NO\textsubscript{x} emission study – theory and experiences of selected fluidized bed boilers

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## List of abbreviations and definitions

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<th>Definition</th>
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<tbody>
<tr>
<td>APC</td>
<td>Advanced Process Control</td>
</tr>
<tr>
<td>BAT</td>
<td>Best Available Techniques</td>
</tr>
<tr>
<td>BFB</td>
<td>Bubbling Fluidized Bed</td>
</tr>
<tr>
<td>BIOMASS</td>
<td>Renewable energy source, wood chips, bark, forest residues, saw dust</td>
</tr>
<tr>
<td>CEMS</td>
<td>Continuous Emission Measurement System</td>
</tr>
<tr>
<td>CFB</td>
<td>Circulating Fluidized Bed</td>
</tr>
<tr>
<td>CHP</td>
<td>Combined Heat and Power</td>
</tr>
<tr>
<td>CO</td>
<td>Carbon monoxide</td>
</tr>
<tr>
<td>COV</td>
<td>Coefficient Of Variance</td>
</tr>
<tr>
<td>DCS</td>
<td>Distributed Control System</td>
</tr>
<tr>
<td>LCP-BREF</td>
<td>Large Combustion Plant Best Available Techniques reference document</td>
</tr>
<tr>
<td>MEAN</td>
<td>Signal mean (average)</td>
</tr>
<tr>
<td>NO</td>
<td>Nitrogen oxide</td>
</tr>
<tr>
<td>NO₂</td>
<td>Nitrogen dioxide</td>
</tr>
<tr>
<td>NOₓ</td>
<td>NO and NO₂ collectively</td>
</tr>
<tr>
<td>NTP</td>
<td>Normal Temperature (273.15 K) and Pressure (101.325 kPa)</td>
</tr>
<tr>
<td>QAL</td>
<td>Quality Assurance Level</td>
</tr>
<tr>
<td>REF</td>
<td>Refuse Derived Fuel</td>
</tr>
<tr>
<td>SCR</td>
<td>Selective Catalytic Reduction</td>
</tr>
<tr>
<td>SNCR</td>
<td>Selective Non-Catalytic Reduction</td>
</tr>
<tr>
<td>STD</td>
<td>Standard Deviation</td>
</tr>
<tr>
<td>SO₂</td>
<td>Sulphur dioxide</td>
</tr>
<tr>
<td>SOₓ</td>
<td>SO₂ and SO₃ collectively</td>
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</tbody>
</table>
Abstract

The purpose of this study is to describe the nitrogen oxide formation in fluidized bed combustion and challenges on reduction of them. General principles and benefits of fluidized bed combustion are introduced. These include possibility to use wide range of different and also low quality fuels, wide control range of the boiler load, low combustion temperature and high combustion efficiency with low CO emissions. In fluidized bed combustion most of the NO\textsubscript{x} emissions are fuel nitrogen based. Nevertheless, formation of fuel based NO\textsubscript{x} can be affected by regulating combustion circumstances. NO\textsubscript{x} levels in fluidized bed boiler can be further reduced with secondary methods SNCR (selective non-catalytic reduction) or SCR (selective catalytic reduction).

For new boilers, the new regulations are easier to fulfill, but for the existing boilers there are more challenges. Case specific study is needed to find the suitable method or methods for NO\textsubscript{x} emission reduction of an existing boiler. Also the cost of retrofit is dependent on the existing layout, equipment and boiler building. Depending on these restrictions SNCR/SCR retrofit cases can be technically unfeasible on old boilers. Indicative cost ranges of investing on fuel feed and air distribution modernization, advanced controls, SNCR or SCR are given for boiler size classes of 100 MW\textsubscript{fuel} and 300 MW\textsubscript{fuel}.

The process data of three BFB and three CFB plants was studied. Plants are briefly introduced regarding combustion technology, fuel power and fuel types and usage. Four to six months of process data has been collected from the plants during normal operation, showing large load range and mill process disturbances. Process data analysis includes the behavior of NO\textsubscript{x} emissions in different boiler loads and factors that have influence on the emissions.

According to the analysis the main factors that affect on NO\textsubscript{x} emissions in fluidized bed combustion are nitrogen content of fuel, boiler load and dimensioning of the boiler. Consequently NO\textsubscript{x} emission correlates with ratio of combustion air staging, flue gas oxygen and CO emission. At lower loads there are less controlling parameters available to adjust combustion circumstances.
Background

Finnish Energy Industries Federation and Finnish Forest Industries Federation ordered the study of the flue gas nitrogen oxide emissions in the selected fluidized bed boilers. This study will be used in the “LCP-BREF (LCP-BREF = Large Combustion Plants Best Available Techniques Reference Documents) wish list” reference document drafting as well as reference material of individual plant license applications. The focus of this study is on NOx emissions of fluidized bed boilers, their level and existing and possible abatement methods as well as their costs. All the researched boilers in the study use peat as a part of their fuel mix.

Fluidized bed combustion in general

Fluidized bed combustion has become one of the most effective methods to burn various solid fuels effectively and with low emissions. In fluidized bed combustion, the combustion takes place in particle bed level that is fluidized with blown air from below. Fluidized bed consists of fuel, sand, ash, coke residue and possible sorbent for SO2 reduction. Fluidized bed combustion technology can be divided in two main types: bubbling fluidized bed BFB and circulating fluidized bed CFB combustion. Both technologies, BFB and CFB, have their own benefits and optimum areas concerning fuel palette used in the boiler, targeted emission limits and economic aspects. Selection is being done case by case after evaluating these factors.

In BFB the sand bed is fluidized with high pressure air and the bed stays in the bottom of the boiler. Fluidizing velocity is normally 0,8 - 1,2 m/s and medium size of particle is around 1 mm. BFB boiler is an effective way to burn wet and high volatile fuels like biomasses.

In the CFB the bed is fluidized with higher velocity and re-circulated back to furnace by means of the cyclone. There is no distinct sand bed in the furnace. Bed material typically consists of fuel, fuel ash, limestone products and sand. Fluidizing velocity is between 2 and 5 m/s and the size of the circulating material less than 0,6 mm. CFB boiler can burn fuels with higher heating value and also wide range of solid fuels and their mixtures.

Both BFB and CFB boilers use auxiliary fuels during start-ups and disturbances. Typically auxiliary fuels are heavy fuel oil and gas.
Advantages of the fluidized bed combustion:

- Low combustion temperatures between 800 °C and 1000 °C
- High combustion efficiency, typically > 99.5 %
- Good fuel flexibility, opportunity to use low-grade fuels
- High control rate by regulating fuel supply
- No need for drying or pulverizing the fuel

NO\textsubscript{x} formation in fluidized bed boilers

Combustion generates nitrogen compounds (nitrogen oxides NO\textsubscript{x}) and of these compounds the most important are nitrogen monoxide (NO) and nitrogen dioxide (NO\textsubscript{2}). Generally NO\textsubscript{x} emissions consist of 95 % NO and 5 % of NO\textsubscript{2}. NO and NO\textsubscript{2} emissions have similar environmental effects because in the atmosphere most of the NO will oxidize to NO\textsubscript{2} in a relatively short time. In the atmosphere NO\textsubscript{x} forms nitric acid which may cause lung damage and promote acid rain.

Important factors that affect formation of NO\textsubscript{x} emissions in fluidized bed combustion are quality of fuel, furnace temperature and air factor. The formation of NO\textsubscript{x} is explained by three different mechanisms.

- Fuel NO\textsubscript{x} is formed from the nitrogen existing in the fuel and depends on the oxygen concentration of the reaction. Fuel NO\textsubscript{x} is high when fuel includes a lot of nitrogen and volatiles because the nitrogen species bound to volatile part of the
fuel are more likely to be oxidized into NO, whereas the char-bound nitrogen may more easily reduce to \( \text{N}_2 \). The dominant factor of NO\(_x\) formation in fluidized bed burning is fuel NO\(_x\).

