CHALMERS
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# The impact of The Medium Combustion Plant Directive on particulate matter, sulfur dioxide and nitrogen oxides prevention techniques.

Master's thesis in Sustainable Energy Systems Programme

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Gothenburg, Sweden 2018

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# Abstract

The Medium Combustion Plant Directive (MCPD) governs the emissions from combustion plants with thermal range of 1 – 50 $MW_{th}$ of Particulate Matter (PM), Sulfur Dioxide ($SO_2$) and Nitrogen Oxide ($NO_x$). The MCPD will come in to play in year 2025 for combustion plants with thermal range 5 – 50 $MW_{th}$ and 2030 for thermal range 1 – 5 $MW_{th}$. This thesis evaluates the impact on the European heat and power generation by the enactment of the MCPD. The analysis will include the impact on different geographical areas and propose suitable technical solutions to retrofit plants to comply with the directive. The work is performed in cooperation with General Electric (GE) and focus on their portfolio of flue gas cleaning techniques.

Based on data on the existing fleet of 1-50 $MW_{th}$ units in Europe an analysis is performed to identify the most concerned regions. In general, plants burning coal are the ones that are most affected by the MCPD due to emissions of PM and $SO_2$. Coal plants are more common in eastern EU than elsewhere in the EU and therefore this is region will be most affected by the new directive. Medium scale biomass- and peat plants may also be affected by the directive. This type of plants are scattered over all areas investigated. Plants with a thermal capacity of 20 – 50 $MW_{th}$ are of primary concern, as this range of capacity has the highest amount of solid fuel consumption, are operated more continuously, and are financially strong to be able to invest in flue gas cleaning. It is likely that most plants should be able to comply with the $NO_x$ limits by use of primary measures while PM and $SO_2$ will require secondary flue gas cleaning.

The most cost effective GE solutions for PM and $SO_2$ control from coal are either Novel Integrated Desulfurization (NID) or Novel Integrated Desulfurization Light (NIDL). These technologies recirculates sorbents, and becomes cost effective compared to, for example, Dry Sorbent Injection (DSI) combined either with an Electrostatic Precipitator (ESP) or a Fabric Filter (FF). For peat- and biomass plants, the required collection efficiency's for $SO_2$ are lower compared to coal, and a DSI in combination with an ESP or a FF is proposed.

Keywords: Medium Combustion Plant Directive (MCPD), Air Quality Control Systems (AQCS), Flue gas cleaning, Electrostatic Precipitator (ESP), Fabric Filter (FF), Particulate Matter (PM), Sulfur Dioxide ($SO_2$)

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Furthermore, besides friends and family, I also wanna thank my father, Christer Mauritzson, who has over 40 years of experience and knowledge within sales, business and engineering in regard to emission control systems, heat and power along with other related industrial applications. His expertise and background in this field has been of huge importance to this thesis.

Finally I would like to thank everyone at the Department of Space, Earth and Environment at Chalmers, along with the colleagues at General Electric (GE) for providing pleasant and friendly working environment.

Philip Mauritzson, Gothenburg, Sweden, Juni 6, 2018

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# 1
# Introduction

The world is plagued with problems related to harmful emissions from heat and power generation. Sulfur oxide ($SO_x$), nitrogen oxide ($NO_x$), particulate matter (PM), mercury (Hg) and volatile organic compounds (VOC) are all common emissions from combustion processes that cause many environmental problems which affects nature, wildlife and human health. The European Parliament estimate that in 2010, approximately 406 000 persons died in premature death due to impact of air pollution in the European Union (EU) [1]. To enable efficient and clean heat and power generation based on combustion the concert of a leveled and adequate legislation for emission standards and efficient and continuously developed emission control techniques is required. This work is performed in cooperation with General Electric Power (GE Power), which is one of the world's leading company in air quality control systems (AQCS) for power- and industrial applications. The current AQCS product catalogue of GE Power is further used in the thesis.

*The Convention of Long-range Transboundary Air Pollution* which was signed by 32 countries in 1979. Today the number of countries who have signed the convention is 51. The aim of the convention was to improve the air quality on local-, national- and regional levels. Since 1979, the agreements has extended to eight protocols for further development and progress for better air quality [2]. The latest protocol, *the Gothenburg protocol*, was introduced in 1999, in which the aim was to set national limits on sulfur dioxides ($SO_2$), $NO_x$, VOC and ammonia ($NH_3$) to reduce the tropospheric ozone as well as the eutrophication and acidification of water. *The Gothenburg protocol* was entered in force by year 2005 and revised in 2012 [3].

*Large Combustion Plant Directive (LCPD)* regulates flue gas emissions from combustion plants with thermal capacity above 50 $MW_{th}$. For combustion plants below 50 $MW_{th}$, also known as medium combustion plants, the *Medium Combustion Plant Directive (MCPD)* applies. Medium Combustion Plant Directive (MCPD) was published on November 25, 2015 by the European Parliament and the council of the EU. It is a part of *The Clean Air Policy Package*, adopted on December 18, 2013 and is based on a Commission proposal. The aim of *The Clean Air Package* was to reduce air pollution within the EU. MCPD regards the allowed levels of PM, $NO_x$, and $SO_2$ that are emitted from medium combustion plants and therefore covers the obligations on $NO_x$ and $SO_2$ arising from the *Gothenburg protocol*. Medium combustion plants are used in a large variety of applications, such as electricity generation, heating and cooling for householders and residencies, along with heat and steam for industrial processes.

At present there are no specific European directive level legislation's addressing to the emission and air pollution for medium combustion plants, although some of the countries in the EU have local legislation's. The allowed emission levels differ across the countries of the EU. [9]

## 1.1 Aim

The aim of this thesis is to analyze effect of the Medium Combustion Plant Directive (MCPD) to the fleet of plants affected within the EU. The work will consider types of plants, regions of the European Union (EU) and the need for technology within flue gas cleaning. Specifically the work will assess:

1. Which regions or countries of the EU that will be most affected by the Medium Combustion Plant Directive (MCPD).
2. The needs and demands of different types of medium combustion plants.
3. How GE Power's current product catalog complies with the needs triggered by the implementation of the Medium Combustion Plant Directive (MCPD).

# 2
# Theory

This chapter includes theory about medium combustion plants, emissions, flue gas cleaning technologies and the MCPD. Only a selection of all combustion plants and flue gas cleaning technologies are described. Figure 2.1 illustrates the principle of a steam power plant, including boiler and an example over a flue gas cleaning equipment combination.

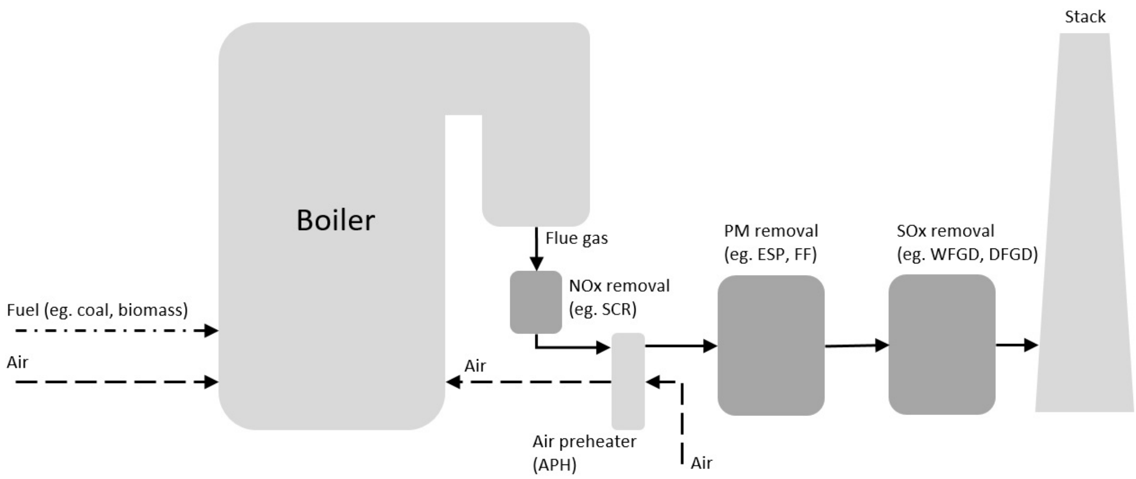


**Figure 2.1:** Overview of a conventional power plant with flue gas cleaning equipment's highlighted.

There are several technologies within flue gas cleaning. The amount of emitted pollutants depends on several factors such as type of fuel and composition, overall efficiency of the power plant, installed primary- and secondary flue gas cleaning technologies along with the type of combustion device [12]. Primary measures refer to actions during combustion, e.g air staging or fuel staging for $NO_x$ reduction. Secondary flue gas cleaning refers to post-combustion treatments.

## 2.1 Combustion facilities

### 2.1.1 Boiler

The term boiler in this report refer to a steam generator water-tube boiler that uses chemical energy from a fuel to produce steam or hot water. The principle of a water-tube boiler is to heat up tubes located in the boiler where water flows inside. The tubes are heated up externally by the heat release from the fuel conversion. [27]

#### 2.1.1.1 Pulverized Coal-fired

In a pulverized coal (PC) fired boiler, PC is burned in the furnace. The concept of using PC, mixed with air and sometimes biomass, is to burn more easily and efficient since the fuel is pulverized into a fine powder. PC is blown into the firebox together with air. The temperature in the furnace of a PC fired boiler is around 1 400 – 1 650 °C. There are three kinds of firing systems, horizontally-, tangentially- and vertically firing systems. The horizontally fired system is characterized by individual flames. The fuel is mixed with combustion air in separate burners. The tangentially fired system has one single flames envelope. Fuel and combustion air is injected from the corners in the furnace, this will create lines that are tangents to a circle which is horizontal and in the center of the furnace. The vertically fired system was the first fired system introduced to a pulverized coal-fired boiler. The concept of the fire and the arrangement of the burners creates an arch or a *U-shaped* vertical flame. The arch firing system is often used for hard coal, with a moisture- and ash-free volatile matter content between 9 – 13 %. [29]

#### 2.1.1.2 Fluidized Bed

The concept of a fluidized bed boiler (FBB) is fluidization of the fuel. Jets of air will make the fuel behave as a free-flowing fluid when it is mixed with ashes and other particulate materials such as sand or limestone. Difficult fuels with high ash level, high moisture level, high sulfur level, low volatile level and low heating value can be burned in a FBB, which would not be suitable for other boilers. The temperature in the furnace of a FBB is around 800 – 900 °C. Temperatures at this level are below the ash-softening temperature of most fuels, that is why a FBB is suited for fuels with high ash content. [30]

Another advantage is the low emission of $NO_x$ due to the low furnace temperature range compared to other boilers. FBBs also has the possibility for $SO_2$ removal by adding eg limestone to the bed, see section 2.2.2 Sulfur Dioxide, for more details about sulfur removal in the boiler.

#### 2.1.1.3 Grate Firing

Grate firing is mainly used for burning waste and biomass. Sometimes coal is burned in smaller furnaces. The firing system called Stokers is located at the bottom of the furnace. Air enters from underneath and the fuel is located above on a grate. There are two general ways of how the stokers are feeding the fuel into the grate, traveling grate stoker and spreader stokers. [31]

In a traveling grate stoker, coal is feed at the end of the grate that horizontal moves along the furnace. The fuel is expected to be burned before it falls at the end of the grate. The following Figure 2.2 illustrates the principle of a traveling grate stoker. [31]

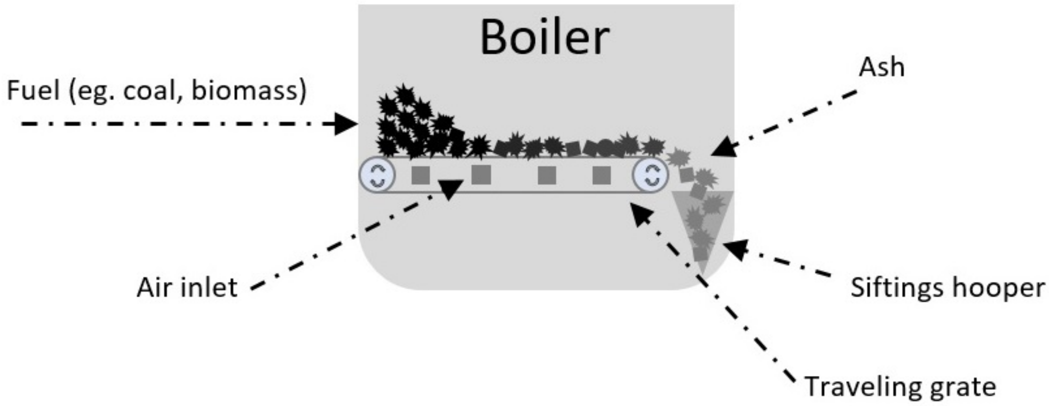


**Figure 2.2:** A traveling grate stoker.

The principle of a spreader stoker is suspension burning and thin-bed grate combustion. The fuel is spread out at a stationary grate. It feeds coal continuously above the grate. [31]

### 2.1.2 Gas turbine

Gas turbine (GT) in this report refer to an industrial GT for power generation. The main components of a GT are compressor, chamber and turbine, see Figure 2.3. The compressor compresses air which thereafter heats up in a chamber by combustion of a fuel such as natural gas. Then the mixture of air and fuel expands in a turbine which produces mechanical energy. The mechanical energy drives a generator that produces electricity. [32]

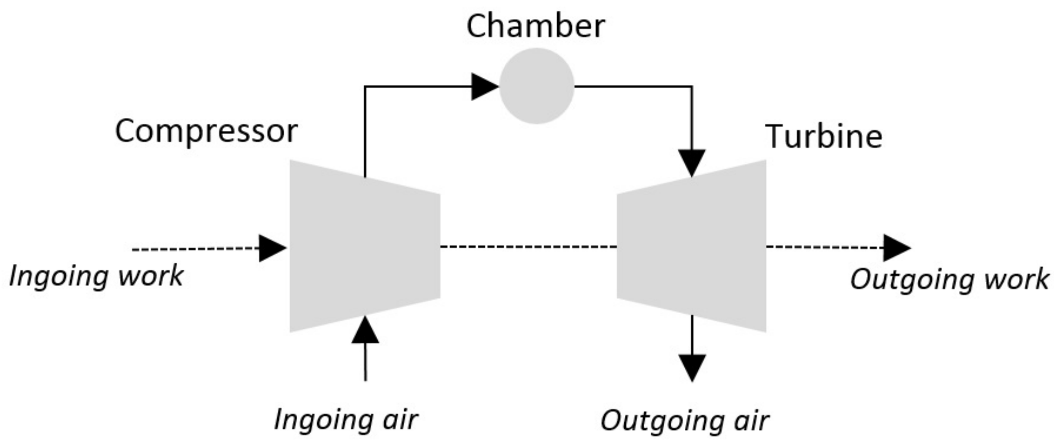


**Figure 2.3:** The principle of a gas turbine GT.

### 2.1.3 Engine

An internal combustion engine that runs on gaseous fuel such as diesel-, bio-, natural- or gasified coal. Engine in this report refers to a stationary type that is used for power generation, where an air fuel mixture is burned in cylinders. Due to the energy released by combustion, a piston puts a crank shaft in motion. When the crank shaft further turns an alternator, it generates electricity. Released heat from the cylinders in the combustion process is often recovered. [35] [34]

## 2.2 Pollutants

### 2.2.1 Particulate Matter

Particulate Matter (PM) is a mixture of small dust particles and liquid droplets, which have negative effects on lungs, liver and hearts when inhaling. *Coarse particles* ($PM_{10}$) has a diameter less than 10 $\mu$m and causes the worst problems. These particles can easily get deep into lungs and even into the bloodstream. Particles with diameter below 2.5 $\mu$m are known as *fine particles* ($PM_{2.5}$) and are also dangerous for humans. PM can be formed due to incomplete combustion, and in the case of solid fuels a large part of the PM will consist of ashes. Dust and soot are visible enough for human eyes to see. The visual particles in the stack can be measured as % opacity or in milligram per normal cubic meters (mg/Nm$^3$). 0 % opacity is clean stack and 100 % is thick smoke that can be seen through. Coal, biomass and other solid fuels contains mineral matter, bottom- and fly ash is a part of the fuel. The bottom ash is removed at the bottom of the furnace and the fly ash downstream in different flue gas cleaning equipment's, such as Electrostatic precipitator (ESP), cyclone, fabric filter (FF) and wet scrubber (WS) are used for separation of PM. The amount of fly ash is normally in the range of 80 – 90 % out of the total ash.

