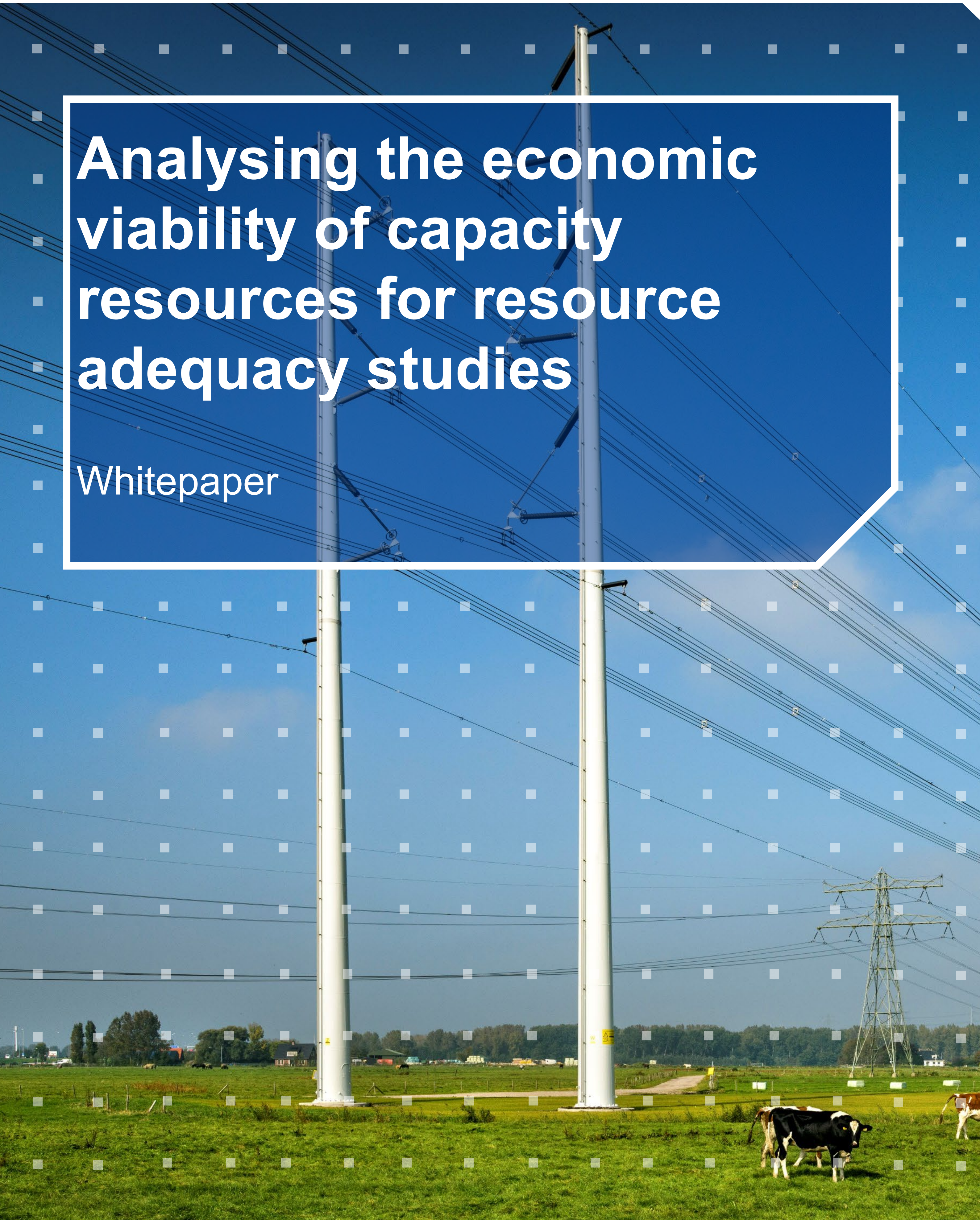
# Analysing the economic viability of capacity resources for resource adequacy studies

Whitepaper



# Analysing the economic viability of capacity resources for resource adequacy studies

## Whitepaper

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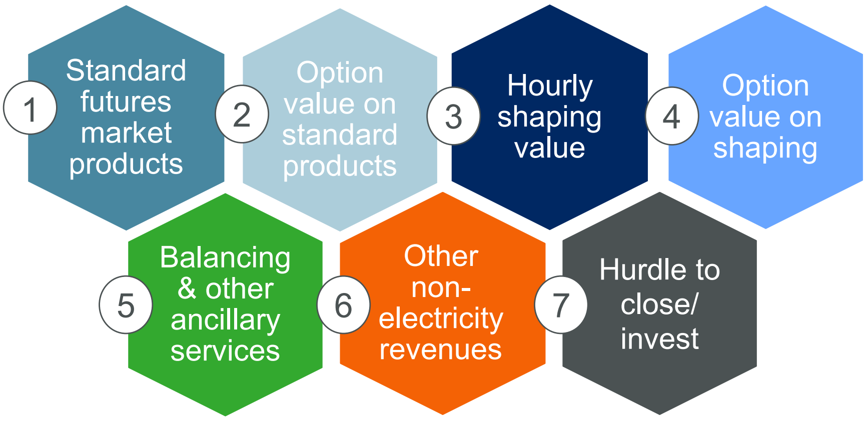
# Summary

Ensuring a reliable power system means having sufficient power plants and other firm capacity resources in the system to keep the lights on at all times. Transmission System Operators such as TenneT assess the electricity resource adequacy by simulating the future power system based on assumptions of how much capacity will be available to meet demand. However, power plants and other capacity resources must have a viable business case to exist: if not, existing plants may retire, and new ones will not be built. Thus, being able to perform robust economic viability analysis of power plants can be a useful tool for checking the plausibility of future power system scenarios, and help in identifying potential risks to resource adequacy in the medium to long term.

In this whitepaper, TenneT presents a new framework for assessing the economic viability of different types of capacity resources. This framework is based on seven key value drivers which encompass the full value capacity resources can derive from markets across all timeframes (e.g. forwards, day ahead, intraday, ancillary services, balancing), additional non-electricity based revenues, as well as the hurdles for retiring or investing in new capacity. With some real-world examples we 'map' our model on practical ways of working in utilities and outline several approaches to quantify the different value drivers.

A key feature of this framework is that it includes extrinsic value, or the additional value that can be derived from an asset as a result of prices for power, fuel and carbon changing over time. Extrinsic value is a crucial economic driver for flexible at-the-money plants such as modern gas-fired power plants, and can represent up to ~50% of the total plant value. While extrinsic value is less well known and more complex to quantify than intrinsic value, this paper identifies several ways it can be done and incorporated into economic viability analysis.

The proposed value driver framework will be progressively applied in future editions of the Dutch national resource adequacy assessment: the *Monitoring Leveringszekerheid*. TenneT welcomes feedback on this whitepaper which will be used to further refine and develop the methodology over the coming years.


1
Standard futures market products
2
Option value on standard products
3
Hourly shaping value
4
Option value on shaping
5
Balancing & other ancillary services
6
Other non-electricity revenues
7
Hurdle to close/ invest

*Seven key value drivers for economic viability*

# Abbreviations

| | |
|---|---|
| ACER | European Union Agency for the Cooperation of Energy Regulators |
| CAPEX | Capital Expenditure |
| CCGT | Combined Cycle Gas Turbine |
| CHP | Combined Heat and Power |
| CRM | Capacity Remuneration Mechanism |
| Cal | Calendar year |
| DSR | Demand-Side Response |
| EPEX | European Power Exchange |
| EEX | European Energy Exchange |
| ENTSO-E | European Network of Transmission System Operators for Electricity |
| ERAA | European Resource Adequacy Assessment |
| EU | European Union |
| EUA | EU (carbon) Allowances |
| EVA | Economic Viability Assessment |
| FCR | Frequency Containment Reserve |
| FIP | Feed-in Premium |
| FLH | Equivalent Full-Load operating Hours |
| FOM | Fixed Operating & Maintenance |
| FRR | Frequency Restoration Reserve |
| GoO | Guarantees of Origin |
| HHV | Higher Heating Value (i.e., Gross calorific value) |
| HV | High voltage |
| ICE | Intercontinental Exchange |
| IRR | Internal Rate of Return |
| MLZ | Monitoring Leveringszekerheid |
| MME | Major Maintenance Event |
| NPV | Net Present Value |
| NRA | National Regulatory Authority |
| OCGT | Open Cycle Gas Turbine |
| PPA | Power Purchase Agreement |
| PV | Photovoltaic |
| RES | Renewable Energy Source |
| RFNBO | Renewable Fuel of Non-Biological Origin |
| SDE | Stimulering Duurzame Energieproductie en Klimaattransitie |
| TSO | Transmission System Operator |
| UCED | Unit Commitment and Economic Dispatch |
| VOM | Variable Operating & Maintenance |
| WACC | Weighted Average Cost of Capital |

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# 1. Introduction and background

Resource adequacy of the electric power system is the ability of the capacity resources in the power system to meet the demand for electricity at all times at a price that consumers are willing to pay.[1] Whether the power system is adequate or not is the result of a long and complex chain of investment, operational and trading decisions which begins years before the actual delivery of electricity takes place, and continues up until real time. As nominated Transmission System Operator (TSO) for the Netherlands, TenneT can only fulfil its task of keeping the system balanced in the short term if there are sufficient capacity resources available in the system from flexible power plants, batteries, cross-border transmission capacity, and Demand-Side Response (DSR) to satisfy the demand for electricity, as well as additional spare capacity for balancing reserves. For this reason, TenneT conducts resource adequacy assessments such as the *Monitoring Leveringszekerheid* (MLZ) and the *European Resource Adequacy Assessment* (ERAA) to monitor the expected demand and supply situation in the coming years and identify where there may be potential risks to resource adequacy (Figure 1).[2] On the basis of these results national policymakers may decide to take action, such as implementing electricity market design reforms, to ensure the target reliability standard is met.[3]

## 1.1 Why is economic viability important for resource adequacy?

Resource adequacy assessments like the MLZ and ERAA are based on a set of future expectations or *scenarios* of how the demand and supply of electricity will develop over time. These scenarios are constructed by TSOs on the basis of historical trends, national energy and climate policies, and data collected from power plant operators on expected retirements and investments in generation capacity. However, a major uncertainty in resource adequacy assessments is whether the capacity resources TSOs assume in their scenarios will actually be operational or not. For example, power plants which are profitable in the market now may become unprofitable as a result of changing market conditions and be closed down. At the same time, the future

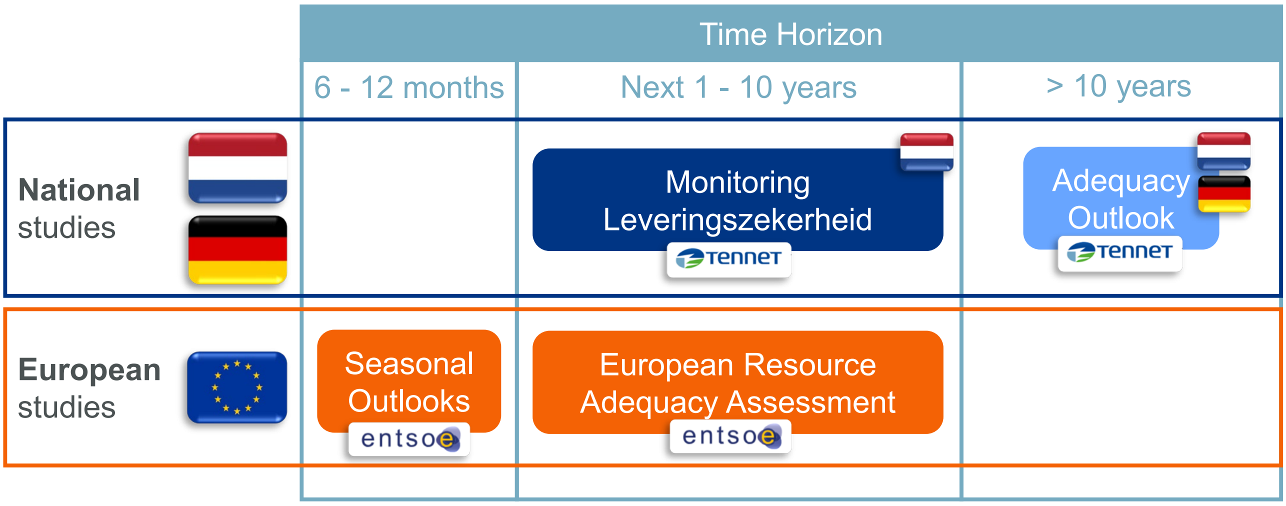

*Figure 1 | Overview of resource adequacy assessments performed by TenneT alone, and European level studies performed together with other TSOs as part of the Europan Network of Transmission System Operators for Electricity (ENTSO-E). Note that TenneT does not perform national adequacy assessments for Germany, as this responsibility lies with the Bundesnetzagentur.*

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[1] While the terms *resource adequacy* and *security of supply* are sometimes used interchangeably, in this paper we use the former to be consistent with the Electricity Regulation and the ERAA methodology [3], and because resource adequacy has a more specific definition as a key component (together with transmission adequacy) of overall system adequacy. Resource adequacy can be considered an element of the broader concept of security of supply, which can also include other aspects e.g., reliable access to affordable fuels.

[2] TenneT also performs additional ad-hoc resource adequacy studies to explore the impact of additional policy measures such as early closure of Dutch coal plants, or the requirements for a reliable net-zero emission energy system in the Adequacy Outlook.

[3] The reliability standard is the target level of resource adequacy. ACER decision 23/2020 explains how this should be calculated as a trade-off between the cost of capacity and the economic cost to society of unsupplied energy [29].

investments TSOs assume in new power plants, batteries and DSR may not take place if the business case is not strong enough, investment risks are too high, or other policy (e.g. permitting) barriers exist. Both of these cases – earlier than expected retirement and overestimation of future installed capacity – may lead TSOs to overestimate the level of future resource adequacy. The energy transition is also presenting new challenges and uncertainties for the power system such as additional demand due to electrification (of industry, heating and transport), accelerating deployment of renewable energy sources (RES), and more volatile prices. For all of these reasons, analysing the economic viability of capacity resources is having an increasingly important role in resource adequacy assessments.[4]

## 1.2 What is economic viability assessment (EVA)?

Economic viability assessment (EVA) is defined in the ERAA methodology as *"a model assessing the profitability of capacity resources, informing decisions on retirement, mothballing and re-entry, renewal/prolongation and new-build of [a] capacity resource"*, where a *capacity resource* means any generation, storage or DSR asset which makes a positive contribution to resource adequacy.

There are two main approaches to perform EVA in resource adequacy assessments. For example, the ERAA methodology states that economic viability should be assessed by comparing the estimated revenues with the estimate costs of each capacity resource expected in the analysed time frame (Figure 2) [1]. Another approach is to perform an optimisation which minimises the total costs of the power system in order to meet demand, balancing the costs of retiring and investing in capacity resources against the costs of unmet demand.[5] When performing EVA for their own assets, market parties also use other methods for power plant valuation such as discounted cash-flow analysis, risk-based approaches, and real option theory ( [2], [3], [4]).

## 1.3 The relevance of EVA for capacity remuneration mechanisms

Capacity remuneration mechanisms (CRMs) are measures aimed at ensuring the reliability standard of a country is reached by remunerating capacity resources for their expected availability during shortages, in addition to the revenues they receive from other market-based sources. CRMs are designed to bridge the expected revenue gap or 'missing money' which is needed to retain (or attract) sufficient capacity on the market

**Revenues**

- **Wholesale electricity markets**
  - Forwards and futures markets
  - Day-ahead market
  - Intraday market
- **Other electricity-related services**
  - Balancing (capacity and energy)
  - Other ancillary services
- **Services outside the electricity sector**
  - Heat/steam
- **Subsidies**
- **Capacity remuneration mechanisms (CRMs)**

**Costs**

- **Variable costs**
  - Fuel costs
  - Carbon costs
  - Variable operating & maintenance (VOM) costs
- **Fixed costs**
  - Fixed operating & maintenance (FOM)
  - Investment (capital) costs (CAPEX)

*Figure 2 | Overview of the main revenue and cost categories which should be considered as part of an EVA (based on Article 6.9 of the ERAA methodology [3])* to achieve the target level of resource adequacy. If an EVA performed as part of a resource adequacy assessment (e.g. a national assessment or the ERAA) shows that the reliability standard of a country would not be met because economically unviable capacity is in danger of retiring and/or new investments are not viable, this could justify the introduction of a national CRM. If EVA is used to assess the viability of capacity resources on the basis of estimated revenues and costs, it is important that the EVA methodology accounts for all key revenue and cost streams for all technologies, and estimates these as robustly as possible.

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[4] Pursuant to Article 23(5)(b) of the Electricity Regulation, performing an economic viability assessment has also become a mandatory step within the ERAA [2].

[5] According to Article 6(6) of the ERAA methodology this system cost based approach is considered a simplification, and has been applied by ENTSO-E in each edition of the ERAA published to date. The two approaches each have their strengths and weaknesses [45], rely on certain assumptions and preconditions, and whether they are completely equivalent in all cases is a matter of debate.

- If revenues (costs) are *overestimated* (underestimated), the EVA may overestimate how much capacity in the system is economically viable, ultimately leading to an overestimation of resource adequacy. If plants retire early and/or new investments do not keep pace with (growing) electricity demand as expected, this could lead to resource adequacy problems and significant economic loss if the TSO must shed some consumer load in critical hours when supply is short to keep the system in balance. As the social cost of involuntary load shedding is estimated to be very high, potentially in the range of 10,000 €/MWh to 70,000 €/MWh [5], earlier introduction of a CRM with enough time to ensure sufficient investments may lead to lower costs for society in the long run.[6]

- If revenues (costs) are *underestimated* (overestimated) and a CRM is in place (or being considered), the volume of capacity contracted under a CRM may be too high, or perhaps a CRM could be implemented when it’s really not necessary. As CRMs are paid for by consumers in their fixed grid connection charges, an unnecessary or over-dimensioned CRMs will increase costs to final consumers with limited benefit for resource adequacy. With the total cost of CRMs across the European Union (EU) expected to reach €7.4 billion in 2023 (up from €5.2 billion in 2022) it is important to ensure these schemes – where necessary – mitigate the resource adequacy risks they’re designed to address in a cost-effective way [6].

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[6] Fundamentally, a CRM is about trading off costs and risks, and can be thought of a bit like insurance. Introducing a CRM increases the cost of capacity with 100% certainty to reduce the risk and costs of involuntary load shedding by an expected amount. If the cost of a CRM outweighs the (risk-weighted) expected reduction in potential load shedding costs in the long term it’s most likely worth it, but you’ll never know for sure.

## 1.4 Aims and structure of this whitepaper

Given the increasing importance of EVA in resource adequacy studies TenneT, with the support of GLEAM Consultancy & Management, has developed a framework for analysing the high-level economic viability of different types of technologies. This framework is based on the identification of several key value drivers for capacity resources, and methodologies for quantifying these value drivers based on transparent market data. By incorporating elements of other EVA approaches applied in industry such as real option theory, this framework considers not only the intrinsic value of capacity resources, but also the *extrinsic* value.

Targeted at experts at national and EU level such as policymakers, regulators, market parties and other TSOs, this whitepaper aims to:

- explain the identified value drivers and their relevance for different types of capacity resources,
- propose methods for how these value drivers can be quantified,
- explain how the value drivers from our framework correspond to practical ways of working in utilities,
- outline how these value drivers can be used to perform EVA, and
- provide a basis for further discussion on economic viability assessment in the context of resource adequacy.