- Thermal NO\(_x\) results from the reaction between the oxygen and nitrogen from the air high temperatures (at temperatures above 1400 - 1600 °C), so this is not the dominant formation mechanism in fluidized bed burning where temperatures are normally much lower. In fluidized bed boilers, thermal NO\(_x\) forms mainly in injection level of the over-air and amount of the thermal NO\(_x\) can be reduced by optimizing ratio of the over air and by improving penetration and mixing.
- Prompt (fast) NO\(_x\) is attributed to the reaction of atmospheric nitrogen N\(_2\) with hydrocarbon compounds. The amount of the Prompt NO\(_x\) is insignificant in fluidized bed combustion.

NO\(_x\) emission increases when temperature or air factor increases. Low excess air ratio leads to lower emission of NO\(_x\). Most of the NO\(_x\) in fluidized bed boilers originate from the fuel nitrogen and the emission is therefore dependent on the fuel nitrogen content.

One of the biggest challenges in biomass boilers generally is to minimize NO\(_x\) emissions by primary or secondary methods. Combustion technical methods are considered as primary methods, and the secondary methods mean flue gas cleaning methods after combustion.

Nitrogen oxides can be effectively reduced with combustion air staging in BFB boilers and high solids circulation in CFB boilers. These methods have been sufficient to reach the former higher NO\(_x\) emission limits. Additional nitrogen oxide reduction can be achieved with urea or ammonia injection (SNCR) or with catalytic removal (SCR). Existing old boilers are not designed for SNCR addition and a suitable temperature window for injection may not be found.

Primary methods in BFB and CFB boilers are:

- Controlling air staging and excess air
- Limiting bed and freeboard temperatures
- Selecting fuels with low N content

Secondary methods:

- SNCR
- SCR
1. Fluidized bed combustion BAT techniques

This chapter describes current BAT techniques for BFB and CFB boilers for controlling NO\textsubscript{x} emissions.

![Bubbling fluidized bed boiler](Source: Metso Power Oy]

Figure 1-1. Bubbling fluidized bed boiler [Source: Metso Power Oy]

**Wide control range**

Fluidized bed boilers are commonly used in CHP power plants. Some of the CHP plants have also condensing features. CHP units are operating based on heat load (process heat and/or district heat) demand. The heat load varies according to industrial processes requirements and district heat demand (weather and ambient temperature). The required operation range for the BFB boilers can be from 25 % to 100 % and for CFB boilers from 35 % to 100 %.

Operating the fluidized bed boilers over a large control range decreases the need to operate small auxiliary boilers during the times when heat demand is small. This way the combined heat and power production is maximized and overall energy efficiency is improved. Auxiliary boilers are often gas or oil fired and thus wide control range of fluidized boilers decreases also the usage of fossil fuels.

**1.1 Fuel quality and handling**

Fuel is an essential factor of the NO\textsubscript{x} formation in the fluidized bed burning. The effectiveness of the NO\textsubscript{x} emission control depends on the fuel nitrogen, volatile content and how the nitrogen is bound to the fuel.
### Table 1.1-1. Typical nitrogen content of different fuels [Source: Metso Power Oy]

<table>
<thead>
<tr>
<th>Fuel</th>
<th>Nitrogen-content (weight % of dry fuel)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bituminous coal</td>
<td>0,8 – 2,2</td>
</tr>
<tr>
<td>Peat</td>
<td>1,3 – 3,0</td>
</tr>
<tr>
<td>Wood chips</td>
<td>0,1 – 0,3</td>
</tr>
<tr>
<td>Bark</td>
<td>0,4 – 0,6</td>
</tr>
<tr>
<td>Straw</td>
<td>0,4 – 1,0</td>
</tr>
<tr>
<td>Packaging waste</td>
<td>0,1 - 1,0</td>
</tr>
<tr>
<td>Municipal waste</td>
<td>1,0 – 5,0</td>
</tr>
<tr>
<td>Agro</td>
<td>0,3 – 4,0</td>
</tr>
<tr>
<td>Pulp and paper mill sludge</td>
<td>1,0 - 2,5</td>
</tr>
</tbody>
</table>

Volatile content of different fuels varies a lot: wood based and agro fuels contain 75 – 85 %, peat 65 – 75 % and bituminous coal 20 – 40 % of dry fuel.

### 1.1.1 BFB

Typical solid fuels burned in BFB boilers are wood based fuels, peat and pulp & paper mill sludge. In BFB boilers the correlation of the NO\textsubscript{x} emissions and nitrogen content of the fuel is obvious. High nitrogen content of fuel produces higher NO\textsubscript{x} emissions in the high volatile fuel. For instance peat and some agro fuels have high nitrogen content and therefore it produces higher NO\textsubscript{x} emissions than wood which has much lower nitrogen content.

### 1.1.2 CFB

Typical fuels used in CFB boilers are wood based biomass, different waste fuels and sludge, peat and coal. The burning capacity of oil and gas is typically limited to 40 - 50 %.

NO\textsubscript{x} emissions do not depend on the fuel nitrogen content as much as in the BFB boiler. NO\textsubscript{x} emissions cannot be calculated directly from the nitrogen content of fuel. NO\textsubscript{x} emission from the coal can be smaller than wood although wood includes less nitrogen than coal. Heterogeneous reactions are controlling the NO\textsubscript{x} formation and reduction especially in CFB boiler. The most important reaction is NO\textsubscript{x} reduction on residual char surfaces. For this reason the NO\textsubscript{x} emission with low volatile fuels (e.g. anthracite coal,
pet coke) can be very low due to the significant amounts of residual char in CFB hot loop circulation.

1.2 Fuel feeding system

Fuel feeding control is generally challenging because especially for biomass, the type of the fuel, moisture and heat value are constantly changing. The mass flow rate of the fuel can vary a lot and this is compensated by running the boiler on excessive air ratio. Running on high excess air ratio keeps the CO level down but increases NO\textsubscript{x} emissions and flue gas heat losses. These fuel feeding requirements are common for both boiler types BFB and CFB.

![Figure 1.2-1. Traditional solid fuel feeding conveyors with feeding screws. [Source: Metso Power Oy]](image)

As a development step to reduce excess air ratio, NO\textsubscript{x} and CO emissions, fuel feeding needs to be as stable and even as possible. Smoothness of the fuel flow helps to keep the ratio of fuel and air constant and CO emissions low.
In CFB boiler the fuel type and quality can vary considerably without adversely affecting the combustion. Combustion is effective because of the turbulent properties of the bed. Formation of carbon monoxide is lower than in BFB boilers because of good mixing of fuel and oxygen in the cyclone.

1.3 Staging of the combustion air

The combustion air system supplies the right amount of air which is needed for combustion into the boiler furnace. Staging of the combustion means that combustion air is supplied to the furnace on different levels of the furnace. This is used to control combustion and combustion temperatures better. In the bottom of the furnace below the secondary air level there is a reducing zone, where fuel nitrogen is reduced to nitrogen gas ($N_2$) and not oxidized to $NO_x$. Stable temperature profile also reduces formation of $NO_x$ emission. Automation of the air staging keeps the temperature profile of the furnace stable by adjusting ratio of the combustion airs.

1.3.1 BFB

The combustion air is divided into primary air and over-fire air. Primary air is for fluidization and combustion and its share of the total air is approximately 35 - 70 %. The primary air is introduced into the furnace through the fluidizing grate.

The purpose of the over-fire air is to complete the combustion in the upper part of the furnace. Over-fire air is divided into two stages: secondary and tertiary air. The secondary air is introduced into the furnace through secondary air ports that are located above the fuel feeding chutes. Tertiary air is introduced into the furnace through tertiary air nozzles.
which are typically located in the upper part of the furnace. With increased air staging (adding a tertiary air level) NO\textsubscript{x} emission can be decreased by 30 % at high loads compared to operation with only secondary air.

Figure 1.3.1-1. Staging of the combustion air in BFB boiler [Source: Metso Power Oy]

As it is shown in the figure 1.3.1-1 above the optimum load of the boiler is between 70 and 100 % in relation to NO\textsubscript{x}. When the boiler load is more than 50 % the secondary air can be used and the combustion is more effective. Below 50 % load the air staging is very limited due to the high fluidizing air flow. Excess air level below 50 % loads tends to increase, which makes NO\textsubscript{x} control difficult. Practically all combustion air is needed to keep the bed fluidized. Flue gas can be used to substitute part of the primary air. This recirculation gas can be used to control bed temperature and depending on the fuel quality also to control air distribution at low loads.