#### 2.2.1.1 Electrostatic Precipitator

The particles are separated from the flue gas by using electrostatic forces between electrodes and collector plates. Collection efficiency higher than 99.99 % can be reached. The particles become negatively charged by the corona created on the discharge electrodes and since the collector plates are positively charged, the particles are drawn to the collector plates. A corona discharge is an electrical discharge that takes place near the high voltage electrode. A typical pressure drop over the ESP is 150 – 250 Pa. [36]

The high voltage electrode discharge system is located between the collector plates. The electrode discharge system is powered from a High Frequency Transformer Rectifier (HFTR). HFTR is an electronic device that increases the voltage and also converts alternating current (AC) into direct current (DC). [37]

A dust layer on the collecting plates will eventually be created during the use of an ESP. There are two ways of removing the dust from the collecting plats, either by rapping system or with help of liquids. When using a rapping system, the ESP is categorized as a Dry Electrostatic Precipitator (DESP). When using liquid for dust cleaning on the collecting plates, the ESP is categorized as a Wet Electrostatic Precipitator (WESP). [36]

DESP is used for removal of particles in dry flue gas. It is the most used ESP. The rapping system consist of hammers located on different levels of the plates to make the dust falling down to the hopper area for collection. [36]

WESP uses water spray to saturate the wet flue gas before it enters the electrical field, and separate roof-spray nozzles to flush and clean the plates from the collected dust. WESP is used for wet flue gas, ie sticky and moist PM, which often occurs after the flue gas passes a wet scrubber.[38]

The fuel composition affects the collection efficiency. For physical properties, two main factors are dust resistivity and particle size. Low resistivity and large size particulates are beneficial for the efficiency of an ESP.

#### 2.2.1.2 Fabric Filter

Fabric Filters (FFs) are used in many applications for separation of dry dust particles. The flue gas passes through a large number of porous fabric filter bags that collects the dust. The number of filter bags varies due to factors such as size of boiler or amount of flue gas. The temperature and chemical composition of the flue gas as well as dust properties will determine what filter bag material to select. The flue gases pass through 100s or 1000s of filter bags. The restricted temperature for the most common fabric filters are 250 – 270 °C. The pressure drop over a FF is typically 1000 – 2000 Pa. [12]

#### 2.2.1.3 Cyclone

A cyclone is a cheaper and simpler flue gas cleaning technology compared to ESP and FF, based on centrifugal forces. To separate the dust from the flue gas, the flue gas enters the cyclone in a tangential inlet and due to swirling motion and Newton's law of motion the particles separates from the flue gas.

For large particles above 20 $\mu$m, the collection efficiency is over 99 %. For smaller particles below 20 $\mu$m, it is inefficient to use a cyclone. Approximately 40 % of dust particles below the size of 5 $\mu$m are removed when using a cyclone. A typical overall efficiency is in the range of 60 – 75 %. It is often used as a precollector upstream on FF to collect glowing coarse particles when biomass is fired in the boiler. [15]

#### 2.2.1.4 Wet Scrubber

In a Wet Scrubber (WS) the flue gas is in contact with a sprayed scrubbing liquid, and the coarse particle's are collected by the liquid and forced out of the flue gas due to chemical composition. For dust separation water is used in a WS. When it comes to removal of $SO_2$ and $NO_x$ other type of liquid and WS are used, see section 2.2.2 Sulfur Dioxide and 2.2.3 Nitrogen Oxide.

### 2.2.2 Sulfur Dioxide

$SO_2$ has significant impacts upon human health, nature and wildlife. It can causes negative effects on the eyes, lung and throat. When $SO_2$ gases dissolves in water droplets it leads to acid rain and thereby affects rivers, lakes and soils which results in damage to wildlife and vegetation [16]. Large amount of sulfur can be found in coal and oil and the level varies between fuels. For coal, there are three forms of sulfur [17][18]. The first is inorganic sulfur, where pyrite is the major inorganic sulfur in most coals. The second is organic sulfur, such as thiophenes and sulfides components. The third is calcium or iron sulfates.

The sulfur content of coal varies between 0.3 % to 4 % by mass, while in modern refined fuel oils its approximately less than 0.1 %. In crude oil it can be in the range of 0.5 % to 2.5 %. For natural gas the sulfur content is very low, some amount of hydrogen sulfides ($H_2S$) can occur in natural gas. The $SO_2$ concentration in the flue gas varies due to the amount of sulfur of the fuel. Practically all sulfur in the fuel is oxidized into sulfur dioxide during combustion, according to equation 2.1. Approximately 0.5 % to 1 % of the $SO_2$ is converted to $SO_3$, which is highly corrosive, especially when Selective Catalytic Reduction (SCR) are installed in power plants.

$$S + O_2 \rightarrow SO_2 \tag{2.1}$$

*In situ* is a primary measure for control of sulfur. By adding sorbents to a Fluidized Bed Boiler (FBB) chamber, the $SO_2$ emission can be controlled and decreased [18]. Calcium- and/or magnesium based sorbents are normally used in this case. Exampels of these are hydrated lime eg calcium hydroxide ($Ca(OH)_2$) or limestome eg calcium carbonate ($CaCO_3$). The principle of the *in situ* reactions with $Ca(OH)_2$ or $CaCO_3$ is shown in equation 2.2 and equation 2.3,

$$CaCO_3 + Heat \rightarrow CaO + CO_2 \tag{2.2}$$

$$Ca(OH)_2 + Heat \rightarrow CaO + H_2O \tag{2.3}$$

When $Ca(OH)_2$ or $CaCO_3$ has been dissociate into calcium oxide (CaO), the sulfur capture process can occur according to equation 2.4 or equation 2.5. As seen in equation 2.4 or equation 2.5, the product is calcium sulfate ($CaSO_4$), which easily can be converted into gypsum.

$$CaO + 0.5O_2 + SO_2 \rightarrow CaSO_4(s) \tag{2.4}$$

$$CaO + SO_3 \rightarrow CaSO_4\ (s) \tag{2.5}$$

A secondary cleaning method for sulfur is flue gas desulfurization (FGD).

#### 2.2.2.1 Flue Gas Desulfurization

FGD is similar to *in situ* sulfur cleaning, different types of sorbents are added in the process to reduce the $SO_2$ emissions. The difference compared to *in situ* is that sorbents are added after the combustion process, and thus not only applicable to FBBs. The major technologies at present are wet flue gas desulfurization (WFGD) and dry flue gas desulfurization (DFGD). The main different between WFGD and DFGD is the products state of matter after the desulfurization process. For WFGD the product is in a slurry liquid form and in DFGD the produced product is in dry waste solid state. [12]

WFGD uses water based sorbents sprayed in the scrubbers. The most commonly used sorbent is limestome or calcium carbonate. The following global reaction, and thereafter the produced gypsum through forced oxidation is shown below in equation 2.6 and equation 2.7.

$$CaCO_3\ (s) + SO_2\ (g) \rightarrow CaSO_3\ (s) + CO_2\ (g) \tag{2.6}$$

$$CaSO_3\ (s) + H_2O\ (l) + 0.5O_2 \rightarrow CaSO_4\ (s) + H_2O\ (l) \tag{2.7}$$

For DFGD, hydrate lime is often used as a sorbent, see equation 2.8. The investment- and operational costs are often lower for DFGD compared to WFGD.

$$Ca(OH)_2\ (s) + SO_2\ (g) \rightarrow CaSO_3\ (s) + H_2O\ (l) \tag{2.8}$$

### 2.2.3 Nitrogen Oxide

High concentration of $NO_x$ cause negative health effect to the blood, liver, lung and spleen. The expression $NO_x$ is a term for nitric oxide (NO) and nitrogen dioxide ($NO_2$). A chemical reaction between oxygen O, $NO_2$ and VOC due to sunlight can form ground-level ozone ($O_3$). $O_3$ is dangerous for human health, crops and other plant life. $NO_x$ causes smog and acid rain. Another problem that $NO_x$ causes is eutrophication. [16]

$NO_x$ is produced at high combustion temperatures. The largest global contributor of $NO_x$ comes from motor vehicles. The second largest contributor of $NO_x$ emission comes from thermal-, power- and other related industrial processes. [19]. The primarily form of $NO_x$ emission during combustion is NO [20].

In primary $NO_x$ reduction, air staging, fuel staging, change of fuel, flue gas recirculation and use of low excess air ratio are commonly used measures to reduce $NO_x$. Technologies for secondary $NO_x$ reduction and control are Selective Catalytic Reduction (SCR) and Selective Non Catalytic Reduction (SNCR).

#### 2.2.3.1 Selective Non Catalytic Reduction

SNCR has an operating temperature between 800 °C and 1100 °C at the end of the combustion boiler. SNCR does not have any catalyst. The amount of NO are reduced by an agent to nitrogen gas $N_2$. Around 30 – 70 % of the $NO_x$ are removed from the flue gas [10]. Either $NH_3$ or urea ($CO(NH_2)_2$) is used in the

SNCR process according to the following chemical reactions in equation 2.9 or equation 2.10.

$$4NO + 4NH_3 + O_2 \rightarrow 4N_2 + 6H_2O \tag{2.9}$$

$$2NO + CO(NH_2)_2 + 0.5O_2 \rightarrow 2N_2 + 2H_2O + CO_2 \tag{2.10}$$

#### 2.2.3.2 Selective Catalytic Reduction

$NH_3$ or $CO(NH_2)_2$ is used together with a catalyst to reduce the amount of NO. The catalyst enables the reduction to proceed at lower temperatures (250 – 450 °C). $NH_3$ reacts with $NO_x$ and $O_2$ along with a catalyst to produce nitrogen and water, according to equation 2.9 and equation 2.11 illustrates the process. The SCR process occurs after combustion. The $NO_x$ removal efficiency is approximately 80 – 90 %. [10]

$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O \tag{2.11}$$

## 2.3 The Medium Combustion Plants Directive

The input thermal range of a medium combustion plant is 1 $MW_{th}$ to 50 $MW_{th}$. The pollutants that the Medium Combustion Plant Directive (MCPD) concerns are $SO_2$, $NO_x$ and PM from conventional combustion plants and gas turbines as well as gas engines. The MCPD fills the gap between the *Large Combustion Plant Directive (LCPD)* and the *Ecodesign Directive (ED)*, see Figure 2.4.


**Figure 2.4:** Overview over Ecodesign Directive (ED), Medium Combustion Plant Directive (MCPD) and Large Combustion Plant Directive (LCPD) on the input thermal range in $MW_{th}$.

LCPD covers large combustion plants, which are combustion plants with input thermal capacity above 50 $MW_{th}$. LCPD is part of the *Industrial Emission Derivative (IED)*, which permits and controls installations, based on the *Best Available Techniques (BAT)*. BAT are the most effective techniques taking environmental protection, economic- and technical aspects into account. ED covers smaller appliances such as heaters and boilers below 1 $MW_{th}$. [5]

Regarding new medium combustion plants, the MCPD will be applied from December 20, 2018. For existing medium combustion plants within the thermal input range of 1 $MW_{th}$ to 5 $MW_{th}$ the MCPD will be implemented from January 1, 2030, while input range above 5 $MW_{th}$ will be implemented from January 1, 2025 [4].

The emission level numbers presented in Table 2.1 summarize the limits for new- and existing (presented as Exist.) medium combustion plants. Emission limits for new- and existing gas turbine as well as engines are presented in Table 2.2. The same unit is used as in the briefing of MCPD from the European Parliament and the council of the EU, i.e milligram per normal cubic meters (mg/Nm$^3$) dry gas. The values presented in Table 2.1 and Table 2.2 are defined at a temperature of 273.15 K and at a pressure of 101.3 kPa. For plants using solid fuels, correction has been done for the water vapor content of the waste gases, and to a standardized $O_2$ content of 6 %. For MCPs burning liquid and gaseous fuels, the standardized $O_2$ content is 3 % and for engines and gas turbines it is 15 %. [7]

**Table 2.1:** Emission limit levels for existing- and new combustion plants, in mg/Nm$^3$ dry gas.

| | | **Biomass** | | **Coal** | | **Oil** | | **Gas** | |
|---|---|---|---|---|---|---|---|---|---|
| | | Exist. | New | Exist. | New | Exist. | New. | Exist. | New |
| **PM** | 1 - 5 $MW_{th}$ | 50 | 50 | 50 | 50 | 50 | 50 | - | - |
| | 5 - 20 $MW_{th}$ | 50 | 30 | 50 | 30 | 30 | 20 | - | - |
| | 20 - 50 $MW_{th}$ | 30 | 20 | 30 | 20 | 30 | 20 | - | - |
| **$NO_x$** | 1 - 5 $MW_{th}$ | 650 | 500 | 650 | 500 | 650 | 300 | 250 | 100 |
| | 5 - 20 $MW_{th}$ | 650 | 300 | 650 | 300 | 650 | 300 | 200 | 100 |
| | 20 - 50 $MW_{th}$ | 650 | 300 | 650 | 300 | 650 | 300 | 200 | 100 |
| **$SO_2$** | 1 - 5 $MW_{th}$ | 200 | 200 | 1100 | 400 | 350 | 350 | - | - |
| | 5 - 20 $MW_{th}$ | 200 | 200 | 1100 | 400 | 350 | 350 | - | - |
| | 20 - 50 $MW_{th}$ | 200 | 200 | 400 | 400 | 350 | 350 | - | - |

**Table 2.2:** Emission limit levels for existing- and new gas turbines and engines, in mg/Nm$^3$ dry gas.

| | **Existing** | | **New** | |
|---|---|---|---|---|
| **Gas turbine** | Oil | Gas | Oil | Gas |
| PM | 10 | - | 10 | - |
| $NO_x$ | 200 | 150 | 75 | 50 |
| $SO_2$ | 120 | - | 120 | |

| | **Existing** | | **New** | |
|---|---|---|---|---|
| **Engines** | Oil | Gas | Oil | Gas |
| PM | 10 | - | 10 | - |
| $NO_x$ | 190 | 190 | 190 | 95 |
| $SO_2$ | 120 | - | 120 | |

# 3
# Methodology

This chapter describes the methodology of the thesis. Figure 3.1 illustrates the main steps of the analysis made. The thesis is based on data stored in two databases which will be described in the next section. The thesis is divided into six steps: Extraction, Categorization, Validation, Selection, Application and Economic.

