# The Calculation of Country Specific Emission Factors for the Stationary Combustion of Fuels in the Electricity Generation Sector

environmental affairs
Department:
Environmental Affairs
REPUBLIC OF SOUTH AFRICA

giz Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) GmbH

On behalf of:
Federal Ministry for the Environment, Nature Conservation, Building and Nuclear Safety
of the Federal Republic of Germany

**IMPRINT**

**Prepared for**

Department of Environmental Affairs

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**Acknowledgements**

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Published in South Africa February 2016

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# LIST OF ABBREVIATIONS AND ACRONYMS

| | |
|---|---|
| Af,m | mass of fuel consumed (metric tons) as received |
| CEEEZ | Centre for Energy, Environment and Engineering Zambia |
| CEM | continuing emissions monitoring system |
| CFR | code of federal regulations |
| $CH_4$ | methane |
| $CO_2$ | carbon dioxide |
| $C_{CO2}$ | average concentration of $CO_2$ in exhaust gas on a wet basis (fraction by volume) |
| $CO_2$ | average concentration of $O_2$ in exhaust gas on a dry basis (fraction by volume) |
| CSP | Climate Support Programme |
| $D_{CO2}$ | density of $CO_2$ |
| DEA | Department of Environmental Affairs |
| E | mass emissions of $CO_2$ (metric tons) |
| EF | emission factor |
| Fc,m | total carbon (from ultimate analysis) as received content of fuel on a mass basis (C % by mass ) |
| $F_{CO2}$ | ratio of the volume of $CO_2$ generated, on a dry basis and at standard temperature and pressure, to the gross calorific value of the fuel combusted ($m^3/kJ$) |
| FD | forced draught |
| $F_{exhaust}$ | ratio of the volume of total exhaust gases generated, on a dry basis and at standard temperature and pressure, to the gross calorific value of the fuel combusted (m3/kJ) |
| GHG | greenhouse gas |
| GIZ | Deutsche Gesellschaft für Internationale Zusammenarbeit |
| GJ | gigajoules |
| IPCC | Intergovernmental Panel on Climate Change |
| kJ | kilojoules |
| $O_2$ | oxygen |
| Q | average volumetric flow rate on a wet basis and at standard temperature and pressure ($m^3$/hour). |
| TACCC | transparency, accuracy, completeness, consistency and comparability |

# 1. INTRODUCTION

## 1.1 Background

The energy sector in South Africa is the main contributor of greenhouse gas (GHG) emissions and a key category in the national GHG inventory (DEA 2014). Hence, it is important that activity data and country specific emission factors from this sector are well known to ensure accurate determination of the national GHG inventory for required national and international reporting. The accurate assessment of GHG emissions in this sector is also important for mitigation purposes thus the National Climate Change Response (DEA 2011: 297) requires the compilation of an accurate, complete and updated GHG emissions inventory to ensure a good foundation for effective mitigation response.

According to the Intergovernmental Panel on Climate Change's (IPCC's) principles of good practice, on the overall, a quality inventory of anthropogenic emissions and removals of GHGs that is credible and convincing should meet the following indicators of quality (IPCC 2006).

- transparency,
- accuracy,
- completeness,
- consistency and
- comparability (TACCC).

One of the prerequisites required for achieving TACCC is migration of emission factors from tier 1 through tier 2 to the tier 3 methodologies developed by the IPCC.

Tier 1 emission factors are readily available national or international factors such as those provided by the IPCC as default values and therefore can be used by all countries in the absence of country specific values. The use of a tier 1 emission estimate for the energy sector requires the following information;

- data on the amount of fuel combusted and
- **default emission factor** (for example, provided by the IPCC).

Tier 2 emission factor standards require an intermediate level of complexity and locally specific data. Generally the use of a tier 2 approach requires:

- data on the amount of the fuel combusted and
- a **country specific emission factor** for each fuel.

**Country-specific emission factors** are developed by taking into account country-specific data, such as:

- carbon content of the fuels used,
- carbon oxidation factors and
- fuel energy content.

Emission factor determination for non-$CO_2$ gases depends on the type of fuel, combustion technology, operating conditions, control technology, quality of maintenance and age of equipment.

It is good practice to use the most disaggregated, technology-specific and country-specific emission factors available, particularly those derived from direct measurements at the different stationary combustion sources.

Tier 3 emission factor standards are the most complex and require the most specific data. A tier 3 approach splits the fuel combustion statistics according to the following variables and uses emission factors that are dependent upon various combinations of each:

- data on the amount of fuel combusted,
- a country specific emission factor for each gas,
- combustion technology,
- operating conditions,

- control technology,
- quality of maintenance and
- age of the equipment used to burn the fuel.

South Africa's power sector is dominated by coal, which accounts for about 88% of energy generation with the remainder being nuclear power (5%), hydroelectric (7%), and a small amount from wind and pumped storage. At the time of study, Eskom, the national utility was running 13 coal fired power stations and four liquid fuel (diesel-kerosene) gas turbine power stations. The utility is in the process of adding two large coal power stations by 2019. These fossil-fuel based power stations are listed in Annex 2. Eskom also operates non-fossil fuel power plants that include six hydropower stations, two pumped storage plants, one nuclear plant and one wind plant with one planned pumped storage power plant and other wind and solar projects (of the order of 4000MW) planned to come on stream. There are also natural gas power plants operated by SASOL of the order of 175MW at Sasolburg and 280MW at Secunda.

## 1.2 Project Description

The Climate Support Programme (CSP) of the Deutsche Gesellschaft für Internationale Zusammenarbeit (GIZ) South African office supports the Department of Environmental Affairs (DEA) in achieving the transition to a low carbon and climate resilient economy as stipulated in South Africa's National Climate Change Response White Paper (DEA 2011). The ability of South Africa to achieve the objective of mitigating GHG emissions is highly dependent on accurate knowledge of its emission trends and the collective ability to alter these trends.

Within the national GHG emissions inventory, the electricity generation sector is identified as a key source category as its emission estimates have a significant influence on the country's total inventory of GHGs (DEA 2014). Increasing the accuracy of GHG calculation by considering use of country-specific emission factors for this sector will go a long way towards mapping the national GHG trajectory and transition to a low carbon economy.

## 1.3 Project Objectives

### *1.3.1 Overall Project Objective*

The overall objective of this study was therefore to improve the accuracy of GHG emissions calculations from the electricity sector by making use of country specific emission factors. The specific objectives were to:

1. Undertake direct emission measurements at selected and representative ESKOM power plants.
2. To apply tier 2 and tier 3 IPCC methodologies in determining the country specific emission factors of the electricity sector.

### *1.3.2 Revised Project Objective*

Due to unforeseen circumstances, the direct measurements could not be made on specific ESKOM plants as initially envisaged. Options that were considered were to make measurements at Kelvin coal power station in Johannesburg and SASOL's Sasolburg and Secunda coal and gas power plants. Permission eventually could not be secured to take measurements at the Kelvin coal power station. In the end, measurements could only be made at Sasolburg and Secunda.

Instead of using direct measurement for the ESKOM plants, the calculation method was the only feasible way to derive emission factors for the utility plants after failing to get permission to take measurements at the power stations. Therefore, though the overall main objective remained the same, the revised specific objectives were as follow:-

1. To undertake direct emission measurements on boilers at Sasolburg and Secunda coal and gas power plants
2. To apply tier 2 and tier 3 IPCC methodology to determine the specific emission factors for the Sasolburg and Secunda power plants
3. To apply the tier 2 IPCC methodology to estimate the country specific emission factors for ESKOM.

# 2. METHODOLOGY

## 2.1 Analytical Framework

In undertaking this assignment, the project was guided by the framework outlined in figure 2.1.

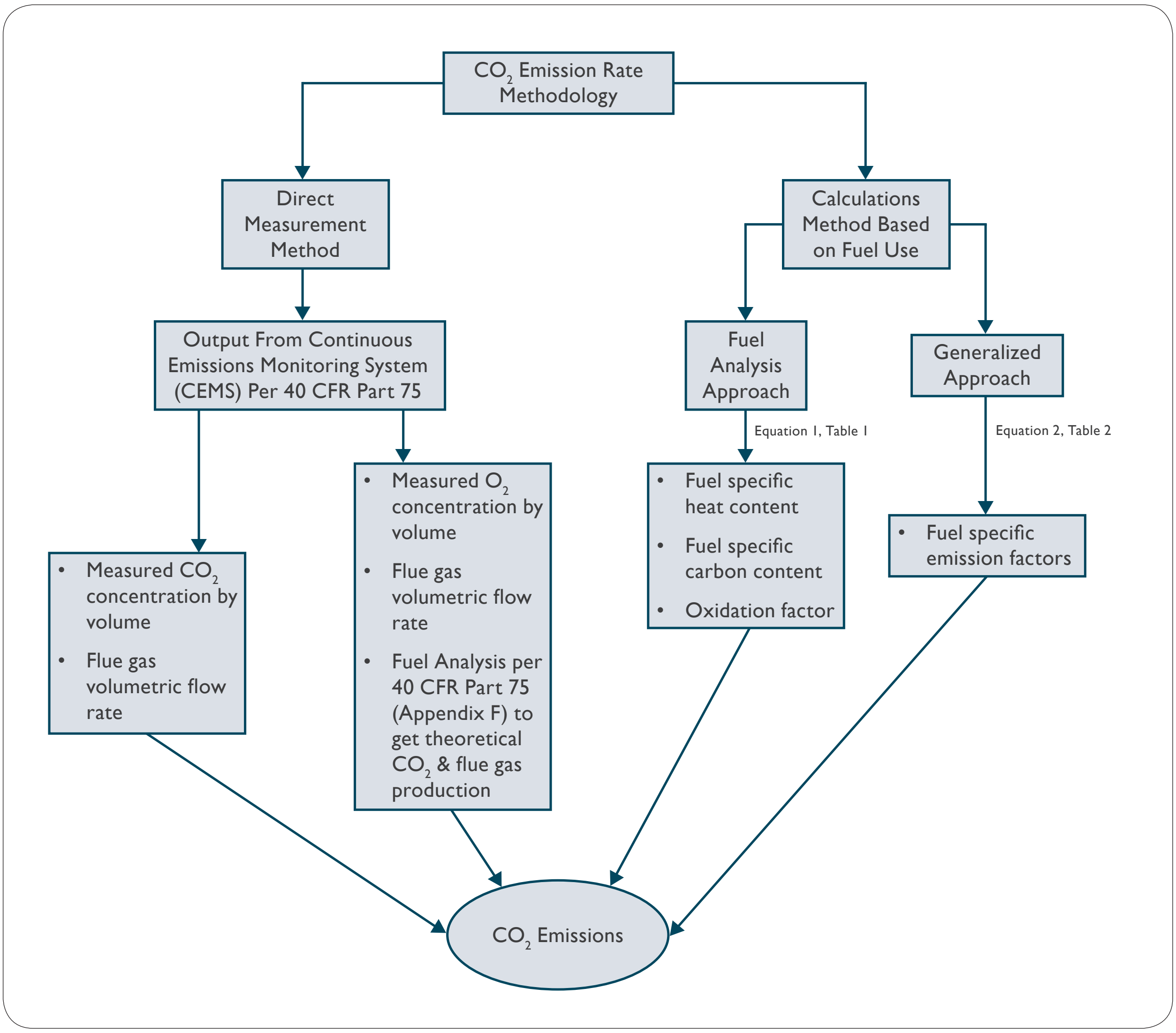



Figure 2.1: Project analytical framework for emission factor estimation

Determination of the country specific emission factors was done using the ***calculation method*** based on fuel use and ***direct measurement***, which are tier 2 and tier 3 IPCC approaches respectively as shown in figure 2.1. This is essential to assist selection of the appropriate methodology for estimating country specific emission factors.