The rest of this paper is structured as follows:

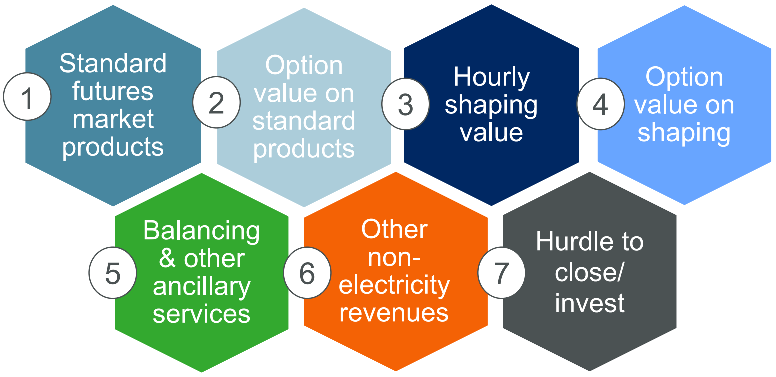
- Chapter 2 explains each of the key value drivers underlying the economic viability of capacity resources with some simple examples showing how each driver can be quantified.
- Chapter 3 explains how these value drivers can be used to perform EVA.
- Chapter 4 reflects on how the proposed methodology could be further developed and applied.

TenneT welcomes questions, comments and feedback regarding the value drivers and EVA framework, which can be sent to servicecenter@tennet.eu.

# 2. Key value drivers for capacity resources

Our EVA framework is based on an assessment of seven key value drivers for capacity resources (Figure 3):

1) value from *standard futures market products,*
2) value from the *optionality value on standard products,*
3) net value from *hourly shaping*,
4) value from the *optionality value on hourly shaping,*
5) net value from *balancing markets and other ancillary services,*
6) value from *other non-electricity revenues*, and
7) *hurdle to close/invest*.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Standard futures market products
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7
Hurdle to close/ invest

*Figure 3 | Seven key value drivers for economic viability*

At high level, value drivers 1 to 5 correspond to the total potential value which can be derived from the so-called 'energy-only' electricity markets across all timeframes including exchange-traded futures and forwards markets, day-ahead spot and intraday markets, as well as real time balancing and ancillary services markets. Driver 6 is the additional value capacity resources can capture from sources outside the energy-only electricity markets, such as the sale of heat or (renewable) Guarantees of Origin. Driver 7 is less tangible than the others and encompasses all potential hurdles to retiring existing capacity from the market or investing in new capacity.

While many readers familiar with electricity markets will directly recognise drivers 1, 3, and 5, drivers 2 and 4 may be less intuitive to non-traders as these represent *extrinsic* power plant value. While extrinsic value may be less well known, it is very relevant for power plant owners. We explain extrinsic value and drivers 2 and 4 in detail later (sections 2.2 and 2.4), but to lay the groundwork it is first important to distinguish and understand three main types of contracts in the power market (Figure 4):

(i) *Tradable standard products*. These are highly standardised contracts traded on power exchanges or bilaterally 'Over the Counter'. For example, a '1 MW Dutch base load Cal-2025' contract is easy to buy and sell because if a company buys this product on the exchange, they know they can sell exactly the same product back to the exchange (or to another counterparty) without any contract negotiations, as there is no ambiguity in the product.

(ii) *Single-Buyer Standardised contracts*. Like exchange traded products these are also standardised contracts, but as there is only one buyer – usually the TSO – these products cannot be traded. Some examples are the ancillary services that TSOs buy from market parties such as balancing contracts, or black start capacity. In most single buyer contracts the TSO buys optionality, i.e., the right but not the obligation to have power injected/withdrawn from the grid.

(iii) *Non-standardised contracts.* These are contracts with tailor-made conditions such as a 15-year offshore wind Purchase Power Agreement (PPA), a tolling agreement for a power plant, or a full supply contract a retail company closes with a household.[7] These contracts are tailor-made and company specific because they contain significant optionality. For example, a full supply contract to a household can result in supplying 4 MWh/y, or 8 MWh/y or 1 MWh/y. Thus, if supplier 'X' wants to sell its full supply contracts to another supplier 'Y', additional negotiations and analysis will be required. PPAs on the other hand usually include exactly how risks/costs are allocated between the seller and the buyer.

As single-buyer and non-standardised contracts come with a lot of optionality, prudent risk management on the part of retailers and utilities requires them to have a strategy for managing this optionality by either owning their own assets, actively trading standard futures products, or buying contracts which provide them flexibility. There is hence lots of optionality value in the power system and a significant part of this optionality value is earned by (flexible) capacity owners either via the traded markets, tailor-made flexibility contracts, or intercompany sales. See Box 1 for a more detailed explanation of how optionality arises from the retail sector. An overview of the seven value drivers summarising how they are derived from the various electricity markets is shown in Figure 5. The rest of the sections in this chapter explain each of the seven value drivers in detail.

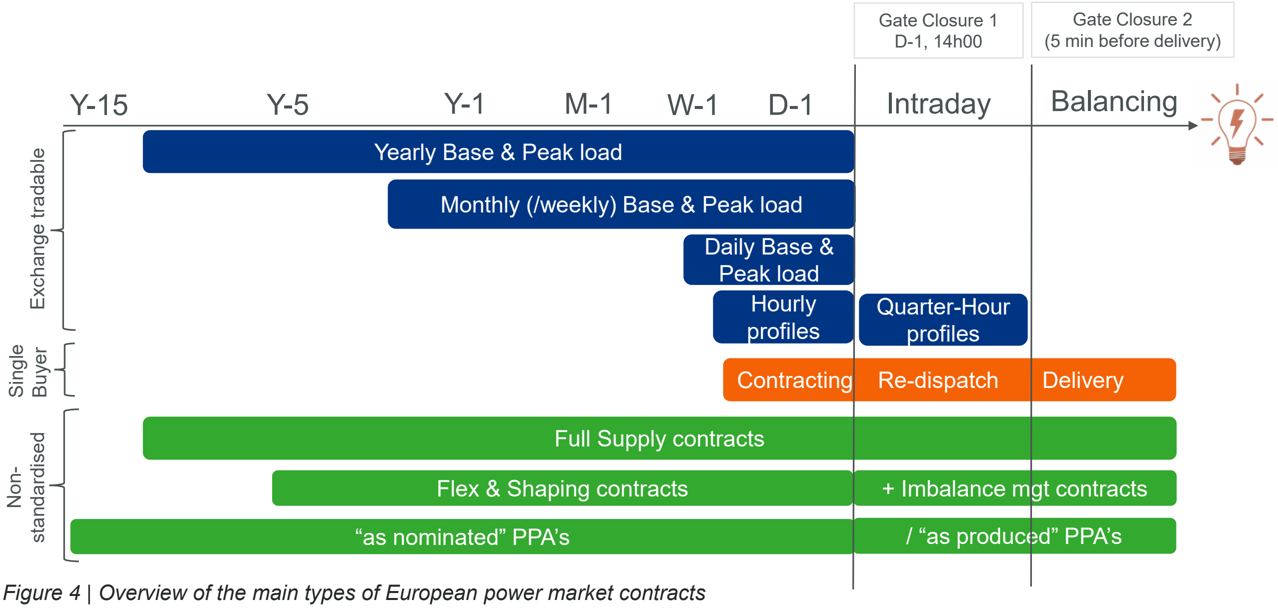
Gate Closure 1
D-1, 14h00
Gate Closure 2
(5 min before delivery)
Y-15
Y-5
Y-1
M-1
W-1
D-1
Intraday
Balancing
Exchange tradable
Single Buyer
Non-standardised
Yearly Base & Peak load
Monthly (/weekly) Base & Peak load
Daily Base & Peak load
Hourly profiles
Quarter-Hour profiles
Contracting
Re-dispatch
Delivery
Full Supply contracts
Flex & Shaping contracts
+ Imbalance mgt contracts
"as nominated" PPA's
/ "as produced" PPA's

*Figure 4 | Overview of the main types of European power market contracts*

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[7] Under a tolling agreement the buyer pays the seller an agreed amount (i.e. a toll) to generate electricity from a power plant. The buyer is responsible for providing the fuel (if any), while the seller is responsible for operating and maintaining the asset.

| Timeframe | Years ahead (YA) | Months ahead (MA) | Weeks ahead (WA) | Days ahead | Day-ahead (DA) | Intraday (ID) | Real time |
|---|---|---|---|---|---|---|---|
| Trading focus | Build portfolio (with PPAs, sales contracts, assets etc.) and manage position on forward markets | | | | Optimise position on day-ahead and balancing capacity markets | Optimise position post day-ahead closure | Optimise on FRR/imbalance |
| | Trade around yearly spread | Trade around monthly spread | Trade around weekly spread | Trade around daily spread | | | |
| Potential (trading) activities and value drivers | 1 Sell yearly base/peak power, buy fuel (and carbon) if spread > acceptable level (e.g. 10 €/MWh)<br>2 Buy back power (sell fuel and carbon) if spread falls (e.g. 4 €/MWh), and sell base/peak power again if spread goes up<br>2 3 4 If have a long position (e.g. own assets), sell optionality e.g. call options, tolling agreements etc.<br>*N.b. If have a short position (e.g. retail contracts), buy optionality* | 1 If have not sold YA, sell months with positive spread<br>2 If have sold YA, buy back months with low/negative spread | 1 If have not sold MA, sell weeks with positive spread<br>2 If have sold MA, buy back weeks with low/negative spread | 1 If have not sold WA, sell days with positive spread<br>2 If have sold WA, buy back days with low/negative spread | 3 For hours with futures/forward contract for delivery, buy back DA where spread < 0 €/MWh<br>3 For hours with no futures/forward contract for delivery, sell DA for hours with spread > 0 €/MWh<br>3 4 For hours where forward delivery cannot be met, (e.g. RES forecast error, outage) buy on DA market<br>5 4 If FCR/FRR capacity price for next day is > spread (and > 0), sell FCR/FRR capacity and buy back DA | 4 If hour sold on DA, buy back hour/ ½-hour/ ¼-hour products if spread < 0 €/MWh<br>4 If hour not sold on DA, sell hour/ ½-hour/ ¼-hour products if spread > 0 €/MWh | 5 If ¼-hour sold on ID, buy back if spread < 0 €/MWh<br>5 If ¼-hour not sold on ID, buy back if spread > 0 €/MWh<br>5 Net imbalance payments *(being on 'right' side of imbalance is positive, being on 'wrong' side of imbalance is negative)* |
| Other drivers | 5 Revenue from other ancillary services (e.g. black start, redispatch)<br>6 Additional revenues from:<br>• sale of heat/steam<br>• sale of Guarantees of Origin (GoO)<br>• government subsidies<br>• capacity remuneration mechanisms (CRMs) | | | | 7 For *existing plants*, hurdles to close e.g.:<br>• value of grid connection<br>• compensation for forced closure<br>• unexpected positive change in market climate<br>7 For *new investments*, hurdles to invest e.g.:<br>• investment risk | | |

*Figure 5 | Overview of the value driver framework for performing EVA and how this value originates from different markets over time*

## Box 1 Flexibility, uncertainty and optionality in the retail sector

Throughout this paper you will regularly come across the term *optionality*, as it is strongly tied to the extrinsic value of power plants. Optionality is a term that should be familiar to energy traders, but can be unfamiliar to those who are not actively participating in the electricity wholesale markets. Optionality can be understood as analogous to the more commonly used term *flexibility*, and can in many cases be used interchangeably. Because this paper focuses on the (business) economic side of the power system, we prefer to use optionality.

Where flexibility generally refers to the ability of the physical assets in the power system to deal with the variability and uncertainty in the system, optionality can be understood as the ability of an energy trader to deal with variability and uncertainty within their portfolio. The risk associated with having insufficient flexibility in the power system is the risk that the system might be unable to cope with unexpected events, potentially requiring the TSO to curtail some consumer demand to ensure system stability. For a trader, the risk associated with insufficient optionality is a financial one, as potential imbalances in a trader's portfolio increase exposure to the risk of high imbalance prices.

A trader representing (mainly) electricity consumers is generally short on optionality, as a retail contract with an electricity supplier has a lot of optionality built into it for the consumer. For example, your household energy contract allows you to consume electricity whenever and in whatever quantity you like, probably for a fixed tariff. However, this freedom in consumption creates significant *uncertainty* for your energy supplier who needs to buy (or generate) electricity on your behalf from the market, and bear all the resulting price and volume risk. Even a consumer with a dynamic hourly tariff will only be charged the hourly day-ahead price, and the volume still poses an imbalance risk for the supplier. As a result, through the retail contract, the supplier faces significant risk and will be short on optionality. *(Conversely, a consumer can be thought of as buying optionality through the retail contract)*

In order to mitigate (hedge) these risks, a retail trader needs to ensure sufficient optionality in their portfolio. This can be achieved by owning their own flexible assets, or buying this optionality from other market parties with contracts such as options (see Box 4) or tolling agreements. Where the traders representing the consumer side of the market are generally short on optionality, traders on the producer side will be *long* on optionality. They can create value from the optionality they have available in their portfolios (even when they are not actively producing) by entering into hedging contracts with parties that are short on optionality. Like flexibility, different assets or contracts can provide optionality for different timeframes. For example, owning a coal-fired power plant might give you optionality for the following day, but it might not be able to ramp up quickly enough to provide optionality for the following hour. Similarly, a power option will have an expiry date, after which it cannot be exercised anymore. Together with market volatility and changing expectations over time, this is the source of the extrinsic value represented by value drivers 2 and 4.

It's important to realise that optionality and risk are two sides of the same coin: for parties long on flexibility (e.g., flexible asset owners) it’s an upside revenue, while for parties short on flexibility (e.g., retailers) it’s a downside cost. Ultimately, the costs of optionality are borne by electricity consumers through mark-ups in their retail contracts. Traders representing RES plants are also generally short on optionality due to the uncertainty with renewable production forecasting, and can be willing to enter into contracts in order to mitigate these risks.

## 2.1 Standard futures market products

While the day-ahead market is considered the key reference market for electricity in Europe, most electricity by far is traded on the futures (and forwards) markets. Value driver 1 refers to the value a plant can derive from selling its output on futures and forward markets, sometimes referred to as *tradable intrinsic value* [7]. To explain this driver, we first need to cover some basic electricity market concepts. Readers already familiar with topics such as base and peak load futures contracts, spreads and hedging can skip through to section 2.2

Electricity futures are contracts to deliver (or consume) a certain volume of electricity at a certain time in the future, for a price agreed upon today. Futures are relatively simple standardised contracts that are traded on power exchanges such as the European Energy Exchange (EEX) or Intercontinental Exchange (ICE). [8] There are currently two main kinds of standard power futures contracts traded on European power exchanges: (i) *base load* power; an obligation to deliver a fixed volume of electricity continuously across a defined maturity period (i.e. 24/7 operation), and (ii) *peak load* power; an obligation to deliver electricity between 8:00 and 20:00 on weekdays only. Both contract types are available with longer-term maturities (e.g., calendar year, quarter, month) as well as shorter-term maturities (e.g. week, day). The value of a futures contract for an asset is determined by the available *spread*: the difference between the wholesale price of electricity and the amount it would cost a power plant to generate the electricity.[9] For a thermal plant the generation cost depends primarily on the cost of the fuel, its efficiency, and the cost of purchasing EU carbon emission allowances (EUA) to cover any carbon dioxide ($CO_2$) emissions (Figure 6). Thus, the spread indicates the gross margin a plant could expect from selling its electricity after variable generation costs are taken into account: a positive spread indicates the plant would make money on a trade, while a negative spread indicates the plant would lose money.[10]

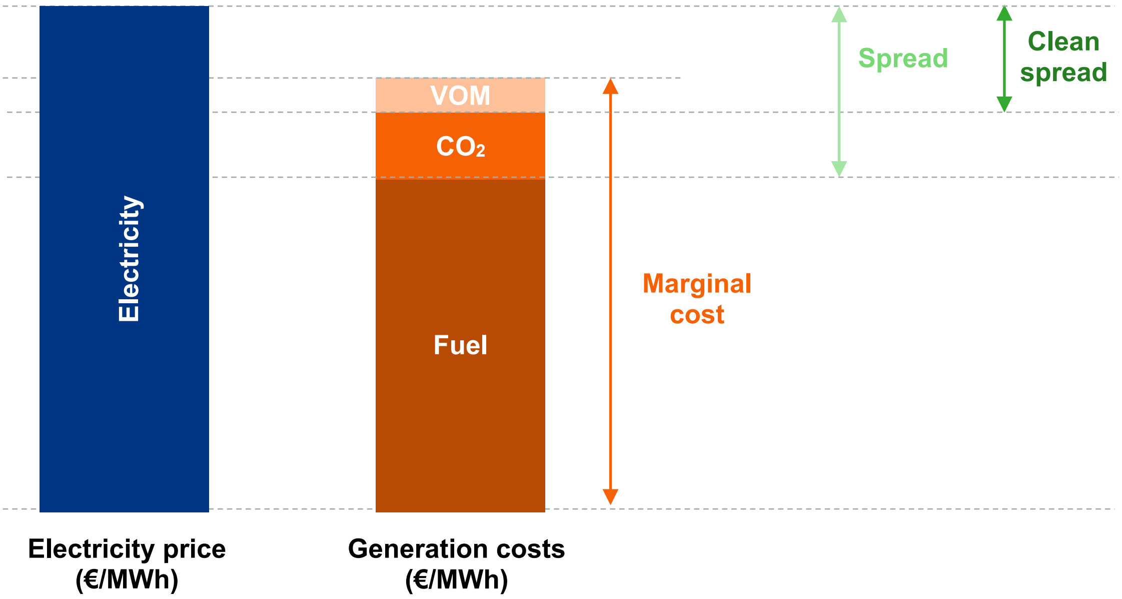

*Figure 6 | The spread is the difference between the price a plant receives for electricity, and its costs for generating that electricity.*

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[8] Futures are standardised contracts that are usually settled financially. Forwards are similar but non-standardised contracts with more flexibility in their terms and conditions, typically settled physically and traded over-the-counter under a so-called EFET master agreement. However, markets for futures and forwards are often referred to collectively as 'forward markets' and value driver 1 includes value from both types of contracts.

[9] The difference between the electricity price and fuel cost is often referred to as the *spark spread* for natural gas plants, and *dark spread* for coal plants. If the cost of purchasing EUA certificates is also included, this is termed the *clean* spark/dark spread.

[10] Plants often incur other variable operating and maintenance (VOM) costs related to consumables and maintenance etc., but these are usually small compared to the other cost components and not typically included in published spreads.

