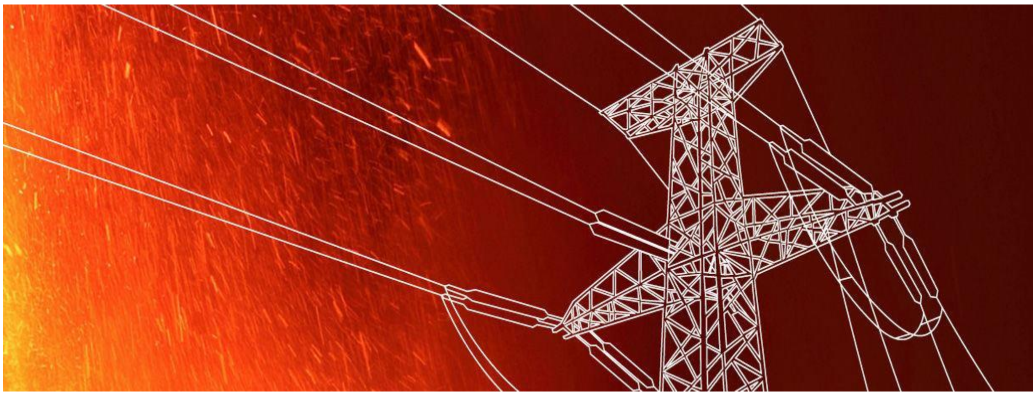
Cost of Capacity for Calibration of the Belgian Capacity Remuneration Mechanism (CRM)



Report
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Abbreviations

AESO	Alberta Electric System Operator
BEREC	Body of European Regulators for Electronic Communication
BEV	Battery electric vehicle
CAPM	Capital asset pricing model
CCGT	Combined cycle gas turbine
CEPA	Cambridge Economic Policy Associates
CMA	Competition and markets authority
CONE	Cost of New Entry
D	Market value of the firm's debt
D/V	Percentage of financing that is debt (gearing)
DLC	Direct load control
DR	Demand response
DSM	Demand Side Management
E	Market value of the firm's equity
EOH	Equivalent Operating Hours
E/V	Percentage of financing that is equity
EUR	Euro
HRSG	Heat Recovery Steam Generator
HVAC	Heating, ventilation and air conditioning
IC	Internal combustion
IC engine	Internal Combustion Engine
k	Kilo
LCOE	Levelized Cost of Electricity
LMDR	Load modifying demand response
O&M	Operation & Maintenance
OCGT	Open cycle gas turbine
PE	Permanent Establishments
PHEV	Plug-in-hybrid electric vehicle
PV	Photovoltaics
Rd	Cost of debt
Re	Cost of equity, which is the shareholders' required return
Rf	Risk-free rate
Rm	Annual return of the market
SDR	Strategic demand reserve
SGR	Strategic generating reserve
Tc	Corporate tax rate
TOU	Time of use
TSO	Transmission System Operator
V	Total value of the firms financing
WACC	Weighted Average Cost of Capital

1. Introduction and Background

1.1 Introduction

According to Belgian Law, the final phase out of the Nuclear is foreseen by 2025. Following this decision, solutions had to be found to ensure security of supply after cessation of the country's major source of electricity.

A Capacity Remuneration Mechanism (CRM) shall ensure the availability of sufficient capacity in the system. This contracted capacity shall be ready for availability when needed and prevent Security of Supply issues due to a structural lack of available capacity leading to the inability to cover demand.

CRMs are support schemes and in need of well-defined, non-discriminatory regulation to allow capacity providers to run a profit while preventing excessive remuneration through adequate tools such as price caps. In order to support the parameters definition of the CRM auctions, a detailed overview over the costs for the technologies that may provide this capacity as well as the investment thresholds and remuneration limits will be assessed in this report.

1.2 Scope of work

This report was commissioned by the Belgian Transmission System Operator (TSO) Elia System Operator S.A. (hereby named Elia) and the Belgian Federal Commission for Electricity and Gas Regulation (CREG). It is based on four main deliverables, which are crucial for the calibration of the design of the Belgian CRM. Namely, these deliverables are the assessment of the Gross CONE, the global auction price cap, an evaluation of the eligible costs in the frame of the determination of the investment thresholds (CREG competences) and the intermediate price cap for existing capacity (TSO competence). Initially, a value for "Weighted Average Cost of Capital" (WACC)[1] is determined, which serves as input for the other deliverables.

The Gross CONE incorporates the technology-specific annualized investment cost and the annual Operation & Maintenance (O&M) costs of new facilities. Based on these costs the technology's marginal revenues will be deducted in order to determine how much financial support is needed to ensure a financial motivation to make its capacity available to the system.

The global auction cap and the intermediate price cap will be determined based on the sensitivity of the Gross CONE calculation and a cost assessment for existing capacities, respectively. They shall be instruments of the mechanism to ensure that all technology providers will be able to offer capacity at a price needed for profitability but prevent excessive remuneration.

For existing units[2], eligible investments that augment the capacity or extend the lifetime will be identified and quantified. The part of Gross CONE that is eligible according to the rules established by CREG will be presented.

[1] The final methodology used will be in line with the methodologies developed in the frame of the EU regulation 2019/943
[2] CCGT (350 - 450 MW), OCGT (100 MW), CHP (380 MW) and Turbojet (20 MW)

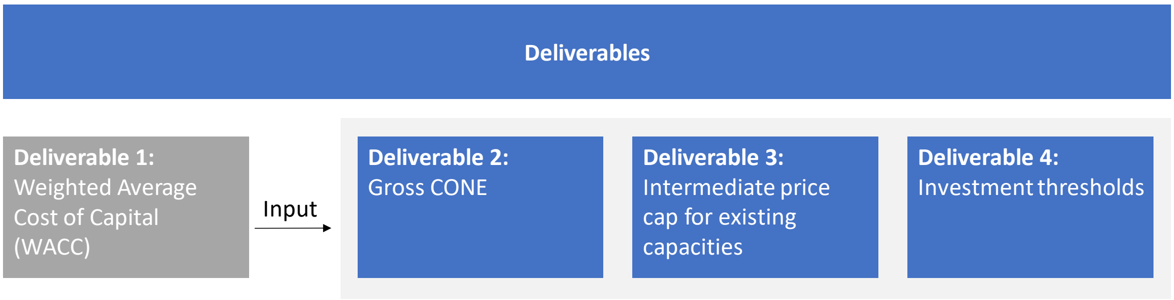

Figure 1: Deliverables (Source: Fichtner, own diagram)

1.3 Structure of the report

The report is structured based on the defined deliverables. In Section 2 a single value for the WACC is assessed by analyzing the cost of capital and the cost of debt that apply for the energy sector in Belgium.

This value will subsequently be considered in the calculations of Gross CONE in Section 3. After assessing the technologies that can act as “new entrants” (newly built units) by the beginning of the Capacity Remuneration Mechanism in 2025, the costs incurred for each technology are assessed.

Section 4 includes the approach to determine the intermediate price cap. The currently existing technologies in Belgium are listed and a cost assessment is made to derive an intermediate price cap.

Eventually, the part of Gross CONE that is eligible for remuneration based on regulation is determined in Section 5.

2. Weighted Average Cost of Capital (WACC)

The weighted average cost of capital (WACC) describes the return on assets a company must earn to satisfy any creditor, owner and other provider of capital. It represents the rate at which a company's future cash flows need to be discounted to arrive at their present value. The WACC consists of the combination of cost of equity and the cost of debt, as shown in Figure 2 according to their respective share (see Section 2.2.2.1).

The principle of WACC and how it is used by investors to make their investment decision is described in multiple standard literature such as (Ernst & Young, 2018), (Brealy, et al., 2011), (Kruschwitz & Loeffler, 2005) and (Independent Pricing and Regulatory Tribunal, 2013).

The following section describes how the value for WACC is calculated.

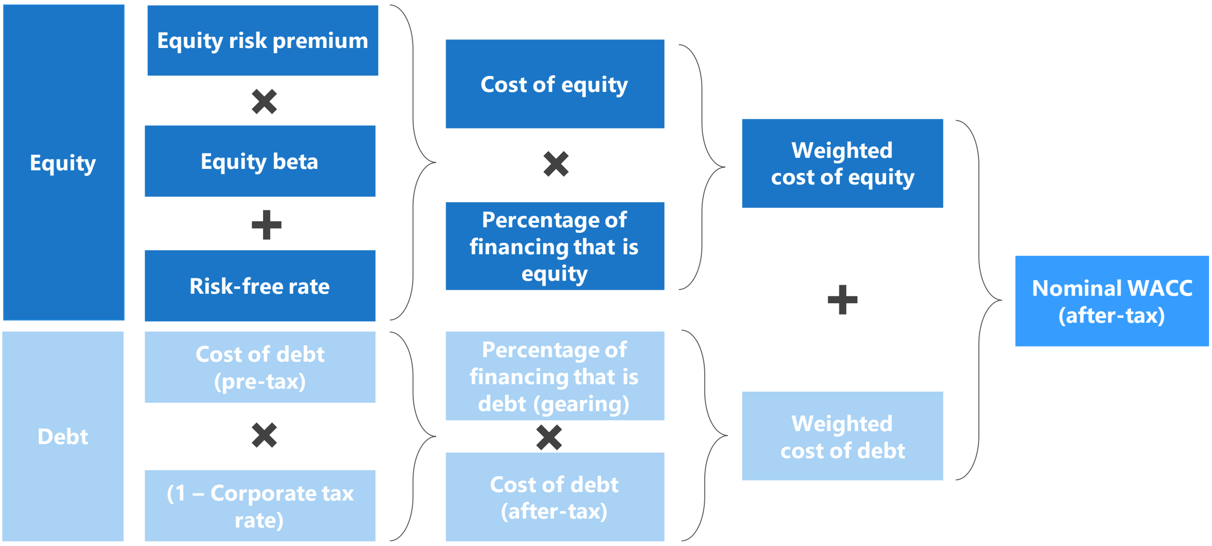

Figure 2: Calculation of the weighted average cost of capital (WACC) (Source: Fichtner, own diagram)

The corporate tax rate has an important influence on the WACC calculation because of tax deductibility of cost of debt in Belgium (Deloitte, 2019) (for details see Section 2.2.1.3).

The calculation of the WACC is used in many similar studies concerning net CONE. Some examples include:

- Calculation of the WACC for capacity payment for peaking plants in Ireland and Northern Ireland, done 2016 by the Cambridge Economic Policy Associates Ltd (CEPA) and Ramboll (CEPA, 2015)
- Calculation of the WACC for CONE parameters for capacity auctions for PJM (regional transmission organization in all or parts of 13 states of the US) (Newell, et al., 2014) and (Newell, et al., 2018)
- Calculation of the WACC for a three-year-forward capacity market for the Alberta Electric System Operator (AESO) in 2018 (Pfeifenberger, et al., 2018)

2.1 Methodology

The WACC is company-, technology- and country-dependent. This is considered in the following approach.

In order to obtain one general value of the WACC that will be used for all further calculations, the calculation of the WACC and the input parameters rely on several assumptions on the project type, the financing structure and the profile of the investor. The following approach applies to new capacities in the Belgian power sector. The investment period is assumed to be 20 years which includes economic lifetime of an asset and its construction period. An investment period of 20 years is a common number which is used for many different power generating technologies. The debt duration is set to 20 years. The entire section relates to funding in the Belgian market. All other assumptions are clarified in the respective section.

Since corporate tax is an important factor, which contributes to the individuality of the Belgian value for the WACC for energy systems, the after-tax WACC is calculated here.

General equation for calculating after-tax WACC:

$$WACC_{after-tax} = \frac{E}{V} \cdot Re + \frac{D}{V} \cdot Rd \cdot (1 - Tc)$$

E	=	Market value of the firm's equity
D	=	Market value of the firm's debt
V	=	Total value of the firms financing (E+V)
$\frac{E}{V}$	=	Percentage of financing that is equity
$\frac{D}{V}$	=	Percentage of financing that is debt (gearing)
Re	=	Cost of equity, which is the shareholders' required return
Rd	=	Cost of debt
Tc	=	Corporate tax rate

Cost of debt (Rd):
There are two options how to determine cost of debt (Rd)[3]. It can be calculated as sum of the risk-free rate (see Section 2.2.1.1) and the company-specific debt premium, or directly provided values for the cost of debt are used, if available.

Cost of equity (Re):
The cost of equity is commonly calculated using the Capital Asset Pricing Model (CAPM). According to this model the cost of equity (after-tax) is calculated as follows:

$$Re = Rf + \beta_e \cdot (Rm - Rf)$$

with

Rf	=	Risk-free rate, which describes the return that can be earned by investing in a riskless security
β_e	=	Equity beta
Rm	=	Annual return of the market
$(Rm - Rf)$	=	Equity risk premium

[3] Cost of debt is typically given as a pre-tax value. The effect of taxation is incorporated in the next step (see methodology).

To calculate the equity beta as an input parameter the asset beta needs to be converted by using the Hamada equation:

$$\beta_e = \beta_a \left[1 + (1 - Tc)\left(\frac{D}{E}\right)\right]$$

β_e	=	Equity beta (levered beta)
β_a	=	Asset beta (unlevered beta)
Tc	=	Corporate tax rate
$\frac{D}{E}$	=	Debt to equity ratio

WACC in real terms vs WACC in nominal terms:
There is a distinction between real and nominal WACC. Real values are adjusted for inflation (inflation is excluded). They are used to ensure the comparability without being distorted by inflation. In nominal values the inflation is included. Nominal WACC can be converted to real WACC (and vice versa) with the Fisher equation given below.

In this study, the WACC is first calculated in a nominal value as most input parameters for the WACC calculation are typically given in nominal terms such as e.g. risk-free rate, corporate tax rate and cost of debt. The nominal WACC is then transferred into real terms with the Fisher Equation (see below). This is in line with the general approach in this study to provide numbers (e.g. CAPEX of generation technologies) in real terms on the price base 2019. From a technical point of view, it is sensible not to mix price developments due to inflation with developments due to technological changes. Expected inflation rates are provided (see Section 2.2.1.4).

The WACC in nominal terms can be transformed into a real value and vice versa by using the Fisher equation:

$$WACC_{real} = \frac{1 + WACC_{nom}}{1 + r} - 1$$

r	=	inflation rate
nom	=	Nominal

2.2 Input parameters

Estimations for the input parameters for the calculation of the WACC for Belgium are presented in the following section. Since specific WACC numbers for individual utilities in Belgium are not available, the given values are based on Fichtner's experience in similar calculations and on literature or studies on the components of the WACC equation (risk-free rate, equity beta etc.). The values are separated into input parameters that are specific for the Belgian market (risk-free rate, equity risk premium, corporate tax rate, inflation rate) and energy sector specific input parameters (gearing, equity beta, cost of debt).

2.2.1 Belgian market-specific input parameters

The risk-free rate, the equity risk premium, the corporate tax rate and the inflation rate are all dependent on Belgian regulations and the general Belgian economy.

2.2.1.1 Risk-free rate Rf

The risk-free rate describes the return that can be earned by investing in a riskless security, such as government securities. The value obtained for the risk-free rate is needed for the calculation of the cost of equity.

Since government bonds are an example for a "safe" investment, one option is to use historical spot values of Belgian government bonds. This approach is enhanced with an outlook on expected developments in the future presented below.

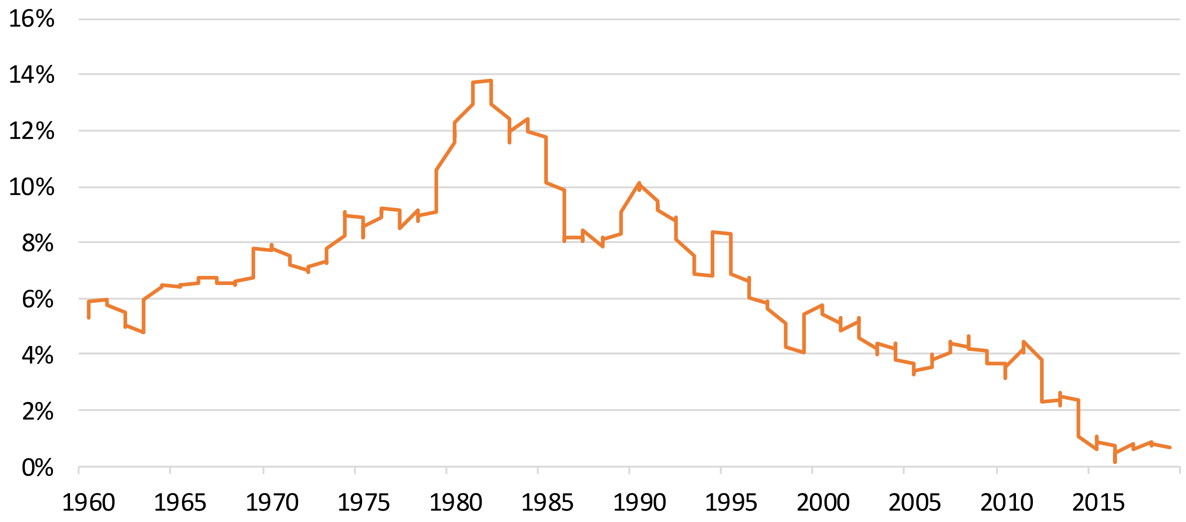

Figure 3: Belgian 10-year Long Term Government Bond Yields from 1960-2019. (Source: (Federal Reserve Bank of St. Louis, 2019))

Figure 3 shows the 10-year government bond yields in nominal terms in Belgium. The average value of the 10-year bonds from the last 5 years is 1,3 %. The average of the last 2,5 years is 1,2 %. This value is in line with the outlook provided by the Belgian Federal Planning Bureau[4] for 2021 (see Figure 4) which is the moment of the first auction (Y-4) for the delivery year 2025.

The Belgian Federal Planning Bureau expects the following development of the nominal long term interest rate (10 years)[5], which can be seen as a proxi for the risk-free rate (Federal Planning Bureau, 2019) (see Figure 4).

[4] "Bureau fédéral du Plan"
[5] "Taux d'intérêt à long terme nominal (10 ans, niveau)"

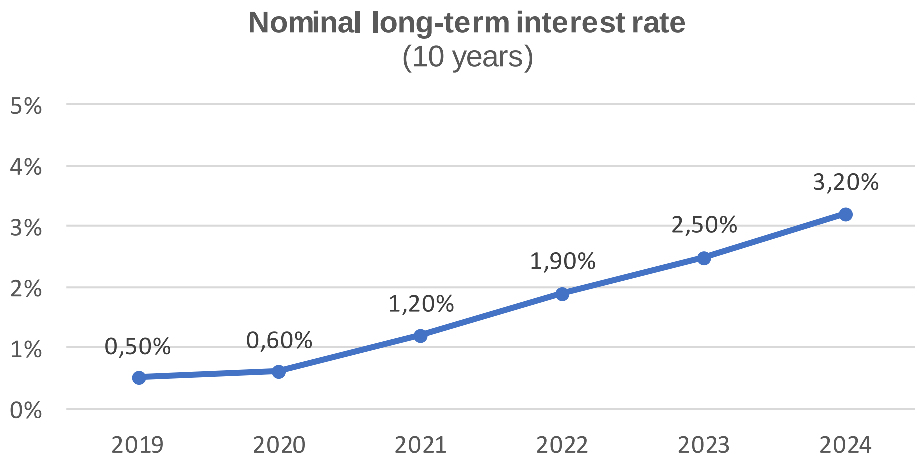

Figure 4: Expected development of the nominal long-term interest rate (Source: Fichtner, based on data from (Federal Planning Bureau, 2019))

Maturity premium:
As demonstrated the investment period is 20 years, the analyzed government bonds and long-term interest rates are based on a 10-year maturity. For this reason, a maturity premium needs to be applied. The maturity premium (20-year bond yields over 10-year bond yields) is assumed with 0,54 % (The Brattle Group, 2015).[6]

Conclusion
The risk-free rate is expected to be 1,2 % (in nominal terms). This is in line with recent historic data for 10-year government bond yields in Belgium and with the expectations of the Belgian Federal Planning Bureau. Additionally, a maturity premium of 0,54 % needs to be added as discussed.
In this study a nominal risk-free rate of 1,74 % is used.

2.2.1.2 Equity risk premium $(\boldsymbol{Rm - Rf})$

The equity risk premium is the extra yield that investors require for the risk they are taking that can be earned over the risk-free rate by investing in the stock market. The equity risk premium has been calculated by several sources, which are presented in the following.

Damodaran's calculation for the equity risk premium was last updated in January 2019. The Belgian value for the equity risk premium in his calculation is $(Rm - Rf) = 6{,}8\ \%$ (Damodaran, 2019b).

The BEREC report has an equity risk premium for Belgium of 5,39 % in 2018. The value is based on historical data (BEREC, 2018).

A study from Deloitte (Deloitte, 2017) which gives an overview on market values in the energy sector shows a value for the equity risk premium of 5,6 % in 2016 and of 5,5 % in 2015 in Belgium.

The value provided by Bloomberg for the equity risk premium in Belgium is 6,73 % in 2015 (Deloitte, 2017).

[6] The maturity premium corresponds in the ballpark to the current difference between a 10 and 20 year government bond for Belgium (Fusion Media Limited, 2020).

The equity risk premium based on a survey from Professor Fernandez from 2018 is assumed with 6,2 % for Belgium (Fernandez, et al., 2018).

Conclusion
The value for the equity risk premium is in the range of 5,4 - 6,8 %.
In this study an equity risk premium of 6,1 % is used as base case.

2.2.1.3 Corporate tax rate Tc

As of 2019, the corporate tax rate for Belgian companies as well as for Belgian PEs of foreign companies is 29,58 %. However, this value will be reduced to 25 % in 2021, due to the cut of the crisis tax (pwc, 2018).

There may be unequal regulations and tax cuts for different companies. However, since the value should be generally applicable for Belgium, the normal corporate tax rate of 25 % will be used. This is in line with a study from Ernst & Young on the Belgian corporate tax reform (Ernst & Young, 2017).

Cost for debt is deductible in Belgium (Deloitte, 2019). The corporate tax rate is incorporated in the WACC calculation and nominal WACC explicitly after-tax is calculated considering this effect.

Conclusion
In this study a value for the corporate tax rate of 25 % is used.

2.2.1.4 Inflation rate r

In the following an estimation for the general inflation till 2025 in Belgium is provided, so that nominal values can be derived from the real values, if required. For the calculation of the WACC in real values it is necessary to adjust the nominal WACC from inflation with the Fisher equation (see Section 2.1) for which the inflation rate is one input parameter.

The “International Monetary Fund” projects the inflation rate in Belgium. The expected average inflation rate till 2025 is 1,58 % (International Monetary Fund, 2019).

Conclusion
In this study the yearly expected average inflation rate of 1,58 % till 2025 is used for Belgium.

2.2.2 Energy-sector-specific input parameters

Gearing as well as the equity beta and the cost of debt are specific for the energy sector. Latter is usually strongly company dependent.

2.2.2.1 Gearing $\frac{D}{V}$

The gearing (or gearing ratio) is defined as the percentage of financing that is debt (D/V).

In the energy market investigation, carried out by the Competition and Markets Authority (CAM) for the UK, the gearing of different companies operating in the UK was at around 40 % in 2013 for six large energy firms (Centrica plc, SSE plc, EDF SA, E.ON SE, Iberdrola SA, RWE AG) and at around 43 % for generation firms (GDF Suez, Drax plc, AES Corp, AEP Corp, Calpine Corp) (Competition and Markets Authority, 2018).

This also corresponds to Damodaran. According to his research the gearing is around 47 % for the power industry and around 52 % for the green and renewable energy industry in Western Europe for 2019 (Damodaran, 2019c).

KPMG identified a value of around 40 % as the gearing ratio for the energy sector in their cost of capital study that was made with data from over 270 companies of different industries from Germany, Switzerland and Austria (KPMG, 2018).

Conclusion
The value for the gearing ratio is in in the range of 40 - 55 %.
In this study a gearing ratio of 47,5 % is used as base case.

2.2.2.2 Equity beta β

Equity beta (levered beta) refers to the volatility of a stock relative to all other stocks in the market. The higher the value of beta, the higher is the uncertainty about the returns on a firm's equity. In contrast to this the asset beta (unlevered beta) is the beta of a company without the impact of debt.

With the Hamada equation (see Section 2.1) it is possible to convert an asset beta into an equity beta considering the corporate tax rate (see Section 2.2.1.3) and the debt to equity ratio (see Section 2.2.2.1).

Damodaran has calculated sector specific asset betas. His value for the Western European power industry is 0,61 (Damodaran, 2019a). Based on this, the following value for the equity beta is calculated (see Table 1):

	Asset beta (unlevered beta) **(Damodaran, 2019a)**	**Equity beta** (levered beta) **(calculated)**
Power Industry	0,61	1,02

Table 1: Calculation of equity beta (Source: Fichtner, based on data from (Damodaran, 2019a))

Values from literature as a reference point:
In a study carried out by Pöyry equity beta ranges from 0,76 to 1,08 which results in a final average value for the equity beta of 0,92 (Pöyry Management Consulting, 2018).