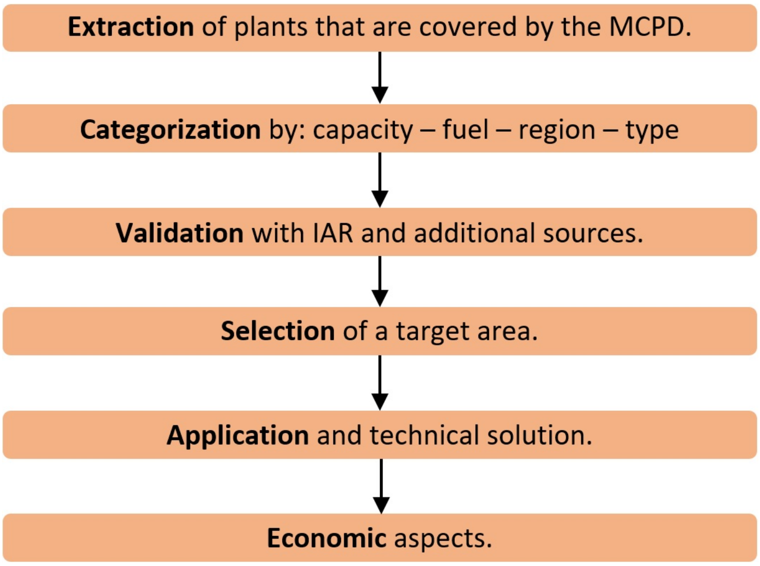


**Figure 3.1:** Methodology and steps of the thesis.

The plants that are affected by the MCPD are extracted from the databases. These plants are categorized with respect to capacity, fuel, region and type. The outcome based on the two sources are compared with other available sources. Based on this, areas that are largely affected by the MCPD is identified. With respect to these areas and previous steps, assumptions are made on the emission levels from the industries are estimated for several fuels. These assumptions are further used in the application. Technical solutions are proposed. Finally economic aspects are considered.

## 3.1 Databases

Two databases are used as input data in this thesis, called the *General Electric Database (GED)* and the *Chalmers Power Plant Database (CPPD)*. Both CPPD and GED are the basis of screening, evaluation and selection process steps. CPPD covers power production units in EU28, including wind and solar power production [6]. Small plants with a fuel input below approximately 3 $MW_{th}$ are challenging to cover and it is this expected that there is a large amount of these plants that are not included in the database. In this thesis, a subset of combustion plants with an electricity production below 20 $MW_{th}$ (implying medium combustion plants, assuming a thermal efficiency of 0.4) using biomass, coal and peat within co-generation, utility and power is used. This subset is thus relatively small compared to the original database. Information such as country, plant name, owner, plant status, fuel, turbine type and thermal capacity is included in the database. The number of data points for each plant in CPPD is 25. CPPD is used at Chalmers for several research and development projects.

GED is a database that covers data on plants world-wide associated with GE along with original equipment manufacturers. Industries such as pulp and paper, waste incineration, textile, iron and steel, bio gas, coking plant among with many others are included. Data on location, capacity, status, boiler type, fuel, industry process, ownership etc is included in GED for more or less within all industries world-wide. The number of data points for each plant in GED is 401, although not all data is available for all plants. When it comes to flue gas cleaning equipment only information on whether there is a flue gas cleaning equipment installed or not. There is no specific technical data on the flue gas cleaning equipment.

Table 3.1 shows the top ten countries and its respective total number of combustion plants according to the GED and the CCPD subset. The total number of combustion plants burning coal, biomass and peat that the subset of CPPD covers is 614 plants in 27 countries in Europe. Of this number, around 30 % are of unknown thermal capacity. The total number of plants using coal, biomass, black liquor, gas, peat, waste, other renewable and unknown fuels in GED is 3 573 located in 26 countries in Europe.

## 3.2 Extraction and categorization

Combustion plants that are covered by the MCPD are extracted from the GE and Chalmers databases. The citations in Appendix A are taken from the official MCPD Legislation's document published by The European Union Law [39], and clarifies the affected combustion plants in the databases. In short, all combustion processes between 1-50 $MW_{th}$ used for heat and power production are extracted. Exceptions are e.g. combustion units in vehicles, on off-shore platforms, on farms, in chemical industries, waste incineration along with pulp and paper.

The extracted combustion plants that are covered by the MCPD are categorized and divided into thermal capacity, fuel, boiler type, country and further into re-

**Table 3.1:** The top ten countries and its respective total number of combustion plants according to GE and Chalmers databases.

| GED | | | CPPD | | |
|---|---|---|---|---|---|
| 1) | Germany | 645 | 1) | Germany | 120 |
| 2) | Italy | 442 | 2) | Poland | 120 |
| 3) | Poland | 381 | 3) | Sweden | 87 |
| 4) | UK | 279 | 4) | UK | 51 |
| 5) | Spain | 257 | 5) | France | 40 |
| 6) | Czech Republic | 240 | 6) | Italy | 36 |
| 7) | France | 196 | 7) | Spain | 28 |
| 8) | Netherlands | 145 | 8) | Austria | 25 |
| 9) | Sweden | 141 | 9) | Finland | 25 |
| 10) | Finland | 138 | 10) | Denmark | 11 |

gions. In this way, an overview and understanding over patterns and concerned combustion plants in the EU is accomplished.

The following Table 3.2 shows the regions and selected countries. The initial step is grouping the plants with thermal capacity ranges of 1 – 5, 5 – 20 and 20 – 50 $MW_{th}$ for both databases. Each countries that the databases covers are thereafter divided into four regions. The countries are grouped into regions by location according to recommendation from GE. The final step is dividing plants for each region according to its fuel and boiler type.

**Table 3.2:** Defined regions with selected countries.

| | | | |
|---|---|---|---|
| **Central** | Austria | Germany | Greece |
| | Italy | Malta | |
| **Eastern** | Bulgaria | Cyprus | Czech Republic |
| | Hungary | Poland | Romania |
| | Slovakia | | |
| **Northern** | Denmark | Estonia | Finland |
| | Latvia | Lithuania | Sweden |
| **Western** | Belgium | France | Ireland |
| | Luxembourg | Netherlands | Portugal |
| | Spain | United Kingdom | |

## 3.3 Validation

This step of the methodology is divided into two parts, *validation with IAR* and *additional sources.*

*Validation with IAR* refer to a report publish by the EU, called Impact Assessment Report (IAR). IAR contains results from previous work assessing impacts of the *Clean Air Policy Package*, and as mention before in *1 Introduction*, the MCPD is based on a Commission proposal, that was a part of the *Clean Air Policy Package*. Relevant results from IAR are considered as validation in the thesis. The EU has gathered data in regard to medium combustion plants from all countries as a part of the *Clean Air Policy Package*.

*Additional sources* refer to consultation and discussion with employees at GE. Involved GE employees have years or decades of experience in business, marketing, sales and/or engineering within industrial applications, thermal power plants and flue gas technologies. The number of participating GE employees in this validation step is 15 people located in Sweden, Finland, Germany, Austria, United Kingdom, Spain, Italy, Slovakia, Czech Republic, France and the United States. The topics of discussions are listed below:

- The distribution and extension of various plant types in the EU.
- Common flue gas cleaning technologies around the EU.
- Local regulations and legislation's on emissions.

## 3.4 Selection

The selection of the target group is based on factors listed below, see Table 3.3. Table 3.3 also indicates colors. Each region in alphabetical order, will be graded by colors (red, yellow and green) for respective factor. These factors are considered for each region when deciding which region that will be most affected by the MCPD. Red indicates that a region is significantly affected by the MCPD regarding the currently investigated aspect, and green indicates a region that is not significantly affected. Yellow is used when a region is moderately affected. The color grading in Table 3.3 is just an example.

After this step, further consultation with GE is done to determine which emissions and thermal capacity sizes that will be studied in this thesis. For the first and third factor, *number of combustion plants* and *estimated emitted emissions*, the following criteria will decide the grading. For percentages above 30 %, the red color is chosen. For percentage between 20 – 30 %, yellow is chosen and below 20 % green is chosen. For the second factor, *type of primary fuel usage*, it will be graded by fuel types. Highest number of coal plants is considered as significantly affected by the MCPD while gaseous- and liquid fuel are considered only slightly affected by the MCPD. For the fourth and fifth factor, *installed flue gas cleaning equipment* and *local regulations and legislation's* are graded based from interviews from GE.

**Table 3.3:** Influenced factors along with an example of the color grading.

| | **Central** | **Eastern** | **Northern** | **Western** |
|---|---|---|---|---|
| Number of combustion plants | | | | |
| Type of primary fuel usage | | | | |
| Estimated emitted emissions | | | | |
| Installed flue gas cleaning equipment | | | | |
| Local regulations and legislation's | | | | |

## 3.5 Application

After selection of regions that are most affected by the MCPD, emission levels for different fuels are estimated, see Table 3.4. Table 3.4 presents assumed emission levels (presented as Unabated) for bituminous coal, lignite, peat, biomass, oil and gas relative to the MCPD limits (presented as Limits) for existing combustion plants with thermal range of 20 – 50 $MW_{th}$. The assumptions are calculated mean values based on internal databases, projects and estimations from GE [8]. Table 3.4 also shows minimum and maximum levels of emissions based on the internal databases, projects and estimations from GE. It should be noted that emission levels for PM, $SO_2$ and $NO_x$ can vary significantly. Several factors such as chemical composition, boiler efficiency and type, type of biomass or coal mine location the coal has been extracted from, can affect the emission levels drastically.

**Table 3.4:** Assumed emission levels (presented as Unabated) and MCPD limits (presented as Limits), in mg/Nm$^3$ at 6 % $O_2$ dry gas.

| | | **Unabated** | **Min.** | **Max.** | **Limits** |
|---|---|---|---|---|---|
| Bituminous | PM | 22 000 | 15 000 | 35 600 | 30 |
| | $SO_2$ | 3 400 | 1 700 | 4 200 | 400 |
| | $NO_x$ | 550 | - | - | 650 |
| Lignite | PM | 40 500 | 22 000 | 95 600 | 30 |
| | $SO_2$ | 2 000 | 600 | 4 800 | 400 |
| | $NO_x$ | 500 | - | - | 650 |
| Peat | PM | 8 900 | 4 000 | 9 600 | 30 |
| | $SO_2$ | 500 | 10 | 500 | 400 |
| | $NO_x$ | 300 | - | - | 650 |
| Biomass | PM | 3 390 | 190 | 18 000 | 30 |
| | $SO_2$ | 250 | 10 | 250 | 200 |
| | $NO_x$ | 200 | - | - | 650 |
| Oil | PM | - | - | - | 20 |
| | $SO_2$ | - | - | - | 350 |
| | $NO_x$ | 135 | - | - | 650 |
| Gas | PM | - | - | - | - |
| | $SO_2$ | - | - | - | - |
| | $NO_x$ | 135 | - | - | 200 |

From this table it can be calculated that flue gas cleaning equipment with a PM removal efficiency above 99 % is required for all fuels. Efficient $SO_2$ reduction is also needed for bituminous coals and lignite. Assumed emission levels for oil and gas is only $NO_x$. According to GE, it is unusual that flue gas cleaning equipment's are installed for PM and $SO_2$ removal regarding combustion plants burning oil and gas.

The proposed technical solutions by GE are five options, see Table 3.5. Table 3.5 also presents estimated collection efficiency for PM and $SO_2$. Novel Integrated Desulfurization (NID) and Dry Sorbent Injection (DSI) with an included Fabric Filter (FF) are existing technologies in GE's current product catalog. Another proposal is a DSI but in combination with an installed Electrostatic Precipitator (ESP). DSI + ESP is not included in GE's current product catalog, it has been proposed for eventual development by GE. A further technical solution is at present under development by GE, and that is a lighter, more compact and flexible version of the NID, called Novel Integrated Desulfurization Light (NIDL). The last proposal is a different version of the current Wet Electrostatic Precipitator (WESP). Instead of flat collecting plates, this version has vertical tubular shaped collecting tubes.

**Table 3.5:** Proposed technical solutions along with estimated collection efficiency for PM and $SO_2$.

| Proposed technical solutions | PM | $SO_2$ |
|---|---|---|
| Novel Integrated Desulfurization (NID) | 99.95 % | 98% |
| Novel Integrated Desulfurization Light (NIDL) | 99.95 % | 90% |
| Dry Sorbent Injection (DSI) + Fabric Filter (FF) | 99.95 % | 75% |
| Dry Sorbent Injection (DSI) + Electrostatic Precipitator (ESP) | 99.95 % | 60% |
| Tubular Wet Eletrostatic Precipitator (TWESP) | 99.95 % | - |

The proposed suggestions by GE are selected because of its adjustment and suitability for small- or medium sized combustion plants. DAS is a cheap and cost effective solution for small- or medium sized combustion plants, along with its flexibility and simplicity when retrofitting. The NID solution was years ago patented and developed for smaller- or medium sized combustion plants by the GE [43] [44] [45].

### 3.5.1 Novel Integrated Desulfurization

The Novel Integrated Desulfurization (NID) is a Dry Flue Gas Desulfurization (DFGD) system, with an integrated hydrator and mixer unit, combined with a Fabric Filter (FF). The purpose of the integrated hydrator-/mixer unit is to reuse the chemical reagent, by recirculate the reagent along with fly ash mixed with water. The reason of recirculate fly ash with water is to cool the flue gas to the optimum temperature to maximize the reaction between the reagent and the flue gas.

Calcium Oxide (CaO), or burnt lime, is commonly used as reagent in this process. Since the NID is combined with a FF, dust particles along with $SO_2$ can also be reduced in the flue gas. Other gaseous pollutants like sulfur trioxide ($SO_3$), hydrochloric acid (HCL) and hydrogen fluoride (HF) can also be reduced when reacting with the reagent. If adding powdered active carbon (PAC) upstream, mercury (Hg) can be removed.

