Analysis of hurdle rates for Belgian electricity capacity adequacy and flexibility analysis for the period 2026-2036

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1.Introduction

Will there be sufficient investment in electricity capacity in Belgium to ensure security of supply ("keep the lights on") over the next decade? To answer this question, Elia publishes every two years a detailed ten-year adequacy and flexibility analysis for the Belgian electricity system.[2] Also at European level, similar analyses are done. In particular, the European Network of Transmission System Operators (ENTSO-E) is mandated by European legislation to make a European Resource and Adequacy analysis.

In the adequacy and flexibility analysis, simulation methods are employed to assess the availability of necessary capacity to ensure security of supply. If a capacity need is identified, an economic viability check should be performed on existing and new capacity for different technologies to see whether they would be viable in the market with the current market design and under the given hypotheses. Within the framework, it is assumed that an investment takes place when the expected return exceeds the project's hurdle rate.

Under the simulation analysis framework, the expected return is computed as the outcome of simulated values from the distribution of inframarginal rents of a technology, together with assumptions on costs and lifetime of the technology. More specifically, the expected return equals the mean outcome of a large number of simulated project returns. The hurdle rates are defined based on a combination of qualitative and quantitative approaches. The quantitative approach involves an assessment of investment risk and risk preferences of the investor. It is complemented by a qualitative assessment relying on feedback from domain experts. A consensus number is determined keeping in mind the objective of evaluating the likelihood of security of supply.

The required rate of return for which investors are willing to invest in a certain technology differs across technologies. Boudt (2022) illustrates this heterogeneity across hurdle rates when evaluating investments in existing versus new capacity across technologies such as wind, photovoltaics, batteries, combined-cycle gas turbines (CCGT), open-cycle gas turbines (OCGT), and demand-side management (DSM).

He recommends a model in which the hurdle rate for new capacity investments in Belgium is determined by the reference Weighted Average Cost of Capital (WACC) and an additional hurdle premium. These components vary across technologies and are time-dependent, adapting to shifts in the macro-financial environment, changes in technology-specific cash flow profiles (including both costs and revenues), and underlying model assumptions.

Several new developments are available today that impact the calibration. Several pieces of new information are available today. Recent changes in macro-financial variables, combined with the unfolding of "what if…" scenarios such as the energy crisis and corresponding policy responses to price

[2] See https://www.elia.be/en/electricity-market-and-system/adequacy/adequacy-studies

spikes, as well as shifts in energy mix policy goals, have introduced new considerations for capacity investment analysis. Additionally, Elia has generated updated distributions of inframarginal rents, which provide refined input for evaluating investment viability. Specifically, Boudt (2022) used the inframarginal rents distributions of Elia (2021) with a price cap at 3k€/MWh. These assumptions have been revised by Elia (2023). In this study we also include the revenues from ancillary income, and use updated cost estimates per technology.

Similar to Boudt (2022), we emphasize that the calibration presented in this note relies on certain simplifications and should not be interpreted as representing an actual current investment case. While the study aims to give insights on the hurdle rates for the period 2026-20236 through a risk assessment, it does not include a full-fledged modelling of the expected return over this horizon. For instance, the predicted trends in energy prices and capacity availability are not taken into account. As such, the expected returns published in this report cannot be used to make any conclusion on economic viability.

The remainder of this note is organized as follows. Section 2 of this note first summarizes the framework used to calibrate the hurdle rates as in Boudt (2022). It then proposes a calibration for the reference WACC based on the current market values. Section 3 then suggests a calibration for the hurdle premiums per technology.

2.Reference WACC

2.1. Background

Helms et al. (2020) and Boudt (2021) explain how expected returns and hurdle rates are used in decision-making for investments in electricity capacity. Specifically, they outline that a project is considered economically viable if its expected internal rate of return surpasses a predefined threshold known as the hurdle rate (τ). In this context, the hurdle rate serves as the minimum return level that the expected internal rate of return must exceed for the investment to be economically viable.

Economic viability: $E[R] \geq \tau$ = Hurdle rate

An investment is thus modelled as financially attractive when the expected project return exceeds the hurdle rate, defined by ACER (2020) as the “minimum rate of return required by fund providers (shareholders and/or creditors) to finance investment in the reference technology in the considered geographic area”. ACER (2020) refers to the hurdle rate as the Weighted Average Cost of Capital ($WACC$). It then consists of a bottom-up calculation in which first the cost of equity (CoE), cost of debt (CoD), and gearing ratio (g, i.e. percentage of debt-based funding) of the project are defined. In addition the corporate tax rate (t) and expected inflation (i) over the project’s investment horizon are needed. All parameters are then aggregated into a (pre-tax and real) value of the WACC given by:

$$WACC = \frac{1 + \left[CoE \cdot \frac{1-g}{1-t} + CoD \cdot g\right]}{1+\pi} - 1$$

where:

- CoE: Cost of equity of the project
- CoD: Cost of debt of the project
- g: Gearing ratio of the project

- t: Tax rate
- π: Expected inflation

When these parameters are known, the project WACC can be directly computed.

Under the simulation-based decision framework, the CoE, CoD and g of the project over the analysed horizon are not known. Instead, based on historical data, one can make a good approximation of the cost of equity, cost of debt and gearing ratio of a potential reference investor. Denote these by CoE^*, CoD^*, and g^*, and let $WACC^*$ be the WACC of the reference investor. The deviations between the reference investor's parameters (CoE^*, CoD^*, and g^*) and the project parameters (CoE, CoD, and g) lead to a hurdle premium that differs across projects:

Economic viability: $E[R] \geq \tau$ = Hurdle rate = $WACC^*$ + hurdle premium

Since the project risk deviates from the risk profile of the reference investor, the presence of a hurdle premium is needed by construction.