### 2.1.1 *Calculation method (tier 2)*

1. **The following equation was used under the calculation method** *(Gillenwater 2005)*

$$E = A_{f,m} \cdot F_{c,m} \cdot F_{ox} \cdot (44/12) \quad \text{.......} \quad 1$$

**Where,**

E = Mass emissions of $CO_2$ (metric tons)

Af,m = Mass of fuel consumed (metric tons) as received

Fc,m = Total carbon (from ultimate analysis) as received content of fuel on a mass basis (C % by mass)

Fox = Oxidation factor to account for fraction of carbon in fuel that remains as soot or ash. Carbon in fly ash should be used

(44/12) = The ratio of the molecular weight of $CO_2$ to that of carbon

#### *2.1.1.1 Calculation Protocol*

Table 2.1 provides guidelines on how each of the parameters in equation 1 are measured or calculated.

Table 2.1: Estimation of $CO_2$ emissions using the calculation method

| Data required | How to measure or calculate | When to measure or calculate |
|---|---|---|
| Mass emissions of $CO_2$ (metric tons) – E | Calculated using equation (1). | Calculated for every unique set of relevant parameters. |
| Mass of fuel consumed (metric tons) - $A_{f,m}$. | Measured using fuel mass flow meter or fuel mass flow receipts, or purchase records at electricity generating plant for every fuel type. | Data supplied by utilities, in this case ESKOM and SASOL. |
| Quantity of electricity generated (kWh) | Noted from plant operation data/ records. | Data supplied by ESKOM and SASOL. For Eskom obtained from annual reports. |
| Carbon content of fuel on a mass basis (metric tons C/metric ton) - $F_{c,m}$. | Quoted from producers of each fuel type or measured from laboratory facilities (in the absence of data from the producers). | Data supplied by ESKOM and SASOL. |
| Oxidation factor to account for fraction of carbon in fuel that remains as soot or ash - $F_{ox}$.The uncertainty is better if the carbon in fly ash is measured. | Measured from combustion efficiency using the Lancom gas analyser used in the project and was to be compared with measurement of unreacted carbon in ash at power stations. | Data to be supplied by ESKOM and SASOL. Oxidation factor also measured by the Lancom instrument. |
| Emission Factor. | Calculated from the IPCC general methodology: *$CO_2$ Emissions* *= Emissions Factor x Activity Data* | Calculated for each set of parameters. |

The approach that was used for this methodology is summarised in the schematic diagram below.

**Step 1: Determine the amount of fuel combusted**

Identify all types of fuels combusted at the facility. Determine annual fuel use by fuel type, measured in terms of physical units (mass or volume)

▼

**Step 2: Convert the amount of fuel combusted into energy flow**

To convert fuel combusted on a mass/volume flow to energy flow, the heating value of each fuel type is used-provided by ESKOM or SASOL

▼

**Step 3: Determine carbon content of fuel consumed**

Total content of fuel, expressed in terms of mass of carbon per mass, volume or energy of fuel, can be determined by fuel sampling and analysis. ESKOM and SASOL provided from their records.

▼

**Step 4: Calculate carbon emitted**

When fuel is burned, most of the carbon is eventually oxidized to $CO_2$. To account for the small fraction of carbon that may not be oxidized during combustion, the carbon content of fuel is determined through combustion efficiency and/or carbon in the ash measurements.

▼

**Step 5: Convert $CO_2$ emitted tons**

To obtain total annual $CO_2$ emitted in units of tons/year, multiply carbon emissions by the ratio of molecular weight of $CO_2$ to carbon (44/12) after taking the carbon in flyash into account and the conversion factor from kg to tonnes.

Figure 2.2: Approach used to calculate emissions

### 2.1.2 *Direct Measurement Method (Tier 3)*

Under the direct measurement method, the following equations were used depending on the conditions on site:

2. **Direct measurement when $CO_2$ concentration is on wet basis** *(Gillenwater 2005)*

$$E = DCO_2 \cdot CCO_2 \cdot Q \qquad (2)$$

**Where,**

E = Mass emissions of $CO_2$ (metric tons/hour)

$DCO_2$ = Density of $CO_2$ (e.g., 1.87 kg/m$^3$ at 1.013 bar and 15°C) at standard temperature and pressure. In South Africa, the temperature standard is 0°C. The density used in South Africa is 44/22.4 = 1.96 kg/m$^3$ at 101.32 and 0°C.

$CCO_2$ = Average concentration of $CO_2$ in exhaust gas on a wet basis (fraction by volume)

Q = Average volumetric flow rate on a wet basis and at standard temperature and pressure (m$^3$/hour).

Under the direct measurement method, the following parameters were measured, determined and/ or calculated (Table 2.2).

Table 2.2: Estimation of CO2 emissions using Direct Measurement Method

| Data required | How to measure or calculate | When to measure or calculate |
|---|---|---|
| Mass emissions of $CO_2$ (metric tons/hour) – E | Calculated using equations (2). | Calculated for every unique set of relevant parameters. |
| Density of $CO_2$ at standard temperature and pressure – $DCO_2$ | Quoted from (default value) at standard temperature and pressure. | Quoted once. A figure of 1.96 kg/m$^3$ was used. |
| Average concentration of $CO_2$ in exhaust gas on a wet basis (fraction by volume) – $CCO_2$ | Measured using the Lancom gas analyser (used in the project). | Measured every 15 seconds for 30 minutes with 10 minute breaks in between measurements. |
| Average volumetric flow rate on a wet basis and at standard temperature and pressure (m$^3$/hour) – Q | Measured using the Lancom gas analyser fuel flow probe and compared with the forced draught (FD) fan flow with a determined correction. | Measured every 15 seconds for 30mins with 10minute breaks in between measurements. |
| Average stack moisture content (fraction by volume) – $CH_2O$ | Determined from historical measurements at the plant. | Data was provided by SASOL |
| Quantity of electricity generated (kWh) | Noted from plant operation data/ records. | Data to be supplied by SASOL |
| Emission factor. | Calculated using the IPCC general methodology: *$CO_2$ Emissions = Emissions Factor x Activity Data** | Calculated for each set of parameters. |

*(IPCC, 2006)

Alternatively, the oxygen concentration can be used as a proxy for $CO_2$ in determining the emission factors as described below. However, this method was not followed in determining the emission factor as further configurations of the instrument were required and there was limited time to undertake the measurements. The method is therefore included for information so that it can be considered in future emission factor (EF) improvements.

3. **Direct measurement when $O_2$ concentration is used as a proxy for $CO_2$. A proxy in this case means measured $O_2$ is used to derive $CO_2$ emissions. The formula below shows how the $CO_2$ can be calculated from the $O_2$ concentration** *(Gillenwater 2005)*.

$$CCO_2 = ((0.209 - CO_2) / 0.209) \cdot FCO_2 / Fexhaust .......3$$

**Where,**

$CCO_2$ = Average concentration of $CO_2$ in exhaust gas on a dry basis (fraction by volume)

$CO_2$ = Average concentration of $O_2$ in exhaust gas on a dry basis (fraction by volume)

0.209 = Fraction of $O_2$ in ambient air by volume

$FCO_2$ = Ratio of the volume of $CO_2$ generated, on a dry basis and at standard temperature and pressure, to the gross calorific value of the fuel combusted (m$^3$/kJ)

Fexhaust = Ratio of the volume of total exhaust gases generated, on a dry basis and at standard temperature and pressure, to the gross calorific value of the fuel combusted (m$^3$/kJ).

Therefore, to determine the $CO_2$ emission factor under both approaches, the following IPCC general method for estimating $CO_2$ emissions from stationary combustion was used:

*$CO_2$ Emissions = Emission Factor x Activity Data* (IPCC, 2006)

Where the activity data is the quantity of fuel consumed or electricity generated and the $CO_2$ emissions are determined in equations (1), (2), and (3).

## 2.2 Measurement Tools

Measurements ($O_2$, CO and $CO_2$ concentrations, flow rate) taken using the Lancom 4 gas analyser were used to derive $CO_2$ EF. The instrument had a provision to measure $CH_4$ and NOx but it was agreed that the concentration of $CH_4$ in flue gas was negligible and hence was not measured. However, as part of the study, $N_2O$ (which has a higher global warming potential) was measured using a SB1000 gas analyser that was purchased together with the Lancom 4 for this project.

## 2.3 Measurements at Sasolburg and Secunda Power Stations

Although permission was granted by SASOL to take measurements at their power plants, the CEEEZ/EECG project team was not allowed to take measurements as only service providers registered with SASOL are allowed to do so. CEEEZ/EECG invited some of those service providers to tender for undertaking measurements at Sasolburg and Secunda and engaged SGS South Africa (Pty) Ltd as the service provider for the emission monitoring.

Measurements were done on two thermal installations at the Sasolburg plant (namely one coal-fired and one natural gas fired boiler) and on one coal fired boiler at Secunda. It was not possible to take measurements on the gas fired boilers at Secunda as these were not running at the time scheduled for measurements.

Stack sampling was done for eight hours for three consecutive days to obtain a 24 hour cycle measurement at normal operating conditions. The instrument was set to take measurements every 15 seconds for 30 minutes with 10 minute intermittent breaks for eight hours. This translated to an average of 1200 data points for analysis per plant.

## 2.4 Limitations and Constraints

The project experienced a number of challenges of an organisational, operational and scheduling nature and problems to do with the instrument. The major organisational issue was that ESKOM requested additional resources to cover for time for its staff. Since the additional resources requested were beyond the original budget provided for the project, the project scope had to be revised. Attempts were made to undertake the project at Kelvin Power Station but the team was unable to take measurements due to operational issues.

SASOL made four plants available for measurements under the condition that these were to be done by service providers registered on their database. To conform to this requirement, a tender was raised for emission testing and monitoring services from among Sasol service providers. SGS based in Johannesburg was selected. During the duration of the measurements by SGS, CEEEZ/EECG was available to attend to emerging issues and challenges.

Once the service provider was appointed, challenges arose with the scheduling of the measurements from SASOL as measurements could only be done when the plants were running. On the first day of measurements, it was discovered that the process conditions were not suitable to leave the instrument to take measurements unattended as initially proposed in the methodology. As a result the methodology had to be revised and restricted to 3 x 8 hour shifts as opposed to 3 x 24 hour shifts.

Another challenge faced was that process conditions were more unfavourable than anticipated since the flue gas contained high particulate loads and the ducts were vibrating, which caused the readings to drift off range. This necessitated the recalibration of the Lancom analyser. Measurements at the Secunda gas turbine could not be made as the plant was not operational on the scheduled date. In addition it was not possible to take measurements for coal plants using the Lancom analyser due to the harsh conditions at the site. Instead Testo gas analysis equipment belonging to SGS was used.

