# Annex B – Methodology for relevant costs

## Contents

# 1 Introduction

The Innovation Fund supports the additional costs that are borne by the applicant as a result of the application of the innovative technology related to GHG emission avoidance. According to Article 5(1) of the Innovation Fund Regulation:

> *"The relevant costs shall be the additional costs that are borne by the project applicant as a result of the application of the innovative technology related to the reduction or avoidance of the greenhouse gas emissions.*
>
> *The relevant costs shall be calculated as the difference between the best estimate of the total capital expenditure, the net present value of operating costs and benefits arising during 10 years after the entry into operation of the project compared to the result of the same calculation for a conventional production with the same capacity in terms of effective production of the respective final product."*
>
> *Where conventional production … does not exist, the relevant costs shall be the best estimate of the total capital expenditure and the net present value of operating costs and benefits arising during 10 years after the entry into operation of the project."*

The relevant cost is not to be confused with the maximum grant award that is equivalent to 60% of the relevant costs.

Since the Innovation Fund is a competitive scheme, and cost-efficiency is one of the five award criteria, once relevant costs have been determined, applicants are free to request less than 60% of the relevant costs – due to a higher contribution from private resources or through public support –to improve their scoring under the award criterion related to cost-efficiency.

# 2 Calculation of relevant costs compared to reference scenario

The calculations of GHG emission avoidance as well as of relevant costs rely on a comparison to reference scenarios that should reflect the current state-of-the-art in the different sectors:

Table 2.1 Reference Scenarios

| | Reference scenarios for GHG emission avoidance |
|---|---|
| Energy-intensive industries, incl. CCU; CCS | EU ETS benchmark(s) |
| Renewable electricity | Expected 2030 electricity mix |
| Renewable heat | Natural gas (NG) boiler |
| Energy storage | Single-cycle NG turbine (peaking power) |

To be consistent with the calculations of the GHG emission avoidance, the calculation of the relevant costs should build on the same reference scenarios and their respective costs.

# 3 Choice of the cost methodology

## 3.1 Decision tree

The Decision tree presented in Figure 3.1 directs applicants to the most appropriate reference scenario for the calculation of their relevant costs. The Decision tree follows the requirements of the Innovation Fund Regulation and is based on the key characteristics of the project. By working down the left side of the diagram, and based on the characteristics of their projects, applicants will end up with the appropriate relevant cost methodology.

The default methodology is Option 1, which is based on a Levelised Cost Model (reference unit costs / price methodology) that should be suitable for a wide variety of projects covering

- Option 1a – Energy/electricity generation
- Option 1b – Product manufacture from energy-intensive industries (as well as the manufacture of innovative renewable or storage technology components from a new production facility[1])
- Option 1c –Electricity storage

The current market prices are considered as the best estimate for the costs of the conventional technologies as used in the reference scenarios.

In limited situations, when a reference unit price is not available, applicants will find that the Decision tree takes them to the reference plant methodology (Option 2). The project costs are compared to the best estimate of the CAPEX and OPEX of a plant with conventional technology (e.g. ETS benchmark installation in the case of industrial products).

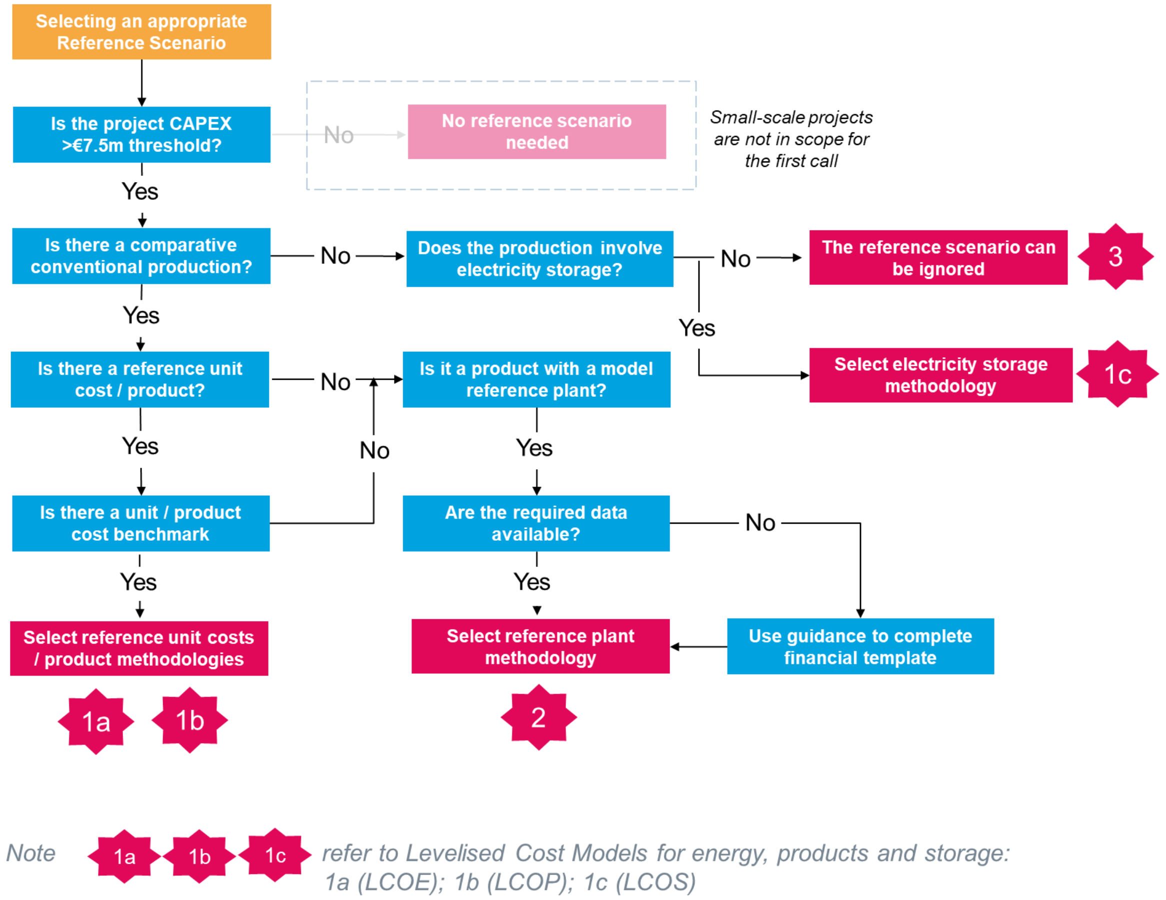
Finally, Option 3 is the “last-resort” methodology for cases where neither Option 1 nor Option 2 is applicable and relies on a methodology without a reference cost scenario.

Applicants will make the final decision whether to deviate from the default methodology in Option 1. Applicants will however have to justify their choice based on the principles outlined below and ensure the traceability and transparency of the calculations.

For the purposes of ensuring a fair and transparent evaluation process, any applicant who wishes to deviate from the methodology on specific parameters will have to provide justification that is defensible and based on considerations such as accuracy and availability of data, and comparability of the final product, or process. The evaluators should be able to understand the quantitative impact from any deviation from specific or default parameters.

[1] Applicants with projects falling under this category should already have demonstrated through the GHG emission avoidance methodology the existence of a buyer of the components (i.e. a company that will run the innovative technology to generate renewable electrical or thermal energy) to ensure that the intended GHG avoidance will be delivered. Therefore, it is assumed in the first instance that the product replaces an existing product in the market where there is a comparable product price.

**Figure 3.1 The Decision tree helps applicants to select the right calculation methodology**




## 3.2 Introduction to the cost methodologies

### 3.2.1 Option 1 – The levelised cost methodology

This methodology calculates the relevant costs based on the difference between the levelised cost of producing an output unit using the project's innovative technology, and the market price expected to be received for the quantity to be produced in the 10 years after entry into operation of the project (be it electricity or an industrial product for example):

- **Energy model (Levelised Cost of Energy - LCOE):** This model can be used for power or heat generation and equates to the well-known LCOE calculation which is a standard when comparing technologies' cost of producing a MWh or equivalent of energy;

  Average wholesale electricity prices of the past two years should be used as the default value for the market price expected to be received.

- **Industrial Product model (Levelised Cost of Product - LCOP):** This model creates a price of production per unit for the new technology and compares this price to the market price of the industrial product;

  The default values for the expected market prices (for the final product but also the EU ETS allowances) will have to be at least as high as the average of the last two years.