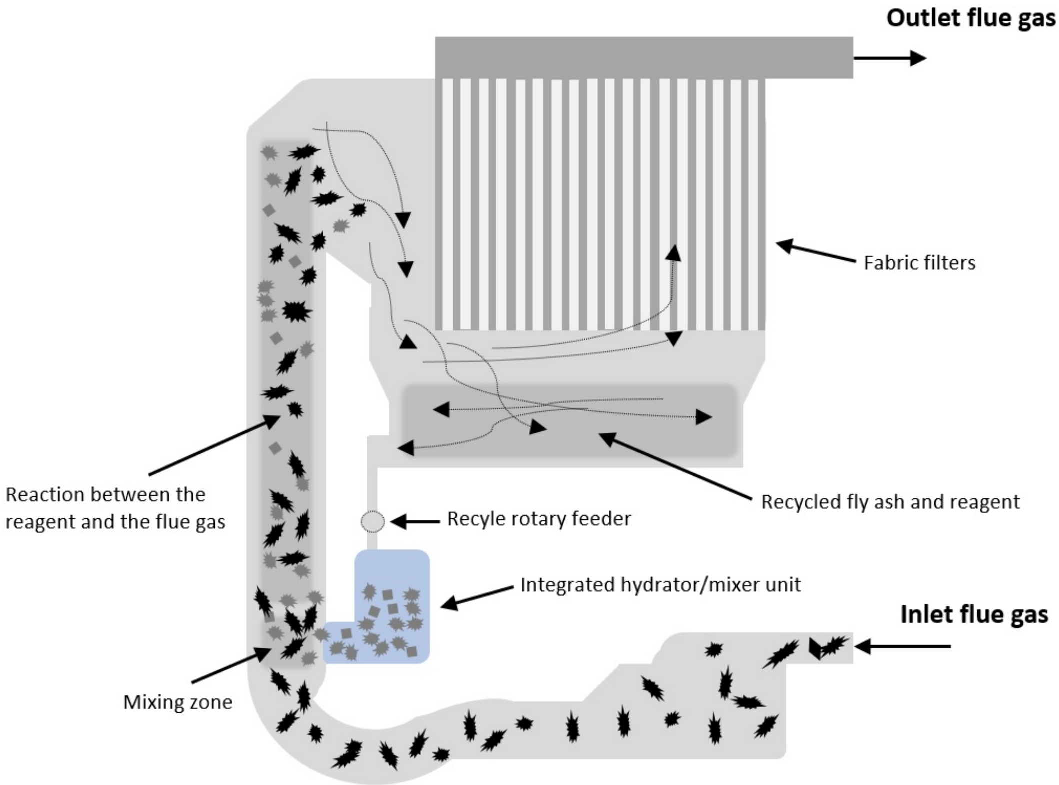


**Figure 3.2:** Principle of a Novel Integrated Desulfurization (NID).

Figure 3.2 shows the principle of the NID. The NID is currently a part of GE's product catalog. The achievable removal efficiency for $SO_2$ can be up to 98 % assuming a maximum inlet concentration of 10 000 mg/Nm$^3$. The particulate emission guarantee by GE is 10 mg/Nm$^3$, and the removal efficiency can be up to 99.9 %. However, at the moment GE is developing a new version, Novel Integrated Desulfurization Light (NIDL). NIDL is a smaller, compacter and more flexible version of the current NID. The estimated removal efficiencies for NIDL are up to 90 % for $SO_2$ and 99.95 % for PM.

The advantages of the NID and NIDL are the flexibility, since its modular and standard design. Another advantages is the high removal efficiency of $SO_2$ compared to DAS. In situations where high sulfur fuels or high levels of $SO_2$ emissions are needed to be removed, the NID and NIDL are reliable compared to a DAS. Also the operational costs are low compared to DAS, because of its simple operation and maintenance requirements. Because of the recirculation of sorbents, less consumption of sorbents are needed in the NID compared to DAS. Exactly how much less sorbents are needed for NID and NIDL compared to DAS with ESP or FF depends on several factors, see Table 3.8 for estimated and assumed sorbents cost values.

The disadvantage compared to DAS is the investment cost. Both NID and NIDL have higher investment cost compared to DAS. The investment cost for NID is higher than the NIDL, see Table 3.7 for estimated and assumed investment costs.

### 3.5.2 Dry Absorption System

A Dry Absorption System (DAS) is a system of injecting dry sorbents such as Calcium Hydroxide ($Ca(OH)_2$) or also known as hydrated lime into the flue gas before it enters the Fabric Filter (FF) or the Electrostatic Precipitator (ESP). This process is also known as Dry Sorbent Injection (DSI). Hydrated lime can be divided into High Quality Hydrated Lime (HQHL) and Standard Hydrated Lime (SHL). The amount of calcium is similar in standard hydrated lime and high quality hydrated lime. High quality hydrated lime has higher specific porous volume, which gives higher mass transfer between the hydrated lime and the $SO_2$. It improves the kinetic reactions and therefore better $SO_2$ removal is accomplished compared to standard lime of the same mass. Another sorbent like Sodium Bicarbonate (SBC) can also be used.

The following Table 3.6 shows the recommended sorbents for each fuel divided into DSI combination. For higher $SO_2$ removal efficiency such as for bituminous coal and lignite, SBC is used when combining a DSI with an ESP. SBC is more effective for $SO_2$ reaction and removal, but more expensive. For lower required $SO_2$ removal efficiency like peat and biomass, lime could be used. Lime has a negative impact on the ESP performance, as it will increase the ash resistivity. SBC does not increase the ash resistivity. If higher collection efficiency is required for peat and biomass, then SBC should be used.

**Table 3.6:** Recommended sorbents for each fuel divided into the two DSI configurations.

| | **DSI + ESP** | **DSI + FF** |
|---|---|---|
| **Bituminous coal** | SBC | HQHL |
| **Lignite** | SBC | HQHL |
| **Peat** | HQHL | SHL |
| **Biomass** | HQHL | SHL |

When it comes to combining a DSI with a FF, lime is preferred over SBC. SBC is more expensive compared to lime. Neither lime or SBC affects the performance of the FF as for the ESP. High Quality Hydrated Lime (HQHL) is recommended for bituminous coal and lignite due to higher removal requirements compared to peat and biomass.

DSI offers many advantages compared to wet or semi-wet Flue Gas Desulfurization, some of these are the simplicity of retrofit at the plant with current installed AQCS, dry waste as a by product and the relatively low capital investment costs. The disadvantages are the high operational cost due to the consumption of sorbents along with operational- and maintenance costs.

The injection of the sorbents can occur anywhere in flue gas path before it enters the particulate control equipment. Typical locations are the upper furnace and the up- or downstream of the air pre-heater etc. It can be combined with both an Electrostatic Precipitator (ESP) or a Fabric Filter (FF). At the moment, GE's current product catalog offers DSI upstream with a FF. When it comes to combining the DSI with an ESP, it is at present purposed to be develop by the GE.

The estimated $SO_2$ and PM removal efficiency when combining DSI with an ESP is up to 60 % for $SO_2$ and 99.95 % for PM. The sorbent used for $SO_2$ removal is SBC for bituminous coal and lignite, and with high quality hydrated lime for peat and biomass. Since the $SO_2$ emission inputs are higher for coal than biomass and peat, SBC is more appropriate.

When combining the DSI with a FF, the estimated removal efficiency is 75 % for $SO_2$ and 99.95 % for PM, assuming using high quality hydrated lime for bituminous coal and lignite along with standard hydrated lime for biomass and peat.

### 3.5.3 Tubular Wet Electrostatic Precipitator

Tubular Wet Electrostatic Precipitator (TWESP) is similar to the Wet Electrostatic Precipitator (WESP), the difference is the design of the collecting areas, and thereby the difference on how the flue gas passes the ESP. The collecting areas are vertical tubes located in parallel. The flue gas enters the TWESP either top or bottom. The high voltage electrode discharge system is located in the centre through the axis of each tubes. The particles become negatively charged by the corona created on the discharge electrodes and since the collector tubes are positively charged, the particles are drawn to the collector plates, see *2.2.1.1 Electrostatic Precipitator*.

The shape of the collecting tubes can either be circular-, square- or hexagonal honeycomb depending on design. When using square or hexagonal tubes, these can be packed closer together compared to cylindrical tubes, and thereby less space is required. However, cylindrical tubes gives better corona charge, since the length from the electrode discharge system to the collecting area are in every direction the same, compared to square or hexagonal tube, see Figure 3.3. As can be seen, the red *long-dash-dot* lines for both squared and hexagonal are longer than their respective blue *dashed* lines.

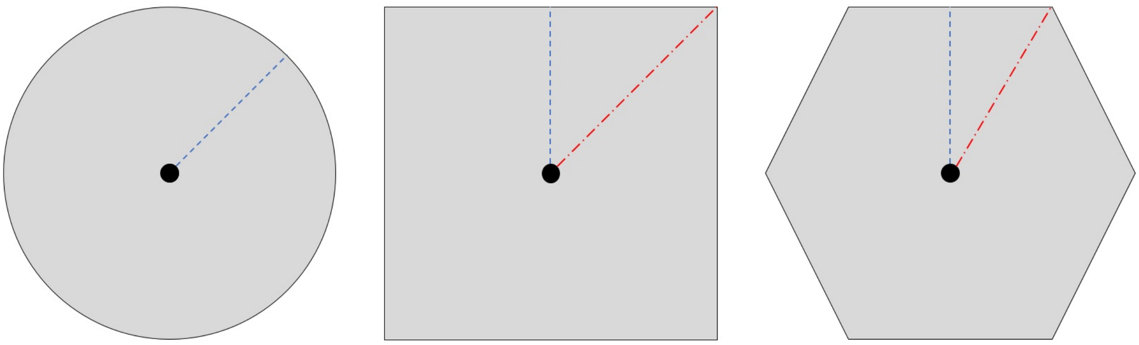

**Figure 3.3:** Cylindrical-, squared- and hexagonal shape.

For many years, TWESP has been used for PM removal and can remove up to 99.9 %. However, when it comes to the history of removing $SO_2$ with the use of a

TWESP, not much is known. Often in cases where a TWEST is used, a separate $SO_2$ removal unit is installed.

## 3.6 Economic aspects

Economic aspects such as investment- and running costs are considered. Estimations made by GE to clarify the difference in consumption of sorbents, investment- and running costs for the proposed options is done. The following scenarios assumes combustion plants with thermal capacity of 36 $MW_{th}$ for each fuel. Out of the total amount of combustion plants with thermal range of 20 – 50 $MW_{th}$, combustion plants with capacity of 36 $MW_{th}$ was the most common one.

The investment costs differ depending on wherever the DSI will be combined with an existing installed ESP, or with a new installed FF. The usual way is either installing a DSI upstream at existing ESP, or installing both a new DSI and a new FF. See Table 3.7 for estimated investment costs in million Euro (m€). When installing a DSI upstream at existing ESP, it is highly common to upgrade the ESP. Depending on which upgrade, the assumed investment cost differs a lot. The assumption in this thesis is set to 1.1 million Euro (m€).

**Table 3.7:** Estimated investment costs assuming thermal capacity of 36 $MW_{th}$.

| **Options** | **million Euro (m€)** |
|---|---|
| NID | 2.3 |
| NID L. | 1.8 |
| DSI+FF | 1.3 |
| DSI+ESP | 1.1 |
| TWESP | - |

The running costs also differs due to different factors, such as maintenance, sorbents consumption, pressure drops etc. Because its difficult to define detailed running costs numbers for each technology due to many factors, only the cost of sorbents is considered. The annual consumption costs (k€/year) in the following Table 3.8 are rough estimates by GE. As can be seen, TWESP is not presented in Table 3.7 – 3.8 as these numbers are unknown.

**Table 3.8:** Estimated annual cost of sorbents, in thousand euro per year (k€/year).

| | **DSI + ESP** | **DSI + FF** | **NID L.** | **NID** | **TWESP** |
|---|---|---|---|---|---|
| **Bituminous coal** | 2 800 | 988 | 247 | 247 | - |
| **Lignite** | 1 120 | 488 | 122 | 122 | - |
| **Peat** | 70 | 20 | 4 | 8 | - |
| **Biomass** | 77 | 23 | 4 | 10 | - |

The following equation 3.1 has been used for roughly determine the total cost (TC) per options divided into fuel. IC refer to investment cost, RC refer to annual running cost due to consumption of sorbents and X refer to years. By plotting each technology per fuel, as a function of TC with respect to years, it can be determined when the proposed technical solutions are economical suitable.

$$TC = IC + RC \times X \tag{3.1}$$

# 4 Result and discussion

Table 4.1 shows the number of combustion plants in General Electric Database (GED) and Chalmers Power Plant Database (CPPD) divided into thermal capacity 0 – 1, 1 – 50 and above 50 $MW_{th}$ for all industries. From Table 4.1, combustion plants within thermal range of 1 – 50 $MW_{th}$ are extracted and then divided by type of fuel, see Table 4.2.

**Table 4.1:** The number of combustion plants for General Electric Database (GED) and Chalmers Power Plant Database (CPPD).

| | GED | CPPD |
|---|---|---|
| **0 - 1 $MW_{th}$** | 7 | 408 |
| **1 - 50 $MW_{th}$** | 1256 | 128 |
| **Above 50 $MW_{th}$** | 2310 | 78 |

**Table 4.2:** The total number of plants (1 – 50 $MW_{th}$) and its share of different fuels.

| **GED** | | **CPPD** | |
|---|---|---|---|
| **Fuel** | **Number of plants** | **Fuel** | **Number of plants** |
| Gas | 437 | Biomass | 111 |
| Coal | 232 | Coal | 14 |
| Waste | 215 | Peat | 3 |
| Biomass | 162 | Oil | 0 |
| Unknown | 106 | Gas | 0 |
| Oil | 89 | Waste | 0 |
| Peat | 15 | Unknown | - |
| **Sum** | **1256** | **Sum** | **128** |

Waste combustion is not included in the MCPD and is therefore not considered further in this study. Unknown fuels are also excluded. Industries such as in pulp and paper, offshore platforms, chemical industries are also excluded, since these are not covered by the MCPD, see Article 2.2 and Article 2.3 in Appendix A for more information. The total number of remaining plants affected by the MCPD are 266 plants for General Electric Database and 128 plants for Chalmers Power Plant Database.

## 4.1 Categorization

Table 4.3 shows the number of combustion plants covered by the MCPD in the used datasets divided into 1 – 5, 5 – 20 and 20 – 50 $MW_{th}$. As can be seen, combustion plants within thermal capacity range of 5 – 20 $MW_{th}$ and 20 – 50 are most common according to GED and CPPD.

**Table 4.3:** Combustion plants covered by the MCPD divided into 1 – 5, 5 – 20 and 20 – 50 $MW_{th}$.

| | GED | CPPD |
|---|---|---|
| **1 - 5 $MW_{th}$** | 21 | 1 |
| **5 - 20 $MW_{th}$** | 127 | 25 |
| **20 – 50 $MW_{th}$** | 118 | 102 |
| **SUM** | **266** | **128** |

Figure 4.1 presents the share of combustion plants for thermal range of 1 – 50 $MW_{th}$ divided into regions. As can be seen, central Europe have the highest share of combustion plants for GED and CPPD. The datasets also agree on that northern Europe have slightly more medium combustion plants than western Europe. A large difference is however the amount of plants in eastern Europe. According to GED, the amount of medium combustion plants are almost the same in eastern Europe as in central Europe, while based on CPPD, eastern Europe is less than a fourth of central Europe. The reason for this discrepancy is not entirely clear. It is however apparent that neither dataset used is fully representative of the distribution of medium combustion plants in Europe, since GED is only based on plants that GE has been in touch with and the CPPD-subset is clearly lacking a lot of plants.

