Accounting for model, policy and downside risk in the economic viability assessment of investments in electricity capacity: The hurdle rate approach

Kris Boudt[1]

This version: February 17, 2021

Abstract:

Simulation methods are often used in a forward-looking evaluation of a country's security of supply of electricity. The framework includes modelling the investors' decision to invest in new or existing capacity. A realistic model needs to account for the large variability and non-normality of the inframarginal rents. This discussion paper first presents an overview of several potential investment rules. Based on this overview, we recommend modelling the investment decision using the simulation-based expected return and hurdle rates that are set equal to the cost of capital of a reference investor plus a hurdle premium. The latter serves as an important cushion to compensate for the predicted project risk under the base scenario, and the model and policy risk related to alternative scenario outcomes. The discussion paper also presents a baseline simulation setup and a proof of concept, including a tentative calibration of the hurdle rate under this simulation setup.

[1] Kris Boudt is professor of finance and econometrics at Ghent University, Vrije Universiteit Brussel and Vrije Universiteit Amsterdam.
Correspondence to: Kris Boudt, Sint-Pietersplein 5, 9000 Gent, Belgium. Email: kris.boudt@ugent.be
Acknowledgements: We are grateful to Elia's Market Development and Grid Development team for generously sharing their expertise on economic viability of investments in electricity capacity. We have also received helpful comments and suggestions from Keven Bluteau, Thorsten Helms, Mikael Petitjean, Koen Schoors, Piet Sercu, Steven Vanduffel, Rudi Vander Vennet, Brecht Verbeken as well as participants at the fifth "Comité de collaboration" between CREG, Elia, Federal Planning Bureau and the Federal Public Service Economy (DG Energy).

Table of Contents

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.

The adequacy and flexibility analysis uses simulation methods to determine the extent of capacity needed to maintain 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 simulation analysis, the investment decision needs to be translated into a rule that mimics a real-world decision maker who, just like a company, wants to maximize rewards and minimize costs. For investors, the reward is expressed in terms of expected return, while the cost is the investment risk. This cost is important for all rational investors, since one of the most basic tenets of modern finance is that investors are risk averse. They demand a risk premium in the sense that investments that increase the risk of their portfolio should also increase the expected return of the portfolio. If this were not the case, then the investment leads to an inefficient portfolio choice, as, by not doing the investment, it is possible to simultaneously increase the portfolio expected return and decrease the portfolio risk (Markowitz, 1952).

From a probabilistic viewpoint, the characterization of the expected return and risk of investing in electricity capacity in Belgium is highly complex due to the high variability and non-normal shape of the investment return distribution and the model uncertainty. The non-normality is partly caused by the occurrence of extreme price peaks during the investment period, while model risk is present due to omitting or misspecifying the impact of the many factors that drive the distribution of inframarginal rents. Scenarios need to be defined to quantify the impact on the return of changes in market parameters compared to a base case scenario. A key concern for some investors may be the risk of unmodelled regulatory and/or political intervention on the electricity market affecting the market design and prices. As noted by Baker et al. (2016), the anticipation of such intervention affects the decision to invest and thus the economic viability of the needed electricity capacity investment in Belgium.

The rule used in the economic viability study needs to be flexible and accommodate for the dynamic nature of the electricity market. Besides technology and regulation, also investment behaviour changes due to time-varying interest rates and risk premia, as well as changes in market share of different types of investors (e.g. utility incumbents, institutional investors and private investors) in electricity generation capacity (Helms et al., 2020).

In this document we first present an overview of investment decision rules that are feasible in the context of an adequacy analysis, such as the one performed by Elia, while accounting for real-word investor risk/return preferences. The recommended approach simulates an investment decision by evaluating whether the expected investment return exceeds the investor's hurdle rate to invest in that project. Since the investment risk differs across technologies, also the hurdle rate differs and a

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

calibration is needed. The developed approach also follows the contours set by the European methodologies decided by ACER on this matter.[3]

Consistent with standard textbook recommendation on capital budgeting, we set the hurdle rate equal to the cost of capital of a reference investor plus a hurdle premium. The latter serves as a cushion to compensate for the predicted project risk under the base scenario, and the model and policy risk related to alternative scenario outcomes. We present a detailed discussion on the calibration of the hurdle rate for a selection of relevant technologies for Belgium.

The remainder of the document is organized as follows. Section 2 first describes the naïve (risk-neutral) decision-maker who invests when the expected return is positive. We then switch to decision-making by the risk averse investor under expected utility theory and prospect theory. The practical version of these theories is to decide based on expected returns and hurdle rates, where hurdle rates reflect the perceived total project risk (combination of risk estimated assuming correct model specification, and a cushion to account for real-world deviations from the assumed model). Sections 3 and 4 discuss the practical implementation of the hurdle rate. Section 5 describes a high-level implementation of the proposed decision rule under the framework of estimating the distribution of investment returns under assumptions on the costs, distribution of yearly inframarginal rents and lifetime of the investment. Section 6 applies the framework in a proof of concept investment evaluation for eight types of electricity capacity investments, namely refurbished CCGT, new CCGT, existing CCGT, new OCGT, DSM300, DSM2000, wind and PV.[4] Suggestions for further research are given in the conclusion. In the appendix, we provide more details regarding the effect of higher order moments on the expected utility theory and the expected project returns.

[3] See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2023-2020_Annexes/ACER%20Decision%2023-2020%20on%20VOLL%20CONE%20RS%20-%20Annex%20I.pdf for the Methodology for calculating the value of lost load, the cost of new entry and the reliability standard.
See https://www.acer.europa.eu/Official_documents/Acts_of_the_Agency/Individual%20decisions%20Annexes/ACER%20Decision%20No%2024-2020_Annexes/ACER%20Decision%2024-2020%20on%20ERAA%20-%20Annex%20I.pdf for the Methodology for the European resource adequacy assessment.

[4] With DSM300 a demand response capacity with an activation price of 300 €/MWh is meant. In this report no further constraints (e.g. energy constraints or limited amount of activations) are taken into consideration.

2. Overview of rules for investment decision making under uncertainty

The problem to solve is an asset valuation problem since by investing in the capacity the investor incurs an immediate cost that is to be balanced with the uncertain cashflows that the project will yield. The investment decision would be straightforward if all project cashflows were predetermined. In practice, only the fixed costs in terms of capital expenditures and operations and maintenance costs are known. The revenues, called inframarginal rents (i.e. the revenues remaining after subtracting the variable costs such as fuel and variable operations and maintenance costs), have a large variability and depend on many parameters, whereby some of them are impossible to be known in advance.

The framework of analysis is thus the one of economic decision making under uncertainty. Investors are assumed to make optimal decisions according to a criterion. Below we describe the use of expected investment value, expected utility, cost of capital modelling and prospect theory. Each approach can be seen as an aggregation of random outcomes. We therefore start with setting up notation that allows us to describe the different approaches.

2.1. Notation

For simplicity in exposition, we assume that the project return is a discrete random variable. This is also consistent with the simulation setup described in Sections 3 and 4, where the randomness of the project return is driven by the simulated sequence of inframarginal rents drawn from a discrete distribution with M possible values.

Let R be the project return and assume it can take n possible values, namely $R_1, R_2, \dots, R_n$ with probability $p_1, p_2, \dots, p_n$. For each euro invested, the investor has thus a payoff equal to 1+R_i euro with probability p_i.[5]

2.2. Expected investment value

A first possible decision criterion is to evaluate the investment based on the expected value of the investment payoff:

$$1 + E[R] = 1 + \sum_{i=1}^{n} p_i R_i,$$

where $E[\cdot]$ is the expectation operator yielding the best possible prediction of the random variable in its argument.

The use of the expected return as the only decision criterion totally ignores the risk of the investment. It is a criterion used by risk-neutral investors. This is not a suitable stand-alone decision criterion for the typical investor who is risk averse. This conclusion is known as the St. Petersburg paradox in which a naive decision criterion who takes only the expected value into account predicts an investment decision that no reasonable person would take.[6]

[5] This value can be interpreted as both a present value or a future value depending on the approach used. See the next section for a more in-depth modelling of the probabilistic outcomes of the multi-period investment.

[6] The St. Petersburg paradox is derived from the St. Petersburg game, proposed by Nicolaus Bernoulli. In this game, a fair coin is flipped until it comes up heads the first time. The player pays a fixed amount initially, and then receives 2^k dollars if the coin comes up heads on the kth toss. The expected value of such a game is $\frac{1}{2}2 + \frac{1}{4}2^2 + \frac{1}{8}2^3 + \cdots = \infty$. The St. Petersburg paradox is the discrepancy between what people seem willing to pay to enter the game and the infinite expected value of participating in the game.

2.3. Expected utility theory

Economic theory makes use of utility functions to evaluate the welfare of the investor as a function of the project value achieved thanks to the investment. As is common, we set the initial project value as a numeraire. It is not the project final value $1+R$ that matters, but the utility of that project: $U(1+R)$, where $U(\cdot)$ is the utility function. The uncertain utility outcomes are aggregated by computing the expected utility, which is given by:

$$E[U(1+R)] = \sum_{i=1}^{n} p_i U(1+R_i).$$

The investment with the highest expected utility is preferred.

Risk averse investors have a utility function that is monotone increasing (more is better) and concave:

$$U\big((1-p)x+py\big) \geq (1-p)U(x)+pU(y).$$

It follows from this inequality that the expected utility of receiving $(1-p)x+py$ with probability 100% (certainty) is always higher than the expected utility of receiving x with probability $(1-p)$ and y with probability p. The two projects have the same expected net cashflow (namely $(1-p)x+py$), but the concave curvature in the utility function penalizes the risky outcome. The penalty for the variability increases as the function becomes more curved. The concavity also implies one additional euro has a higher utility impact at low levels of wealth than at high levels of wealth.

Figure 1 illustrates two common choices of the utility function, namely the CARA and the CRRA utility functions with risk aversion coefficients a for CARA and γ for CRRA. The CARA utility function is

$$U_a(x) = \frac{1-e^{-ax}}{a}$$

where $a \neq 0 \geq 0$ is the risk aversion parameter.[7] The CRRA utility function with risk aversion parameter γ is

$$U_\gamma(x) = \frac{x^{1-\gamma}-1}{1-\gamma}$$

for $\gamma \neq 1 \geq 0$ and, for $\gamma = 1,\ U(x) = \log{(x)}$.[8]

Table 1 provides an overview of various risk aversion parameters used in the literature. Based on this overview, a reasonable choice is to follow Oum et al. (2006) by setting $a = 1.5$ for CARA, and Willems and Morbee (2010) by setting $\gamma = 4$ for CRRA. A sensitivity analysis is always recommended.

---

[7] The corresponding coefficient of absolute risk aversion is $-\frac{U_a''(x)}{U_a'(x)} = a$. Note that this is constant, hence the name Constant Absolute Risk Aversion. For $a = 0,\ U(x) = x$ we have the special case of a risk-neutral investor.

[8] The corresponding coefficient of relative risk aversion is $-\frac{U''(x)x}{U'(X)} = \gamma$. Note that this is constant, hence the name Constant Relative Risk Aversion. For $\gamma = 0,\ U(x) = x-1$ we have the special case of a risk-neutral investor.