The boiler combustion air system and air distribution is designed based on the moisture content of the design fuel mixture. With low moisture fuels the share of fluidization air is small and the share of the over-fire air is larger. This large proportion of over-fire air is advantageous for NO\textsubscript{x} controlling at low loads and the control range is also greater. In wet fuels the ratio of the fluidization air and over-fire air is the other way around.
1.3.2  CFB

The main components of the combustion system are the furnace, fluidizing grid, cyclones and loop seals. Combustion takes place mainly in the furnace but partly in a whole circulation loop. Cyclones separate particles from the flue gas. High efficiency cyclones enable strong circulation of solid matter and long residence time of char and limestone used for sulphur capture. Due to high solids circulation the temperature profile is even and typically around 850 - 950 °C. NO$_x$ emissions in CFB boilers are generally lower than in BFB boilers because of lower combustion temperature and heterogeneous reducing reactions between circulating char and nitrogen oxides all over the furnace freeboard.

**Figure 1.3.2-1.** Circulation fluidized bed boiler [Source: Metso Power Oy]
The primary air flow is approximately between 45 and 100 % of the total air. The rest of the combustion air is called low-secondary and upper-secondary air. Secondary airs are located in the lower furnace. Tertiary air is not normally used in CFB boilers. Staging in CFB boiler is mainly based on fuel based char staging by elutriation to the freeboard. Air staging with high up tertiary air registers like in BFB boilers is not normally feasible due to high solid densities in freeboard and near the furnace walls air nozzles must be located in refractory covered area. Also strong air staging decreases the sulphur capture efficiency which is one of the benefits of CFB technology.

Air staging can be applied only on high loads. With low loads practically 100 % of air is primary air and thus the NOx emission increases with lower loads. Due to the fact that fluidizing velocity has to be maintained also with low loads also the oxygen content starts to increase, increasing NOx emission even higher up with low loads. This can be to some extend compensated by the use of recirculation gas. The principle or air staging shown in figure 1.3.1-1 for BFB boiler is applicable also for CFB boiler.

1.4 Advanced process control for optimizing combustion

Stable and efficient combustion is a key requirement for successful boiler operation. Varying combustion conditions, altering fuel amount or fuel quality and fast/slow boiler load changes can cause variation combustion process. Consequently, by optimizing boiler controls, the boiler efficiency can be increased and flue gas emissions decreased.

Advanced Process Control (APC) solution for fluidized bed boiler controls can increase the boiler efficiency and lower its NOx and CO emissions. By stabilizing the combustion process through regulation of bed and furnace temperature profile, flue gas oxygen and NOx/CO balance, the emissions can be reduced. Also, the APC solution can be extended by a fuel power compensator which on-line compensates heat value changes of fuel by stabilizing the fuel energy content to a fluidized bed boiler.

The APC solution operates on the existing power boiler Distributed Control System (DCS) and it is operable through DCS operator screens. For the best achievable result, the APC solution typically controls fluidized air flow, ratio of over-fire air and total air, ratio of secondary and tertiary air and available symmetry ratios by executing small corrections to the set point values received from air recipes given from boiler specifications.

The achievable NOx reduction range through an APC solution for fluidized bed boiler combustion control can be 10 – 30 % compared to the basic control system.
1.5 SNCR

SNCR (Selective Non Catalytic Reduction) is an ammonia or urea injection system which reduces NO\textsubscript{x} emissions. SNCR method suits boiler plants when the NO\textsubscript{x} reduction with the primary methods is not efficient enough to get below the emission limits of the NO\textsubscript{x}. Operation of the system depends on the furnace design and flue gas temperatures.

In SNCR ammonia water solution or urea is injected straight to the furnace or cyclone inlet and is mixed with the hot flue gas. Ammonia (NH\textsubscript{3}) reacts with nitrogen oxides (NO\textsubscript{x}) producing water (H\textsubscript{2}O) and nitrogen (N\textsubscript{2}).

The main reaction that happens to ammonia:

\[
4 \text{NH}_3 + 4 \text{NO} + \text{O}_2 \rightarrow 4 \text{N}_2 + 6 \text{H}_2\text{O}
\]

The main reaction to urea (NH\textsubscript{2}CONH\textsubscript{2}):

\[
\text{NH}_2\text{CONH}_2 + \text{H}_2\text{O} \rightarrow 2\text{NH}_3 + \text{CO}_2
\]

and

\[
4 \text{NO} + 4 \text{NH}_3 + \text{O}_2 \rightarrow 4 \text{N}_2 + 6 \text{H}_2\text{O}
\]
The reaction requires a certain temperature range to work effectively. Reaching high NO\textsubscript{x} reduction, low ammonia/urea consumption and low ammonia slip requires right temperature at injection point and adequate residence time and good ammonia mixing with the flue gas.

The optimum temperature is between 850 and 1000 °C. Ammonia or urea has to be injected at a certain point in the furnace where the right temperature window is located. Suitable temperature window of the urea is slightly higher than in ammonia. SNCR does not include a catalyst and because of this the temperature must be high enough to evoke a reduction process. At partial loads below 50 % load the available reaction time can be short due to too low furnace temperatures. On the other hand the temperature must not grow too high because ammonia will become oxidized to nitrogen oxides and desired reduction of the NO\textsubscript{x} emissions will not take place.

New BFB boilers are typically equipped with 2 - 3 injection levels. NO\textsubscript{x} reduction is typically 25 - 50 %. In new CFB boilers NO\textsubscript{x} reduction is typically 40 - 70 %. In CFB boilers the temperature window of the furnace is more stable than in BFB boilers.

### 1.6 SNCR retrofit challenges

Suitable temperature window must be found in order to achieve NO\textsubscript{x} reduction with SNCR. Process design or high heat load of an existing boiler can lead to too short reaction time because of too high temperature at the upper furnace for ammonia/urea injection.

![Figure 1.6-1. Example of ammonia injection system with two injection levels. [Source: Metso Power Oy]](image)
1.7 \( \text{NO}_x \) emission control at partial load operation

1.7.1 BFB

Further to previous air staging diagram (figure 1.3.1-1.) controlling \( \text{NO}_x \) emission in partial load is difficult, because the opportunity to use air staging becomes weak. Use of recirculation gas compensates partly weakened air staging.

One possibility to improve the part load operation is to fluidize only the part of the bed. This operation method, however, can increase the agglomeration risk of the bed and can be used only in selected cases.

Temperature dependency of SNCR method at low loads was described in the chapter 1.5. Finding a suitable temperature window for all load points of an existing BFB can be especially demanding because of unique design of a boiler and determinant fuels of each case.

![Figure 1.7.1-1. Example of flue gas temperature profiles of different load points in BFB boiler. [Source: Metso Power Oy]](image)

As it is shown in the figure above the flue gas temperature profile in BFB boiler is variable and dependent on boiler load. In partial loads temperature starts to decrease after secondary air. This is due to fact that radiation inside the furnace cools flue gases more
effectively at low loads than at high loads. In other words the radiation heat transfer does not decrease much as the load goes down.

### 1.7.2 CFB

CFB boilers have the same methods to control NO\textsubscript{x} emission in low loads as in BFB boiler. Air staging becomes weak at partial load, air ratio increases and emissions will increase.

SNCR can be furnished with level of ammonia injection in lower part of the furnace when plant is operating in low boiler load. This method requires finding a suitable temperature area where injection could take place in the lower part of the furnace.

![Diagram of CFB](source: Metso Power Oy)

**Figure 1.7.2-1.** Example of flue gas temperature profiles of different load points in CFB. [Source: Metso Power Oy]

As shown in the figure 1.7.2-1 the temperature profile of CFB is more stable than in the BFB boiler.
1.8 SCR

SCR means selective catalytic reduction of NO\textsubscript{x}. It is the most effective NO\textsubscript{x} reduction method. In SCR method nitrogen oxides are reduced to water (H\textsubscript{2}O) and to molecular nitrogen (N\textsubscript{2}) in the SCR reactor.