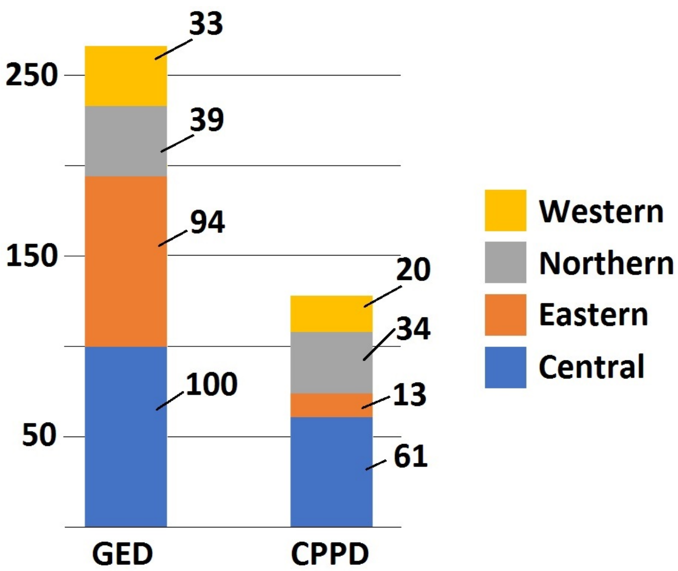


**Figure 4.1:** Number of affected combustion plants for each region divided into GED and CPPD.

Figure 4.2 shows the same combustion plants as in Figure 4.1, but when adding both numbers of GED and CPPD. However, it should be mentioned that there is a risk that some of the plants are duplicate. The overall order for number of combustion plants is central Europe with highest number of combustion plants, followed by eastern-, northern- and western Europe.

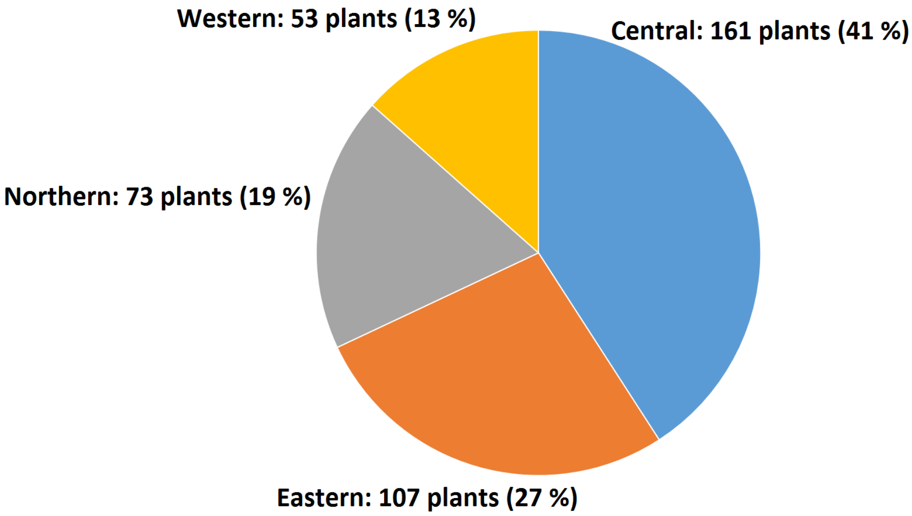


**Figure 4.2:** Number of affected combustion plants for each region.

The following Table 4.4 shows the number of combustion plants per region divided into fuels for General Electric Database (GED) and Chalmers Power Plant Database (CPPD). See Appendix B for the complete list of combustion plants per country divided into fuels for GED and CPPD.

**Table 4.4:** The number of combustion plants per region divided into fuels for General Electric Database (GED) and Chalmers Power Plant Database (CPPD).

| | GED | | | | | CPPD | | | ALL |
|---|---|---|---|---|---|---|---|---|---|
| | Biomass | Coal | Gas | Oil | Peat | Biomass | Coal | Peat | |
| **Central** | 46 | 10 | 37 | 7 | 0 | 60 | 1 | 0 | **161** |
| **Eastern** | 1 | 70 | 16 | 7 | 0 | 0 | 13 | 0 | **107** |
| **Northern** | 26 | 1 | 5 | 1 | 6 | 31 | 0 | 3 | **73** |
| **Western** | 10 | 0 | 22 | 0 | 1 | 20 | 0 | 0 | **53** |
| **ALL** | **83** | **81** | **80** | **15** | **7** | **111** | **14** | **3** | **394** |

As can be seen in Table 4.4, the distribution of coal is most common in eastern Europe. For central and northern Europe, biomass is the most used fuel. Gas is most common in central followed by western Europe. Oil and peat is less used compared to the other fuels.

A similar grouping for boiler types and different fuels for each countries is also performed, see Table 4.5. Grate refers to grate fired boilers, FB refers to Fluidised Bed and Pulv. refers to Pulverized. See Appendix C for the complete list of combustion plants per country divided into boilers for GED and CPPD. Unfortunately due to lack of data, not all combustion plants had information on boiler type, these are categorized as *Unknown.* As seen in Table 4.5, the most known used boiler type is Grate, followed by Fluidised Bed. Central- and eastern Europe has the most amount of boilers, and many of these are grate boilers. For northern Europe, fluidised bed boilers are the most common.

**Table 4.5:** The number of combustion plants per region divided into type of boiler for General Electric Database (GED) and Chalmers Power Plant Database (CPPD).

| | GED | | | | CPPD | | | | ALL |
|---|---|---|---|---|---|---|---|---|---|
| | **Grate** | **FB** | **Pulv.** | **Unkno.** | **Grate** | **FB** | **Pulv.** | **Unkno.** | |
| **Central** | 29 | 1 | 0 | 70 | 33 | 6 | 0 | 22 | **161** |
| **Eastern** | 60 | 1 | 4 | 29 | 11 | 0 | 2 | 0 | **107** |
| **Northern** | 7 | 13 | 0 | 19 | 2 | 16 | 0 | 16 | **73** |
| **Western** | 3 | 5 | 0 | 25 | 7 | 3 | 0 | 10 | **53** |
| **ALL** | **99** | **20** | **4** | **143** | **53** | **25** | **2** | **48** | **394** |

## 4.2 Validation

### 4.2.1 Impact Assessment Report

The relevant and extracted information regarding the MCPD from the Impact Assessment Report (IAR) are estimations on the amount of combustion plants and its total capacity divided into 1 – 5, 5 – 20 and 20 – 50 $MW_{th}$.

Table 4.6 shows the total estimated number of combustion plants in the EU divided into 1 – 5, 5 – 20 and 20 – 50 $MW_{th}$, along with its respective percentage share. As seen, the share of plants within thermal range of 1 – 5 $MW_{th}$ dominates up to 80 %. The thermal capacity of these plants account for 40 %, which is still the largest group. [40]

**Table 4.6:** Estimated number of installed plants according to IAR.

| | Number of installed plants | | Thermal capacity | |
|---|---|---|---|---|
| | **-** | **%** | **GW** | **%** |
| **1 - 5** | 113 809 | 80% | 274 | 40% |
| **5 - 20** | 23 868 | 17% | 232 | 34% |
| **20 - 50** | 5 309 | 4% | 177 | 26% |
| **All** | **142 986** | | **683** | |

There is thus a large discrepancy between the investigated databases and the IAR report. The total number of combustion plants according to IAR is larger than the number of combustion plants in the GE and the CPPD subset. All the member states of the EU had to report data on combustion plants, fuels consumption, emissions etc to the EU during the work of the IAR. This is a possible reason for the difference in number of combustion plants, since GE and Chalmers by themselves have gathered data. The discrepancy is largest for small plants which is not surprising since these plants account for the highest number and are most challenging to collect data from. Also, many of these plants installed in EU are not operated continuously over the year. However, also for larger plants (20–50 mw) there appears to be large gap in the two databases used in this thesis.

Table 4.7 shows the estimated annual fuel consumption in Peta Joule (PJ) per year for each fuel according to IAR in the EU, and with its respective percentage share. As can be seen, plants in the range 5 – 20 $MW_{th}$ consume most fuel. It should also be noted that for plants above 20 $MW_{th}$, the share of solid fuels is higher than smaller plants, and that natural gas is by far the most common fuel for medium combustion plants in the EU. [40]

**Table 4.7:** Estimated annual fuel consumption in Peta Joule (PJ) per year according to IAR.

| | **1 - 5** | | **5 - 20** | | **20 - 50** | | **1-50** | |
|---|---|---|---|---|---|---|---|---|
| | **PJ** | **%** | **PJ** | **%** | **PJ** | **%** | **PJ** | **%** |
| **Nat. gas** | 1 268 | 64% | 1 704 | 73% | 844 | 60% | **3 816** | 67% |
| **Liq. fuel** | 213 | 11% | 290 | 12% | 206 | 15% | **709** | 12% |
| **Other gas.** | 277 | 14% | 125 | 5% | 104 | 7% | **506** | 9% |
| **Biomass** | 163 | 8% | 160 | 7% | 182 | 13% | **505** | 9% |
| **Other solids** | 49 | 2% | 46 | 2% | 74 | 5% | **169** | 3% |
| **ALL** | **1 970** | | **2 325** | | **1 410** | | **5 705** | |

Table 4.8 shows the top five countries and its total amount of estimated plants in the EU divided into 1 – 5, 5 – 20 and 20 – 50 $MW_{th}$. The percentage share can also be seen, with respect to the total amount of medium combustion plants in the EU. [40]

**Table 4.8:** The top five countries and its total amount of estimated plants in the EU according to IAR.

| | **1 - 5 MWth** | | | **5 - 20 MWth** | | | **20 - 50 MWth** | | |
|---|---|---|---|---|---|---|---|---|---|
| **1)** | Germany | 35 500 | 31% | Germany | 3 480 | 15% | France | 1 600 | 30% |
| **2)** | France | 13 399 | 12% | France | 2 951 | 12% | Germany | 767 | 14% |
| **3)** | UK | 10 317 | 9% | UK | 2 681 | 11% | UK | 451 | 8% |
| **4)** | Nether. | 6 995 | 6% | Nether. | 2 250 | 9% | Italy | 274 | 5% |
| **5)** | Italy | 6 268 | 6% | Italy | 1 629 | 7% | Denmark | 263 | 5% |
| | All others | 41 329 | 36% | All others | 10 878 | 46% | All others | 1 954 | 37% |
| | **ALL** | **113 808** | | **ALL** | **23 869** | | **ALL** | **5 309** | |

Table 4.9 shows the estimated emissions in kilo tonnes per year for each region according to IAR, along with a mean value of the percentage share for PM, $SO_2$ and

$NO_x$ [40]. As can be seen, $NO_x$ is the largest emitted pollutant followed by $SO_2$ and PM. On region level, western Europe has the highest number of emissions for PM, $SO_2$ and $NO_x$.

**Table 4.9:** Estimated emissions in kilotonnes per year for each region.

| | PM | | $SO_2$ | | $NO_x$ | | % |
|---|---|---|---|---|---|---|---|
| **Western** | 20,1 | 38% | 106 | 35% | 232 | 42% | **38%** |
| **Central** | 7,2 | 13% | 76,8 | 26% | 181 | 33% | **24%** |
| **Eastern** | 11,5 | 22% | 55,3 | 18% | 79,1 | 14% | **18%** |
| **Northern** | 14,6 | 27% | 62,8 | 21% | 62,4 | 11% | **20%** |
| **All** | **53,4** | | **300,4** | | **554,6** | | |

Figure 4.3 presents all affected combustion plants according to IAR divided into regions. As can be seen, central Europe has the highest number of affected combustion plants, same as according to GED and CPPD. However, for the other regions, the databases disagree significantly.This is especially true for western Europe, where IAR states that 34% of the plants exist while the share is 12% and 16% for GED and CPPD respectively. A possible reason could be that IAR covers a large amount of small backup plants, which GED nor CPPD do, and a large part of these exist in western Europe (see Table 4.8).

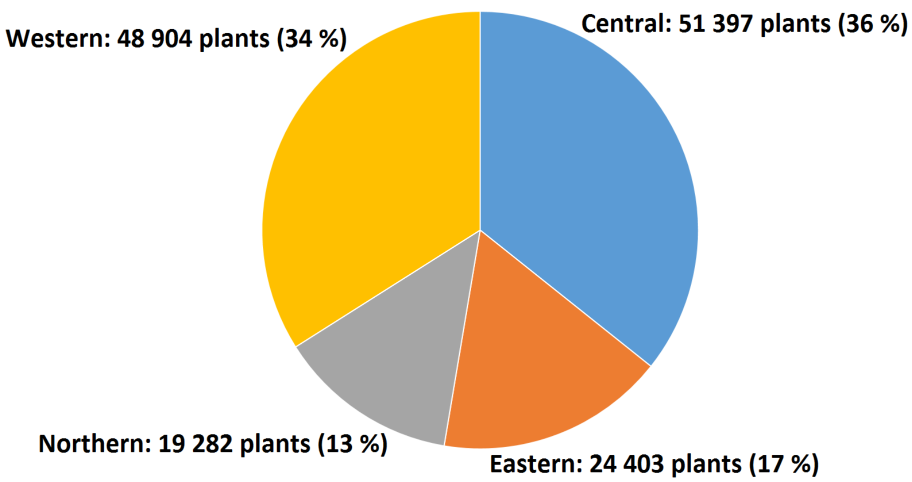


**Figure 4.3:** Number of affected combustion plants for each region according to IAR.

The conclusion from the comparison of GED and CPPD with IAR is thus that there exist significant differences and that most of these originate from the coverage of small combustion plants. Due to its size and creator, IAR is assumed to be most representative of Europes distribution of medium combustion plants. The details on the individual plants are however limited in IAR compared to GED and CPPD, and all three databases will be used in the selection process.

### 4.2.2 Additional source

Only the relevant outcomes of consultations and discussions with employees at GE are presented.