When a power plant operator sells electricity on the futures market it will usually buy contracts for delivery of the fuel and emission allowances it needs to produce that electricity at the same time. In this way it knows exactly what its costs of production will be and it can *lock in* a positive spark spread. Alternatively, the plant operator could wait and buy the fuel and carbon allowances later in the hope that prices fall, and they could achieve a higher spread. However, futures markets are volatile and waiting means taking a risk that fuel and carbon prices increase instead, and the plant operator is forced to spend more on buying the fuel and carbon certificates than it receives from selling the electricity, thereby making a loss. For this reason, it is more common for power plants to lock in or *hedge* spread risk by simultaneously concluding contracts for the required fuel and carbon when it sells electricity. Hedging is used by generators (and retailers) to ensure more stable earnings by reducing uncertainty and volatility in future revenue and costs streams, and provide some long-term visibility on cash flows.[11] By improving financial stability and reducing risk exposure, hedging can also help reduce the cost of capital for new investments. Hedging usually begins up to three years before delivery (i.e., when trade in yearly products starts to become liquid) and over time market parties will progressively hedge the capacity of their assets according to forward market price developments, liquidity constraints, and their particular risk appetite (Figure 7). This hedging pathway is often referred to as a *lock-in strategy*. For example, a more risk-averse producer will often follow a linear lock-in trajectory over time, as this results in achieving the average spread across the period. On the other hand, a producer prepared to take more risk may hedge more of their capacity up front if forward prices are high to lock in spreads, but hold off if forward prices are low in the hope they improve.[12]

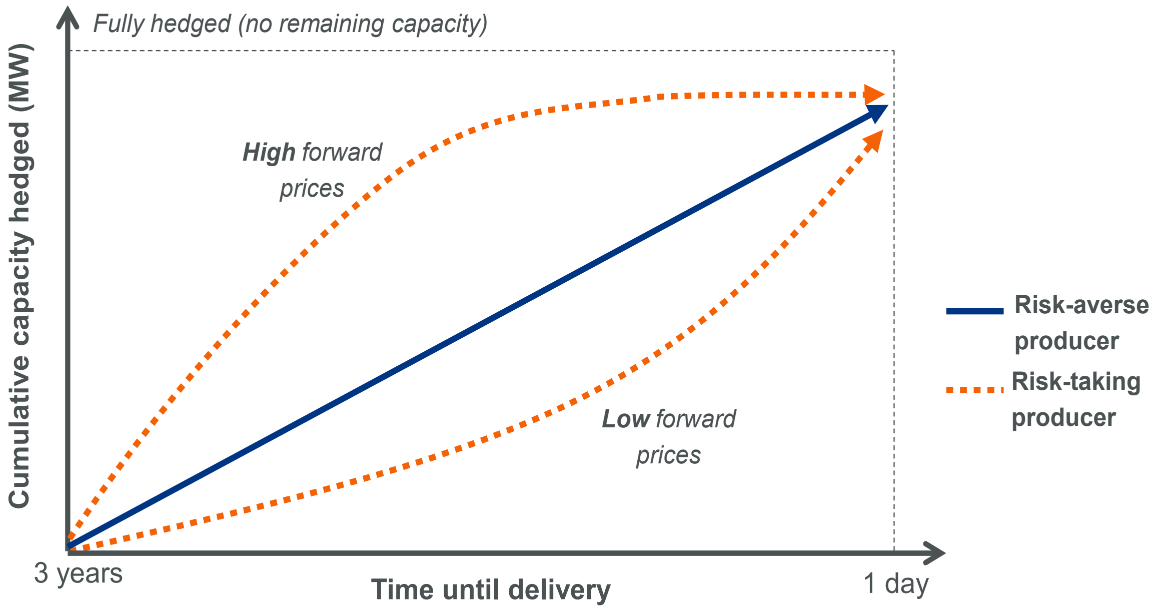

*Figure 7 | Indicative lock-in strategies for risk-averse and risk-taking producers.*

Unlike thermal power plants, RES such as wind and solar photovoltaic (PV) farms are unable to accurately forecast their generation months or years ahead and consequently tend to sell only limited volumes on futures markets. Doing so would entail too much shaping risk as their generation profiles deviate from the standard base and peak load profiles (see section 2.3). Instead, RES plants usually prefer to hedge their generation by entering into a long-term PPA with a counterparty such as a large industrial consumer or retailer. PPAs can be tailored according to the needs of both parties and how they agree to share the various financial risks.[13] An example of how a wind farm can hedge using PPAs is provided in Box 2.

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[11] To give some concrete hedging examples, by the end of September 2023 the Austrian utility Verbund had hedged roughly 51% of its 2024 hydropower generation at 152 €/MWh, and 38% of its 2025 production at 138 €/MWh [33]. The Swedish utility Vattenfall had also hedged roughly 50% of its Nordic output for 2024, and 35% for 2025 by the end of September [34].

[12] Market parties will typically not hedge all their capacity on futures markets but will reserve some to be able to account for power plant outages, have flexibility for trading on shorter term markets, and offering balancing capacity to TSOs.

The value from standard products can be estimated directly from market data by calculating the spread based on futures contract prices available from energy exchanges such as EEX or ICE and multiplying these spreads by the estimated number of equivalent full-load operating hours (FLH). Table 1 gives an example of the spark spread calculation for a combined cycle gas turbine (CCGT) with 50% efficiency, based on a selection of calendar year and quarterly futures contract prices from EEX. Given the relatively high marginal cost of CCGTs, the spark spread is typically only positive for peak load contracts. Assuming roughly 2800 peak contract FLHs per year the potential value from standard products for a CCGT based on selling calendar year (Cal-)2024 peak load would be roughly 9 k€/MW installed capacity.[14] Shorter maturity contracts such as quarterly, monthly, and weekly futures are also traded closer to delivery. These may show higher spreads in certain periods not seen in longer-term contracts, which only consider the average spread across the contract period. Trading these products can allow the plant to avoid periods with low or even negative spreads (e.g., Q2 2024) leading to higher overall value, despite potentially lower volumes. For example, if an operator desired a minimum spread of at least 20 €/MWh to sell forward, the plant would not run at all based on the Cal-2024 spread. However, based on the 2024 quarterly contract prices one could assume the plant would run in Q1 and Q4, leading to an overall standard products value of 42 k€/MW, significantly higher than the 9 k€/MW it would have earned selling Cal-2024.

If an EVA is to be performed for a longer-term horizon and futures market data is not available, electricity market simulations based on unit commitment and economic dispatch (UCED) models can also be used to quantify this value driver. For example, peak and base load contract prices can be estimated on the basis of the hourly prices resulting from the model, while FLH can be calculated from the plant dispatch results.

*Table 1 | Example calculation of the clean spark spread for a gas CCGT based on selected Dutch base and peak load contracts from EEX (via EnAppSys). Prices from 8 August 2023, assuming 50% (HHV) efficiency and emission factor of 0.05 tCO2/GJHHV).*

| | **Dutch Power Futures (€/MWh)** | | **Gas TTF price (€/$\text{MWh}_{\text{HHV}}$)** | **EUA price (€/t)** | **Marginal cost (€/MWh)** | **Clean Spark Spread (€/MWh)** | | **FLH** | **Standard Peak Product Value (€/kW)** |
|---|---|---|---|---|---|---|---|---|---|
| **Period** | Base | Peak | | | | Base | Peak | Peak | |
| Cal-2024 | 124 | 136 | 50 | 89 | 133 | -9 | 3 | 2800 | 9 |
| Q1 2024 | 131 | 153 | 50 | 89 | 133 | -1 | 21 | 700 | 15 |
| Q2 2024 | 108 | 109 | 49 | 89 | 130 | -22 | -21 | 700 | 0 |
| Q3 2024 | 116 | 105 | 49 | 89 | 131 | -15 | -26 | 700 | 0 |
| Q4 2024 | 140 | 175 | 52 | 89 | 137 | 3 | 38 | 700 | 27 |
| Cal-2025 | 120 | 121 | 46 | 92 | 126 | -6 | -5 | 2800 | 0 |
| Cal-2026 | 102 | 105 | 37 | 96 | 109 | -7 | -4 | 2800 | 0 |

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[13] While PPAs are the primary source of hedging for RES, the combined value from potential futures revenues (value driver 1), net hourly shaping (value driver 3) and net ancillary services (value driver 4) is a good proxy for the value a RES plant would be able to derive from a PPA, as these are priced to include risks from shaping, imbalance and other factors. Thus, revenues from PPAs are implicitly included in our value driver framework.

[14] Calculation based on 3120 peak hours per year with ~90% availability. Variable operating and maintenance (VOM) and start-up costs are not included here.

## Box 2 Wind PPA pricing and hedging

In countries like the Netherlands, offshore wind farms have to sell their power directly in the electricity market. It is hence interesting to see how those parks hedge their output. We illustrate this with a hypothetical new build 200 MW wind farm named “Jellyfish”, which we assume will be up and running from 1-1-2028. Assuming a 45% capacity factor, total production is expected to be 790 GWh/y on average.

The costs of Jellyfish are largely known at the moment of the so-called Final Investment Decision and are roughly €55 million per year for 15 years. These costs are mainly fixed costs (investment, financing costs, license fee etc.), so significant financing is required before any positive cash flow comes in. The bank is willing to provide this financing, provided there is a high certainty that the future income from the power sales is enough to service the debt. Jellyfish needs 70 €/MWh (€55 million/790 GWh) for 15 years to cover all costs, including a reasonable profit margin. The current base load products (available on the exchange till 2033) are traded around 80 €/MWh. The traders of Jellyfish consider selling 200 MW base load 2028-2033 on the exchange. However, doing so would leave Jellyfish with significant so-called *shaping and imbalance risks*: base load has to be delivered 24/7 while the wind farm production is variable. On average it will produce 90 MW but sometimes it will generate 200 MW, and in other times 0 MW. If the farm sells 200 MW base load but Jellyfish does not produce enough, the operators will need to buy the shortfall from somewhere else. Selling 200 MW on the exchange would thus increase rather than decrease risk, and the probability that hourly prices will be extremely high when there is no wind is significant. Selling 200 MW on the exchange is hence not an option. As a next step, Jellyfish considers selling 90 MW on the exchange, as that would reduce the exposure to non-windy hours. However, this still gives high risks: in some hours the wind farm will generate 200 MW (meaning 110 MW must be sold on the spot market) while in other hours it will generate 0 MW (meaning 90 MW must be bought on the spot market). Although this would reduce the risk for Jellyfish compared to selling nothing upfront, this is still an unacceptable risk for the bank, as spot prices tend to be high when you buy, and low when you sell (due to the impact of wind on power prices). This is called shaping risk, and further discussed in section 2.3.

Jellyfish hence approaches a creditworthy trader. They offer to buy all the output for 80% of the base load price, i.e., 64 €/MWh under a pay-as-produced PPA. The 20% discount is to cover the shaping and imbalance risk (12-15%), and the profit margin/risk premium of the trader (5-8%). In addition, the trader pays 6 €/MWh for the Guarantees of Origin (GoOs), making sure the wind farm gets its 70 €/MWh. The bank now has ample comfort that the income is secure and will provide the financing. The trader is now long 200 MW ‘wind profile’ power for 15 years for a fixed price of 70 €/MWh. That translates to a financial exposure of €830 million. Imagine the market would go back to the 2018-2021 levels (~35 €/MWh); the loss would be €415 million and that is unacceptable to the risk manager of the trader. Thus, in parallel to buying the wind power from Jellyfish, the trader has already looked for buyers and arranged to sell 25% of the output (including GoOs) at a premium to a hydrogen producer, who needs them for fulfilling ‘RFNBO/green $H_2$’ criteria, and hence needs exactly the ‘wind profile’. The hydrogen producer is not very credit worthy, but that is a risk the trader is willing to take in return for the premium.

In addition, the trader will sell small amounts (25%) of base load in the futures market to hedge the risk of a price collapse. It also may decide to go ‘short’ on gas and carbon (i.e., sell the base load power but not buy gas or carbon), because power prices will only be low when gas and carbon prices go down. In addition, it will contract a flex contract with a 50 MW/200 MWh battery, to mitigate its shaping risk. If the price spread between ‘low-wind’ hours and ‘high-wind’ hours is high they will lose money on the PPA but make money on the battery, and vice versa. Last but not least, the trader has invested in superb forecasting systems and has a very active spot market desk, which will further reduce the shaping and imbalance risk.

The trader will manage the remaining 50% of the farm output on short-term markets. This typically means selling the power on the day-ahead exchange at any price which does not lead to a loss, which in this case would be -6 €/MWh (the GoO price) or higher. For example, if the exchange price is below -6 €/MWh, the wind farm would be scheduled down and ‘self-curtail’ on the day ahead market but could ramp up again if intraday or imbalance prices rose above -6 €/MWh. Alternatively, if the day-ahead price was e.g. 50 €/MWh but intraday prices are below -6 €/MWh, the farm could sell day-ahead, ‘buy back’ power on the intraday market (see section 2.4), and ramp down the wind farm while still making a profit.

The example above illustrates how all the value drivers interact with each other on the energy markets, and that market parties are willing to pay a premium to reduce risks and/or acquire flexibility.

## 2.2 Option value on standard futures products

The value estimated from standard products in the previous section is an example of *intrinsic value*. Intrinsic value refers to the value of a power plant that can be observed (and hedged) against current forward market prices [8].[15] However, power plants also have a second type of value known as *extrinsic value*, sometimes also known as *optionality value*. Extrinsic value represents all the additional value which can be derived from an asset as a result of futures prices for power, fuel and carbon *changing* over time.[16]

Forward prices for electricity change over time in response to changing fuel and carbon prices, as well as market expectations around factors such as the future demand for electricity, expected weather conditions, the policy and regulatory environment, as well as general market sentiment. This combination of price volatility and time provides opportunities for certain types of flexible power plants to generate additional extrinsic value. For example, on futures markets a key component of the extrinsic value of thermal power plants derives from the ability to *buy back* electricity from the market when spreads decline and *resell* electricity again when prices are high (sometimes termed *rolling intrinsic*). It is the ability of flexible plants to adjust and optimise their selling/buying position on futures markets on a rolling basis that represents the bulk of this value driver for most plant types.[17] See Box 3 for a more detailed explanation of buying back and reselling.

The extrinsic value which can be extracted from a plant is affected by several factors including (i) its technical characteristics, in particular marginal cost and flexibility, (ii) market price volatility, (iii) time until delivery, (iv) the trading infrastructure and risk appetite of the owner, (v) portfolio effects, and (iv) market liquidity.[18] Marginal power plant costs (relative to the actual forward price) especially play a major role in determining the extrinsic value of a power plant (Figure 8):

- *At-the-money* plants with a marginal cost roughly equal to the forward price such as CCGTs have the highest extrinsic value as their spreads typically fluctuate around zero, providing several opportunities for buying back and reselling. On the other hand, these plants have very low intrinsic value as, by definition, their forward spreads are close to zero.

- Deeply *in-the-money* plants with a very low marginal cost such as nuclear and RES have very little extrinsic value as their spread is unlikely to turn negative once locked in, and thus they have no opportunities for buying back and reselling. At the same time, their advantageous position in the merit order and significant forward spread means they have very high intrinsic value.

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[15] A further breakdown is sometimes made into *tradable intrinsic* value, how much margin could a plant lock in by selling futures contracts on the forward market and; *hourly intrinsic* value, how much margin could the plant lock in based on an hourly price forward curve [7]. In our framework this additional hourly intrinsic value is captured in Driver 3 (hourly shaping value).

[16] The sum of both the intrinsic and extrinsic value of an asset is sometimes termed the *full value*. Thus, another common definition of the extrinsic value is all the other value an asset can create, apart from its intrinsic value. Extrinsic value is also sometimes referred to as *time value*, or *flexibility value*. For a more in-depth explanation of intrinsic and extrinsic value in the context of asset valuation, KYOS have published several good papers (e.g. [7] [32] [2])

[17] Value driver 2 is limited to extrinsic value from buying back and reselling on futures/forward markets. Extrinsic value which is derived from the day-ahead and intraday markets are covered in value drivers 3 and 4 respectively (see section 2.3 and 2.4).

[18] Market parties usually manage several assets in a portfolio of thermal and/or RES plants, and can meet their delivery obligations with any asset in that portfolio. The first few units may have a higher optionality value than subsequent units as it is common to leave some capacity unhedged to be able to cover illiquid delivery risks associated with other technologies in the portfolio (e.g. wind). Capitalising on the extrinsic value of assets also requires substantial trading infrastructure (e.g. a trading desk with experienced staff), which may not be feasible for small players. Depending on the size and liquidity of futures markets, very large transactions (e.g. selling generation from a large plant) may have an impact on the futures price and spread, reducing the optionality value of remaining units in a portfolio.

- *Out-of-the-money* plants with a marginal cost (significantly) higher than forward prices such as open-cycle gas turbines (OCGTs) have practically no intrinsic value, as they are rarely able to lock in a positive spread in forward markets. This means they also have few opportunities for buying back and reselling. Nevertheless, they still have some extrinsic value due to the asymmetric nature of price risk.

In addition to buying back and reselling, other sources of extrinsic value derived from the forward timeframe are also included in this driver, such as tolling agreements and the sale of options. Due to the asymmetric nature of price risk, even power plants with a very high marginal cost will always have some extrinsic value.[19] Furthermore, flexible plants can be used for risk mitigation within in an asset/retail portfolio. In this case the optionality does not lead to a separate revenue stream, but it still has value.

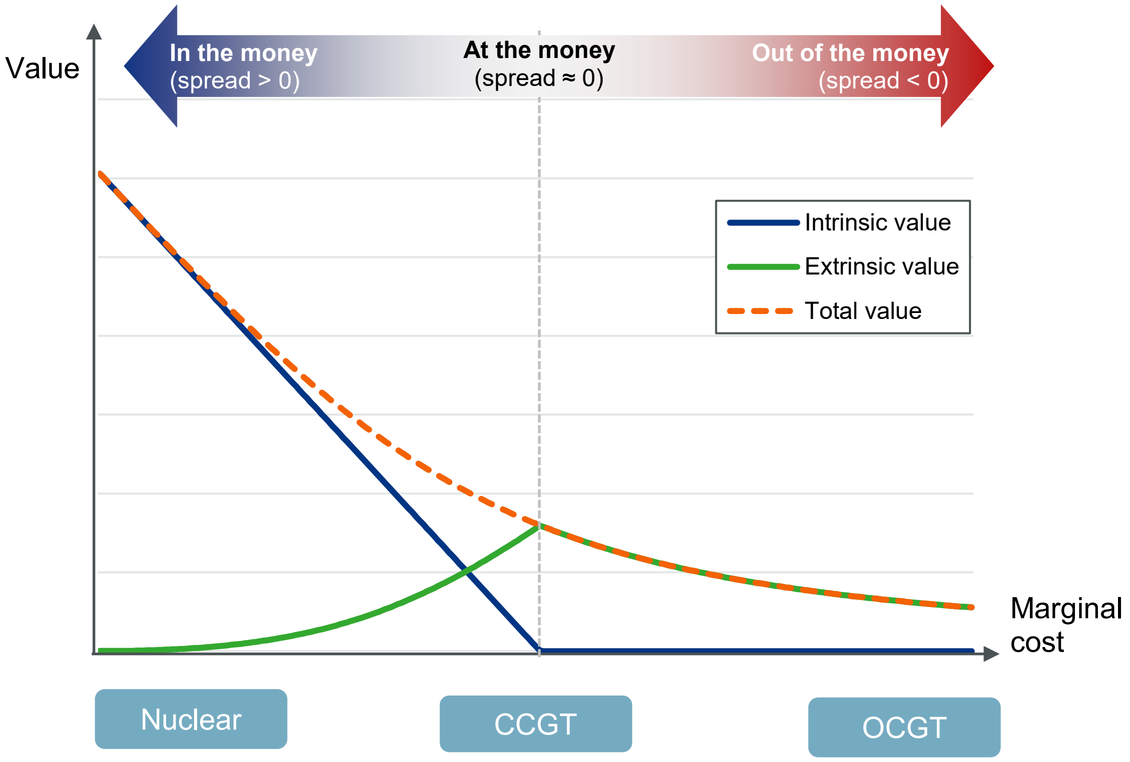

*Figure 8 | Intrinsic and extrinsic value depends on the spread, the difference between the power plant marginal cost and the electricity price. Typically CCGTs have been "at the money" and had the highest extrinsic value, but changes in fuel and carbon prices can shift the merit order and hence extrinsic value.*

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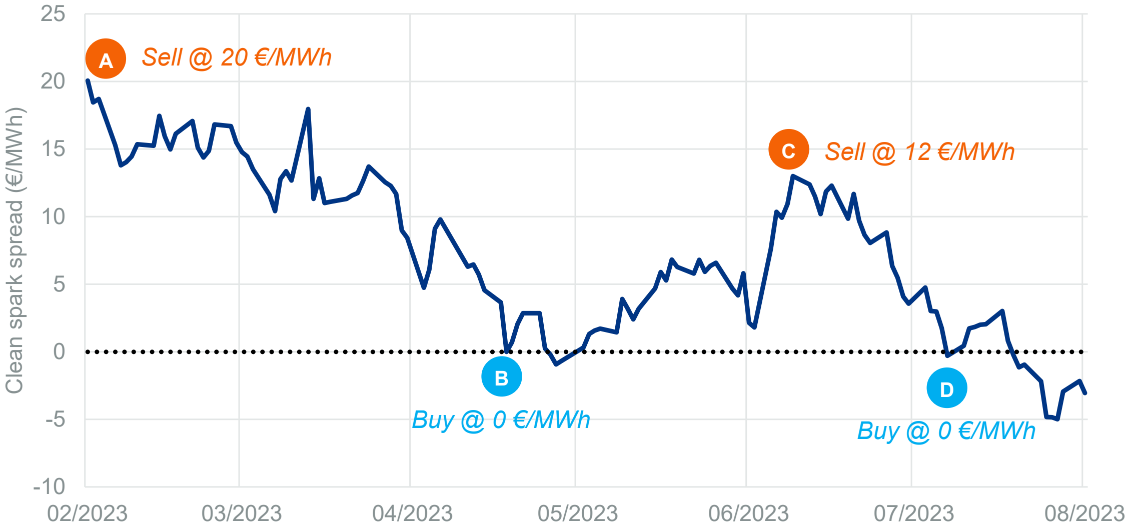
[19] Another example to demonstrate optionality value is shares. Shares in the Dutch company ASML were trading at roughly €560 by the end of October 2023. The cost of an option to buy ASML shares at a strike price of €650 with validity until 15 December 2023 had a value of €3 on the stock exchange. However, the value of the same option with validity until December 2024 had a value of roughly €50. This difference is the so-called time value; there is simply more time that the share could rise above €650, so the option with longer validity has more value.

