

**Working document for the
meeting of 31 January 2012**

**UPDATE OF COST
ESTIMATION FOR LCP**

EGTEI secretariat

20 January 2012

With questions / comments of
KEMA and preliminary answers

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Glossary

A: annualised capital cost

ac: ash content in % w/w for solid and liquid fuels

ar: fraction of ash retained in boiler in % w/w

bse: boiler size in MWe

bst: boiler size in MWth

C^{reagent} : price of reagent in € 2010/ton reagent (country specific)

$C^{\text{electricity}}$: price of electricity in € 2010/kWh(country specific)

$C^{\text{byproduct}}$: price of byproduct in € 2010/ton byproduct. Byproduct can be discharged or sailed. In case of sealable byproduct a negative figure is considered (country specific)

C^{water} : price of industrial water in € 2010/m³ (country specific)

C^{wage} : price of wages in € 2010/man-hour (country specific)

CE^{tot} cost per t pollutant avoided expressed in €/ton pollutant abated

E^{avoided} == E with the abatement technique in ton of pollutant

$CONC_{\text{poll, ref}}$: Concentration of pollutant emitted in mg/Nm³ dry, O₂ ref by the installation (country specific)

$CONC_{\text{poll, tested}}$: Concentration of pollutant emitted in mg/Nm³ dry, O₂ ref to be obtained (can be based on the regulation)

$CONS^{\text{reagent}}$: yearly consumption of reagent in ton reagent /year

η_e : electrical boiler efficiency in %

η : efficiency of pollutant reduction system required in %

Freal, humid: specific real waste gas flow rate produced per unit of fuel energy, at real oxygen conditions, at the temperature outlet of waste gases and real humidity conditions: in m³/GJ

Fref, dry: specific dry waste gas flow rate produced per unit of fuel energy at normal conditions (273 K and 1 atm) in Nm³/GJ at 6 % O₂, dry for solid fuel, and Nm³/GJ at 3 % O₂, dry for liquid and gaseous fuel

i: country

hv: lower heating value in GJ/t

j: sector

l: fuel

n: control equipment lifetime

N: number of working hours at nominal capacity

OC^x : operating cost in €/year due to parameter x which can be reagents, electricity, industrial water, by-products, wages, catalysts,

p: interest rate

Pref: reference pressure condition or 101325 Pa

r: retrofit factor in %

sc: sulphur content of the fuel in % w/w

sr: sulphur retention in ash (fraction) of the fuel in % w/w. 0.05 % for hard coal up to 80 % for some lignite.

SR: reagent concentration in % w/w

Tref: reference temperature condition or 273 K

Φ : hourly fuel consumption at nominal capacity, in GJ/hour

ton: ton metric

WL: water losses in %

Several abbreviations are missing ao. civ, cif, LCP

Where is 'i:country' used?

Civ : component investment variable

Cif : component investment fixed

LCP: Large Combustion Plant (larger than 50 MWth)

i can be associated to several parameters which are country specific ; electricity cost, reagent cost...

For understanding: yellow colour used to highlight needs in validation of data or delivery of data for improving the estimations by the working group

In blue colour, work to be completed

In red colour and italic, comments from KEMA received the 31 January 2012. In black colour and italic answers from the EGTEI secretariat (if necessary, corrections made in the text)

1 Consideration on investments and operating costs

1.1 Investments

Investments **are given without taxes** (to be consistent with GAINS) and are supposed to comprise the following two components:

- Pollution control equipment expenditure (e.g. pollution control device, auxiliary equipment, instrumentation),
- Installation expenditure (e.g. project definition and engineering, contractor selection costs and contractor fees, building and civil works, performance testing and start up).

Total investments cost also include owners cost, contingency, permits and insurance. Will be added.

When applied for an existing combustion installation, the retrofit factor “r” is used.

Investments “I” are expressed in k€. Investments can also be expressed per unit of a representative parameter of a given reference installation and is noted I^{spec} .

As example:

- Per unit of thermal combustion capacity: k€/MWth,
- Per unit of fuel consumed per year for combustion installation: k€/GJ fuel consumed per year (Note: this specific investment figure not only take into account the capacity but also the load factor and running hours of the plant per year (i. e. full-hour equivalents)),

1.2 Annualised investments

Investments are annualised according to the following formula, with A being expressed in k€/y:

A: annualised investment [k€/y]

$$(E1): A = I \cdot \frac{(1+p)^n}{(1+p)^n - 1} \cdot p$$

n: control equipment life time in year.

p: interest rate in [%/100] (**4 % is imposed to be coherent with GAINS but other figures can be tested**).

If the life time of the control equipment is not available, it is assumed that this lifetime equals the life time of the installation.

A^{spec} is the annualised specific investment expressed according to a representative parameter of a given reference installation. The annualised investments can be expressed per unit of capacity of a given reference installation per year.

As example:

- Per unit of thermal combustion capacity: k€/y/MWth,
- Per unit of fuel consumed per year for combustion installation: k€/GJ fuel consumed per year (Note: this specific investment figure takes not only the capacity but also the load and running hours of the plant per year (i. e. full-hour equivalents) into account),

$$A^{\text{spec}} = \frac{A}{\text{Capacity Ref}}$$

Capacity Ref may be expressed in MWth, or in GJ consumed per year.

In a techno-economic analysis the WACC is used to annualize the investment cost, see page1 from previous memo (7310024-PGR/CFP 2011). WACC is higher than 4%

As said above, 4 % is used in many studies carried out in the scope of Integrated Assessment Modelling (IAM) of air pollution. It will be possible to use different figures but for comparison of results of the study with outputs of the GAINS model, 4 % will be used.