**1) The distribution and extension of various plant types in the EU.**

*Most of the coal power plants are located in Poland, Slovakia, Czech Republic or other parts the the eastern Europe. When it comes to biomass and peat, it is more common in the rest of Europe, especially in the northern Europe, like Sweden, Denmark and Finland. Oil and gas are also very common among Europe.*

**2) Common flue gas cleaning technologies around the EU.**

*ESPs and FFs are the most used PM removal equipment in the EU. These are either old or modern. The modern ESPs and FFs will probably fulfill the MCPD limits. Older ESPs and FFs are likely already upgraded to fulfill the MCPD, at least in regions such as northern-, central- or western Europe. For eastern Europe, many ESPs or FFs has been installed, but there are many combustion plants that only has older equipment's like cyclones, at least for medium combustion plants. These combustion plants that only has cyclone installed will probably not fulfill the MCPD.*

**3) Local regulations and legislation's on emissions.**

*Some of the member states in the EU may already have stricter national regulations on emission levels, like Sweden, Finland, Denmark and Germany. When it comes to eastern Europe, in countries such as Slovakia or Czech Republic, regulations of emission levels are often softer compared to the rest of the EU.*

## 4.3 Selection

### 4.3.1 Number of combustion plants in the regions

Table 4.10 and 4.11 presents the grading for the first factor, *number of combustion plants*. Table 4.10 is based on the sum of GED and CPPD, and Table 4.11 is based on IAR. According to Figure 4.2 in 4.1 Categorization, i.e. based on GED and CPPD, central Europe have the highest number of combustion plants followed by eastern-, northern- and western Europe. The percentage share of central Europe is 41 %, for eastern Europe it is 27 %, for northern- and western Europe it is 19 % and 13 %. According to IAR in Figure 4.3, central Europe also has the highest number of combustion plants, but with another decreasing order: western-, eastern- and northern Europe. The percentage share of according to IAR for central Europe is 36 %, for eastern Europe it is 34 %, for northern- and western Europe it is 16 % and 13 %

**Table 4.10:** Color grading in regard to *number of combustion plants*, based on GED and CPPD.

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| **Number of combustion plants** | | | | |
| Type of primary fuel usage | | | | |
| Estimated emitted emissions | | | | |
| Installed flue gas cleaning equipment | | | | |
| Local regulations and legislation's | | | | |

**Table 4.11:** Color grading in regard to *number of combustion plants*, based on IAR.

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| **Number of combustion plants** | | | | |
| Type of primary fuel usage | | | | |
| Estimated emitted emissions | | | | |
| Installed flue gas cleaning equipment | | | | |
| Local regulations and legislation's | | | | |

### 4.3.2 Type of primary fuel usage

Table 4.12 presents the grading for the second factor, *type of primary fuel usage*. According to Table 4.4 coal is most common in eastern Europe, and thereby it is considered as most affected by the MCPD. The second most affected region is central Europe, due to the high distribution of biomass, followed by gas, coal and oil. Northern- and western Europe are graded the same, these regions covers both biomass and gas. Since they not having much coal compared to central- and eastern Europe, these regions are assumed being equally affected by the MCPD for this factor. If comparing northern- and western Europe in Table 4.4, it can be seen that northern Europe has more biomass plants compared to western Europe. However, the difference is assumed to be small and therefore these regions are assumed to be equally affected by the MCPD.

**Table 4.12:** Color grading in regard to *type of primary fuel usage*.

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| Number of combustion plants | | | | |
| **Type of primary fuel usage** | | | | |
| Estimated emitted emissions | | | | |
| Installed flue gas cleaning equipment | | | | |
| Local regulations and legislation's | | | | |

### 4.3.3 Estimated emitted emissions

Table 4.13 presents the grading for the third factor, *estimated emitted emissions*. According to Table 4.9, western Europe has the highest number of emissions, the percentage share is 38 %. Northern Europe has the lowest number of emitted emissions, with a percentage share of 18 %. For central- and northern Europe the percentage shares are 24 % and 20 %.

**Table 4.13:** Color grading in regard to *estimated emitted emissions*.

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| Number of combustion plants | | | | |
| Type of primary fuel usage | | | | |
| **Estimated emitted emissions** | | | | |
| Installed flue gas cleaning equipment | | | | |
| Local regulations and legislation's | | | | |

### 4.3.4 Installed flue gas cleaning equipment

Table 4.13 presents the grading for the fourth factor, *installed flue gas cleaning equipment*. As can be seen, eastern Europe is marked with red while the rest is yellow. According to employees at GE, eastern Europe will be most affected by the MCPD in regard to installed flue gas cleaning equipment. Installed flue gas cleaning equipment in the eastern Europe are in general older than the rest of the Europe. For central-, northern- and western Europe, it is difficult to classify which region that has the best installed flue gas cleaning equipment, that is why these regions has the same color.

**Table 4.14:** Color grading in regard to *installed flue gas cleaning equipment.*

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| Number of combustion plants | | | | |
| Type of primary fuel usage | | | | |
| Estimated emitted emissions | | | | |
| **Installed flue gas cleaning equipment** | | | | |
| Local regulations and legislation's | | | | |

### 4.3.5 Local regulations and legislation's

Table 4.15 presents the grading for the fifth factor, *local regulations and legislation's*. Eastern Europe is marked with red, this region will be most affected by the MCPD according to employees at GE. Central- and western Europe is marked with the same color. It is difficult to determine which region that will be most affected by the MCPD due to local regulations and legislation's. Speculations of which region that would be lest affected by the MCPD according to GE is northern Europe. According to GE, countries like Sweden, Denmark and Finland have the strictest local regulations and legislation's on emissions.

**Table 4.15:** Color grading in regard to *local regulations and legislation's.*

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| Number of combustion plants | | | | |
| Type of primary fuel usage | | | | |
| Estimated emitted emissions | | | | |
| Installed flue gas cleaning equipment | | | | |
| **Local regulations and legislation's** | | | | |

### 4.3.6 Final selection

Table 4.16 shows all color indicators from Table 4.10 – 4.15. The most red marked region is eastern Europe. Central- and western Europe have each two red marks, but central Europe has two more yellow marks. Northern Europe is considered to be least affected by the MCPD, there are no red marks. Eastern Europe is selected as a primary target area, in regard to fuel such as bituminous coal and lignite. The fact that Eastern Europe is green in "estimated emitted emission" might seem counter-intuitive but this estimation is made on total mass of emission, while MCPD considers the performance of individual plants. Since the amount of medium combustion plants is lower in eastern Europe, the specific emission per plant is actually higher (for PM and $SO_2$) for eastern Europe. A secondary target area is selected, which covers biomass- and peat power plants in the rest of Europe. The idea of selecting a secondary target is that, biomass and peat plants in the rest of EU should still be considered a market opportunity for GE. According to GE employees, it is necessary to prepare solutions and technical proposals for biomass plants even of its not a priority at the moment.

**Table 4.16:** All color grading for each region.

| | Central | Eastern | Northern | Western |
|---|---|---|---|---|
| Number of combustion plants | | | | |
| Type of primary fuel usage | | | | |
| Estimated emitted emissions | | | | |
| Installed flue gas cleaning equipment | | | | |
| Local regulations and legislation's | | | | |

Consultation with GE, in regard to selection of which emissions that will be further applied in next steps, along with which thermal capacity is performed. Focus will be on PM and $SO_2$, not $NO_x$. Due to the opportunity of primarily measures rather than secondary measures for $NO_x$ reduction, focus will lie on PM and $SO_2$ reduction. According to GE, it will probably be more common, easier and cheaper for medium sized combustion plants to implement primarily measures rather than secondary measures, since the emission limit of 650 mg/Nm$^3$ for $NO_x$ is relatively generous for solid fuels.

Both target areas will focus on on combustion plants with thermal capacity of 20 – 50 $MW_{th}$. The reason for selecting plants with capacity range from 20 – 50 $MW_{th}$ is that this target area is at present closer to GE Power's customer group. According to experienced engineers and sales at GE, plants with capacity range from 20 – 50 $MW_{th}$ often requires larger investments for flue gas cleaning products compared to smaller plants with a capacity range from 1 – 20 $MW_{th}$. Generally plants above 20 $MW_{th}$ are more financially stable and stronger than plants below 20 $MW_{th}$.

Oil and gas are excluded since, according to GE, almost non flue gas cleaning equipment's for PM and $SO_2$ are used when burning oil and gas. When it comes to flue gas cleaning equipment for oil and gas, the main equipment is for $NO_x$ removal.

## 4.4 Application

Table 4.17 presents which technical solutions that fulfill (presented as green) and technical solutions that don't fulfill (presented as presented as red) the MCPD limits, see Appendix D. No coloring refers to unknown fulfillment. The required collection efficiency (RCE) for each fuel has been calculated, and can be seen in Appendix D. RCE has been compared with the estimated collection efficiency for each technical solutions. As mentioned earlier, the estimated $SO_2$ removal efficiency is unknown for TWESP.

**Table 4.17:** Technologies that fulfill (presented as green) and the options that don't fulfill (presented as presented as red) the Required Collection Efficiency along with fuels and pollutants, based on Table D.1. Non color refers to unknown fulfillment.

| **Fuel** | **Pollutant** | **DSI+ESP** | **DSI+FF** | **NIDL** | **NID** | **TWESP** |
|---|---|---|---|---|---|---|
| Bituminous coal | PM | | | | | |
| | $SO_2$ | | | | | |
| Lignite | PM | | | | | |
| | $SO_2$ | | | | | |
| Peat | PM | | | | | |
| | $SO_2$ | | | | | |
| Biomass | PM | | | | | |
| | $SO_2$ | | | | | |

The only technical option that does not fulfill RCE are options DSI+ESP and DSI+FF for $SO_2$ removal regarding bituminous coal and lignite. Both DSI+ESP and DSI+FF are estimated to remove 60 % and 75 % $SO_2$, which is not enough since RCE for bituminous coal is 88.25 % and 80 % for lignite, see Appendix D.

### 4.4.1 Investment and running costs

Figure 4.4 – 4.7 presents the total cost with respect to time in years, by plotting equation 3.1. As can be seen for all cases in Figure 4.4 – 4.7, using DSI in combination with an ESP is the cheapest initial solution. For bituminous coal and lignite, it takes less than a year before the total cost for DSI + ESP exceeds using DSI + FF. It takes around above 10 years for the DSI + ESP to exceed DSI + FF in total cost for peat and biomass.

The overall cheapest long term solution is NIDL for all cases. It takes around nine months for the NIDL to become the cheapest long term solution for bituminous coal, and around one year and five months for lignite. For peat, it takes around 33 years and for biomass around 27 years. When taking economic- and the required collection efficiency (RCE) aspects into account, the results can be concluded as:

- **For bituminous coal and lignite, NID or NIDL are suitable solutions.**

  These options fulfills the required removal efficiency for Sulfur Dioxide ($SO_2$). These are also long term economical solutions. Only after three years, both solutions are cheaper than DSI + FF/ESP. NIDL is even better, since the investment cost is lower compared to NID. However, if RCE for $SO_2$ would be above 90 %, then NID is only suitable since the estimated collection efficiency is up to 98 % for NID, and 90 % for NIDL.

  The DSI solutions does not fulfill the RCE for bituminous coal and lignite, see Table 4.17. Also the total cost of the DSI solutions exceeds the total cost of NID and NIDL only after 1 – 2 years.

- **For peat and biomass, DSI + ESP or DSI + FF are suitable solutions.**

  All options fulfill the RCE, but the DSI solutions are more cost effective since DSI solutions in these cases are cheaper. DSI + ESP is suitable if is will be used less than 10 – 12 years. If it will be used for more than 10 – 12 years, and not more than 27 – 31 years, DSI + FF is cheaper. NID L will only be economic suitable if it would be used for more than 27 – 31 years.