This two-step approach of first defining the WACC of the reference investor and then computing technology-specific hurdle premiums to obtain the hurdle rates is in theory equivalent to an approach that defines the hurdle rates per technology in one step. However, due to the commonality between the drivers of the hurdle rates of different technologies, a two-step approach is recommended in practice to ensure consistency. A similar observation is made by Brealy et al. (2020) who note that the approach of adding a (relative) project adjustment to a reference cost of capital is easier than estimating each project's cost of capital from scratch. They make the following music analogy: "Most of us, lacking perfect pitch, need a well-defined reference point, like middle C, before we can sing on key." Under the simulation framework, getting the "relative pitch" requires taking into account the variance and non-normality of the project return under the base scenario, as well as the model risk that the actual state of the world is not described by that base scenario. As such, the approach of adding a (relative) project adjustment to a reference cost of capital is easier than estimating each project's cost of capital from scratch.

2.2. Calibration

For the reference cost of equity we recommend to follow the guidelines of ACER (2020). This includes the use of the Capital Asset Pricing Model (CAPM) for the cost of equity calculation.[3]

According to ACER (2020), we have:

$$CoE^* = r_f + \beta \cdot ERP + CRP,$$

where r_f is the long-term risk-free rate, β is the systematic risk of the reference investor, ERP is the equity risk premium and CRP is the country risk premium. For long-term investment in electricity capacity in Belgium over the period 2024-2034, a reasonable calibration is to set the nominal risk-free rate at 2.17% (as based on the average long term interest rate for Germany in September 2024).[4]

[3] Violations of the CAPM assumptions (due to exposure to other priced risk factors and the non-normality of the project returns among others) need to be accounted for in the hurdle premium.

[4] See https://www.ecb.europa.eu/stats/financial_markets_and_interest_rates/long_term_interest_rates/html/index.en.html and https://data.ecb.europa.eu/data/datasets/IRS/IRS.M.DE.L.L40.CI.0000.EUR.N.Z

Following Damodaran, the country risk premium of Germany in July 2024 is 0% while it is 0.73% for Belgium. The general market equity premium is at 4.12%. Using a set of representative utilities and energy companies, the equity beta for a reference investor is estimated at 0.83.[5] Given these parameters we can compute the nominal cost of equity:

$$CoE^{*} = r_f + CRP + \beta^{*} \cdot ERP = 2.17\% + 0.73\% + 0.83 \cdot 4.12\% = 6.3196\%.$$

The cost of debt and gearing ratio can be estimated by analysing the balance sheet of prospective investors and adjusting for the period. A reasonable number here is that in August 2024 the $CoD^{*} = 5\%$.[6] The gearing ratio of typical investors for OCGT was estimated at 44%. For investors in large scale batteries and renewable energy the gearing ratio is expectedly higher. We account for this heterogeneity in the calibration of the hurdle premium.

Assuming a corporate tax rate of 25% we have that the nominal WACC of the reference investor equals

$$\text{Nominal WACC} = CoE^{*} \cdot \frac{1-g^{*}}{1-t} + CoD^{*} \cdot g^{*} = 6.3196\% * \frac{1-0.44}{1-0.25} + 5\% * 0.44 = 6.9186\%$$

The expected long-term inflation is set to 2%.[7]

Assuming a corporate tax rate of 25% we have that the real $WACC^{*}$ is given by

$$WACC^{*} = \frac{1+\left[CoE^{*} \cdot \frac{1-g^{*}}{1-t} + CoD^{*} \cdot g^{*}\right]}{1+\pi} - 1 == \frac{1+6.6.9186\%}{1+2\%} - 1 = 4.8222\%$$

[5] The equity beta, the gearing and the cost of debt parameters take into account publicly available data from energy market players in Europe. Detailed calculations are available from the author.

[6] https://www.euro-area-statistics.org/digital-publication/statistics-insights-money-credit-and-central-bank-interest-rates/bloc-2b.html

[7] See https://www.ecb.europa.eu/stats/ecb_surveys/survey_of_professional_forecasters/html/table_hist_hicp.en.html

3.Hurdle premium in a market design without CRM (energy only market, inadequate)

3.1. Background

Boudt (2021) recommends that, for the scenarios and technologies that are similar to the ones considered in Elia (2021), and when the investment horizon is at least three years, the minimum value of the hurdle premium is the one described by Helms et al. (2020), namely 5% (nominal value).[8] [9] This minimum hurdle premium is needed to compensate for the fact that investors consider that the risk that the actual returns deviate from the expected returns (as computed under the base scenario used in the economic viability assessment) is higher than for the projects for which they use the reference WACC as hurdle rate. The reference WACC is based on the required return for listed companies by investors who can diversify that company risk in their portfolio. For the specific project risk, there are less diversification opportunities and clearly also less liquidity. This concentration and liquidity risk imply a premium for all investments considered. The 5% is the lower bound for the projects and technologies considered.

For the period 2026–2036, substantial policy and model risk persists in capacity investments in Belgium, warranting a minimum nominal hurdle premium of 5% for an investment horizon of three years and more. Key risk factors include fluctuations in energy prices, policy decisions regarding the energy mix, volatility in supply chain and material costs, levels of adequacy or inadequacy that affect price spike probabilities, prospective technological advancements, and possible price caps, among others.

3.2. Calibration of minimum premium

Under the framework described in Subsection 3.1, and using two digits as precision, we set the minimum hurdle premium to $\frac{1+5\%}{1+2\%} - 1$ = 2.94% leading to a minimum (real) hurdle rate of 7.76%.