## Box 3 Buying back and reselling creates extrinsic value

To further explain how buying back and reselling creates extrinsic value, the figure below shows an ex-post calculation of the clean spark spread for a hypothetical CCGT selling peak load power for delivery in August 2023, and some possible trades it could have made with the benefit of hindsight.

As the spread in February was strongly positive (point **A**), the plant hedged some of its capacity on the forward market and locked in a spread of 20 €/MWh by selling peak power contracts, and buying the required fuel and emission allowances. From February to April the spread declined (as a result of falling gas and power prices) and turned negative at the end of April. At this point (**B**), the marginal cost of generating electricity was higher than the price it could be sold for, but the margin of the CCGT was unaffected as it already locked in its prices in February. However, rather than waiting until August and generating the electricity to meet its forward obligation, the plant owner decides to buy back this electricity from the market at a price lower than its marginal cost, simultaneously selling the gas and carbon it previously purchased to cover the cost. Reversing or *unwinding* the hedge in this way allows the plant operator to create revenue without actually generating any electricity, and at the same time frees up the plant to *resell* its capacity on the futures market if spreads turn positive again (point **C**), and potentially even buy back again (point **D**). In this simple example, the plant would have generated extrinsic value of 32 €/MWh, or roughly 8 k€/MW (assuming 276 peak hours and 90% availability) for every MW of output it hedged peak load on the forward market. In practice however, market parties don't have perfect foresight of market price developments and would not necessarily have made the same decisions. For example, many traders would already consider buying back at a spread of 2-3 €/MWh, rather than waiting in hope for the spread to reach zero.



*Calculated clean spark spread over time for a CCGT selling August 2023 German peak load on EEX, assuming 50% (HHV) plant efficiency. TTF price based on August 2023 contracts, EUA prices for Cal-2023.*

The example above also highlights why time until delivery and market price volatility drive extrinsic value: both provide more opportunities for spreads to return to (near) zero and increase again, and more opportunities for buying back and reselling. Unlike purely speculative trading, this type of *asset-backed* trading puts a limit on the downside trading risk as the operator can always fall back on the asset and actually generate electricity to close an open position if needed, rather than being forced to buy the electricity from the market at a high price.

It's important to highlight that buying back and reselling is not a zero-sum game between power plants, where one plant deriving option value implies another plant must be losing money. While in part this value comes from a result of inflexibility and poor trading decisions (in hindsight) on the part of e.g., retailers, large consumers, and speculative traders, much of it is spillover from other markets. Take for example a situation where a trader buys power ('long power') while selling gas ('short gas'), then due to a market shock the price of gas falls by 50% and the price of power falls 40%. The logical thing to do is buy back the gas and sell the power. The trader would make a loss in the power market, but a larger gain on the gas market. To those only looking at the power market the trader would look like a fool, while to those only active in gas markets the trader would look like a genius. But from an overall risk management perspective, the trader makes disciplined decisions.

Estimating the optionality value from standard products is more difficult than estimating the intrinsic value, but several methods are possible with varying levels of complexity based on: (i) power option prices, (ii) spread option prices, (iii) historical futures prices, and (iv) probabilistic modelling. The first two approaches are based on the analogy that a dispatchable power plant such as a CCGT can be conceptualised as a bundle of call options on the fuel/carbon/power spread. The rationale for this (as well as a basic introduction to call and put options) is given in Box 4 but in short, the first approach based on power option prices assumes that the optionality value from standard products can be estimated from the extrinsic value of a call option, with a strike price equal to the plant marginal cost. To illustrate how this approach works, Figure 9 shows call and put option settlement prices for German base load power for Cal-2025 on a particular day. The intrinsic value of the call option is calculated as the difference between the underlying future price (125 €/MWh in this case) and the option strike price (on the x-axis), while the extrinsic value is calculated as the difference between the call option settlement price and the intrinsic value. For an older out-of-the money gas plant with 45% efficiency corresponding to a call option with a strike price (marginal cost) of ~143 €/MWh, the total option value would be ~20 €/MWh, all of which would be extrinsic value. By comparison, for a newer in-the-money CCGT with 55% efficiency corresponding to an option with strike price of ~118 €/MWh, the total option value would be ~30 €/MWh of which ~20 €/MWh would be extrinsic, plus an additional ~10 €/MWh of intrinsic value. Note that the extrinsic value estimated in this way should be seen as a maximum value, while in practice plant owners are unlikely to extract the full value due to other hedging risks (e.g., shifts in underlying fuel and emissions prices), general market volatility, and their own risk appetite. In practice, perhaps only 25% to 50% of this extrinsic value could be realistically extracted.

Major advantages of this first approach are that it is relatively straightforward, and power option prices are transparently published on energy exchanges such as EEX [9]. However, while the extrinsic value of equivalent power call options can provide a rough estimate of plant optionality value, this approach has its limitations. In particular, it does not account for the fact that the underlying option pricing model only considers the volatility of power prices, which ignores potential changes and volatility in the underlying fuel and carbon prices.

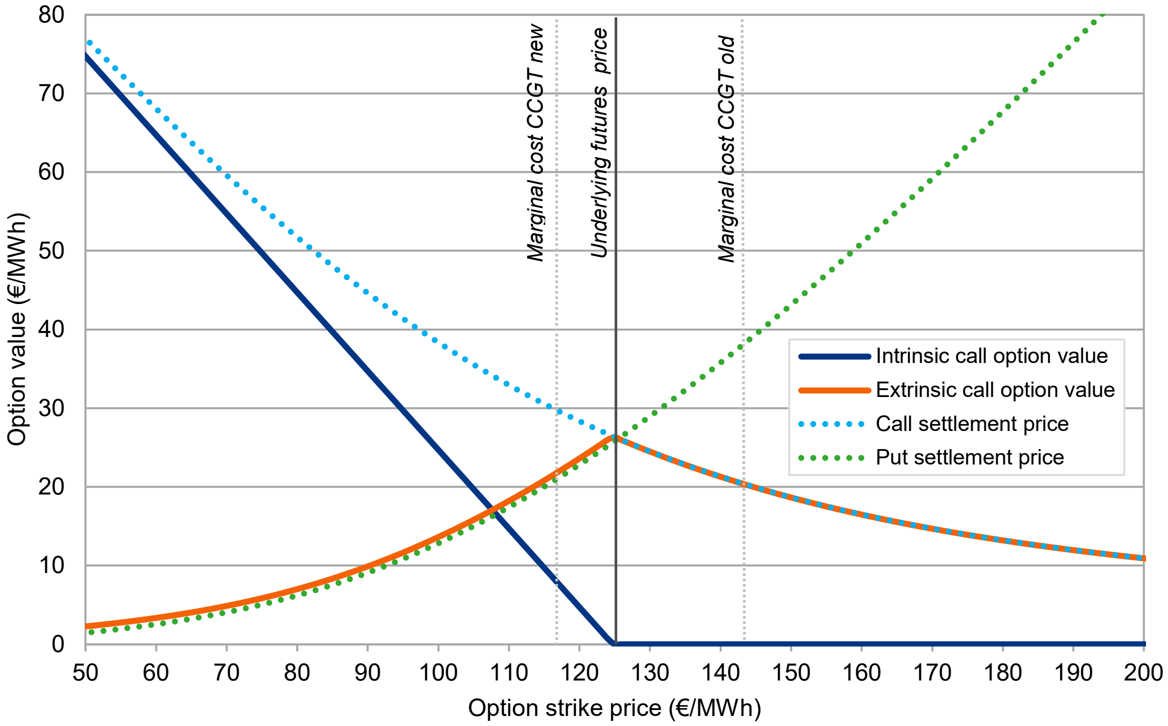


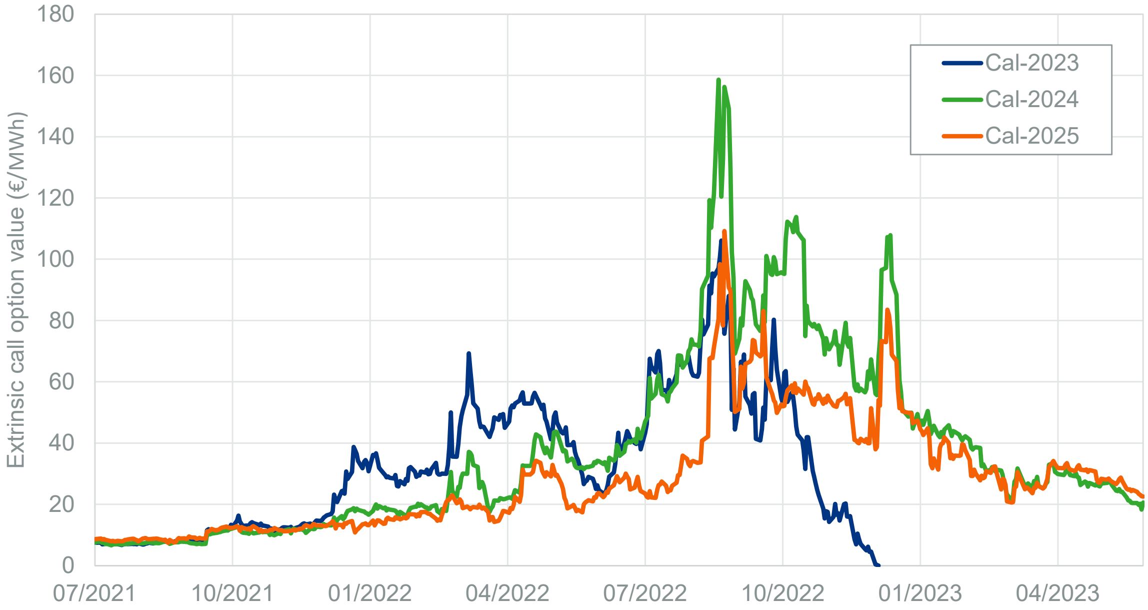
*Figure 9 | Example of how to estimate the (maximum) extrinsic value of a power plant from the settlement price of a European style call option with option strike price equal to the plant marginal cost. Option and futures prices taken for German Cal-25 base load from EEX on 18 August 2023*

## Box 4 Power plants as options

*Options* are financial contracts which gives the holder the right – but not the obligation – to buy (call) or sell (put) a certain quantity of a commodity/asset at a specified strike price, on (or before) a specified date, by paying a certain premium. While perhaps most known in stock markets, options have also become common in electricity markets and are traded on exchanges like the EEX. For example, a power *call option* gives the buyer (e.g., a large consumer) the right to *buy* a specified amount of electricity at a future time from the call seller (e.g. a power plant) at a certain price, for a certain fee. On the other hand, a power *put option* gives the buyer (e.g. a power plant) the right to *sell* a specified amount of electricity at a future time to the put seller (e.g. a retailer) at a certain price. A flexible power plant such as a CCGT can be conceptualised as a bundle of call options, as there are certain similarities in the underlying characteristic and dynamics of both [42]. For example:

- *Both are based on an underlying asset.* In traditional financial options the asset is the underlying stock or commodity e.g. base load power, while for a power plant the asset is the ability to generate and sell electricity.
- *Both have a strike price*. For thermal power plants, this is the variable generation cost (i.e., short-run marginal cost based on fuel, carbon and VOM).
- *Both have a clear potential upside*. If the market price of the underlying asset is above the strike price at expiration, the call option holder can profit by exercising the option and buying the asset at a lower price. Similarly, a power plant has the ability to generate and sell electricity. When electricity market prices rise above the plant's marginal cost, the plant can generate revenue with a positive margin.
- *The extrinsic value of both* is driven by the same underlying factors of strike price (marginal cost), time to expiry (delivery), and volatility.

To show how the extrinsic value of an option or power plant increases with time to expiry and market volatility, we can look to the European energy crisis of 2022. The figure below shows the calculated extrinsic value of a call option on German base load power for Cal-2023, Cal-2024 and Cal-2025 with a strike price corresponding to the marginal cost of a modern CCGT. Before the onset of the European energy crisis in Q3 2021, futures prices for Cal-2023 to 2025 were relatively stable at around 60 €/MWh and the extrinsic value of a call option at the marginal cost of a CCGT was in the order of 7 to 10 €/MWh. During the peak of the crisis in Q3 2022 when gas prices were unprecedently high and French nuclear plant availability added to concerns that Europe may not make it through the winter of 2022 without load shedding, forward prices became extremely volatile and peaked at nearly 1000 €/MWh (Cal-2024). During this period the extrinsic value of a call option at the marginal cost of a CCGT jumped to more than 100 €/MWh. However, by Q1 2023 once futures prices had started to stabilise at around 120 €/MWh, the extrinsic value had fallen to roughly 25 €/MWh.



*Extrinsic value of a call option on German base load power with strike price equivalent to the marginal cost of a 54% efficient (HHV) CCGT for Cal-2023, 2024 and 2025 from EEX from the period July 2021 to June 2023*

While this shortcoming can be accounted for by applying more conservative assumptions (e.g., assuming 25% extrinsic option value capture instead of 50%), a more accurate approach is to base the optionality value of a power plant on the extrinsic value of a call option on the forward *spark spread*, rather than on the forward power price alone. Unfortunately, spread options are exotic products not traded on exchanges and prices are not readily available, but they can be estimated by other means. For example, with some simplifications and limitations, the Margrabe or Kirk models for pricing of swap options can be used to price spread options.[20]

Instead of using power or spread option prices, a third approach is to perform an ex-post calculation of what the maximum potential extractable extrinsic value would have been for an electricity trader with perfect foresight based on historical futures prices, and assume a certain percentage of this could be captured in practice [10]. However, the most detailed approach to estimating extrinsic value – and the one most likely to be used by market parties when performing detailed plant valuations – is a full simulation approach incorporating probabilistic modelling [7]. This approach involves perform a large number of Monte Carlo simulations of future forward (and spot) prices using a co-integrated model which accounts for historical correlations between power, fuel and carbon future prices and their volatiles, and estimating plant extrinsic value based on these simulated prices.

Each of the four methods for estimating extrinsic value from standard products outlined in this section has advantages and disadvantages in terms of accuracy and complexity. While the first two approaches using (spread) option prices are relatively straightforward, the last two approaches are more complex use as they require significant data and modelling capacity. The most suitable approach to apply will depend on the particular situation, how accurate the EVA needs to be, as well as the data and resources available. TenneT will most likely apply the approach (power option prices) in the forthcoming MLZ, while exploring options for applying alternative methods in the future.

## 2.3 Net value from hourly shaping

The first two value drivers represent the total intrinsic and extrinsic value from selling (and buying back) base and peak load contracts several years ahead until roughly two days before delivery. These contracts have at most daily resolution. However, the demand for electricity varies in each hour of the day, and the hourly resolution of the day-ahead market auction provides market parties with a means to adjust and optimise their positions with respect to their forward position. For flexible dispatchable power plants this *hourly shaping* on the day-ahead market is a source of additional hourly intrinsic value. For example, in the case of a CCGT which has sold peak load on the futures market for a particular weekday (Figure 10) for each of the peak load hours where they are committed to generate from the futures market, the plant owner could place a bid on the day-ahead market to buy electricity at a price lower than the plant's marginal cost. If these bids are accepted the plant would not have to generate, and thus could save on fuel and carbon costs. This is sometimes referred to as the *make-or-buy* decision. For each of the off-peak hours where they have no futures commitment, the plant also has the option of placing additional offers on the day-ahead market to generate at a price based on their short-run marginal cost.[21]

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[20] EEX option prices are calculated using the Black-76 model which is a single commodity option pricing model, while the Margrabe and Kirk models account for multiple volatile assets (e.g. power and fuel + $CO_2$). Further details on option pricing models can be found in a paper by de Jong, van Dijken and Bundalova [32].

[21] The short-run marginal cost in this case is based on spot prices, not forward prices.