1.3 Operating costs

Operating costs are composed of fixed and variable operating costs:

$$OC^{\text{tot}} = OC^{\text{fix}} + OC^{\text{var}}$$

The fixed operating costs depend on the capacity or size of the installation, i.e. on the investment and are expressed as a percentage of the unit investment. They include costs of maintenance and repair, insurance, administrative overhead, etc. Taxes are not included in order to be coherent with GAINS.

OC^{fix} is expressed in k€/y.

The variable operating costs is the sum of costs for utilities, wages and all other operating costs.

OC^{var} is expressed in k€/y.

Variable operating costs depend on the level of production, the number of hours of production. Parameters for variable operating costs depend on the type of measure (technology) installed. Some common parameters needed for the calculation of the variable costs are as follows.

- Electricity prices [€/kWh]
- Waste disposal prices [€/ton waste]
- Ammonia prices [€/ton ammonia]
- Sorbent prices [€/ton sorbent]
- Wage [€/man year]
- ...

Variable costs have to be specified for every abatement measure or combination of measures. Depending on the abatement technology used, there might be other parameters not listed above, that are taken into account by a so-called "supplementary cost".

Total operating costs may be negative, in case the implementation of a reduction measure results in the saving of costs (e. g. switch to less expensive fuel, fuel saving, by-product).

The wages should be in the fixed cost, not in the variable cost, since they are independent of the operating hours.

In the previous methodology, wages are considered in variable operating costs. Wages are country specific and can depend, for some techniques, on the operating hours.

The reference document "Economic and cross media effects" considers labour costs in variable operating costs.

1.4 Total annual costs

The total annual costs are the sum of the total operating costs (OC^{tot}) and the annualised investment costs (A).

$$C^{\text{tot}} = A + OC^{\text{fix}} + OC^{\text{var}}$$

C^{tot} : k€/y
 OC^{fix} : k€/y
A : k€/y
 OC^{var} : k€/y

The total annual cost can be expressed according to a characteristic parameter of the installation, as its capacity.

$C^{\text{tot, spec}} = A^{\text{spec}} + OC^{\text{fix, spec}} + OC^{\text{var, spec}}$
 $C^{\text{tot, spec}}$: k€/MWth or k€/GJ per year.
 $OC^{\text{fix, spec}}$: k€/MWth or k€/GJ per year
 A^{spec} : k€/MWth or k€/GJ per year
 $OC^{\text{var, spec}}$: k€/MWth or k€/GJ per year

Costs per ton of pollutant abated

The total cost per t pollutant avoided “CE” is calculated as follows:

$$CE^{\text{tot}} = C^{\text{tot}} / E^{\text{avoided}}$$

CE^{tot} expressed in €/ton pollutant abated

$E^{\text{avoided}} = E$ without the abatement technique – E with the abatement technique in ton of pollutant

Determination of costs:

The definition of costs must be properly transparent. The methodology used by EGTEI is consistent with the methodology used in the GAINS Model, if taxes are removed and the technical lifetime of equipments is considered to calculate annualized costs. By default, 4 % is used and the technical lifetime. Calculation programmes are developed to enable the choice of any parameter, for sensitivity analysis purpose as example. When data different from the default value are used, they have to be described for consistency and transparency.

As far as possible, investments (k€), annual operating costs (k€/y), total annual costs (k€/y) and cost per ton of pollutant abated should be provided for each reduction option.

The source and origin of all data should be recorded as precisely as possible.

As far as possible, **costs are reported as actual expenditure, i.e. for 2010.**

If data from other years are used, they should be expressed in the prices of the most recent year (2010) and in any case, also given in addition as original data with reference year.

The procedure to be used is described in the BREF document “Economics and Cross media effects”[1].

To adjust the cost data into an equivalent price in a selected year, it is necessary to use a price adjuster which can be derived by the following steps:

Step 1

Price adjuster = appropriate price index for the base year of the analysis / appropriate price index for the year to which the raw costs data pertains.

Step 2

Adjusted cost data = original cost data x price adjuster.

The **source of price indices** for the EU is EUROSTAT’s “Data for short term analysis”

<http://epp.eurostat.ec.europa.eu/portal/page/portal/euroindicators/peeis/>

http://epp.eurostat.ec.europa.eu/cache/ITY_PUBLIC/4-05012011-AP/EN/4-05012011-AP-EN.PDF

The **interest to be used is 4 %** to be consistent with GAINS and the previous EGTEI data.

If original data are expressed in a currency different from the €, they should be derived in € by the following steps:

Step 1:

Cost in € for a year N = Costs in currency A for the year N x rate of conversion of currency A in € the year N

Step 2:

Use the previous procedure to define the cost for the actual year.

The **source of exchange rate** for the EU is EUROSTAT's "Data for short term analysis"

http://epp.eurostat.ec.europa.eu/portal/page/portal/exchange_rates/data/main_tables

<http://epp.eurostat.ec.europa.eu/tgm/table.do?tab=table&init=1&language=en&pcode=tec00033&plugin=1>

Technical lifetime is not given. Suggestion done in previous memo (73100024-PGR/CFP 2011) Will be taken into account.

1st URL link, referres to an index for industrial production on short term (only 1 year back). Mostly data is needed that goes back for several years. And the industrial production is not a perfect match for power plant investments.

2nd URL link, referres to industrial producer prices, this should not be used for indexing power plant investments.

The links come from the reference document "Economic and cross media effects". In the slides presented the 31 January, the chemical engineering plant costs is presented. This index will be used. The exchange rates are also presented.

2 Reference installations for LCP and fuels considered

LCP which are considered, have a thermal power larger than 50 MWth are considered. These LCP use different types of fuels and their load factor is various (less than 1000 h/year at the nominal capacity to more).

Installation considered are (for the time being):

- a boiler with a chimney,
- a gas turbine with a chimney.

Stationary engines are not yet considered.