In a study from 2017, the equity beta for the two largest fuel and energy companies being listed on the Warsaw Stock Exchange is given with 0,98 and 1,07 (Koziel, et al., 2017).

Calculating the WACC for the UK energy market, the Competition and Markets Authority (CAM) assumes an equity beta in the range of 0,9 - 1,2 (Competition and Markets Authority, 2018).

KPMG provides a beta factor for the energy and natural resources sector between 0,98 and 1,01 for Germany, Switzerland and Austria (KPMG, 2018).

Conclusion
The calculated value for the equity beta (considering the proposed gearing level of 47,5 %) is 1,02. This is in line with the provided literature.
In this study an equity beta of 1,02 is used.

2.2.2.3 Cost of debt Rd

There are two options how to determine the cost of debt (Rd)[7]:

Option 1:
Cost of debt can be calculated as sum of the risk-free rate (see Section 2.2.1.1) and the company-specific debt premium.

Rd = risk-free rate + debt premium

The debt premium is usually in line with the ratings that credit rating agencies and the banks allot to a certain company. These ratings depend on different factors such as market capitalization and business risks which are specific for the company or the operating sector, in this case the energy sector. The gearing ratio is also important for determining the debt premium, as a company with a high gearing ratio is less likely to maintain a premium credit rating and will typically pay a higher debt premium. Another important factor is the tenor of loan - the longer the financing period, the more expensive the debt.

Pöyry used a debt premium in the range of 1,0 - 3,0 % (Pöyry Management Consulting, 2018). In combination with a risk-free rate of about 1,74 % (see Section 2.2.1.1) this adds up to an average cost of debt of 3,74 %.

Option 2:
Many sources directly provide values for the cost of debt. In the following, values from comparable projects and studies are presented:

Deloitte’s value for the cost of debt in Europe is 3,4 %. The values for the Oil and Gas sector are around 3,3 % and for the renewable energy sector around 4,1 % in 2016 (Deloitte, 2017).

In Damodaran’s calculation the cost of debt is 5,49 % in the coal and related energy industry, 5,11 % in the green and renewable energy industry and 5,11 % in the power industry (Damodaran, 2019c).

[7] Cost of debt is typically given as a pre-tax value. The effect of taxation is incorporated in the next step (see methodology).

Conclusion
For the cost of debt (pre-tax) the value lies between 3,0 - 5,5 %. Fichtner recommends choosing a value at the upper end of this range in line with Damodoran.[8]
In this study a value for the cost of debt of 5.25 % is used as base case.

2.3 Summary of all input parameters

In Table 2 all necessary input parameters to calculate WACC are summarized.

	Low Case	High Case	Base Case
Risk-free rate	1,74 %	1,74 %	**1,74 %**
Equity risk premium	5,40 %	6,80 %	**6,10 %**
Corporate tax rate	25 %	25 %	**25 %**
Gearing ration	40,0 %	55,0 %	**47,5 %**
Equity beta	1,02	1,02	**1,02**
Cost of debt (pre-tax)	3,00 %	5,50 %	**5,25 %**
Yearly average inflation rate till 2025	1,58 %	1,58 %	**1,58 %**

Table 2: Summary of input parameters for WACC calculation (Source: Fichtner, own table)

2.4 Results of the WACC calculation

WACC can be calculated based on the methodology presented in Section 2.1. The individual calculation steps are summarized in Figure 6.

Results are summarized in the following table (Table 3).

	Low Case	High Case	Base Case
Nominal WACC (after-tax)	5,26 %	6,18 %	**6,06 %**
Real WACC (after-tax)	3,62 %	4,53 %	**4,41 %**

Table 3: Summary of results of WACC calculation (Source: Fichtner, own table)

The results are displayed in Figure 5.

[8] Damodoran is the most recent source and refers to the power industry.

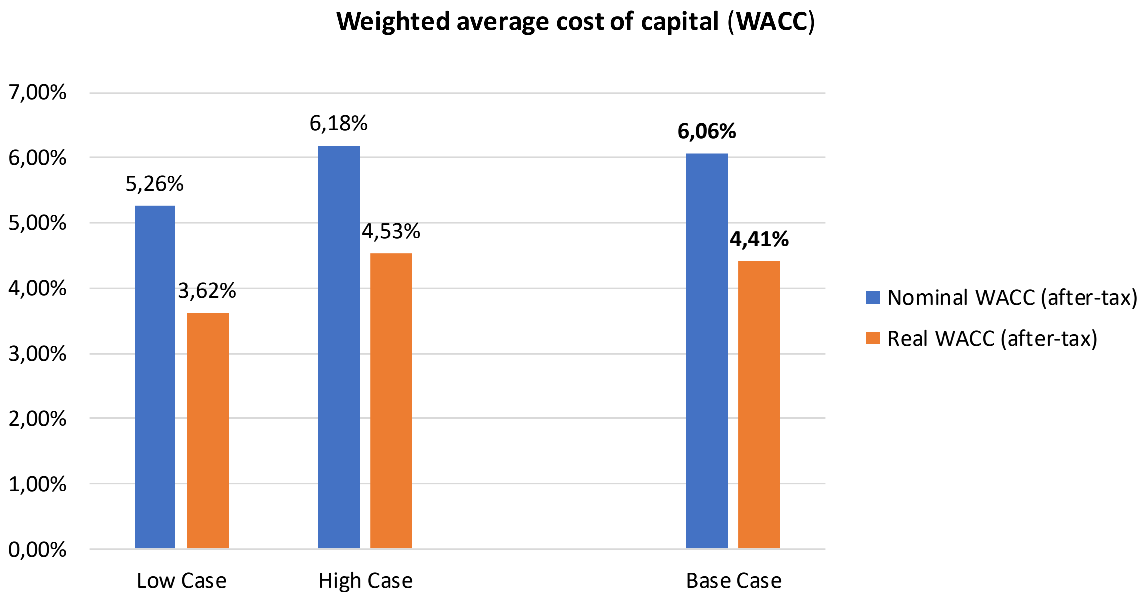

Figure 5: Results of WACC calculation for Low, High and Base case (Source: Fichtner, own diagram)

Conclusion

In this study a nominal WACC (after-tax) of 6,06 % is used as base case.
The base case for the real WACC (after-tax) is 4,41 %.

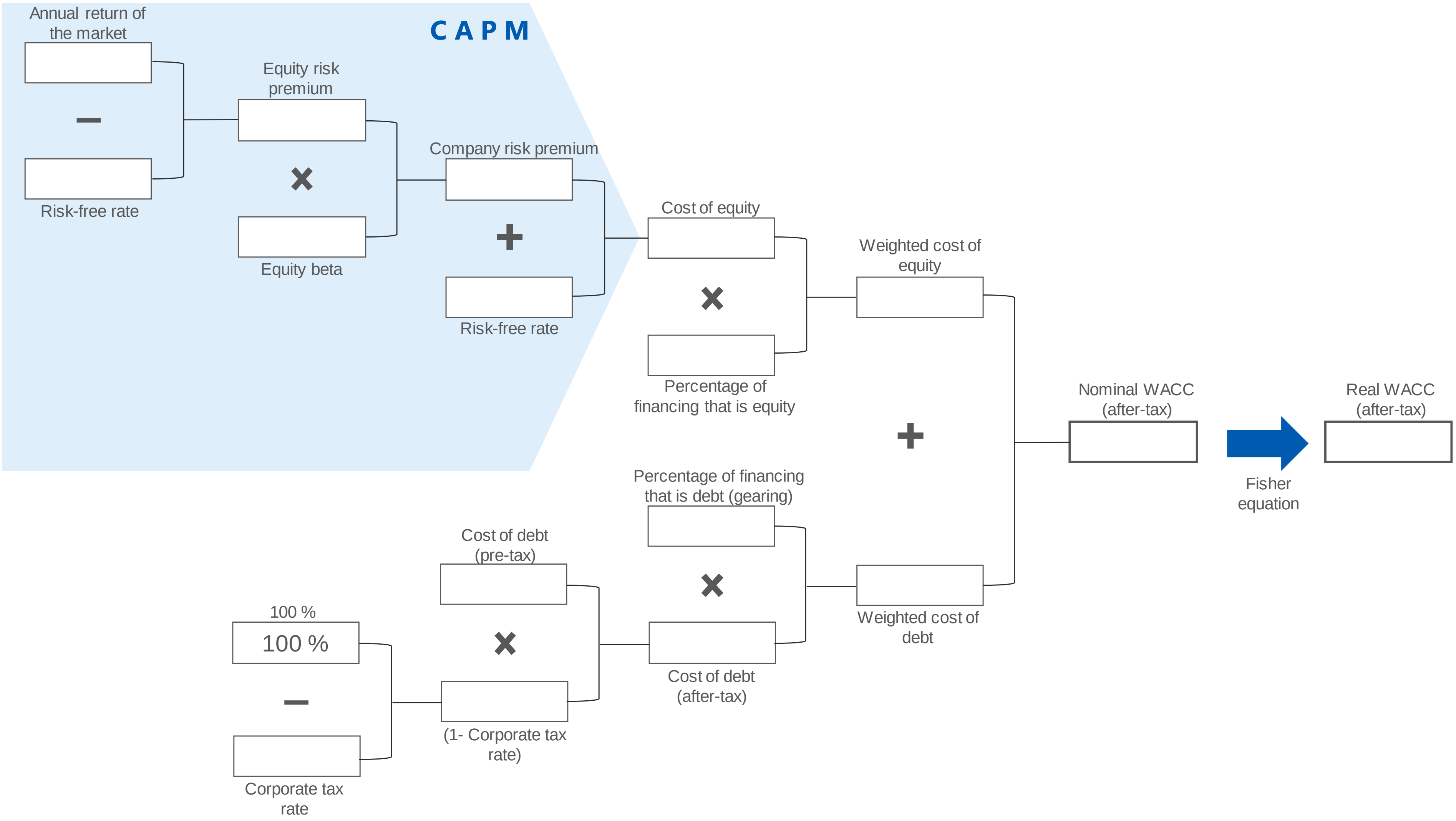

Figure 6: **Detailed WACC calculation as Basis for the Fichtner WACC model (Source: Fichtner, own diagram)**

3. Gross CONE

The Net CONE (“Cost of New Entry”) is needed for the capacity demand curve. It resembles the “missing money” resulting from running a new reference unit in an energy and/or ancillary services market. It derives from the Gross CONE which incorporates the annualized investment cost and the annual fixed O&M cost. The Net CONE results when calculating the insufficient market revenues against these annualized costs including sufficient returns captured in the WACC.

3.1 Technologies eligible for the capacity remuneration mechanism

The Net CONE and consequently the Gross CONE will be the basis for the capacity remuneration. The technologies eligible for the capacity remuneration mechanism shall be assessed in a technology-open, non-discriminatory way.

Initially, an overview on potentially eligible technologies is listed below. This includes all current power sources in Belgium plus technologies that could become reasonably available for the first delivery years of the mechanism. At this stage this only excludes technologies that will be unable to feed power into the Belgian power grid by November 2025 due to long planning, authorization and construction phases or due to technical immaturity.

Levelized Cost of Electricity (LCOE)
For the listed power generating technologies a basic assessment, but strongly supported by assumptions in terms of their profitability, is made. This shall allow focusing on the most cost-efficient technologies and subsequently assess their “Cost of New Entry”. The measure of profitability shall be the Levelized Cost of Electricity (LCOE).

LCOE represents the average net present cost of electricity generation for a generating plant over its lifetime. It considers all discounted costs of the electricity generating plant divided by the discounted sum of the energy produced. LCOE is typically given in euros or dollars per megawatt hour.

The corresponding formula with the respective cost components for calculating the LCOE is:

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + O\&M_t + F_t + C_t}{(1+i)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+i)^t}}$$

$CAPEX_t$	=	Capital expenditure in year t[9]
$O\&M_t$	=	Operation and maintenance costs in year t
F_t	=	Fuel costs in year t
C_t	=	CO_2 certificate costs in year t
i	=	Discount rate
E_t	=	Electricity produced in year t in kWh

[9] Including decommissioning costs in year t

The LCOE is a reliable measure for a first general assessment of the costs incurred by running a certain type of power unit. For capacity-providing technologies such as storages and Demand Side Management (DSM) adequate calculations are provided to quantify their costs of supply.

The values presented for the LCOE are taken from acknowledged sources which are all provided in the respective section including key assumptions of the underlying studies[10]. LCOE is only used as a first general assessment of the profitability of a generation asset. It is not used to exclude technologies from the longlist.

For some technologies, literature provides wide ranges of LCOE. This is because LCOE highly depends on a set of input parameters and the underlying scenario. The most important input parameters regarding the LCOE are

- Full load hours and the respective energy production: With few full load hours LCOE typically rises sharply
- CAPEX and O&M costs: Direct influence on LCOE
- Discount rate: As all costs as well as the produced electricity are discounted (see formula of LCOE above) the discount rate has an important influence on LCOE. The discount rate is a company-specific input parameter and subject to variations
- Fuel and CO_2 certificate costs: Direct influence on marginal costs and the LCOE of a generation asset

In Fichtner's experience variance of LCOE for conventional technologies such as e.g. OCGT is often driven by the operation regime and therefore by the full load hours per year and assumptions regarding fuel price. In the case of renewable energies CAPEX is a key driver. Additionally, local conditions in terms of irradiance and wind yield have an impact on the variance of LCOE. A minimum and a maximum value is used to cover the entire range of possible values.

Methodological approach

- All LCOE are given on the price basis 2019 (EUR_{2019}) adjusted for inflation[11] based on the anticipated situation in 2025
- Some technologies (such as e.g. OCGTs) are mature technologies with only little or no development in CAPEX. Other technologies (such as e.g. batteries) are subject to considerable changes. This is considered, as explained in the following.
- Lead time is important and is taken into account. Example:
  - If an OCGT needs to be available in 2025, CAPEX of 2021-2023 is relevant to allow for purchase, installation and commissioning. This has little effect, as no significant changes in CAPEX (compared to today) are expected for OCGTs
  - In contrary, for batteries a lead time of about only one year is assumed. Therefore, CAPEX in 2024 is relevant. This is of importance as CAPEX is anticipated to further decline compared to today. This effect was accounted for in this study
- Numbers are based on internationally acknowledged publications. LCOE are applicable to the situation in Belgium. Key underlying assumptions are provided. Details can be found in the original source, references are given
- LCOE provided are a first indication for the generation cost of a technology. The numbers are explicitly guide values and a first initial assessment. LCOE depend on the individual local situation and are project specific
- Numbers are rounded and provided in a range to account for uncertainties

[10] The assumptions regarding lifetime of generation assets vary among the studies. Generally, the technical lifetime of an asset can be longer than the economic lifetime. In this study an investment period is assumed to be 20 years.
[11] Inflation rate is chosen with 2 % for the past. This is in line with the inflation rate in Belgium in the last four years (statista, 2020). It further is a typical assumption in many publications.

Technologies considered in the longlist
The following technologies are considered in the longlist:

1. Nuclear power plants
2. Coal-fired power plants
   a. hard coal
   b. lignite
3. Open cycle gas turbine (OCGT)
   a. small (80 MW)
   b. large (200 MW)
4. Combined cycle gas turbine (CCGT)
   a. small (400 MW)
   b. large (850 MW)
5. Internal Combustion Engines (IC engines)
   a. small-scale (200 kW), gas-fired
   b. small-scale (200 kW), diesel-fired
   c. large-scale (80 MW), gas-fired
   d. large-scale (80 MW), diesel-fired
6. Combined Heat and Power (CHP)
   a. providing process heat (5 MW), based on OCGT with HRSG[12]
   b. decentralized (200 kW), based on IC engines
7. Waste incineration
8. Hydropower
9. Photovoltaics (PV)
   a. Residential rooftop PV (10 kWp)
   b. Commercial PV (200 kWp - 1 MWp)
   c. Large-scale PV (> 2 MWp)
10. Wind power
    a. Onshore wind
    b. Offshore wind
11. Pumped hydro storage
12. Battery storage
    a. Residential battery storages
    b. Large-scale battery storages (> 100 kW)
13. Demand Side Management

3.1.1 Nuclear power plants

Electricity from nuclear power plants currently provides for a large part of Belgium's power demand. The country's nuclear power plants are set to close due to the nuclear phase-out but are listed here in order to ensure a technology-open assessment.

The Levelized Cost of Electricity for nuclear power in Belgium has been assessed in a range of 80 to 120 EUR/MWh[13] (European Commission, 2014).[14]

[12] HRSG = Heat Recovery Steam Generator
[13] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[14] Approximated based on figure A4-5 of the source. Underlying assumptions: 60-year lifetime; efficiency = 33 %; 7404 full load hours; WACC (nominal) = 9 %; Technology risk premium = 8 %; OPEX = 6-25 EUR/MWh

3.1.2 Coal-fired power plants (hard coal and lignite)

Fossil fuels such as hard coal or lignite have been deemed as a very cost-efficient source of electricity, however, the rising cost of emitting CO_2 has a strong impact on the generation costs.

Hard coal- or lignite-fired power plants are typically located close to rivers or the sea with a coal supply infrastructure. Furthermore, cooling water is required for the water-steam circuit. The comparably high emissions also limit the choice of locations for hard coal-/lignite-fired power plants.

The start-up procedure of such power plants is rather complex and time-consuming (especially for cold starts). An immense amount of power is needed to start the plant over a period of up to 10 hours.

Hard coal- or lignite-fired power plants are a proven technology. Despite their mechanical complexity, the availability and reliability are acceptable. However, due to high maintenance requirements and necessary overhauls, biomass-fired (and formerly hard coal-fired) power plants have significant planned outages. Inspection downtimes are typically scheduled in the summer.

Belgium is currently not running any power plants on hard coal or lignite. The LCOE for lignite-powered electricity lies between 50 and 80 EUR/MWh[15] (Fraunhofer ISE, 2018)[16] and for hard coal between 60 and 100 EUR/MWh[17] (Fraunhofer ISE, 2018).[18] The wide range results from differing assumptions on full-load hours and CO_2-prices, the latter having a big impact on the emission-intensive burning of hard coal and even more on lignite. Even though, the LCOE of lignite is currently lower, a significantly higher CO_2-price may change this. Therefore, lignite-fired and hard coal-fired power plants will be listed separately.

3.1.3 Open cycle gas turbine (OCGT)

Gas-fired power plants represent a significant share of the energy mix in Belgium and made up for 27 % of the generated electricity in Belgium in 2018 (Elia, 2019b). Several different technologies such as OCGT contribute to this.

With an LCOE of 110 to 220 EUR/MWh[19], OCGT power plants are considerably less cost-efficient than combined cycle gas turbines (CCGT) (Fraunhofer ISE, 2018).[20] However, they can be started very quickly, also from cold conditions. Start-up time varies from type to type but is usually far below 30 minutes. As the available capacity of OCGTs differs significantly, large and small OCGTs are differentiated.

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[15] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[16] Underlying assumptions: 1000 MW capacity; 40-year lifetime; efficiency = 45 %; 6450-7450 full load hours; CAPEX = 1600-2200 EUR/kW; WACC (nominal) = 7,7 %; OPEX (fixed) = 36 EUR/kW; OPEX (variable) = 5 EUR/MWh; lignite price= 1,8 EUR/MWh; 5,3 EUR/t CO_2

[17] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[18] Underlying assumptions: 800 MW capacity; 40-year lifetime; efficiency = 46 %; 5350-6350 full load hours; CAPEX = 1300-2000 EUR/kW; WACC (nominal) = 7,7 %; OPEX (fixed) = 32 EUR/kW; OPEX (variable) = 5 EUR/MWh; hard coal price= 9,6 EUR/MWh; 5,3 EUR/t CO_2

[19] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[20] Underlying assumptions: 200 MW capacity; 30-year lifetime; efficiency = 40 %; 500-2000 full load hours; CAPEX = 400-600 EUR/kW; WACC (nominal) = 7,3 %; OPEX (fixed) = 20 EUR/kW; OPEX (variable) = 3 EUR/MWh; gas price= 21 EUR/MWh; 5,3 EUR/t CO_2

OCGTs are also flexible regarding location as they do not need cooling. Yet, they are typically installed in proximity to loads centers or other generation units. The technology is widespread in Belgium and around the world with a high level of availability and reliability. However, OCGTs are high maintenance and need regular servicing. Many OCGTs are only operated for few peak hours per year. To guarantee high availability, monthly “test starts” are common.

3.1.4 Combined cycle gas turbine (CCGT)

The LCOE of CCGT power plants ranges between 80 to 100 EUR/MWh[21] (Fraunhofer ISE, 2018).[22] Due to the combination of gas and steam turbines high efficiencies around 60 % can be reached. However, CCGTs are disadvantaged over OCGTs in terms of flexibility. State-of-the-art CCGTs can start-up in less than 30 minutes if the unit is already heated.

CCGTs are preferably located in proximity to water as cooling of the water-steam circuit is required. CCGTs are often operated in cogeneration/combined heat and power (CHP) mode to extract heat, for example, for district heating. In this case, the location needs to be close to the heat consumers.

CCGTs are a proven and widely utilized technology with a high availability and reliability. However, due to the additional water-steam circuit, CCGTs are technically more complex compared to OCGTs, resulting in a lower availability. A “trial start concept” is also needed for CCGTs to prove the availability if the plant is not operated on a regular basis.

Smaller dimensioned OCGTs and CCGTs may incur considerably different specific costs compared to large-scale units. Therefore, costs will be assessed for two size ranges.

3.1.5 Internal combustion engines (IC engines)

IC engines rely on the internal combustion of fuels such as gas or diesel. Contrary to turbine technologies a reciprocating motion is initially generated from the combustion which then translates to rotation. Such engines exist in different scales from very small ones with a capacity of just a few kW to large ones with a capacity of several MW. The modularity of these IC engines allows aggregating to large-scale power plants of several hundred MW by interconnecting and combining several individual IC engines.

Key advantages of IC engines are their short start-up time and flexibility to low load operation. There are no special requirements regarding the location of IC engines and no cooling of a water-steam circuit as for other thermal generation technologies is needed. The engines can be cooled by air heat exchangers. The use of both, electricity and process heat, makes this type of power plant economically reasonable for residential as well as industrial use and is often located close to the respective consumer.

This assessment will consider IC engines running solely on gas as well as those running only on diesel as the fuel is a major component for the LCOEs. The following figure illustrates four technological differentiations of IC engines regarding size and fuel.

[21] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[22] Underlying assumptions: 500 MW capacity; 30-year lifetime; efficiency = 60 %; 500-2000 full load hours; CAPEX = 800-1100 EUR/kW; WACC (nominal) = 7,3 %; OPEX (fixed) = 22 EUR/kW; OPEX (variable) = 4 EUR/MWh; gas price= 21 EUR/MWh; 5,3 EUR/t CO_2

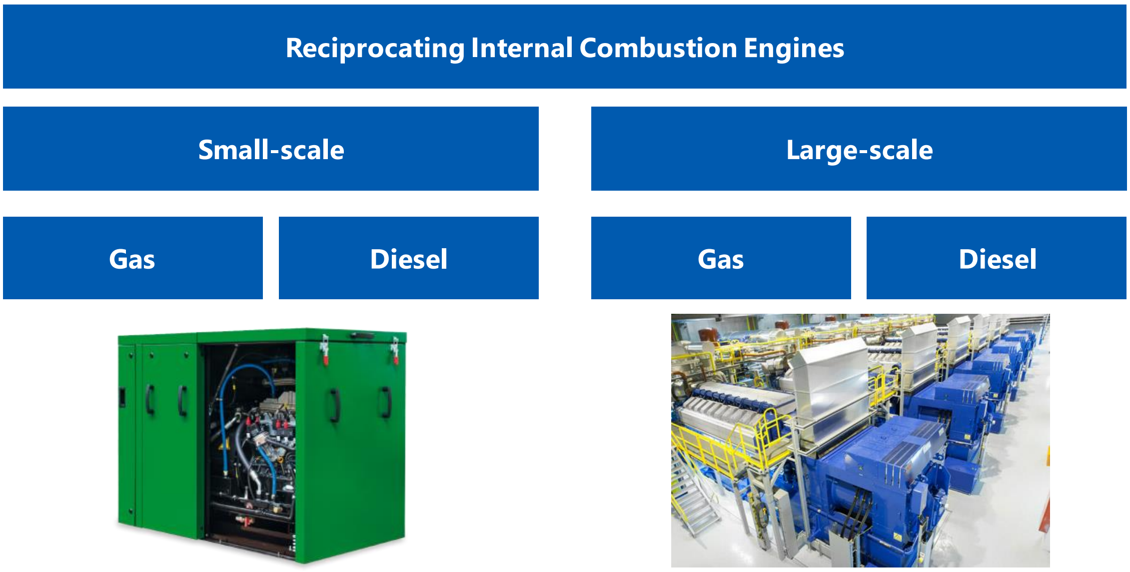

Figure 7: Differentiation of Internal Combustion Engines[23] (Source: Fichtner, own diagram)

The capacity of small-scale IC engines is around 200 kW and the large-scale IC engines are assumed to have a total capacity of 80 MW_{el}.