# 3. RESULTS AND ANALYSIS

This section is divided into two parts. The first part discusses the results obtained from the measurements done at Sasolburg and Secunda. It commences with a description of the results obtained for $O_2$, $CO_2$, plant efficiency and flue gas volumetric flow rates, and $N_20$ results. The analysis of these parameters reflects the interplay with the emission factors being derived. The first part concludes with a discussion of the emission factors obtained using the tier 2 (calculation based emission factor) and tier 3 (direct measurement emission factor) methodologies.

The second part focuses on the results of the emission factor for selected ESKOM plants estimated using tier 2 (calculation based emission factor) methodology, based on fuel consumption data provided from the different plants.

## 3.1 SASOL Direct Measurement Results

### *3.1.1 Sasolburg*

This subsection presents results originating from measurements that were taken on coal fired boiler 7 and on natural gas engine 2 for three days in 8 hour shifts.[1]

***Boiler 7 $O_2$ and $CO_2$ trends***

The gaseous emission trend displayed in figure 3.1 is characterised by low emissions in the morning, which gradually increased to a maximum after 14:00 hrs, whereafter they stabilise before starting a downward trend. On average, the trend is similar for days 1 and 2, with the exception of day 3 which seems to display an elevated emissions level. This could probably be due to a change in the process parameter as the day 1 and day 2 measurements were taken on consecutive days, while the day 3 measurements were taken after a 4-day break. However, on all 3 days, there are 3 distinct phases characterised by morning $CO_2$ average concentrations of 8.28%, mid-morning to early afternoon average concentrations of 9.61% and afternoon average concentrations reaching a maximum of 10.61%. The concentrations seem to respond to changes in ambient temperature.

Furthermore, the graphs show an inverse relationship between the $O_2$ and $CO_2$ concentration in the flue gases as expected, but while the $CO_2$ concentration shows an incremental trend, the $O_2$ concentration shows less variation in comparison to the $CO_2$.

[1] The obtained data were initially cleaned to remove any anomalies before analysis.

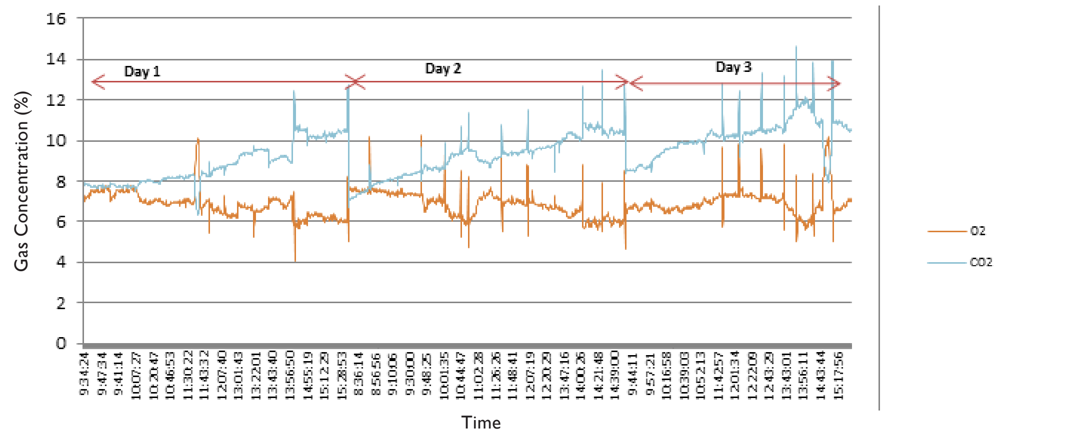



Figure 3.1: Oxygen and carbon dioxide emission trend for coal fired boiler number 7 at Sasolburg

### *Boiler combustion efficiency trend*

The process combustion efficiency trend in figure 3.2 shows a trend which mirrors that of the $CO_2$ concentration in the flue gas. The graph shows that the process combustion efficiency increases as the day progresses, starting between 86% and 88%, and reaching a maximum of 92% in the afternoon before starting a downward trend. A comparison of figures 3.2 and 3.1 shows an inverse relationship between the combustion efficiency and the oxygen concentration as expected since, as combustion efficiency increases, less oxygen participates in the combustion process, which tends to drift towards stoichiometric conditions.

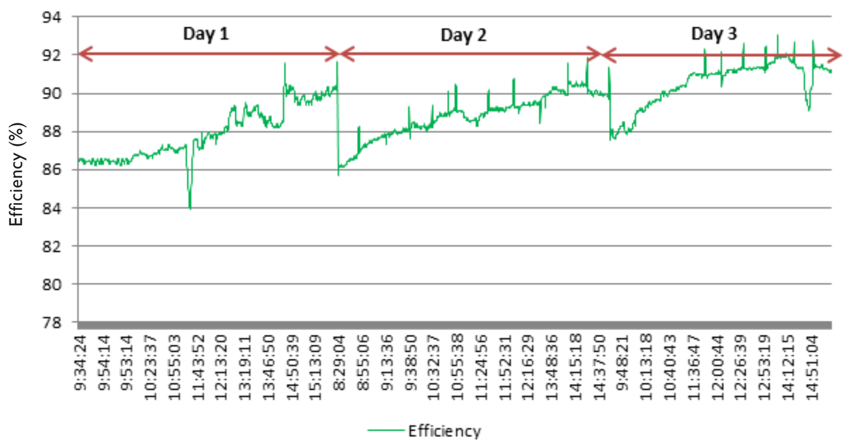



Figure 3.2: Boiler efficiency trend for boiler 7 at Sasolburg

***Gas temperature and ambient temperature trend***

A plot of the ambient temperature and flue gas temperature in figure 3.3 shows that both temperatures increased as the day progressed. A comparison of figure 3.3 with figures 3.1 and 3.2 shows that both the $CO_2$ concentration and process combustion efficiency trends mirror the changes in ambient temperature.

The standard deviation in the data for the three days of 1.83, 2.95, 1.52 for days 1, 2 and 3 respectively, is consistent with the standard temperature deviation for a similar SASOL plant which ranges between 1.71 and 2.32. Therefore the temperature variations are consistent with normal steady state process operation.

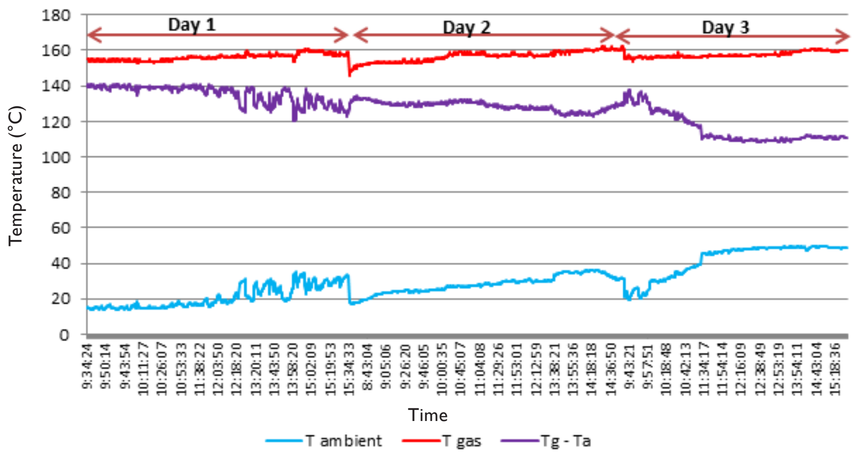



Figure 3.3: Flue gas and ambient temperature trend for boiler 7 at Sasolburg

***Flue gas flow rate trend***

The flue gas flow rate trend in figure 3.4 shows a different trend to that displayed by the $O_2$, $CO_2$ and process combustion efficiency. The graph shows that the flow rate remains more or less constant for the day but is punctuated by process variations that remain constant for some time. In addition, the average flow rate recorded is different for all the three days. This points to possible different steam production rates caused by different steam demand during the measurement period.

Process data from Secunda shows that at steady state operation the coal consumption rate, the steam consumption process flow rate and the total air flow rate have standard deviation ranges of 0.03 to 0.11, 0.89 to 1.65 and 2.70 to 3.40 respectively. By comparison the measured flue gas flow rate has a standard deviation of 7.91, 3.09 and 8.87 for days one, two and three respectively. Therefore only the data on day two reflects the steady state operation that characterises SASOL plants. These flow rate fluctuations could be due to the entrained fly ash in the stack blocking the pitot tubes.

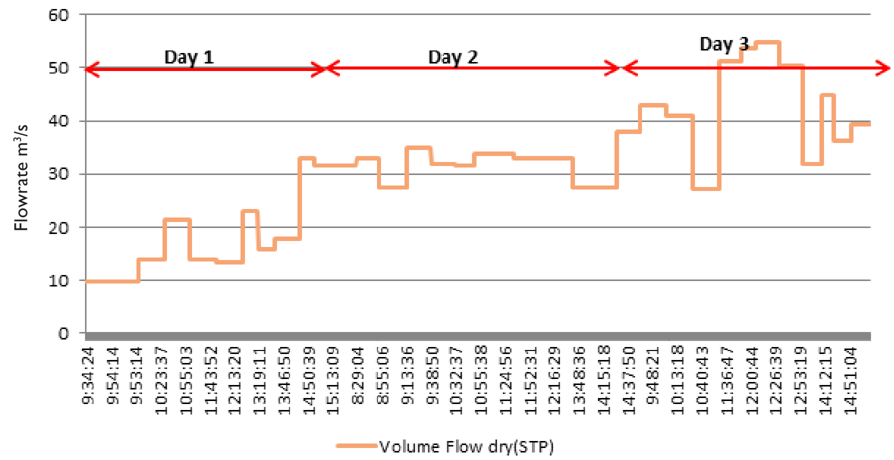



Figure 3.4: Flow rate measurements for boiler 7 at Sasolburg

***Natural gas engine 2 $O_2$ and $CO_2$ trends***

The $O_2$ and $CO_2$ trend in figure 3.5 for the Sasolburg gas engine 2 meets expectations since natural gas combustion is more homogenous and smooth than coal combustion. The average concentration of $CO_2$ is almost constant averaging 6.77% for the 3 days and is less than the minimum average recorded for the coal fired boilers. In addition the $O_2$ concentration is also constant for the period but is higher than the expected $CO_2$ concentration. The lower $CO_2$ concentration is mainly due to the low carbon content of natural gas compared to coal.

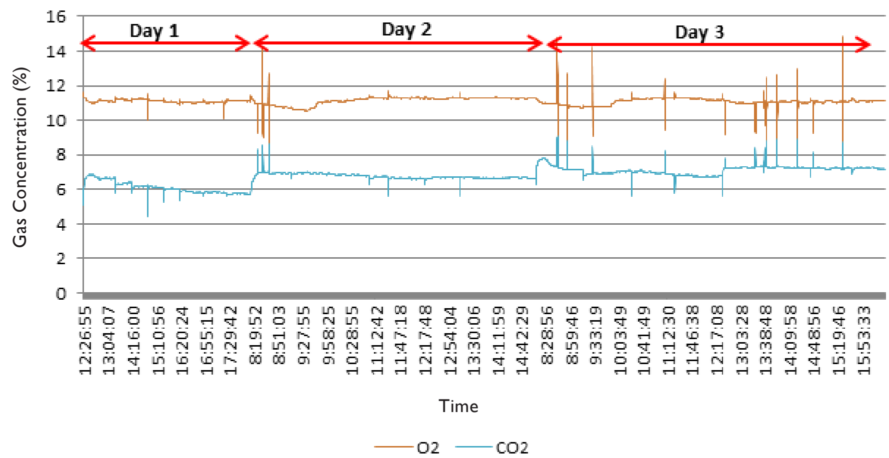



Figure 3.5: $O_2$ & $CO_2$ flue gas concentration for natural gas engine 2 at Sasolburg

***Natural gas engine 2 combustion efficiency trend***

The combustion efficiency trend depicted in figure 3.6 shows an almost similar trend to the $O_2$ and $CO_2$ trends. There is a marked gradual decrease in efficiency on day 1 (from 72% in the morning to 69% by the end of day), which then stabilises at around 72% on the second and third day before settling at 73% by the end of day 3.