Expected returns are computed under a reference scenario. As a guiding principle, we calibrate the premium such that, the higher is the likelihood of substantially lower than expected returns, the higher is the hurdle premium of the technology. The probability of an adverse investment return outcome is evaluated under the reference scenario (which is assumed to an inadequate scenario in terms of capacity), and importantly, also considering the likelihood and impact of other scenarios that would lower the expected investment return (e.g. a scenario of adequacy and/or lower energy prices).

3.3. Description of technologies considered

We study in total 14 technologies, namely

1. Batteries 2h represents the investment in a large-scale battery with 2h energy content.[10]
2. Batteries 4h represents the investment in a large-scale battery with 4h energy content.

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[8] Helms et al. (2020) note that “an additional hurdle premium of 5% or more on the WACC” is common in many industries.

[10] See https://www.elia.be/en/public-consultation/20220506_public-consultation-on-crm

3. DSM 4h represents demand side management capacities with an activation price of 300 €/MWh and maximum activation of 4h per day.
4. New CCGT represents the construction of a new Combined Cycle Gas Turbine with an installed capacity of at least 800 MW.
5. New OCGT represents the construction of an Open Cycle Gas Turbine with an installed capacity of at least 100 MW.
6. Existing OCGT represents the costs related to a OCGT that is already operational and does not require refurbishment.
7. Refurbished OCGT represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
8. Existing CCGT represents the costs related to a CCGT that is already operational and does not require refurbishment.
9. Refurbished CCGT represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
10. Old CCGT represents the costs related to an old CCGT that is already operational and does not require refurbishment.
11. Refurbished old CCGT represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
12. New offshore represents the construction of a new offshore wind installation.
13. New onshore represents the construction of a new onshore wind installation.
14. New PV represents the construction of a new PV solar installation. [11]

The internal rate of return calculations do not take the time to construct into account. The cost related to the time to construct is therefore assumed to be in the CAPEX calculation, as shown in the table below. The table also presents the revenues from ancillary services.

Table 1 CAPEX, FOM, lifetime and average revenues from ancillary services for the technologies considered

technology	CAPEX (€/kW)	FOM (€/kW/y)	Lifetime (years)	Ancillary Services Revenues (€/kW/y)
Batteries_2h	500	22	15	14,72
Batteries_4h	900	22	15	14,72
dsm_4h	0	25	3	13,06
New CCGT	840	30	20	0,94
New OCGT	660	25	20	19,61
Existing OCGT	0	25	3	13,79
Existing OCGT refurbishment	120	50	15	13,79
Existing CCGT	0	40	3	0,09
Existing CCGT refurbishment	144	37	15	0,09
Existing CCGT old	0	37	3	0,09
Existing CCGT old refurbishment	144	37	15	0,09
New offshore	2400	70	15	0
New onshore	1200	50	15	0
New pv	720	25	15	0

[11] The numbers represent a mix of solar installations with different sizes, taking into account the average costs of such PV installations.

Before presenting the simulation results, we first zoom in on two important drivers of the relative magnitude of project return risk: the merit order and the occurrence of extreme high prices over the simulation horizon.

The economic dispatch of different technologies in the electricity market, i.e. the determination which capacities deliver energy at a particular moment, is based on the so-called "merit order" principle. Based on the marginal costs offered by the different capacities available in the market, a supply curve can be conceived in function of increasing marginal costs. The electricity price for any given moment (e.g. on an hourly basis) is determined by the intersection between this supply curve and the demand curve. The higher the variable costs of the marginal technology (i.e. the most expensive technology that is still required to meet the electricity demand), the higher the electricity price for that given moment.

The technologies with marginal costs in the dataset are typically ranked as follows (with increasing marginal costs): renewable energy supply (wind and solar power) and baseload, gas-fired units such as new CCGT, refurbished and existing CCGT, CCGT, OCGT, and DSM 300. The determination of the marginal cost for large scale batteries- is more complex and very variable as it varies with the costs of charging the battery (depending on the market circumstances and flexibility to charge), the battery efficiency and degradation.

While wind and solar power have the lowest marginal costs and typically come first in the merit order, they are intermittent resources, i.e. their availability is obviously fully dependent on the weather conditions.

The market revenues for the market clearing capacity, i.e. the last one selected setting the market price, cover only its marginal costs, while other capacities earn inframarginal rents (i.e. the difference between the electricity price and their marginal costs for a given technology). As a result, capacities with lower marginal costs receive inframarginal rents more often than capacities with a high activation price. The investment case of such capacities with high activation prices depends therefore to a larger extent on the occurrence of price spikes. Stated otherwise, a contribution to the profitability of a capacity only takes place when the (spot) price on the market goes beyond the marginal cost of the considered capacity, i.e. when it is inframarginal. The higher the activation cost, the fewer hours with actual inframarginal rents, the more relevant it is that those more limited hours also actually occur. Hence, in some cases, profitability crucially depends on the occurrence of (very) high prices during only a handful of hours.

In Belgium, very high prices, i.e. moments exhibiting significant inframarginal rents for many capacities, most often occur in case of cold periods during winter (increase of consumption due to heating and low solar power output as the peak consumption typically takes place in the evening when it is already dark outside). When also no or limited wind power is available, this also drives prices up as technologies further in the merit order are needed to meet demand. Note that cold spells are regularly accompanied by low wind generation, which can lead to the so-called "Dunkelflaute", characterized by no wind and little sun.