The reference installation has no reduction technique.

Primary measures considered are:

- SO₂ : low sulphur fuel,
- PM : no primary measure,
- NO_x : low NO_x burners,

Secondary measures considered are (for the time being):

- SO₂ : WET FGD with forced oxidation with limestone (LSFO), WET FGD with natural oxidation with limestone (LSNO), other techniques could be introduced for small capacity plant such as wet FGD with lime and or dry FGD with lime.
- PM : ESP, Fabric filters

- NOx : SCR, SNCR

The following types of fuels considered are as follows:

- BC: Brown coal – Low calorific value between, GJ
- HC1: Hard coal grade 1 – Low calorific value between 22 to 32 GJ/t, %S larger than 1% w/w
- HC2: Hard coal grade 2 – Low calorific value between 22 to 32 GJ/t, %S between 0.6 to 0.8 % w/w
- HC3: Hard coal grade 3 – Low calorific value between 22 to 32 GJ/t, %S lower than 0.6 % w/w
- HF1: Heavy fuel oil grade 1 - Low calorific value between 38 to 42 GJ/t, %S larger than 1 % w/w
- HF2: Heavy fuel oil grade 2 - Low calorific value between 38 to 42 GJ/t, %S between 0.5% to 1 % w/w
- HF3: Heavy fuel oil grade 3 - Low calorific value between 38 to 42 GJ/t, %S lower than 0.5% w/w
- Gas: Natural gas to be completed,
- OS1: Wood to be completed.

Exact characteristics of fuels are country specific.

Specific dry waste gas flow rate produced per unit of fuel energy

$F_{ref, dry}$: specific dry waste gas flow rate produced per unit of fuel energy at normal conditions (273 K and 1 atm) in Nm^3/GJ at 6 % O_2 , dry for solid fuel, and Nm^3/GJ at 3 % O_2 , dry for liquid and gaseous fuel is as follows:

For solid fuels: $F_{ref} = 350 Nm^3/GJ$ (6 % O_2 , dry)

For liquid fuels: $F_{ref} = 280 Nm^3/GJ$ (3 % O_2 , dry)

For gaseous fuels: $F_{ref} = 270 Nm^3/GJ$ (3 % O_2 , dry)

Parameters from reference EGTEI [3].

Parameters to be checked by experts. There is a CEN standard which is being prepared which could be used. Exact figures are not known by the secretariat.

Corrections to derive the specific real waste gas flow rate, produced per unit of fuel energy, F_{real}

This real waste gas flow rate is useful to use some functions of investment from the literature and for some operating costs.

1 - Correction of oxygen

$$(E2): F_{O_2 \text{ monitored}} = F_{ref} \times (21 - O_2 \text{ monitored}) / (21 - O_2 \text{ ref})$$

O_2 in %

On average, what is the O_2 content of flue gases after a boiler and a gas turbine (according to the type of fuel used)?

2 - Correction of humidity

$$(E3): F_{real \text{ humidity}} = F_{ref} \times (100 - H_{real}) / 100$$

H_{real} : real humidity at T_{ref}

The humidity is about 6 to 10 % after a boiler with coal. What are concentrations to be considered on average for the fuels listed above?

3 - Correction of temperature and pressure

$$(E4): F(T_{real}, P_{real}) = F_{ref}(T_{ref}, P_{ref}) \times T_{ref}/T_{real} \times P_{real}/P_{ref}$$

T_{real} temperature of waste gases in K,

T_{ref} 273 K,

P_{real} pressure of waste gases in Pa,

P_{ref} 101325 Pa.

On average, what is the temperature of flue gases after a boiler and a gas turbine (according to the type of fuel used)?

$$(E5): F_{real, humid} = F_{ref} \times (21 - O_2 \text{ monitored}) / (21 - O_2 \text{ ref}) \times (100 - H_{real}) / 100 \times T_{ref}/T_{real} \times P_{real}/P_{ref}$$

Expressed in m^3/GJ , at H_{real} , T_{real} and $O_2 \text{ real}$.

Hourly fuel consumption at nominal capacity

$$(E6): \Phi = 3.6 \times bst$$

Φ consumption of fuel, in GJ/hour

bst boiler size in MWth

3 Desulphurisation

3.1 Emissions of the reference installation

The emissions of the reference installation can be characterised by an emission factor of SO₂ expressed in kg/GJ or a concentration.

Translation of emissions expressed in kg/GJ fuel input in concentrations at normal conditions expressed in mg/Nm³ dry and O₂ ref

The average specific factor F_{ref} is used to derive concentrations of pollutants expressed in mg/Nm³ dry, O₂ ref, from the emission factor of pollutant expressed in mass of pollutant/GJ (kg per GJ fuel input) and vice versa.

For SO₂:

$$(E7): ef_{SO_2} = 20 \times sc_{i,j,l} / hv_{i,j,l} \times (1 - sr_{i,j,l}/100)$$

ef_{SO₂}: kg SO₂/GJ

sc_{i,j,l}: sulphur content (per weight) of fuel l, used in sector j, in country i in % w/w

hv_{i,j,l}: low heating value of fuel l, used in sector j, in country i in GJ/t

sr_{i,j,l}: sulphur retention in ash (fraction) of fuel l, used in sector j, in country i in % w/w.

$$(E8): CONC_{SO_2, ref} = ef_{SO_2} / F_{ref, dry} \times 1\,000\,000$$

CONC_{SO₂, ref}: Concentration of SO₂ emitted in mg/Nm³ dry, O₂ ref

ef_{SO₂}: SO₂ emission factor expressed in kg SO₂/GJ fuel input

F_{ref, dry}: specific dry waste gas flow rate produced per unit of fuel energy at normal conditions (273 K and 1 atm) in Nm³/GJ at 6 % O₂, dry for solid fuel, and Nm³/GJ at 3 % O₂, dry for liquid and gaseous fuel