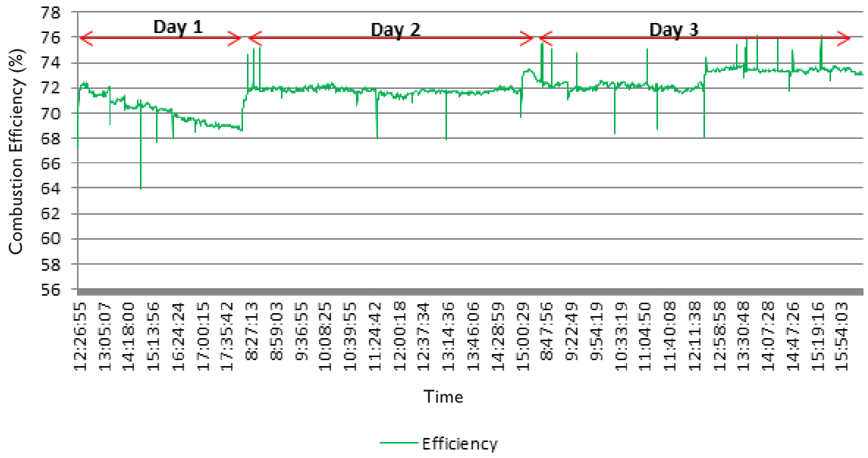



Figure 3.6: Combustion process efficiency of natural gas engine 2 at Sasolburg

***Natural gas engine 2 flue gas and ambient temperature trend***

The temperature trend in figure 3.7 for natural gas displayed a steady profile for the three days due to the more homogenous and smoother nature of combustion in gas turbines compared to coal power plants.

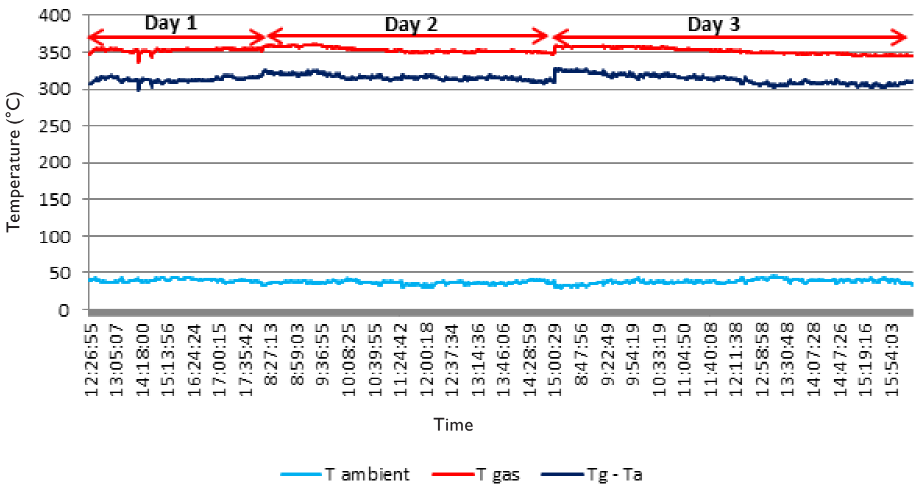



Figure 3.7: Flue gas and ambient temperatures from natural gas engine 2 at Sasolburg

*Natural gas engine 2 flue gas flow rate trend*

The flue gas flow rate, displayed in figure 3.8, remained almost constant for the first day and for part of the morning of the second day. Thereafter it displayed hourly variations, which are characteristic of changes in downstream steam demand resulting in changes in steam production and hence flue gas emissions and flow rate.

The flue gas flow rate recorded on day 1 has a low standard deviation of 0.38, which is typical of steady state operation. Though the standard deviation on days 2 and 3 averages 2.30 and is below the 3.34 recorded for the boiler airflow at Secunda, the fluctuations on days 2 and 3 are atypical of steady state operation.

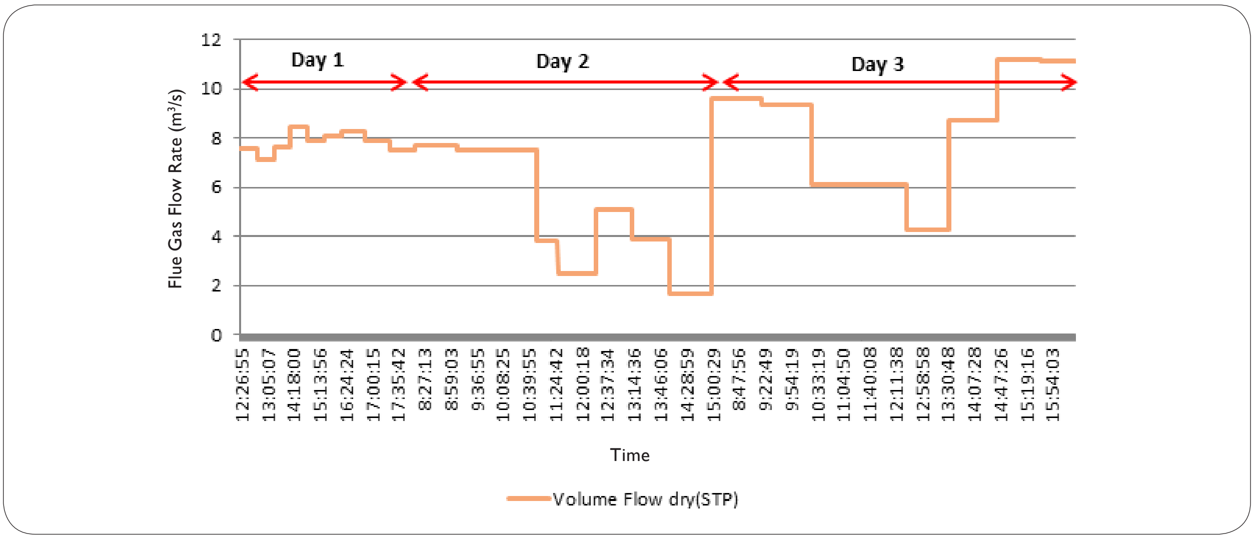



Figure 3.8: Flow rate measurements for boiler 7 at Sasolburg

### 3.1.2 Secunda

Initially, it was proposed to take measurements at one coal fired boiler and at one gas fired engine. However, the Secunda gas fired engine was not available at the time scheduled for measurement and therefore only the measurements on the coal fired boiler were done. Due to technical difficulties with the Lancom 4, this measurement had to be done with a TESTO gas analyser, while the Lancom 4 was used for flue gas flow rate measurements. Consequently, only measurements for two days were analysed as the data from the first day had to be discarded due to poor quality.

*Secunda coal boiler $O_2$ and $CO_2$ trends*

The $O_2$ and $CO_2$ flue gas concentration trend in figure 3.9 shows a constant profile for the two days of measurement. The $CO_2$ concentration averaged around 15% as compared to 3.5% for the $O_2$ concentration.

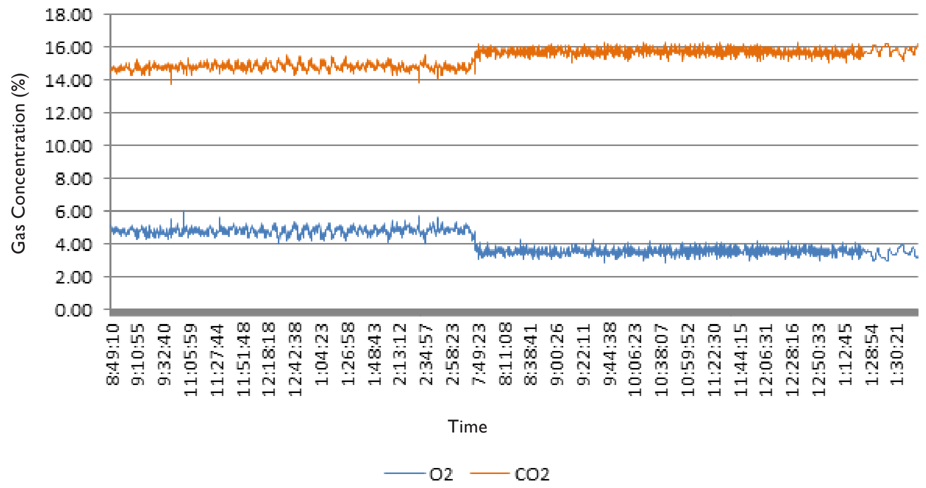



Figure 3.9: $O_2$ and $CO_2$ concentration of flue gas at Secunda boiler 7

***Secunda coal boiler combustion efficiency trend***

The combustion efficiency of boiler 7 at Secunda was constant at an average of 93.5% and was stable throughout the measurement period.

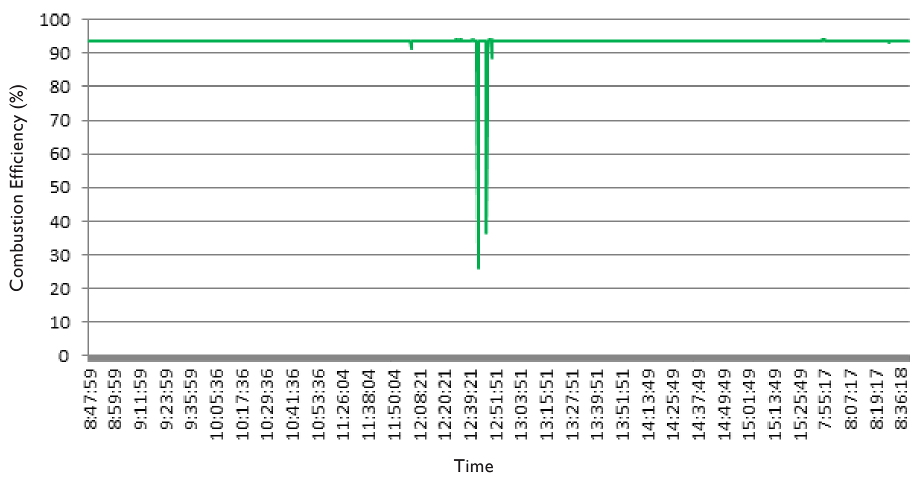



Figure 3.10: Process combustion efficiency of Secunda boiler 7

***Secunda coal boiler flue gas and ambient temperature trend***

The temperature profile in figure 3.11 shows that the average ambient temperature was above 33°C especially during the first day of measurement. The second day of measurement is characterised by a drop in the minimum ambient temperature to 20°C. The gas temperature stabilised at around 220°C.