Small-scale IC engine (gas-fired) (200 kW):
Small-scale, IC engines are generally used in homes or small institutions to contribute to the power and heat supply. Gas-fired versions are generally the preferred choice wherever gas infrastructure exists. The LCOE for small-scale IC engines running on gas is between 70 and 110 EUR/MWh[24] (Fichtner, 2020).[25]

Small-scale IC engine (diesel-fired) (200 kW):
LCOE of small-scale IC engines running on diesel are generally more expensive than gas-fired versions. The LCOE for small-scale IC engines running on diesel is between 100 and 140 EUR/MWh[26] (Fichtner, 2020).[27] LCOE is highly dependent on the operation regime and the annual operating hours. With e.g. only 100 operating hours per year (use case as emergency generator) LCOE are about 850 to 1300 EUR/MWh[28] (Fichtner, 2020).[29]

Large-scale IC engine (gas-fired) (80 MW):
The LCOE of large-scale gas-fired IC engines are between 50 and 70 EUR/MWh[30] (Fichtner, 2020).[31]

[23] Picture sources: www.2-g.com (left); www.wartsila.com (right)
[24] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[25] Key underlying assumptions: 200 kW; CAPEX = approx. 1300 EUR/kW; 5000 operating hours/a
[26] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[27] Key underlying assumptions: 200 kW; CAPEX = approx. 1100 EUR/kW; 5000 operating hours/a
[28] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[29] Key underlying assumptions: 200 kW; CAPEX = approx. 1100 EUR/kW; 100 operating hours/a
[30] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[31] Key underlying assumptions: 80 MW plant (multiple large-scale IC engines); CAPEX = approx. 750 EUR/kW; 6000 operating hours/a

Large-scale IC engine (diesel-fired) (80 MW):
Diesel-fired IC engines show higher LCOEs than gas-fired IC engines. However, if no gas infrastructure exists, diesel might be the preferred choice. The LCOE of large-scale diesel-fired IC engines are between 70 and 110 EUR/MWh[32] (Fichtner, 2020).[33]

3.1.6 CHP

From an engineering point of view there is nothing such as a "CHP-generation technology". CHP is a specific form of operation in which heat and electricity are generated in parallel. Most (if not all) generation technologies such as CCGTs, coal-fired power plants, IC engines etc. can be operated either in "electricity only-operation" or in "CHP operation".

In this report two CHP configurations are to be analyzed:
- "CHP providing process heat"
- "CHP decentralized"

CHP providing process heat:
CHP plants providing process heat are typically based on OCGTs with an HRSG[34]. Fuel is natural gas. LCOE highly depend on the value of heat and the annual operating hours. The operation of CHP plants providing process heat is typically heat driven. Operating hours are significantly higher compared to stand-alone OCGTs which are often used as peaking plants. This has important influence on LCOE. LCOE are between 50 and 70 EUR/MWh[35] (Fichtner 2019) based on data from (Konstantin, 2013).[36]

CHP decentralized:
In this report "CHP decentralized" is subsumed under internal combustion engines. Small IC engines are the typical technology for decentralized operation in CHP mode. Fuel typically is natural gas but can also be diesel or biofuel (typically bio-gas). Again, LCOE highly depend on the operation regime. CHP typically show high numbers of operating hours. LCOE are between 60 and 80 EUR/MWh[37] (Fichtner, 2020) based on data from (Konstantin, 2013).[38]

3.1.7 Waste incineration

Waste-to-energy plants are widely common producers of heat and electricity. Similar to coal power plants these waste incineration plants generate electricity via a steam turbine. These plants are typically located near large agglomerations as they serve as the last part of the waste disposal chain and feed the local district heating system.

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[32] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[33] Key underlying assumptions: 80 MW plant (multiple large-scale IC engines); CAPEX = approx. 900 EUR/kW; 5000 operating hours/a
[34] HRSG = Heat Recovery Steam Generator
[35] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[36] Underlying key assumptions: efficiency (el. net) = 32 %; CAPEX = 660 EUR/kW, value of heat = 20 EUR/MWh$_{t;}$ 6000 operating hours/a
[37] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[38] Underlying key assumptions: efficiency (el. net) = 38 %; CAPEX = 1400 EUR/kW, value of heat = 20 EUR/MWh$_{th}$; 6000 operating hours/a

The LCOE of waste incineration plants range between 170 and 340 EUR/MWh[39] (European Commission, 2014).[40] However, it needs to be considered that the main revenue stream is not based on the generation of electricity but on burning waste.

3.1.8 Hydropower

Hydropower is generated by water running through turbines. Dams are often used to store potential energy that can be transformed to electricity based on demand. However, this is limited to specific geographic conditions.

Run-of-the river hydro is applied without the need of a reservoir and relies on the current of a water system, typically a river. Run-of-the-river technology transforms the current water stream directly into electricity which results in some volatility in generation. Depending on the seasons or the weather more or less water may come from upstream, therefore changing the energy running the turbines. If the turbine capacity is surpassed, the excess energy passes unused.

Hydropower is commonly regarded as a rather inexpensive source of energy but strongly dependent on an adequate location. The scale is a very big factor for the LCOE as large, new installations (50 MW) are estimated at 60 EUR/MWh whereas small new installations (100 kW) go up to around 200 EUR/MWh[41] (BMWi, 2015) (Ingenieurbüro Floecksmühle, 2015).[42]

3.1.9 Photovoltaics (PV)

Photovoltaics are a fairly common around the world. The decrease in production costs have made them profitable even in less sunny regions and affordable for private or smaller commercial applications. Yet, the LCOE of PV is mainly driven by the sun exposure and therefore by the location of the unit. The numbers provided here are based on an assessment by (Fraunhofer ISE, 2018) for Northern Germany, which is reasonably comparable with Belgium in terms of sunlight.

Residential rooftop PV:
PV modules installed on the rooftops of private homes usually reach a capacity of around 5 to 15 kWp. As the amount of installations results in a significant capacity, which, however, comes at higher investment costs than large-scale installations this category is listed separately. The LCOE of such installations is estimated at 90 to 100 EUR/MWh[43]. (Fraunhofer ISE, 2018).[44]

Commercial PV (100 kWp - 1 MWp):
Larger rooftop applications can be found on office buildings or stadiums, for instance. Due to the higher scale and higher cost-efficiency of such commercial installations the LCOE is

[39] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[40] Approximated based on figure A4-23 of the source. Underlying assumptions: 20-year lifetime; efficiency = 21-30 %; 5617 full load hours; CAPEX = 8.437-10.830 EUR/MW; WACC (nominal) = 8 %; Technology risk premium = 5 %; OPEX = 28-160 EUR/MWh
[41] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[42] Underlying assumptions: capacity = 0,1-50 MW; OPEX (variable) = 12 -81 EUR/MWh; interest rate = 3-12 % (depending on scale and business model)
[43] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[44] Underlying assumptions: 25 year lifetime; solar irradiance = 950 kWh/(m²a); CAPEX = 1200-1400 EUR/kW; WACC(nominal) = 3,8 %; OPEX(fixed) = 2,5 % of CAPEX; OPEX(variable) = 0 EUR/MWh

lower than for small-scale rooftop installations. The LCOE is set in a range from 60 to 70 EUR/MWh[45] (Fraunhofer ISE, 2018).[46]

Large-scale PV (> 2 MWp):
Large-scale ground-mounted applications in wide open spaces reach a high yield due to optimized locations and alignments. This as well as a higher cost-efficiency per installed capacity significantly lowers the LCOE. A major cost factor is the cost of land resulting from the large space requirements which could differ greatly between regions. The LCOE ranges between 40 and 60 EUR/MWh[47] (Fraunhofer ISE, 2018).[48]

3.1.10 Wind power

Wind turbines are widespread in Belgium and other European countries and have become more and more cost-efficient. Their profitability depends much on the location (wind conditions, connection costs, foundation) as well as the dimensions of the unit (tower height, generator capacity). A major cost factor is the installation of offshore due to the technical and logistic complexity. Therefore, onshore wind and offshore wind will be differentiated.

Onshore wind:
Wind turbines on land have been installed in large numbers over the past decades worldwide as prices have decreased and the technology has become more and more reliable. The installations range from single privately financed turbines to enormous wind parks with hundreds of turbines. The LCOE is comparably low and in a range between 40 to 80 EUR/MWh[49] (Fraunhofer ISE, 2018).[50]

Offshore wind:
Offshore wind parks are located in areas that guarantee a very steady wind supply with a higher security than onshore. However, the foundations on high sea, the connection to the grid onshore as well as the complex logistics during construction and maintenance result in considerably higher costs compared to onshore wind. The LCOE ranges between 70 and 130 EUR/MWh[51] (Fraunhofer ISE, 2018).[52]

3.1.11 Pumped hydro storage

The start-up time of modern pumped hydro storages is very short (1–2 minutes). Even with old plants taking a few minutes more to start-up, this is still extremely fast compared to conventional thermal generation technologies.

Regarding location, there are clear limitations as pumped hydro depends largely on geographical factors such as elevations/mountains with an efficient drop height.

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[45] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[46] Underlying assumptions: 25 year lifetime; solar irradiance = 950 kWh/(m²a); CAPEX = 800-1000 EUR/kW; WACC(nominal) = 4,1 %; OPEX(fixed) = 2,5 % of CAPEX; OPEX(variable) = 0 EUR/MWh

[47] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[48] Underlying assumptions: 25 year lifetime; solar irradiance = 950 kWh/(m²a); CAPEX = 600-800 EUR/kW; WACC(nominal) = 4,1 %; OPEX(fixed) = 2,5 % of CAPEX; OPEX(variable) = 0 EUR/MWh

[49] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[50] Underlying assumptions: 25 year lifetime; 1800-3200 full load hours; CAPEX = 1500-2000 EUR/kW; WACC(nominal) = 4,6 %; OPEX(fixed) = 30 EUR/kW; OPEX(variable) = 5 EUR/MWh

[51] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

[52] Underlying assumptions: 25 year lifetime; 3200-4500 full load hours; CAPEX = 3100-4700 EUR/kW; WACC(nominal) = 6,9 %; OPEX(fixed) = 100 EUR/kW; OPEX(variable) = 5 EUR/MWh

Pumped hydro shows a high reliability as forced outages are rare and planned outages are low as large overhauls are typically performed every twenty years. Compared to thermal generation technologies the technical lifetime is very long. The technology is mature, and the availability and reliability are high.

For an economic comparison with other technologies the Levelized Cost of Storage (LCOS) are calculated by comparing the overall costs of the unit over its lifetime with the energy output during its lifetime. The value of the lost energy due to limited efficiency is added on top.

The LCOS for newly built pumped hydro is estimated in a range between 150 and 190 EUR/MWh[53] (Lazard, 2016).[54]

3.1.12 Battery storage

The advantages of batteries compared to pumped hydro are their independence in terms of geographical location and the higher expected energy efficiency ratio. However, grid-scale battery technology has only emerged rather recently due to the challenges of volatile power generation. There is still a lot of potential for development and costs are expected to decrease. This is considered in this study.

Residential battery storages:
Batteries installed in households are currently often used as an auxiliary to rooftop PV to allow storage of home-generated electricity. The LCOS for a typical home storage system amounts to approx. 140 to 210 EUR/MWh[55] (Fichtner, 2020).[56]

Large-scale battery storages (> 100 kW):
Large-scale batteries are a potential solution for energy systems switching from conventional power generation to volatile renewables by storing oversupply and feeding it back to the grid when needed. However, currently the only widely used technology for large-scale application are lithium-ion batteries, which rely on expensive resources.

The LCOS of a Lithium-Ion battery storage system of 500 kW calculates to approx. 70 to 100 EUR/MWh[57] (Fichtner, 2020).[58]

3.1.13 Demand side management

Demand side management (DSM), also named demand side response is the umbrella term for different measures and technologies that are used to manage demand in power supply. In the past (conventional) power generation “followed” power demand. The key idea behind DSM is that power usage “follows” the supply of power e.g. from fluctuating, renewable energy generation.

In principle, one distinguishes between load disconnection, load shift and load increase measures. The latter is of no importance for this study since its objectives are technologies

[53] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[54] Original data is measured in USD/MWh: Conversion rate was set at: 1,12 EUR/ = 1 USD
[55] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[56] Fichtner calculation based on 3.3 kW “*sonnenBatterie eco*” and cost of electricity of 120 EUR/MWh
[57] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1
[58] Fichtner calculation for 500 kW battery with 90 % roundtrip efficiency and cost of electricity of 120 EUR/MWh

that add capacity to the grid. Load disconnection and load shift, however, consist of different measures and technologies which can contribute to a capacity gain in the electricity system for a given time. The shifting of load can for example be realized by interconnected controllers, that for instance stop or interrupt the charging of an electric vehicle or even limit the processes at a production facility (e.g. cement factory). The incentive for shifting or disconnecting load is generally monetary: A contract is set in place which specifies the amount of energy and power which can be shifted or disconnected by e.g. an industrial company and the remuneration that is rewarded for it. Capacity markets in other countries (e.g. UK) are also open for DSM e.g. provided by large industrial or commercial businesses with energy intensive operations (GridBeyond, 2019).

DSM can be applied in different sectors. Some sources distinguish the use in the commercial, industrial and the residential sector (Alstone, et al., 2016) and the measures and enabling technologies which are used for DSM in these sectors are plentiful. Table 4 shows some examples for enabling technologies that are used for DSM in the above-mentioned sectors.

Sector	End Use	Enabling Technology Summary
All	Battery-electric and plug-in hybrid vehicles	Level 1 and Level 2 charging interruption
	Behind-the-meter batteries	Automated DR (Auto-DR)
Residential	Air conditioning	Direct load control (DLC) and Smart communicating thermostats (Smart T-Stats)
	Pool pumps	DLC
Commercial	HVAC	Depending on site size, energy management system Auto-DR, DLC, and/or Smart T-Stats
	Lighting	A range of luminaire-level, zonal and standard control options
	Refrigerated warehouses	Auto-DR
Industrial	Processes and large facilities	Automated and manual load shedding and process interruption
	Agricultural pumping	Manual, DLC, and Auto-DR
	Data centers	Manual DR
	Wastewater treatment and pumping	Automated and manual DR

Table 4: Examples for enabling technology options (Source: (Alstone, et al., 2016))[59]

The investment cost for enabling DSM at a certain site can be very low if a highly automated control system exists. An integration of a software tool into an existing building control system and a configuration of what loads to manage would result in low costs. However, if a complex system needs to be automated beforehand, the costs for the investment may be disproportionate compared to its benefit to the system. The resulting activation prices hereby differ greatly on the sector and even the types of industry.

An assessment for several industrial applications has been made by (Ladwig, 2018) citing a wide range of potential costs. Based on these data the lower limit is set at 0 EUR/MWh

[59] For acronyms see section “Abbreviations”

and an upper limit is set at 1480 EUR/MWh[60]. The strategic reserve mechanism which was introduced in Belgium in 2014, and which purpose is to cover any structural shortages in generation during the winter months, contains two sources: SGR which is a strategic reserve that comes from generation units and SDR which is a strategic reserve that is delivered by a reduction on the demand side, thus qualifies as DSM. Elia has constituted a volume of 358,4 MW of SDR in the winter period 2015-2016 with an average activation price of 736,73 EUR/MWh[61] (Elia, 2019d). This falls right in-between the two boundaries set by (Ladwig, 2018) and shows the diversity of possible implementations and the associated costs. This will be elaborated in more detail subsequently. Based on this data the activation cost for DSM is set to 740 EUR/MWh.

3.1.14 LCOE of the assessed technologies

The assessed LCOEs are representative for Belgium. LCOEs may change until the start of the CRM due to technology evolvement and political measures (such as rising cost for emitting CO_2) but are not expected to change on a large magnitude. Therefore, the provided LCOE of the analyzed technologies are an appropriate initial measure for the economic evaluation of the technologies.

This overview of the considered technologies shows a more or less wide array for their respective LCOE. For comparability all technologies are listed with a minimum, a maximum and an average[62] value for LCOE. The following figure visualizes the difference in costs per generated MWh.

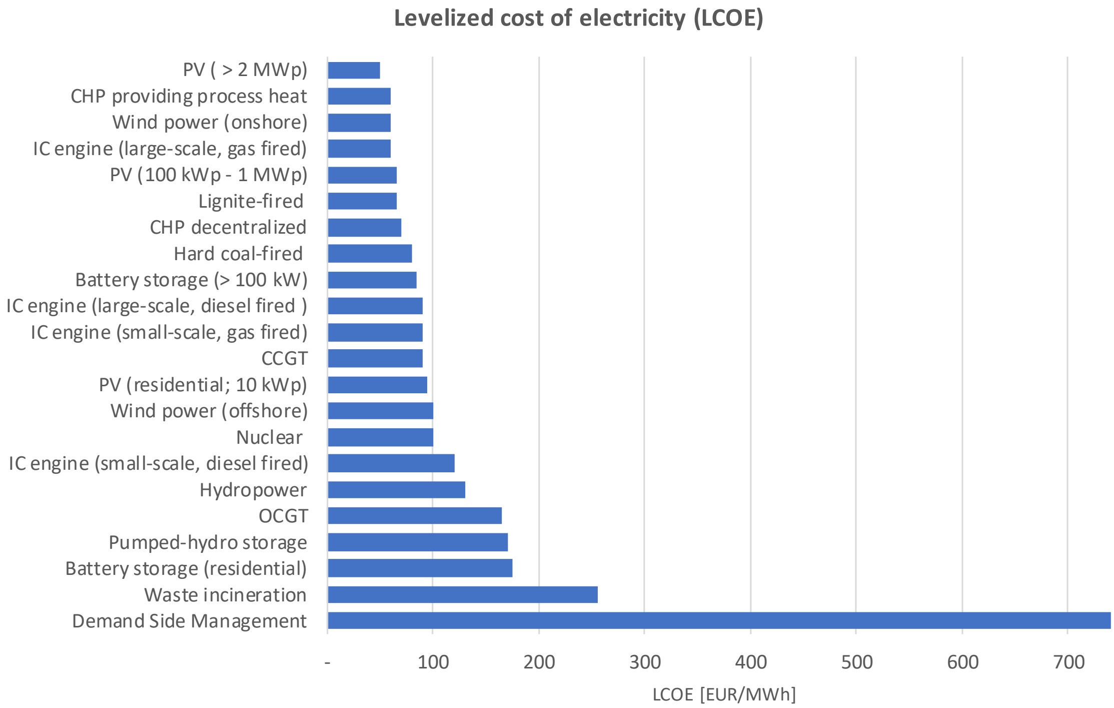

Figure 8: Average LCOE (EUR/MWh) of the listed technologies[63] (Source: Fichtner, own diagram)

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[60] Underlying assumption: Investment cost 14-1239 EUR/kW for load shift measures; 0-21 EUR/kW for load disconnecting measures; Lifetime: 20 years; Reference costs: 0-84 EUR/MWh_{th} for load shifting measures; 96-1500 EUR/MWh_{th} for load disconnecting measures; Activation: 4 hours; 40 times a year

[61] Underlying assumption: Average price: 9,76 EUR/MW/h; Activation: 4 hours

[62] Arithmetic mean of the respective MIN and MAX values

[63] For details on the methodology of the calculation of LCOE including the factors with the greatest influence that lead to the wide range see Section 3.1

Large-scale PV followed by CHP providing process heat and wind power (onshore) show the lowest cost in terms of LCOE. Taking into consideration the strong dependency on the location of the two renewable sources, these numbers differ for less windy or sunny places. Additionally, de-rating factors need to be taken into consideration (see Section 3.2.2.3). As a result, PV as well as wind power are not considered to be the *"Best New Entrant Reference Technology"* (see Section 3.2*).*

3.2 Selection of technologies for determination of Gross CONE

Goal of the following section is to identify a shortlist of technologies which are likely to be the "*Best New Entrant Reference Technology"* (for definition see Section 3.2.1). The selection is based on different criteria which are listed and explained below.

It is important to understand that excluding technologies and not selecting them for the shortlist does <u>not</u> exclude them from the possibility to take part in the CRM. Fichtner is not making any definitive statements on their viability or expectations for future market entries but in Fichtner's opinion they are not appropriate as potential "*Best New Entrant Reference Technology"* at this time for setting up the demand curve CONE parameters.

Section 3.2.2 explains the reasoning behind excluding from or including technologies in the shortlist.

3.2.1 Definition of "Best New Entrant Reference Technology"

"Best New Entrant Reference Technology" can be defined by the following aspects.

- "Best" refers to as most cost-competitive in a CRM Auction, i.e. cost-efficient solutions to contribute to security of supply
- "New Entrant" means that no physical CAPEX investments related to electricity production or demand reduction have taken place in the past
- "Reference**"** refers to as that the technology allows the definition for a representative reference for all investment projects of this kind based on reliable and generic cost information. In other words, any technology where "missing money" differs greatly from one project to another and for which choosing one project or a combination of projects as a reference would not be representative to the "missing money" for most of the projects belonging to the same technology class should not be considered as a "reference technology". This argument is important for the discussion of demand side management (DSM) (see Section 3.2.15).

This means that when entering the market, the *"Best New Entrant Reference Technology"* has the least amount of "missing money" (= Net CONE). Net CONE is defined as the Gross CONE, which is the sum of the yearly fixed cost and the annualized investment costs, minus the revenues earned by the technology (see Figure 9).

The potential of a technology to qualify as reference technology or "best new entrant" depends on several factors such as CAPEX and O&M costs. The Gross CONE of the shortlisted technologies is calculated in Section 3.3 and is then used by Elia and CREG to calculate the Net CONE by a market modelling and to identify the one reference technology that is used to set up the demand curve.

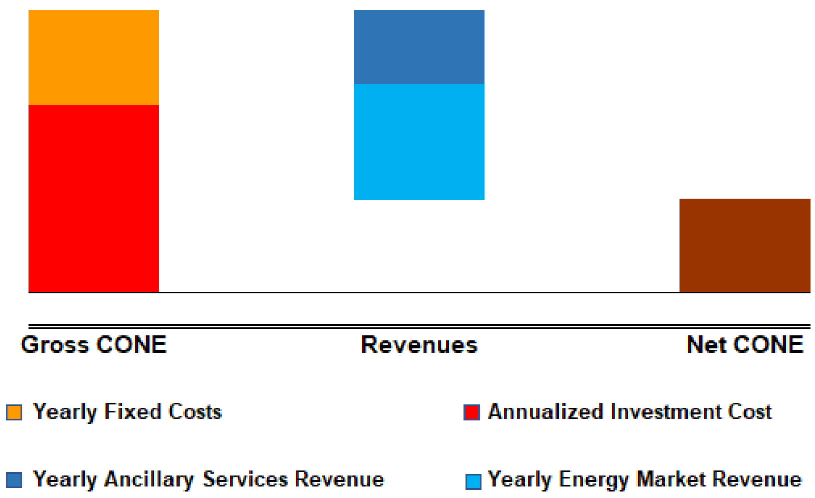

Figure 9: Gross and Net CONE (Source: Fichtner, based on (Elia, 2019c))

In recent CRM studies carried out in other European countries the reference technology was either OCGT or CCGT.[64]

3.2.2 Criteria to include or not include technologies in the shortlist

The following criteria are the basis for identifying the potential *"Best New Entrant Reference Technology"*. The criteria are applied to each technology listed in Section 3.1. A summary of the results is shown in Section 3.2.16.

Every technology is assessed regarding these criteria. If one of the first four criteria (determining exclusion) is not met, the technology is automatically excluded. If the four criteria are met, the other two criteria are used to assess the potential for being the reference technology.

First four criteria must be met (otherwise the technology is directly excluded from shortlist):

1. Availability of the technology in Belgium in 2025
2. Potential in Belgium
3. De-rating factor
4. Compliance with EU emission limits and Belgian Electricity Law

Further additional criteria (only applied, if the first four criteria are met):

5. Levelized Cost of Electricity
6. Uncertainty of cost and technological development

These criteria are explained in the following.

3.2.2.1 Availability of the technology in Belgium in 2025

The CRM aims to, among others, remunerate new entrant plants which provide capacity from 2025 onwards. Therefore, any technology that is for any reason not available in Belgium at that point in time, has no chance of becoming the "*Best New Entrant Reference Technology"*.