During such periods, the contribution of wind and PV to the electricity production is obviously very low. At these moments, the remaining need for electricity (which is already higher given the low temperatures) has to be filled by other technologies such as thermal generation, imports, storage (if not yet depleted) and market response. Given that more expensive technologies (i.e. higher marginal costs) need to be activated to meet electricity demand, the very high price spikes occur typically during these moments with low sun and wind output. As a consequence, the statistical distribution of the inframarginal rents for wind and solar installations are less impacted by the occurrence of price spikes as they are simply not able to capture those spikes due to lack of wind and sun at those moments.

The hurdle premium calibration should take into account the discussed differences of position in the merit order and differences of exposure to high prices across technologies.

3.4. Distribution of inframarginal rents

We consider next three scenarios that define the distribution of inframarginal rents:

(i) **A base scenario of inadequacy** that is close to the scenario of the AdeqFlex study published in 2023. Under the base scenario, we consider a situation described in Elia's 2021 and 2023 Adequacy & Flexibility study where the economic viability of technologies based on energy market revenues (including ancillary revenues) only is at a tipping point. The already installed capacity tends to be profitable but adding more investments to the system would result in a loss. In this scenario, it was observed that the situation was however not yet considered adequate as the reliability standard was not yet met. In this scenario gas is used before coal in the electricity generation merit order and price cap increases are modelled.

(ii) **An alternative scenario of adequacy.** Under the inadequacy scenario, the reliability standard is not yet met. An alternative scenario is to complement the system with extra capacities making the scenario adequate. In such a scenario, we can expect lower average price levels and particularly less extreme price spikes. There is a risk of cannibalization for certain strategies, as a single new unit might put downward pressure to electricity prices, reducing the value of new capacity once operational, and hence reducing the incentives to invest in an energy only market context. Market parties largely depend on each other's choices, but lack perfect insight in these decisions of other investors increasing the uncertainty due to this lack of coordination between investors.

(iii) An alternative scenario of **lower energy prices**
This scenario corresponds to the low prices scenario from the Adequacy & Flexibility study of 2023. This scenario is considered because prices have already dropped compared to the base scenario and could fall further. Lower prices result in lower revenues for most technologies and therefore form an additional risk for capacity holders.

(iv) An alternative scenario of **lower energy prices and no price cap increases**
As a price cap increase have already been blocked in the past, there is a possibility that future price cap increases are also blocked. This mainly affects prices during moments of scarcity when high electricity prices are reached.

For each scenario, a technology has a distribution of inframarginal rents. We now simulate N=10'000 possible investment paths by resampling from the yearly inframarginal rents distribution under the base scenario. For each path, we compute the internal rate of return. This leads to N simulated returns: R_1 , R_2 , …, R_N for which we compute the mean and standard deviation as follow: $\mu = \frac{1}{N}\sum_{i=1}^{N} R_i$ and $\sigma = \sqrt{\frac{1}{N}\sum_{i=1}^{N}(R_i - \mu)^2}$. The value-at-risk and expected shortfall at loss probability α correspond to the α-quantile of the return distribution and the mean return below that quantile: $VaR = R_{(\lceil \alpha N \rceil)}$ and $ES = \frac{1}{\lceil \alpha N \rceil}\sum_{i=1}^{\lceil \alpha N \rceil} R_{(i)}$ where $R_{(1)}, R_{(2)}, \ldots, R_{(N)}$ are the ordered simulated return observations such that $R_{(i)} \leq R_{(i+1)}$. Popular choices for α are 1%, 2.5% and 5%. We further also report the standardized skewness, and the probability of negative returns: $P(R < 0) = \frac{1}{N}\sum_{i=1}^{N} I[R_i < 0]$.

By combining the distribution of inframarginal rents with associated costs and ancillary revenues, we thus derive a distribution of potential returns for investment options, as shown in the illustration below comparing new photovoltaic (PV) and new combined-cycle gas turbine (CCGT) investments. The vertical red dashed line represents the sum of the annual fixed operations and maintenance (FOM) costs and the annualized capital expenditures (CAPEX), providing an indicative threshold that these investments must surpass for profitability in a given year.

For new photovoltaic (PV) investments, the return analysis indicates a lack of profitability, as nearly all inframarginal rents fall below the red dashed line, resulting in mostly negative simulated returns. The variability in these returns is minimal, with a standard deviation of around 1%, highlighting limited risk but consistently low returns. In contrast, investments in new combined-cycle gas turbine (CCGT) facilities show a broader distribution of inframarginal rents, largely due to the uncertainty associated with potential price spikes. This variability translates to a higher standard deviation in the returns distribution, around 5%, suggesting greater volatility and potential for higher returns but with increased risk.