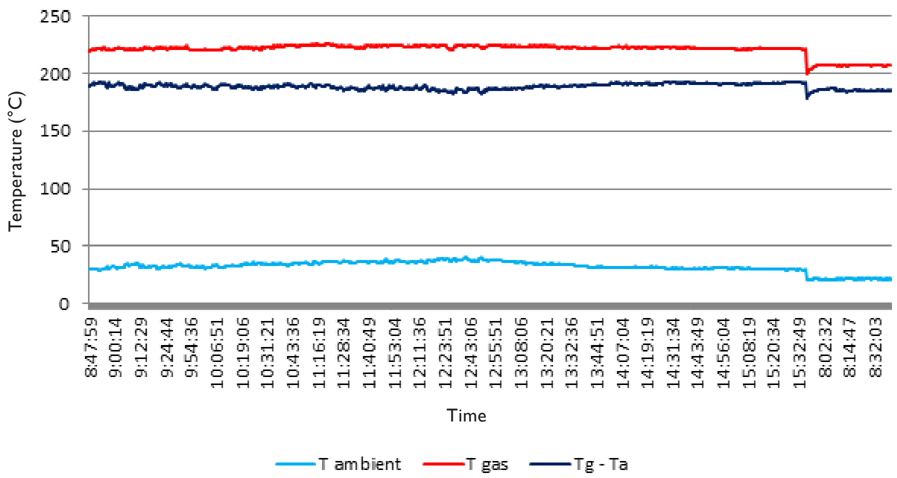



Figure 3.11: Flue gas and ambient temperature of Secunda boiler 7

***Secunda coal boiler flue gas flow rate trend***

The flue gas measurement results displayed in figure 3.12 show a significant variation in flue gas flow rate during the measurement period. In addition the data for day three were recorded only for an hour in the morning before the Lancom 4 battery failed. No further measurements were made since the TESTO gas analyser did not have that functionality. These results are inconsistent with the process data. The process data shows that the process was stable during the three days of measurement and coal feed rate varied only by a margin of +/- 3%. Therefore these results were not considered for the calculation of the emission factor.

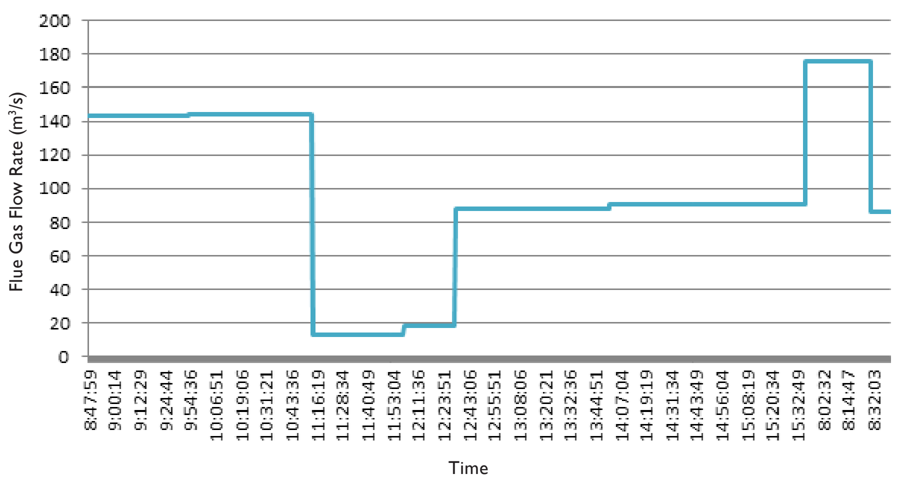



Figure 3.12: Flue gas flow rate of Secunda boiler 7

***$N_2O$ measurements at Sasolburg and Secunda***

Table 3: $N_2O$ measurements at Sasolburg and Secunda (PPM)

| | Plant | |
|---|---|---|
| | Sasolburg | Secunda |
| 5 mins | 1513.3 | 1372.8 |
| 5 mins | 1208.0 | 1380 |
| 2 mins | 1201.88 | 1221.5 |
| Average | 1307.73 | 1324.76 |

It is evident from the results obtained that $N_2O$ emissions averaging 1316.25 ppm (0.0013%) are insignificant when compared with average $CO_2$ emissions of 6.77% obtained from Sasolburg.

## 3.2 Emission Factor Determination

### *3.2.1 Calculation based emission factor*

To calculate the emission factor (EF) under this methodology, equation (I) from section 2.1.1 was used to obtain $CO_2$ emissions for the actual number of hours of test runs for day 1, 2 and 3 (at Sasolburg coal plant, Sasolburg gas turbines and Secunda coal plant) by multiplying the fuel consumption from SASOL for the duration of the run, carbon content of fuel obtained from SASOL, and oxidation rate that accounts for the ash carbon content. These process parameters were obtained from SASOL (refer to Box 1 equation).

To obtain $CO_2$ emissions per annum, the average $CO_2$ emissions (tonne/hour) from the above equation was multiplied by 8 760 hours per year and the yearly plant availability obtained from SASOL. Finally to obtain the EF, the $CO_2$ emissions per annum were divided by the activity data namely the coal consumption and the coal energy content of the coal to arrive at $tCO_2/GJ$ or $tCO_2/MWh$ similar to the units commonly used. The resulting EFs (tons $CO_2$/ton and tons $CO_2$/GJ coal) and tons $CO_2$/ton and tons $CO_2$/GJ NatGas) for Sasolburg and Secunda are shown in table 3.1.

**Box 1**
**Formula used for the calculation method**

**(I) E = Af,m • Fc,m • Fox • (44/12) ..................................................I**

Where,

E = Mass emissions of $CO_2$ (metric tons)

Af,m = Mass of fuel consumed (metric tons) as received

Fc,m = Total Carbon (from Ultimate analysis) as received content of fuel on a mass basis ( C % by mass )

Fox = Oxidation factor to account for fraction of carbon in fuel that remains as soot or ash. Carbon in fly ash should be used

(44/12) = The ratio of the molecular weight of $CO_2$ to that of carbon

Table 3.1: Data parameters to determine EFs at Sasolburg and Sedunda using the calculation methodology

| Sasolburg Coal Boiler | | | | |
|---|---|---|---|---|
| Item | Day 1 | Day 2 | Day 3 | Average |
| **Af,m** - mass of fuel consumed ( tons/hr) | | | | 24.39 |
| **Fc,m** - total carbon ( C % by mass ) | 47.78 | 47.78 | 47.78 | 47.78 |
| **Fox** - oxidation factor (%) | 100 | 100 | 100 | 100 |
| $CO_2$/C molecular ratio | 44/12 | 44/12 | 44/12 | 44/12 |
| **E** - $CO_2$ emissions of (tons $CO_2$ /hr) | | | | 42.730 |
| Coal calorific value (MJ/kg) | 18.67 | 18.67 | 18.67 | 18.67 |
| **Emission Factor** | | | | |
| Tons $CO_2$/ton coal | | | | 1.752 |
| Tons $CO_2$/GJ | | | | 0.094 |
| **Sasolburg Gas Turbine** | | | | |
| **Af,m** - mass of fuel consumed (ton/hr) | 1.730 | 1.706 | 1.728 | 1.722 |
| **Fc,m** - total carbon ( C % by mass ) | 75 | 75 | 75 | 75 |
| **Fc,m** - oxidation factor (%) | 100 | 100 | 100 | 100 |
| $CO_2$/C molecular ratio | 44/12 | 44/12 | 44/12 | 44/12 |
| **E** - $CO_2$ emissions (tons $CO_2$/hr) | 4.8 | 4.7 | 4.8 | 4.7 |
| Natural gas net calorific value (MJ/kg) * | 40.8 | 40.8 | 40.8 | 40.8 |
| **Emission Factor** | | | | |
| Tons $CO_2$/ton natural gas | 2.75 | 2.75 | 2.75 | 2.75 |
| Tons $CO_2$/GJ | 0.067 | 0.067 | 0.067 | 0.067 |
| **Secunda Coal** | | | | |
| **Af,m** - mass of fuel consumed (tons/hr) | 84.5 | 85.0 | 85.3 | 84.6 |
| **Fc,m** - total carbon ( C %by mass ) | 45.8 | 45.8 | 45.8 | 45.8 |
| **Fc,m** - oxidation factor (%)[2] | 100 | 100 | 100 | 100 |
| $CO_2$/C molecular ratio | 44/12 | 44/12 | 44/12 | 44/12 |
| **E** - $CO_2$ emissions (tons CO2/hr) | 141.904 | 142.743 | 141.568 | 142.072 |
| Coal calorific value (MJ/kg) | 20.84 | 20.84 | 20.84 | 20.84 |
| **Emission Factor** | | | | |
| Tons $CO_2$/ton coal | 1.679 | 1.679 | 1.679 | 1.679 |
| Tons $CO_2$/GJ | 0.081 | 0.081 | 0.081 | 0.081 |

* Natural gas calorific value is not different from default values (Biomass Energy Centre n.d.)

2 Measured by Lancom 4

### 3.2.2 *Direct measurement based emission factor (SASOL)*

To calculate the emission factor under this methodology, equation (2) from section 2.1.1 was used to obtain the hourly $CO_2$ emissions (refer to Box 2). The $CO_2$ density of 1.96kg/m$^3$ at 101.32 and 0 degree Celsius was used for the calculation.

To obtain $CO_2$ emission per annum, the hourly $CO_2$ emissions (tonne/hour) from above was multiplied by 8 760 hours/year and the annual plant availability obtained from SASOL. Finally, to obtain the EF, the annual $CO_2$ emissions (tons $CO_2$/year) were divided by the activity data, which in this case is the annual coal consumption. All the process parameters necessary to complete these calculations were provided by SASOL. Secunda provided the most comprehensive process data, which gave hourly data for each of the three days. Sasolburg only gave average natural gas consumption for each of the three days and only the average coal consumption for all three days.

Results of the averaged fuel based emission factors based on direct measurements obtained from test runs for coal power plants and gas turbines at Sasolburg and Secunda are provided in table 3.2.

The results show that, as expected, the hourly emissions for coal fired boilers at Sasolburg and Secunda are more than those from the gas turbines. Figures for Secunda may have to be treated with caution, since the Lancom 4 malfunctioned. In addition, though the quality of the coal used at Sasolburg and Secunda is similar, the calculated EF is higher for Sasolburg than for Secunda. The EF derived from direct measurements for Sasolburg is lower than that for Secunda. The difference may stem from the measured flow rate, which varies considerably from the actual process variations observed from the supplied process data.

**Box 2**

**Formula used for the calculation method**

**E = DCO2 • CCO2 • Q ..........................................................2**

Where,

E = Mass emissions of $CO_2$ (metric tons/hour)

$D_{CO2}$ = Density of $CO_2$ (e.g., 1.87 kg/m$^3$ at 1.013 bar and 15°C) at standard temperature and pressure. In South Africa, the temperature standard is 0°C. The density used in South Africa is 44/22.4 = 1.96 kg/m$^3$ at 101.32 and 0°C.