- **Electricity Storage model (Levelised Cost of Storage - LCOS):** This model creates a blended market price per discharge for a unique and specific use case of a storage technology in a particular country, focusing only on those services offered and remunerated in that country. It then compares that cost to the income that would be received by those services at the levels of remuneration unique to that setting. This second calculation is the assumed market price for that use case. As per the other Levelised Cost methodologies, the difference in these two calculations per unit provides the basis for the calculation of relevant costs.

### 3.2.2 Option 2 – The reference plant methodology

This methodology calculates the project's capital expenditure (CAPEX) and the net present value (NPV) of its net operational benefits[2] and operational expenditure (OPEX) and compares them to those of a reference plant with conventional technology but of the same size and output, over the first ten years of operation. This is the "fall-back" methodology to be used when a reference unit cost or product price is not available.

The reference plant should e.g. be based on a plant that achieves the EU ETS benchmarks for industrial products.

### 3.2.3 Option 3 – The 'no reference scenario' methodology

This methodology derives the relevant costs based on the best estimate of the total CAPEX and the NPV of operational benefits and OPEX arising over the first ten years of operation. This is the "last-resort" methodology that can only be applied in case no reference product or conventional technology is available as reference.

## 3.3 Key parameters and data input

### 3.3.1 Key parameters that will impact the selection of the cost methodology

Applicants need to consider various parameters to determine whether it would be justified to deviate from the default cost methodology under option 1:

**Option 1 – The levelised-cost methodology**

- **Existence of a reference unit cost / product** – here it is recognised that in the vast majority of cases there will be some form of reference product[3]. With regard to substitute products, the same approach will be used.
- **Project boundaries -** A general principle will be establishing an identifiable final product in most cases. Where a project is focused on part of an installation, then this partial process contribution to cost in the full process must be assessed. Where a project combines industrial production with electricity storage, if the latter is integrated into an industrial process then only the LCOP model is used, with the benefit (i.e. electricity cost saving) taken into account. The LCOS model is only for electricity storage as a standalone service.

[2] Defined as covering annual incomes/revenues

[3] Note, this does not refer to ETS product benchmarks which are sometimes wrongly termed 'Reference products' (see https://ec.europa.eu/clima/policies/ets/allowances/industrial_en for more details)

- **Availability of reliable reference product price information** – required to inform the relevant costs calculation;

  If a project is focused only on producing an intermediate product (e.g. liquid steel) or concerns a well-defined innovation in a certain process step, and there exists no reliable market price or substitute product, or it is illiquidly traded, or is uncertain, and internal cost data is more reliable for the calculation of the costs in the reference scenario, then option 2 based on a reference plant scenario should be followed;

<u>**Option 2 – The reference plant methodology**</u>

- **Existence of a reference plant** - which should be a conventional plant (e.g. EU ETS benchmark installation for industrial products or a fossil fuel-equivalent for renewable electricity or heat).
- **Availability of reliable reference plant cost data** – required to inform the relevant costs calculation; and, finally,
- In some cases, neither a substitute product nor a conventional technology will exist (e.g. when a new and additional production step is added to the process or a new service is offered – such as standalone $CO_2$ storage and transport project). Only in these cases and when well documented that only costs are covered related to and necessary for the innovation itself, option 3 can be chosen.

### 3.3.2 Key data inputs across the methodologies

The key data inputs are based on standard financial indicators that would typically form the basis of a project financing model. These include:

- Capacity of the project
- Project life
- CAPEX cost
- Variable annual OPEX
- Fixed annual OPEX
- Non-annual periodic costs
- Decommissioning costs
- Timing inputs
- Expected Annual production (tpa, MWh/annum, $tCO_2$ stored/annum, etc.)
- Operational benefits

Table 3.1 sets out these and other input parameters across the different models and reference scenarios. Applicants will need to ensure they have the complete set of data in order to derive an accurate relevant costs calculation.

## Table 3.1 Input parameters across different relevant costs methodologies

| Parameter | Option 1a<br>Energy Model | Option 1b<br>Industrial Product Model | Option 1c<br>Electricity Storage Model | Option 2<br>Reference Plant Model | Option 3<br>Reference Scenario Ignored |
|---|---|---|---|---|---|
| Capacity | Y | Y | Y | | |
| Capacity Factor | Y | | | | |
| Degradation | Y | | Y | | |
| Total Annual Electricity Discharged | | | Y | | |
| | | | | | |
| Financial Close Date | Y | Y | Y | Y | Y |
| Construction Cost | Y | Y | Y | Y | Y |
| Construction Duration | Y | Y | Y | Y | Y |
| Project Lifetime | Y | Y | Y | Y | Y |
| Production Ramp-Up for First 3 years | Y | Y | Y | | |
| | | | | | |
| Indexation Rate | Y | Y | Y | | |
| Public support related to the price or quantity sold | Y | Y | Y | Y | Y |
| Public support related to support capital or operating expenditures | | | | | |
| Carbon Allowances Sold | | Y | | Y | Y |
| Annual Income Streams | | | Y | Y | Y |
| Associated O&M Costs | | | Y | Y | Y |
| | | | | | |
| Variable Operating Costs | Y | Y | Y | Y | Y |
| Fixed Operating Costs | Y | Y | Y | Y | Y |
| Lifecycle Costs | Y | Y | Y | | |
| Lifecycle Cost Frequency | Y | Y | Y | | |
| Decommissioning Costs | Y | Y | Y | | |
| Terminal Value | Y | Y | Y | | |
| | | | | | |
| Reference Levelised Cost | Y | | | | |
| Reference Product Price | | Y | | | |
| Premium/(Reduction) to Reference | Y | Y | | | |
| Reference Plant Construction Cost | | | | Y | |
| Reference Plant Construction Duration | | | | Y | |
| Reference Plant Annual Revenues | | | | Y | |
| Reference Plant Annual Costs | | | | Y | |
| | | | | | |
| Cost of Equity | Y | Y | Y | Y | Y |
| Cost of Debt | Y | Y | Y | Y | Y |
| Equity % | Y | Y | Y | Y | Y |
| Debt % | Y | Y | Y | Y | Y |
| Corporation Tax Rate | Y | Y | Y | Y | Y |
| | | | | | |
| Proportion of Relevant Costs Applied For | Y | Y | Y | Y | Y |

# 4 Methodologies for calculating relevant costs

## 4.1 Levelised Cost methodology

### 4.1.1 Principles

In many industries there are accepted methodologies used for the calculation of levelised unit costs. The levelised unit cost is the cost of producing a unit of production, including the financing costs (i.e. the return expected from debt and equity investors), over the lifetime of a project. This is akin to an estimated fair price of the unit produced based on the costs of production and the costs of finance.

*Levelised Cost of Energy (LCOE)*

The LCOE = [present value of the costs over the lifetime]/discounted number energy units produced (MWh) over the lifetime

In other words:

$$LCOE\left[\frac{€}{MWh}\right] = \frac{Investment\ cost + \sum_n^N \frac{O\&M\ cost}{(1+r)^n} + \sum_n^N \frac{Fuel\ cost}{(1+r)^n}}{\sum_n^N \frac{Elec_{Produced}}{(1+r)^n}}$$

Where:

- r = discount rate (WACC)
- n = the year

Note that there is no fuel cost in most renewables projects.

*Levelised Cost of Product (LCOP)*

The product price methodology uses the same approach as LCOE to calculate the fixed nominal unit price (over the project lifetime) that would need to be paid for the innovative product in order to justify the investment to build the project (Levelised Cost of Product, or LCOP) including its cost of funding.

In other words:

$$LCOP\left[\frac{€}{Product}\right] = \frac{Investment\ cost + \sum_n^N \frac{O\&M\ cost}{(1+r)^n} + \sum_n^N \frac{Fuel\ cost, Materials\ cost\ etc}{(1+r)^n}}{\sum_n^N \frac{Units_{Produced}}{(1+r)^n}}$$

Where:

- r = discount rate (WACC)
- n = the year

The discount used for the NPV calculations is the Weighted Average Cost of Capital (WACC) of the project. This is the blended cost of capital depending on the ratio of equity and debt in the project and is calculated using the formula below:

*WACC = E/V * Re + D/V*Rd * (1-Td)*[4]

[4] This is a nominal discount rate calculation (the debt and equity funding cost already take into account inflation)

- Re = total cost of equity
- Rd = total cost of debt
- E/V = equity portion of total financing (Equity over total Value)
- D/V = debt portion of total financing (Debt over total Value)
- Td = Tax rate[5]

The resulting LCOE or LCOP for the innovative product will be compared to the market price of the reference product (hereinafter "reference price"). The LCOE or LCOP is the price at which the product would have to be sold on average to reach a market-related return for investors (i.e. the theoretical product market price using the new process). Save for the OPEX costs occurring after ten years, this difference per unit would equal the relevant costs in the Innovation Fund Regulation. Adjustment is therefore made to exclude the post 10-year OPEX in the final calculation of relevant costs using this methodology (see below).