Table 1 Overview of CARA and CRRA risk aversion coefficients

Authors	Application	Value
CARA utility function		
Biais et al. (2010)	Portfolio choice	$a = 1.735$
Jondeau and Rockinger (2006)	Equity portfolio optimization	$a = 1$, $a = 2$, $a = 5$, $a = 10$, $a = 15$ and $a = 20$
Oum et al. (2006)	Managing quantity risk in the electricity market	$a = 1.5$
CRRA utility function		
Ang and Bekaert (2002)	Equity portfolio optimization	$\gamma = 5$
Conine et al. (2017)	Asset pricing model for stocks	Average value for γ of 2.
Martellini and Ziemann (2010)	Equity portfolio optimization	$\gamma = 10$ as reference case and $\gamma = 1$, $\gamma = 5$ and $\gamma = 15$ as alternatives.
Willems and Morbee (2010)	Hedging and investments in the electricity sector	$\gamma = 4$ as it is "in the middle of the typical 2-6 range"

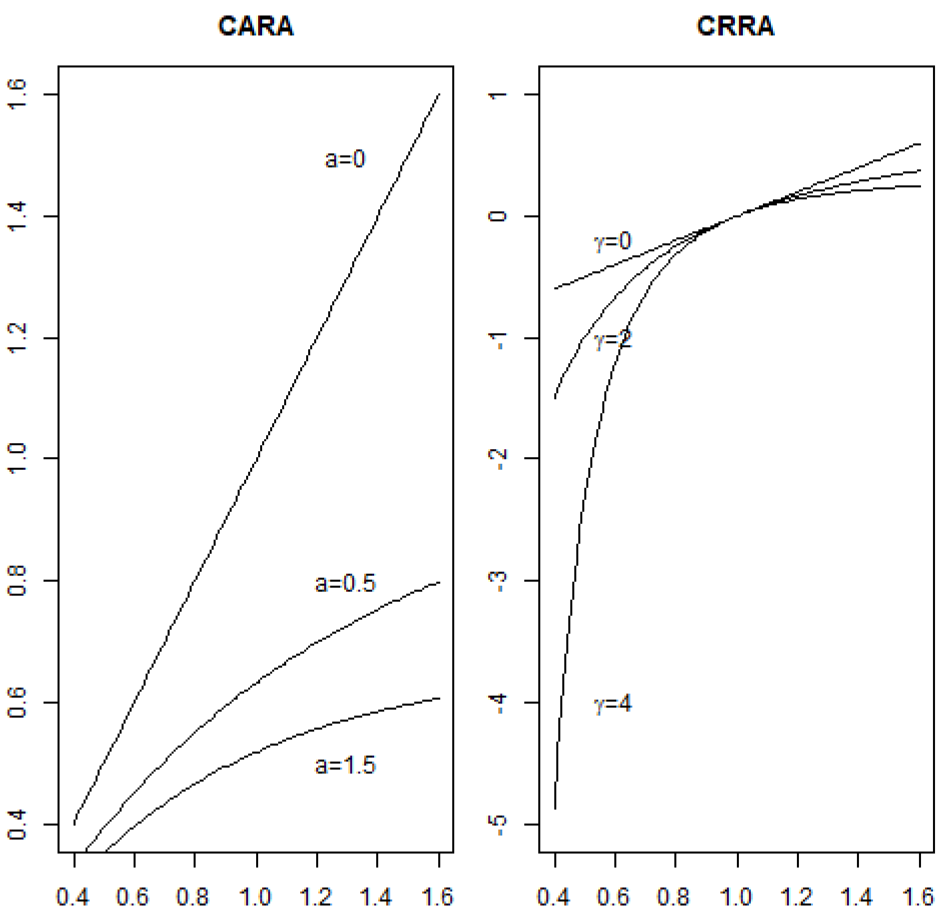

Figure 1 CARA and CRRA utility functions with risk aversion coefficients a for CARA and γ for CRRA. When $a = 0$ and $\gamma = 0$ the utility function is linear, which is the special case of a risk-neutral investor who only considers the expected cashflows and ignores the associated investment risk.

2.4. Impact of higher moments on the investor's expected utility

The higher is the expected utility obtained from the investment project, the better. But how do the stochastic properties of the project return contribute to the expected utility? The decomposition of expected utility in the contribution by the following four moments aids in the interpretation:

- the expected return $\mu = E[R] = \sum_{i=1}^{n} p_i R_i$
  [equals the best possible prediction of the investment return]
- the variance of the return $\sigma^2 = E[(R-\mu)^2] = \sum_{i=1}^{n} p_i\,(R_i-\mu)^2$
  [quantifies total variability of the return]
- the (unstandardized) skewness of the return $\zeta = E[(R-\mu)^3] = \sum_{i=1}^{n} p_i\,(R_i-\mu)^3$
  [quantifies the asymmetry in the distribution. Reference value of zero is achieved when positive and negative deviations cancel each other out (symmetry). Positive skewness results from a higher probability of large positive returns than large negative returns]
- the (unstandardized) kurtosis of the return $\kappa = E[(R-\mu)^4] = \sum_{i=1}^{n} p_i\,(R_i-\mu)^4$
  [quantifies the total variability in the return distribution, but compared to the variance, it gives more weight to the variability of the tails in the distribution]

Scott and Horvath (1980) show that the typical risk averse investor has positive preferences for the odd moments (mean and skewness: the higher, the better) and negative preferences for the even moments (variance and kurtosis: the lower, the better). Note that these are preferences with respect to the unstandardized moments. In the case of a return distribution with a fat right tail (high likelihood of extreme positive returns) all moments (even and odd) are inflated. The net effect depends on the utility function considered and the exact shape of the distribution.

It is common to use Taylor expansion to quantify the effect of each of these variability measures on the expected utility. In the appendix, we show that the CARA and CRRA utility functions can be approximated as follows using the first four moments:

$$EU_a \approx \frac{e^{-a(1+\mu)}}{a}\left(e^{a(1+\mu)} - 1 - \frac{a^2}{2}\sigma^2 + \frac{a^3}{6}\zeta - \frac{a^4}{24}\kappa\right)$$

$$EU_\gamma \approx U(1+\mu) - \tfrac{\gamma}{2}(1+\mu)^{-(\gamma+1)}\sigma^2 + \tfrac{\gamma(\gamma+1)}{6}(1+\mu)^{-(\gamma+2)}\zeta - \tfrac{\gamma(\gamma+1)(\gamma+2)}{24}(1+\mu)^{-(\gamma+3)}\kappa.$$

Consistent with the general result of Scott and Horvath (1980) we find that for CARA and CRRA utility function, a risk averse investor has positive preferences for the mean and skewness and negative preferences for the variance and kurtosis.[9] The higher order expansion of the expected utility function is important since the returns on investing in electricity capacity are non-normal. Price spikes in the electricity markets inflate all moments, and especially the higher moments because of the power transformation.

While the different utility functions agree on the sign of the effect of the moments, they differ in terms of the respective impact on the expected utility function. Assuming one specific utility function (and risk aversion parameter) for all investors may therefore be considered as restrictive.

[9] In the simulation study one can check the accuracy of the approximation using the first four moments. The interpretation of moments greater than four is a subject for further research.

2.5. Prospect theory

Expected utility theory makes heroic assumptions about the rationality of investors. Behavioral finance describes decision making under uncertainty by normal people. The main framework in this literature is the prospect theory of Kahneman and Tsversky (1979) that explicitly models the loss aversion preferences of an investor. There are two key elements of this theory. First, individuals do not make choices based on a utility function but on a value function in which outcomes are compared to a reference point, called anchor. The value function is concave for gains (outcomes higher than the anchor; risk-aversion), convex for losses (risk-seeking), and steeper for losses than for gains. Experiments show that the impact of a loss tends to be twice as large as the impact of a gain of the same magnitude.

A second key element is that investors use decision weights for each outcome that are a nonlinear transformation of the true probability. The probability transformation is such that the decision maker tends to overweight small probabilities and underweight high probabilities. Tsversky and Kahneman (1992) propose the following probability transformation function:

$$\pi(p) = \frac{p^{\delta}}{(p^{\delta} + (1-p)^{\delta})^{1/\delta}}.$$

For long-term electricity capacity investment, the low probability event of interest is that over the long investment cycle there will be no price spikes. This is a concern as the occurrence of a price spike is a main driver of the expected investment return. From the viewpoint of the investor, a loss scenario thus occurs when there is no price spike over the investment horizon. Under prospect theory, (s)he will tend to overweight this low-probability scenario leading to a lower perceived return than the actual expected return.

The objective function under prospect theory is the perceived weighted value of the different outcomes:

$$\sum_{i=1}^{n} \pi(p_i)V(1 + R_i - A),$$

where A is the anchor and $V(\cdot)$ is the function that expresses the perceived value. The value function is increasing (the more the better), with the absolute impact of a loss roughly equal to two times the impact of a gain of the same magnitude: $|V(0) - V(-d)| \approx 2(V(0) + V(d))$ (loss aversion: effect of loss is twice the one of a gain). The value function $V(\cdot)$ is concave (resp. convex) for gains (resp. losses).

Figure 2 illustrates a hypothetical value function and probability transformation function. The anchor is 1. Values of $1 + R_i$ above one are considered as gains and valued using a concave increasing function, values below one are considered as losses and therefore valued using a convex increasing function. In the probability transformation plot we see that low probabilities receive a higher decision weight than their actual probability.

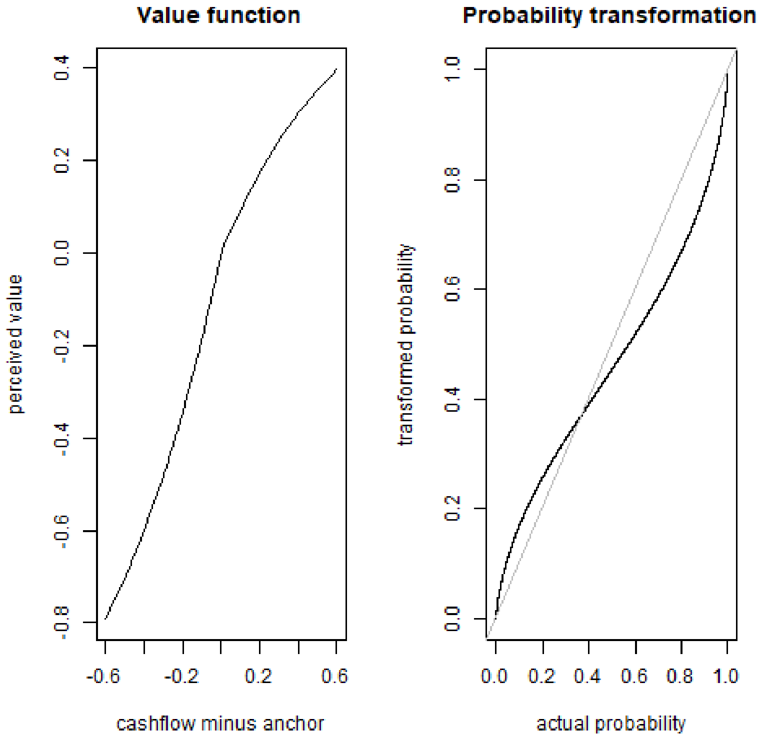

Figure 2 Hypothetical value function and probability transformation function used in prospect theory

2.6. Internal rate of return, hurdle rate determinants and cost of capital modelling

The expected utility theory and prospect theory are popular frameworks in economic theory, but they are less often used in practice. The standard textbook solution for capital budgeting is to compute the project's net present value as the sum of discounted expected cashflows, where the discount factor assumes a Weighted Average Cost of Capital (WACC) of debt and equity.

An equivalent approach is to compute the internal rate of return and decide to invest when the expected internal rate of return exceeds the so-called hurdle rate (Helms et al., 2020). The hurdle rate is thus the threshold τ that the expected internal rate of return of the project needs to exceed for the project to be economically viable.

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

We can directly estimate the expected return from simulations, like the ones used in the adequacy and flexibility analysis. The estimation of expected return should take the randomness of the investment cashflows into account. In Appendix B we show how the moments of the cashflows affect the expected returns.

Setting the hurdle rate requires a combination of qualitative and quantitative approaches. The qualitative approach relies on surveys of investors and market experts.[10] Such surveys have been conducted by Meier and Tarhan (2007) and Graham and Harvey (2018), among others. They can be

[10] It is to be noted that in the context of this study the author of this study has discussed with a number of experts from academia, financial institutions and market actors in order to cross-check whether the developed reasoning can also be sufficiently backed up by practice.

complemented by an analysis of recent investment opportunities in similar projects.[11] The quantitative approach supports the qualitative approach by providing numbers on the project risk, and by aggregating the hurdle rates suggested by several experts into a single consensus number.

When estimating the investor's hurdle rate for the project under consideration, it is important to evaluate the consequences of over -and underestimation of the hurdle rate. Based on the confusion matrix in Table 2, two mistakes are possible:

- False positive mistake: Simulation-based rule classifies the investment project as economically viable while it is not
- False negative mistake: Simulation-based rule classifies the investment project as economically unviable while it is

From the viewpoint of guaranteeing security of supply ("keep the lights on") the false positive mistake is the most damaging one. This implies that the hurdle rate can be set in a conservative way, but not in an excessive way as to avoid also inefficient use of available resources.

Table 2 Confusion matrix when algorithms needs to predict actual investment. The null hypothesis is that there is no investment. The simulation-based decision maker seeks for sufficient data evidence to reject that null and thus conclude that there will be an investment[12]

		Simulation-based decision to invest	
		Economically not viable (do not reject the null, negative)	Economically viable (reject the null, positive)
Actual investor's decision	No investment (null hypothesis is true)	True negative (Correct inference)	False positive (Error of type I)
	Investment (null hypothesis is false)	False negative (Error of type II)	True positive (Correct inference)

2.7. Overall recommendation

The overview paper by Helms et al. (2020) describes the use of expected returns and hurdle rates to decide on investing in electricity capacity. We recommend using this approach in economic viability assessments. The corresponding decision algorithm is described below.

1. Use simulation techniques to estimate the distribution of the internal rate of return of the project under the base scenario
2. Use qualitative and quantitative methods to set the hurdle rate (see next section)
3. Invest when the expected return exceeds the hurdle rate.

[11] A data-driven approach could be to compute the largest expected returns of the investments for which there has not been an investment and the lowest expected return for which there has been an investment in recent times. The hurdle rate is in between these two numbers. In the ideal case where one has a large number of observed returns, regression techniques can be used to quantify the compensation for the risk taken.

[12] The analogy can be made with judicial decision: someone is innocent until proven guilty. Here the project is not economically viable until proven viable.