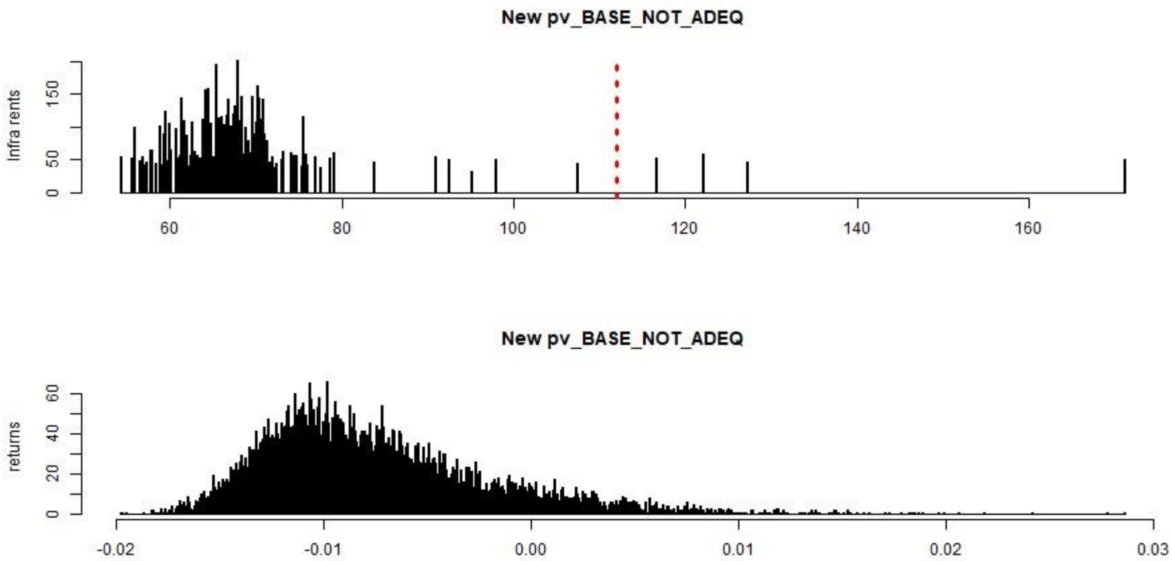

Figure 1 Distribution of yearly inframarginal rents (top figure) and simulated return over the lifetime (bottom figure) for investments in PV

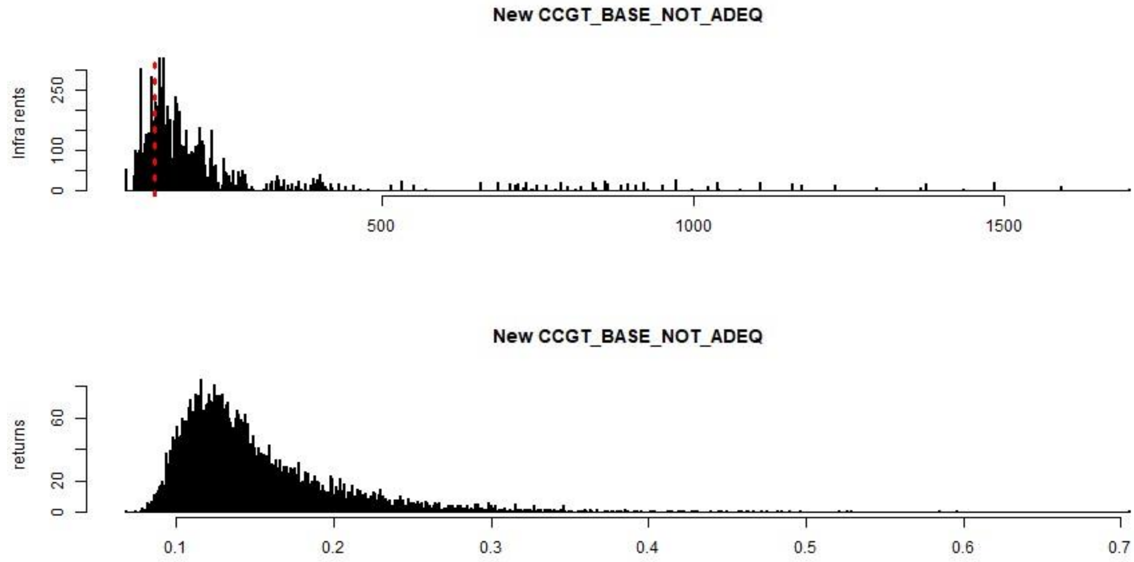

Figure 2 Distribution of yearly inframarginal rents (top figure) and simulated return over the lifetime (bottom figure) for investments in new CCGT

3.5. Distribution of returns under the main scenario of inadequacy

Table 2 presents the summary statistics of the return distribution for the different technologies under the main scenario.

We find that the risk of lower returns than expected is the lowest for investments in new onshore, offshore, PV and batteries. Their standard deviation is only 0.5% (new onshore, new offshore, new PV) and 0.9% (batteries). Under this scenario, the returns have thus only low deviation from their expected value and are thus highly predictable.

The other technologies have positive expected returns, but a substantial standard deviation. Through the lense of downside risk, we can evaluate the risk of losing money using the 5% value-at-risk and expected shortfall. For all the CCGT investments, we find that the downside risk is minor. The probability of below WACC returns is (nearly) zero.

For the OCGT investments, there is more downside risk. The probability of negative returns is at least 10%. The downside risk is higher for existing OCGT than for new OCGT.

The highest downside risk is observed for DSM 4h.

Table 2 Summary statistics of investment returns under the main scenario of inadequacy

scenario 2	mean	sd	P(R<0)	median	skew	5% VaR	5% ES
:----------------------- --------	-----:	----:	------:	------:	----:	------:	-----:
Batteries_2h	-0,02	0,009	0,974	-0,021	0,475	-0,034	-0,036
Batteries_4h	-0,041	0,008	1	-0,042	0,511	-0,053	-0,055

dsm_4h	0,112	0,473	0,552	-0,046	2,263	-0,257	-0,39
New CCGT	0,149	0,05	0	0,135	2,23	0,097	0,091
New OCGT	0,06	0,063	0,15	0,05	1,751	-0,019	-0,027
Existing ocgt	1,103	2,148	0,128	0,398	3,685	-0,069	-0,105
Existing ocgt refurbishment	0,062	0,098	0,302	0,049	1,674	-0,055	-0,067
Existing ccgt	1,322	1,338	0	0,907	3,951	0,523	0,46
Existing ccgt refurbishment	0,244	0,135	0	0,203	3,436	0,134	0,124
Existing ccgt old	1,094	1,382	0	0,679	4,172	0,25	0,191
Existing ccgt old refurbishment	0,184	0,126	0	0,15	3,558	0,076	0,065
New offshore	0,025	0,005	0	0,024	1,015	0,018	0,017
New onshore	0,046	0,005	0	0,045	0,912	0,039	0,038
New pv	-0,008	0,005	0,899	-0,009	1,13	-0,014	-0,016

3.6. Model risk: impact of adequacy on expected returns

An alternative scenario is to complement the system with extra capacities making the scenario adequate. Below we can see that this is reflected in a negative delta between the expected return under adequacy and the expected return under inadequacy: under adequacy, for nearly all technologies, the expected return is lower than under inadequacy. The biggest differences are observed for the existing OCGT and CCGT, as well as for DSM 4h.