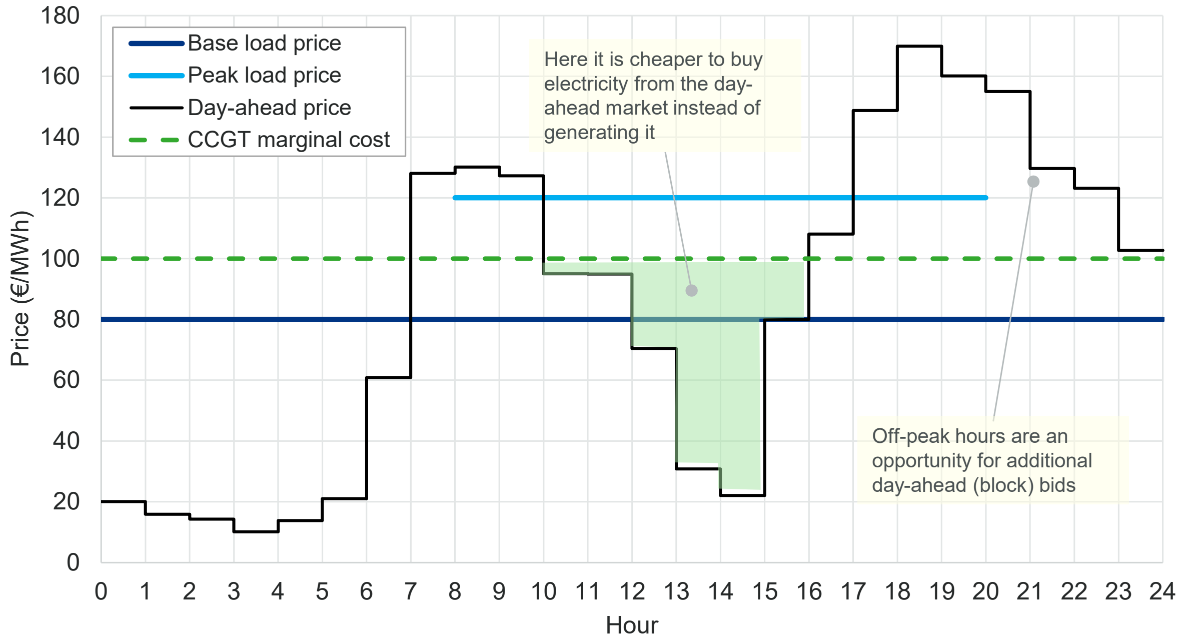

*Figure 10 | Illustrative example of the positive hourly shaping value for a dispatchable power plant such as a CCGT. In hours with forward commitments they can buy back power from the day-ahead market in hours with negative spreads, and place additional bids in non-commitment hours with positive spreads.*

Unlike flexible plants which have a *positive* shaping value, the inability of RES to perfectly forecast generation output means they usually have a net *negative* hourly shaping value when compared with the intrinsic forward (base load) value (Figure 11). There are two main reasons for this. Firstly, in hours where they have a forward commitment to deliver a certain volume of electricity (e.g., the share of the remaining output not sold under a PPA) but do not expect to be able to supply this themselves, the shortfall must instead be bought from the day-ahead market. Secondly, in hours where they expect to produce more electricity than needed to meet their obligations, this must be sold on the day-ahead (or intraday) market. As market prices are typically inversely correlated with solar and wind production, the result is that RES plants usually have to buy at a higher price on the spot markets than the base load price, and sell at a lower price than the base load price.

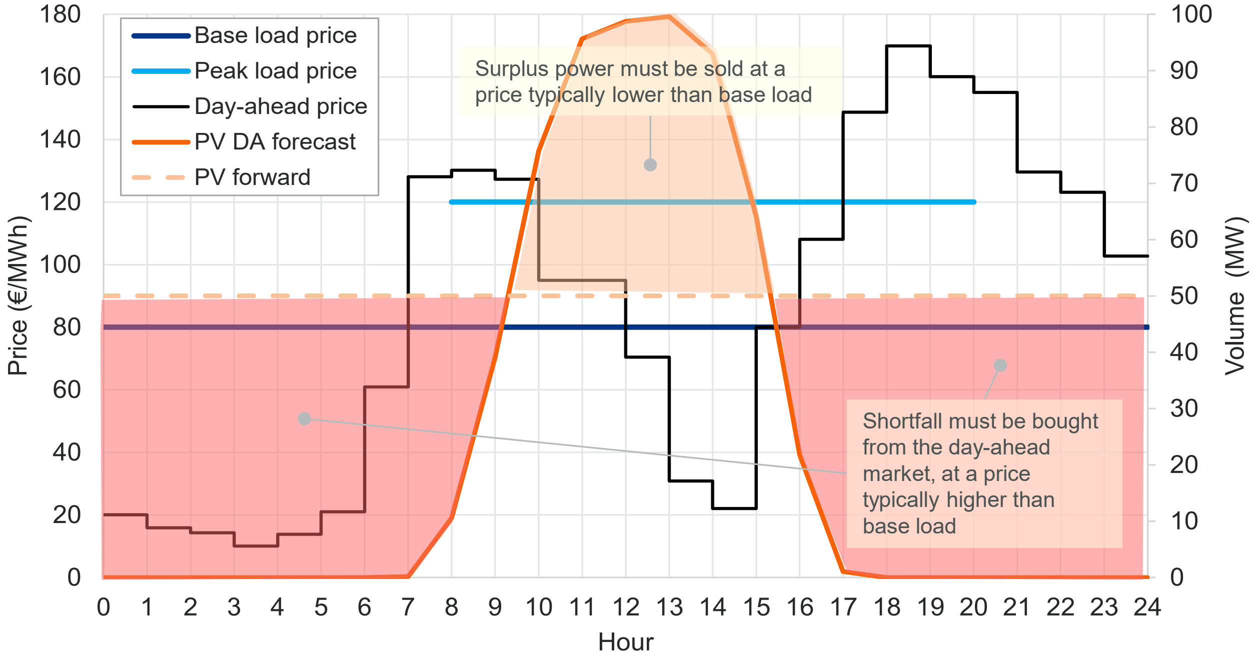

*Figure 11 | Illustrative example of negative hourly shaping value for a solar PV plant. Shortfall power must usually be bought at a higher price than base load, while surplus power sold at a discount to base load.*

To illustrate hourly shaping value with some actual prices, Figure 12 shows hourly EPEX prices for the Netherlands in a somewhat volatile week in October 2023. A 400 MW CCGT with marginal cost of 80 €/MWh which had sold its output as peak load on the forward market at 100 €/MWh would have been able to lock in roughly €22.4 million, or 56 k€/MW for the year in total. On Monday, Tuesday and Thursday, the plant would have delivered on its forward obligations by generating in the peak hours, as the EPEX price never fell below its marginal cost. However, on Wednesday 11/10, instead of generating it could have bought back electricity during 7 peak hours for an average price of 18 €/MWh (simultaneously selling fuel and carbon for 80 €/MWh), thus adding a further ~175 k€ to the year ahead revenue.[22] Placing additional day-ahead (block) bids for the evenings of Monday, Wednesday, Saturday and Sunday when prices were above 80 €/MWh could also have delivered additional value.

The value from hourly shaping can be estimated in two main ways: (i) using capture rates, or (ii) hourly market simulations. The *capture rate* is the average price a power plant (or technology) receives for the electricity it generates as a percentage of the average base load market price and can be calculated from historical market data. For example, in 2021 the average Dutch base load price was roughly 100 €/MWh. The capture rate of Dutch natural gas plants was 110%, while for solar PV was 78% (see Appendix A1). The hourly shaping value in this case was thus 10 €/MWh for gas plants and –22 €/MWh for solar PV. Hourly shaping value can also be computed based on the calculated plant revenues from an electricity market simulation model (see Box 5).

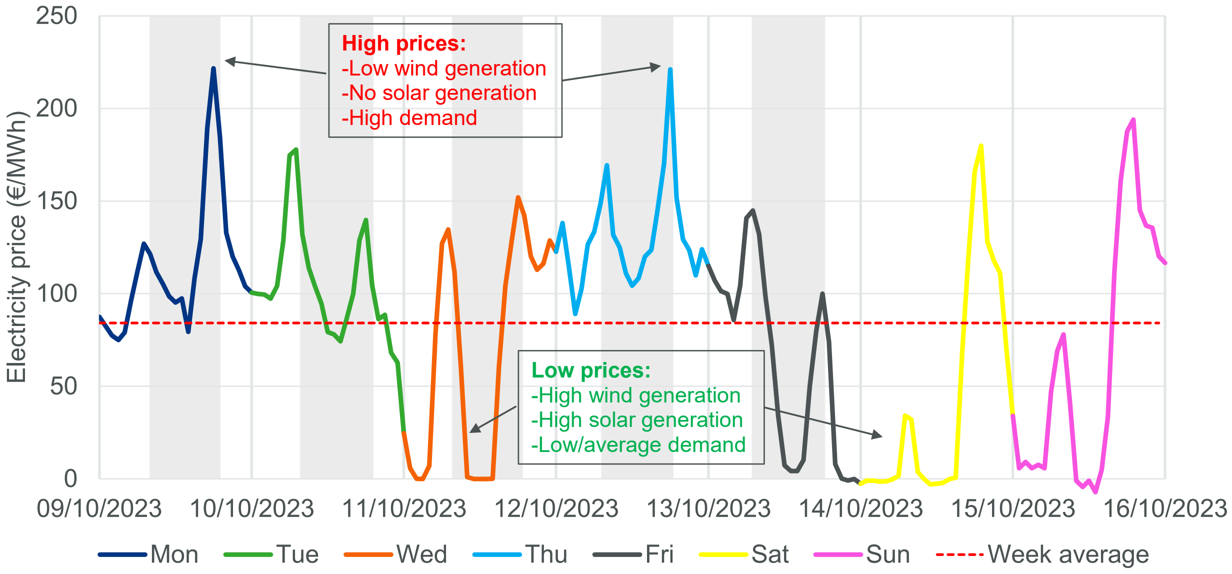

*Figure 12 | Hourly EPEX day-ahead prices for the Netherlands for the week 9-16 October 2023. The grey bars show peak hour contract periods (8:00 – 20:00 weekdays)*

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[22] The annual forward revenue of 56 k€/MW is based on 400 MW capacity * 20 €/MWh clean spark spread * 3120 peak hours per year * 90% availability (excluding start-up costs). This simple example also assumes fuel and carbon prices in the October week (and hence marginal cost) were the same as the forward levels. It is ultimately the actual spread which counts for the make-or-buy decision and resulting dispatch, not the forward spread.

## Box 5 Aligning markets, models and plant value

Hedging on futures/forwards markets provides electricity producers (consumers) with a means of mitigating price risk and locking in revenue certainty by selling (buying) electricity ahead of time. However, parties are not obliged to do so and there is always the alternative to wait until the day-ahead (or intraday) market and trade electricity there. Given this freedom to trade in either market, there will be a correspondence between the price on forward/futures and the day-ahead market. A common view is forward prices will be related to the expected spot price according to fundamental market expectations. In the words of one European regulator "*what a forward market does is aggregate all potential [electricity] price scenarios into one forward price, given the forward prices of fuel and $CO_2$ prices known at that moment. This forward price can be viewed as the expected [day-ahead] spot price (with a risk premium). This expected spot price is equal to the average of all potential scenarios, weighted by their probability to occur [at that moment]*" [16].

When performing EVA for capacity resources, revenues should be estimated on futures market prices whenever these are available, as these are the prices which matter in reality. However, for EVA performed on future years where no futures market prices are available, an alternative option is to resort to fundamental models based on unit-commitment and economic dispatch (UCED). What these models do is find the cost-optimal dispatch of all power plants in the system, assuming perfect foresight of load and RES generation under ideal theoretical market conditions. If these models are run at hourly resolution assuming perfect foresight, using the day-ahead market price cap and accounting for balancing capacity reservation for TSOs, one could interpret the hourly prices coming from the model as a rough proxy for the day-ahead price. Moreover, as plants will (usually) only be dispatched in the model if the electricity price is at or above their short-run marginal cost, the resulting power plant dispatch can be seen as the combined outcome of previous trades which may have taken place on the futures/forwards markets, including subsequent adjustments made on the day-ahead market. Power plant revenues calculated from such a model thus implicitly include the combined intrinsic value from the futures/forward and day-ahead timeframe: in other words, the sum of value drivers 1 and 3. However, as the volatility of futures, intraday and balancing energy (activation) markets are not included in most electricity market models, value drivers 2 and 4 (and 5) are not included and need to be estimated separately. To give two concrete examples of this:

- For an at-the-money CCGT, the plant may be frequently price setting, but in many hours, it will not be dispatched. As it often sets the price at its marginal cost, and it makes no revenue when it is not dispatched, its annual inframarginal rent is likely small. Once fixed operating and maintenance and start-up costs are taken into account, its annual profit may be close to zero, or potentially even negative. However, the model misses the fact that in reality the plant could have sold futures products at a higher price, and bought back if the spot price was lower than its marginal cost (e.g. the peak hours when it is not dispatched but price is lower than marginal cost).

- For an out-of-the-money OCGT, the plant may only be dispatched very rarely by the model, or potentially not at all in a given year. Accounting for fixed costs would result in a negative annual profit. However, in reality it may have sold options or entered into bilateral contracts.

Thus caution must be taken when using standard UCED electricity market models based on cost optimal dispatch. They can be useful for estimating intrinsic value, but extrinsic value needs to be estimated separately in most cases.

## 2.4 Option value on hourly shaping

In the same way that plants committed on forward markets can extract additional extrinsic value by buying back (and reselling) electricity on the day-ahead market, plants committed on the day-ahead market can further optimise their position by buying back (and reselling) electricity on the intraday market. For example, a CCGT committed to delivery on the ahead market can place intraday bids to buy electricity at a price below its marginal cost. Plants with near-zero marginal costs such as wind farms may ramp or shut down during periods with (very) negative intraday prices, and buy back the electricity on the intraday market to meet any delivery commitments from prior markets. Given the lower trading volumes on intraday markets and less time to make trades, the optionality value on hourly shaping is usually lower than the optionality value on standard products.

While it would be possible to use a model-based approach to quantify this value driver, a simple rule of thumb approach based on technology type should be sufficient in most cases. For example, as extrinsic value in the intraday timeframe can only be captured by flexible assets which can modulate their output in the intraday timeframe, this driver is only significant for these types of capacity providers (Table 2). For these plants the optionality value from hourly shaping can be estimated to contribute roughly 1 to 10 €/MWh to the gross margin.

*Table 2 | Relevance of optionality on shaping value for different plant types*

| Technology type | Flexible dispatch (within day) | Typical place in merit order | Optionality on shaping value significant? |
|---|---|---|---|
| **Nuclear** | Limited | Deep-in-the-money | No |
| **Coal** | Yes | At-the-money | Yes |
| **Lignite** | Yes | At-the-money | Yes |
| **CCGT** | Yes | At-the-money | Yes |
| **OCGT** | Yes | Out-of-the-money | Yes |
| **Battery** | Yes | In-the-money | Yes |
| **DSR** | Yes | Out-of-the-money | No |
| **Hydro** | Yes | Deep-in-the-money | Limited |
| **Solar PV** | Yes (downward) | Deep-in-the-money | Limited |
| **Wind offshore** | Yes (downward) | Deep-in-the-money | Limited |
| **Wind onshore** | Yes (downward) | Deep-in-the-money | Limited |

## 2.5 Net value from balancing and other ancillary services

In addition to intrinsic and extrinsic value from electricity markets, capacity resources can also derive value by offering ancillary services to the TSO. The range of ancillary services plants can provide depends on their technical capabilities but can include: (i) balancing reserve capacity and balancing energy in the form of Frequency Containment Reserve (FCR), automatic (aFRR), and manual Frequency Restoration Reserve (mFRR), (ii) voltage support (i.e., reactive power, or MVAr), (iii) black start facility, and (iv) redispatch and other congestion management services. Value driver 5 thus represents the total net value a capacity resource can derive from providing all these sorts of services.[23]

In the case of balancing, this driver includes the total combined revenues from provision of balancing capacity and balancing energy, as well as the *net* revenues from the balancing process. This value may be positive or negative. For example, the net combined balancing revenues for flexible thermal plants are typically positive as these assets are capable of providing balancing capacity (and other services) to TSOs and, being fully dispatchable, can usually ensure they are on the 'right' side of the system imbalance (i.e. supporting the system).[24] By contrast, net combined balancing revenues for RES are typically negative as RES cannot perfectly forecast generation, have a higher chance of being on the 'wrong' side of the system imbalance, and thus more likely suffer higher imbalance cost penalties. RES also don't (currently) provide many other ancillary services for TSOs.

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[23] Compensation of TSO grid losses is handled via the electricity markets, and not included in this driver.

Assuming that the total costs incurred by the TSO for procuring ancillary services are the same as the total ancillary services revenues paid to market parties, quantifying the net value from ancillary services typically relies on collecting historical data on the average volume and cost of each ancillary service product procured by the TSO, extrapolating these costs and volumes out to future years, and allocating the total corresponding costs/revenues to the individual (groups of) capacity resources which are expected to provide these ancillary services in the future. Data on historical ancillary services costs and volumes is typically available from TSO websites, annual reports and platforms such as *Regelleistung* [11] and the *ENTSO-E Transparency Platform* [12]. If these data show current prices and volumes for a particular ancillary service are relatively stable over time, these levels may be assumed to continue. However, if trends in the data are identified (e.g., increasing volumes and/or prices) these can be extrapolated based on statistical analysis or expert views. Ancillary services revenues can then be allocated to individual (groups of) plants on the basis of historical data, or otherwise simply allocated pro-rata in proportion to installed capacity, annual generation or expert views, depending on the type of service.

The ability to quantify this value driver accurately depends very much on the quality of data available, and how robustly the volumes and prices for these services can be estimated. For most plant types however, the value from ancillary services usually represents only a small fraction of the total value, and it is not a decisive factor in the overall economic evaluation. It's also important to recognise that due to opportunity costs and the timing of electricity and ancillary service markets, trading decisions require trade-offs to be made across the value drivers. For example, hourly bids on the EPEX day-ahead market must be entered by 12:00 CET the day before delivery, while bids for providing aFRR capacity to TenneT must be entered by 09:00 CET the day before delivery [13]. Thus, capacity which is offered and committed to providing aFRR cannot be used for further optimisation on EPEX. Market participants must take these opportunity costs and trade-offs into account when optimising their trading decisions across markets in order to maximise the value generated by their assets.

## 2.6 Other non-electricity revenues

Value driver 6 includes all the other additional revenues capacity resources can earn from sources outside the electricity and TSO ancillary services markets including:

(i) the production of heat and/or steam for own use, or sale to end consumers (e.g., district heating, industrial facilities),
(ii) the sale of Guarantees of Origin certificates,
(iii) government subsidies and policies, including RES support schemes, and
(iv) CRMs, where applicable.

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[24] The Dutch balancing process applies so-called *passive balancing*. TenneT publishes the real-time imbalance price and balance responsible parties (BRPs) which are imbalanced in the direction which helps the overall system balance are paid the imbalance price, while BRPs which are contributing to the overall imbalance must pay TenneT. BRPs with flexible assets can thus decide for themselves to increase their imbalance if it helps the overall system balance and makes financial sense for them. In other countries the situation may be different, and in some countries any deviation from the nominated schedule after intraday market closure may be penalised.

Revenues from the sale (or the value of own usage) of heat are typically only relevant for combined heat and power (CHP) plants. These can be estimated from the technical characteristics of the plant (e.g., efficiency), the FLH, and any available data on the price (or opportunity cost) of heat.[25] For some CHP plants the revenues earned from heat/steam sales may actually be the key value driver, rather than electricity sales. Thus, if this value cannot be estimated robustly it may be reasonable to assume that a plant with a long-term contract to deliver heat/steam will remain economically viable as long as a heat supply contract is in place.

Guarantees of Origin (GoO) are EU certificates which serve as proof that a certain amount of electricity (or other energy carrier) has been generated from a renewable energy source, often a particular plant. Producers of renewable energy are issued these certificates by the national issuing body and can sell them to retailers and large consumers willing to pay a premium to demonstrate their electricity comes from sustainable sources. Prices for European GoO are often published by energy information companies (e.g., Argus, Montel). In August 2023, prices for GoO from Nordic hydropower, EU wind and solar were trading at around 6 €/MWh for Cal-2023 and 7.5 €/MWh for Cal-2024 [14].