3.2 Required abatement efficiency for SO₂ removal

$$(E9): \eta_{SO_2, reg} = \frac{CONC_{SO_2, ELV} - CONC_{SO_2, raw}}{CONC_{SO_2, raw}} \times 100$$

$$(E9): \eta_{SO_2, reg} = (1 - CONC_{SO_2, ELV} / CONC_{SO_2, raw}) \times 100$$

η_{SO₂, reg}: efficiency of the desulphurisation required in %

CONC_{SO₂, reg ELV}: Case specific emission limit, mostly derived by regulation or other source (can corresponds to IED-ELV) in mg/Nm³ dry, O₂ ref

CONC_{SO₂, raw}: Concentration of SO₂ (upstream of the desulphurisation unit) in mg/Nm³ dry, O₂ ref

E9 required abatement efficiency = 1 - Concso2,ELV / CONCso2, rev corrected

CONCSO2, reg does not come back in E9 corrected

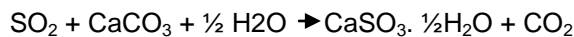
3.3 DeSOx techniques considered up to now

Reduction techniques considered are (January 2012):

- LSFO: wet FGD with limestone and forced oxidation for gypsum production
- LNFO: wet FGD with limestone and natural oxidation

Other techniques could be added later.

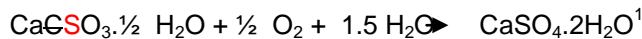
In **wet FGD**, SO₂ is removed by scrubbing the flue gas with either a limestone or lime slurry. The following reaction is involved with limestone:



Two different modes to treat the by products exist.

In the natural oxidation mode, LNFO, calcium sulphite is partly oxidised by the oxygen contained in the flue gas. The slurry obtained has no recovery application and must be disposed according to local rules, after specific treatment such as dewatering.

In the process with forced oxidation, air is bubbled through the slurry of the calcium sulphite hemi hydrate obtained to form gypsum which is saleable for plaster production as example, according to the following reaction:



Wet FGD with natural and forced oxidation are considered.

In natural oxidation system indeed, by products obtained are wastes which must be disposed.

On contrary, in the forced oxidation mode, saleable products are obtained. This reduces overall costs.

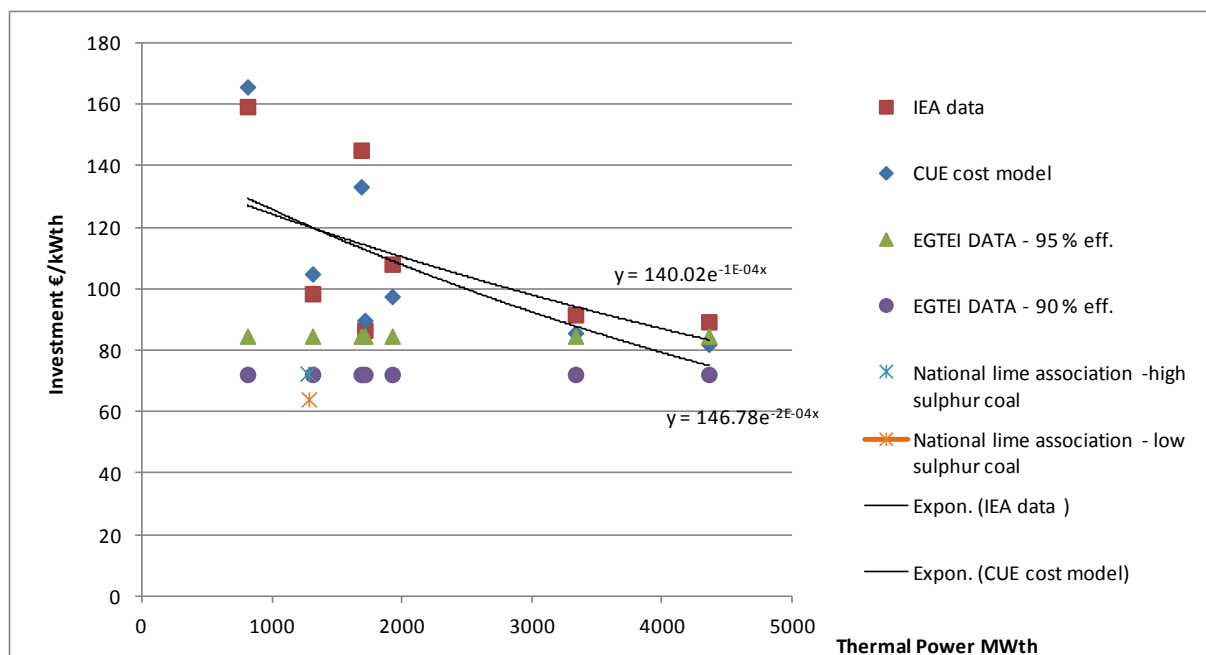
A wet FGD system operates at low temperatures between 45 and 60 °C and is the most often located at the end of the chain of reduction equipment.

Chemical formula is wrong corrected

3.4 Investments

Using methodologies described here above, different investments have been obtained. The results are presented in the following figures. All costs are expressed in Euro 2010

Figure 1: comparison of investments (€2010/Wth) from the literature for coal, after correction of costs to have the same reference year 2010



IEA data: reference [5]

CUE cost model: applied for the same plants in reference [5]

EGTEI data: from reference [3]

National lime association: from reference [4]

¹ Corrected according to comments from KEMA – 27 January

The parameters of the investment function of the current EGTEI methodology [3], are the following ones.