[64] See for example (Pöyry Management Consulting, 2018)

One example is the phase out of nuclear power. This criterion is a determining exclusion if not met. If the answer regarding the availability in Belgium is “no”, the technology is unarguably excluded from the shortlist.

3.2.2.2 Potential in Belgium

In order to be able to supply enough power, the potential for the technology in Belgium must exist. If the potential is limited or non-existent the technology is most likely to not qualify to be the “*Best New Entrant Reference Technology”*. The “Potential in Belgium” is also a criterion determining exclusion if not met. Technologies with limited or no potential in Belgium are excluded from the shortlist.

Further aspects under this criterion:
- The technology should have a minimum proven viability to participate in the electricity market in practice, either through past participation in the market or successful test cases with known plans for development by the delivery year
- The technology should not strongly depend on changes in the current National Energy Policy
- The technology should be capable to be erected within the longest interval between Capacity Auction and Delivery Period (defined in the law at 4 years).

3.2.2.3 De-rating factor

For the CRM not only the installed and added capacity but also the expected contribution to the security of supply must be considered. The purpose of de-rating in the context of CRM is to compare a technology’s installed capacity to its expected contribution to the security of supply.

Due to certain circumstances, like weather changes, some technologies (mainly renewable technologies) have a fluctuating power output. Their contribution to the security of supply is smaller compared to other technologies. In the CRM this is considered with the so-called de-rating factors. For generation technologies, these factors are calculated by taking the ratio between the average available capacity during adequacy dimensioning moments (constrained due to e.g. outages, climatic conditions, energy constraints) and the installed capacity. This leads to a percentage per technology. Consequently, the de-rating reflects that some technologies are technically better equipped to contribute to security of supply than others, e.g. if adequacy dimensioning moments are more related to winter evening peaks. Based on this logic it makes sense that a PV-installation per MW contributes less than a thermal unit with the same rated power.

These factors are typically in the 90 %’s for technologies only subject to outage (e.g. thermal power plants) (National Grid, 2018), but they can be very constraining for PV and wind. This is because the adequacy problem is typically a winter peak issue in Belgium when there is little solar or wind power available. For DSM and storage systems, the de-rating depends on the energy constraint: The less hours the unit can (continuously) deliver for, the more strongly it is derated. Therefore, the de-rating factor for storage systems depends on the discharge time.

Figure 10 shows the de-rating factors for storage systems in the UK.

Name for Technology Class	Plant Types Included		De-rating factors T-1 (%)	De-rating factors T-4 (%)
Storage	Conversion of imported electricity into a form of energy which can be stored, the storing of the energy which has been so converted and the re-conversion of the stored energy into electrical energy Includes hydro Generating Units which form part of a Storage Facility (pumped storage hydro stations).	Storage Duration: 0.5h	17.50	14.91
		Storage Duration: 1h	34.21	29.40
		Storage Duration: 1.5h	50.00	43.57
		Storage Duration: 2h	62.80	56.68
		Storage Duration: 2.5h	71.96	66.82
		Storage Duration: 3h	78.09	73.76
		Storage Duration: 3.5h	81.57	77.78
		Storage Duration: 4h	95.52	80.00
		Storage Duration: 4.5h	95.52	95.52
		Storage Duration: 5.0h	95.52	95.52
		Storage Duration: 5.5h	95.52	95.52
		Storage Duration: 6.0h	95.52	95.52
		Storage Duration: 6.5h	95.52	95.52
		Storage Duration: 7.0h	95.52	95.52
		Storage Duration: 7.5h	95.52	95.52
		Storage Duration: 8.0h	95.52	95.52
		Storage Duration: 8.5h	95.52	95.52
		Storage Duration: 9.0h	95.52	95.52
		Storage Duration: 9.5h	95.52	95.52
		Storage Duration: 10.0h	95.52	95.52
		Storage Duration: 10.5h	95.52	95.52
		Storage Duration: 11.0h	95.52	95.52
		Storage Duration: 11.5h	95.52	95.52
		Storage Duration: 12.0h	95.52	95.52

Figure 10: De-rating factors for storage systems in the UK, including hydropower (Source: (National Grid ESO, 2019))

The de-rating will determine the volume with which a unit can bid into the Capacity Auction. In consequence, if two units with the same "missing money" per MW installed enter the auction, the one with the lower de-rating factor will be less competitive in the CRM as it will have to bid this "missing money" over less offered volume. The derating-factor itself is no excluding criteria but applies in combination with the LCOE of a generation asset in comparison to other technologies.

Therefore, any technology that is subject to a significant de-rating with a similar level of LCOE compared to other competing technologies is excluded from the shortlist as it is highly unlikely that such a technology will become the "*Best New Entrant Reference Technology".* The LCOE values for the different technologies are provided in Figure 8.

3.2.2.4 Compliance with EU emission limits and Belgian Electricity Law

The technology must be legally allowed to participate in the CRM, particularly:

- No technologies based on nuclear fission (as by the Belgian Electricity Law of 1999, Article 7) (see also criterion "Potential in Belgium")
- No technologies surpassing the emission limits set out in Article 22 §4 of the Clean Energy Package

According to the EU Clean Energy Package there are two requirements for generation capacities that want to participate in the CRM, of which at least one needs to be met (European Parliament and the council of the European Union, 2019).

Emission limits to be met:

1. Below 550 g CO_2/kWh or
2. Below 350 kg CO_2 on average per year per installed kW

These criteria affect all technologies running on fossil fuel (gas, diesel, hard coal, lignite). If the first limit of 550 g CO_2/kWh is kept, the technology is not excluded from the shortlist based on this criterion.

If the first emission limit is not met the generation asset can still comply with EU regulations by fulfilling the second emission limit. To meet this limit the maximum allowed operating hours of a plant per year are restricted, in order to not overshoot the 350 kg CO_2 on average per year per installed kW. Consequently, this limit can only be met, if the plant operates as a peaking plant with little operating hours per year.

The decision if a technology is suitable to operate as a peaking plant and therefore to only be in operation a few hours per year, depends on different factors. One factor is the original investment costs (CAPEX). A technology with lower CAPEX and possibly comparable high operation costs (fuel costs) is more likely to be used as a peaking plant. To examine if a technology is suitable as a peaking plant, the respective CAPEX is provided in (EUR_{2019}/kW)[65] and considered.

A "yes" in this category, indicates that the technology complies with EU emission limits.

3.2.2.5 Levelized Cost of Electricity

The Levelized Costs of Electricity (LCOE) are given in Section 3.1. They can help to classify the technologies concerning their economic efficiency. Generally, the investment should be recovered solely on revenues from the Capacity Market and normal commercial revenues (e.g. no government subsidies).

Whereas low LCOE is a good indication for the potential "*Best New Entrant Reference Technology*", high LCOE is not a reason to exclude the technology from the shortlist. A "yes" in this category indicates that the technology was among the 50 % of technologies[66] with the lowest LCOE.

3.2.2.6 Uncertainty of cost and technological development

Other studies used this argument to exclude technologies with a high degree of uncertainty (e.g. DSM in the study (Pfeifenberger, et al., 2018)). In this study no technology is excluded from the capacity auction due to uncertainty of cost or technological developments but can be excluded as a potential reference technology.

[65] If adjustment of literature values is necessary, an inflation rate of 2 % is assumed.
[66] With 20 different technologies being analyzed in this study

3.2.3 Nuclear

1. Availability of the technology in Belgium in 2025
The Belgian government has decided to phase out nuclear power by 2025, thus nuclear power will not be available in Belgium from 2025 onwards and will therefore not be considered any further and is excluded from the shortlist (FPS Economy Belgium, 2003).

Conclusion:
Since criterion 1 is a criterion determining exclusion and is not met by nuclear power, the other criteria are not assessed. The technology is not suitable as a "*Best New Entrant Reference Technology"* and is excluded from the shortlist.

3.2.4 Lignite/hard coal-fired

1. Availability of the technology in Belgium in 2025
Lignite- and hard coal-fired power plants will still be available in 2025. This criterion is met.

2. Potential in Belgium
Apart from CO_2-limits (see section "Compliance with EU emission limits") lignite and hard coal-fired power plants do have a potential in Belgium. The criterion is met.

3. De-rating factor
Lignite- and hard coal-fired power plants have a high contribution to the security of supply. Their de-rating factor is favorably high. In the United Kingdom conventional steam generators using coal are estimated with a de-rating factor of 86,5 % in the "Capacity Market Auction Guidelines" (National Grid, 2018). Therefore, the criterion is met for lignite- and hard coal-fired power plants.

4. Compliance with EU emission limits and Belgian Electricity Law
The limit of 550 g CO_2/kWh is exceeded by lignite and hard coal-fired power plants respectively. Hard Coal has an average CO_2 emission of 815 g/kWh for generated electricity and lignite has a CO_2 emission of 1142 g/kWh for generated electricity (Umweltbundesamt, 2019). In order to meet the second EU emission limit (350 kg CO_2 on average per year per installed kW) lignite- or hard coal-fired power plants could only be in operation for the following operating hours (calculation by Fichtner):

Lignite:

$$\frac{350\ \frac{kg}{kW_{inst}}}{1{,}142\,\frac{kg}{kWh}} \approx 306\ hours\ per\ year$$

Hard coal:

$$\frac{350\ \frac{kg}{kW_{inst}}}{0{,}815\,\frac{kg}{kWh}} \approx 429\ hours\ per\ year$$

CAPEX for lignite-fired power plants is approximately 2240 EUR/kW (Fichtner, 2020)[67] and for hard coal around 1720 EUR/kW (Fichtner, 2020)[68]. CAPEX is too high for an economic operation as a peaking plant with only around 300-400 hours per year. Therefore, this criterion is not met.

[67] Based on (Konstantin, 2013)
[68] Based on (Konstantin, 2013)

Conclusion:
Due to the high CO_2 emission and the unprofitability as a peaking-plant, hard coal- and lignite-fired power plants do not comply with EU emission limits and are therefore not considered as the "*Best New Entrant Reference Technology"* and excluded from the shortlist.

3.2.5 Open cycle gas turbine (OCGT)

1. Availability of the technology in Belgium in 2025
OCGT power plants will still be available in 2025. This criterion is met.

2. Potential in Belgium
There is no reason to believe that OCGT power plants do not have potential in Belgium. This criterion is met.

3. De-rating factor
Like lignite- and hard coal-fired power plants OCGT power plants have a high contribution to security of supply. Their de-rating factor is favorably high. In the United Kingdom OCGTs are estimated with a de-rating factor of 95,1 % in the "Capacity Market Auction Guidelines" (National Grid, 2018). Therefore, this criterion is met for OCGTs.

4. Compliance with EU emission limits and Belgian Electricity Law
Natural gas has a CO_2 emission of approximately 201 g/kWh based on primary energy consumption (Umweltbundesamt, 2019). The emission of an OCGT plant is around

$$\frac{201\frac{g}{kWh}}{0{,}4} = 502{,}5\frac{g}{kWh}$$

which keeps the first emission limit and therefore this criterion is met.[69]

5. Levelized Cost of Electricity
OCGTs typically have comparably high LCOE (see Section 3.1). They do not place in the lowest 50 %. However, as mentioned above, OCGT are often operated as peaking plants with only a few operating hours. This usually leads to comparably high generation cost.

6. Uncertainty of cost and technological development
Like lignite- and hard coal-fired power plants, OCGTs are no new technologies. Costs can be estimated and projected with a high certainty.

Conclusion:
OCGT technology is included in the shortlist as it is potentially the "*Best New Entrant Reference Technology"*.

3.2.6 Combined cycle gas turbine (CCGT)

1. Availability of the technology in Belgium in 2025
CCGT power plants will still be available in 2025. This criterion is met.

[69] Based on an average efficiency of 40 % (Carlsson, et al., 2014)

2. Potential in Belgium
There is no reason to believe that CCGT power plants do not have potential in Belgium. This criterion is met.

3. De-rating factor
Like OCGT power plants CCGT power plants have a high contribution to the security of supply. Their de-rating factor is favorably high. In the United Kingdom CCGTs are estimated with a de-rating factor of 89,1 % in the "Capacity Market Auction Guidelines" (National Grid, 2018). Therefore, the criterion is met for CCGTs.

4. Compliance with EU emission limits and Belgian Electricity Law
Natural gas has a CO_2 emission of approximately 201 g/kWh based on primary energy consumption (Umweltbundesamt, 2019). With an average efficiency for OCGTs of 60 % (Carlsson, et al., 2014), which might even slightly increase in the future, the emission of a CCGT plant is around

$$\frac{201\frac{g}{kWh}}{0{,}6} = 335\frac{g}{kWh}$$

which clearly keeps the first emission limit and therefore the criterion number 4 is met.

5. Levelized Cost of Electricity
LCOE are presented in Section 3.1. CCGTs are among the 50 % of technologies with the lowest LCOE.

6. Uncertainty of cost and technological development
CCGT are no new technologies. Like for OCGT costs can be estimated and projected with a high reliability. In fact, many other Net CONE studies which were made to identify the "*Best New Entrant Reference Technology"* for CRM have opted for CCGT.

Conclusion:
CCGT technology is included in the shortlist as it is potentially the "*Best New Entrant Reference Technology"*.

3.2.7 Internal combustion engines (IC engines)

All four versions of IC engines that are mentioned in Section 3.1 are examined concerning each criterion: Diesel and gas-fired IC engines in small- (200 kW) or large-scale (approx. 80 MW installations[70]).

1. Availability of the technology in Belgium in 2025
Small- and large-scaled, diesel or gas-fired IC engines are available in 2025 in Belgium.

2. Potential in Belgium
There is potential for IC engines of any size, running on diesel or gas.

3. De-rating factor
The de-rating factor for IC engines of any size, diesel or gas-fired, is very favorable, especially if they are constructed in a modular design. In the United Kingdom IC engines are estimated with a de-rating factor of 95,1 % in the "Capacity Market Auction Guidelines" (National Grid, 2018). Therefore, the criterion is met for IC engines.

[70] 80 MW made up of multiple large-scale IC engines

4. Compliance with EU emission limits and Belgian Electricity Law

The compliance with the emission limits needs to be checked for all four versions of the IC engines separately.

a) Gas:

To ensure that gas-fired IC engines could qualify to be the "*Best New Entrant Reference Technology*", the CO_2 emissions need to meet the same criteria as lignite and hard coal. As mentioned before, the CO_2 emissions of natural gas are 201 g/kWh (Umweltbundesamt, 2019) based on primary energy consumption.

With an efficiency of around 49 % (ASUE, 2014) for large-scale applications, this would yield a specific CO_2 emission of 410 g/kWh which is below the first criterion of 550 g CO_2/kWh (European Parliament and the council of the European Union, 2019).

$$\frac{201\,\frac{g\,CO_2}{kWh}}{0{,}49} \approx 410\,\frac{g\,CO_2}{kWh}$$

For lower efficiencies like 38 % (ASUE, 2014), which are more common for small-scale gas-fired IC engines the limit is still met.

$$\frac{201\,\frac{g}{kWh}}{0{,}38} \approx 528\,\frac{g\,CO_2}{kWh}$$

Both the small- and the large-scale gas-fired IC engines comply with the first emission limit and therefore this criterion is met.

b) Diesel:

As diesel has higher specific CO_2-emissions compared to gas, diesel-fired engines small- and large-scale do have problems to comply with EU regulations regarding specific CO_2 emissions.

The CO_2-emissions of diesel-combustion amount to 266 g/kWh (Bundesamt für Wirtschaft und Ausfuhrkontrolle, 2019).

Average efficiency of large-scale diesel-fired IC engines is up to 46 % (ASUE, 2014).

$$\frac{266\,\frac{g\,CO_2}{kWh}}{0{,}46} \approx 578\,\frac{g\,CO_2}{kWh}$$

Average efficiency of small-scale diesel-fired IC engines: 40 %

$$\frac{266\,\frac{g\,CO_2}{kWh}}{0{,}40} \approx 665\,\frac{g\,CO_2}{kWh}$$

Thus, small-scale diesel-fired IC engines do not comply with the first emission limit.

This makes clear, that the first criterion is not met by either small-scale or large-scale diesel-fired IC engines.

The question is, if diesel-fired IC engines meet the first emission limit if biodiesel is added to the fuel. According to the diesel norm DIN EN 590, the maximum admixture of biodiesel is 7 % (BSI, 2015). The specific CO_2-emissions of biodiesel are about 65 % of conventional diesel (Umweltbundesamt, 2012). Even with adding biodiesel, the first EU emission limit is not met by diesel-fired IC engines.

The second emission limit is only met if the following operation hours are not exceeded:

Large-scale:

$$\frac{350\,\frac{kg}{kW_{inst}}}{0{,}578\,\frac{kg}{kWh}} = 605\ hours\ per\ year$$

Small-scale:

$$\frac{350\,\frac{kg}{kW_{inst}}}{0{,}665\,\frac{kg}{kWh}} = 526\ hours\ per\ year$$

Small-scale diesel-fired IC engines are in some cases used as emergency generators with only a couple of operation hours. Thus, the second emission limit can be met and therefore small-scale diesel-fired IC engines are included in the shortlist.

Large-scale diesel-fired IC engines have a specific CAPEX of about 790 EUR/kW (Fichtner, 2020)[71]. An economic operation with annual operating hours below 605 hours is not realistic based on current market conditions and Fichtner's experience.[72] Thus, the emission limit excludes large-scale diesel IC engines from the shortlist.

5. Levelized Cost of Electricity

Generally, gas-fired IC engines have a lower LCOE compared to diesel-fired IC engines (see Section 3.1). Small- as well as large-scale gas-fired IC engines are both placed within the 50 % of the lowest LCOE technologies (see Figure 8).

Small-scale diesel-fired IC engines are comparably expensive in operation with higher LCOE due to more expensive fuel costs for diesel compared to natural gas. This is another reason, why diesel-fired engines are often only used as emergency generators.

6. Uncertainty of cost and technological development

For all the IC engine technologies there is enough data available to generalize the technology for the situation in Belgium. Therefore, this is no reason for exclusion.

Conclusion:

- Small-scale gas-fired IC engines are included in the shortlist.
- Small-scale diesel-fired IC engines are included in the shortlist since they are frequently used as emergency generators. With only few operating hours they comply with EU emission limits.
- Large-scale gas-fired IC engines are included in the shortlist. They easily comply with EU emission limits.
- Large-scale diesel-fired IC engines are not considered because they have difficulties to comply with EU emission limits. The operation as a pure peaking plant is very unlikely.[72]

[71] Based on (ASUE, 2014)

[72] In this study it is assumed that current economic conditions do not change fundamentally in the next years e.g. with extreme price spikes for electricity.

3.2.8 CHP

3.2.8.1 CHP providing process heat

As presented in Section 3.1 CHP plants providing process heat are typically based on OCGTs with an HRSG[73]. Fuel is natural gas.

As presented, OCGTs comply with all criteria and are included in the shortlist as potential *"Best New Entrant Reference Technology".* This is also true for OCGTs with an HRSG in CHP mode as relevant parameters such as LCOE, specific CO_2-emissions etc. improve in CHP operation. Subsequently CHP providing process heat (OCGTs with an HRSG) are included in the shortlist as potential *"Best New Entrant Reference Technology".*

3.2.8.2 CHP decentralized

As presented in Section 3.1 "CHP decentralized" is subsumed under small-scale gas-fired IC engines.[74]

As presented, small-scale gas-fired IC engines comply with all criteria and are included in shortlist as potential *"Best New Entrant Reference Technology".* This is also true for small-scale gas-fired IC engines in CHP mode as relevant parameters such as LCOE, specific CO_2-emissions etc. improve in CHP operation. Subsequently CHP decentralized (small-scale gas-fired IC engines in CHP mode) are included in the shortlist as a potential *"Best New Entrant Reference Technology".*

3.2.9 Waste incineration

1. Availability of the technology in Belgium in 2025
There is no reason to believe that waste incineration will not be available in 2025.

2. Potential in Belgium
There is potential for further waste incineration plants in Belgium.

3. De-rating factor
Waste incineration can contribute to the security of supply. In the United Kingdom they are estimated with a de-rating factor of 86,6 % in the "Capacity Market Auction Guidelines" (National Grid, 2018). Therefore, the criterion is met for waste incineration.

4. Compliance with EU emission limits and Belgian Electricity Law
The CO_2 emission of waste incineration depends on the waste that is burned. In a study made for the Hamburg waste incineration, for household waste an emission of 326,4 g CO_2/kWh was assumed (Rabenstein, 2019). This is below the first EU emission limit. Industrial waste has an even lower CO_2 emission of approximately 256 g CO_2/kWh (Rabenstein, 2019). Therefore, the emission limit is no reason to exclude the waste incineration technology from the shortlist.

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[73] HRSG = Heat Recovery Steam Generator

[74] From an engineering point of view there is nothing such as a "CHP-generation technology". CHP is a specific form of operation in which heat and electricity are generated in parallel. Most (if not all) generation technologies such as CCGTs, coal-fired power plants, IC engines etc. can be operated in either "electricity only-operation" or in "CHP operation". In this report "CHP decentralized" is subsumed under internal combustion engines. Small IC engines are the typical technology for decentralized operation in CHP mode. Fuel can be (natural) gas, diesel or biofuel (typically bio-gas).

5. Levelized Cost of Electricity
LCOE of waste incineration is very high (see Section 3.1) and it is among the most expensive technologies.

6. Uncertainty of cost and technological development
The range of different sizes of waste incineration plants, as well as the range of the waste composition makes a precise cost calculation rather difficult. There is also a degree of uncertainty concerning the price development in the following years.

Conclusion:
Usually Waste incineration plants are built, because waste needs to be handled. Energy generated from a waste incineration is more a byproduct of this system. In general, waste incineration plants are too expensive to be considered further, as can be seen from their LCOE and CAPEX. For these reasons, waste incineration plants are excluded from the shortlist.

3.2.10 Hydropower

1. Availability of the technology in Belgium in 2025
Hydropower (run-off-river technology) is available in Belgium in 2025. The criterion is met.

2. Potential in Belgium
The potential for hydropower in Belgium is limited. Additions of small-scale projects might be possible, (UNIDO, 2016), however, will result in considerably higher costs. Therefore, it can be stated that the (economic) potential for new hydropower in Belgium is not given. The criterion is not met. Hydropower projects will not be a candidate for the "*Best New Entrant Reference Technology"*.

Conclusion:
As criterion 2. is a criterion determining the exclusion and is not met by hydropower the other criteria are not assessed any further. The technology is not suitable as a "*Best New Entrant Reference Technology"* and is excluded from the shortlist.

3.2.11 Photovoltaics (PV)

The following applies equally to residential rooftop PV (10 kWp), commercial PV (200 kWp - 1 MWp) and large-scale PV (> 2 MWp).

1. Availability of the technology in Belgium in 2025
Belgium is striving towards an increase in renewable generation. Therefore, PV will be part of the generation in Belgium in 2025. The criterion is met.

2. Potential in Belgium
As a central European country, Belgium does not have the amount of solar radiation as southern European countries. Nevertheless, potential for solar power is still there. The criterion is met.

3. De-rating factor
Generation capital is (also) needed during winter and evening hours when the demand typically is high (peak load). This is a time when solar power provides no or low feed-in. Therefore, not only the installed capacity but also the expected contribution to the security of supply must be considered (see details in Section 3.2.2.3).

There are no official values for the de-rating of solar power in Belgium yet, however, studies on the same topic for the UK and France have de-rating factors between 1,17 %[75] in UK (National Grid ESO, 2019) and 25 % in France (Rte, 2019). This wide range can, among others, be explained by the yearly amount of average solar radiation in the UK[76] compared to the one in France[77]. Values for Belgium can be expected to be in between these two cases, or even closer to the value from the UK.

The LCOE for PV is similar to other generation technologies in the longlist (see Figure 8). However, the de-rating factor is expected to be very low as presented above. This combination makes it very unlikely that PV will be competitive in a capacity auction and become the "*Best New Entrant Reference Technology".*[78]

Conclusion:
Because criterion three is a criterion determining the exclusion, PV of any size (residential, commercial and large-scale applications) are not considered further and will not be part of the shortlist.

3.2.12 Wind power

The following applies equally to onshore and offshore wind power.

1. Availability of the technology in Belgium in 2025
Wind technology, on- as well as for offshore will be available as a generation technology in 2025.

2. Potential in Belgium
Belgium has potential for on- as well as offshore wind power. It has a coast with the Northern Sea, where there is usually plenty of wind. Thus, this criterion is met.

3. De-rating factor
Wind power, like all other technologies, is subject to de-rating (for details see Section 3.2.2.3). Even though the Levelized Cost of Electricity for on- and offshore power are promising, both technologies (on- and offshore) will be de-rated in the capacity market due to the smaller contribution to security of supply.