The reactions for aqueous ammonia are:

\[
4 \text{NO} + 4\text{NH}_3 + \text{O}_2 \rightarrow 4 \text{N}_2 + 6 \text{H}_2\text{O}
\]

\[
\text{NO} + \text{NO}_2 + 2\text{NH}_3 \rightarrow 2 \text{N}_2 + 3 \text{H}_2\text{O}
\]

The purpose of the catalyst is to speed up the reaction. The catalyst is not consumed in the reaction but the operating conditions may cause erosion or pollution to the catalyst element. Catalyst elements may have to be cleaned or regenerated occasionally or changed for new ones. In SCR the amount of the injected ammonia is markedly smaller than in SNCR. Catalyst can be dimensioned to achieve required NO\textsubscript{x} reduction of up to 95%.

Fuel composition, flue gas temperature and required NO\textsubscript{x} are considered when electing the SCR system. Alternatives for catalyst arrangement are High-dust SCR and Low-dust SCR.

High-dust SCR

High-dust system is generally located in the flue gas duct between economizer and the air heater. The typical operating temperature of the catalytic NO\textsubscript{x} reduction is between 300 and 400 °C with coal, and 260 - 350 with biomass. High dust configuration is best suitable for fossil fuels, coal, oil, gas and also applicable to peat and clean biomass. Peat and biomass increase catalyst deactivation compared to e.g. coal.

Slip catalyst

The slip catalyst system can be used in situation where sufficient reduction level is not possible to achieve only with SNCR or the ammonia slip is too high. The slip catalyst is located between the economizer and the air heater and it doesn’t have its own ammonia injection. The nitrogen oxides are partly reduced in the furnace and partly by the catalyst. Ammonia slip is consumed in the catalytic reaction of NO to N\textsubscript{2}. A slip catalyst can typically reduce about 50 % of incoming NO\textsubscript{x}. However, the reduction rate depends on the amount of available ammonia slip. The reduction efficiency of this combination is less dependent on the load than the efficiency of SNCR. Lower loads decrease NO\textsubscript{x} reduction in the SNCR system and increase NO\textsubscript{x} reduction in the catalyst.
Low-dust SCR

In Low-dust arrangement the catalyst is placed after dust removal. Flue gases are cleaned from dust, acid gases and other pollutants before ammonia injection and catalyst. Low-dust application is typically suited for fuels with high catalyst poison levels (alkalis, phosphorus, heavy metals from recycled fuels). Suitable operating temperature is between 165 and 280 °C depending on flue gas SO₂ concentration. In the low-dust SCR arrangement the catalyst is bigger than the catalyst in the high-dust arrangement because the temperature of the low-dust SCR is lower. Low-dust arrangement will become more important in the future if the use of recycled fuels will increase.

1.9 SCR retrofit challenges

The used fuel mix palette and the desired load level of the boiler are the key issues when planning SCR retrofit to an existing boiler. The main challenges are layout, ductwork, flue gas draft system and steel structure changes. Lack of space for the catalyst and layout
modification of the flue gas duct is a typical problem for SCR retrofit. SCR requires correct operating temperature window to work. Placement of the catalyst and method of temperature control at low loads has to be solved case-specifically and can require relocation of heating surfaces. The increased pressure drop of the SCR must also be taken into account and existing steel structure of the boiler building must be examined.

**Figure 1.9-1.** In this boiler plant case SCR configuration requires larger modification. Extensive layout and steel structure changes will be needed due to lack of space. [Source: Metso Power Oy]

**Figure 1.9-2.** In this boiler case High-dust SCR configuration is easier to execute because there has already been a reservation for the layout of SCR system. [Source: Metso Power Oy]
2. Cost of NO\textsubscript{x} reduction methods

Chapter two includes cost estimates of selected methods for reducing NO\textsubscript{x} formation in combustion and methods for reducing NO\textsubscript{x} in flue gases at fluidizing bed boiler plants. Costs have been estimated for two different boiler sizes. Calculation is suggestive and estimated at 2011 price level. Not all methods to decrease NO\textsubscript{x} emission can be used at existing boiler plants. Primary (combustion technical methods) NO\textsubscript{x} emission control methods are applicable only for old fluidized bed boilers.

The total investment cost depends heavily on design, lay-out requirements and need to update existing systems. Each boiler needs to be studied separately to evaluate case specific investment costs and investment cost may exceed the presented values depending on the circumstances.

2.1 Combustion modification

Fuel feeding equipment modification

Existing fuel feeding equipment is changed by adding double robbing screw conveyor with a surge bin. Existing chain conveyor and rotary feeder are kept unchanged if possible. The most important cost factors are the original layout of the boiler, incoming steel structure changes and changes of fuel feeding conveyors. Insufficient space for the fuel feeding equipment results in increased cost.

Air distribution modification

Air distribution modification is preferably executed together with fuel feeding equipment modification. Existing secondary air nozzles are replaced by advanced nozzles with improved jet penetration and air ducts are modified accordingly. Similar changes may be necessary to execute also for tertiary air nozzles. The price level for tertiary air level modification is slightly lower than for secondary air.

Air nozzle modification is suitable for boilers that have an old fashioned air distribution system where air penetration is not up to today’s standards.

The price depends on the number of air nozzles and wall opening changes.
Table 2.1-1. Estimated cost for fuel feeding equipment and air distribution modernization. Included in the cost estimate are mechanical modifications, process and layout changes. Excluded are electrification and DCS updates and civil works. [Source: Metso Power Oy]

<table>
<thead>
<tr>
<th>Technology</th>
<th>MW_fuel</th>
<th>Investment costs M€</th>
</tr>
</thead>
<tbody>
<tr>
<td>Fuel feeding equipment modification and secondary air distribution modernization</td>
<td>100</td>
<td>0.5 – 1.5</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>1 – 2.5</td>
</tr>
</tbody>
</table>

2.2 Advanced controls

Advanced controls for optimizing combustion of a fluidized bed boiler or for compensating varying heat value of fuel.

Table 2.2-1. Estimated cost for advanced controls [Source: Metso Automation Oy]

<table>
<thead>
<tr>
<th>Technology</th>
<th>MW_fuel</th>
<th>Investment costs M€</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced controls for optimizing combustion or for compensating varying heat value of fuel</td>
<td></td>
<td>0.15 – 0.3</td>
</tr>
</tbody>
</table>

2.3 SNCR

The cost includes mechanical modification work for SNCR system with two injection levels.

The factors influencing on the cost:

- Layout and process design
- Required steel structure changes and number of injection levels
- Injected reagent: ammonia water/urea
Table 2.3-1. Estimated cost for SNCR. The cost estimate includes mechanical modifications, process and layout changes. Electrification and DCS updates and civil works are excluded. [Source: Metso Power Oy]

<table>
<thead>
<tr>
<th>Technology</th>
<th>$MW_{fuel}$</th>
<th>Investment costs M€</th>
</tr>
</thead>
<tbody>
<tr>
<td>SNCR</td>
<td>100</td>
<td>0,8 – 1,5</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>1 – 2</td>
</tr>
</tbody>
</table>

2.4 SCR or SNCR + slip catalyst

The required modifications for the boiler (SNCR + slip):

- Layout and process design
- Steel structure changes
- Addition of catalyst with ductwork
- Mechanical modifications for SNCR system

The factors influencing on the cost:

- Layout and process design
- Required steel structure changes
- Injected reagent: ammonia water/urea
- Existing flue gas system (e.g. flue gas fan and arrangement of heating surfaces)
- Possible need to rearrange heating surfaces or equipment in the boiler house
- Location of a suitable temperature window
- Civil works (not included in the cost estimation)

The required modifications for the boiler (SCR):

- Layout and process design
- Steel structure changes
- Addition of catalyst with ductwork
- Mechanical modifications for ammonia system

The factors influencing on the cost:

- Layout and process design, (high-dust or low-dust)
- Required steel structure changes
- Existing flue gas system (e.g. flue gas fan and arrangement of heating surfaces)
• Possible need to rearrange heating surfaces or equipment in the boiler house
• Location of suitable temperature window
• Civil works (not included in the cost estimation)

Table 2.4-1. Estimated cost for SNCR + slip catalyst or SCR. The cost estimate includes mechanical modifications, process and layout changes. Electrification and DCS updates and civil works are excluded. [Source: Metso Power Oy]

<table>
<thead>
<tr>
<th>Technology</th>
<th>MW fuel</th>
<th>Investment costs M€</th>
</tr>
</thead>
<tbody>
<tr>
<td>SNCR + slip catalyst or SCR</td>
<td>100</td>
<td>2 – 6</td>
</tr>
<tr>
<td></td>
<td>300</td>
<td>3 – 10</td>
</tr>
</tbody>
</table>

The costs are not including possible upgrade or replacement of a flue gas fan, rearrange heating surfaces and rearrangement of other equipment in boiler house.