Table 1: Coefficients of the investment function for SO₂ removal techniques

Fuel - type of plant	Technology	cif , € 2000/kWth	civ , 10 ³ €
Hard Coal existing plant	Wet Flue Gas Desulphurisation	33.65	0
Brown Coal existing plant	Wet Flue Gas Desulphurisation	42.30	0
HF existing plant	Wet Flue Gas Desulphurisation	28.85	0
Other fuels existing plants	Wet Flue Gas Desulphurisation	34.92	0
Hard Coal new plant	Wet Flue Gas Desulphurisation	39	0
Brown Coal new plant	Wet Flue Gas Desulphurisation	48.75	0
HF new plant	Wet Flue Gas Desulphurisation	33.15	0
Other fuels new plants	Wet Flue Gas Desulphurisation	40.3	0
Hard Coal new plant	High Efficiency FGD	45.25	0
Brown Coal new plant	High Efficiency FGD	55	0
HF new plant	High Efficiency FGD	39.4	0
Other fuels new plants	High Efficiency FGD	46.55	0

Please specify investment function from EGTEI methodology [3]. Without this function it is not possible to validate the coefficients of table 1.

A questionnaire is being developed to collect information on recent investments.

The current EGTEI cost functions are linear and depend on the nominal capacity of the plant.

The CUEcost model [17] presents the following capital cost algorithm for wet FGD FSFO:

Table 2 : capital cost algorithm for wet FGD FSFO

	x	Equation	A	B
FSFO process equipment	MWth	$(X \times 1000 \times A \times X^B)/1.3$	4456.5	-0.6442
ID fans and ductwork	Chimney afcv	$(A \times X + B)/1.3$	1.6225	3 000 000
Chimney	Chimney afcv	$(A \times X + B)/1.3$	3.4736	5 000 000
Support equipment	MWth	$(0.0003 \times X^3 - 1.0667 \times X^2 + 1993.8 \times X + 1177674) \times 1.22$		

The data have been translated to convert the acfm in m³/h in real conditions. The investments are obtained for new installations. Using the retrofit factor of 30 %, the investments are rather lower than those presented above.

According to reference [16] an exponential power function is characteristic of the cost evolution with size. Sizing is done with the help of.

$$I_{cap1}/I_{cap2} = (Cap1/Cap2)^p$$

I_{cap1}: investment cost of installation with characteristic capacity 1

I_{cap2}: investment cost of installation with characteristic capacity 2

Cap1: characteristic capacity 1 e.g. 300 MWth

Cap2: characteristic capacity 2 e.g. 500 MWth

p: the ratio for combustion plant is between 0.6 and 0.7 according to one participant to the meeting.

This relation is never respected even with data from reference [5].

Investments are larger for smaller plants. It is why, it is necessary to differentiate typical ranges of size of installations.

For SO₂, examples of investments from experts would be useful for a representative set of installations in order to derive the investment function for the entire range of thermal capacity.

Paragraph 3.4 should be based on the function given in the previous memo (73100024-PGR/CFP 2011). Erroneously the term exponential is used in this memo; this should be power, since the formula is a power function. This function cannot be transferred into an exponential function, it could be transferred into a logarithmic function. Please note that this function is based on total investment cost and not on specific investment cost.

When the following values are used (based on IEA data from Figure 1)

Cap1 = 1000

Cap2 = 4000

*Icap1 = 140*1000 = 140 000*

*Icap2 = 90*4000 = 360 000*

Then exponent p should be 0.68, which is between 0.6 and 0.7.

With this formula it should not be necessary to differentiate typical ranges of size of installation.

A questionnaire has to be sent to collect investment. Functions will be derived the investments collected from real cases.

3.5 Variable operating costs

Operating costs are derived to be able to estimate them according any concentration to be obtained and reference situation both for liquid fuels and solid fuels.

3.5.1 Reagent consumption

At stoichiometry, 1 mole CaCO₃ abates 1 mole SO₂. In terms of mass, the ratio Ca/S = 1, accounts to CaCO₃ consumption of 1.5625 t CaCO₃/t SO₂.

In the current EGTEI methodology [3], the rate of use of limestone is as follows:

Efficiency of SO ₂ removal η	t CaCO ₃ /t SO ₂	Ratio Ca/S
85.0%	1.41	0.90
90.0%	1.48	0.95
95.0%	1.59	1.02

Due to its characteristics, limestone is used at about 95 to 97 % according to reference [4]. The purity is not 100%.

The current EGTEI data, do not take into account the rate of use of limestone and the purity. With a commercial reagent, considering 95 % reactivity and purity, the limestone consumption is as follows according to the efficiency required:

Efficiency of SO ₂ removal η	t CaCO ₃ /t SO ₂	Ratio Ca/S
85.0%	1.48	0.95
90.0%	1.56	1.00
95.0%	1.67	1.07

The specific limestone demand λ^s can be derived as follows according to the efficiency required:

$$(E10): \lambda^s = 1.8947 \times \eta_{\text{SO}_2, \text{reg}} - 0.1333$$

λ^s : specific limestone demand in ton CaCO₃/ton SO₂ removed

$\eta_{\text{SO}_2, \text{reg}}$: removal efficiency required, calculated according to formula (E9)

According to information provided by an expert of EDF [10], a consumption of CaCO₃ of 1.25 t CaCO₃/t SO₂ is necessary to obtain efficiency of 90 %.

1.25 t CaCO₃/t SO₂ is too low. Accordingly to the theory stated in the first sentence of paragraph 3.5 this number should be higher. Other data should be collected for this study.