3. Calibration of the hurdle rate

In this section, we first present the theoretical hurdle rate obtained when the project cost of equity, cost of debt, taxation ratio, expected inflation and gearing ratio are known. We then translate the theory into practice by introducing a decomposition of the hurdle rate into the WACC of a reference investor and a project-specific hurdle premium. The hurdle premium is needed to account for the observed risk under the base scenario used to compute the expected return. It also adjusts for the empirical fact that investors do not evaluate their investment within the boundaries of a single scenario. They account for the model risk and policy risk of lower than expected returns due to deviations from the return distribution obtained under the base scenario. Linked to this latter aspect, in the context of this study, the hurdle premium also accounts for the boundaries set by the simulation setup.

3.1. General framework

An investment is 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:

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

where:

- CoE: Cost of equity of the project
- CoD: Cost of debt of the project
- g: Gearing ratio of the project
- t: Tax rate
- i: 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 potential investors. Denote these by CoE^* , CoD^* , and g^* , and let $WACC^*$ be the WACC of the reference investor.

In Appendix, we document how 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. Brealy et al. (2020) note 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. But anyone who can carry a tune gets relative pitches right."

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.[13]

Firstly, the reference CAPM cost of equity calculation ignores the project-specific risk in terms of both the return variance and the non-normality of the return distribution. Specifically, ignoring the non-normality leads to an omitted variable bias in the standard CAPM cost of capital calculation versus the higher order moment CAPM cost of capital models (see e.g. Kraus and Litzenberger (1976) and Jurczenko and Maillet (2006)). In Appendix D we provide a short overview of alternative approaches for calibrating the cost of equity.

The effects for a typical risk-averse investor are economically significant given the large deviations of the distribution of project returns for electricity capacity from the normal distribution. It can therefore be expected that the CAPM cost of equity calculation leads to biased conclusions in terms of economic viability of investments in electricity capacity. A practical solution for this is to compensate for this effect by taking the effects of the non-normality of the returns into account when calibrating the hurdle premium. Candidate metrics are non-parametric downside risk estimates (simulated value-at-risk and expected shortfall) and expected utility evaluations using the simulated distribution of returns.[14]

Secondly, for medium to long-term investments in electricity capacity in which simulations are used to compute the expected return and risk, there is an inevitable model risk. Elimination of model risk is impossible due to the non-linear dependence between decisions of various market players (modelled as an iterative process), the long horizon of the investment, the international context of the electricity market, the uncertainty about economic and energy policy, and the risk of regulatory and/or political market intervention, e.g. in case of a sustained period of extreme high prices. Indeed, the electricity market context has proven to evolve quickly over the last decades with changing emphases on policy objectives, introduction of new approaches and interventions supporting policy objectives, market design changes, etc. In Europe, the liberalisation of the sector to facilitate the internal energy market, the gaining importance of sustainability targets resulting in a drive to foster an energy transition, upcoming digitalisation of the sector, emerging security of supply concerns,… are clear witnesses of model and policy risk. Capturing these risks in a specific modelling setup aiming to assess investor's behaviour is inevitably never perfect. While a modelling setup clearly provides useful insights, it is important to recognise the more nuanced and complex decision-making process of (risk averse) investors when using such model outputs to take conclusions on for instance economic viability.

The model risk is related to the scenario used, as well as possible (direct or indirect) price intervention affecting the value of the inframarginal rents. Policy makers or regulators may intervene in market

[13] Note also that, even if the reference WACC is a correct representation of the actual cost of capital, there may still be a positive hurdle premium due to the irreversibility of the investment or when investors are cautious (Driver and Temple, 2010).

[14] In Section 5 we describe a break-even analysis to quantify the return premium requested by an investor in order to be indifferent between two projects with the same expected return but a different return distribution.

prices by setting price caps (Jamasb and Pollitt, 2000). This could happen in various ways, e.g. by market design changes, support measures, market rules changes affecting prices,… and could be considered by investors as capping prices or resulting in discounting higher prices resulting from simulations when assessing investments. Also explicit price caps imposed by governments or through changed market rules to safeguard the customers against extreme electricity prices cannot be excluded, there can also be implicit price caps when owners of the electricity generation capacity sell at lower prices than they rationally would because of the threat of a regulatory investigation of market abuse. When this intervention is not modelled in the simulation design, then investors will ask additional return compensation for the risk that price intervention leads to lower actual inframarginal rents than the simulation would predict.

In conclusion, the presence of a hurdle premium accommodates the investor's requirement for a cushion to offset the model risk that the project cashflow distribution is framed in a too optimistic way (Helms et al., 2020) and/or the failure of the model-based capital cost calculation to take the variability and the non-normality of the project return distribution into account.

3.2. Range for the hurdle premium

From the numeric analysis in the next sections, it will become clear that the marginal impact of each driver on the hurdle rate is economically significant. The hurdle premium aggregates those marginal impacts. A formula for this aggregation is not possible given the unknown dependence between the project risk factors and the weight associated to them by the investor. We thus need to resort to a reasonable heuristic rather than overly conservatively pancaking all individual impacts.

For the scenarios and technologies that are similar to the ones considered in Section 6 of this report, we recommend that, 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).[15] [16] 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 5% is the lower bound for the projects and technologies considered. In fact, we will conclude that for most technologies the hurdle premium is above 5% for the economic viability assessment study considered.

In addition to the minimum bound, we also assume an upper bound on the hurdle rate for the projects considered. Specifically, we assume the simulation analysis considers technologies that are feasible provided the financial return is high enough. Formally, this means we exclude the case of an infinite hurdle rate. Moreover, it is natural to assume that, in the most extreme scenario, the risk of the project is prohibitive for attracting debt and all investments are equity-based. In this case the hurdle rate corresponds to:

$$\frac{1+\left[\frac{CoE}{1-t}\right]}{1+i}-1,$$

where CoE is the true cost of equity of the project as defined in Subsection 3.1. Based on discussions with stakeholders, academic peers and financial investors as well as supported by the numeric

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

[16] We recommend a minimum hurdle premium of 0% for projects with an investment horizon that is less than three years.

analyses in Section 6, a natural rule of thumb is to set the upper bound at two times the (real and pre-tax) WACC of a fully-equity funded project with a CoE equal to the reference CoE.[17]

Based on the above, we have the following interval for the hurdle rate of a project in electricity capacity in Belgium with a significant initial capex investment and uncertain inframarginal rents over an investment horizon of three years and more:

$$\text{Hurdle rate } \tau \in \left[WACC^* + \left(\frac{(1+5\%)}{(1+i)} - 1\right),\ 2 \cdot \left(\frac{1+\frac{CoE^*}{1-t}}{1+i} - 1\right)\right]$$

$$\text{Hurdle premium} \in \left[\left(\frac{(1+5\%)}{(1+i)} - 1\right),\ 2 \cdot \left(\frac{1+\frac{CoE^*}{1-t}}{1+i} - 1\right) - WACC^* \right]$$

The interval approach to defining the hurdle rate is needed to account for the variation in risk between the investment projects considered. All other things being equal, when two projects have the same expected return, an investor prefers the one with the lowest hurdle rate.

The interval approach corresponds visually to a risk barometer. The utmost left point on the risk barometer corresponds to a project with pre-tax nominal hurdle premium of 5%.

Compared to the hurdle rate of this base project, the hurdle rate of a project increases when:

1. There is a decrease in the gearing ratio (higher reluctance of banks to provide debt financing), which could vary according to the risks exhibited by the kind of project, e.g. the technology considered
2. There is an increase in the project return variance and downside risk as quantified assuming the (non-normal) distribution of inframarginal rents under the base scenario is correct. The reference simulation setup is the one considered to be the best estimate representation of reality (among the considered setups) assuming continuity of energy policy, consumer and producer preferences, continued market design (incl. no market intervention in terms of imposing price caps or other kinds indirectly affecting the occurrence of high prices).
3. There is an increase in the project return variance and downside risk that is expected but not modelled under the base scenario. Examples of expected losses when the actual state of the world is not as described by the reference model are:
    a. Changes in policy (e.g. uncertainty about implementation of EU Green Deal) affecting the future capacity mix and resulting energy prices
    b. Impact of policy decision on the profitability of certain technologies (e.g. support schemes for RES or limitations on fossil fuel-based generation, additional requirements on future gas mix, etc.).
    c. Sustainability of price spikes in the reference setup and perceived risk that actual prices may be directly or indirectly capped.

[17] If the hurdle rate is higher than twice the CoE^* , the analyst doing the simulation analysis should exclude the project from the evaluation.

This aspect is of increased importance in a modelling setup where the profitability is assessed within the boundaries of a single scenario (i.e. the setup used throughout the context of this study) and not by weighing different scenarios that could to some extent account for the above mentioned effects.

4. There are less opportunities to mitigate the project risk by hedging and/or there is an increase in the cost of financial and operational hedging. For instance, for baseload and merit order technologies forward products are more appropriate hedging instruments than for technologies with high activation costs.

The minimum hurdle premium might decrease when:

1. The uncertainty of the project return is exclusively driven by short term risk factors. This is the case for investments with a horizon less than three years for which we recommend setting the minimum hurdle premium to 0%.
2. Market design is substantially changed, resulting in a more stable revenue stream for investments in the energy market (e.g. implementation of a capacity remuneration mechanism with fixed capacity payments).

3.3. Calibration of the reference WACC and hurdle rate interval in practice

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.[18]

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 investors, ERP is the equity risk premium and CRP is the country risk premium.

For long-term investment in electricity capacity in Belgium in 2021, a reasonable calibration is to set the risk-free rate at 0.47%, the country premium at 0.36%, the equity premium at 6.1%, and the equity beta at 1.02.[19] It follows that $COE^* = 7.052\%$.

The cost of debt can be estimated by analysing the balance sheet of prospective investors. A reasonable number here is that $CoD^* = 4\%$. Assuming a gearing ratio of 40%, corporate tax rate of 25% and expected inflation of 1.60%, we have that $WACC^*$ = 5.53%.

The project WACC equals the reference WACC plus a hurdle premium. Under the framework described in Subsection 3.1, we set the minimum hurdle premium to $\frac{1+5\%}{1+1.6\%} - 1$ = 3.3465% leading to a minimum hurdle rate of 8.90%. The maximum hurdle rate is $2 \cdot \left(\frac{1+\frac{7.052\%.}{1-0.25}}{1+1.6\%} - 1 \right)$ = 15.36%.

Based on the above calibration, the total hurdle rate for projects with an investment horizon of three years and more) is thus between 8.90% and 15.36%, implying an hurdle premium between 3.3% and

[18] 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.

[19] 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.

9.8%, for which within this range a differentiation by kind of technology is relevant as projects of different technologies are affected differently by the individual risks.

Minimum hurdle premium = 3.3%	Hurdle premium of technologies considered ⟷	Maximum hurdle premium = 9.8%

4. Taxonomy of technology-specific drivers of the hurdle premium

Investments in electricity capacity are not equal. They differ in terms of technology used, costs (capex, fixed operation and maintenance (FOM), variable costs), inframarginal rents, and economic lifetime. This heterogeneity leads to differences in hurdle premium across investment projects. This section establishes a taxonomy of determinants of the premium.

4.1. Calibration of the hurdle premium per technology using the distribution of returns obtained under the base scenario

The central paradigm of finance is that rational investors optimize their portfolio by maximizing expected returns and minimizing risk. If two portfolios have the same expected return, the rational risk-averse investor chooses the portfolio with the lowest risk. The portfolio risk depends on the weights of each investment, the individual risk of each investment and their dependence.

Under the simulation framework, we can quantify the individual risk of each investment under the base scenario, which is the one considered to be the best representation of reality (among the considered setups) *assuming continuity of energy policy, consumer and producer preferences and no market intervention affecting the occurrence of (very) high prices.*

It is important to not limit the analysis to the variance, but consider all the risk measures that an investor would consider. Specifically, this includes downside risk measures like value-at-risk and expected shortfall, the semi-variance and the probability of negative returns. Given the non-normality of the return distribution, the downside risk evaluation of the project is likely to differ from the evaluation when only using the return variance. Accounting for the non-normality is needed since the reference WACC calculation ignores this when assuming the CAPM approach for the cost of equity calculation.

In addition a break-even analysis can be performed between the project that has the most attractive risk profile and alternative projects. The details of this analysis are presented in the next section.

4.2. Calibration of the hurdle premium per technology by evaluating the "what if…" questions an investor may consider

The observed variability in the base scenario simulation setup ignores many risk drivers and is thus an underestimation of the perceived project (downside) risk. As such the return and risk evaluations under the base scenario are *ceteris paribus* numbers. Rational investors however do take into account the additional variability caused by deviations from the model assumptions. It is *for example* widely accepted that policy uncertainty increases the option value of deferring long-term investments, and thus elevates the cost of capital and reduces actual investment volume (Baker et al., 2016).

The base scenario is thus (at best) the best representation of reality (among the considered setups) assuming continuity of energy policy, consumer and producer preferences and no market intervention affecting the occurrence of (very) high prices. When calibrating the hurdle premium it is crucial to consider the return impact of alternative scenarios.

We refer to Arnold and Yildiz (2015), Holdermann et al. (2014) and Peña et al. (2014) for a selection of academic references regarding the importance of sensitivity analysis to the input parameters of the simulation approach used in the evaluation of the profitability of energy project investments.