3. Process data analysis

3.1 Process data

Process data consists of selected signals, analogy measurements and controls which are on average 70 pieces per boiler. Collected and analyzed data are validated weighted hour average values of continuous 5 – 6 month periods during the year 2011. Validated air emission values were collected from Metso DNA Information Management systems of power plants. Validation is done already in information system of power plants according to principles defined in LCP directive. The emission values used in this study are validated one hour (or half-hour) arithmetic mean values, which are standardized (NTP) and reduced to 6 % O$_2$ content. Measured emission values are corrected by using QAL 2 (Quality Assurance Level) calibration function. The 95 % confidence intervals are not subtracted from the values.

Validated value means that start-ups and shutdown periods of boiler and testing, maintenance or breakdown periods of CEMS (continuous emission measurement system) are excluded from the mean value calculation. Criteria for validated mean value (1 h, ½ h) is that 2/3 of data is valid according to criteria defined above. In some cases also some disturbance or abnormal situations are automatically excluded from the calculation. Typically those are breakdowns of flue gas cleaning system (for example electrostatic precipitator).
3.2 Method of data analysis

Data analysis in this report is based on the process data collected from the boiler plants listed in the section 3.3. The process data has been collected as hourly averages. However, for improving confidence of statistical data analysis, collected data from each boiler has been filtered to exclude time periods when boiler output steam flow is zero (boiler is off).

For other non-statistical analysis, collected data from each boiler has been filtered to exclude time periods when:

- Boiler output steam flow is zero (boiler is off)
- Boiler output steam flow measurements are outside of 99 % confidence range
- NOX measurements are outside of 99 % confidence range

All the emission analyzers are maintained and calibrated as required in EN 14181 standard and the 95 % confidence intervals of the analyzers are within the limits set in the LCP directive. In this study, calibration of the analyzers has not been separately confirmed for verifying the analyzers’ performance.

For statistical analysis, the following statistic measures are used consistently for NOX emission and boiler output steam flow:

- Maximum value (Max)
- Mean value (Mean)
- Minimum value (Min)
- Standard deviation (STD)
- Coefficient of variation (COV)

For analyzing and visualizing data sets, the applied data analysis methods are mainly time-domain based. The methods include:

- Signal trending for one signal
- XY-plots for two signals
- Polynomial fits for XY-plots based on least squares method
- Histogram-based breakdown calculations
- Cross-correlation analysis

Figure 3.2-1 shows all the measured NOX emissions (vertical, mg/Nm3) with respect to boiler load (horizontal, %). Thickened vertical and horizontal lines denote 99 % confidence min/max –limits leaving outside those outliers which are not included in the
data analysis. These measurements are 1% of all measurements equaling to 0.01 x 4343 samples = 43 samples leaving 4300 samples for any further analysis.

![Graph showing relationship between Boiler output vs. fuel power and NOx emission study](image)

**Figure 3.2-1.** NO\textsubscript{x} emissions with respect to boiler load. \(N = 4343\) samples and 99% confidence min/max -limits. Emission expressed in mg/Nm\textsuperscript{3} 6% O\textsubscript{2}, in dry gas.

### 3.3 The studied boiler plants

Studied boiler plants are introduced in table below.

**Table 3.3-1.** Summary of the studied boiler plants

<table>
<thead>
<tr>
<th>Plant</th>
<th>[MW\textsubscript{fuel}]</th>
<th>Boiler type</th>
<th>Main fuels</th>
<th>SNCR</th>
<th>Year of start-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kaukaan Voima</td>
<td>410</td>
<td>CFB</td>
<td>Biomass and peat</td>
<td>Yes</td>
<td>2009</td>
</tr>
<tr>
<td>Kymin Voima</td>
<td>294</td>
<td>BFB</td>
<td>Biomass, peat and sludge</td>
<td>No</td>
<td>2002</td>
</tr>
<tr>
<td>Porin Prosessivoima</td>
<td>206</td>
<td>CFB</td>
<td>Biomass, peat and REF</td>
<td>Yes</td>
<td>2009</td>
</tr>
<tr>
<td>Rauman Voima</td>
<td>120</td>
<td>BFB</td>
<td>Biomass, peat, REF and sludge</td>
<td>Yes</td>
<td>2006</td>
</tr>
<tr>
<td>Stora Enso Veitsiluoto</td>
<td>280</td>
<td>BFB</td>
<td>Biomass, peat and sludge</td>
<td>No</td>
<td>1996</td>
</tr>
<tr>
<td>Tornion Voima</td>
<td>143</td>
<td>CFB</td>
<td>Peat, biomass and CO gas</td>
<td>Yes</td>
<td>2007</td>
</tr>
</tbody>
</table>
None of the six studied boiler plants are base-load plants but all of them supply heat to industrial processes and to district heat network. Plants are located in different parts of Finland.

3.4 Results

This section gives an insight to results obtained from data analysis of six Finnish fluidized bed boilers (FBB) fueled with biomass and peat. The time period for the analysis was 5-6 months in order to cover both high boiler loads (winter time) and low boiler loads (summer time).

3.4.1 Fuel mixtures

All of the analyzed boilers burn mixed solid fuel mainly consisting of wood based biomass and peat. Some boilers burn also sludge, coal or REF. These fuels have been included in calculation of fuel nitrogen content. For start-up and support fuels heavy fuel oil and natural gas are used. However, since the share of supporting fuels is rather marginal compared to the volumes of biomass and peat, their rather insignificant impact has been omitted in the analysis.

The mix of fuels does not stay unchanged but varies with respect to a season, fuel availability and boiler operational reasons. The first month of the analysis is from a middle winter where as the last month is from an early summer. The average temperature in the middle winter (January) in Finland is -4...-14 °C depending on the geographical location whereas the average temperature in early summer (June) in Finland is +12...+15 °C. Due to the changes in ambient temperatures the heat demand of industrial processes and district heating networks change and thus the boiler loads vary also.

Figure 3.4.1-1 illustrates how the nitrogen content varied along the six month period. The nitrogen content of the mixed fuel was calculated on a monthly basis based on the fuel data obtained from the mills. The calculated nitrogen values do not directly imply the total amount of nitrogen fed to the boiler combustion but it shows the average nitrogen content of the mixed fuel.
Figure 3.4.1-1. Nitrogen content (%) of the mixed fuel. Left: BFB boilers 1-3. Right: CFB boilers 1-3. Nitrogen content is expressed by weight percent in dry matter.

The nitrogen content of the fuel mix can be as low as 0.4 % - 0.5 % on a single boiler or, alternatively, close to 2 % or slightly more. In addition, the nitrogen content on a single boiler can change by 0.5 nitrogen -% at the maximum corresponding a relative change of 25 % – 50 % in the nitrogen content.

Figure 3.4.1-2 clearly shows how the nitrogen content of the fuel mix increases with respect to increasing peat share in the mixed fuel. This observation is a consequence of peat having larger nitrogen content (1.4 % - 2.5 %) as fuel as biomass type fuels containing wood (0.4 % - 0.5 %). The nitrogen content of peat itself depends on a geographical location of the peat field.
The nitrogen and sulphur contents of peat are much higher than in biomass originating from wood. Typical nitrogen contents are 1.3 – 3.0 % for peat and 0.1 - 0.5 % for wood. Corresponding figures for sulphur contents are 0.2 – 0.4 % for peat and approximately 0.05 % for wood. Although pulp and paper mill sludge contain both sulphur and nitrogen and can cause slight variation in results can SO$_2$ emissions be indirectly used for estimating the nitrogen content changes of the fuel. Figure 3.4.1-3 shows NO$_x$ emissions with respect to SO$_2$ emissions for the BFB boilers 1 and 3.