The potential value of the support is calculated by building a financial model for the innovative project and using the reference product (benchmark) price as the unit sales price assumption.

A key component of the models is the calculation of the NPV of the operational costs (OPEX) of the project. In order to calculate this NPV, an appropriate discount rate needs to be applied to the OPEX over the lifetime of the project, in order to calculate a Levelised Cost (unit cost including financing cost).

The NPV (using the WACC as the discount rate, and the nominal market unit price) of the free cashflows from the innovative project (including all CAPEX and OPEX) will be negative and this amount is defined as the relevant costs.

The financial model for each innovative project should ideally be based on a template model available to download along with other information to assist potential applicants.

### 4.1.2 Detailed approach

#### 4.1.2.1 Summary of the steps for calculating the relevant costs using the Levelised cost methodology

***Step 1: Establish the CAPEX and OPEX***

Upfront costs of construction and ongoing operational costs (OPEX) for the full project lifetime must be established.

***Step 2: Reduce the OPEX by any additional operational benefits (such as EU ETS Allowance sales or preferential electricity tariffs)***

See section 4.1.2.6 below on Carbon Price Assumptions.

***Step 3: Determine the number of units forecast to be produced by the project***

***Step 4: Discount the OPEX and units produced over the project lifetime using the WACC***

See section 4.1.2.3 below on Determining the WACC.

***Step 5: Divide the CAPEX plus NPV of the OPEX by the discounted Units produced over the project lifetime***

***Step 6: Establish the difference between the Levelised Cost and the Reference price***

See section 4.1.2.5 below on Determining a comparable Reference price.

[5] Note that the inherent tax shield reduces the debt cost.

***Step 7: Multiple this financial difference by the discounted units produced over the project lifetime***

***Step 8: Calculate the percentage of Levelised Cost that the OPEX after 10 years of operation represents***

See section 4.1.2.13 below on OPEX adjustment.

***Step 9: Subtract this percentage from the total in Step 7***

This will be the relevant cost.

#### 4.1.2.2 Rules regarding input parameters

In the two models (Option 1a and 1b) under this relevant costs methodology (and also appropriate to other Methodologies to varying degrees – see Table 3.1), applicants need to make assumptions in order to enable a robust calculation of relevant costs across the following areas:

- WACC (discount rate);
- Tax rate;
- Determining a comparable Reference product price (reference scenario);[6]
- Carbon Price;
- Project lifetime;
- Indexation/inflation;
- Terminal value;
- Decommissioning;
- Write down of existing (old) technologies; and,
- How to account for possible differences in regulatory regimes and public support.

Each of these aspects is briefly described in the following sections:

#### 4.1.2.3 Determining the WACC (discount rate) across different project types

The WACC is applied to discount future income and cost streams over the project lifetime to make them comparable.

Many applicants will be experienced and familiar with the cost of equity and debt - and therefore the WACCs used - in their company and sector. For some applicants, however, this could pose a challenge. This section helps applicants to understand what the appropriate WACC should be for a particular project / sector and how to go about deriving the WACC for their project.

Applicants should use the indicated default values for the WACC, including cost of equity and cost of debt. The applicants should justify any higher values in relation to increased risks and quantify its impact on the relevant costs.

***<u>i) Establishing the WACC for a renewable energy project</u>***

As a default, the applicant shall use the company discount rate (WACC) or follow the methodology provided in this section.

***Cost of equity***

If for a project a comparable technology project construction equity return (IRR) is known, applicants should use that construction equity return. If that is not available, applicants can use a

[6] Product price will be assumed to include Carbon Costs.

premium to another benchmark that is available across the market for construction equity. For example, if looking at construction equity return for an offshore wind investment, applicants can make realistic assumptions regarding the premium to a known reference. The all-in equity return expectations would typically be in the range of 8 to 16% based on observed transactions, but these might be different in exceptional circumstances. Table 4.1 below provides an indicative cost of equity for five different groups of EU countries, although applicants should note that in some markets the speed of development may mean rates could fall quickly in a short period (for example, with offshore wind).

Table 4.1 Indicative cost of equity for WACC calculation for RES projects

| | Group 1 | Group 2 | Group 3 | Group 4 | Group 5 |
|---|---|---|---|---|---|
| Offshore Wind | 8.50% | 9.50% | 11.00% | 13.00% | 16.00% |
| Offshore Floating Wind | 10.50% | 11.50% | 13.00% | 15.00% | 18.00% |
| Floating Solar PV | 8.00% | 9.00% | 10.50% | 12.50% | 15.50% |
| Biomass (Advanced Technologies) | 10.00% | 11.00% | 12.50% | 14.50% | 17.50% |
| Geothermal | 10.00% | 11.00% | 12.50% | 14.50% | 17.50% |
| Tidal | 12.00% | 13.00% | 14.50% | 16.50% | 19.50% |
| Wave | 12.00% | 13.00% | 14.50% | 16.50% | 19.50% |

*Source: ICF*

| Country Grouping | *Relates to where project is located |
|---|---|
| Austria | 1 |
| Belgium | 2 |
| Bulgaria | 3 |
| Croatia | 4 |
| Republic of Cyprus | 4 |
| Czech Republic | 3 |
| Denmark | 2 |
| Estonia | 5 |
| Finland | 3 |
| France | 3 |
| Germany | 1 |
| Greece | 4 |
| Hungary | 5 |
| Ireland | 3 |
| Italy | 3 |
| Latvia | 5 |
| Lithuania | 5 |
| Luxembourg | 1 |
| Netherlands | 3 |
| Poland | 5 |
| Portugal | 2 |
| Romania | 5 |
| Slovakia | 3 |
| Slovenia | 3 |
| Spain | 3 |

| Country Grouping | *Relates to where project is located |
|---|---|
| Sweden | 3 |

*Source: ICF*

### *Cost of debt*

Applicants can assume a margin for risk above the base rate[7] as they would be quoted for project finance by a commercial lender (project finance bank). If a reference is not available for the particular technology a premium over an established technology debt margin can be used.

Unlike the cost of equity, it is not possible to provide applicants with market assumptions about the cost of debt, since this requires knowledge of the base rate in each country (and currency) and then the margin for debt in each country and for each technology. It will also have a different base rate depending on the tenor of the debt for each specific project. However, applicants should consider a default range of 150 to 650 basis points over the base rate, or alternatively use the credit spread of BBB- to C[8]. Applicants should provide appropriate documentation for their chosen cost of debt.

For renewable projects the expected debt-to-equity ratio should be used. In some cases, this might be 100% equity.

### ***ii) Establishing the WACC for an energy-intensive industrial project[9] or for an innovative manufacturing facility***

As default, the applicant shall use the company discount rate (WACC) or follow the methodology provided in this section. For innovative manufacturing facilities (for example, of renewables components), the new products will inevitably fall into a specific market sector, in which case applicants should use the WACC calculations for industry, not a renewables project.

The final product price should be determined in the financial model based on calculations assuming a specific WACC, whether calculated or provided by the company's internal treasury.

If the applicant is an SME or a Special Purpose Vehicle (SPV), then the general WACC for the sector covering the project should be applied. This is also the approach taken when assessing State aid to companies. To achieve this, applicants would need to justify their WACC calculation using appropriate reference sources (for example, as noted in a published annual report).

WACC rates for energy-intensive industrial projects should be calculated according to the country in which the projects will be executed as well as the sector. Reference Market Betas for Industrial projects, as well as the Equity Risk premium by country, are provided to applicants in order to perform this calculation and are included in Appendix 1 at the end of this document.