Like for PV there are no official de-rating numbers available for Belgium yet. In the UK, the de-rating factor for onshore wind technologies is around 8,45 % and for offshore wind technologies it is around 13 % (National Grid ESO, 2019). Similar values can be expected for Belgium.

Due to the low de-rating factor and no significant difference in the LCOE (see Figure 8) it is highly unlikely that wind power is competitive in a Capacity Auction and to become the "*Best New Entrant Reference Technology". *[79]

Conclusion:
Due to the de-rating of wind power in the CRM, the technology is unlikely to be the "*Best New Entrant Reference Technology"* and is therefore not included in the shortlist. Since criterion 3. is a criterion which is determining the exclusion, no further criteria are assessed concerning wind power.

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[75] The de-rating factor determines the volume with which a unit can bid into the capacity auction. A de-rating factor of e.g. 5 % implies that only 5 % of the installed capacity is taken as basis for the remuneration.
[76] 900 - 1400 kWh/m^2
[77] 1200-1900 kWh/m^2
[78] For details see Section 3.2.2.3
[79] For details see Section 3.2.2.3

3.2.13 Pumped hydro storage

1. Availability of the technology in Belgium in 2025
Pumped hydro storages will be available in 2025 in Belgium. This criterion is met.

2. Potential in Belgium
The potential for pumped hydro storages in Belgium is very limited. Innovative concepts such as the "iLand" project[80] allow for additional capacity, but the costs of such projects are far beyond the beforementioned LCOE for pumped hydro (Fraunhofer ISE, 2018). A capacity addition to Belgium's major pumped hydro site Coo-*Trois-Pons* by means of a new or adjusted reservoir is possible but is considered as a retrofit as opposed to a new entry and therefore disregarded here (Ladwig, 2018). This is reason enough to exclude pumped hydro storage from the shortlist.

Conclusion:
Due to the little potential, the pumped hydro storage is disregarded in the shortlist. Since criterion 2 is a criterion, which determines the exclusion, the further criteria are not assessed for pumped hydro storages.

3.2.14 Battery storage

The following applies equally to residential energy storages and large-scale application.

1. Availability of the technology in Belgium in 2025
Batteries (residential energy storage and as large-scale application) will be available in Belgium in 2025. This criterion is met.

2. Potential in Belgium
The potential in Belgium for batteries is given. This criterion is met.

3. De-rating factor
As mentioned before (see details in Section 3.2.2.3) and as shown in Figure 10, storage systems are de-rated based on their discharge time.

For batteries the storage duration is described with the power-to-energy ratio (called "C-rate"). Typical new large-scale batteries as well as residential energy storages have a discharge time between 0.5 and max. 4 hours. This is because CAPEX significantly rises with higher discharge times. This potentially exposes them to low de-rating factors. It can be expected that de-rating in Belgium of any discharge time below 4 hours will be significant. The combination of high investment cost, leading to high LCOE and the not negligible de-rating factor excludes batteries from the shortlist as this criterion is not met.

Conclusion:
In general, battery storages are among the more expensive technologies to provide capacity (see LCOE in Section 3.1). This especially applies for residential small-scale batteries which are specifically much more expensive in terms of CAPEX compared to large-scale applications. In combination with a significant de-rating factor, batteries (neither residential energy storages nor large-scale applications) will be competitive in a Capacity Auction and will not be the "*Best New Entrant Reference Technology".* Therefore, residential energy storages and large-scale applications are excluded from the shortlist.

[80] Source: www.iland-energystorage.be

3.2.15 Demand side management (DSM)

General Remark

DSM itself does not represent one single technology (for details see Section 3.1.13). The approaches and measures for reducing or shifting demand in the several sectors are plentiful and diverse. A study made for the DSM potential in California identified the cumulative availability and the average levelized cost ($/kW-year) by different categories (Alstone, et al., 2016). The results are shown in Figure 11. Prices and cumulative capacity for DSM highly differ from technology to technology. This is also expected for the Belgian case.

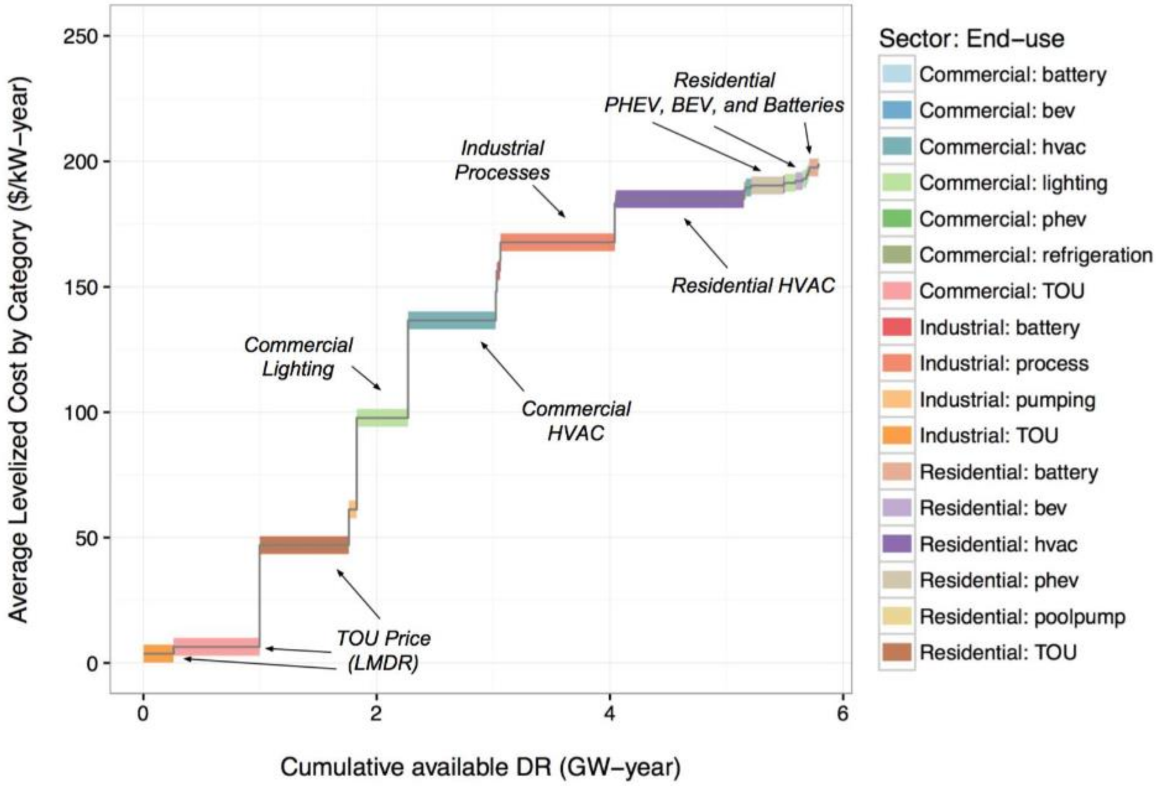

Figure 11: Average levelized cost for different technology categories and the contributions to cumulative demand response in a medium demand response scenario, as presented for California[81] (Source: (Alstone, et al., 2016))

There is no such thing as a “standard demand-side resource” that could be used for the cost estimation to identify Gross CONE. The characteristics of DSM depend on the type of load that is curtailed during peak load periods. Goal of this section is to identify potential “*Best New Entrant Reference Technologies”.* As presented in Section 3.2.1, “Reference**”** refers to a technology which actually allows the definition for a representative reference for all investment projects of this kind based on reliable and generic cost information. This is not given for DSM. Therefore, DSM will not be the “*Best New Entrant Reference Technology”* and is excluded from the shortlist.

1. Availability of the technology in Belgium in 2025

DSM technologies are currently available and evolving in Belgium.

[81] bev: Battery electric vehicle; hvac: heating, ventilation and air conditioning; phev: plug-in hybrid electric vehicle; TOU: Time of use; LMDR: load modifying demand response

2. Potential in Belgium
There is high potential in Belgium. Among others, Belgium already has a strategic reserve program, which includes demand side response contracts.

3. De-rating factor
Like storage technologies, DSM will often be associated with a de-rating, depending on the hours during which power can be delivered continuously. There will be a de-rating factor which is likely to be very low and which scales with the duration as for storages (for details see Section 3.2.2.3).

4. Compliance with EU emission limits and Belgian Electricity Law
This is not applicable for DSM, since it can be expected that DSM involves no or very low CO_2-emissions.

5. Levelized Cost of Electricity
As explained in Section 3.1 LCOE of DSM can go from 0 EUR/MWh to around 1500 EUR/MWh. This makes any qualitative statements about the overall ranking of DSM within the range of other technologies useless and impossible.

6. Uncertainty of cost and technological development
As described before, it is not possible to define the technology “DSM” as it consists of different measures and technologies itself.

Conclusion:
Since it is impossible to identify a “reference” DSM technology as it is explained above and also in Section 3.2.1, DSM is not suited to be the “*Best New Entrant Reference Technology”*. It is therefore not considered in the shortlist.

3.2.16 Conclusion - shortlist

Following the reasoning presented above, the technologies that were identified to have potential of becoming the “*Best New Entrant Reference Technology”* are listed below.

1. OCGT
    a. Small (80 MW)
    b. Large (200 MW)
2. CCGT
    a. Small (400 MW)
    b. Large (850 MW)
3. IC engine
    a. Small-scale (200 kW), gas-fired
    b. Small-scale (200 kW), diesel-fired
    c. Large-scale (80 MW), gas-fired
4. CHP
    a. Providing process heat (5 MW), based on OCGT with HRSG[82]
    b. Decentralized (200 kW), based on IC engines

[82] HRSG = Heat Recovery Steam Generator

		Criteria 1-4: First four criteria must be met, otherwise the technology is directly excluded from shortlist				Criteria 5-6: Further additional criteria only apply, if the first four criteria are met		Conclusion
		1	2	3	4	5	6	
Technology	**Size / specification**	**Availability of the technology in Belgium in 2025**	**Potential in Belgium**	**Not excluded due to de-rating factor**	**Comply with EU emission limits and Belgian Electricity Law**	**Among the 50 % of technologies with lowest LCOE**	**Availability of data**	**Included in shortlist** (potential "*Best New Entrant Reference Technology*")
Nuclear	-	no	n.a.	n.a.	n.a.	n.a.	n.a.	**no**
Lignite /hard coal	-	yes	yes	yes	no	n.a.	n.a.	**no**
OCGT	-	yes	yes	yes	yes	no	yes	**yes**
CCGT	-	yes	yes	yes	yes	yes	yes	**yes**
IC engine	Small-scale (200 kW), gas	yes	yes	yes	yes	yes	yes	**yes**
	Small-scale (200 kW), diesel	yes	yes	yes	yes	no	yes	**yes**
	Large-scale (80 MW), gas	yes	yes	yes	yes	yes	yes	**yes**
	Large-scale (80 MW), diesel	yes	yes	yes	no	n.a.	n.a.	**no**
CHP providing process heat	OCGTs with an HRSG	yes	yes	yes	yes	yes	yes	**yes**
CHP decentralized	Small-scale gas-fired IC engines in CHP mode	yes	yes	yes	yes	yes	yes	**yes**
Waste incineration	-	yes	yes	yes	yes	no	yes	**no**
Hydropower	-	yes	no	n.a.	n.a.	n.a.	n.a.	**no**
Photovoltaics	Residential (10 kW)	yes	yes	no	n.a.	n.a.	n.a.	**no**
	Commercial (200 kW - 1 MW)	yes	yes	no	n.a.	n.a.	n.a.	**no**
	Large-scale (>1MW)	yes	yes	no	n.a.	n.a.	n.a.	**no**

		Criteria 1-4: First four criteria must be met, otherwise the technology is directly excluded from shortlist				**Criteria 5-6:** Further additional criteria only apply, if the first four criteria are met		**Conclusion**
		1	2	3	4	5	6	
Wind power	Onshore	yes	yes	no	n.a.	n.a.	n.a.	**no**
	Offshore	yes	yes	no	n.a.	n.a.	n.a.	**no**
Pumped hydro	-	yes	no	n.a.	n.a.	n.a.	n.a.	**no**
Battery	Residential	yes	yes	no	n.a.	n.a.	n.a.	**no**
	Large-scale	yes	yes	no	n.a.	n.a.	n.a.	**no**
DSM	-	yes	yes	yes[83]	yes	n.a.	no	**no**

Table 5: Overview of valuation of different technologies based on defined criteria (Source: Fichtner, own table)

[83] Like storage technologies, DSM will often be associated with a de-rating. For details see Section 3.2.15.

3.3 Detailed cost calculation for the shortlist of technologies

The longlist of technologies was defined in Section 3.1 (deliverable B.1) and then reduced to a shortlist of technologies in Section 3.2 (deliverable B.2). In Section 3.3 (deliverable B.3) the shortlist of technologies is subject to a detailed cost analysis.

Goal of this part of the study is to provide a detailed cost calculation for the shortlisted technologies including the capital costs and fixed O&M costs which are both needed for the calculation of the Gross CONE. Furthermore, the short-term variable operating costs are provided for additional calculations (e.g. Net CONE). This study explicitly considers the Belgian context.

The following cost categories are to be analyzed in this part (Section B.3) of the study:
1. Capital costs
2. Fixed O&M costs
3. Short-term variable operating costs

A segmentation of and a detailed discussion on the cost components is presented in the following. Section 3.3.1 describes the general approach.

3.3.1 Methodology and cost segmentation

The following cost segmentation and the figures provided are based on Fichtner's long term experience as an engineering consultancy in the power industry. Numbers were discussed internally with senior engineers. In addition, among others, the following internationally acknowledged publications were used as benchmark: (The Brattle Group, 2018), (Konstantin, 2013), (ASUE, 2014), (Analysis Group, Inc., 2016), (Pöyry Management Consulting, 2018), (CEPA, 2015).

Capital costs, fixed O&M costs as well as short-term variable operating costs vary greatly from technology to technology. Therefore, an examination of each technology is needed. The costs are split into the following cost categories. A detailed definition of the cost components is provided in the respective section.

1. Capital costs (EUR)
- EPC contract price
- Land purchase costs
- Initial connection costs to the grids (electricity, gas, water)
- Owner's contingency
- Financing fees
- Construction insurance
- Initial filling of fuel tanks
- Project development
- Commissioning costs
- Operating spare parts
- Miscellaneous
- Interest and equity costs during construction

2. Fixed O&M costs (EUR/a)

- Operating costs
- Insurances
- Maintenance (fixed)

3. Short-term variable operating costs (EUR/MWh)

- Fuel costs
- Variable O&M costs
- CO_2 certificate costs

All costs figures presented in this study are provided in real terms on price basis 2019 (EUR_{2019}).

3.3.2 Capital costs

In the following section capital costs are presented.

3.3.2.1 EPC contract price

The EPC (engineering, procurement and construction) contract price comprises the plant *engineering*, the *procurement* of main technical components and the *construction* of the plant. It is assumed that the plants have a full "turnkey" scope with an EPC contractor. EPC costs are the main part of the investment. They are often used as a reference for further assumptions on project-specific costs.

Procurement and construction significantly differ from technology to technology. Based on several literature sources such as (Analysis Group, Inc., 2016) and Fichtner's experiences, engineering is assumed with 5 % on top of the procurement of main technical components for all considered technologies.

The goal in the following is to determine the EPC contract price for all technologies under consideration.

OCGT:
Every year the Gas Turbine Handbook (GTW, 2019) publishes current turbine prices based on real machines sold. For 2019 there was a slight price drop for gas turbines caused largely by an increased use of renewable energies. Considering the GTW, literature sources (such as (ISILF, 2015)) and Fichtner's own experience in similar projects, Fichtner assume a value for the procurement of main technical components of approx. 370 EUR/kW in the 80 MW-class and about 260 EUR/kW in the 200 MW-class is assumend. The main technical components comprise a gas turbine, generator, associated mechanical and electrical auxiliaries, systems and an operational control system (GTW, 2019).

For construction Fichtner calculates with 25 % of the procurement costs, based on (Konstantin, 2013) and Fichtner's experiences. Adding the cost for engineering (5 % of the procurement of main technical components) this adds up to the total EPC contract price which is presented in Table 6.

CCGT:
The approach for the CCGT is slightly different because the Gas Turbine Handbook already provides the entire EPC contract price for CCGT plants. The main equipment of the CCGT comprises a gas turbine genset with matching HRSG, single steam turbine genset, water-

cooled condenser, generator and integrated plant control systems. Furthermore, the mechanical and electrical auxiliaries as well as the construction and engineering are considered within the EPC scope. The specific EPC contract price for the small CCGT (400 MW) is around 640 EUR/kW and for the large CCGT (850 MW) the EPC price is approximately 550 EUR/kW (GTW, 2019), both based on a 1x1 configuration.

IC engine:
The shortlist of technologies includes three different types of IC engines. A distinction is made between the respective capacity and the fuel used (see Section 3.1.5).

The EPC contract price for the small-scale IC engines is estimated based on the "BHKW-Kenndaten" (ASUE, 2014). It provides values for the main equipment which are around 840 EUR/kW for the gas-fired and about 740 EUR/kW for the diesel-fired IC engine. For the large-scale gas-fired IC engine the provided value is around 440 EUR/kW. In addition, the "BHKW-Kenndaten" provide costs for the installation (construction of main technical components). In the 200-kW class this adds 4 % and in the 80-MW class 15 % on top of the procurement.

CHP providing process heat:
CHP in this configuration is based on an OCGT (5 MW-class) with a heat recovery steam generator (HRSG) as defined in Section 3.1.6. The price for the procurement of main technical components is 630 EUR/kW (GTW, 2019), plus a surcharge of 160 EUR/kW for the HRSG (EPA, 2017).

CHP decentralized:
"CHP decentralized" is based on a small-scale gas-fired IC engine where the heat is decoupled. Therefore, the same EPC contract price is applied with a surcharge of 210 EUR/kW for the heat exchanger which is needed for the heat recovery (EPA, 2017).

Summary:
Based on the assumptions for the EPC contract price mentioned above, the values for the various technologies are summarized in Table 6.

Technology		EPC contract price (EUR)	Specific EPC EUR/kW
OCGT	Small (80 MW)	38.700.000	480
	Large (200 MW)	68.400.000	340
CCGT	Small (400 MW)	257.000.000	640
	Large (850 MW)	471.000.000	550
IC engine	Small-scale (200 kW), gas-fired	183.000	920
	Small-scale (200 kW), diesel-fired	161.000	810
	Large-scale (80 MW), gas-fired	42.400.000	530
CHP	CHP providing process heat (5 MW)	5.140.000	1.030
	CHP decentralized (200 kW)	229.000	1.150

Table 6: EPC contract prices of shortlisted technologies (Source: Fichtner, own table)

The EPC contract price considers the economy of scale[84] and is therefore used as a base for the provided values of the project specific components.

[84] Large units typically have lower specific costs compared to units with a smaller capacity

3.3.2.2 Land purchase costs

For newly added capacity it is assumed that agricultural land will be used as site for the power plants with the investor already having the planning permission to build on it. The land price for agricultural land in Belgium is around 14 EUR/m² (World Bank Group, 2016). Land prices have been fluctuating greatly in the past years; however, due to the uncertainty of future developments this price is used to calculate further investments.

OCGT:
The specific area required for OCGTs is given in the table below (Table 7). The number is based on Fichtner's experience with comparable projects and in line with relevant studies such as Pöyry (Pöyry Management Consulting, 2018). With the given square meter price for agricultural land in Belgium the land purchase costs are calculated.

CCGT:
The specific area required for the CCGT is higher compared to the OCGT due to several necessary additional components such as HRSG, steam turbine and required auxiliary units for the Clausius-Rankine cycle. Fichtner estimates the numbers for CCGTs as presented in the table below (Table 7).[85] The purchase costs of the land are calculated taking into account the price per square meter in Belgium.

IC engine:
For small-scale IC engines, it is assumed that the engines are integrated in existing buildings (e.g. basement). Therefore, no specific additional land is needed. The specific area required for large-scale IC engines is given in the table below (Table 7) (Fichtner, 2020).

CHP:
The CHP providing process heat is based on an OCGT with an HRSG. Therefore, this system requires more space compared to an OCGT. The CHP decentralized is based on a small-scale IC engine and can be integrated in an existing building (see IC engine). The specific area required is stated in the table below (Table 7).

Table 7 summarizes the figures used for the different technologies.

Technology		Specific area required (m^2/kW)
OCGT	Small (80 MW)	0,10
	Large (200 MW)	0,10
CCGT	Small (400 MW)	0,18
	Large (850 MW)	0,18
IC engine	Small-scale (200 kW), gas-fired	-
	Small-scale (200 kW), diesel-fired	-
	Large-scale (80 MW installation), gas-fired	0,15
CHP	CHP providing process heat (5 MW)	0,18
	CHP decentralized (200 kW)	-

Table 7: Specific area required of shortlisted technologies (Source: Fichtner, own table)

[85] Numbers are in line with Pöyry (Pöyry Management Consulting, 2018)

3.3.2.3 Initial connection costs to the grids (electricity, gas, water)

Electricity:
In order to integrate the power plant into the already existing grid, additional transmission lines and transformers need to be installed. It is assumed that an existing transmission system substation is located within 5 km.

Gas:
It is assumed that an existing gas grid is located within 2 km and a connection via pipelines is possible. A contingency of 25 % is added as it is usual for gas networks to cover potential reinforcements or upgrade costs.

Water:
Most technologies of the shortlist do not need large amounts of water for operation. The water demand for OCGTs and IC engines is lower compared to CCGTs (steam generation to run their steam turbines) and CHP-applications (water as heat transfer medium).

The values for the initial connection costs vary from technology to technology. Based on the above-mentioned assumptions, values from literature and Fichtner's own experience, Fichtner calculates with the following values: For OCGTs Fichtner calculates with 13 %[86], for CCGTs with 5,5 % of the EPC contract price (Analysis Group, Inc., 2016), (The Brattle Group, 2018) and (Pöyry Management Consulting, 2018). For the IC engines a value of 37,5 % - 41 % of the EPC contract price is applied (ASUE, 2014).[87]

3.3.2.4 Owner’s contingency

The Owner’s Contingency is a provision for unforeseen events or circumstances. It covers events such as project delays, additional civil work costs as a result of unexpected sub-terrain and project delays due to force majeure. The purpose of a contingency is to incorporate funds within the final approved budget.

Based on several literature sources (Analysis Group, Inc., 2016), (The Brattle Group, 2018), (Pöyry Management Consulting, 2018) and Fichtner’s experiences the owner’s contingency is set to 5 % of the EPC contract price for all shortlisted technologies. This typically covers the additional cost increases for the various technologies discussed in this study.

3.3.2.5 Financing fees

Financing fees are expenses incurred by a debtor in connection with the financing of a specific project. The costs are associated with raising funds, such as loan commission fees or processing fees. This explicitly does not include interest during construction, which is covered under “interest and equity costs during construction” as a separate cost segment (see Section 3.3.2.6).

Based on Fichtner's experience and considering values from literature (Analysis Group, Inc., 2016), (The Brattle Group, 2018) and (Pöyry Management Consulting, 2018) the financing fees are estimated as 2,5 % of the EPC contract price for all shortlisted technologies.

[86] Comparably low EPC contract price of OCGTs compared to CCGTs
[87] Numbers for initial connection costs are taken from acknowledged sources. All cost components such as electricity, gas and water connection are considered.

3.3.2.6 Interest and equity costs during construction

In order to determine the “interest and equity costs during construction”, the construction period during which these costs accrue needs to be taken into account.

Fichtner assumes the following construction periods for the different shortlisted technologies (see Table 8). These assumptions are based on Fichtner's own experience and benchmarks from literature (Pöyry Management Consulting, 2018).

Technology		Construction period (months)
OCGT	Small (80 MW)	20
	Large (200 MW)	20
CCGT	Small (400 MW)	30
	Large (850 MW)	30
IC engine	Small-scale (200 kW), gas-fired	12
	Small-scale (200 kW), diesel-fired	12
	Large-scale (80 MW installation), gas-fired	20
CHP	CHP providing process heat (5 MW)	20
	CHP decentralized (200 kW)	12

Table 8: Construction periods for the shortlisted technologies (Source: Fichtner, own table)

The real WACC after-tax in Belgium is calculated in Section 2. It is the basis to determine the cost component “interest and equity costs during construction”.[88] Considering the construction period and the commissioning year of 2025, the respective values are calculated.

3.3.2.7 Construction insurance

The construction insurance costs are estimated to be 0,9 % of the EPC contract price. This is in line with Fichtner's experience in similar projects and values from literature (Pöyry Management Consulting, 2018), (CEPA, 2015).

3.3.2.8 Initial filling of fuel tanks

This cost component considers the cost of fuel for the initial filling of fuel tanks for the shortlisted technologies. Since natural gas is supplied via pipelines there are no major costs for the initial filling of fuel tanks for gas-fired technologies. Fichtner estimates this cost component with 1,5 % of the EPC contract price[89] (Fichtner, 2020).