**Figure 3.4.1-2.** Nitrogen content (%) of the fuel mix with respect to peat share (%) in the mix. Left: BFB boilers 1-3. Right: CFB boilers 1-3.
**3.4.1 NO\textsubscript{x} emission study – theory and experiences of selected fluidized bed boilers**

**Figure 3.4.1-3.** NO\textsubscript{x} emission (mg/Nm\textsuperscript{3}) with respect to SO\textsubscript{2} emission (mg/Nm\textsuperscript{3}). Upper: BFB 1. Lower: BFB boiler 3 (\(N = 4300\) samples). This illustrates correlation between SO\textsubscript{2} and NO\textsubscript{x} emissions. It is liable to assume that higher SO\textsubscript{2} emission reflect higher fuel’s nitrogen content at that particular time. Emission expressed in mg/Nm\textsuperscript{3} 6 % O\textsubscript{2}, in dry gas.

**3.4.2 Annual boiler load variations**

Boiler load is defined by the main steam flow (kg/sec or tons/h) generated by the boiler. The resulted boiler load is then converted to a relative scale (%) where 100 % load corresponds to the nominal designed boiler load.

The BFB boiler load statistics using the relative scales are given in table 3.4.2-1. The highlighted yellow area involves mean values with 99 % confidence limit values (high 99 % confidence range limit, low 99 % confidence range limit) within which 99 % of the boiler load values reside.
Table 3.4.2-1. Boiler load statistics for BFB boilers 1-3 ($N=4300$ samples).

<table>
<thead>
<tr>
<th>Measure</th>
<th>BFB 1</th>
<th>BFB 2</th>
<th>BFB 3</th>
<th>Average of BFB 1-3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max</td>
<td>106%</td>
<td>112%</td>
<td>99%</td>
<td>106%</td>
</tr>
<tr>
<td>High 99% limit</td>
<td>100%</td>
<td>105%</td>
<td>91%</td>
<td>99%</td>
</tr>
<tr>
<td>Mean</td>
<td>69%</td>
<td>56%</td>
<td>50%</td>
<td>58%</td>
</tr>
<tr>
<td>Low 99% limit</td>
<td>47%</td>
<td>37%</td>
<td>26%</td>
<td>37%</td>
</tr>
<tr>
<td>Min</td>
<td>24%</td>
<td>27%</td>
<td>26%</td>
<td>26%</td>
</tr>
</tbody>
</table>

The maximum load for the BFB boiler 1 is 106 % with respect to its design value (design boiler load = 100 %) but on the average the boiler load has been at 69 % level. The 99 % confidence boiler load range was from 47 % to 100 %.

The maximum load of the BFB boiler 2 is the highest of all, 112 %, while its average load is 56 % being clearly lower than that of the BFB boiler 1. The 99 % confidence range of the BFB boiler 2 is from 37 % to 105 % being wider than that of the boiler BFB 1.

The maximum load of the BFB boiler 3 is 99 % having the lowest maximum load of the BFB boilers. However, the average load is 50 % and the 99 % confidence range is from 26 % to 91 %.

The CFB boiler loads in their relative scales are given in table 3.4.2-2. The highlighted yellow area involves mean values with 99 % confidence limit values (high 99 % confidence range limit, low 99 % confidence range limit) within which 99 % of the boiler load values reside.

Table 3.4.2-2. Boiler load statistics for CFB boilers 1-3 ($N=4300$ samples).

<table>
<thead>
<tr>
<th>Measure</th>
<th>CFB 1</th>
<th>CFB 2</th>
<th>CFB 3</th>
<th>Average of CFB 1-3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Max</td>
<td>100%</td>
<td>109%</td>
<td>106%</td>
<td>105%</td>
</tr>
<tr>
<td>High 99% limit</td>
<td>96%</td>
<td>108%</td>
<td>101%</td>
<td>102%</td>
</tr>
<tr>
<td>Mean</td>
<td>68%</td>
<td>79%</td>
<td>82%</td>
<td>76%</td>
</tr>
<tr>
<td>Low 99% limit</td>
<td>38%</td>
<td>35%</td>
<td>48%</td>
<td>40%</td>
</tr>
<tr>
<td>Min</td>
<td>11%</td>
<td>17%</td>
<td>38%</td>
<td>22%</td>
</tr>
</tbody>
</table>
The maximum load for the CFB boiler 1 is 100 % with respect to its design value (design boiler load = 100 %) but on the average the boiler load has been at 68 % level. The 99 % confidence range was from 38 % to 96 %.

The maximum load of the CFB boiler 2 is the highest of all, 109 %, while its average load was 79 %. The 99 % confidence range of the CFB boiler 2 is from 35 % to 108 % being the widest range of the CFB boilers.

The maximum load of the CFB boiler 3 is 106 % and the boiler has the highest average load of the BFB boilers: 82 %. The 99 % confidence range is from 48 % to 101 %.

Breakdown of boiler loads for all the boilers are plotted as histograms in figure 3.4.2-1. The horizontal axis denotes the boiler load (%) whereas the vertical axis shows for how long the boiler load has been at that specific load level during the inspected period.

**Figure 3.4.2-1.** Breakdown of boiler loads for all the boilers. Left: BFB boilers 1-3. Right: CFB boilers 1-3 ($N = 4300$ samples).
Figure 3.4.2-1 shows that the BFB boilers have rather evenly distributed boiler loads but the load profiles vary because of differences in industrial process heat demands. CFB boilers have basically two boiler load levels which are more frequent than other load levels (camelback shape) and those boiler load levels are at both ends of the typical operational range.

3.4.3 NO\textsubscript{x} emissions

Having the boiler load ranges as given in tables 3.4.2-1 and 3.4.2-2 and plotted in figure 3.4.2-1, the NO\textsubscript{x} emission time trends for the same five month time period are plotted in figure 3.4.3-1 (BFB boilers) and figure 3.4.3-2 (CFB boilers).

**Figure 3.4.3-1.** NO\textsubscript{x} emission time trends for BFB boilers 1-3 for a five month period ($N = 4300$ samples). Emission expressed in mg/Nm\textsuperscript{3} 6 % O\textsubscript{2}, in dry gas.
The trends clearly show how the NOx emissions vary during the five month period which basically starts in the middle winter ending up to late spring or early summer. The trends show both fast and slow variations that are there in the NOx emissions.

The zero NOx emission values in figures 3.4.3-1 and 3.4.3-2 basically indicate situations when the boiler has not been running but has been down.

Tables 3.4.3-1 (BFB boilers) and 3.4.3-2 (CFB boilers) give the statistic measures of the NOx emissions (max/mean/min, 99 % confidence range, standard deviation and coefficient of variation). To enable comparison between the boilers with different NOx emissions levels, the same values are presented in a relative scale (%) where 100 % corresponds to the average NOx value of the boiler.

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Table 3.4.3-1. NO\textsubscript{x} emission statistics for BFB boilers 1-3 (\(N = 4300\) samples). Emission expressed in mg/Nm\textsuperscript{3} 6\% O\textsubscript{2}, in dry gas.

<table>
<thead>
<tr>
<th>Measure</th>
<th>BFB 1</th>
<th>BFB 2</th>
<th>BFB 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>mg/Nm\textsuperscript{3}</td>
<td>%</td>
<td>mg/Nm\textsuperscript{3}</td>
</tr>
<tr>
<td>Max</td>
<td>437</td>
<td>168</td>
<td>478</td>
</tr>
<tr>
<td>High 99% limit</td>
<td>401</td>
<td>154</td>
<td>353</td>
</tr>
<tr>
<td>Mean</td>
<td>260</td>
<td>100</td>
<td>258</td>
</tr>
<tr>
<td>Low 99% limit</td>
<td>80</td>
<td>31</td>
<td>171</td>
</tr>
<tr>
<td>Min</td>
<td>53</td>
<td>20</td>
<td>56</td>
</tr>
<tr>
<td>Std</td>
<td>55</td>
<td>21</td>
<td>37</td>
</tr>
<tr>
<td>COV</td>
<td>21%</td>
<td></td>
<td>14%</td>
</tr>
</tbody>
</table>

Table 3.4.3-2. NO\textsubscript{x} emission statistics for CFB boilers 1-3 (\(N = 4300\) samples). Emission expressed in mg/Nm\textsuperscript{3} 6\% O\textsubscript{2}, in dry gas.