Below we provide a non-exhaustive list of important additional sensitivity analyses to perform in order to calibrate the hurdle premium of an investment project.

4.2.1. What if high price spikes are heavily discounted or subject to a perceived price cap?

While expected revenues could be simply represented by means of an average, it is relevant to consider the effect of high price spikes in such approach as – obviously – such price spikes are affecting the average project return significantly. What if investors tend to discount (or not consider at all) such price spikes in their profitability assessment due to risks attached to their occurrence or other reasons?

Market parties – and behind them investors – may for instance consider that a system relying on high price spikes over time may be prone to interventions that would limit the occurrence of such price spikes. Such interventions could be driven by political concerns on the effects of price spikes and may go up to a review of the prevailing market design. Note in this respect that worldwide markets sometimes undergo drastic changes after some events, even if before the event, rules turned out very stable and well-thought.

Through the public consultation ran by Elia on the updated methodology for the economic viability assessment, market parties have indicated that they indeed heavily discount high price spikes in their profitability assessment, as in view of risk management they prefer not to rely on those. This viewpoint also seems to be endorsed by Belgian policy makers in their choice of the capacity mechanism design opted for.[20] By opting for a reliability option approach, the design foresees that energy market revenues above a certain threshold (strike price) are to be reimbursed as otherwise it would constitute a double remuneration with the capacity mechanism. Market parties in a CRM are believed to bid their 'missing money' in the auction, which includes their assessment of what could be reasonable expected inframarginal rents from the energy market. This assessment takes into account their risk profile. As some price spikes are deemed not to be considered in this assessment they will rather be covered through the capacity remuneration offered by the CRM. The reliability option mechanism ensures that available capacities are only remunerated once if moments of scarcity with high price spikes do occur in reality[21]. Driven by competitive pressure in the auction, market parties have no reason to take more risk averse assumptions in this approach than what fits their risk profile. Finally, the European Commission also seems to endorse this viewpoint in its sector enquiry, concluding that a reliability options mechanism is likely the most optimal as it limits windfall profits.

Such strike price is typically in the range of a few hundreds of euros per MWh when looking at similar schemes in Italy and Ireland and also when looking at the proposal recently put forward by Elia. In this

---

[20] The explanatory note to the CRM Act states that the reliability option mechanism has been selected as it limits the possibility to gain exceptional profits in case the electricity market is more beneficial to capacity providers than initially foreseen.

[21] As also described in section 1.5.4 of the PWC study: https://economie.fgov.be/sites/default/files/Files/Energy/Rapport-Bepaling-van-het-mechanisme-voor-de-vergoeding-van-capaciteit-voor-Belgie-en-de-voorbereiding-van-het-wettelijk-kader.pdf

respect market parties[22] have for instance indicated that any prices above 300 €/MWh are less likely to be considered in their revenue assessment.

4.2.2. What if the merit order would change?

The determination of which capacities deliver energy at a particular moment, is based on the so-called "merit order" principle. The effect of merit order changes may significantly affect the business case of an investor. Merit order changes could be driven by various factors, such as fuel price evolutions, CO_2-prices, capacity mix (domestically, but also abroad due to increased interconnection levels throughout Europe), etc. This is essentially part of scenarios taken into account by investors. Note that this can be clearly driven by policy as well (e.g. measures impacting carbon prices, measures (e.g. taxes) on fuels, etc.).

See for instance the impact on prices (and consequently inframarginal rents) when comparing the outcomes of the different scenarios in Elia's BESET study[23].

To illustrate the effect such change could resort, the calculations in the proof of concept compare a coal before gas with a gas before coal scenario building on the dataset used throughout this study.

4.2.3. What if a technology becomes obsolete?

More radically than a merit order change, would be considering what the effect on profitability would be if a technology becomes obsolete over time resulting for instance in (close to) zero revenues in the last 5 or 10 years of its initially assumed economic lifecycle. While being more extreme, it illustrates well the effect (changing or reinforcing a) policy may have especially if 'becoming obsolete' is not the result of business-as-usual evolutions in a sector but rather the result of market intervention or policy measures such as decarbonisation (e.g. coal units are becoming obsolete due to high CO_2 emissions). While the objectives of such policy from a societal perspective may be well justified, in some cases it might undeniably affect individual investments from the past.

4.2.4. What if we go from inadequate to adequate?

Throughout this study, the calculations are done on a scenario output taken from Elia's 2019 Adequacy & Flexibility study corresponding to a situation where following that study the economic viability of technologies was at a tipping point. It could be considered as the equilibrium where based on energy market revenues investments were just 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. If the system would be complemented with extra

[22] FEBEG presentation of the Task Force of 13.06.2019.
[23] See Elia's BESET study "Electricity Scenarios for Belgium towards 2050" (p. 29) for the description of the different scenarios "Base Case", "Decentral" and "Large Scale RES" reflecting different capacity mixes. The same study gives an overview on the impact of these different scenarios on the profitability of different technologies (see section 4.5 of the BESET study).

capacities making the scenario adequate, that would have reduced average price levels and particularly the number of price spikes.

Therefore, adding to the uncertainties the investors are facing, there is the issue of cannibalization. A single new unit might put downward pressure to electricity prices, reducing the value of new capacity once operational, 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.

In addition, it is likely that investors would believe that political measures would be taken in order to ensure an adequate scenario in which the reliability standard would be met. If an investor would take such political intervention as hypothesis, he will build its investment case on an adequate scenario, i.e. with reduced average price levels and lower number of price spikes, negatively affecting its rate of return.

The equilibrium may be fragile. Adding 'deus ex machina' (e.g. by means of targeted intervention) capacity to the system and the market, may also directly affect profitability of all other projects in the market (that would be excluded from the intervention).

4.2.5. What if fixed operations and maintenance (FOM) costs are higher

Under the base scenario, costs are deterministic. In practice, there is a risk that costs are higher than expected. To study the sensitivity of the results to the level of the costs, it is recommended to consider the return impact of alternative calibration of the costs, such as for example CAPEX and FOM.

4.3. Additional considerations for the calibration of the hurdle premium per technology

The above considerations have stressed the potential variability of the project returns. In practice, the investor may use operational and financial hedging to reduce the variability at the level of the investment portfolio. The hurdle premium across technologies needs to be differentiated taking into account the possibility for hedging. For instance, for baseload and merit order technologies forward products are more appropriate hedging instruments than for technologies with high activation costs operating at fewer moments.

The impact of model and policy uncertainty increases with the horizon of the project. All other things being equal, technologies with a longer investment horizon require a higher hurdle premium than those with a shorter horizon.

For some technologies, there is uncertainty about the cost and time needed to install the capacity in Belgium. The higher this uncertainty, the higher is the hurdle premium.

The perceived regulatory instability may also differ across technologies. There is a substantial option value of waiting when investors expect a change in market design that results in a more stable revenue stream for investments in the energy market (e.g. implementation of a capacity remuneration mechanism with fixed capacity payments or the introduction of support measures for investments in sustainable technologies).

5. Implementation in a simulation setup

Here we discuss how the investment decision that compares expected returns with hurdle rates can be implemented in a simulation setup. We first list the assumptions on the costs and revenues of the investment projects. These assumptions are made to set a framework. It is up to the reader to modify the assumptions as (s)he sees fit. Next we describe the simulation approach to compute expected return and risk of the project.

5.1. Assumptions on revenues and costs

The viability assessment is part of a simulation analysis. A hypothetical investor is considered who needs to make an investment decision. To formalize this decision we need assumptions on revenues and costs that determine the cashflows for the investor. All values are in real terms.

General assumptions:

1. The investment has a lifetime of K years (including the construction period).
2. The terminal value of the project is zero.

Assumption on revenues:

1. The distribution of annual inframarginal rents takes M equally likely positive values (annual values denoted by IR_1 , IR_2 , … , IR_M). All amounts are in real terms and net of taxes.
2. The annual inframarginal rents are independently and identically distributed.

Assumption on costs:

1. At the start of the investment, there is a one-time cost of the initial capital expenditures (total amount is denoted by $CAPEX$). This amount is predetermined. The initial $CAPEX$ investment is completely irreversible.
2. There are fixed operation and maintenance costs that need to be paid each year (annual amount is denoted by FOM). This amount is predetermined and the same every year. The amount is paid at the beginning of each year.
3. The initial investment (outflow of cashflows at time 0) equals all the cashflow needed to cover all costs foreseen over the lifetime of the investment:

$$I = CAPEX + \sum_{t=1}^{K} \frac{FOM}{(1+r)^{t-1}}$$

with $r \geq 0$ the (risk-free) interest rate and $t = 0,1, \dots , K$ is the time index, with $t = 0$ the start date.[24]

[24] This assumption guarantees that the project vehicle has under all scenarios enough cashflow to complete. There is no risk of insolvency.

5.2. Simulation of sequence of cashflows and calculation of return

Under the above assumptions, we have M possible values for each year and thus M^K different sequences for a project with lifetime equal to K years.

For each sequence, we can compute the internal rate of return and hence estimate the distribution. Let $IR(t)$ be the inframarginal rents in year t. The internal rate of return for a sequence of cashflows is the rate R for which the net present value equals 0:

$$NPV = -I + \sum_{t=1}^{K} \frac{IR(t)}{(1+R)^t} = 0.$$

The investment risk is due to the differences in return between these different sequences. See Artelys (2015, p. 28) for a similar approach.

In the proof of concept, we also consider the decision to use an existing CCGT without any refurbishment. The lifetime of such a project is one year. When $K = 1$, we have that $R = (IR - I)/I$ where I represents the FOM if no capex investments have to be made. The return is positive when the inframarginal rent exceeds the initial investment, and vice versa.[25]

5.3. The distribution of returns and simulation-based estimates of average return and risk

The simulation study with N (e.g. 10000) runs, leads to N simulated returns: R_1 , R_2 , ..., R_N . A picture is worth a thousand words. The analysis should start with a graphical inspection of the histogram. Next summary quantities are to be computed. We get the simulated mean, standard deviation, skewness and kurtosis as follows:

$$\mu = \frac{1}{N}\sum_{i=1}^{N} R_i$$

$$\sigma = \sqrt{\frac{1}{N}\sum\nolimits_{i=1}^{N} (R_i - \mu)^2}$$

$\zeta = \frac{1}{N}\sum_{i=1}^{N}(R_i - \mu)^3$ and standardized skewness = $\frac{\zeta}{\sigma^3}$

$\kappa = \frac{1}{N}\sum_{i=1}^{N}(R_i - \mu)^4$ and standardized kurtosis = $\frac{\kappa}{\sigma^4}$.

In a similar fashion we can compute downside risk estimates. The semideviation measures the “bad” volatility in terms of the variability in the lower than expected returns:

$$SemiDev = \sqrt{\frac{1}{N}\sum\nolimits_{i=1}^{N} (\min\{R_i - \mu, 0\})^2}$$

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:

$$VaR = R_{(\lceil \alpha N \rceil)}$$

[25] The return is risky due to the uncertainty about the inframarginal rents. In practice, for such short horizons, the uncertainty can be immunized to a large extent on the forward market, particularly for baseload and mid-merit technologies. There is however still a substantial model risk due to the deviation between the expected return received on the real-world forward market and the expected return obtained from the scenario.

$$ES = \frac{1}{\lceil \alpha N \rceil} \sum_{i=1}^{\lceil \alpha N \rceil} R_{(i)}$$

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%.

It can be expected that the investor anchors his decision versus two reference values: 0 and the reference WACC. We therefore also report the probability that the return is below those reference values:

$$P(R < 0) = \frac{1}{N} \sum_{i=1}^{N} I[R_i < 0]$$

$$P(R < WACC^{*}) = \frac{1}{N} \sum_{i=1}^{N} I[R_i < WACC^{*}] = \frac{1}{N} \sum_{i=1}^{N} I[R_i < 5.53\%]$$

where $I[.]$ is the indicator function that is one if the condition is fulfilled, and zero otherwise. $P(R < 0)$ is the probability of losing money in investment.

5.4. Break-even analysis for quantifying the return compensation needed for difference in risk

Under the reference simulation setup, we can compute the expected utility of the investor. Suppose we have *n* simulation paths and R_i is the annualized return in simulation *i.* Suppose the reference investment has simulation returns Y_i . For the project risk premium, we only care about the impact of variability and thus center both Y_i and R_i to have a zero expected return . Then we seek for the break-even project risk premium *m* such that the investor is indifferent between the project and the reference investment:

$$\frac{1}{n} \sum_{i=1}^{n} U\left[\left(1 + \tilde{R}_i + m\right)^{L}\right] = \frac{1}{n} \sum_{i=1}^{n} U\left[\left(1 + \tilde{Y}_i\right)^{L}\right],$$

with *L* the lifetime (in years) of the investment and $\tilde{R}_i$ and $\tilde{Y}_i$ are the centered returns.

6. Application of hurdle rate decision framework to the investment decision considered in the economic viability assessment

This section provides a proof of concept of the methodology outlined in the previous sections. The investment decisions that we model are inspired by Elia's 2019 Adequacy & Flexibility study. The used distributions of inframarginal rents are not necessarily representative of a current investment case.[26] Results are presented to illustrate the hurdle rate approach to deciding on the economic viability of investments in electricity capacity.