3.3.2.9 Project development

The project development costs are divided into three stages: The pre-development stage, the development stage and the post-development stage. The project development costs comprise permits and licenses, engineering fees, legal advisor, owner’s administration costs etc.

[88] The real WACC after-tax is used to calculate the monthly interest rate. Based on this the “interest and equity costs during construction” are calculated for all technologies considering their construction period and investment costs.
[89] This applies to the small-scale diesel-fired IC engine

Based on literature such as (Konstantin, 2013), (Pöyry Management Consulting, 2018) and Fichtner's expertise, the project development costs are assumed to be 7,5 % of the EPC contract price for all shortlisted technologies.

3.3.2.10 Commissioning costs

Commissioning or startup costs comprise the costs which accrue during the commissioning phase of the project. They include costs of fuel and electricity which are needed during this phase.

Fichtner estimates the commissioning costs to be 2 % of the EPC contract price for all shortlisted technologies except CCGTs. This is in line with literature such as (Analysis Group, Inc., 2016), (The Brattle Group, 2018) and (Pöyry Management Consulting, 2018). Due to the higher technical complexity of CCGTs (additional water-steam circuit, HRSG, steam turbine etc.), Fichtner estimates the commissioning costs of CCGTs as 2,5 % of the EPC contract price.

3.3.2.11 Operating spare parts

This section covers the cost of spare parts that must be stored on site. Operating spare parts are needed e.g. for systems and components under a corrective maintenance strategy. Furthermore, they are important to repair damages as quickly as possible to not further limit the electricity production in case of forced outages. In addition, spare parts are needed for overhauls after a certain number of operating hours to ensure plant availability.

Taking into account values from literature (Analysis Group, Inc., 2016), (The Brattle Group, 2018) and (Pöyry Management Consulting, 2018) the cost of operating spare parts is assumed to be 1 % of the EPC contract price. For CCGTs this value is 1,25 % of the EPC contract price due to the more complex system.

3.3.2.12 Miscellaneous

Miscellaneous costs summarize costs that are not directly related to the other capital cost components. This includes e.g. costs for landscaping or disposal of construction waste and unforeseen costs. Fichtner estimates miscellaneous costs as 0,5 % of the EPC contract price (Fichtner, 2020) which should be sufficient to cover all costs incurred.

3.3.2.13 Summary

The following table (Table 9) summarizes the capital costs of the various technologies.

	OCGT small (80 MW)	OCGT large (200 MW)	CCGT small (400 MW)	CCGT large (850 MW)	IC engine small, gas (200 kW)	IC engine small, diesel (200 kW)	IC engine large, gas (80 MW)	CHP providing excess heat (5 MW)	CHP decen-tralized (200 kW)
EPC contract price	38.700	68.400	257.000	471.000	183	161	42.400	5.140	229
Land purchase costs	115	287	1.030	2.190	0	0	172	13	0
Initial connection costs	5.030	8.890	14.200	25.900	76	67	15.900	669	94
Owner's contingency	1.940	3.420	12.900	23.500	9,2	8,1	2.120	257	11
Financing fees	968	1.710	6.430	11.800	4,6	4,0	1.060	129	5,7
Interest and equity costs during construction	1.480	2.610	13.900	25.500	5,2	4,6	1.920	196	6,5
Construction insurance	348	616	2.320	4.240	1,7	1,5	382	46	2,1
Initial filling of tanks	0	0	0	0	0	2,4	0	0	0
Project development	2.900	5.130	19.300	35.300	14	12	3.180	386	17
Commissioning costs	774	1.370	6.430	11.800	3,7	3,2	848	103	4,6
Operating spare parts	387	684	3.220	5.890	1,8	1,6	424	51	2,3
Miscellaneous	194	342	1.290	2.350	0,9	0,8	212	26	1,1
Total	**52.800**	**93.500**	**338.000**	**619.000**	**299**	**266**	**68.600**	**7.020**	**374**

Table 9: Capital costs of the shortlisted technologies [kEUR] (Source: Fichtner, own table)

The specific investment costs based on the results from Table 9 are shown in the following figure (Figure 12):

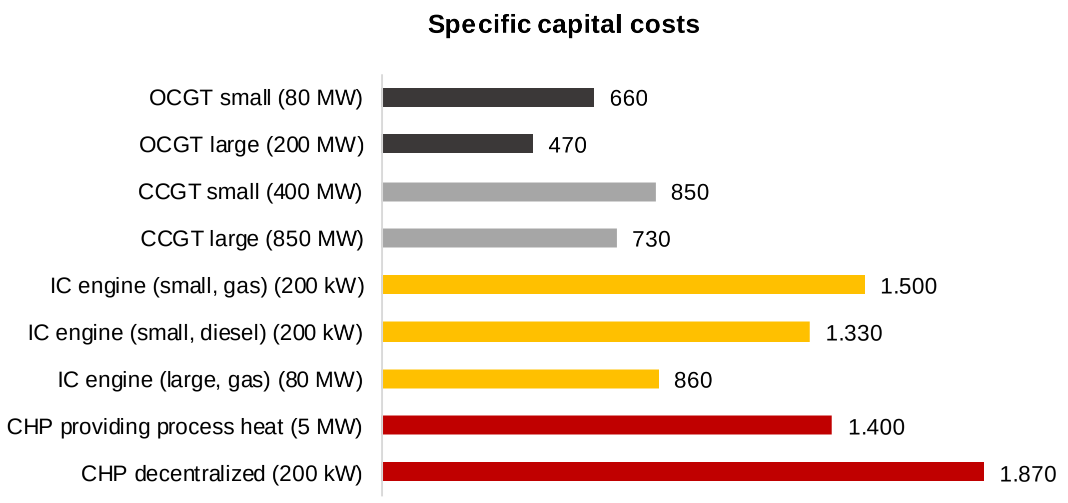

Figure 12: Specific capital costs of the shortlisted technologies [EUR/kW] (Source: Fichtner, own diagram)

3.3.3 Fixed O&M costs

In the following the fixed O&M costs (given in EUR/a) for the shortlisted technologies are presented.

The following cost components are covered:
1. Operating costs (fixed)
2. Insurances
3. Maintenance (fixed)

3.3.3.1 Operating costs (fixed)

The operating costs are the main part of the annual fixed O&M costs. They include the following cost components:
- Personnel costs
- Administrative costs
- Electricity transmission charges
- Gas transmission charges

Fuel costs, CO_2 certificate costs and variable O&M costs are explicitly not part of the fixed operating costs covered in this section.

Total fixed O&M costs for the different technologies are given in several studies such as (IEA, 2010). They are usually presented as a percentage of the EPC contract price. Considering the estimates for insurances (Section 3.3.3.2) and for fixed maintenance costs (Section 3.3.3.3) the operating costs are calculated.

Small-scale IC engines (200 kW) (both gas- and diesel-fired) are typically operated behind the meter and can therefore avoid part of the transmission charges.[90]

The results for the fixed operating costs are presented in Table 10 and Figure 13, which are part of the summary (see Section 3.3.3.4).

3.3.3.2 Insurances

The annual insurance covers the O&M insurance for general liability, machine breakdown and interruption of operation for the power plant.

The annual costs for insurances are set to 0,5 % of the EPC contract price for all technologies based on Fichtner's experience and values from (Konstantin, 2013) and (Pöyry Management Consulting, 2018).

The results for the insurance costs are presented in Table 10 and Figure 13, which are part of the summary (see Section 3.3.3.4).

3.3.3.3 Maintenance (fixed)

This section considers the annual costs for recurrent maintenance including ongoing intra-year maintenance and major overhauls. It also comprises the costs for consumables (e.g. filters, gaskets etc.) which are necessary for the recurrent maintenances.

Based on Fichtner's expertise and values from literature (Konstantin, 2013), (Pöyry Management Consulting, 2018) the fixed maintenance costs are estimated with 0,5 % of the EPC contract price for all technologies except from CCGTs and CHPs. These technologies are technically more complex and have additional components (e.g. HRSG or steam turbine) and therefore the value is set to 0,75 % of the EPC contract price.

The results for the fixed maintenance costs are presented in Table 10 and Figure 13, which are part of the summary (see Section 3.3.3.4).

3.3.3.4 Summary

Table 10 and Figure 13 summarize the above-mentioned cost components and present the results for the total fixed O&M costs.

[90] Numbers used in this study for the fixed part of operating costs are taken from reliable sources, checked against other technologies and are explicitly based on the respective capacity of the generation assets. A further segmentation of "fixed operating costs" as an already very detailed cost component is not given.

	OCGT small (80 MW)	OCGT large (200 MW)	CCGT small (400 MW)	CCGT Large (850 MW)	IC engine small, gas (200 kW)	IC engine small, diesel (200 kW)	IC engine large, gas (80 MW)	CHP providing excess heat (5 MW)	CHP decentralized (200 kW)
Operating costs (fixed)	1.350	2.390	13.500	24.700	9,4	8,3	2.160	190	13
Insurances	194	342	1.290	2.350	0,9	0,8	212	26	1,1
Maintenance (fixed)	194	342	1.930	3.530	0,9	0,8	212	39	1,7
Total fixed O&M costs	**1.740**	**3.070**	**16.700**	**30.600**	**11,3**	**9,9**	**2.580**	**254**	**15,5**

Table 10: Estimated fixed O&M costs of the shortlisted technologies [kEUR/a] (Source: Fichtner, own table)

The specific fixed O&M costs based on the results from Table 10 are shown in Figure 13.

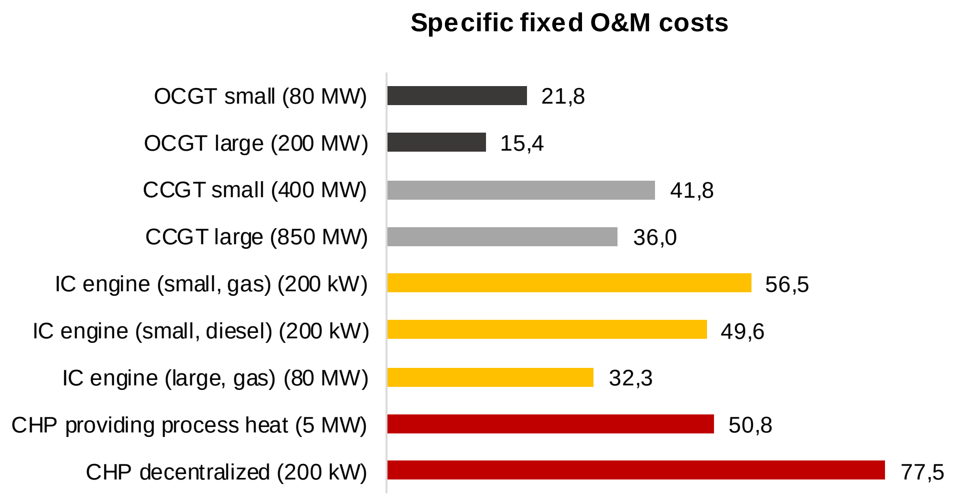

Figure 13: Specific fixed O&M costs of the shortlisted technologies [EUR/kW/a] (Source: Fichtner, own diagram)

3.3.4 Short-term variable operating costs

This chapter presents the variable costs of power generation (given in EUR/MWh) for the technologies of the shortlist.

The following cost components are covered:

- Fuel costs (depending on the plant efficiency and fuel price) (EUR/MWh)
- CO_2 certificate costs (depending on the fuel type and the CO_2-price) (EUR/MWh)
- Variable O&M costs (VOM) which are costs associated with the operation of the unit that are proportional to its generation output (EUR/MWh)

The short-term variable operating costs are a function of the energy production of the generating unit. Therefore, their share of the total (fixed and variable) O&M costs varies with the energy production of the generating unit.

The efficiency of the respective unit is an important input for the calculation of the specific fuel costs and the CO_2 certificate costs. To provide valid numbers, for each technology an exemplary turbine or engine model was selected as shown in Table 11.[91] The table shows the overall cycle efficiencies of the different assets which are used to calculate the further cost components (fuel costs and CO_2 certificate costs).

A traditional 1x1 configuration is chosen for the CCGTs and used in the cost calculation. This is consistent with the configuration selected in Section 3.3.2.1.

For the 5 MW CHP plant a gas turbine with heat extraction is assumed as defined. The 0,2 MW CHP plant correlates with the small-scale gas-fired IC engine as defined in Section 3.1 and 3.2.

[91] The selected assets in Table 11 are representative, realistic examples of existing units matching the generation capacity selected in this study.

	OCGT small (80 MW)	OCGT large (200 MW)	CCGT small (400 MW)	CCGT large (850 MW)	IC engine small, gas (200 kW)	IC engine small, diesel (200 kW)	IC engine large, gas (80 MW)	CHP providing process heat (5 MW)	CHP decentralized (200 kW)
Efficiency	36,8 %	39,8 %	60,2 %	64,1 %	37,4 %	40,4 %	48,6 %	32,6 %	37,4 %
Model	6F.03	7F.05	9F.04 (1x1 config.)	9HA.02 (1x1 config.)	2G-KWK-200 EG	SEV-DE 260 D	18V50SG	M5A-01D	2G-KWK-200 EG
Manu-facturer	GE Power	GE Power	GE Power	GE Power	2G Energy AG	Pro2 Anlagen-technik GmbH/ SEVA Energie AG	Wärtsilä Deutschland GmbH	Kawasaki Heavy Industries	2G Energy AG
Source	(GTW, 2019)	(GTW, 2019)	(GTW, 2019)	(GTW, 2019)	(ASUE, 2014)	(ASUE, 2014)	(ASUE, 2014)	(GTW, 2019)	(ASUE, 2014)

Table 11: Efficiencies of exemplary turbines and engines for the shortlisted technologies (Source: Fichtner, based on (GTW, 2019) and (ASUE, 2014))[91]

3.3.4.1 Fuel costs

The fuel costs make up the largest part of the short-term variable operating costs of conventional power plants. The cost of natural gas is based on the “Stated Policies” scenario of the “World Energy Outlook” (WEO) from 2019 (IEA, 2019a). The cost of diesel[92] is calculated according to “Energy prices and taxes” (IEA, 2019b).

This results in the following prices:[93]

- Natural gas: 23,60 EUR/MWh_{el}
- Diesel: 58,53 EUR/MWh_{el}

The specific estimated fuel costs of the shortlisted technologies are summarized in Table 12.

3.3.4.2 CO_2 certificate costs

The CO_2 certificate costs depend on the emission factor of the used fuel and the CO_2 price. The CO_2-price used in this study is based on the World Energy Outlook (WEO) from 2019 (IEA, 2019a).

CO_2 certificate costs:

- CO_2-price:[93] 28,53 EUR/t_{CO2}

Emission factor:

- Natural gas: 201 kg_{CO2}/MWh_{th}
- Diesel: 266 kg_{CO2}/MWh_{th}

The estimated CO_2 certificate costs of the shortlisted technologies are summarized in Table 12 (see Section 3.3.4.4).

3.3.4.3 Variable O&M cost (VOM)

This section presents the variable O&M costs (VOM). The VOM include costs associated with consumables and variable maintenance costs.[94]

The VOM summarized in Table 12 are based on numbers from literature such as (Konstantin, 2013), (ASUE, 2014) and the publication “Cost and Performance Assumptions for Modelling Electricity Generation Technologies” (NREL, 2010) in combination with Fichtner’s experience.

Credit for CHP:
Technologies in CHP operation generate electricity and heat. In CHP operation, hot flue gases are not released (unused) via the exhaust gas system but are used to generate heat at OCGTs or IC engines in CHP operation. If electricity and heat is generated in CHP mode, a credit for heat needs to be applied to the specific short-term variable generation cost of electricity. The calculation of this credit consists of three steps (Konstantin, 2013):

1. Calculation of the produced heat per MWh of produced electricity.
For this step, the “CHP coefficient “or “utilization factor” of the unit under consideration is needed:

- 84,6 % for the 5 MW CHP plants (Kawasaki, 2019)
- 85,2 % for the 0,2 MW CHP plants (ASUE, 2014)

[92] The fuel category “light fuel oil” was used
[93] Fuel and CO_2 costs are for the year 2025 with price basis 2019
[94] VOM explicitly exclude fuel and CO_2 certificate costs which are separate cost categories

2. Identification of the costs that would accrue[95] to produce the same amount of heat with a competing alternative technology (typically a conventional boiler). For the boilers the following efficiency is assumed:

- 99 % for the 5 MW CHP plant (Fichtner, 2020)
- 98 % for the 0,2 MW CHP plant (Fichtner, 2020)

- Credit for CHP for the 5 MW CHP plant (Fichtner, 2020)
  - Fuel costs: 23,83 EUR/MWh_{th}
  - Emission costs: 3,63 EUR/MWh_{th}
  - Total cost: 27,47 EUR/MWh_{th}

  - Heat generated: 1,60 MWh_{th}/MWh_{el}
  - **Credit for CHP: 43,8 EUR/MWh_{el}**

- Credit for CHP for the 0,2 MW CHP plant (Fichtner, 2020)
  - Fuel costs: 24,08 EUR/MWh_{th}
  - Emission costs: 4,58 EUR/MWh_{th}
  - Total cost: 28,66 EUR/MWh_{th}

  - Heat generated: 1,28 MWh_{th}/MWh_{el}
  - **Credit for CHP: 36,6 EUR/MWhel**

3. Subtraction of the credit for CHP from the total variable costs of the CHP plant as presented in Table 12.

3.3.4.4 Summary

Table 12 summarizes the short-term variable operating costs of the shortlisted technologies.

[95] Based on the same gas prices and prices for CO_2 certificate costs

	OCGT small (80 MW)	OCGT large (200 MW)	CCGT small (400 MW)	CCGT large (850 MW)	IC engine small, gas (200 kW)	IC engine small, diesel (200 kW)	IC engine large, gas (80 MW)	CHP providing excess heat (5 MW)	CHP decentralized (200 kW)
Fuel costs	64,1	59,3	39,2	36,8	63,1	144,9	48,6	72,4	63,1
CO_2 certificate costs	15,6	14,4	9,5	8,9	15,3	18,8	11,8	17,6	15,3
Variable O&M cost (VOM)	6,3	6,3	4,0	4,0	15,5	16,7	4,1	6,9	17,0
Credit for CHP	0,0	0,0	0,0	0,0	0,0	0,0	0,0	-43,8	-36,6
Total	**86,0**	**80,0**	**52,7**	**49,8**	**93,9**	**180,4**	**64,5**	**53,1**	**58,8**

Table 12: Short-term variable operating costs of the shortlisted technologies [EUR/MWh] (Source: Fichtner, own table)

Figure 14 presents the specific short-term variable operating costs.

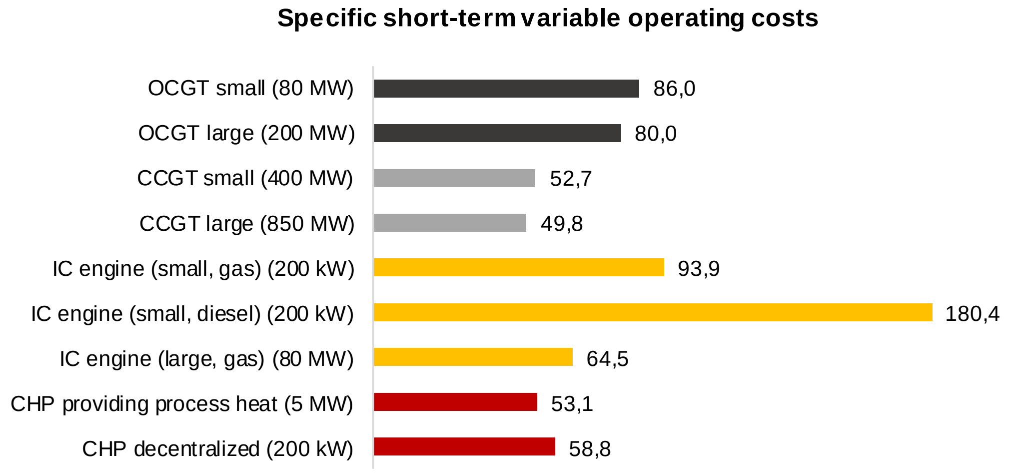

Figure 14: Specific short-term variable operating costs of the shortlisted technologies [EUR/MWh] (Source: Fichtner, own diagram)

3.3.5 Summary - annual total fixed costs

Table 12 summarizes the annual total fixed costs of all shortlisted technologies including the following cost components:

1. Annualized capital costs

- Based on Table 9 (see Section 3.3.2)
- WACC (see Section 2.4)
- An investment period which is assumed to be 20 years (for details see Section 2.1)

$$\text{Annualized capital costs} = \frac{CAPEX \times WACC}{1-(1+WACC)^{-n}}$$

n = investment period

2. Fixed O&M costs (FOM)

- Based on Table 10 (see Section 3.3.3)

Annual total fixed costs:
The annual total fixed costs are calculated based on the following formula:

$$\text{Annual total fixed costs} = \text{annualized capital costs} + \text{FOM}$$

	OCGT small (80 MW)	OCGT large (200 MW)	CCGT small (400 MW)	CCGT Large (850 MW)	IC engine small, gas (200 kW)	IC engine small, diesel (200 kW)	IC engine large, gas (80 MW)	CHP providing excess heat (5 MW)	CHP decentralized (200 kW)
Annualized capital costs	4.027	7.132	25.782	47.216	22,8	20,3	5.233	535	28,5
Fixed O&M costs	1.740	3.070	16.700	30.600	11,3	9,9	2.580	254	15,5
Total	**5.767**	**10.202**	**42.482**	**77.816**	**34,1**	**30,2**	**7.813**	**789**	**44,0**

Table 13: Annual total fixed costs of shortlisted technologies [kEUR/a] (Source: Fichtner, own table)

Figure 15 presents the annual total fixed costs (annualized capital and annual fixed O&M costs):

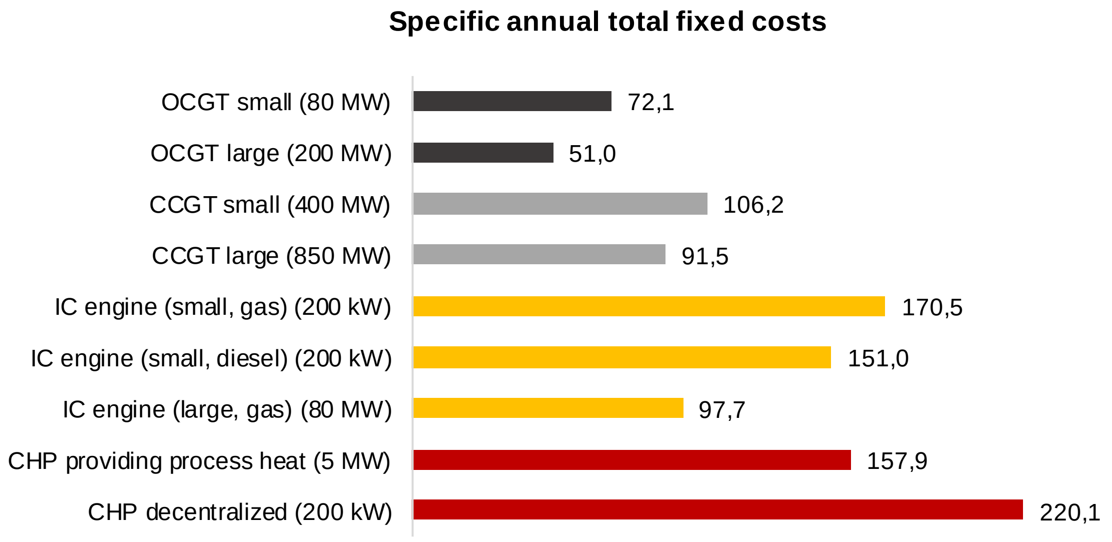

Figure 15: Specific annual total fixed costs of shortlisted technologies [EUR/kW/a] (Source: Fichtner, own diagram)

4. Intermediate Price Cap for Existing Capacities

Besides "new entrants" the CRM shall also cover retrofits and maintenance measures on existing power generating units aiming to increase their capacity or extend their lifetime. An *intermediate price cap* will be implemented as the upper boundary for remuneration for projects applying for a 1-year capacity contract.

The intermediate price cap will be calibrated based on the highest "missing money" of the considered existing technologies, i.e. the financially worst performing technology. The intermediate price cap intends to limit windfall profits and additionally serves as market power mitigation measure. Importantly also, the intermediate price cap should not obstruct capacity from participating in the CRM.

In order to find an adequate balance between these two objectives a detailed cost study among the existing technologies is performed. This assessment is limited to routine costs and excludes costs that are attributed to retrofits to augment the capacity or extend the lifetime of a plant.