Government subsidies are another important source of revenue for certain technologies. For example, the *Stimuleringsregeling Duurzame Energieproductie en Klimaattransitie* (SDE) scheme, originally introduced in 2008 and adjusted and extended several times into the SDE+ and SDE++ scheme, has contributed significantly to the accelerating deployment of RES in the Netherlands by providing a feed-in premium for many RES and other low-carbon technologies.[26] The SDE(++) is designed to cover the difference between the cost price of electricity from RES and the wholesale market price, for a maximum number of annual FLH. If detailed data on subsidy levels for different technologies are available these can be taken into account in EVA. However, as subsidies are usually designed to ensure market viability, it can be reasonable to assume technologies covered by subsidies will be viable (at least during the period for which they are eligible to receive financial support) and can be excluded from EVA.

For plants operating in countries which have a CRM in place, revenues from existing capacity contracts should be taken into account in EVA. The price paid for capacity can be estimated from the result of national capacity auctions, or average remuneration levels can be taken from aggregated data reported by regulatory authorities. For those plants which are awarded capacity contracts under a CRM the price paid typically lies in the range of 10 to 70 k€/MW [6], but can vary significantly across countries and over time. For countries like the Netherlands which do not have a CRM in place, CRM capacity revenues do not need to be considered.[27]

## 2.7 Hurdle to close/invest

Assuming drivers 1 to 6 can be robustly and accurately quantified as part of an EVA and the results showed that an existing plant was unviable, the final decision to shut down the plant would not be based solely on the six value drivers. There are additional factors which represent hurdles to closing a plant which would need to be considered. Similarly, even if EVA for a new investment suggests it may be economically viable, additional factors must be considered which represent hurdles to new investments. This seventh value driver represents all these hurdles and should be interpreted differently for existing and new plants. For existing plants, this driver can be thought of as the *real option value* of owning a power plant. Plants with higher real option value have a higher hurdle to closure and thus lower risk of closure. For new investments, this value driver can be thought of as encapsulating the *investment risk* involved in committing capital to a new venture. These risks are hurdles to investment which would play a role in the final investment decision.

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[25] If the price of heat is not known, the heat price can be roughly estimated as 2/3 the average price of natural gas, which is the main fuel used by CHP plants in the Netherlands.

[26] Relevant RES technologies covered by the SDE(++) include onshore wind and large-scale solar PV (> 15 kW) installations. Offshore wind is not covered by the SDE but supported by a separate tender program, while small-scale solar PV is supported by net-metering.

[27] This may change if Dutch power plants are allowed to participate in CRMs in neighbouring countries (e.g. Belgium), or if a CRM is one day introduced in the Netherlands.

The following sections explain how this value driver can be assessed for both existing plants and new investments.

### 2.7.1 Hurdle to closure (existing capacity)

If the total revenues of an existing power plant are not sufficient to cover its ongoing operation and maintenance costs and it is at the verge of economic unviability, the plant owner may consider shutting down the plant.[28] For thermal power plants, this moment typically arises when significant investments are required to keep the plant operating such as a major repairs after an unplanned outage, or when a plant is due for an overhaul, or some other kind of major maintenance event (MME). MMEs are planned outages in which significant maintenance work is carried out every few years to keep a plant operating safely, efficiently, and reliably.

If the economic situation of the plant is expected to improve in the short- to medium- term, an operator may choose to close the plant temporarily, often referred to as *mothballing*. Mothballing the plant in this way reduces fixed operating costs, while retaining the option to restart the plant at a later time if conditions improve. However, closing a plant permanently means giving up the option to ever start it again, and every option has a value irrespective of how unlikely it may seem.[29] Thus, there is an intrinsic hurdle to either temporarily mothballing or closing a plant. The question faced by operators is whether the *costs to maintain the option* of keeping the power plant available are outweighed by the potential upside scenarios for the *real option value* of the plant (Table 3).

As real option value is very plant and location specific, and opportunity costs are difficult to quantify, a qualitative evaluation is often needed for this value driver. One approach is to score each plant on several real option aspects and whether these represent a relatively low or high hurdle for plant closure (Table 4). The fewer hurdles a plant has to closure, the less likely it is to be kept on the market. Ultimately the decision to mothball or retire a plant is not straightforward, but for the purpose of resource adequacy studies it may not be necessary; simply determining a plant has high likelihood of being unviable on the market can be enough to assess the impact on resource adequacy.

*Table 3 | Examples of potential costs for maintaining a power plant option, and potential real option value*

| Examples of costs to maintain the option | Examples of real plant option value |
|---|---|
| • Fixed operating & maintenance (FOM) costs<br>• Major maintenance event (MME) costs<br>• Mothballing and de-mothballing costs<br>• Other opportunity costs of keeping the plant online (e.g., value of capital, value of land) | • Sudden favourable shift in position in the merit-order due to unexpected fuel/carbon price shift<br>• Policy change (e.g., compensation for plant closure)<br>• Unexpected adequacy issues driving up prices<br>• Value of grid connection |

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[28] In the context of longer term resource adequacy studies, the term ‘existing plant’ is also used to refer to capacity which is *assumed* to be built and operational in the market as part of a scenario, even if the plant does not exist yet.

[29] A good example of this is Figure 8 in section 2.2. Another example is the energy crisis of 2022. Triggered by the post-COVID recovery, the war in Ukraine, and French nuclear troubles, unprecedently high gas and power prices in Europe caused many power plants which were previously out-of-the-money such as aging coal and OCGTs to suddenly find themselves at- or in-the-money.

*Table 4 | Examples of hurdles to closure for existing plants*

| Real Option Aspect | Lower hurdle to closure | Higher hurdle to closure | Rationale |
|---|---|---|---|
| **Physical location of plant** | • Located in or near a populated area<br>• Located in an area with significant public opposition | • Located in a more rural/remote area<br>• Located in an area with no public opposition | • Opportunity cost of land is higher in areas with higher land value. Thus, plants on land with higher value have a lower hurdle to closure.<br>• Plants subject to public opposition entail higher reputational cost to the owner, and lower hurdle to closure. |
| **Location of plant in the electricity grid** | No local grid constraints | Significant local grid constraints | An existing connection has higher value in a congested grid area due to possibilities for connection pooling and providing ancillary services to the TSO. Thus, plant has higher real option value, and higher hurdle to closure. |
| **Mothballing costs** | • High (de-) mothballing costs<br>• High risk of losing operating license when not running | • Low (de)mothballing costs<br>• Low risk of losing operating license when not running | • Higher costs for (de)mothballing are a high cost to maintain the option, thus low hurdle to closure.<br>• Staying mothballed for too long may lead to operating and emission (e.g., NOx) licenses to expire |
| **Likelihood for government compensation for early closure** | No history (low likelihood) of compensation | Past history (high likelihood) of compensation | Staying online longer could lead to higher likelihood for compensation for early closure |

### 2.7.2 Hurdle to invest (new capacity)

There are a variety of profitability metrics which can be used to assess economic viability. Two of the most commonly used are the net present value (NPV) and internal rate of return (IRR).[30] These metrics are usually calculated on the basis of estimated investment and operating costs, as well as expected revenues over the lifetime of the investment (see Appendix A2). However, even if a prospective investment appears profitable on the basis of these metrics, there are other factors which play a role in deciding whether an investment will actually take place. For example, a major hurdle for new investments is *investment risk*. Investment risks represent the uncertainty and potential for economic loss that companies face when investing in the development, construction, and operation of new capacity. There are many potential sources of investment risk which are often technology, country or time specific, and can be challenging to quantify (Table 5).

One popular method used to account for investment risk is the *hurdle rate* approach [15].[31] All investments imply some level of risk, and the logic behind the hurdle rate approach is that investors will expect a higher return for projects which carry higher investment risks. According to this approach, a potential investment is deemed to be economically viable if the expected return on the investment is higher than the hurdle rate ($H$) which is the sum of (i) a reference weighted average cost of capital ($WACC$) and (ii) a technology-specific hurdle premium ($h$):

$$H = WACC + h$$

---

[30] NPV is the difference between the present value of cash inflows and the present value of cash outflows over a period of time. A positive NPV implies an investment is profitable, as the expected revenues exceed expected costs for a given discount rate. The IRR is the discount rate required to achieve a NPV of zero, and shows what return an investment needs to deliver to be considered profitable.

[31] The hurdle rate approach has been used by the Belgian TSO Elia in their *Adequacy and Flexibility study for Belgium* for the past several years [22], and the 'hurdle to invest' aspect of value driver 7 draws heavily on their work. The hurdle rate approach is also commonly applied in industry.

In essence, the hurdle rate is simply a risk-adjusted discount rate. The $WACC$ in this equation represents the discount rate of a reference investor in the industry and accounts for the cost of equity and debt, the gearing ratio, expected inflation and tax rates. The technology-specific hurdle rate is usually calibrated based on a mix of quantitative and qualitative investment risk factors such as policy, technology and revenue risks. For technologies with relatively low policy and downside revenue risk such as RES, the hurdle premium can be in the range of 2% to 5% [16]. For technologies with relatively high revenue volatility risks such as OCGTs, the hurdle premium may be in the order of 7% to 10%. Thus, assuming a reference WACC of 5% (recently computed for Belgium [15]) and a technology with a hurdle premium of 5%, the calculated IRR would need to exceed a hurdle rate of 10% to be considered economically viable.

*Table 5 | Examples of investment risks (Sources: [35] [36] [15] [37], Frontier Economics)*

| Risk category | Sub-risk | Description and examples |
|---|---|---|
| **Volume risk*** | Weather risk | Changes in generation (e.g. from a wind farm) due to weather variability, and long-term potential impacts of climate change. |
| | Construction risk (volume) | Delays in construction due to permitting, receiving a grid connection, or other technical issues mean contracted volumes cannot be delivered. |
| | Balancing risk | Inability to adequately forecast expected generation (or load) increases exposure to imbalance price. |
| **Price risk*** | Flat price risk | Refers to uncertainty about the future absolute market price level due to changes in underlying demand, fuel prices, etc. |
| | Basis risk | Basis risk relates to the price difference between the price that is being hedged, and the price of the futures contract used for hedging. Includes risks related to time/calendar spreads, locational spreads, and quality/product spreads. |
| | Interacting price-volume risk | Mutually dependent price and volume changes, such as electricity price variations caused by variations in the output of RES (e.g. cannibalisation risk), and price variations due to temperature-driven heat demand. |
| **Credit risk** | Settlement risk | The risk of losing defined value e.g., volume delivered under a fixed price contract but not being paid. |
| | Replacement risk | The risk of having to replace a purchase (or sale) at a price different from the initial contract price. |
| **Operational risk** | Technical risk | Risk of unplanned costs due to a technical plant failure. |
| | Construction risk (cost) | During the construction phase for a power plant there is the risk of construction cost overruns, or delay of completion |
| | Fuel risk | Plants which require fuels are subject to the risk of volatile prices, and fuel unavailability (e.g. import disruption) |
| **Regulatory risk** | Market design | Changes in market design such as bidding zone re-configuration, or introduction of a CRM. |
| | Support policies | Changes in support policies (e.g. SDE++, GoOs) which impact plant revenues. Regulatory divergence may lead investors to invest in jurisdictions with more favourable regulatory and conditions (i.e. regulatory arbitrage) |
| | Balancing mechanism | Changes in balancing market design and imbalance settlement arrangements. |
| | Tariff designs | Changes in electricity (or gas) grid tariff structures and fees. |
| | Wider (climate) policy | Changes in wider national or EU policies such as taxation rules, climate goals, technology phaseouts (e.g. nuclear, coal), or the Emissions Trading System (ETS) design. |

**Volume and price risk together are often referred to as market risk*

## 2.8 Relative importance of the value drivers for different technologies

The seven value drivers outlined in the previous sections provide a comprehensive overview of how different capacity resources can derive value. However, not all technologies are the same. While most drivers play at least some role for all technologies, each type of capacity resource usually has at least one or two major value drivers from which they derive most of their value (Table 6).

*Table 6 | Major (M) and additional minor (+) value drivers for selected types of capacity resources. A (-) indicates it is a net negative value driver for a particular technology*

| | Value driver | | | | | | |
|---|---|---|---|---|---|---|---|
| **Technology** | 1 Standard futures products | 2 Option value on standard products | 3 Hourly shaping value | 4 Option value on shaping | 5 Ancillary services & balancing | 6 Other revenues | 7 Hurdle to close or invest |
| **Thermal plants** | | | | | | | |
| **- At-the-money** *(e.g., CCGT, coal)* | + | M | M | + | + | | +/M |
| **- Out-of-the-money** *(e.g., OCGT, oil)* | + | | M | + | + | | M |
| **- Deep In-the-money** *(e.g., nuclear)* | M | | + | | + | | M |
| **- CHP*** | + | | + | + | + | M | M |
| **- Waste** | M | | | | + | M | M |
| **RES (solar and wind)** | M | | - | | - | + | + |
| **Hydro – Run of River** | M | | | | | + | + |
| **Hydro – Reservoir** | M | | + | + | + | + | + |
| **Hydro – Pumped** | | | M | + | + | + | + |
| **Battery storage** | | | + | + | M | | + |
| **DSR** | | | M | + | + | | +/M |

**The value drivers for CHP are very plant specific and depend on many factors including the fuel type, technology type (e.g. power-to-heat ratio), heat demand profile, and availability of technologies which provide flexibility (optionality) such as a thermal storage, a heat-only boiler or a heat pump*

For thermal power plants, the contribution of the different value drivers to the overall economic value primarily on their technical characteristics and their location in the merit order. Extrinsic value is especially relevant for at-the-money plants such as CCGTs and other flexible technologies, while for deeply in-the-money plants like nuclear and RES, the intrinsic value is usually the most important driver.

The importance of each value driver is likely to vary over time. For example, changes in the underlying fuel and carbon price will change the relative position of thermal technologies in the merit order, and subsequently the ratio between their extrinsic and intrinsic value. Also, batteries currently derive most of their revenue from TSO ancillary services markets, but as these markets saturate over time an increasing share of battery value is likely to come from trading on intraday and day-ahead markets.

# 3. Economic viability evaluation methodology based on the value drivers

The value drivers outlined in the previous chapter can be used to evaluate the economic viability of any capacity resource following three main steps:

- The first step is quantifying the first six value drivers outlined in the previous chapter, which in total represent the estimated *annual net revenue* for a plant in a given target year.
- The second step is estimating the *fixed costs* of the capacity resource based on available data or literature sources.
- In the third step, economic viability is assessed by comparing the estimated net revenues with (a range of) estimated fixed costs.

If estimated revenues cover fixed costs by a sufficient margin, the plant is considered likely to be market viable. If not, the plant is deemed unlikely to be viable. The approach is slightly different for existing capacities and new investments. This chapter explains each of the above steps in more detail and provides some numerical examples for several technologies.

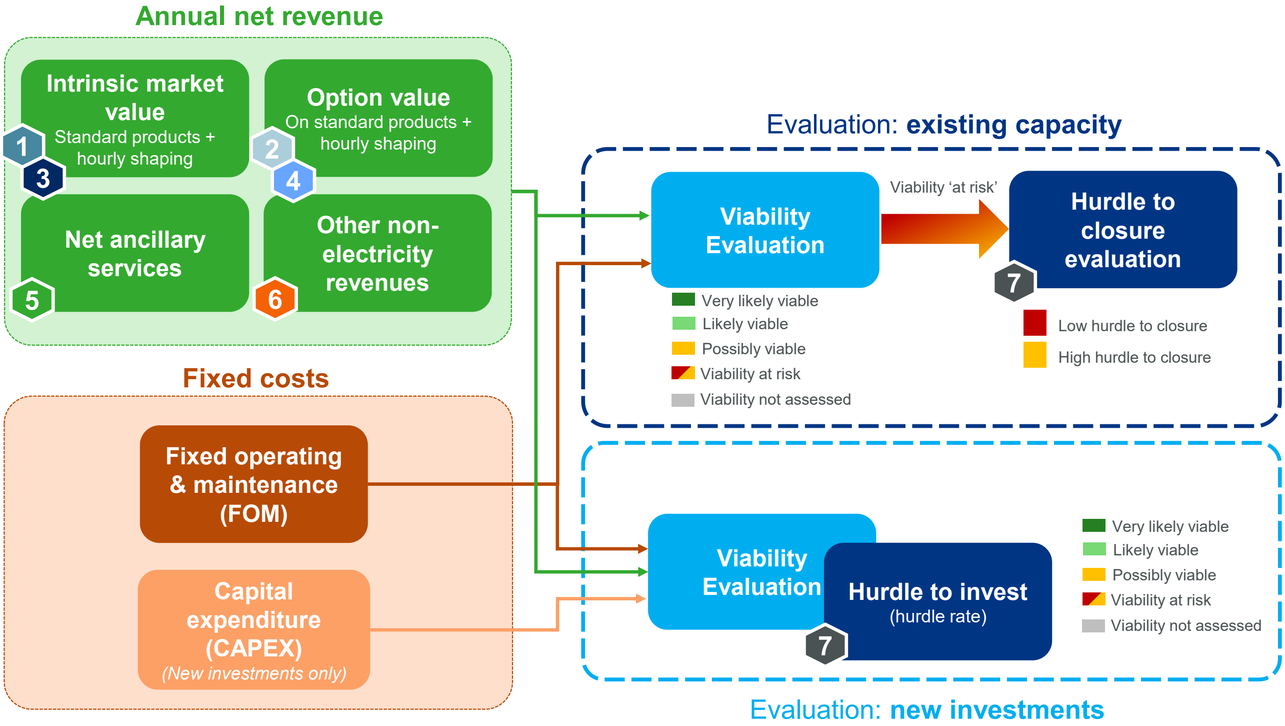

Annual net revenue
Intrinsic market value
Standard products + hourly shaping
1
3
Option value
On standard products + hourly shaping
2
4
Net ancillary services
5
Other non-electricity revenues
6
Fixed costs
Fixed operating & maintenance (FOM)
Capital expenditure (CAPEX)
(New investments only)
Evaluation: existing capacity
Viability Evaluation
Viability 'at risk'
Hurdle to closure evaluation
7
🟩 Very likely viable
🟩 Likely viable
🟨 Possibly viable
🟥 Viability at risk
⬜ Viability not assessed
🟥 Low hurdle to closure
🟨 High hurdle to closure
Viability Evaluation
Hurdle to invest
(hurdle rate)
7
🟩 Very likely viable
🟩 Likely viable
🟨 Possibly viable
🟥 Viability at risk
⬜ Viability not assessed
Evaluation: new investments

*Figure 13 | Overall approach for performing economic viability evaluation on the basis of the seven value drivers*

## 3.1 Annual net revenue

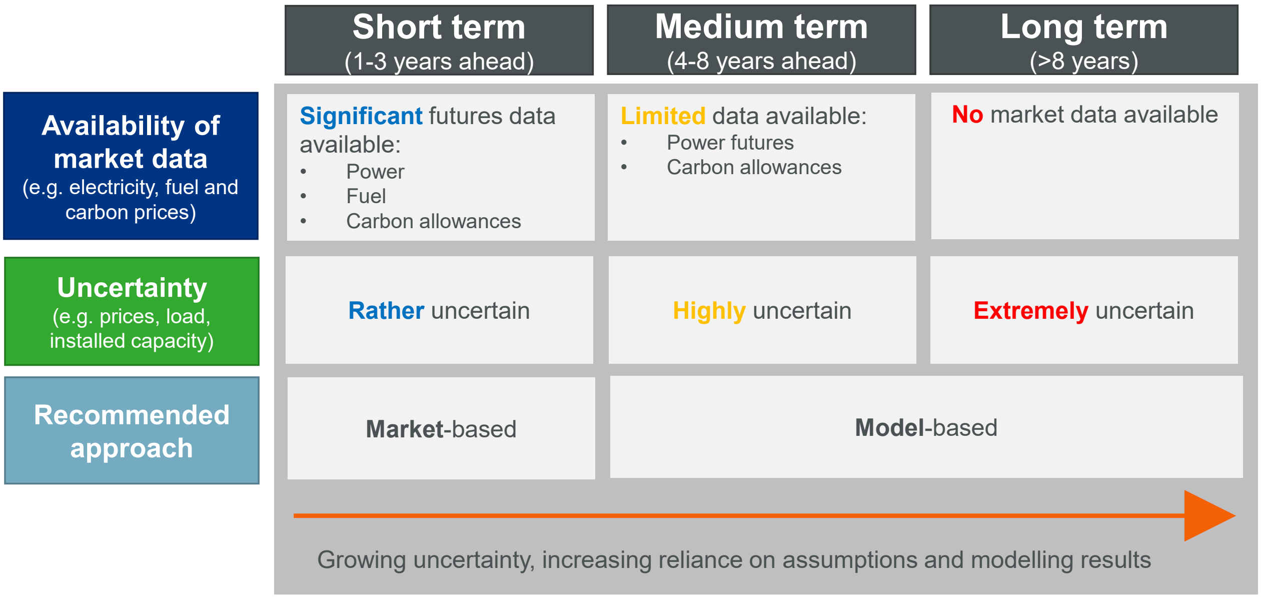
The first step is estimating the *annual net revenue* based on the value drivers as outlined in chapter 2. The annual net revenue has four components:

- *Intrinsic market value* is the sum of value drivers 1 (Value from standard futures products) and 3 (Hourly shaping value) and represents the total intrinsic value which can be derived from the electricity futures and spot markets.
- *Option value* is the sum of value drivers 2 (Optionality value from standard futures products) and 4 (Optionality value on hourly shaping) and represents the additional extrinsic value which can be derived from these markets.
- *Net ancillary services* is the value from value driver 5, including (net) revenues from balancing and other ancillary services; and
- *Other revenues* includes revenues from all other sources (e.g., GoO and heat), as outlined in value driver 6 (Other non-electricity revenues).