We first describe the simulation setup. We then compute the expected return and risk under the base scenario. Next, we quantify the impact on expected return and risk of alternative scenarios. We conclude with a tentative conditional calibration of the hurdle premium based on a combination of quantitative and qualitative assessments.

6.1. Design

6.1.1. Assumptions about investment project under the base scenario

We now illustrate the simulation-based decision analysis for eight investment cases that differ in terms of technology used and yield a different distribution of inframarginal rents. They also differ in terms of lifetime (that we denote by K years) and costs (both the initial $CAPEX$ and the yearly FOM cost). All technologies considered require substantial $CAPEX$ and have uncertain cashflows over an investment horizon of three years and more (justifying a minimum nominal pre-tax hurdle premium of 5%).

The eight technologies (their lifetime and related fixed costs used to illustrate the outcome) are as follows

- New CCGT (*K=20* years, CAPEX = 600 €/kW, FOM = 25 €/kW/y) represents the construction of a new Combined Cycle Gas Turbine with an installed capacity of at least 800 MW.
- New OCGT (*K=20* years, CAPEX = 400 €/kW, FOM = 20 €/kW/y) represents the construction of an Open Cycle Gas Turbine with an installed capacity of at least 100 MW.
- Existing CCGT (K=1 year, CAPEX = 0 €/kW, FOM = 30 €/kW/y) represents the costs related to a CCGT that is already operational and does not require refurbishment.
- Refurbished CCGT (*K=15* years, CAPEX = 100 €/kW, FOM = 30 €/kW/y) represents the refurbishment of an existing CCGT for a lifetime extension of 15 years.
- DSM300 (*K*=3 years, CAPEX = 0 €/kW, FOM = 50 €/kW/y) represents demand side management capacities with an activation price of 300 €/MWh.
- DSM2000 (*K=3* years, CAPEX = 0 €/kW, FOM = 50 €/kW/y) represents demand side management capacities with an activation price of 2000 €/MWh.
- Wind (*K=15* years, CAPEX = 1650 €/kW, FOM = 65 €/kW/y) represents the construction of a new wind installation.[27]

---

[26] The specification of the best possible distribution reflecting the relevant income distribution of the investor is beyond the scope of this study.

[27] The numbers represent a mix of onshore and offshore installations and take into account the average costs for such wind installations.

- PV (*K=15* years, CAPEX = 600 €/kW, FOM = 25 €/kW/y) represents the construction of a new PV solar installation. [28]

The cost related to the time to construct is assumed to be in the CAPEX calculation.[29] As in Section 3, the nominal (long term) risk free rate is set at 0.47%.

As in Elia (2019), we use simulated rents obtained under a model in which there is a maximum energy price at which the modelled market can clear. In the base scenario, there is a price cap at 3k€/MWh , which is considered as the reference price cap, as it corresponds to the current "European harmonized maximum clearing price for the Day-Ahead market in Belgium and all other modelled markets as set according to a decision from ACER upon the proposal by the NEMOs (i.e. the power exchanges) following Art. 41 of the CACM guidelines" (Elia, 2019).

The base scenario that we consider corresponds to a situation where the economic viability of technologies is at a tipping point. It can be considered as the equilibrium where based on energy market revenues investments were just 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.

In the base scenario gas is used before coal in the electricity generation merit order.

6.1.2. Merit order and extreme prices under the base scenario

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 in the dataset are typically ranked as follows (with increasing marginal costs): wind and solar power (a close to zero marginal cost), gas-fired units such as new CCGT, refurbished and existing CCGT, CCGT, OCGT (order of magnitude 30 to 100 €/MWh, depending on natural gas and CO_2 prices), DSM 300, and DSM 2000 each corresponding to demand side management that can be activated at costs of respectively 300 and 2000 €/MWh (those latter cost levels are typically linked to the opportunity cost of not consuming electricity).

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.

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

[29] An alternative approach is to increase the lifetime variable *K* and let the specification of revenues and cost depend on the time elapsed since the initial investment.

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 (e.g. DSM 2000). 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 activation 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.

The figure below illustrates graphically the above.

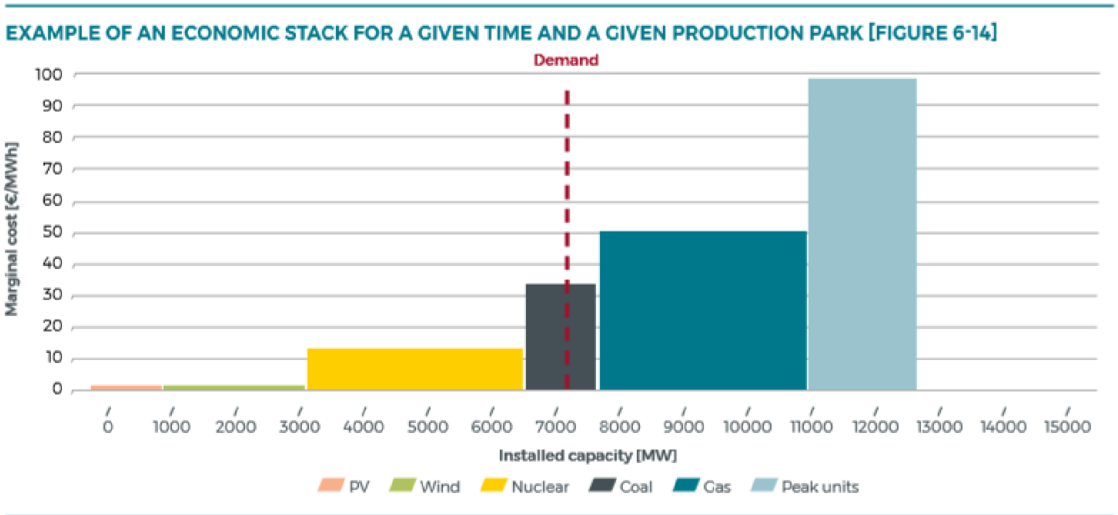

Figure 3 Illustration of merit order (source: Elia's Adequacy and Flexibility Study for Belgium 2020 - 2030)

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.

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.

6.1.3. Distribution of inframarginal rents under the base scenario

The below table and histogram plot describe the distribution of the yearly inframarginal rents for the technologies considered.

For the actual investment return analysis, the inframarginal rents need to be analyzed jointly with their costs and the horizon of the investment. This is the object of the next subsection. However, since the costs are fixed, it is useful to analyze the variability of the inframarginal rents to gauge differences in risk between the projects.

Consistent with the fact that DSM300 and DSM2000 have the largest activation costs and they are last in the merit order, we find that there is every year 18% and 61% probability that these technologies are not activated resulting in a zero inframarginal rent. [30]

Wind and PV have the lowest variability. For PV (resp. Wind), all inframarginal rents are between 52.18 and 76.16 €/kW (resp. 133.88 €/kW and 252.32 €/kW). For the CCGT and OCGT technologies, the maximum rent is above 500 €/kW. The low variability of Wind and PV is driven by their top position in the merit order book, on the one hand side, and by the fact that they have no upside variation in case of the extreme high prices at times where wind and PV are jointly non-available for capacity generation. This high probability of unavailability of solar and wind power during moments of high consumption causes the highest price spikes leading to the extreme high values in the inframarginal rents of the CCGT, OCGT and DSM technologies.

The lower sensitivity of the yearly aggregate inframarginal rents of wind and PV to price spikes is also clear in terms of the almost negligible difference between their median and mean value, as opposed to the gap between median and mean inframarginal rents for all other technologies.

In case of price peaks, all technologies in the dataset are mostly activated to meet the energy demand, provided that they are available. Wind and PV will be used to their maximum capacity in case of scarcity, subject to their availability dependent on the weather conditions. This explains why all inframarginal rents are right-skewed and fat-tailed. Under a normal distribution, the skewness is zero (symmetry) and the kurtosis equals 3. Kurtosis values higher than 3 indicate fat tails. Note that for all technologies considered, the skewness and kurtosis differ extensively from their reference value under the normal distribution, indicating non-normality of the distributions. Standardized skewness is the lowest for PV (1.81) and the highest for DSM2000 (3.23). The kurtosis is above 3 for all technologies, and hence the distribution has fatter tails than would be expected under a normal distribution.

[30] Note that there is time diversification. Under the assumption of independently and identically distributed inframarginal rents, we thus have each year a probability of 18% that the inframarginal rent of a DSM300 investment equals 0. A DSM300 investment has a lifetime of 3 years under the base scenario. The probability of observing a zero inframarginal rent equal to zero in each of those 3 years equals $(18\%)^3 < 1\%$.

Table 3 Summary statistics of inframarginal rents (in €/kW/y) under the base scenario

	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000	Wind	PV
P(IR=0)	0.00	0.00	0.00	0.00	0.18	0.61	0.00	0.00
P(IR>100)	0.21	0.15	0.18	0.18	0.12	0.06	1.00	0.00
min	35.31	0.25	21.41	21.41	0.00	0.00	133.88	52.18
median	57.52	7.49	39.93	39.93	1.95	0.00	157.62	56.34
mean	104.66	52.13	87.43	87.43	42.71	12.52	158.90	58.41
max	560.11	500.05	543.04	543.04	451.55	159.79	252.32	76.16
sd	115.13	110.69	114.75	114.75	100.02	34.65	20.69	5.74
skew	2.73	2.87	2.74	2.74	2.94	3.23	2.91	1.81
kurt	10.00	10.75	10.09	10.09	11.15	12.79	13.80	5.63

For the project return calculation, we use random sampling with replacement from the distribution of inframarginal rents for each year. The occurrence or not of a price peak within the investment horizon will lead to different modes in the distribution of returns. Suppose that the yearly probability of a price peak leading to inframarginal rents higher than 100 €/kW is 2/33. Then the probability of not observing a price peak over $K = 10, 15, 20$ periods is $(\frac{31}{33})^K$, namely 53.5%, 39.1% and 28.6%, respectively.[31]

[31] Calculation based on the binomial distribution: pbinom(q=0, prob=2/33, size=20) yields 0.2863882.

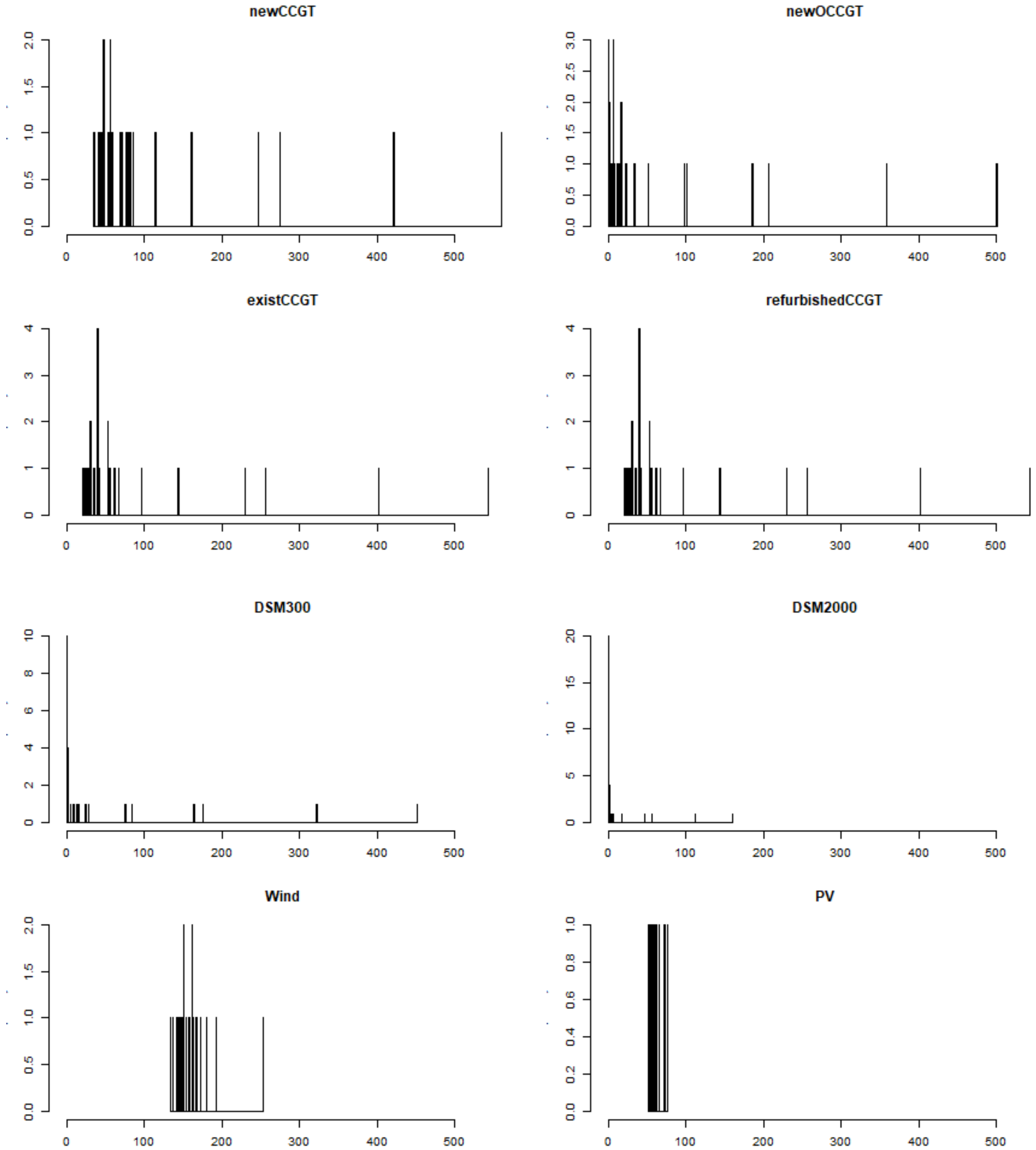

Figure 3 Histogram of yearly inframarginal rents under the base scenario

6.2. Project return distribution and hurdle premium calibration under the base scenario

We now compute the expected return under the base scenario. This is a direct input for the decision: when the expected return under the base scenario exceeds the hurdle rate, the investment is classified as economically viable. We also compute the investment downside risk under the base scenario. This risk characterization is one of the two dimensions of risk considered in the hurdle premium calibration: (i) project return distribution and downside risk under the base scenario and (ii) model and policy risk. Investment risk resulting from the model and policy risk is assessed in the next section 6.3.