λ^s : specific limestone demand in ton CaCO₃/ton SO₂ removed to be checked by experts; Other data expected to derive the correct demand of CaCO₃ for different efficiencies of reduction.

$$(E11): \text{CONS}^{\text{CaCO}_3} = \lambda^s \times \Phi \times \text{ef}_{\text{SO}_2} \times N \times 0.001$$

$\text{CONS}^{\text{CaCO}_3}$: yearly consumption of CaCO₃ in ton CaCO₃ /year

λ^s : specific limestone demand in ton CaCO₃/ton SO₂ removed calculated according to formula (E10)

Φ fuel consumption at nominal capacity, in GJ/hour calculated according to formula (E8)

ef_{SO_2} : SO₂ emission factor expressed in kg SO₂/GJ fuel input calculated according to formula (E6)

N: number of working hours at the nominal capacity

$$(E12): \text{OC}^{\text{CaCO}_3} = \text{CONS}^{\text{CaCO}_3} \times \text{C}^{\text{CaCO}_3}$$

$\text{OC}^{\text{CaCO}_3}$: operating cost in €/year due to CaCO₃ consumption

$\text{CONS}^{\text{CaCO}_3}$: yearly consumption of CaCO₃ in ton reagent /year calculated by equation (E11)

C^{CaCO_3} : price of reagent in € 2010/ton reagent

In France, costs of CaCO₃ are about 30 to 40 € 2010/ton reagent. Obtain other examples of prices of CaCO₃ in countries from experts of the group.

3.5.2 Industrial water consumption

According to reference [9], the slurry concentration SR for CaCO₃ is typically 15 to 20 % solids. According to the expert [10], the slurry concentration is 30 %.

Validate the concentration to be taken into account in case of LSFO and LSNO.

Water is recycled after its extraction from byproducts. With gypsum production, a concentration of water of 10% still occurs in gypsum.

There is evaporation of water (losses) and water purges are necessary to maintain a good quality of water. Water losses and purges have to be compensated: WL in %.

Propose rates of water addition to be added to compensate losses and purges in case of LSFO and LSNO.

The yearly demand in industrial water is:

$$(E13): \text{CONS}^{\text{water}} = \text{CONS}^{\text{CaCO}_3} / \text{SR} \times \text{WL}$$

$\text{CONS}^{\text{water}}$: yearly consumption of industrial water in m³/year

$\text{CONS}^{\text{CaCO}_3}$: yearly consumption of CaCO₃ in ton reagent /year calculated by equation (E11)

SR: slurry concentration in CaCO₃ %

WL: water losses to be compensated in %.

3.5.3 By-product production

According to the process used, CaSO_3 or CaSO_4 is produced. CaSO_3 can be considered as a waste to be discharged. CaSO_4 is a salable product.

λ^{bp} : specific byproduct production in ton byproduct/ton SO_2 removed

(E14): $\lambda^{\text{bp}} = \lambda^{\text{s}} \times 136 / 100$ in case of CaSO_3 produced or $\times 151/100$ in case of gypsum produced

(E15): $\text{CONS}^{\text{bp}} = \lambda^{\text{bp}} \times \Phi \times \text{ef}_{\text{SO}_2} \times \text{N} \times 0.001$

CONS^{bp} : yearly production of byproduct in ton byproduct /year

λ^{bp} : specific byproduct production in ton byproduct/ton SO_2 removed according to formula (E14)

Φ fuel consumption at nominal capacity, in GJ/hour calculated according to formula (E8)

ef_{SO_2} : SO_2 emission factor expressed in kg SO_2 /GJ fuel input calculated according to formula (E6)

N: number of working hours at the nominal capacity

(E16): $\text{OC}^{\text{bp}} = \text{CONS}^{\text{bp}} \times \text{C}^{\text{bp}}$

OC^{bp} : operating cost in €/year due to by-product elimination or recovery and selling.

CONS^{bp} : yearly production of byproduct in ton byproduct /year

C^{bp} : cost of waste disposal in case in not sealable product (CaSO_3) or price of CaSO_4 sold in € 2010/ton byproduct

Obtain examples of prices of sealable CaSO_4 and of waste disposal of CaSO_3 / CaSO_4 in countries from experts of the group.

3.5.4 Electricity consumption

According to reference [4] for a coal with 1.3 % S and a desulphurisation efficiency of 98 % for an unit of 500 MWe, auxiliary power for fans to overcome system pressure drop, caused by the flue gas flow through the absorber and other auxiliary equipment such as mist eliminator, is 5.46 MW for a total pressure drop of 0.2 m water column, in a LSFO. This gives 1.1 % of the net electricity production of the unit.

Reference [5] provides 1.1% of the net generation for a coal with a sulphur content of about 1 % and 1.5 % for a coal with a sulphur content of 2.25 % for a LSFO. The FGD efficiency is not provided. For a FSNO, it is 1 % instead of 1.5%.

Reference [10] provides auxiliary power of 10 to 12 MW for a unit of 600 MWe and a de SO_x efficiency of 90 % for a LSFO.

Obtain other data to derive a function according to the sulphur content of coal or a fuel and the efficiency of desulphurisation required. Differences between LSFO and LSNO to be taken into account.

λ^{elec} : specific electricity demand in % of the net electricity generation defined as a function of the sulphur content of fuel in % w/w (%S) and the efficiency of the reduction to be obtained (η_{SO_2} in %).

(E17): $\lambda^{\text{elec}} = \text{function} (\%S, \eta_{\text{SO}_2, \text{reg}})$

(E18): $\text{CONS}^{\text{elec}} = \lambda^{\text{elec}} \times \text{bse} \times \text{N}$

$\text{CONS}^{\text{electricity}}$: yearly consumption of electricity in MWh /year

bse: boiler size in MWe

N: number of working hours at nominal capacity

(E19): $\text{OC}^{\text{elec}} = \text{CONS}^{\text{elec}} \times \text{C}^{\text{elec}}$

OC^{elec} : operating cost in €/year due to electricity consumption.

$\text{CONS}^{\text{elec}}$: yearly electricity consumption of the FGD in MWh /year

C^{elec} : cost of electricity in € 2010/MWh

Obtain examples of prices of electricity in countries from experts of the group.