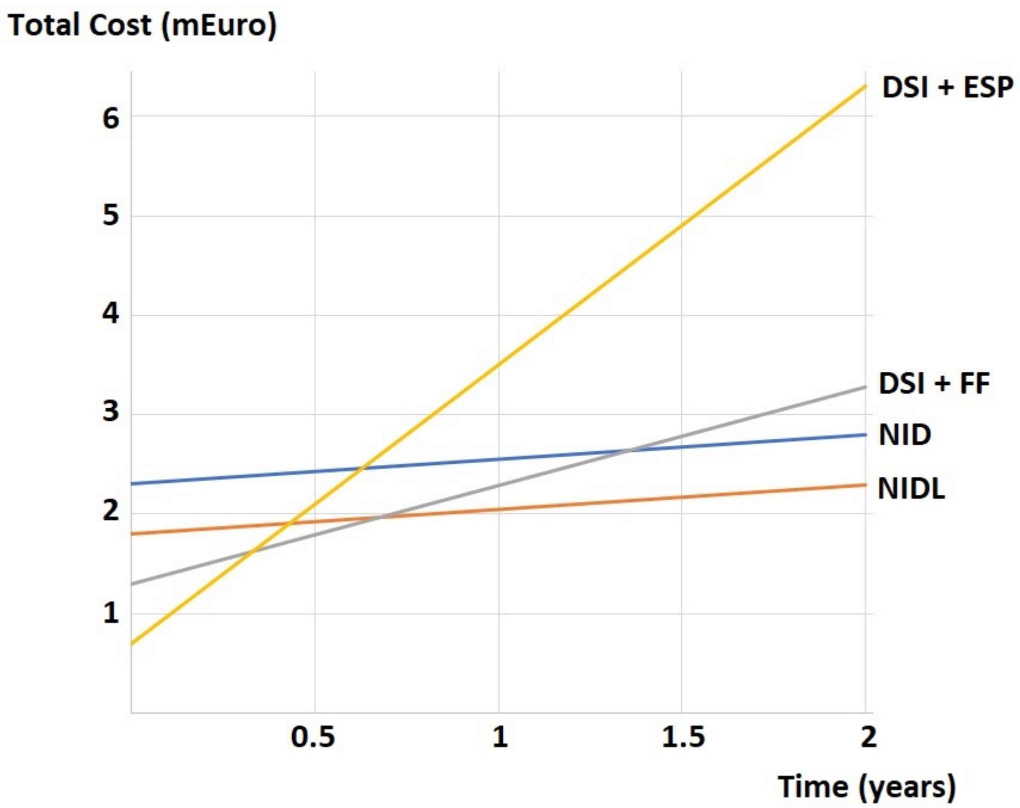


**Figure 4.4:** Total Cost (TC) with respect to time in years, for bituminous coal.

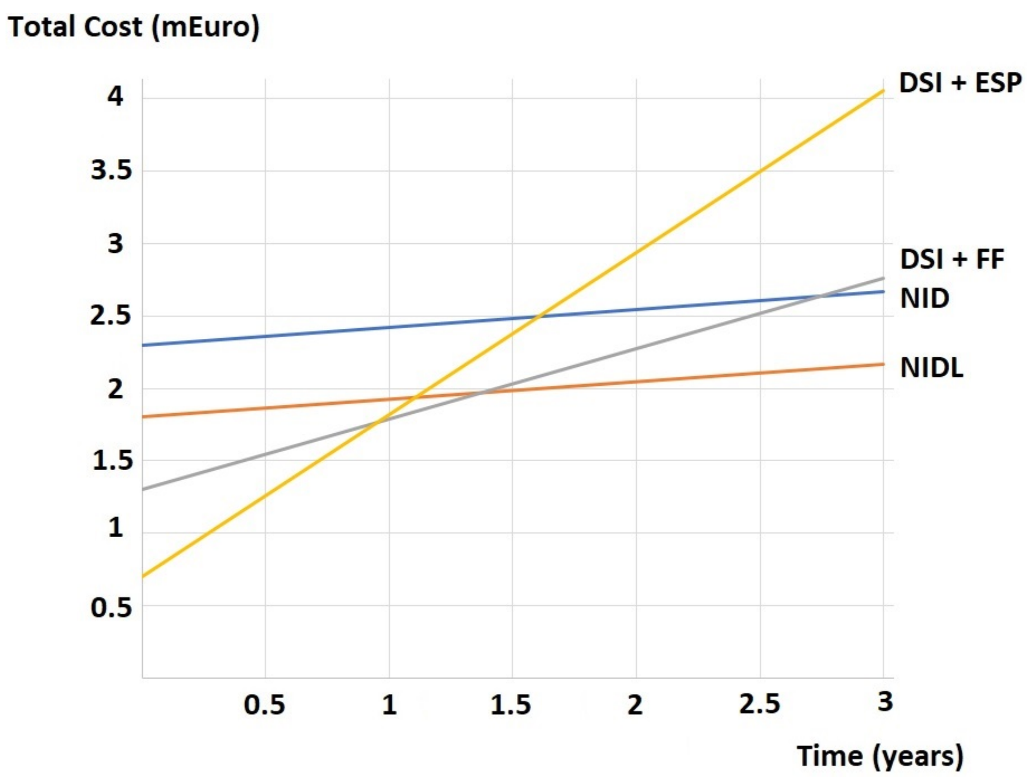


**Figure 4.5:** Total Cost (TC) with respect to time in years, for lignite.

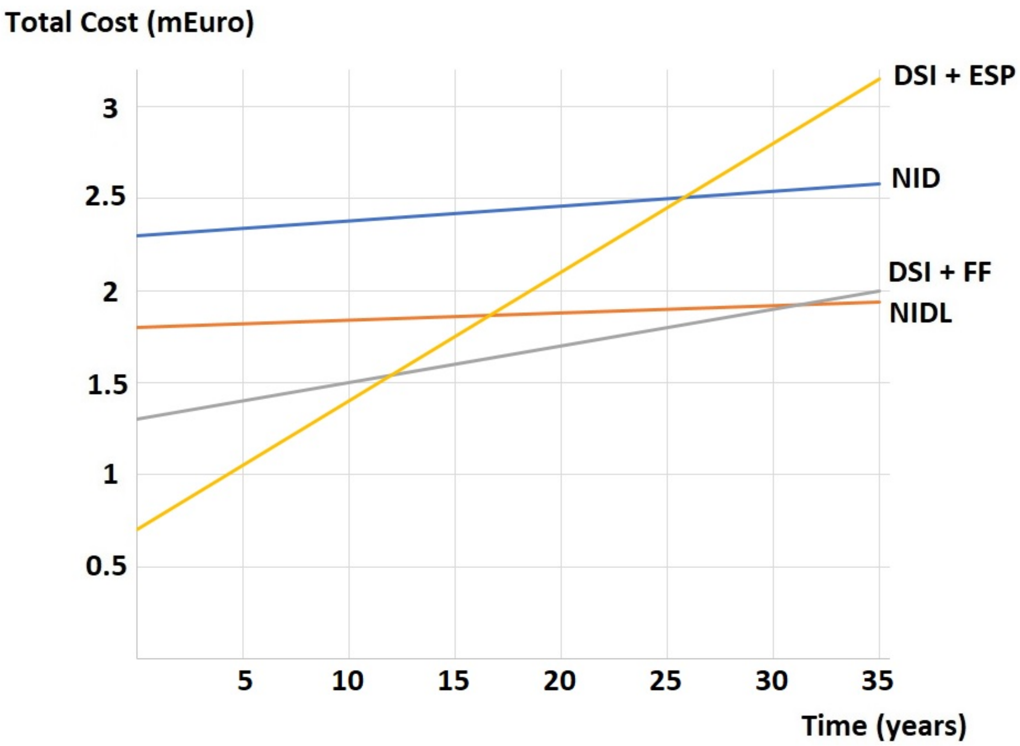


**Figure 4.6:** Total Cost (TC) with respect to time in years, for peat.

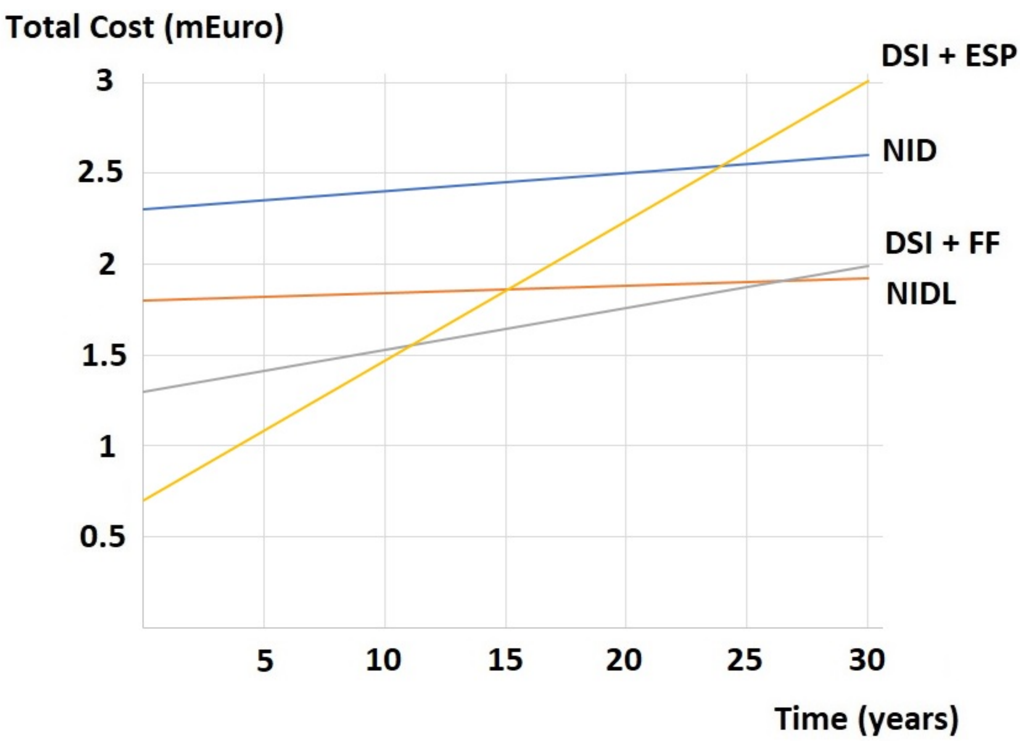


**Figure 4.7:** Total Cost (TC) with respect to time in years, for biomass.

## 4.5 General reflections

The following section presents some general reflections that have arisen during this thesis. The market for flue gas cleaning and environmental control systems is largely dependent on laws and legislation. Most flue gas cleaning equipment is just an extra cost for the owners of the combustion plan and the owner is often more interested in making investments in the production quality and capacity of the combustion plant. Legislation is therefore necessary for emission reduction.

According to the Impact Assessment Report (IAR), from Table 4.7 in *4.2 Validation*, 67 % of the estimated annual fuel consumption of affected MCPD plants in the EU is natural gas. Biomass and other solid fuels like coal or peat account for 9 % and 3 %. This clearly indicates that natural gas is more common than solid fuels for medium- and small sized combustion plants. Emissions of $SO_2$, $NO_x$, PM and volatile organic compounds (VOC) are lower (except maybe NOx under certain conditions) from natural gas compared to coal, peat, biomass and oil [42]. Due to this, some of the medium combustion plants burning solid fuels may choose to switch to natural gas rather than investing in flue gas cleaning. Exactly how such decisions are made is difficult to say, as it may depend on location of the boiler type, current distance to pipelines, economic prospects etc. It is also possible that combustion plants that are not financially strong cannot afford to operate and thus have to shut down. MCPD limits are tougher on solid fuels and oil based power plants compared to natural gas, as PM emission from gaseous fuels is expected to be very low even without cleaning. Another observation regarding is that the emission limits get stricter and tougher for increased size of the boiler. The reason is that more emissions are emitted for larger boilers. The market for flue gas cleaning will therefore be biggest for plants in the 20-50 MWth range. The kind of flue gas cleaning equipment that plants require differs. It depends on fuel, size of the boiler, current flue gas equipment, required collection efficiency etc. It appears that the most common equipment upgrade caused by the MCPD is PM removal. When it comes to PM the question is mostly whether you need an ESP or a FF. It depends on application and the required removal efficiency. In general it can be said that for the same efficiency an ESP is slightly more expensive to buy, but cheaper to operate in the long run due to the lower pressure drop. The FF is cheaper to buy but more expensive to operate due to the higher pressure drop and bag replacement every 3 – 5 years. However, with a FF you can guarantee PM down to 5 mg/Nm$^3$ or sometimes even lower, while for an ESP you normally don't guarantee lower than 10 – 15 mg/Nm$^3$. The performance of an ESP is very sensitive to the resistivity of the dust, which the FF is not. Instead the FF is sensitive to the chemical composition of the flue gas as it effects the lifetime of the bags. If the current installed PM removal unit is a cyclone, then it will be required that either an ESP or a FF, depending on process application, replaces the existing cyclone. There is no point in keeping the existing cyclone as it just cost extra pressure drop in the system and does not provide enough removal efficiency. ESPs and FFs generally have higher collecting efficiency for smaller particles, and are therefore suitable for stricter required collection efficiency. [46]

# 5
# Conclusion

The thesis analyzes the impact of the Medium Combustion Plant Directive (MCPD) for the fleet of plants affected in the EU. It considers which regions of the EU that will be most affected, along with needs and demands for different types of combustion plants as well as how General Electric (GE)'s current product complies by the MCPD.

Central Europe has the highest number of combustion plants concerned by the MCPD. However, the analysis shows that eastern Europe is expected to be most affected by the MCPD, see Table 4.16. In this part of Europe, coal power plants are most common. The installed flue gas cleaning equipment in the eastern Europe are relatively old and will, in many cases, require an upgrade to comply with the MCPD. Fuels like biomass, peat, oil and gas are common in all geographical areas, where biomass and peat are the most concerned fuels.

Particulate Matter (PM) and Sulfur Dioxide ($SO_2$) emissions from solid fuel combustion for plants with a thermal capacity of 20 – 50 $MW_{th}$ are most likely to require new flue gas cleaning. Nitrogen Oxide ($NO_x$) requirements in the MCPD are assumed to be able to comply with by primary measures, which are more cost-effective than secondary measurements.

Novel Integrated Desulfurization (NID) and Novel Integrated Desulfurization Light (NIDL) are proposed to be used for power plants burning coal, such as bituminous coal and lignite. The pay back time relative to techniques like Dry Sorbent Injection (DSI) with lower investment but higher running costs are 1 – 2 years. NIDL is recommended for removal efficiency for $SO_2$ below 90 %, and NIDL is recommended for collection efficiencies between 90 – 98 %.

For peat and biomass, DSI in combination with an Electrostatic Precipitator (ESP) or a FF is recommended. DSI in combination with an ESP is recommended for expected life time of 10 –12 years. DSI + FF is recommended for 27 – 31 years. NIDL is recommended for even longer lifetimes. The DSI solutions are more cost effective compared to NID and NIDL, since the the required collection efficiency's for $SO_2$ are much lower for peat and biomass, and therefore less sorbent is needed.

# 6
# Future work

Recommended future work are further investigation in distribution and share of affected combustion plants in Europe, based on other sources than General Electric Database (GED) and Chalmers Power Plant Database (CPPD). Hence, either more validation to this thesis conclusions are accomplish, or other yet unknown conclusions can be identify that this thesis didn't accomplish. Also, deeper studies of current installed flue gas cleaning equipment's is recommended do be done. In this way, it would be easier to identify which areas or combustion plants that would not be needed for any flue gas cleaning equipment's .

Other recommended future studies would be current national legislation's on emission levels. Taking today's emission levels limits into account, further screening or validation can be done to evaluate where MCPD affects the most. Another future work would be investigating in the opportunity of combining Tubular Wet Electrostatic Precipitator (TWESP) with $SO_2$ removal. This thesis did not accomplish to investigate the possibility of integrating $SO_2$ removal in a TWESP, along with economic aspects.

# Abbreviations

**$CO(NH_2)_2$** Urea.
**$CO_2$** Carbon Dioxide.
**CO** Carbon Monoxide.
**$Ca(OH)_2$** Calcium Hydroxide.
**$CaCO_3$** Calcium Carbonate.
**CaO** Calcium Oxide.
**$CaSO_3$** Calcium Sulfite.
**$CaSO_4$** Calcium Sulfate.
**HCL** Hydrochloric Acid.
**HF** Hydrogen Fluoride.
**$H_2O$** Water.
**$H_2S$** Hydrogen Sulfide.
**Hg** Mercury.
**$MW_{th}$** Thermal Megawatt.
**$NH_3$** Ammonia.
**$NO_2$** Nitrogen Dioxide.
**$NO_x$** Nitrogen Oxide.
**NO** Nitric Oxide.
**$N_2$** Nitrogen Gas.
**$NaHCO_3$** Sodium Bicarbonate.
**$O_2$** Oxygen Gas.
**$O_3$** Ground-Level Ozone.
**O** Oxygen.
**$PM_{10}$** Particulate Matter with diameter of between 2.5 – 10 $\mu$m.
**$PM_{2.5}$** Particulate Matter with diameter of below 2.5 $\mu$m.
**PM** Particulate Matter.
**$SO_2$** Sulfur Dioxide.
**$SO_3$** Sulfur Trioxide.
**$SO_x$** Sulfur Oxide.
**S** Sulfur.
**VOC** Volatile Organic Compound.
**$mg/Nm^3$** milligram per normal cubic meters.

**AC** Alternating Current.
**AQCS** Air Quality Control Systems.

**BAT** Best Available Techniques.

**CPPD** Chalmers Power Plant Database.

**DAS** Dry Absorption System.
**DC** Direct Current.
**DESP** Dry Electrostatic Precipitator.
**DFGD** Dry Flue Gas Desulfurization.
**DSI** Dry Sorbent Injection.