6.2.1. Project return distribution under the base scenario

We now follow the approach described in Section 5 and simulate 10000 possible investment paths. For each path, we compute the internal rate of return. This leads to a distribution of internal rate of returns for which we present descriptive statistics in the below table and histogram.

The first row in the table shows the mean of all simulated returns. This is the expected return estimate which is a key quantity in the investment decision, as the project is considered economically viable when the expected return exceeds the hurdle rate.

The use of an existing CCGT that does not require refurbishment is extremely profitable in terms of expected returns. This can be attributed to the harvesting of inframarginal rents under price spikes which are multiples of the cost required to operate an existing CCGT[32]. The calculation is simple. Since there is only a horizon of one year, the return for each simulation outcome is calculated as the percentage difference between the inframarginal rent received and the initial investment. The initial investment represents the fixed operating and maintenance costs and equals 30 €/kW/y. Under the base scenario, the worst outcome for the inframarginal rent is 21 €/kW/y, while the best outcome is 543.04 €/kW/y. On average, the return is 195%.

When refurbishment is needed, the expected return drops from 195% to 12.5%. In case of a greenfield investment in new CCGT the expected return is 6.4%, while for OCGT it is only 1.5%. The expected returns for Wind, PV, DSM300 and DSM2000 are negative under the base scenario.

[32] This result is highly affected by the use of a non-adequate scenario, resulting in more price spikes. Section 6.3 provides the result in case of an adequate scenario.

Table 4 Summary statistics of project returns under the base scenario

	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000	Wind	PV
mean	0.064	0.015	1.952	0.125	-0.275	-0.678	-0.016	-0.017
sd	0.035	0.057	3.839	0.083	0.635	0.343	0.004	0.003
P(R<0)	0.006	0.384	0.152	0.009	0.709	0.973	0.999	1.000
P(R<WACC*)	0.446	0.783	0.274	0.180	0.778	0.978	1.000	1.000
median	0.060	0.015	0.331	0.110	-0.513	-0.773	-0.016	-0.017
min	-0.015	-0.173	-0.286	-0.020	-1.000	-1.000	-0.026	-0.025
max	0.280	0.326	17.101	0.647	2.413	0.594	0.004	-0.005
skew	0.837	0.218	2.704	1.467	1.419	0.958	0.648	0.408
kurt	4.330	3.831	9.810	6.682	4.860	2.815	3.390	3.028
semidev	0.022	0.040	1.453	0.048	0.348	0.197	0.002	0.002
5% VaR	0.015	-0.081	-0.197	0.021	-0.916	-1.000	-0.021	-0.021
5% ES	0.008	-0.102	-0.242	0.009	-0.965	-1.000	-0.022	-0.022

The calibration of the hurdle premium needs to respect the economic logic that, all others things being equal, investors require a higher expected return for projects that add more risk to their portfolio.

An important caveat in the interpretation of the reported risk numbers is that we need to separate the effect of the expected return from the risk that the return deviates from that expected return. Such deviations are by construction computed with centered moments such as the variance, skewness and kurtosis.

It is only for the deviation of the returns from the expected returns that a hurdle premium is needed. While we will discuss several types of risk measures, there is no pancaking in the overall assessment as we make sure not to double-count return and risk effects.

A necessary condition for the presence of investment risk is that there is volatility in the returns. Looking at the reported standard deviations, we can see that, under the basis scenario, the standard deviation of the project return for PV and wind is less than 0.1%. The return variation is thus very small: the range (difference between maximum and minimum return) is 3% for both PV and wind. PV and wind are thus the projects for which the returns are the most predictable and thus least risky.

The returns for an existing CCGT with no refurbishment vary between -28.6% and 1710.1%.[33] The explosion in terms of extreme maximum returns is explained by the low cost (zero CAPEX, low FOM) in comparison with the maximum values for the inframarginal rents. There is no time diversification effect as the horizon is one year. The standard deviation is extreme, but most of the volatility is “good” volatility in terms of upside potential for the investor: the return is above the reference WACC with a probability of 78%. The high positive skewness effect dominates thus here leading to the assessment that the overall investment risk under the base scenario is very low.

[33] The maximum return is observed in a year with simulated inframarginal rent equal to 543 €/kW/y. The FOM is 30 €/kW/y. Given the investment horizon of one year, the return is (543/30)-1= 17.1.

Refurbishing an existing CCGT requires a CAPEX investment and a longer investment horizon. The latter reduces volatility because of the assumed time series independence of yearly rents. Since returns express revenues relative to costs, the higher cost of refurbishing an existing CCGT versus the case of no refurbishments leads to a return distribution with a lower variability. The minimum and maximum return are -2% and 64.7%. The standard deviation is 8.3%. The risk of negative return is nearly zero leading to positive values for the 5% value-at-risk and expected shortfall. The shape of the return distribution is thus beneficial for the investor: most of the volatility is good volatility. There is still a 72.6% probability of a return that exceeds the reference WACC. Hence the assessment is that the investment risk for refurbishing an existing CCGT is very low.

The standard deviation of the return on investing in a new CCGT is 3.5% which is less than half of the standard deviation of investing in a refurbished CCGT. The standard deviation is lower because the longer time horizon (20 years instead of 5 years) and the higher CAPEX (600 €/kW instead of 100 €/kW) reduce the relative effect of the occurrence of a price spike on the investment return. For new CCGT, returns are between -1.5% and 28%. While the downside is still attractive (the 5% VaR and ES are positive) there is less upside potential than for refurbished and existing CCGT. The probability of a return exceeding the reference WACC is now 55.4%. Overall, the investment risk is still low.

For new OCGT, the investment risk is substantially higher than new CCGT. The minimum return is -17.3%. Note that the returns are annualized numbers. The eventual effect of a negative return on investor wealth is thus larger than portrayed in the tables: the future value of investing 100 € at a return of -17,3% is 2.4 € after 20 years. The 5% expected shortfall is -10%. Compared to new CCGT, the higher downside risk is explained only partly by the lower expected return. It is also driven by the higher standard deviation and lower skewness. For new OCGT the risk is substantially higher than for new CCGT.

For DSM300 and DSM2000, the 5% expected shortfall is -91% and -96%. The minimum return is -100%. The median is -50% and -77.3%. For DSM300 there is more upside potential than for DSM2000, but overall, the investment risk for both DSM300 and DSM2000 is extreme. The standard deviation of DSM300 and DSM2000 is driven by two opposite forces: on the one hand there are the price spikes that lead to an explosion of the standard deviation, while on the other hand there are the many years with zero inframarginal rents leading to an implosion of the standard deviation. The overall effect is that DSM300 and DSM2000 have both a high standard deviation (63.5% and 34.3%, respectively). DSM 300 is more often activated due to lower activation prices. The standard deviation for DSM2000 is lower than for DSM300, since its distribution is close to the -1 lower bound already. In 97% of the cases the return is negative. In more than 5% of the case there is a total loss for the investor.

Based on the standard deviation, probability of losses and expected shortfall, we can group the risk exposure of the different technologies as follows:

- Negligible uncertainty (standard deviation $\leq 1\%$) under the base scenario[34]: PV and Wind
- Low volatility and no risk of losses under the base scenario: new CCGT
- High volatility and no risk of loss: refurbished CCGT
- Extreme volatility but compensated by the extreme positive skewness (most of the volatility is “good” volatility in terms of upside potential), the low investment cost and short horizon: existing CCGT
- Medium volatility and risk of losses: new OCGT
- Very high volatility and risk of losses: DSM 300

[34] There is still risk due to model and policy risk justifying the hurdle premium. See below.

- Extreme risk of loss: DSM 2000

We now have a ranking of the difference technologies in terms of risk driven by the revenue distribution and downside risk[35]. Note that the ranking is closely related to the dispatch of technologies under the merit order principle: (i) wind and solar power (close to zero marginal cost), (ii) gas-fired units such as new CCGT, refurbished CCGT, (iii) demand side management technologies. Remember also the scenario used (i.e. a scenario at the tipping point of overall economic viability for new capacity as referred to in Elia's (2019) Adequacy & Flexibility study which is characterized by not yet being adequate and hence exhibiting several price spikes) and the fact that profitability is only assessed from the perspective of inframarginal rents in the energy market (i.e. excluding any more stable revenues streams that may come from other markets, such as a capacity remuneration mechanism).

A challenging problem is to determine the associated premium for which there is no readily available financial theory. A technical approach is to consider a break-even analysis based on expected utility. We set the benchmark strategy to PV as it has the lowest standard deviation of all strategies considered. To neutralize the effect of the expected return, we center all return series such that they have the same expected return as PV. We then compute the premium in terms of expected return that is required by a CRRA investor ($\gamma = 4$) to be indifferent. Except for the investment in existing CCGT which is an absolute outlier in terms of standard deviation, the obtained premiums for the CRRA investors are consistent with the above grouping based on the risk estimates.

[35] The impact of model and policy risk is assessed in the next section.

Table 5 Break-even returns between the centered return on PV and alternative investments

	newCCGT	newOCCGT	existCCGT	refurbishedCCGT	DSM300	DSM2000	Wind	PV
CRRA	0.024	0.084	2.182	0.077	0.659	0.300	0	0

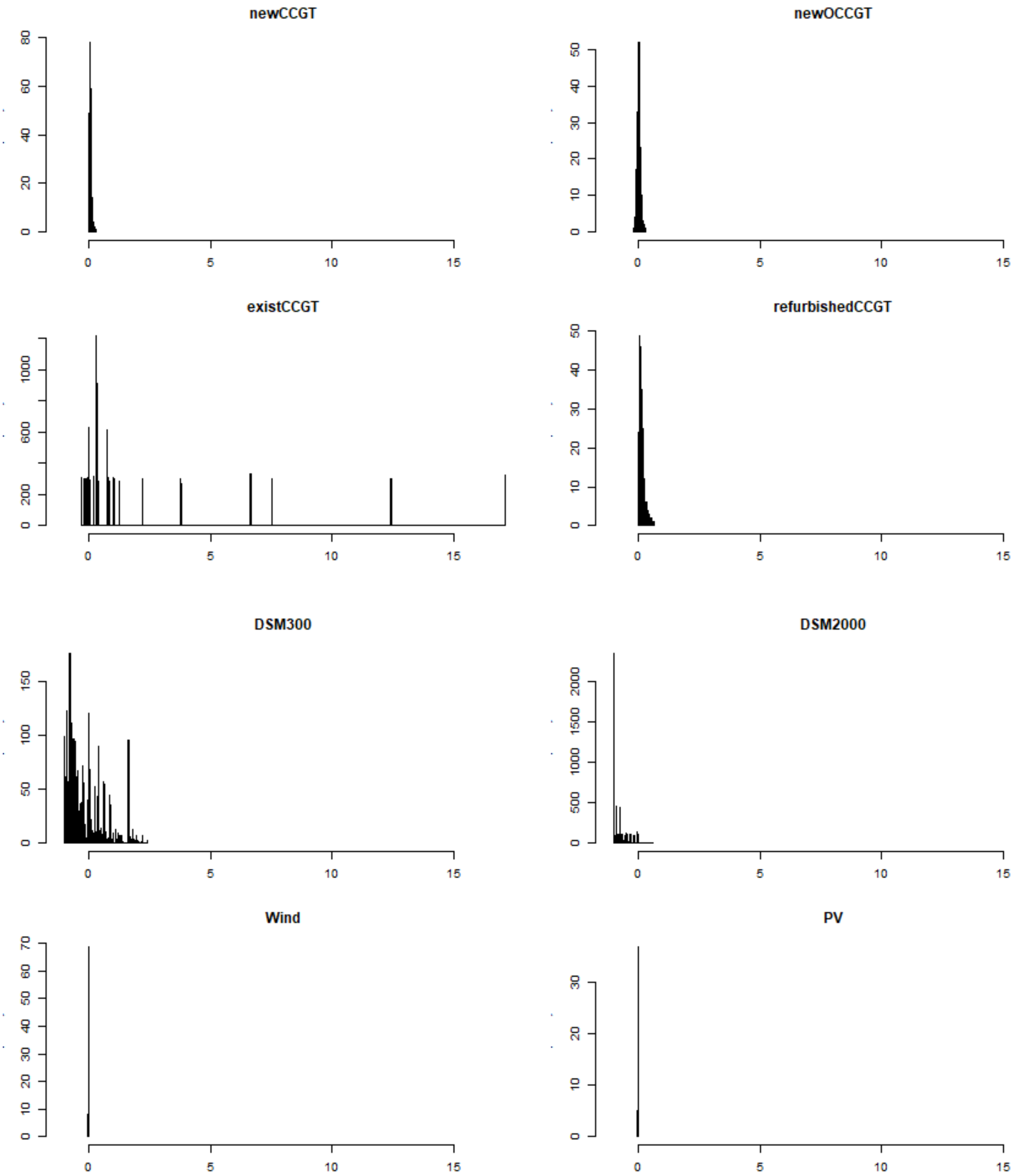

Figure 4 Histogram of internal rate of return of investments under the base scenario

6.2.2. Impact of financial risk under the base scenario on the hurdle premium of technologies

Analysis of the base scenario shows clear heterogeneity in the return distribution of the projects considered. The variability is determined by the cost, lifetime, efficiency and consequent position in the merit order book of the technology. The downside risk analysis lets us compute key risk characteristics such as the return variance, the magnitude of the returns that are less than expected, the probability of negative returns and the value-at-risk and expected shortfall describing the 5% worst outcomes.