The calculation will follow the following steps for a notional project, as shown in Figure 4.1:

Figure 4.1 Calculation of the Cost of Equity for a notional innovative project in Poland in the Chemicals sector

| | | Reference |
|---|---|---|
| **Risk Free Rate (a)** | 0.65% | Eoipa Figures |
| **Market Risk Premium (b)** | 5.20% | Domadoran |

[7] Base rate will be the risk-free rate: from the ten-year government bond yield of the country of the project

[8] Anything above this is considered not risky enough and anything below this is considered too risky

[9] Typically those not financed on a project basis, but rather on a corporate basis

| | | |
|---|---|---|
| **Equity Return (Market)** | 5.85% | ***a+b = c*** |
| **Chemical Sector Unlevered Beta (d)** | 1.79 | Domadoran (we assume a sector standard leverage at project and company level) |
| **Equity Return** | 10.50% | ***c*d = e*** |

Applicants may add a further premium in case the high degree of innovation leads to risks that go beyond the sector or company WACC. However, such an "innovation premium" must be related to the determined degree of innovation and take into account how many process steps or products are being changed. To the extent possible, the applicant should quantify the perceived risks. Furthermore, the applicant should calculate and transparently show the impact of the "innovation premium" on the relevant costs. The upper bound on such an "innovation premium" is 4%.[10]

#### 4.1.2.4 Tax rate assumptions

As shown above (section 4.1.1), an important aspect of the WACC formula is the determination of the prevailing tax rate which prevails in the country of project demonstration.

#### 4.1.2.5 Determining a comparable Reference Price

***i) Assumptions about the price of the product from the project and implications for the Reference price***

Achieving some comparability over product prices in relevant costs calculations is important, both for ensuring fairness and as this will determine the project's revenue line.

As the levelised cost of the innovative product includes a cost of capital, it should be compared to a market price, or production cost plus an appropriate profit margin in the reference scenario.

***ii) General rules for establishing Reference prices***

Unless specified otherwise, applicants need to provide Reference price data. The default choice should be a two-year historic average price, but applicants may be able, in specific cases, to propose another methodology if there are specific reasons why historic average pricing would not provide a good basis for forecasting future prices.

*For energy (power/heat) projects using the LCOE approach:*

The project LCOE should be compared against the long-term market price for either power or heat.[11]

*For industrial projects using the LCOP approach:*

The market price of the innovative product should be compared with the market price of its reference product.

***iii) Consideration of EU ETS costs in Reference prices***

For the LCOP and LCOE methodologies, the market price (i.e. the comparable reference) should already include the EU ETS costs (of the marginal installation) that are passed on to consumers.

[10] This percentage has been calculated as a blended market observed equity risk premium based on research from Ibbotson Associates, Duff and Phelps and KPMG (see Appendix for further details on premia by company size)

[11] The reference price will be the wholesale market price with an appropriate discount applied for the achievable PPA (i.e. the long-term project contract with PPA off-takers and do not receive 100% of the market price of wholesale electricity). An appropriate discount would normally be in the region of 90-95% of the wholesale market price.

In case of use of unit costs (that do not include EU ETS costs of the marginal installation), the EU ETS costs of the marginal installation would need to be added to the unit cost as per the product emissions calculation, if that particular unit cost benchmark does not include Carbon costs. This might vary from cost benchmark to cost benchmark and will have to be verified by the applicants.

***iv) Obtaining Reference price data***

It is assumed that applicants that are considering the introduction of an innovative product into an existing market will know what the reference price is for the product they are seeking to compete with or displace. Indeed, in many cases, applicants will be seeking to enhance their own existing production facilities and will be therefore already well versed in reference costs and prices.

Reference price data is available for most sectors, including non-ferrous metals, basic chemicals, electricity, etc. For products that have a clear reference price that applies across Member States (for instance, London Metal Exchange prices for certain metals), applicants may choose to specify a fixed source for the reference price. The price of most products will vary by country and therefore applicants will need to propose the most appropriate reference in each case.

In general, historic information is often available, as well as limited spot and futures traded prices. Prices are however volatile and widely different results are typical, depending on the timeframe you calculate any average for.

Pricing for speciality chemicals is more opaque, but it is likely that most project sponsors will already have activities in the relevant sector and will therefore be able to provide EU evaluators with pricing information and supporting evidence.

***v) Determining an appropriate reference price for new or multiple products***

Whilst it is recognised that in many cases, perfect substitute products will be generated by an innovative project, and hence the price should be the same irrespective of the production technology, there are likely to be exceptions. For example:

- If a product can be obtained by several processes (i.e. hydrogen from steam reforming or hydrolysis), the process with the largest current market share should be used.
- For CCU projects, the reference should be guided by what it will replace (the reference is a proxy for the price that the innovative product will sell for).
- Projects in some sectors might not have comparable prices that are easy to establish and therefore a comparable product is required. For example, alternative fuels / oil-based products are two such identified sectors, where mineral oil could be a comparable product.
- If a project is focused only on producing an intermediate product (e.g. liquid steel) or concerns a well-defined innovation in a certain process step, and there exists no reliable market price or substitute product, or it is illiquidly traded, or is uncertain, and internal cost data is more reliable for the calculation of the costs in the reference scenario, then option 2 based on a reference plant scenario should be followed.

***vi) Approach to follow where the innovative product is different in quality to its reference***

Where a product will substitute another one of different composition (for example, ethanol to substitute gasoline in transport, rather than ethanol as a fine chemical), the relevant EU ETS sector of the substituted product may be chosen (the refinery sector in this case).

A new product that is not identical to the reference product may attract different prices in the market, either more or less. Applicants applying into the IF will most likely have already proved the production process at small scale. Sample production from a pilot plant is then used to obtain offtake contracts for the proposed larger plant (often required before the plant can be financed). It should therefore be clear in most cases if there is going to be a product price difference.

The achievable market sale price for the new product produced by the applicant is the reference price.

If the price of the new product and reference is expected to be different, because of either a premium for 'being Green' or a better product, adjustments need to be made. In the product unit price model, if a qualitatively different product is produced which has a price premium, the cost line should be reduced by the premium in calculation of the unit price to compare to the market product price (of the similar but lower priced reference product).

A new superior product may not initially be able to secure a price premium until the market has fully understood and proven the benefits. Therefore, it might be reasonable to assume that a new product starts at the same price as the reference but is able to obtain a premium in the market after a period of time. For reasons of simplicity, the model does not allow for this level of detail.

There may also be situations where the new product will be sold into more than one market (i.e. supply of hydrogen for transport and heating), with different prices achievable in each market. In these situations, the weighted average reference price should be used.

#### 4.1.2.6 Carbon price assumptions

The expected revenues from the sale of the free allocation of EU ETS allowances during operation will need to be taken into account in the calculation of the relevant costs. Furthermore, if the product price or unit cost does not yet include the carbon costs, the applicant need to include the carbon costs in the calculation of the revenues in the reference scenario.

To be conservative in view of the volatility of the carbon price, applicants are advised to use at least a carbon price estimate based on an averaged EU ETS price over the last two years before application (the average price through 2018/19 was 20.15 EUR/t). However, applicants are free to use higher carbon prices if they consider this appropriate.

Projects that reduce the GHG emissions compared to the reference scenario will benefit from the revenues from the sale of the free allocation of EU ETS allowances that they have received and do not need to submit because of the reduced process emissions below the applicable benchmark(s). These additional revenues from the sale of the excess allowances need to be taken account of in the calculation of the operating revenues. While installations could theoretically hold onto the excess allowances for sale later, for the purposes of calculation, the excess allowances are assumed to be sold in the years received.

#### 4.1.2.7 Project lifetime assumptions

For the purposes of the calculation of the relevant costs using the Levelised Cost methodology, the project lifetime is likely different from the 10-year relevant cost horizon.

The 10-year horizon forms the basis of the relevant costs calculations, as set out in Article 5 of the Innovation Fund Regulation, since this covers the *"additional operating costs and benefits arising during 10 years after the entry into operation of the project compared to the result of the same calculation for a conventional production with the same capacity in terms of effective production of the respective final product".*

This period then links to the amount of the Innovation Fund support which can be disbursed (in accordance with paragraph 5 of Article 6) after the financial close, which *"shall be dependent on the avoidance of greenhouse gas emissions verified on the basis of annual reports submitted by the applicant for a period between 3 to 10 years following the entry into operation."*

This means that while for the purpose of calculating the relevant costs the 10-year period after entry into operation is taken.

However, the Levelised Cost calculation of the project is performed by discounting the OPEX for the full assumed project lifetime. Applicants will be required to use a market standard asset lifetime with no terminal value (as stated in section 4.1.2.9 below). This will normally be the same for all the projects in a sector (generally associated with the depreciation period of the assets financed or asset lifetime which is typically 20 – 25 years for renewables but in some cases may extend to 25 or 30 years or longer). For some industrial projects the asset lifetimes might be shorter.