$C_{CO2}$ = Average concentration of $CO_2$ in exhaust gas on a wet basis (fraction by volume)

Q = Average volumetric flow rate on a wet basis and at standard temperature and pressure (m$^3$/hour)

Table 3.2: Data parameters for determination of EF at Sasolburg and Secunda using the direct measurements methodology

| **Sasolburg Coal Boiler** | | | | |
|---|---|---|---|---|
| Item | Day 1 | Day 2 | Day 3 | Average |
| **$D_{CO2}$** - density of $CO_2$ | 1.96 | 1.96 | 1.96 | 1.96 |
| **$C_{CO2}$**- average concentration of $CO_2$ in exhaust gas (%) | 8.79 | 9.20 | 10.19 | 9.35 |
| **Q** - average volumetric flow rate ($m^3$/hr) | 66 853 | 115 557 | 154 080 | 110 114 |
| **E** - mass emissions of $CO_2$ (metric tons/hour) | 11.998 | 20.828 | 30.812 | 20.723 |
| **Af,m** - coal consumption rate (tons/hr) * | 24.39 | 24.39 | 24.39 | 24.39 |
| Coal calorific value (MJ/kg) | 18.67 | 18.67 | 18.67 | 18.67 |
| **Emission Factor** | | | | |
| Tons $CO_2$/ton coal † | 0.492 | 0.854 | 1.263 | 0.850 |
| Tons $CO_2$/GJ | 0.026 | 0.046 | 0.068 | 0.046 |
| **Sasolburg Gas Turbine** | | | | |
| **$D_{CO2}$** - density of $CO_2$ | 1.96 | 1.96 | 1.96 | 1.96 |
| **$C_{CO2}$**- average concentration of $CO_2$ in exhaust gas (%) | 6.10 | 6.75 | 6.95 | 6.77 |
| **Q** - average volumetric flow rate ($m^3$/hr) | 28 181 | 18 173 | 24 489 | 25 261 |
| **E** - mass emissions of $CO_2$ (metric tons/hour) | 3.365 | 2.423 | 3.371 | 3.370 |
| **Af,m** - natural gas consumption rate (ton/hr) | 1.730 | 1.706 | 1.728 | 1.722 |
| Natural gas net calorific value (MJ/kg) | 40.8 | 40.8 | 40.8 | 40.8 |
| **Emission Factor** | | | | |
| Tons $CO_2$/ton natural gas | 1.94 | 1.42 | 1.95 | 1.96 |
| Tons $CO_2$/GJ | 0.048 | 0.035 | 0.048 | 0.048 |
| **Secunda Coal** | | | | |
| **$D_{CO2}$** - density of $CO_2$ | 1.96 | 1.96 | 1.96 | 1.96 |
| **$C_{CO2}$**- average concentration of $CO_2$ in exhaust gas (%) | | 14.83 | | |
| **Q** - average volumetric flow rate ($m^3$/hr) | | 304 749 | | |
| Mass emissions of $CO_2$ (tons/hour) | 0.000 | 88.465 | 0.000 | 88.465 |
| **Af,m** - coal consumption rate (tons) | | 85.0 | | |
| Coal calorific value (MJ/kg) | 20.84 | 20.84 | 20.84 | 20.84 |
| **Emission Factor** | | | | |
| Tons $CO_2$/ton coal | | 1.041 | | |
| Tons $CO_2$/GJ | | 0.050 | | |

* Figure to be supplied by SASOL
† To be calculated with data from SASOL

## 3.3 Estimated Emission Factor for Selected Eskom Power Plants

### 3.3.1 ESKOM energy consumption data

Eskom provided its coal consumption data from 2001 to 2014 through the Department of Environmental Affairs (DEA) and the results are displayed in figure 3.13. The graph shows that ESKOM's coal consumption has grown steadily at an average rate of 2 million tons per year. Maximum consumption was recorded in 2007 probably responding to demand.[3]

Furthermore, Table 3.3 shows that plants were constructed at different times and the fuel quality varies from place to place. The oldest plant (Komati) was commissioned in 1961 and the newest plants in 2007. The calorific value of the coal is as low as 14.53 GJ/t (found at Lethabo) and as much as 21.43 GJ/t at Arnot. The diversity in the age of the power plants and coal quality indicates the need for the emission factor to be calculated by taking into account these plant specific characteristics. Table 3.3 also provides the emission factor (tons $CO_2$/ton and tons $CO_2$/GJ coal) for selected Eskom plants).

### 3.3.2 ESKOM fuel based emission factor

The methodology described in section 3.2.1 was used to calculate the emission factor for ESKOM power plants. However, the following assumptions were made since ESKOM did not supply the requisite data to enable calculation based on actual data:

1. ***Total carbon content:*** A comparison was also made with figures derived from calorific values using a linear relationship C=2.55 x CV (Trikam & Lloyd 2004)[4] and results in table 3.3 show the estimated carbon content of coal used at each power stations.
2. ***Oxidation factor:*** - An oxidation factor range of 100% was assumed.
3. Emissions and emission factor were calculated based on consumption of generation coal and plant specific coal calorific values.

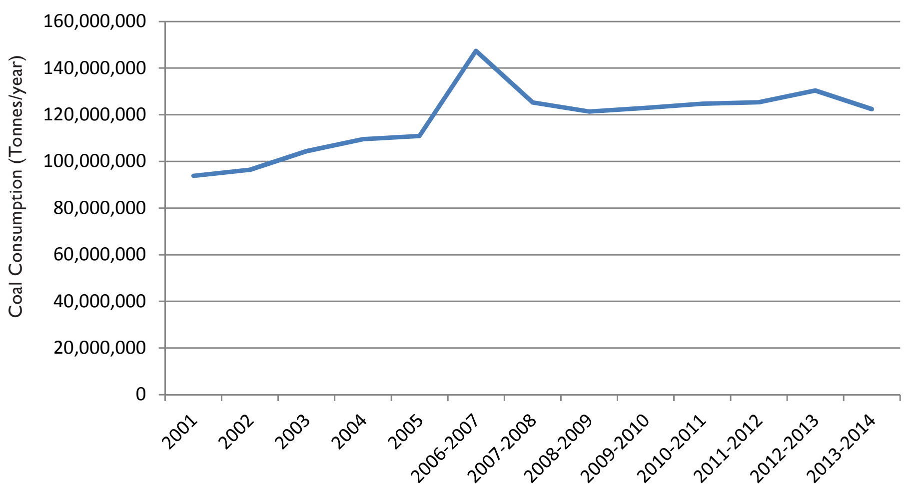



Figure 3.13: Flue gas flow rate of Secunda boiler 7

[3] Measured by Lancom 4

[4] Derived from previous relationship of coal carbon content and calorific value at selected stations

Table 3.3: Eskom plant fuel calorific values and estimated carbon content

| Power plant | Installed capacity | Commissioning date | Coal calorific value | Estimated carbon content from calorific value | Emission factor | |
|---|---|---|---|---|---|---|
| | | | (GJ/t) | % | Ton $CO_2$/ton | Ton $CO_2$/GJ |
| Arnot | 1980 | 9/21/1971 | 21.43 | 54.7 | 2.006 | 0.094 |
| Duvha | 3450 | 1/18/1980 | 20.39 | 52.0 | 1.907 | 0.094 |
| Hendrina | 1895 | 5/12/1970 | 20.51 | 52.3 | 1.918 | 0.094 |
| Kendal | 3840 | 10/1/1988 | 17.87 | 45.6 | 1.672 | 0.094 |
| Kriel | 2850 | 5/6/1976 | 21.64 | 55.2 | 2.024 | 0.094 |
| Lethabo | 3558 | 12/22/1985 | 14.53 | 37.1 | 1.360 | 0.094 |
| Matimba | 3690 | 12/4/1987 | 19.15 | 48.9 | 1.793 | 0.094 |
| Majuba | 3843 | 4/1/1996 | 19.58 | 50.0 | 1.833 | 0.094 |
| Matla | 3450 | 9/29/1979 | 18.19 | 46.4 | 1.701 | 0.094 |
| Tutuka | 3510 | 6/1/1985 | 19.83 | 50.6 | 1.855 | 0.094 |
| Camden | 1600 | 12/21/1966 | 20.45 | 52.2 | 1.914 | 0.094 |
| Grootvlei | 1200 | 6/30/1969 | 20.01 | 51.1 | 1.874 | 0.094 |
| Komati | 1000 | 11/6/1961 | 19.72 | 50.3 | 1.844 | 0.094 |

Based on these assumptions, table 3.3 shows the estimated $CO_2$ emission factor (tons $CO_2$/ton and tons $CO_2$/GJ coal) from selected ESKOM coal fired power plants. The emission factor based on fuel, varied between 1.360 and 2.024 tons $CO_2$/ton coal, and the emission factor based on energy (tons $CO_2$/GJ coal) remained constant at 0.094. This was due to the non-availability of actual carbon content from ESKOM for specific plants. It should be noted that the emission factors based on fuel for Sasolburg and Secunda with actual carbon content were estimated at 1.752 and 1.679 tons $CO_2$/ton and tons $CO_2$/GJ coal, respectively. Similarly, the emission factors based on energy for Sasolburg and Secunda were estimated at 0.094 and 0.081 tons $CO_2$/GJ coal, respectively. It can further be observed that the emission factors obtained are within ESKOMs range of emission factors.

## 3.4 Comparison of Country Specific Factors with IPCC Default Factors

Table 3.4 shows a comparison of the calculated and measured EFs with the default IPCC EFs for Sasolburg, Secunda and Eskom.

The following observations can be made from the results in table 3.4.

**i. Calculated emission factor**

- The calculated EF for Sasolburg is within the range of the recommended IPCC default values.
- The calculated EF for Secunda is less than that for Sasolburg and the default IPCC values. This is because Secunda coal has a higher calorific value and lower carbon content than Sasolburg coal. However this

Table 3.4: Comparison of country specific factors with IPCC default factors for stationary combustion (tons $CO_2$/GJ)

| Method | Emission Factor ($tCO_2$/GJ) - Coal | | | | |
|---|---|---|---|---|---|
| | Sasolburg | Secunda | Eskom | IPCC Default* | |
| | | | | Min | Max |
| Calculated | 0.094 | 0.081 | 0.094 | 0.092 | 0.1 |
| Measured | 0.046 | 0.050 | | | |

* Calculated from the measurements[5]

| Method | Emission Factor ($tCO_2$/GJ) - Natural Gas | | | | | |
|---|---|---|---|---|---|---|
| | Sasolburg | Secunda | Eskom | | IPCC Default* | |
| | | | Min | Max | Min | Max |
| Calculated | 0.067 | | | | 0.0543 | 0.0583 |
| Measured | 0.048 | | | | | |

* Calculated from the study[6]

needs to be verified since calorific value is a function of the carbon content.

- The calculated EFs for ESKOM power plants are above the IPCC default values. However, more work is required to update emission factors for ESKOM using actual coal carbon content and calorific value for the specific power plants.

- The calculated EF for Sasolburg coal is within the IPCC default value range, whereas that for Secunda is slightly below the IPCC default value range. More work is required at Secunda in view of the challenges experienced with the Lancom gas analyser.

**ii. Measured emission factor**

- Measured EFs for both Sasolburg and Secunda are lower than the IPCC default emission factors. The EF for Secunda can be disregarded since the Lancom instrument was malfunctioning at this stage. Possible causes for the low EF for Sasolburg could be the following:

  - Sasolburg only supplied the average coal consumption for the three days of measurement as opposed to an average for each day of measurement; however, this value could have varied significantly over the three days.