Based on the arguments above, we have the following ranking for compensation for (downside) risk under the base scenario. Note that this is an ordinal representation.

Minimum compensation	↔					Maximum compensation
Wind, PV	New CCGT	Refurbished CCGT	Existing CCGT	New OCGT	DSM 300	DSM 2000

6.3. Impact on project return distribution of alternative scenarios

The simulation results obtained under the base scenario are heavily dependent on the assumptions that define the scenario. Given the projected distributions, a real-world investor will also consider alternative scenarios. We integrate this in our decision making model by means of the hurdle premium calibration based on a combination of quantitative and qualitative conclusions.

We use here the same quantitative setup as in the previous subsection but modify assumptions leading to a different return distribution. The change in expected return and risk inform about the magnitude of the impact of making alternative assumptions.

The more importance the investors attaches to adverse scenarios defined by the investor, the lower the perceived return. Since the expected return calculation used in the viability assessment is limited to the boundaries of using a single scenario, we need to account for these adverse effects through the hurdle premium calibration. The more negative the effect is of a plausible adverse scenario, the higher the hurdle rate is (*ceteris paribus*).

6.3.1. What if high price spikes are heavily discounted or subject to a perceived price cap?

As in Elia (2019), we use simulated rents obtained under a model in which there is a maximum energy price at which the modelled market can clear. In the base scenario, there is a price cap at 3000 €/MWh. We now study the effect on the project return of an implicit or explicit price cap at 300, 1000 and 2000 €/MWh.

Under the base scenario, higher prices than 300, 1000 and 2000 €/MWh are likely to coincide with periods in which part of the capacity of wind and PV are not available.

Analyzing the impact of lowering the price cap from 3000 €/MWh to 300, 1000 and 2000 €/MWh is therefore especially relevant for the CCGT, OCGT and DSM technologies.

For the DSM technologies, the impact can be easily predicted. A DSM2000 is only activated if prices are above 2000 €/MWh. Investors who expect a price limit to be at 2000 €/MWh will never invest in a DSM2000 since their investment return is -100% (zero revenues). For DSM300, the revenues will be reduced when lowering the price cap to 1000 and 2000 €/MWh. In the table below, we can see that the return drops further from -27.5% to -39.5% and -57.9% when lowering the price cap to 1000 and 2000 €/MWh. At a price cap of 300 €/MWh, there are no revenues and hence the investment return is -100% with certainty.

In the table below we can further see that imposing the price cap reduced the expected return for existing CCGT without refurbishment costs from 195% to 152%, 97% and 49%. It thus has a large impact, but the project remains economically viable when capping prices at 300€/MWh.

Imposing lower price caps impacts the economic viability of investments in existing CCGT that require a refurbishment. Their expected return drops from 12.5% to 9.5%, 5.5% and 1.7% when lowering the price cap from 3000 €/MWh to 2000, 1000 and 300 €/MWh.

For investments in new CCGT we find that there is also a substantial loss in expected return when investors consider a lower price cap in their expected return evaluation. The expected return drops from 6.4% to 4.8%, 2.7% and 0.6% when the price cap is set at 2000, 1000 and 300 €/MWh instead of the 3000 €/MWh considered in the base scenario.

Investments in new OCGT are not economically viable under the base scenario. Accounting for the model risk that the actual price limit may be lower reinforces this conclusion. Its expected return drops from 1.5% to -1.3%, -5.7% and -11.8% when lowering the price cap from 3000 €/MWh to 2000, 1000 and 300 €/MWh.

Lowering the price caps impact the good part of return variability: maximum return and positive skewness drop, while the downside risk does not improve.

To conclude, if investors perceive that a potential future outcome is that prices are capped at a level lower than 3000 €/MWh, they will revise their expected returns downward. Keeping our decision rule with expected returns computed under the basis scenario, this means that (minus 1 times) the perceived difference in expected lower return needs to be added to the hurdle rate.

Based on the arguments above, we have the following ordinal ranking for compensation for a lower maximum price under the base scenario.

Minimum compensation						Maximum compensation
Wind, PV	New CCGT	Refurbished CCGT	Existing CCGT	New OCGT	DSM 300	DSM 2000

Table 6 Summary statistics of impact of price limits on expected return and risk of investments in CCGT and OCGT

Bound at 3000€/kW(base)	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000
mean	0.064	0.015	1.952	0.125	-0.275	-0.678
sd	0.035	0.057	3.839	0.083	0.635	0.343
median	0.060	0.015	0.331	0.110	-0.513	-0.773
min	-0.015	-0.173	-0.286	-0.020	-1.000	-1.000
max	0.280	0.326	17.101	0.647	2.413	0.594
skew	0.837	0.218	2.704	1.467	1.419	0.958
kurt	4.330	3.831	9.810	6.682	4.860	2.815
5% ES	0.008	-0.102	-0.242	0.009	-0.965	-1.000
Bound at 2000€/kW						
mean	0.048	-0.013	1.521	0.095	-0.395	-1
sd	0.025	0.044	2.713	0.056	0.459	0
median	0.046	-0.010	0.331	0.088	-0.555	-1
min	-0.015	-0.175	-0.286	-0.021	-1.000	-1
max	0.186	0.191	11.775	0.407	1.424	-1
skew	0.567	-0.177	2.438	0.976	0.966	
kurt	3.560	3.231	8.452	4.751	3.386	
5% ES	0.006	-0.110	-0.242	0.006	-0.967	-1
Bound at 1000€/kW						
mean	0.027	-0.057	0.969	0.055	-0.579	-1
sd	0.014	0.032	1.479	0.031	0.271	0
median	0.026	-0.054	0.315	0.052	-0.653	-1
min	-0.016	-0.180	-0.286	-0.022	-1.000	-1
max	0.088	0.049	6.196	0.209	0.368	-1
skew	0.329	-0.369	2.047	0.496	0.596	
kurt	3.083	2.955	6.707	3.361	2.489	
5% ES	0.001	-0.129	-0.242	0.000	-0.974	-1
Bound at 300€/kW						
mean	0.006	-0.118	0.492	0.017	-1	-1
sd	0.007	0.021	0.594	0.014	0	0
median	0.006	-0.116	0.278	0.016	-1	-1
min	-0.018	-0.197	-0.286	-0.025	-1	-1
max	0.032	-0.052	2.049	0.063	-1	-1
skew	0.078	-0.296	0.987	0.101		
kurt	2.893	2.803	3.062	2.873		
5% ES	-0.007	-0.163	-0.242	-0.011	-1	-1

6.3.2. What if the merit order would change?

We consider a change in merit order by assuming a lower carbon price. This reduces the marginal cost of OCGT from 92.5 €/MWh to 79 €/MWh, for new CCGT from 59 €/MWh to 49.6 €/MWh and from 67.8 €/MWh to 56.9 €/MWh for refurbished CCGT. The other marginal costs remain the same: 300/1000/2000 €/MWh for DSM100/1000/2000 and 0 €/MWh for wind and PV.

The assumption on the CO_2 price affects the clearing price in the energy market and therefore affects the inframarginal rents of most technologies. It can be expected that this change in merit order lowers expected returns for all investments except DSM capacities. Indeed, if coal's marginal cost becomes cheaper, gas-fired installations such as CCGTs will be less often activated. As DSM capacities are only activated at the end of the merit order (due to the high activation price), changing only the marginal costs for technologies in the beginning of the merit order do not affect the inframarginal rents for DSM.

The above intuition is confirmed by the simulation results. There is no impact for the expected returns of DSM investment projects. For new OCGT the impact is negligible, as it is further in the merit order and hence less impacted. For wind and PV the expected returns drops from -1.6% and -1.7% to -4.2% and -4.3%. The merit order change has also a large impact on new, existing and refurbished CCGT for which the expected return drops from 6.4%, 195.2% and 12.5% to 3.3%, 143% and 8.7%, respectively.

The impact is thus material. It is of the order of 2-3 percentage points for wind, PV and new CCGT. For the existing CCGT it is of the order of 5 percentage points when refurbishments are needed and 50 percentage points otherwise. There is little impact on the risk statistics. It follows that, when investors consider that there is a probability that the marginal cost of coal is reduced in the future compared to the level assumed in the base scenario, they will then expect lower expected return which means that the hurdle rate used in the base scenario needs to be increased. This is the case for all technologies except DSM.

Moreover, besides the impact of CO_2 and gas prices, a change in merit order can also be driven by a different capacity mix than in the base scenario. Elia's BESET study "Electricity Scenarios for Belgium towards 2050" demonstrates that the scenario choice on the capacity mix ("base case", "decentral", "large scale RES") affects the profitability of new CCGTs the most. Based on the arguments above, we have the following ordinal ranking for the increase in hurdle premium needed when investors expect a negative return impact due to a reduction of the marginal cost of coal as compared to the base scenario:

Minimum compensation	↔				Maximum compensation
DSM300 DSM2000	New OCGT	Wind, PV	New CCGT	Refurbished CCGT	Existing CCGT

Table 7 Summary statistics of project returns when carbon price is reduced

	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000	Wind	PV
mean	0.033	0.013	1.430	0.087	-0.276	-0.678	-0.042	-0.043
sd	0.037	0.058	3.827	0.086	0.636	0.343	0.004	0.003
P(R<0)	0.191	0.395	0.547	0.129	0.709	0.973	1.000	1.000
P(R<WACC)	0.750	0.788	0.547	0.387	0.779	0.978	1.000	1.000
median	0.030	0.014	-0.086	0.076	-0.512	-0.773	-0.043	-0.043
min	-0.060	-0.189	-0.655	-0.086	-1.000	-1.000	-0.052	-0.051
max	0.253	0.327	16.613	0.606	2.413	0.594	-0.021	-0.029
skew	0.537	0.173	2.742	1.217	1.418	0.958	0.761	0.457
kurt	3.734	3.827	9.998	5.993	4.855	2.815	3.485	3.035
semidev	0.025	0.041	1.429	0.052	0.348	0.198	0.003	0.002
5% VaR	-0.025	-0.085	-0.599	-0.030	-0.915	-1.000	-0.048	-0.048
5% ES	-0.035	-0.108	-0.627	-0.045	-0.964	-1.000	-0.049	-0.049

6.3.3. What if we go from inadequate to adequate?

The base scenario that we consider corresponds to a situation where existing capacity is profitable but but adding more investments to the system would result in a loss. The available capacity is not adequate. Consider now the case where investors expect that nevertheless there will be additional investment such that we end up in an adequate scenario. Since there is more supply, electricity prices will be lower on average and therefore we expect lower expected returns for all technologies.

This is confirmed in the simulation results. While for wind and PV, the effect is small, we find that expected returns are significantly affected (i.e. 6, 9, 140, 10, 37 and 17 percentage points lower) for new CCGT, OCGT, existing CCGT without and with refurbishments, DSM300 and DM2000. For new and refurbished CCGTs the switch from an inadequate to an adequate scenario results in a higher risk of losses: the 5% ES becomes negative and the probability of negative returns increases from 0.6% to 48.5% (new CCGT) and from 0.9% to 41.8% (refurbished CCGT).

Switching from an inadequate to an adequate scenario has thus a large impact on the economic viability of the investments. Note that the risk is partly endogenous to the investment decisions.

Based on the obtained simulation results, we have the following ranking for compensation due to a perceived risk of switching from an inadequate to an adequate scenario.