There are also large differences of 7-8 per cent for new CCGT and new OCGT. Given the long lifetime of the investment, this is a significant factor of model risk for them.

Similarly, for the refurbished CCGT and OCGT we see a loss in expected return of 10% and higher.

For batteries, onshore and offshore the differences are small.

Table 2 Impact of adequacy on expected returns

	Expected return inadequacy	Expected return adequacy	Delta
Batteries_2h	-0,02	-0,035	-0,015
Batteries_4h	-0,041	-0,04	0,001
dsm_4h	0,112	-0,401	-0,513
New CCGT	0,149	0,066	-0,083
New OCGT	0,06	-0,012	-0,072
Existing ocgt	1,103	0,346	-0,757
Existing ocgt refurbishment	0,062	-0,036	-0,098
Existing ccgt	1,322	0,547	-0,775
Existing ccgt refurbishment	0,244	0,1	-0,144

Existing ccgt old	1,094	0,323	-0,771
Existing ccgt old refurbishment	0,184	0,043	-0,141
New offshore	0,025	0,009	-0,016
New onshore	0,046	0,028	-0,018
New pv	-0,008	-0,024	-0,016

<u>3.7. Model risk: impact of lower energy prices on expected returns</u>

The fuel and CO_2 prices are key components of the marginal costs of several fossil fuel technologies. The higher the expected CO_2 or fuel costs, the higher the marginal costs of such technologies, which will affect its place in the merit order. Therefore, assumptions on CO_2 and fuel prices play a crucial role in the profitability of such assets. Also, given that these fuel and CO_2 assumptions affect the marginal costs of some technologies, these have an impact on the clearing price and thus on the inframarginal rents of other technologies.

The main scenario has relatively high energy prices as assumption. Alternative is to assume lower energy prices. The table below show that lower than expected energy prices lead to lower expected returns for all technologies. The highest sensitivity is for the existing CCGT.

Table 3 Impact of lower energy prices on expected returns

	Expected return inadequacy with high energy prices	Expected return inadequacy with lower prices	Delta
Batteries_2h	-0,02	-0,053	-0,033
Batteries_4h	-0,041	-0,077	-0,036
dsm_4h	0,112	0,076	-0,036
New CCGT	0,149	0,086	-0,063
New OCGT	0,06	0,047	-0,013
Existing ocgt	1,103	0,966	-0,137
Existing ocgt refurbishment	0,062	0,045	-0,017
Existing ccgt	1,322	0,86	-0,462
Existing ccgt refurbishment	0,244	0,161	-0,083
Existing ccgt old	1,094	0,76	-0,334
Existing ccgt old refurbishment	0,184	0,126	-0,058
New offshore	0,025	-0,049	-0,074
New onshore	0,046	-0,034	-0,08
New pv	-0,008	-0,074	-0,066

Below we present the results in case prices are lower and there are no price cap increases. The presence of no cap increases further reduces the expected return. The effect is however of a smaller order of magnitude than the effect of the lower energy prices.

	Expected return inadequacy	Expected return inadequacy with low prices and without price cap increases	Delta
Batteries_2h	-0,02	-0,058	-0,038
Batteries_4h	-0,041	-0,08	-0,039
dsm_4h	0,112	0,071	-0,041
New CCGT	0,149	0,082	-0,067
New OCGT	0,06	0,041	-0,019
Existing ocgt	1,103	0,87	-0,233
Existing ocgt refurbishment	0,062	0,034	-0,028
Existing ccgt	1,322	0,817	-0,505
Existing ccgt refurbishment	0,244	0,157	-0,087
Existing ccgt old	1,094	0,719	-0,375
Existing ccgt old refurbishment	0,184	0,116	-0,068
New offshore	0,025	-0,05	-0,075
New onshore	0,046	-0,035	-0,081
New pv	-0,008	-0,075	-0,067

3.8. Model risk: impact of higher costs on expected returns

Until now, we have focused on the randomness of the inframarginal rents keeping costs pre-determined. This is of course also a strong assumption. As a sensitivity we study the impact on expected returns of increasing the CAPEX and FOM for each technology with 25%. For all technologies, the impact is substantial, implying sensitivity of the investment decision to the cost assumption. The largest impact is on the existing CCGT and OCGT investments.