Once the Levelised Cost has been established, the difference between this figure and reference price is calculated and subsequently multiplied by the discounted number of units produced in the first 10 years after entry into operation.

#### 4.1.2.8 Indexation/inflation assumptions

Indexation refers to the adjustment of CAPEX / OPEX by inflation over the period of the action. Applicants are allowed to provide their own inflation rate linked to the Member State where the project is planned to operate. Table 4.2 provides Harmonised Indices of Consumer Prices (HICP) which are designed for international comparisons of consumer price inflation. Due to the variation evident between years, applicants are advised to use an inflation rate averaged over the last two years (i.e. 2018/19).

Table 4.2 Harmonised Indices of Consumer Prices (HICP), Inflation rate - Annual average rate of change for EU27 (%)

| | 2015 | 2016 | 2017 | 2018 | 2019 |
|---|---|---|---|---|---|
| EU (27 countries - from 2020) | 0.1 | 0.2 | 1.6 | 1.8 | 1.4 |
| Euro area - 19 countries (from 2015) | 0.2 | 0.2 | 1.5 | 1.8 | 1.2 |
| Belgium | 0.6 | 1.8 | 2.2 | 2.3 | 1.2 |
| Bulgaria | -1.1 | -1.3 | 1.2 | 2.6 | 2.5 |
| Czechia | 0.3 | 0.6 | 2.4 | 2.0 | 2.6 |
| Denmark | 0.2 | 0.0 | 1.1 | 0.7 | 0.7 |
| Germany | 0.7 | 0.4 | 1.7 | 1.9 | 1.4 |
| Estonia | 0.1 | 0.8 | 3.7 | 3.4 | 2.3 |
| Ireland | 0.0 | -0.2 | 0.3 | 0.7 | 0.9 |
| Greece | -1.1 | 0.0 | 1.1 | 0.8 | 0.5 |
| Spain | -0.6 | -0.3 | 2.0 | 1.7 | 0.8 |
| France | 0.1 | 0.3 | 1.2 | 2.1 | 1.3 |
| Croatia | -0.3 | -0.6 | 1.3 | 1.6 | 0.8 |
| Italy | 0.1 | -0.1 | 1.3 | 1.2 | 0.6 |
| Cyprus | -1.5 | -1.2 | 0.7 | 0.8 | 0.5 |
| Latvia | 0.2 | 0.1 | 2.9 | 2.6 | 2.7 |
| Lithuania | -0.7 | 0.7 | 3.7 | 2.5 | 2.2 |
| Luxembourg | 0.1 | 0.0 | 2.1 | 2.0 | 1.6 |
| Hungary | 0.1 | 0.4 | 2.4 | 2.9 | 3.4 |
| Malta | 1.2 | 0.9 | 1.3 | 1.7 | 1.5 |
| Netherlands | 0.2 | 0.1 | 1.3 | 1.6 | 2.7 |
| Austria | 0.8 | 1.0 | 2.2 | 2.1 | 1.5 |
| Poland | -0.7 | -0.2 | 1.6 | 1.2 | 2.1 |
| Portugal | 0.5 | 0.6 | 1.6 | 1.2 | 0.3 |
| Romania | -0.4 | -1.1 | 1.1 | 4.1 | 3.9 |
| Slovenia | -0.8 | -0.2 | 1.6 | 1.9 | 1.7 |
| Slovakia | -0.3 | -0.5 | 1.4 | 2.5 | 2.8 |
| Finland | -0.2 | 0.4 | 0.8 | 1.2 | 1.1 |
| Sweden | 0.7 | 1.1 | 1.9 | 2.0 | 1.7 |

*Source: Eurostat*[12]

#### 4.1.2.9 Terminal value assumptions

For project costs, applicants are advised that terminal value beyond the asset lifetime is not to be taken into account in the relevant costs calculations.

The exclusion of terminal value is consistent with project finance practice for calculation of IRR (which is usually done on the useful life of the assets)[13], and should normally also equate to the depreciation period (in the absence of preferential accelerated depreciation treatment which has been introduced by an authority for tax benefit reasons).

#### 4.1.2.10 Decommissioning assumptions

Where decommissioning costs arise during the first 10-year period, this may be taken into account as part of the relevant costs calculation. Cost estimates will vary by project and therefore need to be accurately accounted for in the calculation.

#### 4.1.2.11 Write down of existing (old) technologies

It is recognised that some large company applicants may have to replace old technology that is not fully depreciated. The costs associated with any stranded assets that might arise as a result of a project being supported are not allowable under the relevant costs calculations. Therefore, for the purposes of calculating the relevant costs for any calculation methodology, no compensation should be included as a cost.

This approach is necessary not only because it is difficult to incorporate this aspect into the relevant costs methodology, but it also ensures a level playing field with new market players, who would be disadvantaged having not made previous investments in technology and would not be able to claim such a benefit.

#### 4.1.2.12 How to account for possible differences in regulatory regimes and public support

There could be differences in electricity prices, indirect cost compensation or other operational costs (OPEX) and operational benefits (i.e. income from electricity tariffs) due to differences in regulatory regimes. Where applicants are aware of particular regulatory features of their Member State that could have a positive or negative impact on their relevant costs calculation, they should provide key points and insights to enable evaluators to understand fully some of the underlying factors affecting their project proposal.

For example, in the calculation of OPEX in the Levelised Cost methodology and the Operational benefits in the Reference Plant model, it is important to include public support that is related to the price or quantity sold of the final product, such as a feed-in tariff offered to a renewable generation technology offered by a Member State.

As a guiding principle, any such public support that is equally applicable and accessible to all market participants and is known to be certain (i.e. not conditional on any outstanding application or competition) at the time of application must be included either as a reduction of OPEX in the Levelised Cost methodology or as an Operational benefit in the Reference plant model.

[12] https://ec.europa.eu/eurostat/tgm/table.do?tab=table&init=1&language=en&pcode=tec00118&plugin=1

[13] While terminal value would normally have a bearing on per unit cost or NPV, terminal value is actually not taken into account for LCOE or in project finance models.

On the other hand, any public support that is related to support the capital or operating expenditures of the project itself (i.e. that which is either conditional or uncertain and not known at the time of application and unique to the project) will not enter the calculation of the relevant costs. However, such public support needs to be counted as “other contributions” in the meaning of Article 11(1)(e) of the Innovation Fund Regulation for the purposes of the calculation of the cost efficiency criterion.

#### 4.1.2.13 OPEX adjustment

The default adjustment is based on the assumption that the relative share of OPEX in total costs is equal between the project and conventional technologies. While this will be a good approximation, the relative share of OPEX may in some cases significantly differ between the project and conventional technologies, and introduce an inconsistency in the calculation. In such cases, the applicant should verify the effect of the NPV of the difference between the OPEX of the project and of the pre-dominant conventional technology for the remaining lifetime after 10 years of operation. In case of a significant impact on the relevant costs, given a reliable estimate of the OPEX for the pre-dominant conventional technology, a more detailed calculation should be applied for the OPEX adjustment.[14]

## 4.2 Electricity storage methodology

### 4.2.1 Principles

Electricity storage technologies can be used in numerous applications or ‘use cases’ offering different services to different components of the electricity system. Different regulatory treatments, availability of commercial service requests and technical requirements across Member States determine the applicability of use cases. For example:

- Pumped hydro and underground compressed air energy storage are characterised by relatively slow response times (>10 seconds) and large minimum system sizes (>5 MW). Therefore, they are ill suited to fast response applications such as primary response and power quality and small-scale consumption applications.
- Flywheels and supercapacitors are characterised by short discharge durations (<1 hour) and are not suitable for applications requiring longer-term power provision.
- Seasonal storage requires power provision for months which is a requirement that can only be met by technologies where energy storage capacity can be designed fully independent of power capacity.

An electricity storage project proposed for support under the IF will envisage a specific ‘use case’ within the country in which it is implemented. This will in turn determine the nature of the services to be provided and the extent to which these services can be rewarded in that market; it will also affect the Levelised Cost of Storage (LCOS) of the ‘use case’. Therefore, LCOS comparisons should always be application (use case) specific.

[14] This effect will be amplified where the project has a very different cash flow profile to that of the comparable technology (i.e. a very high CAPEX, low OPEX compared to Very low CAPEX and High OPEX and the reverse), and the project carries a far higher WACC than the conventional technology would bear.