**ED** Ecodesign Directive.
**ESP** Electrostatic Precipitator.
**EU** European Union.

**FBB** Fluidized Bed Boiler.
**FF** Fabric Filter.
**FGD** Flue Gas Desulfurization.

**GE** General Electric.
**GE Power** General Electric Power.
**GED** General Electric Database.
**GT** Gas Turbine.

**HFTR** High Frequency Transformer Rectifier.
**HQHL** High Quality Hydrated Lime.

**IAR** Impact Assessment Report.
**IC** Investment Cost.
**IED** Industrial Emission Derivative.

**K** Kelvin.
**kPa** Kilo Pascal.

**LCPD** Large Combustion Plant Directive.

**MCPD** Medium Combustion Plant Directive.

**NID** Novel Integrated Desulfurization.
**NIDL** Novel Integrated Desulfurization Light.

**PAC** Powdered Activated Carbon.
**PC** Pulverized Coal.

**RC** Running Cost.
**RCE** Required Collection Efficiency.

**SCR** Selective Catalytic Reduction.
**SHL** Standard Hydrated Lime.
**SNCR** Selective Non Catalytic Reduction.

**TC** Total Cost.
**TWESP** Tubular Wet Electrostatic Precipitator.

**WESP** Wet Electrostatic Precipitator.
**WFGD** Wet Flue Gas Desulfurization.
**WS** Wet Scrubber.

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# A

# Medium Combustion Plant Directive

**Parts of the MCPD Legislation's document: *Directive (EU) 2015/2193.***

*This Directive lays down rules to control emissions of sulphur dioxide ($SO_2$), nitrogen oxides ($NO_x$) and dust into the air from medium combustion plants, and thereby reduce emissions to air and the potential risks to human health and the environment from such emissions. This Directive also lays down rules to monitor emissions of carbon monoxide (CO).*
**(Article 1)**

*This Directive shall apply to combustion plants with a rated thermal input equal to or greater than 1 MW and less than 50 MW ('medium combustion plants'), irrespective of the type of fuel they use.*
**(Article 2.1 )**

*This Directive shall also apply to a combination formed by new medium combustion plants pursuant to Article 4, including a combination where the total rated thermal input is equal to or greater than 50 MW, unless the combination forms a combustion plant covered by Chapter III of Directive 2010/75/EU.*
**(Article 2.2)**

*This Directive shall not apply to:*

- *combustion plants covered by Chapter III or Chapter IV of Directive 2010/75/EU;*
- *combustion plants covered by Directive 97/68/EC of the European Parliament and of the Council;*
- *on-farm combustion plants with a total rated thermal input less than or equal to 5 MW, that exclusively use unprocessed poultry manure, as referred to in Article 9(a) of Regulation (EC) No 1069/2009 of the European Parliament and of the Council (2), as a fuel;*
- *combustion plants in which the gaseous products of combustion are used for the direct heating, drying or any other treatment of objects or materials;*

- *combustion plants in which the gaseous products of combustion are used for direct gas-fired heating used to heat indoor spaces for the purpose of improving workplace conditions;*
- *post-combustion plants designed to purify the waste gases from industrial processes by combustion, and which are not operated as independent combustion plants;*
- *any technical apparatus used in the propulsion of a vehicle, ship or aircraft;*
- *gas turbines and gas and diesel engines, when used on offshore platforms;*
- *facilities for the regeneration of catalytic cracking catalysts;*
- *facilities for the conversion of hydrogen sulphide into sulphur;*
- *reactors used in the chemical industry;*
- *coke battery furnaces;*
- *cowpers;*
- *crematoria;*
- *combustion plants firing refinery fuels alone or with other fuels for the production of energy within mineral oil and gas refineries;*
- *recovery boilers within installations for the production of pulp;*

**(Article 2.3)**

*A combination formed by two or more new medium combustion plants shall be considered to be a single medium combustion plant for the purposes of this Directive and their rated thermal input shall be added together for the purpose of calculating the total rated thermal input of the plant, where:*

- *the waste gases of such medium combustion plants are discharged through a common stack, or*
- *taking into account technical and economic factors, the waste gases of such medium combustion plants could, in the judgement of the competent authority, be discharged through a common stack.*

**(Article 4)**

*Member States shall take the necessary measures to ensure that, as of 1 January 2024, no existing medium combustion plant with a rated thermal input greater than 5 MW is operated without a permit or without being registered.*

*Member States shall take the necessary measures to ensure that, as of 1 January 2029, no existing medium combustion plant with a rated thermal input of less than or equal to 5 MW is operated without a permit or without being registered.*

**(Article 5.2)**

*Without prejudice to Chapter II of Directive 2010/75/EU, where applicable, the emission limit values set out in Annex II to this Directive shall apply to medium combustion plants.*

*The emission limit values set out in Annex II shall not apply to medium combustion plants located in the Canary Islands, French Overseas Departments, the Azores and Madeira. The Member States concerned shall set emission limit values for those plants in order to reduce their emissions to air and the potential risks to human health and the environment.*
**(Article 6.1)**

*Member States may exempt existing medium combustion plants which do not operate more than 500 operating hours per year, as a rolling average over a period of five years, from compliance with the emission limit values set out in Tables 1, 2 (and 3) of Part 1 of Annex II.*

*Member States may extend the limit referred to in the first subparagraph to 1 000 operating hours in the following cases of emergency or extraordinary circumstances:*

- *for backup power production in connected islands in the event of an interruption of the main power supply to an island,*
- *medium combustion plants used for heat production in cases of exceptionally cold weather events.*

*In all cases set out in this paragraph, an emission limit value for dust of 200 mg/Nm3 shall apply for plants firing solid fuels.*
**(Article 6.3)**

*From 1 January 2025, emissions into the air of $SO_2$, $NO_x$ and dust from an existing medium combustion plant with a rated thermal input greater than 5 MW shall not exceed the emission limit values set out in Tables 2 (and 3) of Part 1 of Annex II.*

*From 1 January 2030, emissions into the air of $SO_2$, $NO_x$ and dust from an existing medium combustion plant with a rated thermal input of less than or equal to 5 MW shall not exceed the emission limit values set out in Tables 1 (and 3) of Part 1 of Annex II.*
**(Article 6.2)**

*From 20 December 2018, emissions into the air of $SO_2$, $NO_x$ and dust from a new medium combustion plant shall not exceed the emission limit values set out in Part 2 of Annex II.*
**(Article 6.7)**

*Member States may exempt new medium combustion plants which do not operate more than 500 operating hours per year, as a rolling average over a period of three years, from compliance with the emission limit values set out in Part 2 of Annex II. In the event of such exemption, an emission limit value for dust of 100 mg/Nm$^3$ shall apply for plants firing solid fuels.*

**(Article 6.8)**

*Where a medium combustion plant simultaneously uses two or more fuels, the emission limit value for each pollutant shall be calculated by:*

(a) *taking the emission limit value relevant for each individual fuel as set out in Annex II;*

*(b) determining the fuel-weighted emission limit value, which is obtained by multiplying the individual emission limit value referred to in point (a) by the thermal input delivered by each fuel, and dividing the product of multiplication by the sum of the thermal inputs delivered by all fuels; and*

*(c) aggregating the fuel-weighted emission limit values.*

**(Article 6.13)**

# B
# Plants per country and fuel

**Table B.1:** Number of plants per country, divided into fuel for 1 – 5 $MW_{th}$.

| | GED | | | | CPPD | | ALL |
|---|---|---|---|---|---|---|---|
| | **Biomass** | **Coal** | **Gas** | **Oil** | **Biomass** | **Coal** | |
| **Germany** | 1 | 3 | 3 | | | | **7** |
| **Czech R.** | | 4 | | 1 | | | **5** |
| **Austria** | 3 | | | | | | **3** |
| **Spain** | | | 3 | | | | **3** |
| **France** | | | 2 | | | | **2** |
| **Nether.** | | | | | 1 | | **1** |
| **Poland** | | 1 | | | | | **1** |
| **ALL** | **4** | **8** | **8** | **1** | **1** | **0** | **22** |

**Table B.2:** Number of plants per country, divided into fuel for 5 – 20 $MW_{th}$.

| | GED | | | | | CPPD | | All |
|---|---|---|---|---|---|---|---|---|
| | **Biomass** | **Coal** | **Gas** | **Oil** | **Peat** | **Biomass** | **Coal** | |
| **Germany** | 8 | 3 | 13 | | | 6 | | **30** |
| **Austria** | 16 | | 3 | 3 | | 3 | | **25** |
| **Czech Rep.** | | 9 | 9 | | | | | **18** |
| **Poland** | | 13 | | | | | 1 | **14** |
| **Sweden** | 8 | | | | 2 | 3 | | **13** |
| **France** | 2 | | 4 | | | 3 | | **9** |
| **Spain** | | | 8 | | | | | **8** |
| **Finland** | 4 | | 2 | | 1 | 1 | | **8** |
| **Italy** | | | 3 | | | 2 | | **5** |
| **Denmark** | 3 | 1 | 1 | | | | | **5** |
| **Nether.** | | | 1 | | | 3 | | **4** |
| **Hungary** | | 1 | 2 | | | | | **3** |
| **Slovakia** | | | | 3 | | | | **3** |
| **Latvia** | | | | | | 3 | | **3** |
| **Greece** | | | 2 | | | | | **2** |
| **Ireland** | 1 | | | | 1 | | | **2** |
| **ALL** | **42** | **27** | **48** | **6** | **4** | **24** | **1** | **152** |

**Table B.3:** Number of plants per country, divided into fuel for 20 – 50 $MW_{th}$.

| | **GED** | | | | | **CPPD** | | | **All** |
|---|---|---|---|---|---|---|---|---|---|
| | **Biomass** | **Coal** | **Gas** | **Oil** | **Peat** | **Biomass** | **Coal** | **Peat** | |
| **Germany** | 5 | 4 | 4 | | | 30 | | | **43** |
| **Poland** | | 23 | | | | | 12 | | **35** |
| **Sweden** | 8 | | | | 2 | 16 | | 1 | **27** |
| **Austria** | 5 | | 3 | 2 | | 15 | 1 | | **26** |
| **Czech R.** | | 12 | 3 | 3 | | | | | **18** |
| **Italy** | 8 | | 4 | | | 4 | | | **16** |
| **France** | 4 | | | | | 5 | | | **9** |
| **Spain** | 3 | | 4 | | | | | | **7** |
| **Finland** | | | | | 1 | 4 | | 2 | **7** |
| **Lithu.** | 1 | | 2 | | | 2 | | | **5** |
| **UK** | | | | | | 5 | | | **5** |
| **Hungary** | | 4 | | | | | | | **4** |
| **Greece** | | | 2 | 2 | | | | | **4** |
| **Slovakia** | | 3 | | | | | | | **3** |
| **Romania** | 1 | | 2 | | | | | | **3** |
| **Portugal** | | | | | | 3 | | | **3** |
| **Estonia** | | | | 1 | | 1 | | | **2** |
| **Denmark** | 2 | | | | | | | | **2** |
| **Latvia** | | | | | | 1 | | | **1** |
| **ALL** | **37** | **46** | **24** | **8** | **3** | **86** | **13** | **3** | **220** |

# C

# Plants per country and boiler

**Table C.1:** Number of plants per country, divided into boiler types for 1 – 5 $MW_{th}$.

| | GED | | | | CPPD | | | | ALL |
|---|---|---|---|---|---|---|---|---|---|
| | **Grate** | **FB** | **Pulv.** | **Unknown** | **Grate** | **FB** | **Pulv.** | **Unknown** | |
| **Germany** | 4 | | | 3 | | | | | **7** |
| **Czech Rep.** | 4 | | | 1 | | | | | **5** |
| **Spain** | | | | 3 | | | | | **3** |
| **France** | | | | 2 | | | | | **2** |
| **Austria** | 1 | | | | | | | | **1** |
| **Poland** | 1 | | | | | | | | **1** |
| **ALL** | **10** | **0** | **0** | **9** | **0** | **0** | **0** | **0** | **19** |

**Table C.2:** Number of plants per country, divided into boiler types for 5 – 20 $MW_{th}$.

| | GED | | | | CPPD | | | | ALL |
|---|---|---|---|---|---|---|---|---|---|
| | **Grate** | **FB** | **Pulv.** | **Unknown** | **Grate** | **FB** | **Pulv.** | **Unknown** | |
| **Germany** | 6 | | | 14 | 4 | | | 1 | **25** |
| **Czech Rep.** | 9 | | | 9 | | | | | **18** |
| **Austria** | 7 | | | 6 | | 1 | | | **14** |
| **Poland** | 13 | | | | 1 | | | | **14** |
| **Spain** | | | | 8 | | | | | **8** |
| **France** | | 1 | | 4 | | 2 | | | **7** |
| **Denmark** | 2 | 2 | | 1 | | | | | **5** |
| **Sweden** | 1 | 3 | | | | 1 | | | **5** |
| **Finland** | | 2 | | 1 | | 1 | | | **4** |
| **Nether.** | | | | 1 | 1 | | | 1 | **3** |
| **Slovakia** | | | | 3 | | | | | **3** |
| **Hungary** | | | | 2 | | | | | **2** |
| **Italy** | | | | | 1 | | | | **1** |
| **Latvia** | | | | | | | | 1 | **1** |
| **ALL** | **38** | **8** | **0** | **49** | **7** | **5** | **0** | **3** | **110** |

**Table C.3:** Number of plants per country, divided into boiler types for 20 – 50 $MW_{th}$.

| | GED | | | | CPPD | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | **Grate** | **FB** | **Pulv.** | **Unknown** | **Grate** | **FB** | **Pulv.** | **Unknown** | |
| **Poland** | 23 | | | | 10 | | 2 | | **35** |
| **Germany** | 7 | 1 | | 3 | 19 | 4 | | | **34** |
| **Sweden** | 1 | 5 | | | 2 | 8 | | | **16** |
| **Czech Rep.** | 5 | 1 | 3 | 6 | | | | | **15** |
| **Austria** | 1 | | | 3 | 7 | | | | **11** |
| **Italy** | 3 | | | 2 | 2 | 1 | | | **8** |
| **Finland** | | 1 | | | | 6 | | | **7** |
| **Spain** | 2 | 1 | | 4 | | | | | **7** |
| **France** | 1 | | | | 2 | 1 | | | **4** |
| **Greece** | | | | 4 | | | | | **4** |
| **Hungary** | 4 | | | | | | | | **4** |
| **UK** | | | | | 4 | | | | **4** |
| **Portugal** | | 3 | | | | | | | **3** |
| **Slokavia** | 1 | | 1 | 1 | | | | | **3** |
| **Denmark** | 2 | | | | | | | | **2** |
| **Estonia** | 1 | | | | | | | | **1** |
| **Romania** | | | | 1 | | | | | **1** |
| **ALL** | **51** | **12** | **4** | **24** | **46** | **20** | **2** | **0** | **159** |

# D

# Required collection efficiency for each options

This appendix on the next page shows in detail which options that fulfill the MCPD limits, and the options that don't fulfill the MCPD limits. It is based on assumed emission level limits, see Table 3.4 along with Required Collection Efficiency (RCE).

**Table D.1:** All the options and respective estimated collection efficiency for different fuels and pollutants due to the assumed emission limits (presented as Unabated) as well as the MCPD limits (presented as Limits).

| **Fuel** | **Pollutant** | **Unabated** | **Limits** | **RCE** | **DSI+ESP** | **DSI+FF** | **NID L.** | **NID** | **TWESP** |
|---|---|---|---|---|---|---|---|---|---|
| Bituminous | PM | 22000 | 30 | 99.86 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % |
| | SO2 | 3400 | 400 | 88.24 % | < 60 % | < 75 % | < 90 % | < 98 % | - % |
| Lignite | PM | 40500 | 30 | 99.93 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % |
| | SO2 | 2000 | 400 | 80 % | < 60 % | < 75 % | < 90 % | < 98 % | - % |
| Peat | PM | 8900 | 30 | 99.66 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % |
| | SO2 | 500 | 400 | 20 % | < 60 % | < 75 % | < 90 % | < 98 % | - % |
| Biomass | PM | 3390 | 30 | 99.12 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % | < 99.9 % |
| | SO2 | 250 | 200 | 20 % | < 60 % | < 75 % | < 90 % | < 98 % | - % |