  - The measured flue gas flow rate varied significantly during the three days of measurement.

  - The measured EF for Sasolburg gas is below the IPCC default value.

## 3.5 Capacity Building Achieved

Initially, the CEEEZ and DEA teams were introduced to the new Lancom 4 gas analyser by the supplier, Protea, as the CEEZ team had previously used the Lancom 3. This was to familiarise the project team with new features in

5 Data determined or measured from the current study

6 ibid

the Lancom 4 including the capability to measure flow rate. Both boardroom training and in situ training at a nearby boiler were conducted.

After appointment of the SGS team to take measurements at SASOL power plants, the CEEEZ team trained personnel from SGS and additional staff from the DEA on how to operate the Lancom gas analyser and to calculate the EF using IPCC methodologies. Two people were trained from each organisation and the group included one woman. The CEEEZ team worked with the SGS personnel to collect data and troubleshoot any problems with the measuring instrument. This capacity building process has ensured that there is a reasonable critical mass of expertise in the key public and private sector organisations that can continue to undertake an EF improvement programme.

# 4. UNCERTAINTY ASSESSMENTS

## 4.1 Estimated Level of Uncertainty

This section summarises the results of uncertainty analysis performed on the measurements conducted to determine $CO_2$ emission factors from stationary combustion devices that use coal and natural gas in two sites (Sasolburg and Secunda). The uncertainty analysis methodology performed in this study follows the Monte-Carlo simulation, which is equivalent to an IPCC tier 2 uncertainty analysis approach. Table 4.1 summarises the probability distribution functions that were imposed on the parameters used to quantify the emission factors.

The IPCC tier 2 methodology requires assessment of uncertainty based on a 95% uncertainty range. This range has been followed in this Monte-Carlo simulation with the exception of the $CO_2$ EF uncertainty assessment, which is only considered at 90 per cent interval due to the less-normal nature of the PDF associated with the outcome of the assessment.

The results of this assessment are summarised in Table 4.2 and presented in figures 4.1–4.3 for each combustion installation device that was assessed for $CO_2$ EFs.

Table 4.1: Imposed probability distribution functions on parameters used to quantify $CO_2$ emission factors

| Parameter | Unit of measure | Probability distribution function (PDF) |
|---|---|---|
| Mass of fuel consumed | Metric tons | Triangle |
| Total carbon content | % carbon on dry basis | Truncated-triangle |
| Calorific values | MJ/kg | Triangle |
| Oxidation factor | % | Truncated-triangle |
| Plant availability | % | Triangle |

Table 4.2: Uncertainty analysis results based on $CO_2$EF measurements

| Parameter | Unit of measure | $CO_2$ emission factors | | | |
|---|---|---|---|---|---|
| | | Averaged | Minimum | Maximum | Units |
| Sasolburg | Coal-fired | 0.094 | 0.072 | 0.10 | Tons $CO_2$/GJ |
| Sasolburg | Gas-turbine | 0.0016 | 0.0014 | 0.0017 | Tons $CO_2$/$Nm^3$ of gas |
| Secunda | Coal-fired | 0.081 | 0.072 | 0.092 | Tons$CO_2$/GJ |

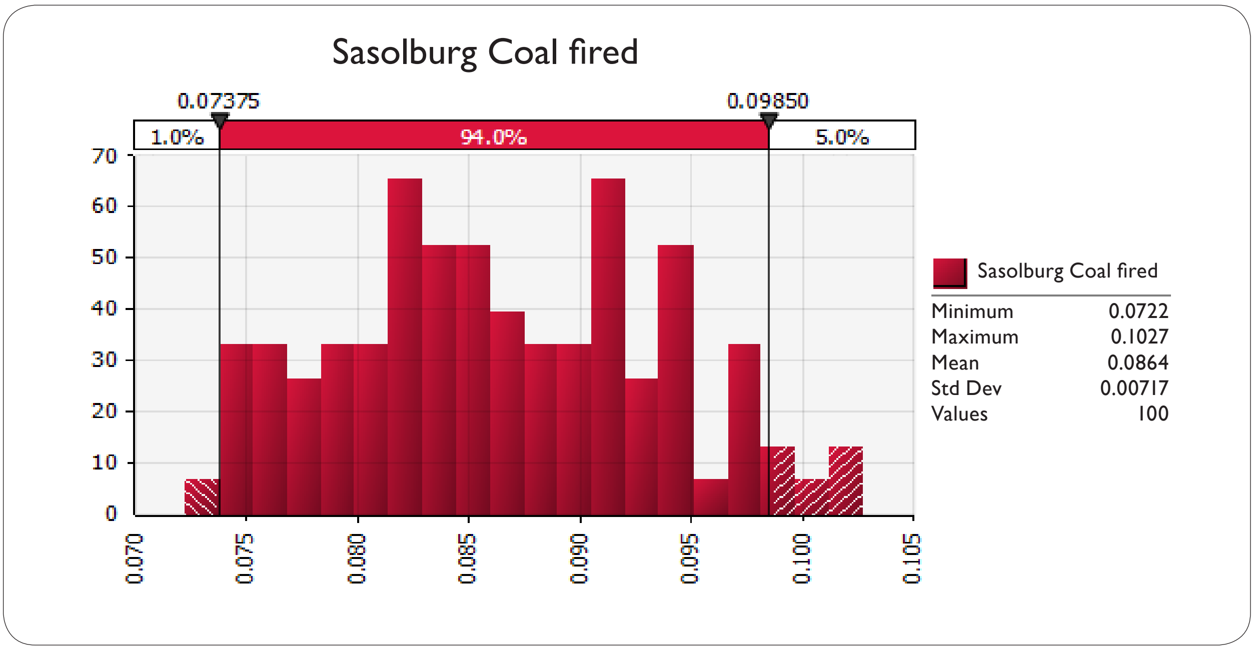



Figure 4.1: Results of uncertainty analysis for coal-based $CO_2$ emission factor (Sasolburg)

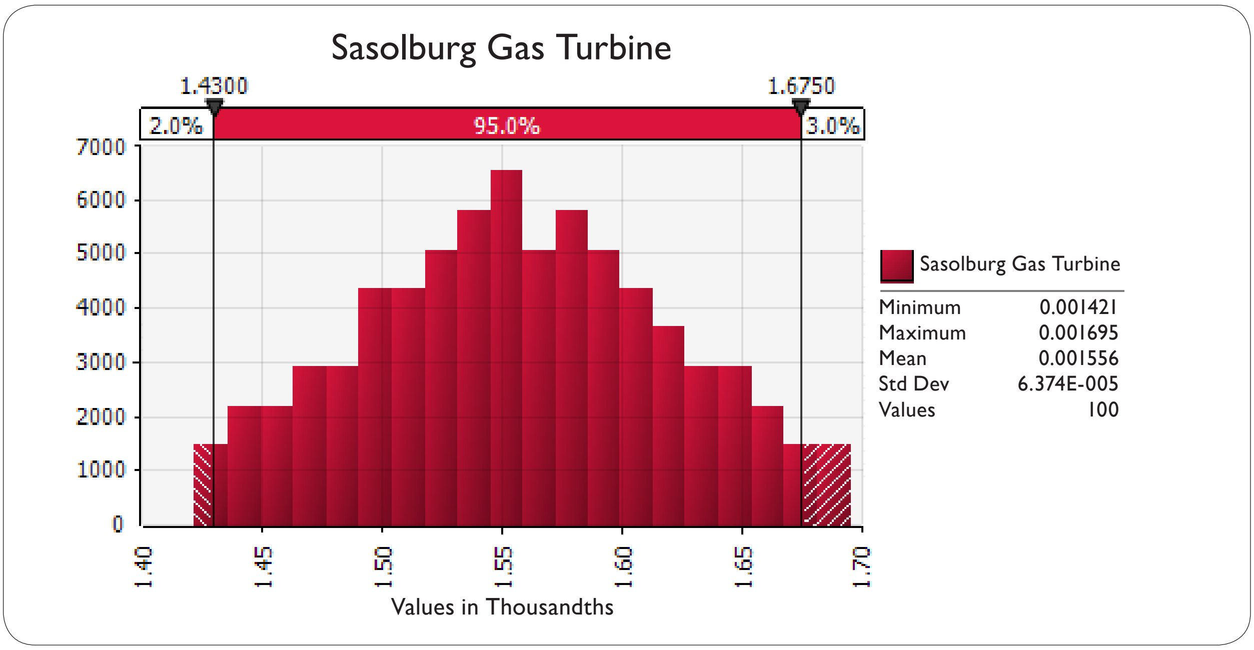



Figure 4.2: Results of uncertainty analysis for gas-based $CO_2$ emission factor (Sasolburg)

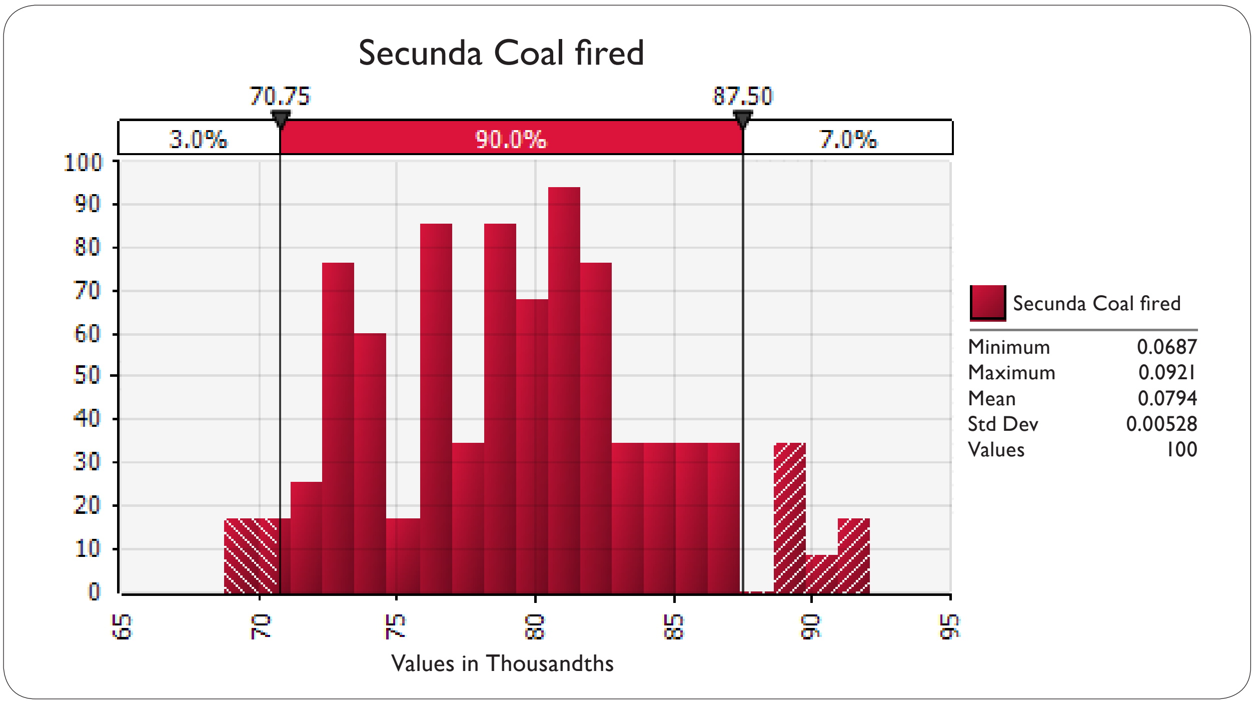



Figure 4.3: Results of uncertainty analysis for coal-based $CO_2$ emission factor (Secunda)