3.5.5 Wages

12 operators (40 hours / week) are needed for an FGD control in an existing plant according to reference [4] but 8 on a new plant. Reference [10] provides 10 operators for a 600 MWe. According to the reference 8 the need is constant whatever the size is. However this need has to be checked for power plant between 50 to 100 MWth or a little bit more. Maintenance labour costs should also be included, as the wages are country specific. According to the same reference, the maintenance labour cost is just a little bit lower than the operating labour costs.

λ^{wage} : specific demand in human resource for control of the FGD and its operation as well as maintenance operation in number of man year. Function according to the size to be determined from examples provided by experts for LSFO and LSNO.

(E20): λ^{wages} = function to be determined (based on the size probably)

(E21): $OC^{WAGES} = \lambda^{wages} \times C^{wages}$

OC^{wages} : operating cost in €/year due to human resource required.

C^{wages} : cost of wages in € 2010/man year

Obtain examples of prices of human resources from experts of the group.

3.6 Fixed operating costs

The fixed operating costs depend on the capacity or size of the installation, i.e. on the investment and are expressed as a percentage of the unit investment. They include costs of maintenance and repair, insurance, administrative overhead, etc. Taxes are not included in order to be coherent with GAINS.

According to reference [4] fixed operating costs are 2.5 % of investment for an existing plant and 3.3 % for a new installation. Reference includes labour costs for maintenance but they have been excluded.

EGTEI [4] considered 4 % of the investment.

4% seems to be too much, even when wages are included in the fixed cost. Data will be collected on that issue.

Percentage to be validated: 4 % of the investment or another factor. Is the factor lower for LSFO than for FSNO?

4 NOx Abatement

For the purpose of this calculation, NOx shall be a 95% NO and 5% NO₂ mixture and loads are expressed as NO₂-equivalents, as mostly referred to in the corresponding literature.

4.1 Required abatement efficiency for NO_x removal

$$(E1): \eta_{\text{NOx, req.}} = \frac{\text{CONC}_{\text{NOx, ELV}}}{\text{CONC}_{\text{NOx, raw}}} \times 100$$

$$(E1): \eta_{\text{NOx, req.}} = (1 - (\text{CONC}_{\text{NOx, ELV}} / \text{CONC}_{\text{NOx, raw}})) \times 100$$

$\eta_{\text{NOx, req}}$ efficiency in %

$\text{CONC}_{\text{NOx, ELV}}$: Case specific emission limit value, mostly derived by regulation (i. e. corresponding IED-ELV) in mg/Nm³ dry, O₂ ref.

$\text{CONC}_{\text{NOx, raw}}$: Raw gas concentration of NOx (upstream of corresponding DeNOx unit) in mg/Nm³ dry, O₂ ref

$$E1 \text{ required abatement efficiency} = 1 - \text{ConcNox,ELV} / \text{CONCNox, rev}$$

4.2 Techniques considered up to now

Reduction techniques considered are (January 2012):

- **Primary Measures: Low NOx Burner of 1st & 2nd generation**

HC-fired units:

Most currently operating power plant installations have a type of low NOx burner (LNB) already installed. Within the last 20 years research in combustion and fuel injection has led to huge improvements of LNBs. In the case of coal fired power plants, reference [11] and [12] cite average baseload emission levels of **400-600 mg/Nm³ (dry bottom boiler) and 600-800 mg/Nm³ (wet bottom boiler)** as average emission levels.

Plants without any type of LNB device are very rare. 1980ies data as well as literature on first generation LNBs suggest baseline emissions of 800-1.000 mg/Nm³ for tangentially fired units and 1.000-1.300 mg/Nm³ for wall-fired units.

New types of LNB for coal firing are expected to reach emission levels as low as 300-350 mg/Nm³, see for example the tangentially-fired unit Hemweg 8, NL (reference [13]).

BC-fired units: to come

HFO-fired units: to come

NG-fired boiler units: to come

NG-fired GT-units: to come

Flue gas recirculation for gaseous fuels: **to be considered?**

Average baseload emission levels seem to be high.

- **Secondary Measures**

Selective Catalytic Reduction (SCR)

SCR can be used at all fuel types. Current benchmark for modern coal fired power plants, as defined by E.On in reference [13] are:

- NOx conversion of 90% at SO₂/SO₃ conversion rates < 1%
- NOx outlet concentration 35-40 mg/Nm³ (in combination with new generation LNBs)

- o NH_3 slip < 1ppmv

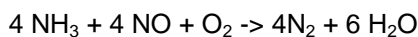
These values require 3-5 catalyst layers and shorter operating periods between catalyst regeneration.

Co-firing biomass, mostly solid biomass, lead towards higher catalyst deactivation rates and therefore shorter catalyst lifetimes. Reference [13] cites cycles as short as one year, in comparison to upper levels of up to three years.

Selective Non-Catalytic Reduction (SNCR) **to be considered for smaller plants?**

Primary measures inhibit NO_x formation by creating a non-favourable surrounding, for example O₂-lean regions or non-favourable temperature levels at O₂-rich regions.

Secondary measures abate NO_x by reducing NO / NO₂ to pure N₂ with the use of appropriate reagents, mostly ammonia (NH₃) or urea (CO(NH₂)₂). In the case of ammonia and NO, the reaction is as follows:



For urea and NO₂, the reaction is similar.

4.3 Investments

The parameters of the investment function of the current EGTEI data [3], are the following ones.