4.1 Existing technologies to be considered for the cost study

This section assesses the existing technologies for electricity generation in Belgium as a basis for a detailed cost calculation. It contains the different types of thermal power plants as well as renewables, existing storage technologies and DSM. The description includes numbers on the installed capacity in 2018 to understand each technology's current importance for the Belgian electricity system.

Nuclear:
Nuclear power has been a key element of the Belgian electricity mix ever since the first commercial reactor went online in 1974. At present, Belgium operates seven reactors, four in Doel and three in Tihange, which currently makes up for half the country's power demand. However, the installed capacity of 5919 MW will be offline by 2025 due to the nuclear phase-out (Elia, 2019a). This technology will therefore be disregarded for the further cost study.

Open cycle gas turbine:
A capacity of 344 MW is currently available via OCGTs in Belgium. Due to their low profitability these power plants are usually not running and therefore contribute little to the electricity mix. However, due to their high flexibility they are an important strategic reserve to cover demand peaks and to provide black start service (Elia, 2019a). The costs of existing OCGT technology in Belgium will be assessed to determine the "missing money" due to its limited possibilities to make a profit on the energy market.

Combined cycle gas turbine:
With a total installed capacity of 4685 MW, CCGTs are the most important provider of electricity after nuclear power plants (Elia, 2019a). After the nuclear phase-out they will be key to securing a steady base load for Belgium and need to be assessed in terms of their costs and potential need for remuneration.

Turbojet:
Kerosene-fueled Turbojet units exist on seven locations throughout Belgium and provide a capacity of 140 MW (Elia, 2019a). They are in the same situation in terms of operation as OCGTs as they are mostly on stand-by for times of high demand or generation shortages. A cost study for this technology is important to assess its profitability.

Waste capacity:
Waste capacity provide for an electrical capacity of 319 MW in Belgium (Elia, 2019a). The economic situation of these plants is more complex as the municipal disposal of waste may be the primary reason for keeping them running with the revenues of electricity and heat as an offset for the costs for waste management. The special circumstances will be taken in account for the cost calculations.

Decentralized CHP:
Decentralized CHPs in Belgium account for a capacity of 1942 MW (778 MW of individually modelled units and 1164 MW of profiled units) (Elia, 2019a). The profitability of such CHPs depends very much on the fuels they use. Some operators may prefer to run them on biomass for sustainability reasons while others will go for the most cost-efficient option which, however, can change due to changing commodity and CO_2-prices. The cost assessment will therefore have a common approach but be differentiated concerning the fuel costs.

Hydroelectric:
The electrical capacity of Belgium's hydroelectric power plants is rather limited with about 114 MW (Elia, 2019a). The cost assessment is limited to run-of-river hydro as no large dams exist in Belgium and pumped-storage hydro will be assessed separately.

Photovoltaics:
PV provide a big part of the installed capacity in Belgium with 3932 MW in 2018 (Elia, 2019a). Due to the different scales and business models of the applications a differentiation is made: Residential PV (2473 MW) for small-scale rooftop-PV, Commercial PV (696 MW) for medium-sized installations (primarily on large rooftops) and Industrial PV (763 MW) for large-scale, primarily ground-mounted installations.[96] The costs for keeping these technologies online will be assessed accordingly as they differ in installation type, yield, land costs, revenues and so on.

Wind power:
Costs for wind power will be assessed individually for onshore and offshore as costs vary strongly due to the high complexity of installations offshore. Onshore wind power is rapidly developing in Belgium, currently amounting to 2254 MW in 2018. Offshore wind power provided an electrical capacity of 1051 MW in 2018 with large quantities to be added in the years to come (Elia, 2019a).

Pumped hydro storage:
Belgium's pumped hydro installations Coo-Trois-Ponts and Plate Taille offer a storage volume of 1308 MW to the system (Elia, 2019a). As they are subject to maintenance and operation costs the pumped hydro technology will be included in the cost study.

Battery storage (large-scale):
Large-scale battery storage accounted for an installed capacity of 26 MW in Belgium in 2019 (Elia, 2019a). As for residential storage solutions, no considerable grid-connected capacities have been registered yet. They will therefore be disregarded for the cost assessment of existing technologies. As the predominant large-scale battery technology in terms of technical and economic feasibility is lithium-ion, this will be the reference in the cost assessment.

[96] Segmentation of installed capacity is based on data by APERe published in (PVP4Grid, 2018)

Demand side management (DSM):
In 2018 there was around 1236 MW of market response in Belgium (Elia, 2019a). This can be further structured into the different allowed use hours (1, 2, 4 or 8 hours). Around 528 MW were part of the maximum use of 4 hours category. More than 90 % of the volume could be used for more than 1 hour. The number includes the strategic demand reserve capacities which are part of the strategic reserve mechanism, as well as other ancillary services.

The table below gives an overview on the currently active technologies for electricity generation in Belgium.

	Technologies	Capacity [MW]
Thermal power plants	Nuclear power[97]	5919
	Open cycle gas turbine (OCGT)	344
	Combined cycle gas turbine (CCGT)	4685
	Turbojet	140
	Biomass and waste capacity	319
	CHP (decentralized)	1942
Renewable power	Hydropower	114
	PV (residential)	2473
	PV (commercial)	696
	PV (industrial)	763
	Wind power (onshore)	2254
	Wind power (offshore)	1051
Power storage	Pumped hydro storage	1308
	Battery storage (large-scale)	26
DSM	Market response volume, >1 hour	1236

Table 14: Overview of existing technologies (Source: Fichtner, based on (Elia, 2019a))

4.2 Detailed cost calculation for shortlisted existing technologies

Based on the given scope of work, this section provides a detailed cost calculation for the shortlisted[98] existing[99] technologies in Belgium.

Based on a detailed reasoning in Section 3.2 the following technologies are identified to have potential of becoming the "*Best New Entrant Reference Technology"* and are part of the shortlist.[100 and 101]

1. OCGT
2. CCGT
3. IC engine
4. CHP

[97] Will be disregarded for cost study due to nuclear phase out until 2025
[98] See shortlist of technologies in Section 3.2.16
[99] See overview of existing generation assets in Belgium in Table 14.
[100] The evaluation considers the respective LCOE, the de-rating factor etc. to evaluate competitiveness. For details see Section 3.2.
[101] Most of the existing wind and PV capacities in Belgium receive subsidies such as green certificates. For this reason, they are likely not to be eligible for CRM. Batteries are usually built for very specific system services, such as Frequency Containment Reserves (FCR), which cover their investment. They are therefore unlikely to have the highest amount of missing money as their remuneration depends on a structural need by a specific party (e.g. the TSO for FCR) rather than the instantaneous electricity price on the market.

The existing technologies in Belgium are provided in Table 14 in Section 4.1. They are listed in the following:
- Thermal power plants
- Renewable power
- Power storage
- Demand side management (DSM)

The approach of combining these two groups is demonstrated in Figure 16.

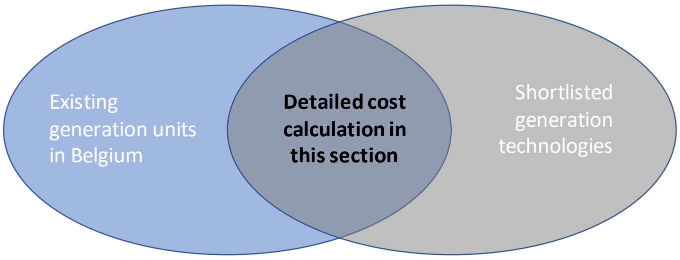

Figure 16: Methodology to determine the units for the detailed cost calculation (Source: Fichtner, own diagram)

The following cost components are calculated and presented in this section:[102]
1. Fixed O&M costs[103] (EUR/a)
2. Short-term variable operating costs (EUR/MWh)

Based on the shortlisted existing units in Belgium a distinction is made between the following technologies:
- OCGTs and turbojets
- CCGTs
- CHP decentralized

4.2.1 Fixed O&M costs of existing units in Belgium

Total fixed O&M costs for existing units highly depend on the operator and the underlying operation and maintenance concept, the size of the respective power plant fleet, regional staff cost etc. Therefore, it is not possible to present generally valid numbers as they can vary significantly from operator to operator even in one country for good reasons. This is Fichtner's experience as technical consultant from comparable benchmark studies for different power plant operators with (theoretically) comparable generation units.

However, the following numbers provide a first assessment and a "typical" estimation for the costs that can be expected for a generation technology and the underlying size and configuration of the unit.

The following cost components are included in fixed O&M costs:

1. Operating costs (fixed)[104]
    - Personnel costs
    - Administrative costs

[102] The costs include routine investments not directly linked to a lifetime extension or capacity augmentation of a plant.
[103] Operation and maintenance costs are typically referred to as "O&M cost".
[104] Fuel costs, CO_2 certificate costs and variable O&M costs are explicitly not part of the fixed operating costs.

- Electricity transmission charges
- Gas transmission charges

2. Insurances
3. Maintenance (fixed)[105]

4.2.2 Short-term variable operating costs of existing units in Belgium

The following cost components are included in short-term variable operating costs.:

1. Fuel costs

- Fuel costs make up the largest part of the short-term variable operating costs of conventional power plants. For natural gas a price of 23,60 EUR/MWh is applied, in line with the assumptions in Section 3.3.
- The efficiencies for all units under consideration in this section are presented in Table 15 and Table 16.
- Numbers for efficiencies of specific units are taken from publically available sources such as the homepages of the respective operator. If no data are publically available data are based on literature (e.g. (GTW, 2019), (ASUE, 2014)) and comparable units are used in combination with Fichtner's experience.
- For the OCGTs for which no publically available data is available, different efficiencies are assumed by Fichtner depending on the installed capacity of the power plants. OCGTs are divided into three different capacity classes less than 20 MW, 30-50 MW and 110-130 MW). For each capacity class an individual efficiency is calculated by assessing and averaging different efficiencies of representative OCGTs in the mentioned capacity class provided e.g. by (GTW, 2019).
- Different from OCGTs, there is more data publically available on specific CCGT units in Belgium. As a result efficiencies of the individual units used in Fichtner's calculation are provided by the respective operators or external sources and not estimated by Fichtner for multiple units (sources are presented in Table 16). For remaining units with no data given, the efficiencies are assumed by assigning the units in two classes determined by the year of construction and capacity.
    - 400 MW-class, built in 1990-2000: For units with no data publically available, the efficiency is estimated in line with the historic development of typical efficiencies of CCGTs based on (GE Power Systems, 2000).
    - 400 MW-class, built in 2000-2020: For units with no data publically available the efficiency is calculated by averaging all given efficiencies of the CCGTs in the respective class.

2. Variable O&M costs (excl. fuel and CO_2 costs)

- As discussed for fixed O&M costs this cost component also highly depends on the operator. A generally valid number cannot be provided. However, the following numbers are a good indication for average reasonable O&M costs based on the individual assets and its technical specification.
- Variable O&M costs summarize the following cost components:
    - Variable maintenance costs
    - Consumables

[105] Fixed maintenance considers the annual costs for recurrent maintenance including ongoing intra-year maintenance/"regular inspections" and "major overhauls" which are conducted after a certain number of years or Equivalent Operating Hours (EOH). In other words, fixed maintenance estimates also include the provision of larger maintenance activities that are performed once every few years. It also comprises the costs for consumables (e.g. filters, gaskets etc.) which are necessary for the recurrent maintenances. However, cost for "lifetime extensions" are not included. These maintenance services are further defined in Section 5.2 and Figure 24.

3. CO_2 certificate costs

- In this calculation a price for CO_2 certificates of 28,53 EUR/t_{CO2} is applied. This is in line with the assumptions in Section 3.3.
- The emission factor for natural gas was considered with 201 kg_{CO2}/MWh_{th}.

4. Credit for CHP (only applicable for CHP units)

- For CHP (decentralized) Fichtner applied a credit for generated heat in CHP operation in line with the methodology and the assumptions presented in Section 3.3.4.3.

4.3 Results for the existing units in Belgium

4.3.1 Existing OCGTs in Belgium

The following figure from Elia (Elia, 2019a) presents a good overview of the existing OCGT and turbojet capacities in Belgium.

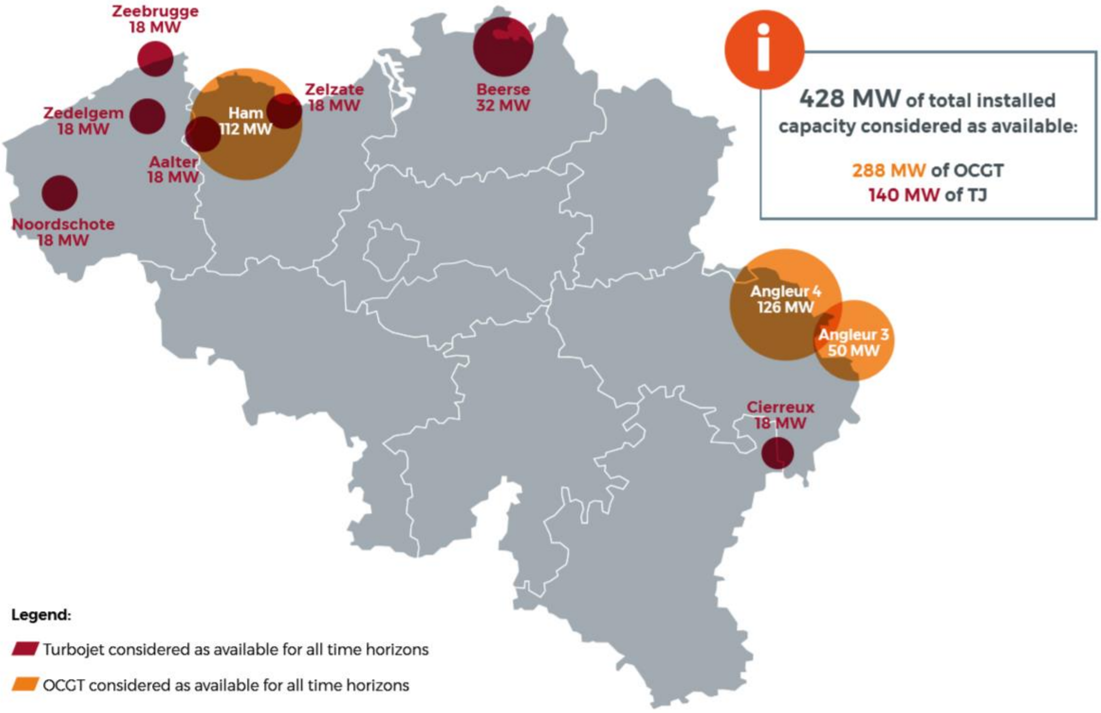

Figure 17: Total installed OCGT and turbojet capacity available in Belgium in 2019 (Source: (Elia, 2019a)

1. Fixed O&M costs (EUR/a)

As explained, fixed O&M costs for existing units highly depend on the operator and (technical) specifics of the individual unit (see Section 4.2.1). It is not possible to provide generally valid numbers as they can vary significantly from operator to operator for good reasons. This is Fichtner's experience from benchmark studies. The numbers provided in Table 15 are estimations and reference values from Fichtner as a technical consultant.

2. Short-term variable operating costs (EUR/MWh)

Cost components, approach and sources used for Fichtner's estimation of short-term variable operating costs are provided in Section 4.2.2.

Name of unit	Capacity[106] (MW)	Year of construction	Efficiency	Configuration	Source (for efficiency and configuration)	Estimated fixed O&M costs (EUR/a)	Estimated short-term variable operating costs (EUR/MWh)
Angleur 3	50	-	35,0 %	OCGT	(Fichtner, 2020) based on (GTW, 2019)	1.270.000	90,2
Angleur 4	126	-	35, 3%	OCGT	(Fichtner, 2020) based on (GTW, 2019)	2.330.000	89,5
Ham	112	2006	35,3 %	OCGT	(Fichtner, 2020) based on (GTW, 2019)	2.170.000	89,5
Cierreux	18	-	33,4 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	609.000	94,2
Beerse	32	-	35,0 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	926.000	90,2
Zelzate	18	-	33,4 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	609.000	94,2
Aalter	18	-	33,4 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	609.000	94,2
Zedelgem	18	-	33,4 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	609.000	94,2
Noordschote	18	-	33,4 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	609.000	94,2
Zeebrugge	18	-	33,4 %	Turbojet	(Fichtner, 2020) based on (GTW, 2019)	609.000	94,2

Table 15: Estimated fixed O&M costs and short-term variable operating costs for existing technologies (OCGTs and turbojets) in Belgium (Source: Fichtner, own table)

[106] Source: (Elia, 2019a)

The following figures (Figure 18 and Figure 19) present the specific fixed O&M costs and short-term variable operating costs of the assets.[107] Numbers in the Table 15 are estimated by Fichtner (Fichtner, 2020) based on the data provided for the individual units, the methodology presented (i.a. in Section 4.2) and Fichtner's experience as technical consultant.

1. Specific fixed O&M costs

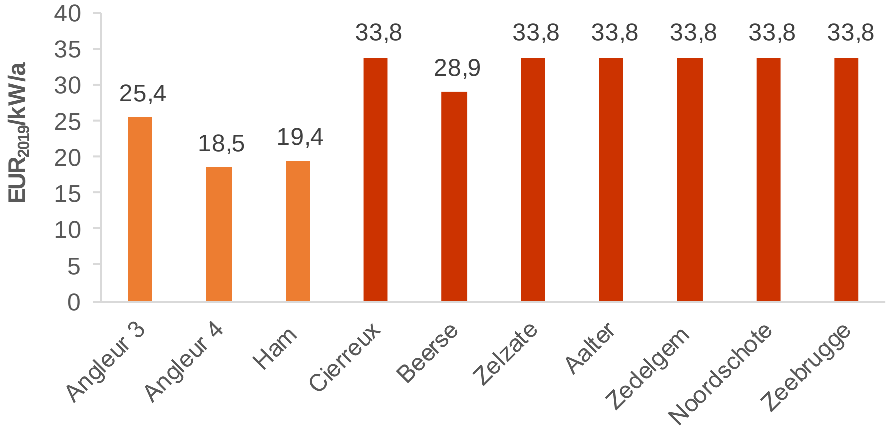

Figure 18: Estimated specific fixed O&M costs of existing technologies (OCGTs and turbojets) in Belgium [EUR/kW/a] (Source: Fichtner, own diagram)

2. Short-term variable operating costs

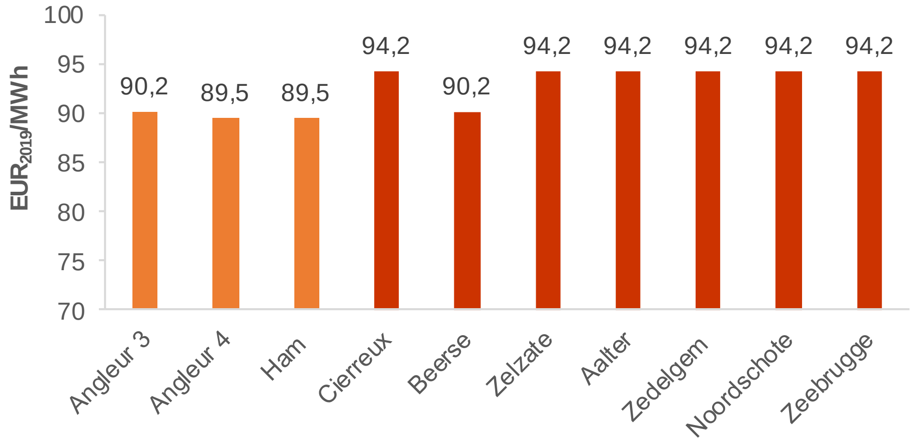

Figure 19: Estimated short-term variable operating costs of existing technologies (OCGTs and turbojets) in Belgium [EUR/MWh] (Source: Fichtner, own diagram)

[107] To provide a reliable variance or confidence interval of these costs, a case by case analysis of the individual assets and a technical assessment on site would be necessary.

4.3.2 Existing CCGTs in Belgium

Figure 20 gives a good overview of the existing CCGT capacities in Belgium.

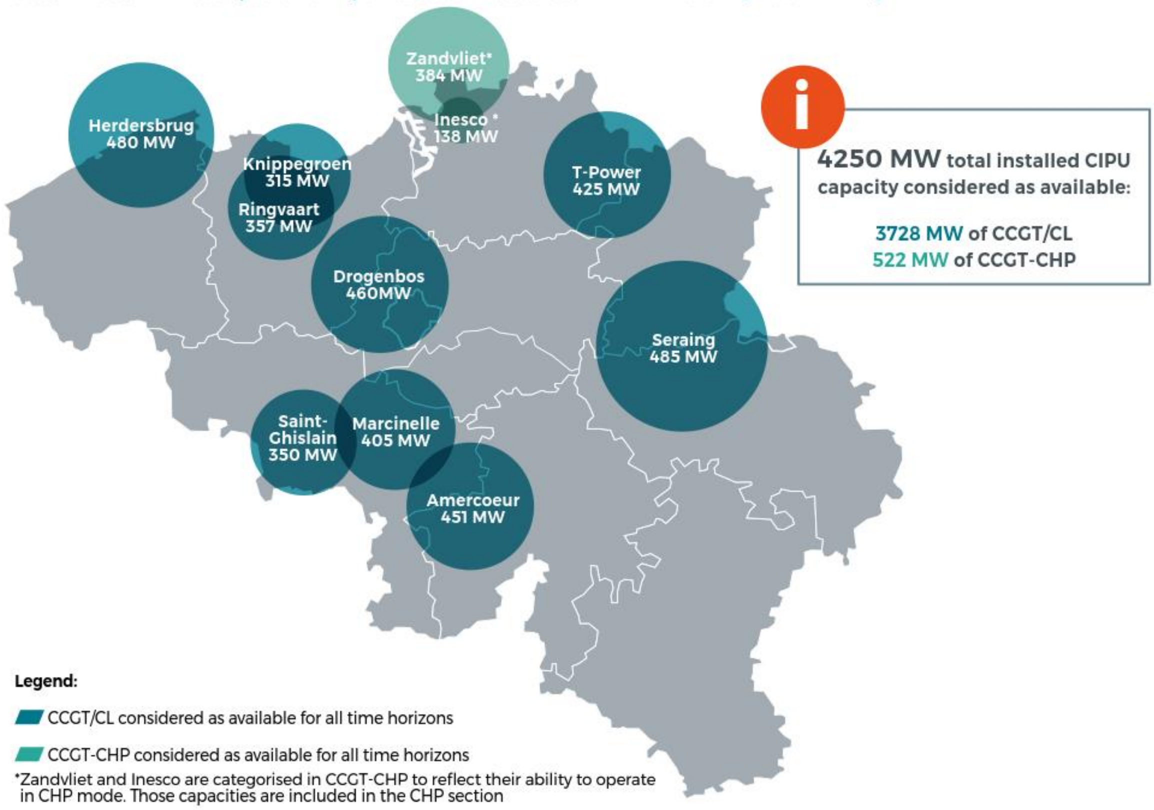

Figure 20: Total installed CCGT/CCGT-CHP/CL capacity available in Belgium in 2019 (Source: (Elia, 2019a))

1. Fixed O&M costs (EUR/a)

Also for CCGTs fixed O&M costs for existing units highly depend on the operator and (technical) specifics of the individual unit (see Section 4.2.1). As presented, it is not possible to provide generally valid numbers as they can significantly differ from operator to operator for good reasons. This is Fichtner's experience from benchmark studies. The numbers provided in Table 16 are estimations and reference values from Fichtner as technical consultant.

2. Short-term variable operating costs (EUR/MWh)

Cost components, approach and sources used for Fichtner's estimation of short-term variable operating costs are provided in Section 4.2.2.

Name of unit	Capacity[108] (MW)	Year of construction	Efficiency	Confi-guration	Source (for efficiency and configuration)	Estimated fixed O&M costs (EUR/a)	Estimated short-term variable operating costs (EUR/MWh)
T-Power	425	2011	59,7 %	1x1	(Siemens, 2020)	17.600.000	53,1
Seraing	485	1994	52,5 %	2x1	(Fichtner, 2020), (GE Power Systems, 2000)	19.500.000	59,9
Amercoeur	451	2010	57,0 %	1x1	(Global Energy Observatory, 2020)	18.300.000	55,5
Marcinelle	405	2011	57,7 %	1x1	(Fichtner, 2020), (GE Power Systems, 2000)	16.900.000	54,9
Saint-Ghislain	350	2000	56,0 %	1x1	(Engie Electrabel, 2020), (Federal Planning Bureau, 2017)	15.100.000	56,4
Drogenbos	460	1993	52,5 %	2x1	(Fichtner, 2020), (GE Power Systems, 2000)	18.700.000	59,9
Knippegroen	315	2010	42,0 %	1x1	(Engie Electrabel, 2020b)	13.900.000	73,9
Ringvaart	357	1998	55,5 %	1x1	(Fichtner, 2020), (GE Power Systems, 2000)	15.400.000	56,9
Herdersbrug	480	1998	55,5 %	2x1	(Fichtner, 2020), (GE Power Systems, 2000)	19.300.000	56,9
Zandvliet	384	2005	56,4 %	1x1	(Wikipedia, 2020)	16.200.000	56,0
Inesco	138	2007	52,0 %	2x1	(Power Engineering International, 2020)	7.450.000	60,4

Table 16: Estimated fixed O&M costs and short-term variable operating costs for existing technologies (CCGTs) in Belgium (Source: Fichtner, own table)

[108] Source: (Elia, 2019a)

The following figures (Figure 21 and Figure 22) present the specific fixed O&M costs and short-term variable operating costs of the assets.[109] Numbers in the Table 15 are estimated by Fichtner (Fichtner, 2020) based on the data provided for the individual units, the methodology presented (i.a. in Section 4.2) and Fichtner's experience as technical consultant.