<table>
<thead>
<tr>
<th>Measure</th>
<th>CFB 1</th>
<th>CFB 2</th>
<th>CFB 3</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>mg/Nm\textsuperscript{3}</td>
<td>%</td>
<td>mg/Nm\textsuperscript{3}</td>
</tr>
<tr>
<td>Max</td>
<td>342</td>
<td>257</td>
<td>286</td>
</tr>
<tr>
<td>High 99% limit</td>
<td>240</td>
<td>180</td>
<td>250</td>
</tr>
<tr>
<td>Mean</td>
<td>133</td>
<td>100</td>
<td>134</td>
</tr>
<tr>
<td>Low 99% limit</td>
<td>13</td>
<td>95</td>
<td>59</td>
</tr>
<tr>
<td>Min</td>
<td>0.003</td>
<td>0.02</td>
<td>34</td>
</tr>
<tr>
<td>Std</td>
<td>5</td>
<td>21</td>
<td>37</td>
</tr>
<tr>
<td>COV</td>
<td>21%</td>
<td></td>
<td>27%</td>
</tr>
</tbody>
</table>

The NO\textsubscript{x} emissions have both fast (hourly, daily) variations but also slow (weekly, monthly) variations due to many affecting factors later treated in this chapter. The monthly NO\textsubscript{x} averages are plotted in figure 3.4.3-4. The environmental permit NO\textsubscript{x} limit values for the studied BFB boilers are between 280 and 400 mg/Nm\textsuperscript{3} and for CFB boilers between 150 and 230 mg/Nm\textsuperscript{3}.
Figure 3.4.3-4. Monthly averages of NO\textsubscript{x} (mg/Nm\textsubscript{3}) for a five month period (\(N = 4300\) samples). Left: BFB boilers 1-3. Right: CFB boilers 1-3. Emission expressed in mg/Nm\textsuperscript{3} 6 \% O\textsubscript{2}, in dry gas.

The breakdowns of the NO\textsubscript{x} emissions for the BFB boilers are plotted as histograms in figure 3.4.3-5. The histograms show that shapes of the NO\textsubscript{x} distributions are rather symmetric resembling the Gaussian distribution for all boilers.

The average NO\textsubscript{x} emission is 258 – 290 mg/Nm\textsubscript{3} for the BFB boilers (see table 3.4.3-1) but the high 99 % confidence limit is as high as 353 – 401 mg/Nm3 depending on the boiler. Relatively, the high 99 % limit equals to 137 % - 154 % of the average NO\textsubscript{x} emission over the five month period.

The maximum values being over 400 mg/Nm3 for all BFB boilers imply that under certain circumstances the NO\textsubscript{x} emissions can be close to two times higher than the average value. The maximum value of 1038 mg/Nm3 for the BFB 3 is a measurement outlier that falls outside of the 99 % confidence range and, therefore, is not considered in the further analysis.

The deviation measure (Std) is 37 – 55 mg/Nm3 for the BFB boilers indicating that the NO\textsubscript{x} emission values are rather wide spread. In addition, the coefficient of variation (COV = STD / MEAN) values 14 % - 21 % confirm the same observation.
**Figure 3.4.3-5.** Breakdown of NO\textsubscript{x} emissions for BFB boilers 1-3 (\(N = 4300\) samples). Emission expressed in mg/Nm\(^3\) 6 % O\textsubscript{2}, in dry gas.

The breakdowns of the NO\textsubscript{x} emissions for the CFB boilers are plotted as histograms in figure 3.4.3-6. The histograms show that shapes of the NO\textsubscript{x} distributions are rather symmetric resembling the Gaussian distribution for all boilers. But the distributions are clearly narrower than those of the BFB boilers. In addition, the CFB boiler 1 has a long flat tail to the high end of the NO\textsubscript{x} emission distributions.

The average NO\textsubscript{x} emission is 133 – 144 mg/Nm\(^3\) for the CFB boilers (see table 3.4.3-2) being indisputable lower than that of the BFB boilers. Similarly, the high 99 % confidence...
limit is lower than that of the BFB boilers: 216 – 250 mg/Nm³ depending on the boiler. Relatively, however, the high 99 % limit equals to 150 % - 187 % of the average NOₓ emission over the five month period.

The maximum values being 286 - 342 mg/Nm³ for the CFB boilers imply that under certain circumstances the NOₓ emissions can be 2 – 2.5 times higher than the average value. However, these peak values fall outside of the 99 % confidence range and, therefore, are not considered in the further analysis.

The deviation measure (Std) is 5 – 37 mg/Nm³ for the CFB boilers indicating that the NOₓ emission values are not that wide spread as they are for the BFB boilers. Nevertheless, the coefficient of variation (COV = STD / MEAN) values 17 % - 27 % reveals that the NOₓ emission values of the CFB boilers normalized by their means are equally, if not even more, scattered and distributed than for the BFB boilers.

![Graph showing breakdown of NOₓ emissions for CFB boilers 1-3](image)

**Figure 3.4.3-6.** Breakdown of NOₓ emissions for CFB boilers 1-3 (N = 4300 samples). Emission expressed in mg/Nm³ 6 % O₂, in dry gas.
3.4.4 Combustion circumstances affecting NO\textsubscript{x} emissions

The degree of explanation between the NO\textsubscript{x} emission and each combustion variable are shown at tables 3.4.4-3 and 3.4.4-4. The explanation degree for perfect match is 100 % whereas 0 % explanation degree indicates that there does not exist explanation between two variables.

For air staging, the depictive variable is the ratio between over fire air (OFA) and total combustion air. Similarly, for estimating impact of fuel nitrogen content to the NO\textsubscript{x} emissions, the fuel nitrogen content is indirectly represented by the SO\textsubscript{2} emission which in the case of peat and wood biomass burning correlates in BFB boilers with fuel N and NO\textsubscript{x} emissions as seen in figure 3.4.1-3. Some factors e.g. SNCR, other sulphur containing fuels and SO\textsubscript{2} control methods can weaken the correlation as in the case of BFB 2. For estimating impact of the other variables which are boiler load, flue gas oxygen or recycled flue gas on the NO\textsubscript{x} emission, the variables are as such.

Table 3.4.4-3. Degrees of explanation for combustion variables affecting NO\textsubscript{x} emissions on the BFB boilers 1-3 (N = 4300 samples). The explanation degree percentages are presented as relative figures of the total correlation coefficient.
Table 3.4.4-4. Degrees of explanation for combustion variables affecting NO\textsubscript{x} emissions on the CFB boilers 1-3 ($N = 4300$ samples). The explanation degree percentages are presented as relative figures of the total correlation coefficient.

<table>
<thead>
<tr>
<th>Explanatory combustion variable</th>
<th>CFB 1</th>
<th>CFB 2</th>
<th>CFB 3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Explanation degree of all combustion variables to NO\textsubscript{x} (total correlation coefficient)</td>
<td>Fairly Good (0.55)</td>
<td>Good (0.70)</td>
<td>Fairly Good (0.54)</td>
</tr>
<tr>
<td>Degree of explanation %</td>
<td>(0 = None ... 100 = Perfect)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Boiler load</td>
<td>19 %</td>
<td>7 %</td>
<td>34 %</td>
</tr>
<tr>
<td>OFA/Total air ratio</td>
<td>6 %</td>
<td>3 %</td>
<td>8 %</td>
</tr>
<tr>
<td>Flue gas oxygen</td>
<td>70 %</td>
<td>68 %</td>
<td>37 %</td>
</tr>
<tr>
<td>Fuel nitrogen content (indirectly by SO\textsubscript{2})</td>
<td>5 %</td>
<td>16 %</td>
<td>7 %</td>
</tr>
<tr>
<td>Recycled flue gas</td>
<td>Not used</td>
<td>6 %</td>
<td>13 %</td>
</tr>
</tbody>
</table>

Also, the correlation coefficients between the NO\textsubscript{x} emission and each combustion variable were calculated in for variables listed in tables 3.4.4-3 and 3.4.4-4. However, in some cases they failed in showing dependency and interaction between two variables as they indicate only linear correlation, not correlations of higher order systems (e.g. correlation that could be of U-shape type). Therefore, the correlation coefficients have not applied in this section.