Lazard publishes a LCOS survey each year which examines the different use cases for each type of existing storage application and offers a number of examples for markets around the world[15]. The Universe of use cases proposed by Lazard is presented in Figure 4.2:

Figure 4.2 Summary of Energy Storage Use Cases

| | | | Use Cases | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | Description | Wholesale | Transmission & Distribution | Wholesale (PV + S) | Commercial (Standalone) | Commercial (PV + S) | Residential (PV + S) |
| A Wholesale | Demand Response—Wholesale | Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand | | | | ☐ | ☐ | ☐ |
| A Wholesale | Energy Arbitrage | Storage of inexpensive electricity to sell later at higher prices (only evaluated in the context of a wholesale market) | ☐ | ☐ | ☐ | | | |
| A Wholesale | Frequency Regulation | Provides immediate (four-second) power to maintain generation-load balance and prevent frequency fluctuations | ☐ | ☐ | ☐ | ☐ | ☐ | |
| A Wholesale | Resource Adequacy | Provides capacity to meet generation requirements at peak loading | ☐ | ☐ | ☐ | ☐ | ☐ | |
| A Wholesale | Spinning/ Non-Spinning Reserves | Maintains electricity output during unexpected contingency a short period of time (non-spinning reserve) events (e.g., outages) immediately (spinning reserve) or within | ☐ | ☐ | ☐ | ☐ | ☐ | |
| B Utility | Distribution Deferral | Provides extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding distribution system investment | | ☐ | | | | |
| B Utility | Transmission Deferral | Provides extra capacity to meet projected load growth for the purpose of delaying, reducing or avoiding transmission system investment | | ☐ | | | | |
| B Utility | Demand Response—Utility | Manages high wholesale price or emergency conditions on the grid by calling on users to reduce or shift electricity demand | | | | ☐ | ☐ | ☐ |
| C Customer | Bill Management | Allows reduction of demand charge using battery discharge and the daily storage of electricity for use when time of use rates are highest | | | | ☐ | ☐ | ☐ |
| C Customer | Backup Power | Provides backup power for use by Residential and Commercial customers during grid outages | | | | ☐ | ☐ | ☐ |

*Source: **Lazard (2019)***

The LCOS electricity storage methodology has been specifically developed for standalone storage facilities providing specialist services of storage only. It can take account of the different types of business cases for electricity storage: multiple services are able to be inputed, based on revenue 'stackability', thereby avoiding any limitations in the relevant costs calculations and creating a more realistic assessment.

If an energy-intensive industry project incorporates storage stoppage which provides, for example, some heat and electricity to the project, it will represent an increased CAPEX but will reduce the OPEX (energy costs) of that project calculation. Consequently, applicants for such a project would use the LCOP approach. If the project is designed to also operate electricity services then it should be regarded as a discrete project and will follow the LCOS methodology.

## 4.2.2 Detailed approach

The LCOS methodology is unique to electricity storage and follows a similar methodology to that applied in the product based LCOE/LCOP approaches. However, because electricity storage technologies can be used in numerous applications covering the entire electricity supply chain, it is applied differently and therefore forms a unique relevant costs approach in its own right.

Revenue streams from different technologies and applications vary enormously according to the following factors:

[15] Most recently, Lazard's Levelised Cost of Storage Analysis – Version 5.0, November 2019. Available at: https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf [Accessed 20 Feb 2020]

1. Time to dispatch (which will determine the service it can provide);
2. Where the storage is located (i.e. front-of-meter (FTM) or behind-the-meter (BTM)[16];
3. Whether (in the case of FTM) it is serving the wholesale market, it is embedded in the transmission operations addressing local network constraints or a combination of the two which may allow revenue stacking; and,
4. The extent to which the jurisdiction in which it is implemented rewards (or has a market to reward) the specific service that it provides.

The LCOS methodology quantifies the discounted cost per unit of discharged electricity for a specific storage technology and application over the first 10 years of the project. It accounts for all capital and ongoing costs affecting the lifetime cost of discharging stored electricity in order to derive the relevant costs of the project.

For calculation purposes, the LCOS can be described as the total lifetime cost of the investment in an electricity storage technology divided by its cumulative delivered electricity, including financing costs (as per the LCOE/LCOP approach). Note that since terminal costs are not covered by the IF, the end-of-life cost has been excluded (Figure 4.3).

Figure 4.3 IF Relevant Cost LCOS equation without end-of-life costs

$$LCOS\left[\frac{€}{MWh}\right] = \frac{Investment\ cost + \sum_n^N \frac{O\&M\ cost}{(1+r)^n} + \sum_n^N \frac{Charging\ cost}{(1+r)^n}}{\sum_n^N \frac{Elec_{Discharged}}{(1+r)^n}}$$

It is important for applicants to note that the calculation is different both for each use case and for each market.[17] The revenues for each use case differ from country to country, as do the O&M costs for each use case. In calculating their relevant costs, applicants should reflect these differences for their specific installation in their specific regulatory environment.

#### 4.2.2.2 Determining the Reference price

Applicants should also be aware that unlike, for example, the LCOE model for renewable power, the reference price in this electricity storage model is **not** a single external market price. The 'market price' for the LCOS model is derived by using the WACC and the prices for each service achievable in the particular market to determine a breakeven price (i.e. the Cost of Storage per unit) for the unique set of services offered. This derived market price is compared to the actual cost of the innovative technology.

The actual or expected market price for specific services related to storage is used (either as published by the Regulator or as forecast auction prices).

#### 4.2.2.3 Determination of the WACC

As for LCOE, the determination of WACC is an important component of calculation when determining the LCOS. In order to be consistent with current available LCOS calculations in the

[16] BTM storage installation typically refers to storage connected behind the meter of commercial, industrial or residential consumers, whereas FTM storage is connected to the distribution or transmission network or in conjunction with generation. For the avoidance of doubt, FTM are also metered for utilisation and settlement purposes. However, there are some network specific services (not provided by storage) that are truly not metered (for example, tap stagger).

[17] Use case refers to the combination of services that a single installation might use in a particular market. For example, a 'wholesale' use case might include frequency response, capacity, and demand response.

market, notably that of Lazard, it is suggested that applicants adopt a standard leverage model in order to be comparable when calculating the relevant costs. In this case, leverage is assumed to be 30% debt: 70% equity in the absence of confirmed funding leverage for the project in question.

A standard debt margin for a project such as this should be employed. The default for all electricity storage applications to use is a debt margin of swap rate plus a margin of 450 bps (which is approximately the margin associated with higher risk, but proven technologies in the renewables market[18]). Applicants are free to deviate from this suggested debt margin if well justified.

Equity Cost of Capital will vary from technology to technology, country to country, by currency and must be justified by the applicant based on a relevant reference, publicly available date or recent funding round. It is expected that equity Cost of Capital for electricity storage projects will be in the range of 8-15%, although it could fall out of this range in unique circumstances and Member States. Applicants have to justify any deviation from the default values and to calculate the impact on the relevant costs.

#### 4.2.2.4 Calculating the relevant costs

***Step 1: Definition of use case***

The use case should be justified based on the best estimated revenue streams for the project, i.e. should be based on their best forecast of achievable revenues for each service (based on bid pricing, observed pricing, or regulatory pricing). Where a specific use case is envisaged, but the associated revenue stream is uncertain and there is no market data whatsoever, this service may be excluded from the calculation of benefits.

***Step 2: Calculate LCOS for that specific technology with a specific use case***

As per the LCOE calculation, and following the formula shown in Figure 4.3 above, the LCOS calculation will include:

- CAPEX (the same rules in options 1a and 1b apply);
- OPEX (the same rules in options 1a and 1b apply, although the fuel cost (i.e. the non O&M costs relate to charging instead);
- Market price for each individual service in the use case - here, this is based on each service provided for that specific installation in that specific country;
- Benefits – revenue based on the use cases and firm market prices[19] (this is not used for the LCOS calculation of the IF project, but is used instead to determine the reference price per discharge which is achievable based on the aggregate of the income derived from each market service at its corresponding price);
- The tax rate will be the tax rate of the country in question (required for the calculation of the cost of debt in the WACC calculation for the Levelised Cost and Reference Price calculation);
- The LCOS calculation would also contain certain storage specific elements in the calculations:
  - Depth of discharge
  - Storage efficiency
  - O&M

[18] Based on a sample of transactions reviewed by the contractors

[19] Where this is a market price determined by auction or by competitive process (for example Capacity market, Frequency response, Spinning reserve, Non-spinning reserve – this shall be the average for the last two years)

- Discharges per annum
- Project lifetime

***Step 3: Determine the use case breakeven LCOS based on best estimate market revenue***

This will be the LCOS needed to be achieved, assuming the only revenue was from the use cases (revenue streams) which are envisaged by the applicant and using the same WACC.