1. Specific fixed O&M costs

According to Fichtner's own estimates the following figure presents the specific fixed O&M costs of the assets.

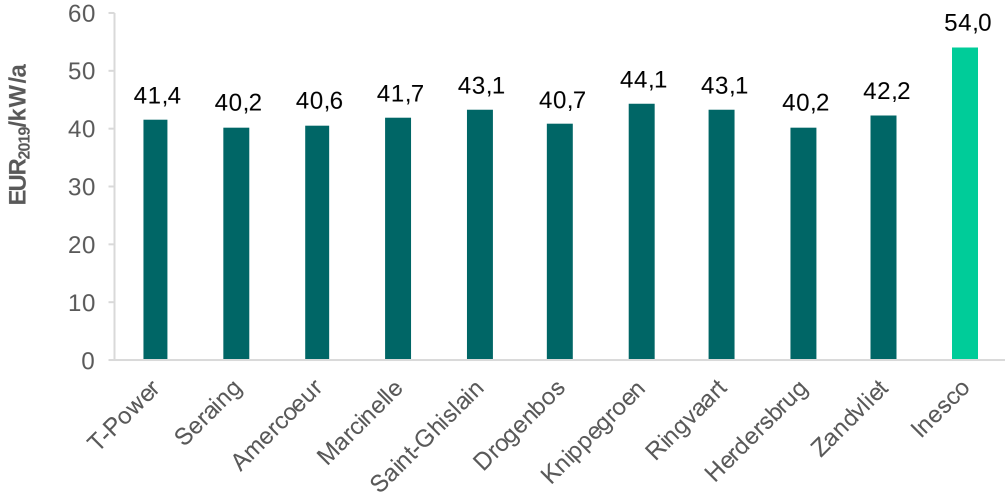

Figure 21: **Estimated specific fixed O&M costs of existing technologies (CCGTs) in Belgium [EUR/kW/a] (Source: Fichtner, own diagram)**

2. Short-term variable operating costs

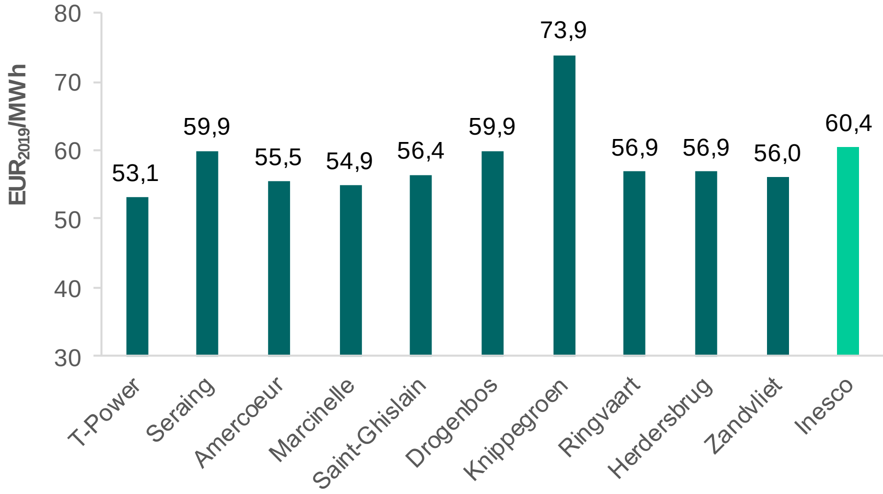

Figure 22: **Estimated short-term variable operating costs of existing technologies (CCGTs) in Belgium [EUR/MWh] (Source: Fichtner, own diagram)**

[109] To provide a reliable variance or confidence interval of these costs, a case by case analysis of the individual assets and a technical assessment on site would be necessary.

4.3.3 Existing CHP decentralized in Belgium

The following assumptions are made for the existing gas-fired decentralized CHP assets in Belgium:

- The CHP plants correlate with the small-scale gas-fired IC engine in CHP mode as defined in Sections 3.1 and 3.2. This assumption is based on the generally accepted “bathtub curve”, which is often used to analyze and characterize maintenance activities for generation assets. Fichtner assumes that the existing assets under discussion (CHP decentralized) are neither in their “infant mortality period” nor in the “wear-out period” (at the very end of their technical lifetime).
- The electrical efficiency was assumed with 37,4 %, the CHP coefficient or “utilization factor”: 85,2 %
- Same gas and CO_2-price as for all other generation assets

Results:

Fixed O&M costs:	15.500 EUR/a
Specific fixed O&M costs: [110]	77,5 EUR/kW/a
Short-term variable operating costs:	58,8 EUR/MWh

[110] To provide a reliable variance or confidence interval of these costs, a case by case analysis of the individual assets and a technical assessment on site would be necessary.

5. Investment on Existing Capacities

In this section, the investment in existing capacities shall be assessed.[111] Investments to augment the capacity or extend the unit's lifetime are evaluated and quantified.

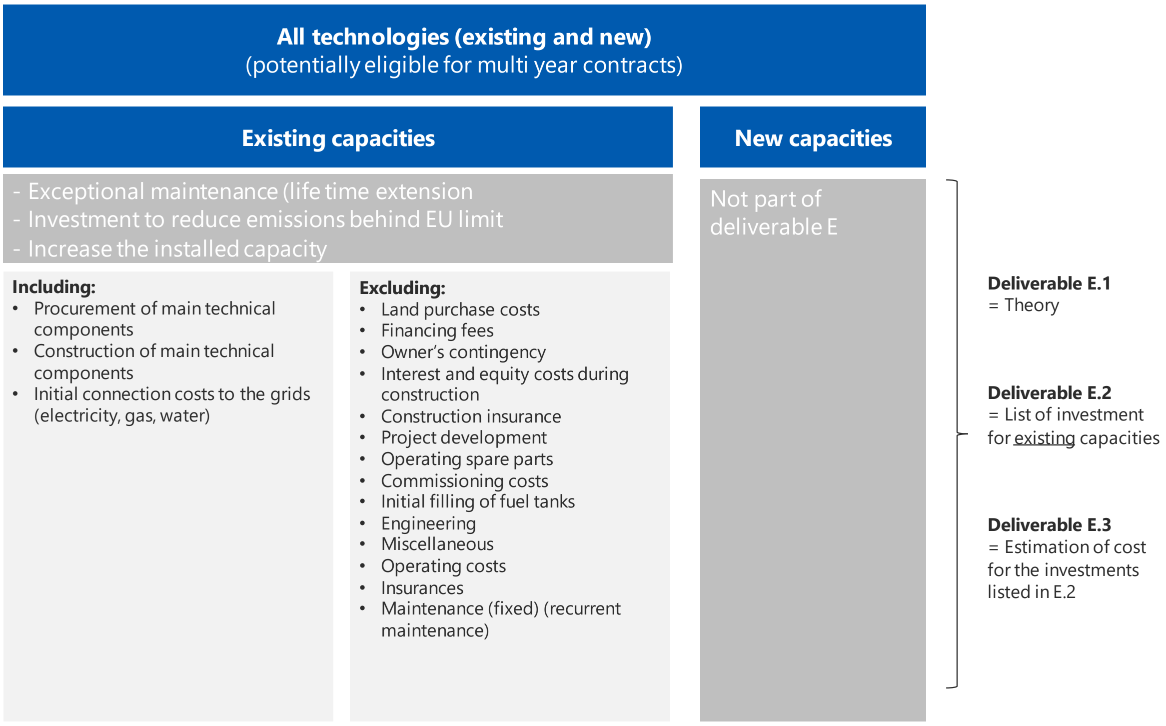

Figure 23: Segmentation of investment threshold (Source: Fichtner, own diagram)

5.1 Eligible costs

The following general cost requirements expressed by CREG are the basis for a definition of eligible and non-eligible costs used in order to classify a capacity in a category of capacity.

Physical CAPEX:
This includes all expenditures that can be allocated directly to the acquisition of physical assets. It contains all major technical components, such as a gas or steam turbine, which can easily be verified in a transparent market, e.g. in price lists.

Unavoidable costs:
Costs unavoidable to ensure the availability of capacity to the system. This may include the connection costs to the power grid and the gas, water and district heat networks, if applicable.

Non-recurring costs:
This limits the eligible costs to expenditures which do not occur regularly. Hence, this excludes regular expenses such as insurance costs or regular maintenance.

The proportion of eligibility and non-eligibility of the total investment costs will be assessed for each technology based on the cost categories defined in the Gross CONE calculations.

[111] CCGT (350 - 450 MW), OCGT (100 MW), CHP (380 MW) and Turbojets (20 MW)

The following list gives an overview of the eligible costs with access to the multi-year contracts:

Eligible cost components	Non eligible cost components
• Procurement of main technical components • Construction of main technical components • Initial connection costs to grids	• Land purchase costs • Financing fees • Owner's contingency • Interest and equity costs during construction • Construction insurance • Project development • Operating spare parts • Commissioning costs • Initial filling of fuel tanks • Engineering • Miscellaneous • Operating costs • Insurances • Maintenance (fixed) (recurrent maintenance)

Table 17: Eligibility of costs for classification of existing capacities in categories of capacities (Source: Fichtner, own table)

5.2 Investments for existing capacities augmenting the amount of capacity in the system

Not only newly built units can add capacity to the system but also existing facilities that are upgraded to a higher capacity or units undergoing a lifetime extension. A large variety of technology-specific measures can be taken to increase the installed capacity of a unit or to extend its lifetime through adequate retrofits or repairs.

More specifically, costs are eligible to classify in a category of capacity that gives right to multi-years delivery periods if the installed capacity is increased, if the lifetime is extended[112] or if the investments reduce emissions below the EU limits which would otherwise force the power plant to be decommissioned.

In order to maintain a power plant and to ensure its operability several maintenance services need to be done. In the following section the maintenance services are classified into three categories as it is shown in Figure 24. This classification is based on the extent and frequency of the measures which are usually conducted through the maintenance service.

Whereas "regular inspection" includes primarily short inspections for monitoring purposes, the last category "lifetime extension" includes the replacement of major parts of the power plant in order to extend its lifetime or capacity. "Major overhauls" include conventional maintenance activities that must be carried out from time to time. There are various maintenance strategies such as "planned (preventive) maintenance", "condition monitored maintenance", "corrective (variable) maintenance" etc. determining the sequence of "major overhauls".

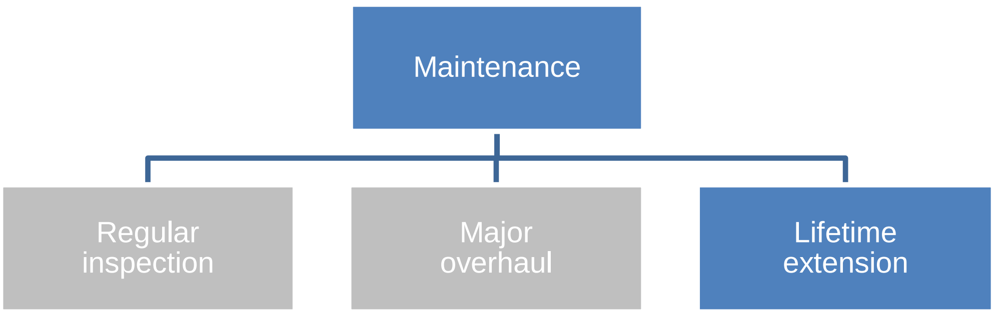

Figure 24: Categories of maintenance activities (Source: Fichtner, own diagram)

Example - maintenance of an OCGT:
Table 18 shows some more detailed information about the categories mentioned above.

- **Regular inspections** are usually conducted every 8.000 Equivalent Operating Hours (EOH) and include inspection and, when needed, replacement of parts which are known to wear off fast. These measures can be typically performed in only a few hours or days to reduce downtime.
- After 48.000 EOH and several regular inspections a **major overhaul** is conducted. This contains a thorough inspection of the power plants' equipment and repairs or replacement of some major parts or components. After a major overhaul the power plant can be operated for another period of 48.000 EOH with only some regular inspections in between.
- After two or three major overhauls some essential parts of a power plant are worn out and a **lifetime extension** is needed to maintain the power plants capacity. This

[112] Applies to plants which would otherwise go offline in less than 8.000 hours

typically contains the replacement of entire component groups such as e.g. the gas or steam turbines or the generator (or the HRSG for CCGTs). Those measures often include an augmentation of the power plants capacity (output in MW) because of technological improvements which have taken place since the plants' first commissioning. These kinds of measures preserve a capacity which otherwise would be taken off the grid or even create new capacity (if capacity is augmented) and are entitled to a multi-year contract.

Category	Regular inspection	Major overhaul	Lifetime extension
Time	Every 8.000 EOH (Eggart, et al., 2017)	Every 48.000 EOH (Eggart, et al., 2017)	After 136.000 EOH (Siemens, 2019)
Augment capacity	x	x	(✓)
Lifetime extension	x	x	✓
Entitled for multi-year contract	x	x	✓
Measures	Short disassembly, inspection of parts, which are recognized as being the first to require replacement and repair Inspection and reparation/replacement of - fuel nozzles - liners and - transition pieces	Examination of all the internal rotating and stationary components from the inlet of the machine through the exhaust Reparation/replacement of - bearings/seals - compressor blades - exhaust system	Replace/upgrade turbine, compressor Combustor improvements New operation data counter

Table 18: Specification of the categories of maintenance measures (Source: Fichtner, based on (Eggart, et al., 2017))

5.2.1 List of investments for existing capacities that augment capacity in the system

This section provides a list of measures that augment the capacity of existing power plants or extend their lifetime. A selection of four power plant technologies will be considered, including OCGT, CCGT, CHP and turbojets.

There is a wide range of measures that can be performed to augment the capacity of an existing power plant or to extend its lifetime. The set of measures that is needed for a certain power plant differs strongly and depends on many factors. This includes the power plants type, its age and the condition of the built-in components. A list of the most common measures is provided in Table 19. All replacement and repairing measures help to provide a lifetime extension of the power plant, but only some of them also potentially augment the installed capacity. This applies particularly to those components which are responsible for energy conversion as their efficiency and capacity can be increased through a replacement.

	Augment capacity	Lifetime extension
Replace HP, IP and LP rotors of turbines		✓
Replace steam chest		✓
Improve/Renew Combustor	✓	✓
Replace generator	✓	✓
Replace transformer		✓
Re-tubing Condenser		✓
Repair/Replace exposed steelwork, roof and cladding		✓
Replace gas turbine	✓	✓
Replace steam turbine	✓	✓

Table 19: List of measures for lifetime extension (Source: Fichtner, based on (Parsons Brinckerhoff, 2014))

5.2.2 Estimation of the cost for lifetime extension

As mentioned above, the costs for refurbishment measures can vary in a wide range depending on the exact set of measures that need to be conducted. To provide reliable values for the considered technologies several sources were evaluated and combined with internal expert experience of Fichtner.

Parsons provides some case studies where refurbishment data alongside with the specific CAPEX for a lifetime extension is provided for several gas-fired power plants (Parsons Brinckerhoff, 2009).[113] Figure 25 gives an overview of the reviewed power plants in this study. The average lifetime extension costs of the power plants with OCGT technology are 390 EUR/kW whereas 420 EUR/kW is the result for CCGT plants.

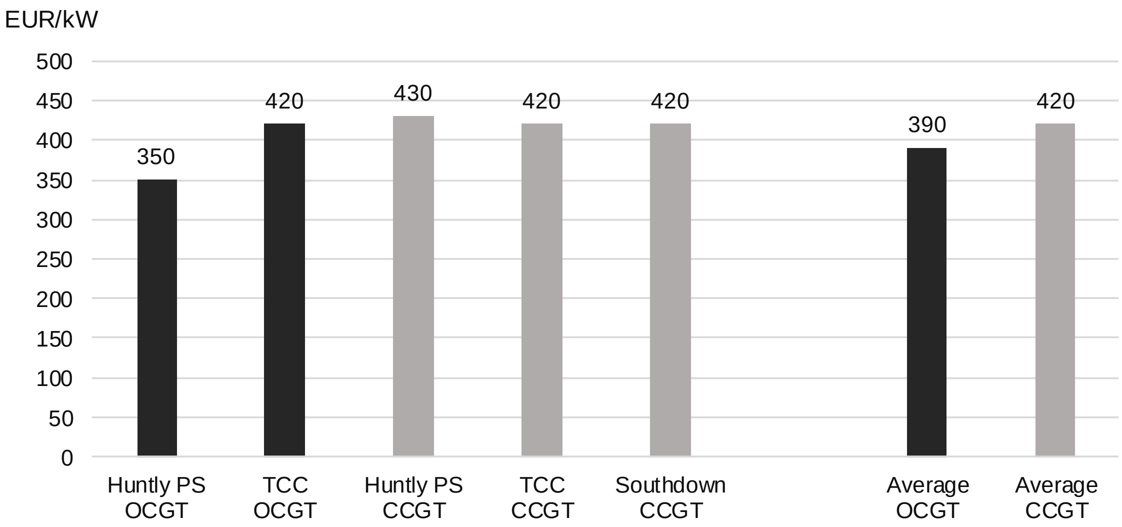

Figure 25: Specific lifetime extension costs for reviewed power plants (Source: Fichtner, based on (Parsons Brinckerhoff, 2009))

In (ACIL Tasman, 2013) the costs for the refurbishment of OCGT, CCGT and CHP power plants are given as a percentage of the initial CAPEX for a new construction. They were

[113] The source is still valid, although it is from 2009. Prices are adapted and given on price basis 2019.

combined with values for the specific CAPEX for new plants stated in this study, as it is shown in Table 20.

This results in costs of 600 EUR/kW for CCGT plants. For the OCGT the refurbishment has a specific CAPEX of 520 EUR/kW. It can be seen that the percentage of the initial CAPEX for OCGT plants is higher than the values of the other technologies. This matches the experience of Fichtner as OCGT plants have a much smaller piping and cable network than CCGT and CHP plants due to the non-existing HRSG system. Therefore, the gas turbine, which is replaced during most refurbishment projects, has a higher share in the initial CAPEX. The specific refurbishment costs for CHP plants are 300 EUR/kW. The 20 MW turbojet technology is assumed to correspond to an OCGT unit and has the highest refurbishment costs with a value of 680 EUR/kW.[114]

Technology	Initial CAPEX [EUR/kW]	Share of initial CAPEX for refurbishment	Refurbishment/ lifetime extension CAPEX [EUR/kW]
OCGT (100 MW)	610	85 %	520
CCGT (350 - 450 MW)	850	70 %	600
CHP (380 MW)	430	70 %	300
Turbojets (20 MW)	800	85 %	680

Table 20: Specific refurbishment costs (Source: Fichtner, based on (ACIL Tasman, 2013))

In a study conducted by Fichtner, five different cases were examined. While some of the reviewed power plants were based on gas-fired steam turbine technologies before the refurbishment, all of them used the CCGT technology after the retrofit. Figure 26 shows the specific investment for the refurbishment of the reviewed cases. The costs vary in a range between 440 EUR/kW and 950 EUR/kW. This is a good example for the aforementioned wide span of costs for refurbishments. However, except the “Claus power plant” all other units are relatively close to the average of about 630 EUR/kW, which is perfectly in line and in the range given in the other sources.

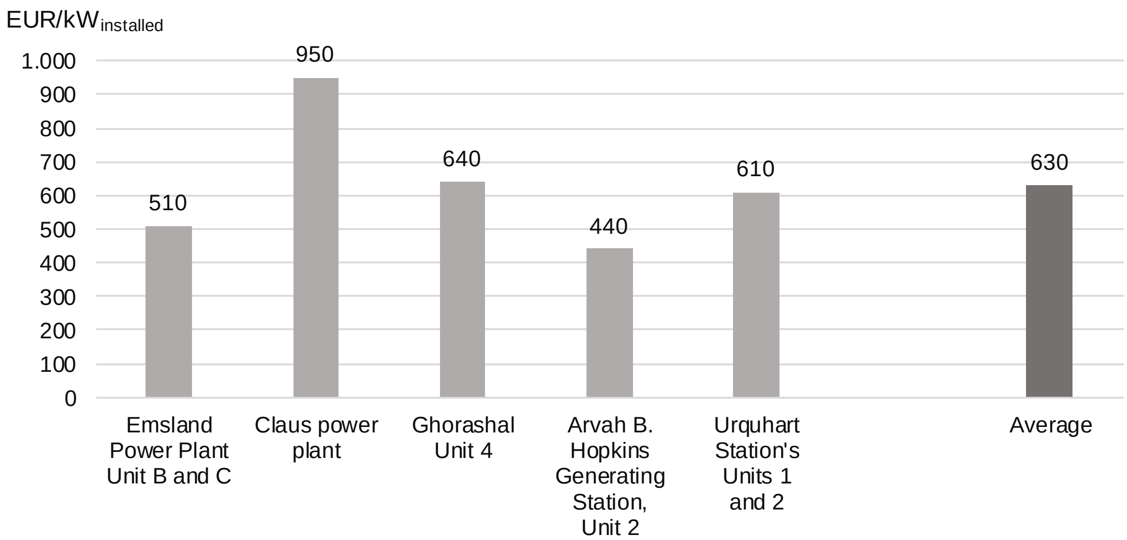

Figure 26: Specific investment for reviewed CCGT plants (Source: Fichtner, own diagram)

[114] This comparably high number is reasoned by the relatively small (and therefore specifically expensive) turbojet of only 20 MW.

Summary:
The sources analyzed provide a consistent picture. In combination with Fichtner's experience the costs for lifetime extension for the plants under discussion are assumed as follows (see Table 21 and Figure 27). The considered technologies often come in convoy standardized configuration. As explained, key component groups are often replaced if a lifetime extension is carried out (new turbine, generator, control system etc.). This clearly explains the comparably high cost for a lifetime extension.

	OCGT (100 MW)	CCGT (350 - 450 MW)	CHP (380 MW)	Turbojets (20 MW)
Costs for lifetime extension [EUR/kW]	460	550	300	680

Table 21: Average specific costs for lifetime extension for the considered technologies (Source: Fichtner, own table)

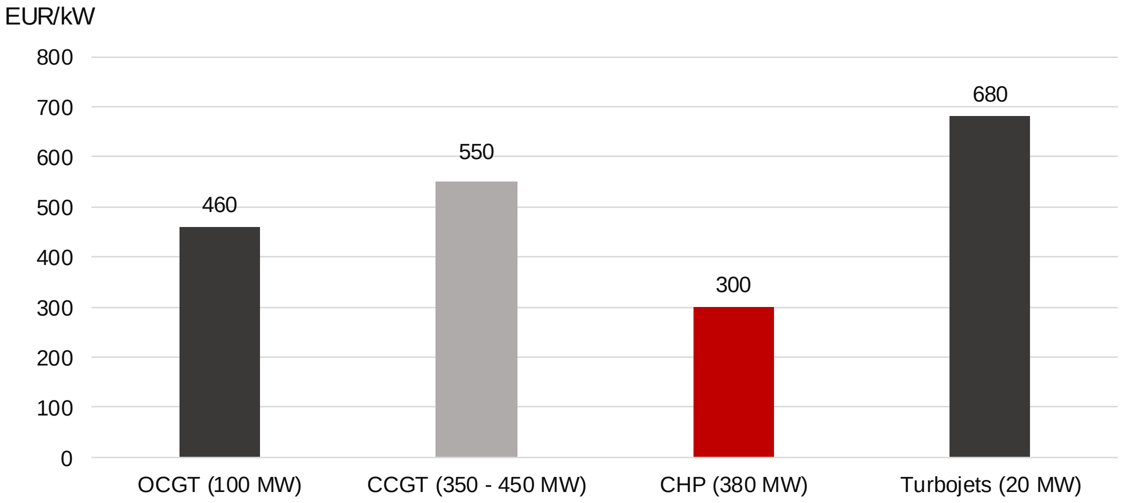

Figure 27: Average specific costs for lifetime extension for the considered technologies (Source: Fichtner, own diagram)

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