3.4.5 NO\textsubscript{x} emissions and boiler load

As it was shown in tables 3.4.4-3 and 3.4.4-4, the boiler load is one of the best variables for explaining behavior of the NO\textsubscript{x} emission. Its degree of explanation varied between 9 % and 77 % for the BFB boilers and from 8 % and 34 % for the CFB boiler. Polynomial fits are shown with the 99 % confidence range data in figure 3.4.5-1.
Figure 3.4.5-1. NO\textsubscript{x} emissions with respect to boiler load and the polynomial data fit. (\(N = 4300\) samples). Emission expressed in mg/Nm\textsuperscript{3} 6 % O\textsubscript{2}, in dry gas.

The fits between NO\textsubscript{x} emission and boiler load for the BFB boilers and the CFB boilers are plotted in figure 3.4.5-2. It shows that the NO\textsubscript{x} emission of the BFB boilers does not stay constant at different boiler loads but, instead, it heavily tends to increase at low loads below 35 % - 50 % and also at the high load over 70 % for the BFB boiler 2.

For CFB boilers, the NO\textsubscript{x} emission has a minimum typically within load range of 60 - 80 %. The emission increases at low and high end boiler loads. Use of SNCR system evens out the variation.
**Figure 3.4.5-2.** NO$_x$ emissions with respect boiler load ($N = 4300$ samples). Upper: BFB boilers 1-3. Lower: CFB boilers 1-3. Emission expressed in mg/Nm$^3$ 6 % O$_2$, in dry gas.

### 3.4.6 NO$_x$ emissions and air staging

The degree of explanation for air staging varied between 12 % and 24 % depending on the BFB boiler. For the CFB boilers, however, the explanation degree was smaller ranging from 6 % to 8 %. In practice, air staging involves not just distribution between over-fire air (OFA) and fluidized air but also secondary / tertiary (for BFB) or lower / upper secondary (for CFB) of OFA airs. However, to simplify the analysis without losing its generality, the ratio between OFA and total combustion air has chosen to describe air staging. It can be seen that all boilers are unique and have their own optimum load points.
The polynomial data fits between NO\textsubscript{x} emissions and ratio of OFA and total combustion air for all boilers are plotted in figure 3.4.6-1.

![Figure 3.4.6-1](image.jpg)

**Figure 3.4.6-1.** NO\textsubscript{x} emissions with respect to air ratio (= OFA air/Total air) and the polynomial data fit. (\(N = 4300\) samples). Emission expressed in mg/Nm\(^3\) 6 % O\textsubscript{2}, in dry gas.

### 3.4.7 NO\textsubscript{x} emissions and flue gas oxygen

The degree of explanation for flue gas oxygen varied between 12 % and 48 % depending on the BFB boiler. For the CFB boilers, the explanation degree was even better varying from 37 % to 70 %.
The polynomial data fits between NO\textsubscript{x} emissions and flue gas oxygen for all boilers are plotted in figure 3.4.7-1. It clearly shows that the NO\textsubscript{x} emission of both BFB and CFB boilers increases proportional to flue gas oxygen level. To reduce the NO\textsubscript{x} emissions the flue gas oxygen should be kept as low as possible. However, this is a challenge especially for low boiler loads for which the fluidized air needed exceeds the amount of combustion air needed resulting in excessive flue gas oxygen in the boiler furnace. With the CFB boilers, the impact of flue gas oxygen on NO\textsubscript{x} emission is clearly bigger compared to the BFB boilers.

**Figure 3.4.7-1.** NO\textsubscript{x} emissions with respect to flue gas oxygen and the polynomial data fit. \((N = 4300\) samples). Emission expressed in mg/Nm\textsuperscript{3} 6 \% O\textsubscript{2}, in dry gas.
3.4.8 NO\textsubscript{x} emissions and CO emissions

The CO emissions are strongly related to the flue gas oxygen level and NO\textsubscript{x} emissions. Yet, the CO emissions cannot be used for regulating the NO\textsubscript{x} emissions but they should be considered together with the NO\textsubscript{x} emission in order to maintain a well-balanced ratio between CO and NO\textsubscript{x}.

The polynomial data fits between NO\textsubscript{x} emissions and CO emissions for all boilers are plotted in figure 3.4.8-1. It shows that the NO\textsubscript{x} emissions are inversely proportional to the CO emissions, that is, the NO\textsubscript{x} emissions decrease when the CO emissions increase (except for the BFB boiler 3).

![Figure 3.4.8-1. NO\textsubscript{x} emissions with respect to flue gas CO emission and the polynomial data fit. (N = 4300 samples). Emission expressed in mg/Nm\textsuperscript{3} 6 % O\textsubscript{2}, in dry gas.](image-url)
3.4.9 NO\textsubscript{x} and Selective Non-Catalytic Reduction

There are four boilers out of six that apply SNCR injection for regulating the NO\textsubscript{x} emissions: one BFB boiler and all CFB boilers.

Figure 3.4.9-1 illustrates how SNCR injection is applied on the CFB boiler 2. Ammonia water is applied on constant flow to control NO\textsubscript{x} emission against daily average limit. The effect of the SNCR cannot be analyzed because it is used all the time. There were no useful data for analyzing obtained from other boilers either.

![SNCR flow vs. Boiler load](image)

**Figure 3.4.9-1.** SNCR injection flow (l/h) with respect to time (upper) and boiler load (lower). Upper: SNCR injection flow time trend. Lower: SNCR injection flow with respect to boiler load (N = 4300 samples).
4. Conclusion

The focus of this study is on the NO\textsubscript{x} emission levels and reduction methods in fluidized bed boilers. There are several variables which have an effect on NO\textsubscript{x} emissions in fluidized bed boilers, for example:

- Boiler design
- Fuel properties: nitrogen content and volatile content
- Boiler load variations
- Combustion air staging
- Flue gas oxygen content in furnace
- Recycled flue gas
- Secondary NO\textsubscript{x} reduction methods

In fluidized bed combustion nitrogen oxide is formed mainly from the fuel nitrogen. Amount of volatiles in fuel has also influence on the formation rate. The nitrogen content of different bio fuels has a large variance. N content of wood varies from 0.1 to 0.5 wt-% ds, peat up to 2.5 wt-% ds and agro up to 4 wt-% ds. Nitrogen oxides can be reduced by controlling combustion conditions such as combustion air staging, furnace oxygen level and furnace temperature level or by secondary NO\textsubscript{x} reduction methods. Boiler load and dimensioning have significant influences on NO\textsubscript{x} formation. At lower boiler loads effective air staging and low flue gas oxygen level in furnace are more difficult to achieve and there are less controlling parameters to adjust combustion conditions.

Six fluidized bed boilers located in Finland were analyzed based on process data retrieved from the boilers for a 5-6 month operation period. The data was collected during the normal operation without any specific tests on the boilers. Based on the data analysis, the following conclusions can be drawn:

- Boiler load, fuel’s nitrogen content, flue gas oxygen level in furnace and combustion air staging are the most important variables on NO\textsubscript{x} emission
- Fuel nitrogen content and NO\textsubscript{x} emission have a strong correlation. As the nitrogen content of the fuel increases the NO\textsubscript{x} emission increases especially in BFB boilers.
- At low boiler loads NO\textsubscript{x} emissions increase. Depending on the boiler dimensioning, emissions can also increase at high boiler load.
- Flue gas oxygen level in furnace correlates with NO\textsubscript{x} emission level. The higher the flue gas oxygen level is the higher the NO\textsubscript{x} emission.
- The effects of different variables on NO\textsubscript{x} emissions cannot always be generalized because all boilers are unique (design, fuel etc.)

Based on different features in combustion technologies of BFB and CFB, the NO\textsubscript{x} emissions, when using only primary methods are higher in BFB compared to CFB boilers. Both technologies, BFB and CFB, have their own benefits and optimum areas concerning fuel palette used in the boiler, targeted emission limits and economic aspects. Selection is being done case by case after evaluating these factors.
For new boilers the emission requirements can be taken into account by boiler design and applicable secondary methods. The performance of an existing boiler depends on the design. The lowest reachable NO\textsubscript{x} level and the cost of the required investment must be studied case specifically.

**References**

Metso Power Oy, unpublished internal sources

Metso Automation Inc. unpublished internal sources