	Expected return inadequacy with expected costs	Expected return inadequacy with 25% higher than expected costs	Delta
Batteries_2h	-0,02	-0,045	-0,025
Batteries_4h	-0,041	-0,065	-0,024
dsm_4h	0,112	-0,015	-0,127
New CCGT	0,149	0,11	-0,039
New OCGT	0,06	0,031	-0,029
Existing ocgt	1,103	0,809	-0,294
Existing ocgt refurbishment	0,062	0,025	-0,037
Existing ccgt	1,322	1,001	-0,321

Existing ccgt refurbishment	0,244	0,184	-0,06
Existing ccgt old	1,094	0,81	-0,284
Existing ccgt old refurbishment	0,184	0,133	-0,051
New offshore	0,025	-0,004	-0,029
New onshore	0,046	0,015	-0,031
New pv	-0,008	-0,034	-0,026

3.9. Tentative and conditional calibration of premiums per technology

In this section, for several considered technologies an indicative estimation of a reasonable hurdle premium is provided. They are conditional on the base scenario considered, as that scenario defined the observed variability and downside risk of the investment return and also the model and policy risk of lower than expected project returns due to the deviations from the base scenario that investors at the date of writing this report may consider. A change in market design, such as the implementation of a capacity remuneration mechanism with fixed capacity payments requires a complete re-evaluation of the hurdle premium for each technology (i.e. the implementation of a capacity remuneration mechanism would result in a lower hurdle premium).

No direct mathematical relationship can be established between the different identified risks and uncertainties and the level of the hurdle premium. The hurdle premium is rather to be set heuristically, and supported by the calculations performed in the context of this study (taking into account their underlying assumptions), based on an assessment of the different identified risks.

The resulting hurdle premium is an absolute number expressing the increase in the hurdle rate of the investment project with respect to the reference WACC used. In our setup the hurdle premium of investment projects in electricity capacity in Belgium at the time of writing this document is constrained by:

- The minimum hurdle premium for projects with a horizon of more than three years.
- The consistency in terms of relative ordering between the reference WACC investment and the technologies considered, on the one hand, and the internal ordering of the technologies (based on their investment risks), on the other hand.
- The discussed drivers of the hurdle premium: (i) explained variability and risk of losses under the basis scenario, (ii) model and policy risk and (iii) additional considerations such as hedging opportunities, difference in gearing ratio, difference in lifetime and CAPEX between investments, and impact of state-dependent preferences.

The feedback from market parties, financial investors and academic peers, as well as the results of the numerical analysis demonstrate that the model and policy risk is more influential to the investment decision compared to the revenue distribution and downside risk.

Below, we use as a rule of thumb that, for all technologies with an investment horizon of three years and more, the minimum compensation for model and policy risk equals the minimum hurdle premium of $\frac{1+5\%}{1+2\%}-1$ = 2.94%. Technologies with a shorter investment horizon can have a lower hurdle premium. We calibrate the hurdle premiums by ordering the technologies such that technologies with a higher investment risk have a higher hurdle premium.

The technologies with the lowest hurdle premium are

- those that have low variability of investment returns both under the reference scenario and across scenarios: solar, (offshore and onshore) wind. Batteries belong also to this category but have a slightly higher premium because of the investment required and technology risk.
- those that do not require a CAPEX investment, have a short investment period, and have a large upside potential: old CCGT, and existing CCGT/OCGT without refurbishment.

The technologies with the highest hurdle premiums are

- the investments in new gas turbines for which the investment case assumes a long lifetime and high capex, and whereby the choice for gas turbines in the energy mix implies high model and policy risk, namely a new CCGT and OCGT
- A moderately high premium is then for the existing CCGT and OCGT investments that require CAPEX investments for refurbishments.

Before presenting the numbers intended for use in the economic viability assessment, we repeat the important caveat that a change of context, modelling setup or other crucial factors may of course lead to another estimation of such hurdle premiums. All premiums are expressed in real terms.

3.9.1. Investment in new solar installation, (onshore or offshore) wind: Lowest premium (2.94%)

Risk of lower than expected returns under base scenario: Very low. The simulation analysis under the base scenario has demonstrated that the variability of returns is "very low" for these installations. Therefore, this parameter has limited impact on the hurdle premium. For wind and solar installation, the availability is obviously fully dependent on the weather conditions. It follows from the simulations, that they have less potential to benefit from price spikes.

Risk of lower than expected returns due to model and policy risk: Low. The profitability of an investment in these installations appears to be quite robust to alternatives. Indeed, the impact on expected return is more limited compared to other technologies. The main risk is the one of becoming obsolete. The current policy framework is supportive on the development of renewable energy capacities (e.g. Green Deal), but this can evolve during the economic lifetime of more than 15 years. Moreover, due to recent developments, model risk has increased for these capacities given that new policy measure target the taxation of excess revenues.

3.9.2. Investing in an existing OCGT in the market without refurbishment: Lowest premium (2.94%)

Risk of lower than expected returns under base scenario: low

The balancing revenues compensate to a large extent for the FOM. Market revenues show high variability but a significant part of it can be hedged. Note indeed that the variability of the revenue distribution and the downside risk can be immunized by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as OCGTs, in the forward markets. Optimization is possible to balance stable revenues from hedging and upside potential of price spikes when not hedged.

Risk of lower than expected returns due to model and policy risk: low. These technologies have a high sensitivity to the model assumptions such as the impact of high prices on the merit order (gas before coal vs coal before gas) and the status of (in)adequacy of the market. Also a tax-based ceiling on the project return has a large impact. The risk is reduced by the short horizon of 3 years and the fact that there is no CAPEX needed as initial investment. Alternative scenarios considered lead often to higher expected returns leading to upside potential.

3.9.3. Keeping an old CCGT in the market or keeping an existing CCGT in the market without refurbishment: Lowest premium (2.94%)

Risk of lower than expected returns under base scenario: low

Very high but, because of the short horizon of 3 years, a significant part of it can be hedged. Note indeed that the variability of the revenue distribution and the downside risk can be immunized by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as CCGTs, in the forward markets. There is model risk attached to this, given that the hedging analysis uses simulated spot prices, whereas there is no perfect one-to-one link between the forward prices. Optimization is possible to balance stable revenues from hedging and upside potential of price spikes when not hedged.