The approach for estimating these components is explained the following sections.

### 3.1.1 Intrinsic market value

When performing EVA, it is usually better to use actual market data for electricity, fuel and carbon prices to ensure revenues are computed on consistent prices and grounded in reality. Unfortunately, robust futures prices are usually only available for the coming three years as beyond this point futures markets are generally not sufficiently liquid. The approach used to quantify market value thus depends on the timeframe an EVA is to be performed for. For shorter term studies looking up to ~3 years ahead, a *market-based* approach is generally recommended based on available futures prices from exchanges. For longer term studies looking more than ~3 years ahead where limited or no futures prices are available, a *model-based* approach is typically needed (Figure 14). In the model-based approach, electricity market simulations based on UCED are used to forecast future electricity prices and dispatch patterns based on assumptions about fuel and carbon prices, hourly electricity demand, and the installed capacity of power plants.



| | **Short term** (1-3 years ahead) | **Medium term** (4-8 years ahead) | **Long term** (>8 years) |
|---|---|---|---|
| **Availability of market data** (e.g. electricity, fuel and carbon prices) | **Significant** futures data available:<br>• Power<br>• Fuel<br>• Carbon allowances | **Limited** data available:<br>• Power futures<br>• Carbon allowances | **No** market data available |
| **Uncertainty** (e.g. prices, load, installed capacity) | **Rather** uncertain | **Highly** uncertain | **Extremely** uncertain |
| **Recommended approach** | **Market**-based | **Model**-based | |

Growing uncertainty, increasing reliance on assumptions and modelling results

*Figure 14 | EVA requires different approaches depending on the timeframe of analysis and market data available*

Using the market-based approach, value driver 1 is estimated from futures prices and calculated spreads following the example provided in section 2.1 (see Table 1). Value driver 3 can be estimated as explained in section 2.3 by extrapolating historical (or modelling) capture rates and multiplying these by the relevant base load futures price for the relevant target year(s). Using the model-based approach, value drivers 1 and 3 are estimated together based on the net market revenue calculated from the model simulation results. This is because power plant electricity revenues calculated from such a model (e.g., as the product of the hourly generation and market price) implicitly represent the combined intrinsic value from both the futures/forward and day-ahead timeframes: in other words, the sum of value drivers 1 and 3 (see Box 5). The net market revenues should thus represent the inframarginal rent (Figure 15), including any start-up costs.[32]

When modelling, it is recommended to align the fuel and carbon price assumptions for future years to the current futures prices for these commodities where available. This allows the modelled electricity prices to be compared with actual futures prices, as an additional check of model robustness. If there are discrepancies which cannot be explained, it may be necessary to adjust the electricity price (or revenues) from the model based on a calibration before applying them in EVA.

The decision to keep a plant in operation or take it off the market is not typically based on revenues in a single year, but on forecast revenues in the short- to medium term to take into account expected developments in fuel and market conditions. Thus, where possible, it is better to perform an EVA based on expected revenues over the coming e.g., 3 years, rather than a single year. If market data is not available for all these years, it may be necessary to extrapolate prices based on market trends for the missing years or take a hybrid approach and use model results to fill the missing year(s). When it comes to new investments, decisions are usually based on expected economic performance over the lifetime of the investment which can be 15 years or more for large power plants. Thus, assessing the viability of new investments ideally incorporates a model-based approach where revenues are based on simulations across a longer-term horizon.

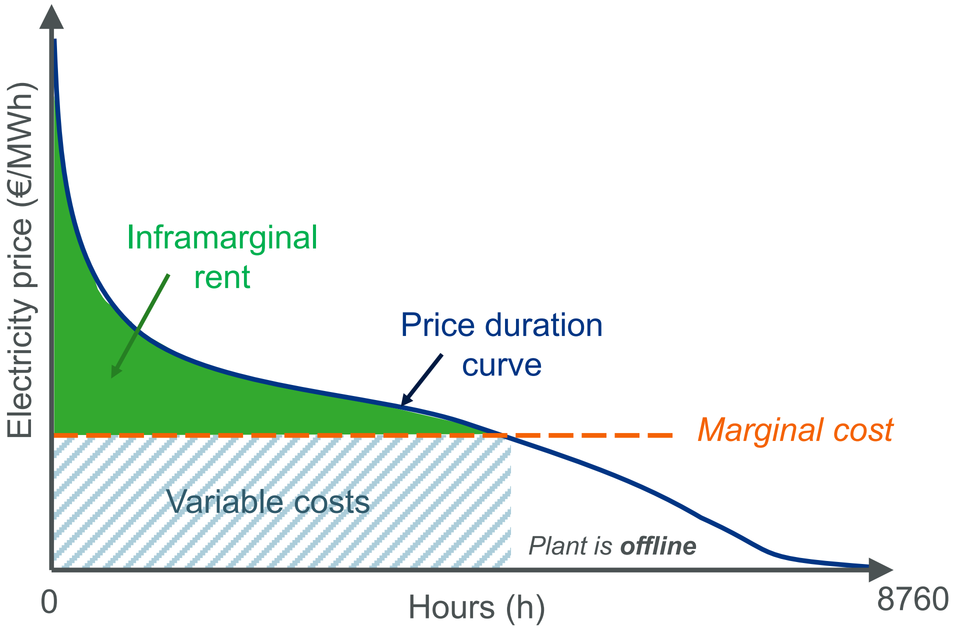


*Figure 15 | The annual inframarginal rent (IMR) is the difference between the hourly electricity revenue and the variable generation costs, summed across all hours of the year in which a plant is operating.*

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[32] The term ‘net revenue’ means that the revenues are net of variable generation costs i.e. fuel, carbon, variable operating & maintenance costs (VOM), and start-up costs.

### 3.1.2 Option value

The total optionality value is estimated by summing the contributions from value drivers 2 and 4, following one of approaches outlined in section 2.2 and 2.4 respectively. Given the uncertainties involved in modelling future prices, let alone future price volatility, it is recommended to estimate future optionality value based on an extrapolation of historical optionality, rather than trying to model price volatility and optionality value in the future. This applies to both the market- and model-based approaches.

### 3.1.3 Ancillary services and balancing, and other revenues

The remaining components of net market value are estimated following one of the approaches outlined in section 2.5 and 2.6 based on historical data, extrapolation of existing trends and expert assumptions where needed (especially for EVA studies with a longer time horizon).

## 3.2 Fixed costs

The second step in EVA is quantifying the fixed costs of the capacity resource. For existing technologies this refers only to Fixed Operating and Maintenance (FOM) costs, which are the annual costs of operation irrespective of the amount of electricity generated. The FOM includes elements such as staff salary costs, long-term maintenance agreements, insurance, electricity and gas grid connection tariffs, property tax, and provision for MMEs. MMEs are planned outage periods where significant maintenance work must be carried out every few years to keep a plant operating safely and efficiently. These MMEs can be seen as investments in the continued operation of the plant, and a plant must earn sufficient revenues on average in non-maintenance years to cover the cost of MMEs when they are needed.[33]

Electricity grid transport tariffs are an important component of the FOM costs for technologies which (also) consume electricity, such as batteries. These costs depend on the different types of contracts (e.g. firm or non-firm), and discounts may be available for limiting consumption during challenging periods for the grid [17].

Estimates of the FOM costs for different technologies are usually available from equipment suppliers, research institutes, energy agencies or consultant studies. As the FOM costs of individual plants can vary significantly (e.g., depending on age and previous investments), and it is not always clear if FOM estimates include an allowance for MMEs, several estimates of the FOM can be used (e.g. low, medium, high) to account for this uncertainty in the EVA.[34] If evaluating the viability of new investments, additional data is needed to account for the capital expenditure (CAPEX) for the plant including the overnight construction cost, the construction time, the economic life which ultimately feed into the formula for the IRR.[35]

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[33] For example, CCGTs need a major overhaul every 25,000 to 50,000 FLH (roughly once every 5 to 10 years) they operate, which can cost €15-25 million per unit [38]. Other types of MMEs are also needed more regularly, but are less costly.

[34] Plant operators may also follow different strategies to cover MMEs. For example, some operators may choose to only run a plant if a sufficient margin is made to also contribute towards the next MME, while for other (older) plants you may simply run until it breaks down, and not put aside funds for MMEs. A similar approach of comparing estimated revenues with a range of FOM values has also been used by Elia in previous adequacy studies [47].

[35] CAPEX is not considered for existing plants as these are treated as sunk costs, and the financing arrangements of individual plants are impossible to know with certainty. Some existing plants may still be paying off financing debt, but using an upper FOM estimate partly accounts for this.

## 3.3 Viability evaluation

The evaluation of economic viability is different for existing capacities and new investments. For existing capacities, a comparison is made between the estimated specific annual net revenues and a range of estimated FOM costs. The assumption is that a capacity resource is considered economically viable if it delivers a zero or positive gross margin. Uncertainties in the FOM (and hence the gross margin) are reflected in the evaluation (Figure 16):[36]

- If the revenues are higher than the higher FOM estimate (i.e., the plant achieves a *positive gross margin* even in the most pessimistic FOM case), the plant is deemed *very likely viable*.
- If the revenues lie between the medium and high FOM estimates, the plant is deemed *likely viable.*
- If the revenues lie between the low and medium FOM estimates, the plant is deemed *possibly viable.*
- If the revenues are below the low FOM estimate, the viability of the plant is deemed *at risk*.

For capacities in this last category whose viability is deemed at risk, a second hurdle to closure evaluation can be performed to determine if the plant is at high risk of closure, based on value driver 7 (see section 2.7).

To assess the potential economic viability of new investments, the IRR of an investment candidate is calculated based on the forecast annual net revenues and fixed costs including both FOM and CAPEX – expected to be incurred in each year of an investment's construction and economic life. The calculated IRR is then compared with the technology-specific hurdle rate following the methodology outlined in section 2.7. If the IRR exceeds the hurdle rate, the investment is deemed viable, otherwise it is deemed unviable.

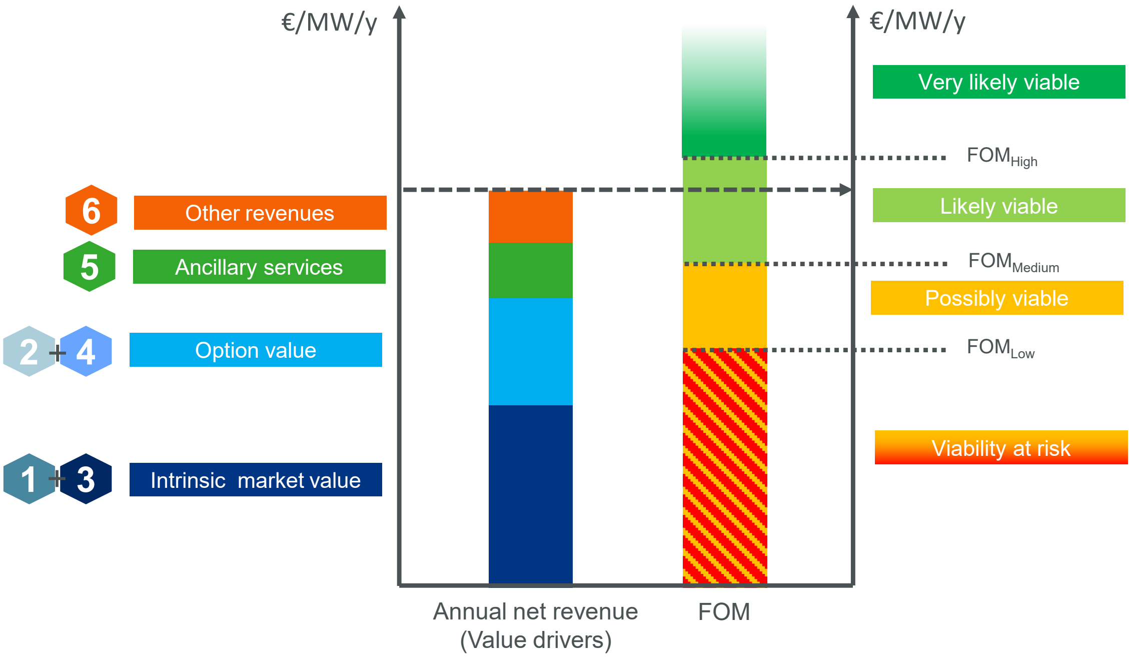

*Figure 16 | The viability evaluation for existing capacities is based on the difference between the annual net revenue and the FOM. In this example the total net revenue lies between the medium and high FOM estimates, and the plant would be considered likely viable.*

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[36] The gross margin is the difference between the total revenue and the direct costs incurred at plant level to produce the electricity. It does not include other costs of doing business such as corporate-level overheads, taxes, or depreciation.

Given the uncertainties involved in the determination of the hurdle rate, a range of hurdle rates can also be used for different technology types, rather than a single value. For example, to perform the viability evaluation the IRR can be calculated for each investment based on the median (50th percentile) annual net revenues from the simulations, as well as the reference fixed cost assumptions.[37] The range in which the IRR falls is then compared with the hurdle rate corresponding to its assigned risk category (Figure 17):

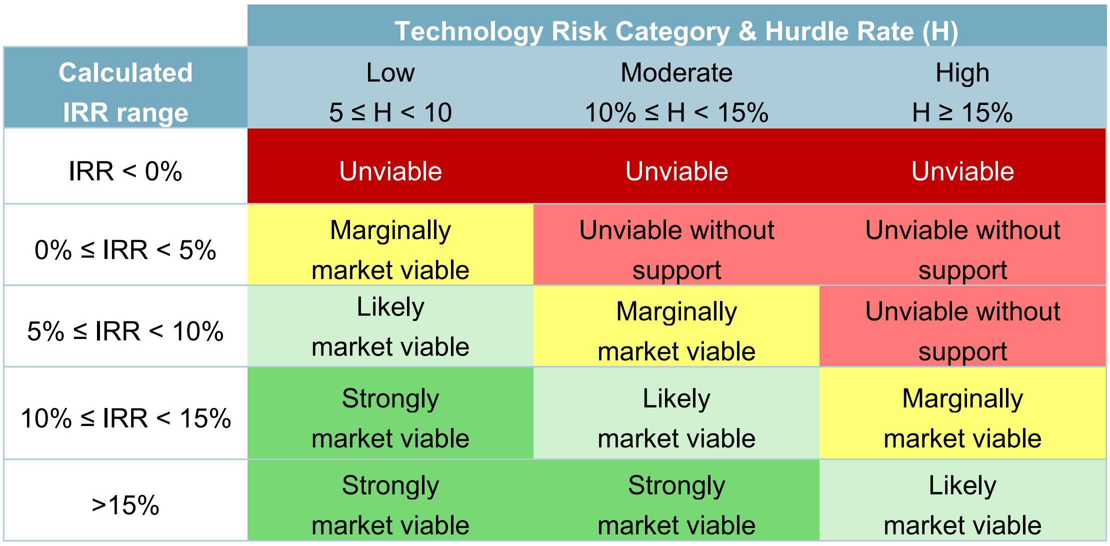
- if the IRR < 0%, the investment is deemed *unviable* as the total returns are less than the initial investment, irrespective of the assumed discount rate;

- if the IRR > 0% but significantly below the minimum required hurdle rate, the investment is deemed *unviable without support* as the return is considered too low for a private investor without state support;

- if the IRR falls just below the indicated hurdle rate, the investment is deemed *marginally market viable*. Viability in this case may still be possible for investors with a particularly low risk profile;

- if the IRR is in the same range as the hurdle rate, the investment is *deemed likely market viable* as the expected returns are comparable to the required hurdle rate; and

- if the IRR is significantly higher than the hurdle rate, the investment is deemed *strongly market viable*, as it indicates a robust return above the minimum required.



| | **Technology Risk Category & Hurdle Rate (H)** | | |
|---|---|---|---|
| **Calculated IRR range** | Low<br>5 ≤ H < 10 | Moderate<br>10% ≤ H < 15% | High<br>H ≥ 15% |
| IRR < 0% | Unviable | Unviable | Unviable |
| 0% ≤ IRR < 5% | Marginally market viable | Unviable without support | Unviable without support |
| 5% ≤ IRR < 10% | Likely market viable | Marginally market viable | Unviable without support |
| 10% ≤ IRR < 15% | Strongly market viable | Likely market viable | Marginally market viable |
| >15% | Strongly market viable | Strongly market viable | Likely market viable |

*Figure 17 | Evaluation of economic viability for new investments is based on the difference between the calculated IRR and the assumed hurdle rate*

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[37] Some argue that the mean revenue should be used rather than the median, as the latter does not capture potential years with (extreme) upside revenues [42]. However, investors are more likely to base their decisions on the 'most likely' scenario rather than the average across many potential scenarios, which can be skewed higher due to years with infrequent and unpredictable price spikes [43].

## 3.4 Example EVA calculations for selected technologies

To show how the overall EVA based on value drivers can be applied, in the following section we provide some simplified examples for three technologies: a modern CCGT, an offshore wind farm, and a 2-hour grid-scale battery. These calculations are based on an evaluation of the value drivers for 2025 using the price assumptions given in Table 7. Note that these examples are only intended to be illustrative of the market-based approach to performing EVA. The advantage of this approach is that it can be done without a complex model, simply on the basis of transparent assumptions and publicly available market data. Nevertheless it is important to keep in mind the assumptions and caveats below:

- Forward prices are volatile, thus an EVA based on limited market data only provides a snapshot of potential economic viability at a given point in time.
- Plants are assumed to be price takers, and market depth is not considered.
- Value driver 2 (Optionality on standard products) is estimated based on German base load option prices for Cal-2025, averaged across May 2023. In this example we assume only 25% of the maximum potential extrinsic value is captured.
- For new investments:
    - a reference WACC of 5.5% is used based on a value calibrated for Belgium [16], assuming this is also applicable for the Dutch context.
    - extrinsic value (i.e., value from drivers 2 and 4) is treated the same as intrinsic value, and contributes equally to annual net revenues.
    - net annual revenue for all future years of the economic life is assumed to remain the same as for 2025.