***Step 4: Calculate the difference between the two LCOS figures***

This will be the difference between the LCOS per discharge of the applicant's project, and the average market price per discharge market price per discharge realisable at best estimate prices and discharge volumes based on the services provided by this specific installation in its specific market (applicants should refer to the worked example in the Guidance for further information).

***Step 5: Multiple this by the MWh discharged over the project lifetime***

***Step 6: Calculate the percentage of Levelised Cost that the OPEX after 10 years of operation represents***

***Step 7: Subtract this percentage from the total in Step 5***

This will be the Relevant Cost.

## 4.3 Reference Plant methodology

### 4.3.1 Principles

The Reference Plant methodology – designed to be used when a reference unit cost or product price is not available – does not apply in many cases. It is considered therefore to represent a fall-back option when the reference unit cost/price approach (Option 1) simply does not work.

Examples of situations where the Reference Plant methodology may be preferable to a product-based approach includes processes that either generate intermediate or multiple products, which do not have easily establishable market prices, or are illiquidly traded, or are uncertain, or where neither market prices nor substitute products exist whatsoever and internal cost data delivers more reliable results.

The Reference Plant scenario assumes an installation that exactly emits the emissions at the level of the applicable benchmark value (the 'benchmark setter'). This installation will therefore have zero costs under the EU ETS because the emissions for which it has to surrender corresponding allowances are equal to the amount of free allowances it receives under the EU ETS.

Further rules that applicants should adhere to in their choice of Reference plant are shown in the box below.

**Applicants should follow the following rules when considering reference plants:**

***Establishing the type of reference plant to be used for industrial products***

The reference plant should be defined by the product produced, not the sector.

***Choosing the type and location of the reference plant***

The reference plant should be the most widely deployed process in the EU or, if required, globally for producing a given product, i.e. that which is the best in class for each sector and sets the standard. In the first instance it shall always be the benchmark plant under the EU ETS if such a plant exists. This means that applicants should choose their reference plant in the first instance from the Member State where the project is to be located, or else a European installation or, if that does not exist, then internationally. A strong justification will be required for the use of a different plant,

The methodology is based on a formula that examines the difference in CAPEX and the difference in the Net Present Value (NPV) of the operational costs (OPEX) and operational benefits over a 10-year period for both the project and the reference plant:

$$
\begin{aligned}
&Relevant\ costs \\
&= (IF\ project\ investment\ cost - Reference\ Plant\ investment\ cost) \\
&+ (NPV\ of\ IF\ project\ operational\ costs - NPV\ of\ Reference\ Plant\ operational\ costs) \\
&- (NPV\ of\ IF\ project\ operational\ benefits - NVP\ of\ Reference\ Plant\ operational\ benefits
\end{aligned}
$$

In the calculation of the NPV, the level of the applied WACC will differ for the project and the reference plant (see section 4.3.2.1 below for more details).[20]

## 4.3.2 Detailed approach

In the Reference plant model, applicants need to be fully aware of the following key assumptions in order to enable a robust calculation of relevant costs for their project:

- WACC (discount rate);
- Tax rate;
- Plant Operational benefits (i.e. income);[21]
- Plant Operational costs (OPEX);
- Carbon Price;
- Project lifetime; and,
- Indexation/inflation.

### 4.3.2.1 Calculating the WACC

The discount rate to be used for the calculation of the NPV will follow the WACC approach, as set out more fully in Option 1 (see section 4.1.2.3). However, there are key differences in the WACC for the reference plant and the project plant.

***i) Cost of equity for project plant***

The WACC calculation for the project plant shall follow the guidelines set out in section 4.1.2.3. The cost of equity should be based on the default values of company WACC and sector average. An innovation premium could be added but must be justified by the nature of risk of the project, the company's hurdle rate for new investment and in any event be limited by the upper investment bound of 4% set out in the preceding section.

***ii) Cost of equity for reference plant***

The reference plant WACC will follow the guidelines set out in in section 4.1.2.3 with the following differences:

- For renewables projects, the cost of equity shall follow the methodology set out in section 3.1.2.3, but the cost of equity shall be assumed to be (for the purposes of calculation) 2%

[20] Subject to the maximum differences between project and reference scenario, as explained further below.

[21] Product price will be assumed to include Carbon Costs

lower than that for offshore wind[22] (which is used as a baseline cost of equity comparator in the tables presented previously).

- For energy-intensive industrial projects: The cost of equity shall be limited to the company WACC or the sector average.

***iii) Cost of debt***

- For the project plant: Applicants can assume a margin for risk above the base rate[23] as they would be quoted for project finance by a commercial lender (project finance bank). If a reference is not available for the particular technology, a premium over an established technology debt margin can be used.
- For the reference plant: Applicants should make a uniform assumption of 2% above the base rate.

***iv) Leverage***

- For the project plant: Applicants must use whatever achievable debt equity ratio they expect for their plant. In certain cases, for example for higher risk propositions, the new plant might only be able to secure 100% equity.
- For the reference plant: Applicants must assume a uniform debt-to-equity ratio of 70:30.

#### 4.3.2.2 Tax rate

As shown in section 4.1.1, an important aspect of the WACC formula is the determination of the prevailing tax rate which prevails in the country of project demonstration.

#### 4.3.2.3 Plant Operational benefits (i.e. income)

This covers all sources of revenue into the IF project.

Applicants should also review the rules on how to account for public support – see section 4.1.2.12.

#### 4.3.2.4 Plant Operational costs (OPEX)

This covers all operational costs (both fixed and variable) over the lifetime of the project.

#### 4.3.2.5 Carbon Allowances

The treatment of the Carbon Allowance income calculation will be the same as for the LCOP methodology, and applicants should refer to section 4.1.2.6 above for the correct approach.

#### 4.3.2.6 Project lifetime

Applicants should review section 4.1.2.7.

[22] In the Cost of Equity tables presented under Option 1, Offshore Wind is used as a benchmark cost of equity for the calculations. It is assumed that mature technologies will have a cost of equity which is 2% lower than for offshore wind. This is an assumption for calculation purposes, but is deemed robust based on observations of transactions in the period 2015-2020.

[23] Base rate will be the risk-free rate: from the ten-year government bond yield of the country of the project

#### 4.3.2.7 Indexation/inflation

Applicants should review section 4.1.2.8.

## 4.4 Calculations in the absence of a reference product or conventional technology

### 4.4.1 Principles

As noted in Section 1, the Innovation Fund Regulation creates an exception to the use of a reference scenario where conventional production does not exist. This “last-resort” option will apply to very few projects because in most cases it will be possible to identify a reference product or plant based on a conventional technology. In such circumstances, Article 5(1) states that:

> *“the relevant costs shall be the best estimate of the total capital expenditure and the net present value of operating costs and benefits arising during 10 years after the entry into operation of the project.”*

Such projects can therefore use a much simpler relevant cost calculation methodology:

> *Relevant cost = CAPEX + NPV of OPEX – NPV of Operational Benefits*

It is incumbent upon the applicant to justify in detail why it was not possible to apply another methodology. In a situation where the evaluators find that another methodology should have been applied, the project will not receive any points under the cost efficiency criterion.

### 4.4.2 Detailed approach

This methodology derives the relevant costs based on the best estimate of the total capital expenditure and the NPV of operational costs and operational benefits arising over the first ten years of operation.

It mimics the Reference Plant model approach (Option 2), however applicants do not include the Reference plant data.

Under this methodology, the following rules need to be adhered to:

1. Any applicant choosing this methodology cannot use the other methodologies.

2. The discount rate to be used for the calculation of the NPV will follow the WACC approach, set out more fully in Option 1 (see section 4.1.2.3);

3. The approach taken for CAPEX is that it is committed (price wise) in its entirety on day one and therefore does not need to be discounted;

4. Any CAPEX and OPEX must strictly be related to and necessary for the innovative aspects as identified in the award criterion on degree of innovation. CAPEX and OPEX should not be included if they were related to other activities based on conventional technology and not necessary for carrying out the identified innovative aspects. CAPEX and OPEX, which are e.g. related to replacement investments, deployment of conventional technologies, are not to be included in the calculation.

5. Any additional revenues, which are due to the project, are to be included in the calculation. Any applicant needs to justify in detail the scope of the included revenues and costs.