Risk of lower than expected returns due to model and policy risk: low. These technologies have a high sensitivity to the model assumptions such as the situation of inadequacy of the energy market, the FOM costs and imposing ceilings on returns and /or inframaraginal rents. The risk is reduced by the short horizon of 3 years and the fact that there is no CAPEX needed as initial investment. Alternative scenarios considered lead often to higher expected returns leading to upside potential.

3.9.4. Investment in large scale batteries: Hurdle premium of 3.5%

Batteries have a similar financial risk profile as wind and energy under the base scenario. Their hurdle premium is slightly higher than for PV and wind to compensate for the higher technology risk (large scale battery projects are rather new leading to an increased technology risk) and model risk. Moreover, over the years, there is also a significant degradation risk for batteries.

3.9.5. Investment in low activation cost DSM 4h: Hurdle premium of 3.5%

Risk of lower than expected returns under base scenario: Medium. There is a high variability in returns because of the dependence of activation on prices exceeding the DSM activation threshold. Such dependence is inherent to a DSM investment project and somewhat desirable from an operational perspective. Accounting for such state dependent preference implies discounting the "high risk profile" from a pure unconditional risk assessment to "medium".

Risk of lower than expected returns due to model and policy risk: Low-Medium. The profitability of an investment in new demand response is significantly impacted if the scenario becomes adequate. Given that the economic lifetime is short (around 3 years) and there is no substantial CAPEX involved, the model risk is limited.

3.9.6. Keeping an existing/old CCGT in the market with refurbishment: Hurdle premium of 4.5%

Risk of lower than expected returns under base scenario: Medium. A small top-up is given to compensate for the observed risk under the base scenario. The compensation for that risk (above what is already included in the reference WACC) is small given the possibilities for hedging part of that risk on forward markets (cf. previous section for more explanation on the impact of hedging).

Risk of lower than expected returns due to model and policy risk: Medium-high. The investment horizon is 15 years implying that when the existing CCGT is in operation, the conditions of the base scenario may no longer hold. There can be a more competition (e.g. resulting in changes in the merit order), higher costs. Their impact on the expected return is substantial and therefore justify the hurdle premium compensation for model and policy risk.

3.9.7. Investment in a new CCGT: Hurdle premium of 5.5%

Risk of lower than expected returns under base scenario: low. The analysis has demonstrated that the variability in the returns and downside risk is low for new CCGT installations. This variability of the revenue distribution and the downside risk can be further mitigated by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as CCGTs, in the forward markets. Although forward prices usually do not provide a more than three-year forward hedging horizon, which is too short to build a business case for a CCGT, future hedging opportunities might reduce investor's uncertainty as variability on historical forward prices is lower compared to spot prices. In addition, at the moment of the investment decision, given the time to construct such a CCGT unit (which takes 2 or 3 years), no forward contracts are available on which the investment can be hedged.

Risk of lower than expected returns due to model and policy risk: very high. The profitability of an investment in a new CCGT is highly impacted by the use of different scenarios. Thermal capacities, such as gas-fired installations, particularly run the risk that policy measures might impose stricter requirements on their operations in the future (e.g. the obligation of a minimum share of "green" fuel). Alternatively, such policies might ban these installations altogether). In addition, the business plan of gas-fired installations can also be significantly impacted by policy decisions that stimulate the development of renewable energy sources (e.g. such risk is real in view of the implementation of the Green Deal) as they may directly impact the position of such gas-fired units on the merit order. Moreover, a (perceived) implicit or explicit price cap would further decrease the asset's profitability. The higher the likelihood of these scenarios, the more reluctant the investor is to invest, and thus the higher is the hurdle premium required. The probability of these scenarios has increased compared to the previous evaluation in Boudt (2021), which explains the higher premium.

The significant economic lifetime of a CCGT of at least 20 years further aggravates this model and policy risk, given that the uncertainties and associated risks increase over time.

The significant impact of all these different scenarios, combined with the uncertainties related to the modelling of forward prices, and the long economic lifetime of at least 20 years, results in a “high” assessment for this parameter for new CCGTs.

3.9.8. Investing in an OCGT in the market with refurbishment: Hurdle premium of 5.5%

Risk of lower than expected returns under base scenario: high Very high but part of it can be hedged. Note indeed that the variability of the revenue distribution and the downside risk can be immunized by the risk-mitigating opportunities that exist particularly for baseload and mid-merit technologies, such as OCGTs, in the forward markets.

Risk of lower than expected returns due to model and policy risk: Medium-high. These technologies have a high sensitivity to the model assumptions such as the impact of high prices on the merit order (gas before coal vs coal before gas) and the status of (in)adequacy of the market.

3.9.9. Investment in a new OCGT: Hurdle premium of 6.5%

Risk of lower than expected returns under base scenario: High. The analysis has demonstrated that the revenue distribution and downside risk is “high” for OCGT installations, driven by the later position in the merit order book as compared to CCGT

Risk of lower than expected returns due to model and policy risk: Very high.

The profitability of an investment in a new OCGT is impacted by the use of different scenarios (increase in gas prices leading to a change in merit order, reaching adequacy in the market).

Furthermore, thermal capacities, such as gas-fired installations, particularly run the risk that policy measures might impose stricter requirements on their operations in the future (see explanation on CCGTs above). Finally, a (perceived) implicit or explicit price cap further decreases the asset’s profitability .

The significant economic lifetime of an OCGT of at least 20 years further aggravates this model and policy risk, given that the uncertainties and associated risks increase over time.

The impact of all these different scenarios, combined with the long economic lifetime of at least 20 years, results in a “very high” assessment for this parameter for new OCGTs.

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