any of the proposed renewable energy legislation including possible tax credits. In contrast, the comparison case for biomass results in an annual benefit of over $0.9M and favorable returns in excess of 15% per year. As noted previously, adding in tax credits, green power incentives, or other valued renewable energy benefits only increases the disparity between these cases.

## 5.0 CONCLUSIONS

Natural gas reburn has already emerged as a commercially viable $NO_X$ control strategy. It has proven effective in obtaining substantial reductions in $NO_X$ and $SO_2$ emissions at a number of power plants across the United States. However, natural gas remains a premium fossil fuel.

It appears that for a moderate investment in biomass handling and processing equipment, some power plants will be able to capitalize on low-cost opportunity fuels to lower production costs and obtain $NO_X/SO_2$ emissions comparable to those obtained using natural gas. Additionally, since biomass fuels are renewable, $CO_2$ reductions are also obtained. Although not valued in this analysis, a substantial value may eventually be attributed to this benefit.

It is important to point out an additional item with respect to reburn technologies whether natural gas or biomass is used as the fuel. In these cases, reburn uses a secondary fuel to obtain $NO_X$ control. The cost of these fuels is dependent on their supply and demand. Therefore, there is a direct relationship between the ability of the plant to meet its $NO_X$ requirements in a cost effective manner and the availability of fuels at a reasonable price. For biomass, this will mean new fuel supplier relationships and potential new fuel management issues. However, this analysis suggests that the rewards will be worth the hassle and a competitive edge may be gained by those willing to modify their business practices to take advantage of them.

Power plants in the Northeast are facing more stringent air emission regulations. Since this part of the country is also rich in biomass resources, these plants should consider biomass reburn as an option. The focus of this report, Dunkirk Station, is well positioned to capitalize on this opportunity. The plant is already undergoing retrofits to cofire biomass, and much of the equipment needed to explore reburn is already on-site. This analysis suggests that biomass reburn can be even more economically attractive than biomass cofiring and that a demonstration project should be seriously considered. As part of the demonstration, the effort represented by this report should be revisited with a more in-depth technical and economic analysis of the plant's performance, with more precise data collected from combustion models and vendor/contractor quotes.

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# ANALYSIS DETAILS