*Table 7 | Price assumptions used for the example EVA calculations (based on prices in early August 2023 unless otherwise stated)*

| Commodity/contract | Value | Source |
|---|---|---|
| **Dutch Cal-2025 base load power** | 120 €/MWh | EEX, via EnAppSys |
| **Dutch Cal-2025 peak load power** | 121 €/MWh | EEX, via EnAppSys |
| **TTF Cal-2025** | 46 €/MWh$_{HHV}$ | EEX, via EnAppSys |
| **EUA DEC 2025** | 92 €/tCO$_2$ | EEX, via EnAppSys |
| **GoO** | 7.5 €/MWh | S&P Global [14] |
| **Balancing reserve capacity**[38] | | |
| FCR capacity (Dutch auction, symmetric) | 20 €/MWh/h | TenneT [18] |
| aFRR capacity price (upward) | 10 €/MWh/h | TenneT [18] |
| mFRR capacity price (upward) | 5 €/MWh/h | TenneT [18] |

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[38] Prices for balancing reserve capacity (especially FRR) have increased in recent years due to the impact of the energy crisis. Rather than using actual values for 2023 (which are around 45 €/MW/y for aFRR), we assume reserve prices return closer to historical levels by 2025 as a result of gas and wholesale electricity prices stabilising, and additional competition on reserve markets from batteries putting downward pressure on reserve prices [20].

### 3.4.1 Combined cycle gas turbine (CCGT)

Table 8 provides a simple EVA for a modern 55% efficient CCGT. As an at-the-money plant it has rather limited value based on standard futures products, but has significant optionality value on standard products and hourly shaping value thanks to its flexibility. Accounting for some additional revenues from optionality on shaping and ancillary services leads to total estimated revenue of roughly 130 k€/MW. In this example the optionality value represents roughly 40% of the total value, showing how significant optionality value can be for CCGTs. On the basis of these revenues, an existing plant would be considered very likely viable when compared with typical FOM estimates. However, in the case of a new CCGT investment, the IRR is found to be below the minimum required hurdle rate and thus would not be viable.

*Table 8 | Simplified example of an economic viability evaluation for an existing CCGT in the Netherlands for 2025*

| | Valuation | | | Explanation |
|---|---|---|---|---|
| | €/MWh | Multiplier | k€/MW/y | |
| **Annual net revenue** | | | | |
| 1 | 121 – 84 –30 – 1.5 = 5.5 | 2800 | 15 | Power: 121 €/MWh (peak load)<br>Fuel: 46 / 55% = 84 €/MWh<br>Carbon: 3.6 GJ/MWh / 55% * 0.05 $tCO_2/GJ_{HHV}$ * 92 €/$tCO_2$ = 30 €/MWh<br>VOM: 1.5 €/MWh (assumption)<br>Multiplier: 3120 peak hours * ~90% availability |
| 2 | 25 * 25% = 6 | 7900 | 49 | Extrinsic value of German Cal-25 base load power option with strike price ~115 €/MWh: ~25 €/MWh<br>Assume only 25% of extrinsic value can be captured: 6 €/MWh<br>Multiplier: 8760 base hours * ~90% availability |
| 3 | (115%-1) * 120 = 18 | 2800 | 50 | Based on gas 115% capture rate in recent years (see Appendix A1), multiplied by the base load price |
| 4 | 1 | 2800 | 2.8 | Firm, flexible, at-the-money capacity |
| 5 | - | - | 10 | Conservative assumption of 10 k€/MW for all ancillary services |
| 6 | - | - | - | Assuming no other e.g. heat revenues |
| Total | | | **128** | Sum of value drivers 1 to 6 |
| **Fixed costs** | | | | |
| FOM | - | - | Low: 20<br>Med: 30<br>High 40 | Based on range of values reported including MMEs (e.g. [19] [20]) |
| CAPEX | - | - | ~96 k€/MW/y (850 k€/MW) | Based on a new CCGT with capacity in range of 400 and 800 MW [20] |
| **Overall viability evaluation** | | | | |
| Existing capacity | Computed gross margin is higher than the High FOM estimate, thus deemed **very likely viable**. | | | Value driver 7 not evaluated for viable capacity |
| New capacity | The calculated IRR is 8.5%.<br>As the IRR does not exceed the hurdle rate of 10%, new investment deemed **unlikely to be viable** | | | Assumptions:<br>• FOM: 30 k€/MW/y<br>• Construction time: 3 years<br>• Economic life: 20 years<br>• Hurdle premium: 5% [16]<br>• Hurdle rate: 5% (WACC) + 5% = 10% |

### 3.4.2 Offshore wind farm

Table 9 provides a simple EVA for an offshore wind farm. In reality, the plant owner would likely sell the majority of output via a long-term PPA (see Box 2) at a fair price negotiated with an offtaker. In our framework this is represented by a combination of value driver 1 (the reference forward base load price for electricity), driver 3 (the hourly shaping risk on the base load price) and driver 5 (imbalance risk). Additional revenues from GoO sales contribute to the margin. On the basis of these revenues and given FOM range, an operating wind farm plant would be very likely viable. Taking CAPEX into account, the calculated IRR suggests a new investment could also be viable.

*Table 9 | Simplified example of an economic viability evaluation for an offshore wind farm in the Netherlands for 2025*

| | Valuation | | | Explanation |
|---|---|---|---|---|
| | €/MWh | Multiplier | k€/MW/y | |
| **Annual net revenue** | | | | |
| 1 | 120 | 4000 | 480 | Power: 120 €/MWh (base load)<br>Multiplier: assume 4000 FLH/y (45% capacity factor) |
| 2 | - | - | - | Not relevant for wind, too deeply in-the-money |
| 3 | (80%-1) * 120 = -30 | 4000 | -120 | Based on ~80% capture rate (see Appendix A1), equivalent to a ~20% shaping risk on a PPA. |
| 4 | - | - | - | Not a major value driver for wind |
| 5 | -5% * 120 = -6 | 4000 | -24 | Assumption of net 5% imbalance cost |
| 6 | 7.5 | 4000 | 30 | Assume GoO price 7.5 €/MWh<br>*Note: No SDE subsidy considered for offshore wind.* |
| **Total** | | | **366** | Sum of value drivers 1 to 6 |
| **Fixed costs** | | | | |
| FOM | - | - | Low: 35<br>Med: 50<br>High 70 | Based on range from literature. |
| CAPEX | - | - | ~210 k€/MW/y (2300 k€/MW) | Based on the average of offshore wind CAPEX reported for period until 2025 from Elia [20] and the Danish Energy Agency [19]. In the Netherlands the cost of connecting an offshore wind farm to the onshore grid are borne by TenneT, which is not considered here. |
| **Overall viability evaluation** | | | | |
| Existing capacity | Computed gross margin is higher than the High FOM estimate, thus deemed **very likely viable**. | | | Value driver 7 not evaluated for viable capacity |
| New capacity | The calculated IRR is 11.2%.<br>As the IRR exceeds the hurdle rate, new investment is deemed **viable** | | | Assumptions:<br>• FOM: 50 k€/MW/y<br>• Construction time: 3 years<br>• Economic life: 25 years<br>• Hurdle premium: 3% [16]<br>• Hurdle rate: 5% (WACC) + 3% = 8% |

### 3.4.3 Grid-scale battery (2-hour)

Table 10 shows a simplified EVA for a large utility-scale battery connected to the High Voltage (HV) (i.e.,100 to 150 kV) grid. The main value drivers are hourly shaping and optionality value on day-ahead and intraday markets, as well as ancillary services revenues from providing balancing reserve capacity and energy. Thanks to their flexibility, batteries have a lot of optionality and are well placed to optimise their value across these different markets. Arbitrage between low and high spot prices provides a major share of the revenue, and average expected discharge and charging prices are based on an analysis of hourly day-ahead prices in 2023.[39] To account for the fact that capacity committed for day-ahead delivery cannot be used to provide upward reserve capacity (and vice versa), maximum potential balancing capacity revenues are discounted by 40%.

*Table 10 | Simplified example of an economic viability evaluation for a 2-hour battery in the Netherlands for 2025*

| | Valuation | | | Explanation |
|---|---|---|---|---|
| | €/MWh | Multiplier | k€/MW/y | |
| **Annual net revenue** | | | | |
| 1 | - | - | - | Not relevant for batteries |
| 2 | - | - | - | Not relevant for batteries |
| 3 | 180-(60/85%)= 109 | 365 * 1.5 * 2 = 1095 | 120 | Assumed capture price: 180 €/MWh (150% base load price)<br>Assumed charging price: 60 €/MWh (50% base load price)<br>Efficiency (round trip): 85%<br>Average cycles per day: 1.5 (~570 cycles/year [21]) |
| 4 | 10 | 1095 | 11 | To account for buying back power on the intraday market. |
| 5 | FCR: 20<br>aFRR: 10 | 8760 * 50% * 60% = 2628 *(for both FCR & aFRR)* | (20 + 10) * 2628 / 1000 =79 | Assuming:<br>• 50% capacity offered as FCR, 50% as aFRR<br>• 40% reduction in reserve revenues to account for limitations imposed by arbitraging between wholesale and balancing markets<br>• Not considering revenues for aFRR energy activation |
| 6 | - | - | - | Not considered |
| **Total** | | | **210** | Sum of value drivers 1 to 6 |
| **Fixed costs** | | | | |
| FOM | | | Low: 20<br>Med: 80<br>High: 185 | Low: based on typical FOM excluding grid fees.<br>High: based on 'Low' plus 165 k€/MW/y 2024 grid fees (assuming HV grid connection) with no discount<br>Med: based on 'Low' plus 60 k€/MW/y grid fees, assuming 65% discount on 2024 fees with non-firm contract and optimised time-of-use |
| CAPEX | | | ~110 k€/MW/y (1000 k€/MW) | TenneT estimate |
| **Overall viability evaluation** | | | | |
| Existing capacity | Computed gross margin is higher than the High FOM estimate, thus **very likely viable**. | | | Value driver 7 not evaluated for viable capacity |
| New capacity | The calculated IRR is 8.6%.<br>As the IRR roughly equals the hurdle rate, new investment deemed **marginally viable** | | | Assumptions:<br>• FOM: 80 k€/MW/y<br>• Construction time: 3 years<br>• Economic life: 15 years<br>• Hurdle premium: 3.5% [16]<br>• Hurdle rate: 5% (WACC) + 3.5% = 8.5% |

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[39] The price levels assume batteries are charged (roughly) at the 25th percentile of hourly prices within a day and discharged at the 75th percentile of hourly prices within a day.

Unlike thermal plants and wind farms, batteries are also consumers of electricity and thus liable to pay transport fees (i.e. grid tariffs) for the right to use the grid.[40] For batteries connected to the HV grid, tariffs have risen to 165 k€/MW/y in 2024. However, under the recent grid tariff reforms proposed for the Netherlands [22], by optimising their time of use to avoid consuming in congested periods and opting for a so-called ‘non-firm’ contract, in the near future batteries can be reasonably expected to be able to achieve a 65% discount on their grid tariffs.[41] Thus, instead of 165 k€/MW they would pay roughly 60 k€/MW/y. On the basis of these revenues and given FOM range, an operating battery which did not need to consider CAPEX would be very likely viable. However, taking CAPEX into account, the calculated IRR suggests a new battery investment would be at the margin of viability. In this case, small changes in e.g. the achieved price differential, assumed reserve price, CAPEX and/or grid fees would change the outcome of the viability assessment.

# 4. Conclusion

This whitepaper outlines TenneT’s proposed framework for performing high-level economic viability assessment of capacity resources for the purpose of conducting resource adequacy studies. The framework is based on seven key value drivers which encompass the full value capacity resources can derive from across all market timeframes (e.g. forwards, day ahead, intraday, ancillary services, balancing), additional non-electricity based revenues, as well as the hurdles for retiring or investing in new capacity. This framework is not a replacement for more detailed unit-specific economic analyses that market parties will conduct when considering to retire or invest in new capacity, as performing such elaborate analyses would not be feasible for TSOs to perform as part of an adequacy study. However, by quantifying the key value drivers at high level TenneT considers the proposed framework strikes the necessary balance between simplicity and accuracy. The framework outlined here was developed with European (and in particular Dutch) market conditions in mind, but the basic principles and value drivers will remain valid for other countries with similar liberalised electricity markets.

A key feature of this framework is that it includes extrinsic value, or the additional value that can be derived from an asset as a result of prices for power, fuel and carbon changing over time. Extrinsic value is a crucial economic driver for flexible at-the-money plants such as CCGTs, and can represent up to ~50% of the total plant value. While extrinsic value is less well known and more complex to quantify than intrinsic value, this paper identifies several ways it can be done and incorporated into EVA approaches.[42]

TenneT intends to apply the overall EVA framework as outlined in this whitepaper in future editions of the Dutch national resource assessment, the *Monitoring Leveringszekerheid*. However, the exact implementation and assumptions may vary as detailed methodologies are refined further in the coming years.

TenneT welcomes any feedback and suggestions to improve the methodology from stakeholders, market parties and other experts, which can be sent to servicecenter@tennet.eu.

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[40] This is the situation in the Netherlands. In other countries grid tariffs may be different and this should be considered in the analysis.

[41] Under a non-firm contract TenneT would have the right to limit the battery consumption (or production) for up to 15% of the year. This may also have an impact on battery revenues, which is not considered in this simple calculation. Note that batteries connected to the Extra High Voltage (EHV) grid would have lower grid fees of around 144 k€/MW/y.

[42] Including extrinsic value is also compliant with the ERAA methodology, which should include all revenues expected to be collected by capacity resources from the wholesale electricity market (Article 6(9)(a)) including forward, day-ahead and intraday markets.

# Acknowledgements

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# Appendices

## A1 Dutch capture rates

Figure A1 shows estimated historical annual capture rates for selected technologies in the Netherlands. Power plants running on natural gas (all types) achieve an average capture price higher than the base load price, and this difference is increasing over time. On the other hand, capture rates for RES have declined in recent years, especially for solar PV

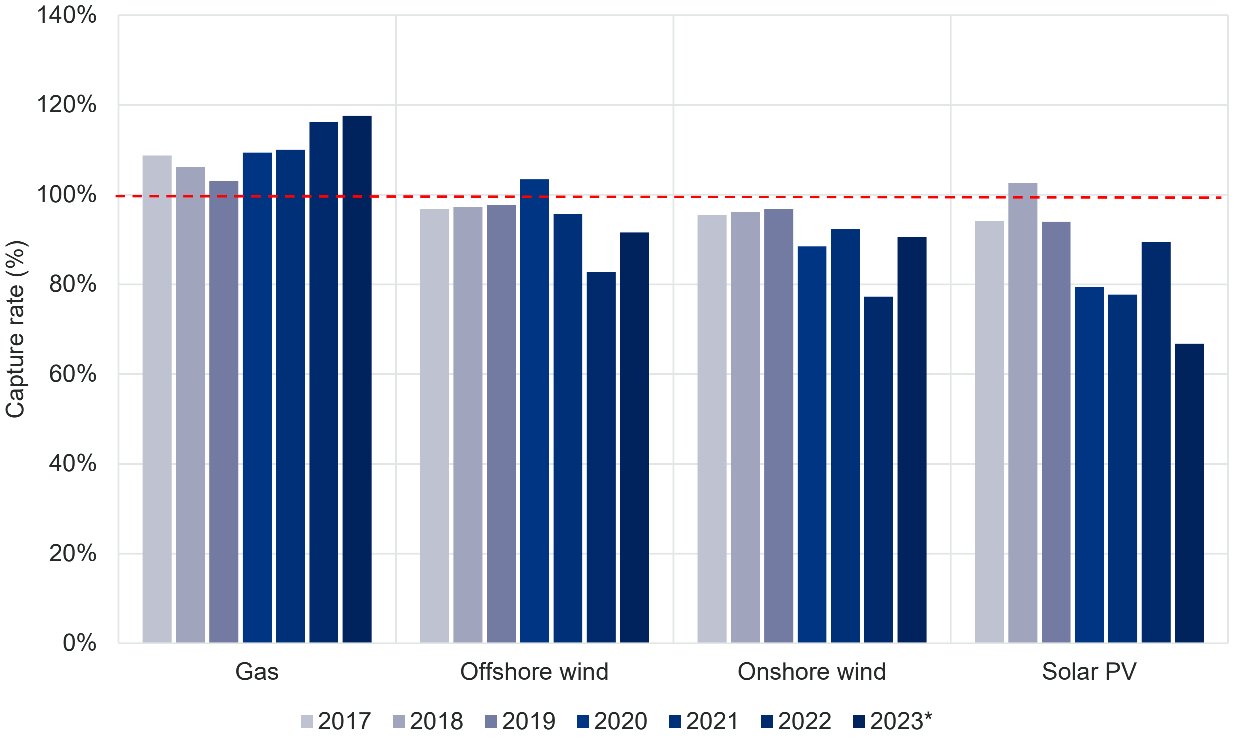

*Figure A1 | Estimated historical annual capture rates for selected generation technologies in the Netherlands. Data for 2023 only includes up to 30 September 2023. Data provided by EnAppSys.*

## A2 Net Present Value (NPV) and the Internal Rate of Return (IRR)

The Net Present Value (NPV) of a potential investment is the total value of all expected future cash flows (positive and negative) over the entire economic life of an investment, discounted to the present. A simple formula for the NPV of an investment is given below [23]:

$$NPV = \sum_{t=1}^{Y} \frac{CF_t}{(1+r)^t} - I_0$$

where:

$NPV$ is the Net Present Value (€),
$t$ is the year in the project lifetime (y),
$Y$ is the (economic) lifetime of the investment (y),
$CF_t$ is the expected net cash flow (i.e. income minus operating cost) from the project in year $t$ (€),
$I_0$ is the overnight cost of the initial investment (€),[43] and
$r$ is the assumed discount rate (%).

Following the NPV rule, an investment should only be made if the present value of the future cash flows of the project exceeds the initial investment costs for a given discount rate (i.e., the NPV is greater than or equal to zero). Another common indicator of profitability is the Internal Rate of Return (IRR), which is the discount rate which yields an NPV of zero.

The choice of discount rate has a significant impact as the higher the value of $r$, the higher NPV a project needs to deliver to be viable. As most projects are usually financed by a combination of equity and debt, the discount rate typically reflects the weighted average cost of capital (WACC). However, as explained in section 2.7.2, the WACC can also be adjusted to account for investment risk with the addition of a technology-specific hurdle premium [15]:

$$H = WACC^* + h$$

Following this risk-adjusted approach, a potential investment is considered viable if the NPV of the investment is greater than (or equal to) zero when the discount rate is set at the hurdle rate – or equivalently – if the calculated IRR is greater than (or equal to) the assumed hurdle rate.

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[43] In this simple formula the initial investment is assumed to be made ‘overnight’ in the first year of the project, but the formula can also be modified to account for projects where investment costs are spread over multiple construction years.