## 4.2 Sources of uncertainty

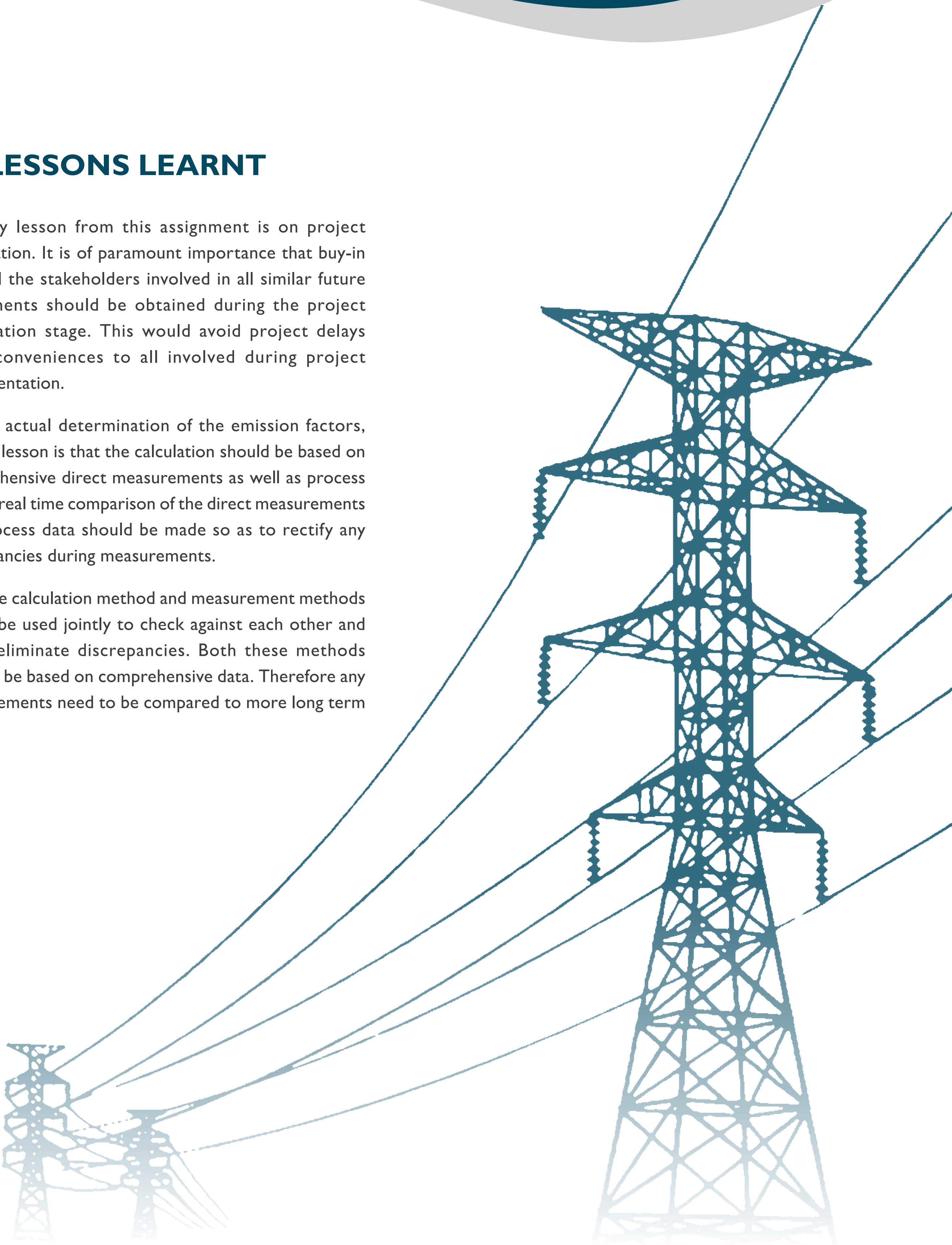
- Instrument failure-of Lancom at Secunda affecting its accuracy.
- Harsh measurement conditions at Sasolburg and Secunda.
- Different staff doing measuring and analysis.
- For Eskom – assumption of 2010 coal carbon content.

# 5. LESSONS LEARNT

The key lesson from this assignment is on project preparation. It is of paramount importance that buy-in from all the stakeholders involved in all similar future assignments should be obtained during the project preparation stage. This would avoid project delays and inconveniences to all involved during project implementation.

On the actual determination of the emission factors, the key lesson is that the calculation should be based on comprehensive direct measurements as well as process data. A real time comparison of the direct measurements and process data should be made so as to rectify any discrepancies during measurements.

Both the calculation method and measurement methods should be used jointly to check against each other and hence eliminate discrepancies. Both these methods need to be based on comprehensive data. Therefore any measurements need to be compared to more long term trends.



# 6. CONCLUSIONS AND RECOMMENDATIONS

## 6.1 Conclusions

The key conclusions from the above analysis are discussed below.

**Capacity building**

The capacity building done is crucial for future measurements by the DEA. However, more still needs to be done since the DEA personnel were not able to use the instrument on a real plant because they were not allowed to accompany SGS into the SASOL plant and therefore lack practical experience. In addition, one of the personnel who was trained at SGS has since left the organisation. Additional similar capacity building is therefore required.

**Measurement programme**

A measurement programme has been established for both coal and natural gas plants for future measurements. However, the necessary preparatory work has to be done before measurement can commence. This includes obtaining firm commitments from the stakeholders involved and an agreement on the measurement protocol prior to the hiring of consultants such as CEEEZ.

For consistency, the measurements and analysis need to be done by one company and the process data needs to be provided and monitored during the measurements.

**Variations in flue gas measurements**

The variations in process flow measurements observed in the results could have emanated from the instrument or be due to improper placement of the probe during the measurements. The instrument was calibrated during the measurements and at this stage human error cannot be ruled out as the CEEEZ team was not in control of the measurements.

**Emission factors**

The methods for measuring EFs from electricity plants have been used and have demonstrated that corroboration of the results can be achieved with consistent data.

The actual results obtained using the calculation based methodology show the expected range of EFs for such fuel types, although more measurements at different plants would be required to cover the range of combustion efficiency of plants in the country. For Sasolburg, a more comprehensive set of process data is needed to come up with a conclusive measured EF.

A more reliable EF for ESKOM power stations will only be achieved if Eskom can provide the required data. More effort is required in future to get that data.

Lastly, EFs per energy generated were not derived as both SASOL and Eskom did not want those results to be in the public domain.

## 6.2 Recommendations

The following recommendations are proposed.

1. Verify EFs for Sasolburg coal and natural gas using comprehensive process data to be supplied by Sasolburg.

2. Repeat similar measurements at additional power stations both to maintain momentum in developing capacity for improving EFs and to add to a complete result.

3. Procure data from Eskom. This should comprise full secondary data for the calculation method and measurements at ESKOM sampled plants to complement results from SASOL and to create both fuel based and energy based EFs for the full grid.

4. Train more professionals in EF measurement in the DEA and in companies like SGS for continuity in the country. CEEEZ/EECG can always provide support in achieving this.

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# **APPENDIX:** LIST OF FOSSIL FUEL BASED POWER STATIONS OPERATED BY ESKOM

| Power station | Utility owner | Location | Longitude | Latitude | Fuel type | Total capacity at power station 2009 | No. of units | Size of units (MW) | Age of units | Type of technology | Plant efficiency % | Plant availability % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arnot | Eskom | Middelburg | S25.944 | E29.791 | Coal | 2 280 | 6 | 350 | 1975 | | 33.4 | |
| Camden | Eskom | Ermelo | S26.620 | E30.091 | Coal | 0.094 | 8 | 200 | 1967 | | 37.6 | 89.5 |
| Duvha | Eskom | Witbank | S25.959 | E29.340 | Coal | 0.094 | 6 | 600 | 1975 | | 32.9 | |
| Grootvlei | Eskom | Balfour | S26.769 | E28.499 | Coal | 0.094 | 6 | 200 | 1969 - 1984 | Dry cooling | 34.2 | 88.78 |
| Hendrina | Eskom | Middelburg | S26.031 | E29.601 | Coal | 0.094 | 10 | 200 | 1970 - 1976 | | 35.3 | 93.69 |
| Kendal | Eskom | Witbank | S26.088 | E28.968 | Coal | 0.094 | 6 | 686 | 1982 - 1993 | | 30 | |
| Komati (2009 – 11) | Eskom | Middelburg | S26.090 | E29.474 | Coal | 0.094 | 5; 4 | 100; 125 | 1961 - 1966 | | 36.9 | 93.37 |
| Kriel | Eskom | Bethal | S26.254 | E29.180 | Coal | 0.094 | 6 | 500 | 1979 | | 37.8 | 93.05 |
| Lethabo | Eskom | Viljoensdrift | S26.740 | E27.975 | Coal | 0.094 | 6 | 618 | 1980 - 1990 | | 35.2; 37.7 | 97.17 |
| Majuba | Eskom | Volksrust | S27.095 | E29.770 | Coal | 0.094 | 3; 3 | 665; 716 | 1996 - 2001 | | 35 | 93.67 |
| Matimba | Eskom | Lephalale | S23.667 | E27.612 | Coal | 0.094 | 6 | 665 | 2001 | Largest dry cooling | 37.6 | 93.89 |
| Matla | Eskom | Bethal | S26.280 | E29.142 | Coal | 3 600 | 6 | 600 | 1974 - 1983 | | 38 | 93.41 |
| Tutuka | Eskom | Standerton | S26.775 | E29.352 | Coal | 3 654 | 6 | 609 | 1985 - 1990 | | | |
| Medupi (2012 – 15) | Eskom | Lephalale | | | Coal | 4 800 | 6 | 800 | | | | |
| Kusile (2013 – 16) | Eskom | Witbank | | | Coal | 4 800 | 6 | 800 | | | | |
| **Total** | | | | | | 37 773 | | | | | | |
| Acacia | Eskom | Cape Town | S33.884 | E18.533 | Gas/Liquid | 171 | 3 | 57 | 1976 | Gas turbines – Boeing 707 engines | 30.3 | 99.09 |
| Ankerlig | Eskom | Atlantis | S33.592 | E18.460 | Gas/Liquid | 1 338 | 4; 5 | 149.2; 148.3 | 2006 - 2007; 2008 - 2009 | Open cycle gas turbines | | |
| Gourikwa | Eskom | Mossel Bay | S34.165 | E21.960 | Gas/Liquid | 746 | 3; 2 | 149.2 | 2007 | Open cycle gas turbines | | |
| Port Rex | Eskom | East London | S33.027 | E27.883 | Gas/Liquid | 171 | 3 | 57 | 1976 | Gas turbines – Boeing 707 engines | 30.3 | 98.73 |
| **Total** | | | | | | 2 426 | | | | | | |

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Publishing date: February 2016

www.environment.gov.za