6. As with other methodologies, close attention is required for the treatment of carbon costs and benefits. These must be included as per the rules referred to earlier in this document (see section 4.1.2.6). Specifically, any revenues from the sale of excess allowances must be included in the calculation.

7. Finally, regarding the write down of existing (old) technologies, as with other methodologies, the costs associated with any stranded assets that might arise as a result of a project being supported are not allowable under the relevant costs calculations.

# 5 Appendix 1 – Support with WACC calculations

## A1.1 Reference Market Betas for Industrial project Cost of Equity calculation

| European Market Sector Betas | | |
|---|---|---|
| **Industry Name** | **Number of firms** | **Beta** |
| Advertising | 84 | 0,90 |
| Aerospace/Defense | 49 | 1,30 |
| Air Transport | 39 | 1,01 |
| Apparel | 124 | 1,04 |
| Auto & Truck | 25 | 1,55 |
| Auto Parts | 55 | 1,70 |
| Bank (Money Center) | 122 | 1,31 |
| Banks (Regional) | 69 | 0,50 |
| Beverage (Alcoholic) | 51 | 0,60 |
| Beverage (Soft) | 16 | 0,61 |
| Broadcasting | 23 | 1,23 |
| Brokerage & Investment Banking | 69 | 0,71 |
| Building Materials | 86 | 1,01 |
| Business & Consumer Services | 207 | 1,06 |
| Cable TV | 8 | 1,19 |
| Chemical (Basic) | 53 | 0,92 |
| Chemical (Diversified) | 7 | 1,79 |
| Chemical (Specialty) | 95 | 1,22 |
| Coal & Related Energy | 16 | 1,10 |
| Computer Services | 204 | 1,05 |
| Computers/Peripherals | 38 | 1,44 |
| Construction Supplies | 111 | 1,20 |
| Diversified | 65 | 1,28 |
| Drugs (Biotechnology) | 202 | 1,46 |
| Drugs (Pharmaceutical) | 116 | 1,15 |
| Education | 12 | 1,31 |
| Electrical Equipment | 131 | 1,34 |
| Electronics (Consumer & Office) | 17 | 1,36 |

| | | |
|---|---|---|
| Electronics (General) | 160 | 1,29 |
| Engineering/Construction | 139 | 1,13 |
| Entertainment | 152 | 1,21 |
| Environmental & Waste Services | 49 | 0,97 |
| Farming/Agriculture | 47 | 0,77 |
| Financial Svcs. (Non-bank & Insurance) | 127 | 1,02 |
| Food Processing | 144 | 0,71 |
| Food Wholesalers | 11 | 0,78 |
| Furn/Home Furnishings | 44 | 1,13 |
| Green & Renewable Energy | 48 | 0,92 |
| Healthcare Products | 183 | 1,23 |
| Healthcare Support Services | 46 | 0,98 |
| Heathcare Information and Technology | 93 | 1,12 |
| Homebuilding | 45 | 1,04 |
| Hospitals/Healthcare Facilities | 31 | 0,75 |
| Hotel/Gaming | 109 | 0,97 |
| Household Products | 72 | 0,86 |
| Information Services | 30 | 1,04 |
| Insurance (General) | 45 | 0,91 |
| Insurance (Life) | 20 | 1,20 |
| Insurance (Prop/Cas.) | 16 | 0,76 |
| Investments & Asset Management | 337 | 0,84 |
| Machinery | 214 | 1,31 |
| Metals & Mining | 101 | 1,28 |
| Office Equipment & Services | 26 | 1,19 |
| Oil/Gas (Integrated) | 14 | 1,27 |
| Oil/Gas (Production and Exploration) | 110 | 1,55 |
| Oil/Gas Distribution | 27 | 1,28 |
| Oilfield Svcs/Equip. | 68 | 1,54 |
| Packaging & Container | 51 | 1,11 |
| Paper/Forest Products | 36 | 1,07 |
| Power | 71 | 0,86 |
| Precious Metals | 59 | 1,13 |

| | | |
|---|---|---|
| Publishing & Newspapers | 89 | 0,81 |
| R.E.I.T. | 169 | 0,56 |
| Real Estate (Development) | 60 | 0,79 |
| Real Estate (General/Diversified) | 66 | 0,72 |
| Real Estate (Operations & Services) | 246 | 0,49 |
| Recreation | 59 | 0,83 |
| Reinsurance | 4 | 0,98 |
| Restaurant/Dining | 40 | 0,86 |
| Retail (Automotive) | 25 | 0,82 |
| Retail (Building Supply) | 22 | 1,00 |
| Retail (Distributors) | 112 | 0,90 |
| Retail (General) | 16 | 0,85 |
| Retail (Grocery and Food) | 27 | 0,80 |
| Retail (Online) | 79 | 1,23 |
| Retail (Special Lines) | 72 | 1,08 |
| Rubber& Tires | 8 | 1,26 |
| Semiconductor | 34 | 1,87 |
| Semiconductor Equip | 19 | 2,08 |
| Shipbuilding & Marine | 62 | 1,43 |
| Shoe | 8 | 2,01 |
| Software (Entertainment) | 46 | 1,32 |
| Software (Internet) | 30 | 1,02 |
| Software (System & Application) | 283 | 1,15 |
| Steel | 55 | 1,39 |
| Telecom (Wireless) | 13 | 0,90 |
| Telecom. Equipment | 56 | 1,31 |
| Telecom. Services | 78 | 0,77 |
| Tobacco | 6 | 0,58 |
| Transportation | 37 | 0,96 |
| Transportation (Railroads) | 5 | 0,93 |
| Trucking | 26 | 1,11 |
| Utility (General) | 21 | 0,68 |
| Utility (Water) | 10 | 0,49 |

| | | |
|---|---|---|
| Total Market | 6702 | 1,06 |
| Total Market (without financials) | 5897 | 1,08 |

*Source: Damadoran Columbia University 2020*

## A1.2 Equity Risk premium by country

| **Equity Risk premium by country** | |
|---|---|
| **Country** | **Total Equity Risk Premium** |
| Croatia | 8,16% |
| Czech Republic | 5,80% |
| Estonia | 5,89% |
| Hungary | 7,37% |
| Latvia | 6,38% |
| Lithuania | 6,38% |
| Poland | 6,04% |
| Romania | 7,37% |
| Serbia | 8,75% |
| Slovakia | 6,04% |
| Slovenia | 6,77% |
| Austria | 5,59% |
| Belgium | 5,80% |
| Cyprus | 8,16% |
| Denmark | 5,20% |
| Finland | 5,59% |
| France | 5,69% |
| Germany | 5,20% |
| Greece | 9,64% |
| Iceland | 6,04% |
| Ireland | 6,04% |
| Italy | 7,37% |
| Luxembourg | 5,20% |
| Malta | 6,04% |
| Netherlands | 5,20% |
| Norway | 5,20% |
| Portugal | 7,37% |

| | |
|---|---|
| Spain | 6,77% |
| Sweden | 5,20% |
| Switzerland | 5,20% |

*Source: Damadoran 2020*

## A1.3 Innovation premium benchmarks for Cost of equity Calculations

The Innovation premium is based on observed Small Cap equity risk premia observed in three studies:

Figure A1.1 Small Cap Equity premia across three studies

| Company size | Premium |
|---|---|
| Large companies USD 3,322m < | 0.00% |
| Mid-cap companies USD 774m-USD 3,321m | +1.04% |
| Low-cap companies USD 202m-USD 773m | +1.75% |
| Micro-cap USD 201m < | +3.47% |

*Source: Ibbotson Associates 2015*

| Company size | Premium |
|---|---|
| Market cap USD 1,400m < | 0.00% |
| Market cap USD 845m-USD 1,400m | +1.6% |
| Market cap USD 449m-USD 844m | +2.0% |
| Market cap USD 210m-USD 448m | +2.5% |
| Market cap USD 109m-USD 209m | +4.0% |

*Source: Duff & Phelps 2016 Valuation Handbook*

| Company size | Premium |
|---|---|
| Market cap USD 1,001m < | 0.0% |
| Market cap USD 501m-USD 1,000m | 0.0% |
| Market cap USD 251m-USD 500m | 0.9% |
| Market cap USD 101m-USD 250m | +1.4% |
| Market cap USD 51m-USD 100m | +3% |
| Market cap USD 50m < | +5% |

*Source: KPMG (Australia) study 2017 on Small Cap premia*