Table 3: Coefficients of the investment function for NO_x removal with LNBS

Fuel - type of plant	cif , €/kWth	civ ,10 ³ €
HC1 existing plant	2.15	780
HC2 existing plant	2.15	780
HC3 existing plant	2.15	780
HF existing plant	2	600
Gas existing plant	1.8	560
HC3 new plant	0	0
HF new plant	0	0
Gas new plant	0	0

Table 4: Coefficients of the investment function for NO_x removal with SCR

Fuel - type of plant	cif , €/kWth	civ ,10 ³ €
HC1 existing plant	2.15	780
HC2 existing plant	2.15	780
HC3 existing plant	2.15	780
HF existing plant	2	600
Gas existing plant	1.8	560
HC1 new plant	2.15	780
HC2 new plant	2.15	780
HC3 new plant	2.15	780
HF new plant	2	600
Gas new plant	1.8	560

The current EGTEI cost functions are linear and depend on the nominal capacity of the plant.

For deNO_x techniques, examples of investments from experts would be useful for a representative set of installations in order to derive the investment function for the entire range of thermal capacity.

Please specify investment function from EGTEI methodology [3]. Without this function it is not possible to validate the coefficients of table 3 and 4.

Cost functions should not be linear, but accordingly to the function given in the previous memo (73100024-PGR/CFP 2011)

Taken into account. A collection of investments is initiated. The function will be derived according to data collected.

4.4 Operating costs

Operating costs are derived to be able to estimate them according any concentration to be obtained and reference situation.

4.4.1 Reagent consumption

With **an average molar stoichiometry of 0.85** (NH_3/NO_x , reference [14]), the NH_3 consumption equals 0.31 t NH_3 / t NO_x (as NO_2 equiv.).

Flue gas specific reagent consumption equals to:

$$(E2) \text{CONS}^{\text{NH}_3, \text{vol}} [\text{mg NH}_3/\text{Nm}^3 \text{ @ ref. O}_2 \text{ content, dry}] = (\text{CONC}_{\text{NO}_x, \text{inlet}} - \text{CONC}_{\text{NO}_x, \text{outlet}}) \times [0.39-0.40 \text{ mg NH}_3/\text{mg NO}_x]$$

Annual reagent consumption, analogous to (E11) for SO_2 , equals to:

$$(E3) \text{CONS}^{\text{NH}_3, \text{a}} [\text{t/year}] = \text{CONS}^{\text{NH}_3, \text{vol}} [\text{mg}/\text{Nm}^3] \times \text{Fref} [\text{Nm}^3/\text{GJ}] \times \Phi [\text{GJ}/\text{h}] \times \text{N} [\text{h}/\text{year}] \times 10^{-9} [\text{mg}/\text{t}]$$

Consequently, yearly reagent costs are:

$$(E4) \text{OC}^{\text{NH}_3} [\text{€}/\text{year}] = \text{C}^{\text{NH}_3} [\text{€}/\text{t}] \times \text{CONS}^{\text{NH}_3, \text{a}} [\text{t}/\text{year}]$$

If ammonia losses during storage and distribution occur, this has to be added by an appropriate factor.

If the SCR is operated with urea, each mole of urea decomposes to 2 moles of ammonia-equivalents (NH_2 -ions), accordingly, the stoichiometric ratio needs to be adjusted by this factor of 2.

Accordingly to theory stoichiometry should be 1.0, and thus NH_3 consumption is higher. Will be corrected

4.4.2 Additional power consumption

Power consumption is needed for reagent storage, distribution & injection as well as for the compensation of the corresponding pressure drop.

In SCR appliances, pressure drop is depending on the injection, static mixers and the total catalyst length (no. of standard 1 m catalyst layers). Some references cite a total pressure drop of 25-35 mbar across a standard SCR system, others 10 mbar per layer. Further pressure drop due to deposits (ash, ABS) may arise during operations.

In reference [15], the US EPA calculates with total SCR related energy consumption of 0.3-0.4% of total gross electricity generation.

Assumption: Total additional power consumption is 0.3% of gross electricity generation.

4.4.3 Catalyst regeneration and replacement

For this issue of standardized calculations, a reference SCR unit shall have a 3+1 catalyst layer management system, i. e. 3 active catalyst layers plus 1 spare layer. Furthermore, it shall be assumed that a catalyst layer will be taken to regeneration after a certain time of operation. Each catalyst can be regenerated for a certain number of times until the layer will exceed its expected lifetime and will be replaced by a new layer.

With proper regeneration and clean coals, **total catalyst lifetime may be as high as 80,000 operating hours** [18]. Catalyst regeneration cycles depend on fuel specifics as well, **cycles may be as short as one year**, when firing high percentages of biomass [13].

Catalyst regeneration cost seems to be high. To be investigated with a questionnaire.

Parameters for calculating SCR operating costs

Parameter	Unit	Initial Suggestion
Ammonia Price (if used)	€/t NH ₃ (100% pure NH ₃ equivalents or ~20% aqueous solution)	380 €/t anhydrous ammonia
Urea Price (if used)	€/t Urea (dry or solution incl. %)	340 €/t urea prills
Internal Cost of Electricity	€/MWh	
Catalyst Regeneration Cost	€/m ³ or €/layer	50% of Replacement Cost
Catalyst Replacement Cost	€/m ³ or €/layer	5,000-7,000 €/m ³
Catalyst Lifetime until Regeneration	Operating Hours	1-3 years
No. of Regeneration Cycles until Catalyst Layer Replacement	Number	4-5
Average SCR abatement efficiency (3+1 layer), for coal, gas, oil boiler and GT	%	85% (hard and brown coal)

4.5 Fixed operating costs

The fixed operating costs depend on the capacity or size of the installation, i.e. on the investment and are expressed as a percentage of the unit investment. They include costs of maintenance and repair, insurance, administrative overhead, etc. Taxes are not included in order to be coherent with GAINS.

EGTEI [3] considered 4 % of the investment.

Percentage to be validated: 4 % of the investment or another factor?

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