Minimum compensation					Maximum compensation
Wind, PV	New CCGT	New OCGT	Refurbished CCGT	DSM2000	Existing CCGT and DSM 300

Table 8 Summary statistics of project returns under the scenario of adequacy

	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000	Wind	PV
mean	0.002	-0.083	0.532	0.015	-0.647	-0.849	-0.020	-0.022
sd	0.026	0.068	2.429	0.057	0.476	0.231	0.003	0.002
P(R<0)	0.485	0.908	0.637	0.418	0.831	0.998	1.000	1.000
P(R<WACC)	0.969	0.993	0.668	0.780	0.852	1.000	1.000	1.000
median	0.001	-0.070	-0.164	0.012	-0.814	-0.988	-0.020	-0.022
min	-0.046	-0.252	-0.674	-0.086	-1.000	-1.000	-0.028	-0.028
max	0.137	0.143	11.629	0.335	1.519	0.049	-0.006	-0.015
skew	0.586	-0.194	3.720	0.898	1.806	1.625	0.526	0.335
kurt	3.178	2.108	15.996	4.102	5.406	4.657	3.329	3.067
semidev	0.017	0.050	0.700	0.036	0.221	0.114	0.002	0.001
5% VaR	-0.033	-0.193	-0.633	-0.056	-1.000	-1.000	-0.024	-0.025
5% ES	-0.036	-0.210	-0.654	-0.062	-1.000	-1.000	-0.025	-0.026

6.3.4. What if we go from inadequate to adequate and the merit order changes?

The change from inadequate to adequate and the reduction of the carbon price are two adverse effects for the investors in CCGT. The "what if…" analysis done so far is a partial effect analysis studying the effect on the expected return and risk if one of the design parameters is changed (while keeping others constant). In practice, investors may also consider scenarios where several design parameters change at the same time. To illustrate that the joint effect may differ from the largest partial effect, we show below the return distribution when the scenario is adequate (see Subsection 6.3.2) and the carbon price is lower (see Subsection 6.3.3) than in the base scenario.

For new CCGT, the expected return is now -3.3% while it is 0.2% under the adequacy scenario of Subsection 6.3.3 and 3.3% under the merit order change scenario of Subsection 6.3.2. We thus see that considering joint effects leads here to an even lower expected return. The probability of observing negative returns is now 84% and the 5% expected shortfall is -8.3%. A similar finding holds for existing CCGT and refurbished CCGT. The latter has now an expected return of -2.4% instead of the 1.5% under the adequacy scenario and the 8.7% of the reduced carbon price scenario.

For the other technologies, there is less difference between the joint effect and the largest partial effect. For new OCGT and DSM, the largest partial effect is observed for the adequacy scenario, while for wind and PV, it is the reduction in the carbon price.

Based on the obtained simulation results, we have the following ranking for compensation due to considering the joint effect of switching from an inadequate to an adequate scenario and a reduction in the marginal cost of carbon versus only their partial effect.

Minimum incremental compensation versus partial effect analysis		Maximum incremental compensation versus partial effect analysis
Wind, PV, DSM300, DSM2000		New CCGT, existing CCGT, refurbished CCGT

Table 9 Summary statistics of project returns under the scenario of adequacy and lower carbon price

	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000	Wind	PV
mean	-0.033	-0.085	0.176	-0.024	-0.648	-0.849	-0.046	-0.048
sd	0.032	0.071	2.420	0.065	0.475	0.231	0.003	0.002
P(R<0)	0.840	0.910	0.847	0.640	0.831	0.998	1.000	1.000
P(R<WACC)	0.995	0.993	0.877	0.885	0.852	1.000	1.000	1.000
median	-0.034	-0.072	-0.527	-0.023	-0.814	-0.988	-0.047	-0.048
min	-0.095	-0.279	-0.853	-0.148	-1.000	-1.000	-0.054	-0.054
max	0.107	0.144	11.286	0.311	1.514	0.048	-0.031	-0.040
skew	0.345	-0.257	3.773	0.613	1.803	1.625	0.678	0.453
kurt	2.594	2.169	16.286	3.211	5.391	4.656	3.488	3.139
semidev	0.022	0.053	0.672	0.043	0.221	0.114	0.002	0.001
5% VaR	-0.079	-0.202	-0.839	-0.110	-1.000	-1.000	-0.050	-0.051
5% ES	-0.083	-0.223	-0.846	-0.118	-1.000	-1.000	-0.051	-0.052

6.3.5. What if a technology becomes obsolete and revenues go to zero 15, 10, 5 years after investment?

The merit order is a key determinant for the revenues that an investment in electricity capacity will earn. For long-term investments, there is the risk that research and development will lead to more efficient technologies or that policy changes would favor new types of capacities, making the current technologies obsolete.

We replicate this in our simulation setting by keeping the initial investment horizon at 20 years for new CCGT and OCGT, and 15 years for the CCGT with refurbishments, wind and PV. However, at the time the technology becomes obsolete we set all subsequent inframarginal rents to zero. The remaining FOM reserve included in the initial investment is modeled as a cash inflow at the time when the technology becomes obsolete.

A reduced economic lifetime of the investment impacts expected return and risk. The risk increases as there is less benefit from time diversification. The expected return decreases since the initial CAPEX investment has a higher relative weight if there are less years with revenues.

The impact is the largest for the investment with high CAPEX and long lifetime. When after 15, 10 or 5 years, it turns out that the new CCGT is obsolete, then the expected return is no longer 6.4% but 4.9%, 1.8% and -6.9%. Similarly for new OCGT, the expected return drops from 1.5% to 0.2%, -2.5% and -10%.

For Wind and PV the lifetime is 15 years. If it becomes 10 or 5 years, then the expected return is -5% and -14% instead of -1.6% and -1.7%.

For refurbished CCGT, the lifetime is also 15 years. If it becomes 10 or 5 years, then the expected return is 10.5% and 6.1% instead of 12.5%.

Based on the obtained simulation results, we have the following ordinal ranking for compensation due to a perceived risk of the technology becoming obsolete.

Minimum compensation	⟷	Maximum compensation
Refurbished CCGT	Wind, PV	New CCGT, OCGT

Note: Not applicable for DSM 300, DSM 1000 and existing CCGT since their horizon is 3 years or less.

Table 10 Summary statistics of project returns when technology becomes obsolete

Base: 20 yr CCGT+OCGT, others 15	newCCGT	newOCCGT	refCCGT	Wind	PV
mean	0.064	0.015	0.125	-0.016	-0.017
sd	0.035	0.057	0.083	0.004	0.003
median	0.060	0.015	0.110	-0.016	-0.017
min	-0.015	-0.173	-0.020	-0.026	-0.025
max	0.280	0.326	0.647	0.004	-0.005
skew	0.837	0.218	1.467	0.648	0.408
kurt	4.330	3.831	6.682	3.390	3.028
5% ES	0.008	-0.102	0.009	-0.022	-0.022
Obsolete over 15 yrs					
mean	0.049	0.002	0.125	-0.016	-0.017
sd	0.039	0.058	0.082	0.004	0.003
median	0.044	-0.002	0.109	-0.016	-0.017
min	-0.031	-0.117	-0.027	-0.026	-0.025
max	0.262	0.327	0.715	0.004	-0.004
skew	0.757	0.556	1.406	0.656	0.400
kurtosis	3.778	3.502	6.387	3.435	3.000
5% ES	-0.013	-0.095	0.009	-0.022	-0.022
Obsolete over 10 yrs					
mean	0.018	-0.025	0.105	-0.050	-0.050
sd	0.046	0.064	0.090	0.004	0.003
median	0.013	-0.031	0.090	-0.050	-0.050
min	-0.061	-0.126	-0.034	-0.060	-0.058
max	0.266	0.315	0.648	-0.028	-0.034
skewness	0.777	0.747	1.330	0.822	0.522
kurtosis	3.553	3.483	5.707	3.661	3.107
5% ES	-0.048	-0.115	-0.012	-0.056	-0.055
Obsolete over 5 yrs					
mean	-0.069	-0.102	0.061	-0.144	-0.142
sd	0.062	0.082	0.109	0.006	0.004
median	-0.086	-0.128	0.030	-0.145	-0.142
min	-0.151	-0.191	-0.071	-0.156	-0.151
max	0.245	0.320	0.673	-0.112	-0.119
skew	1.122	1.184	1.421	1.331	0.851
kurtosis	4.041	4.191	5.359	5.251	3.607
5% ES	-0.139	-0.186	-0.054	-0.152	-0.148

6.3.6. What if fixed operations and maintenance (FOM) costs are higher

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 final sensitivity we study the impact on expected returns of increasing the FOM for each technology with 25%.

A large impact is observed for the technologies for which we assumed zero CAPEX, namely existing CCGT and DSM. The expected return for existing CCGT drops from 195.2% to 136.2%, for DSM 300 and DSM2000 we have a reduction from -27.5% and -67.8% to -35.4% and -71%, respectively. Also for CCGT with refurbishments the expected return drops from 12.5% to 8.9%.

For the other technologies the reduction in expected return is smaller (between -1 and -1.4 percentage point).

Based on the obtained simulation results, we have the following ranking for compensation due to a 25% increase in the assumed FOM costs.

<table>
<tr><td>Minimum compensation</td><td colspan="4"></td><td>Maximum compensation</td></tr>
<tr><td>Wind, PV</td><td>New CCGT
New OCGT</td><td>DSM2000</td><td>Refurbished CCGT</td><td>DSM300</td><td>Existing CCGT</td></tr>
</table>

Table 11 Summary statistics of project returns under the base scenario but with an increase of FOM costs by 25%

	newCCGT	newOCCGT	existCCGT	refCCGT	DSM300	DSM2000	Wind	PV
mean	0.050	0.001	1.362	0.089	-0.354	-0.710	-0.026	-0.028
sd	0.031	0.053	3.071	0.068	0.544	0.308	0.004	0.003
P(R<0)	0.033	0.475	0.305	0.062	0.801	0.983	1.000	1.000
P(R<WACC)	0.607	0.863	0.396	0.339	0.803	0.991	1.000	1.000
median	0.047	0.003	0.065	0.079	-0.562	-0.788	-0.027	-0.028
min	-0.025	-0.180	-0.429	-0.042	-1.000	-1.000	-0.036	-0.036
max	0.240	0.277	13.481	0.480	1.909	0.408	-0.008	-0.016
skew	0.692	0.023	2.704	1.131	1.248	0.942	0.648	0.410
kurt	3.921	3.480	9.810	5.421	4.205	2.767	3.388	3.025
semidev	0.020	0.038	1.162	0.041	0.306	0.178	0.002	0.002
5% VaR	0.004	-0.090	-0.357	-0.004	-0.922	-1.000	-0.032	-0.032
5% ES	-0.003	-0.111	-0.394	-0.015	-0.969	-1.000	-0.033	-0.033

6.3.6. What if zero cost hedging is possible

CREG (2020) suggested us a further interesting variation on the base scenario, namely a scenario in which the investor uses forward markets to hedge part of the investment risk. This scenario is of course relevant and considered by investors. In the hurdle premium calibration, we will apply a discount when hedging is feasible to reduce the observed downside risk under the base scenario. Below we reflect further on the challenges of including hedging in the base scenario or "what if…" scenarios.

An extreme variation to the base scenario is to assume that zero cost hedging is possible at the time of the investment for the complete time cycle. As such, expected returns under the base scenario can be computed using the corresponding forward prices, and the hurdle rate could be replaced by the risk free rate. It is inconsistent to assume this scenario under our framework for two reasons.

First, for most of the investments considered, the forward markets do not exist for delivery at the lifetime of the investment (maturity of the forward markets in Belgium is limited to Y+3 with even a very low liquidity on the Y+3 forward markets, while economic lifetime is for several technologies a multitude of this).

Second, mapping the simulated prices to forward prices introduces model risk. Indeed, accounting for the forward market in the simulation setup is challenging, as there is no generally accepted one-to-one relationship between the price distribution and the forward rate due to the impossibility of storage. Bessembinder and Lemon (2002) provide a model that links the spot and forward price. The model leads CREG (2020) to conclude that "*what a forward market does, is aggregating all potential price scenario's into one forward price, given the forward prices of fuel and CO2 prices known at that moment. This forward price can be viewed as the expected spot price (with a risk premium). This expected spot price is equal to the average of all potential scenario's, weighted with their probability to occur. This means that if all scenario's have the same probability, one needs to take a simple average*." The validity of the approach is conditional upon several specificities and assumptions that are not necessarily verified in practice. Empirical analysis of spot and forward prices seem to confirm this (see e.g. Botterud et al., 2009, and Redl et al., 2009).

CREG (2020) recommends, as an alternative scenario, that for each year in the lifetime of the investment, the modeler should separate the risk factor into two types:

(i) *"Class A variables: these are variables that are not known by the investor in year 0 but will be known by this investor in year 10. For example the forward price for delivery in year 12 of gas and power is not known in year 0 by the investor but it is known in year 10 by this same investor."*

(ii) "Class B variables: these are variables that are known by the investor in year 0 and by the investor in all subsequent years. For example the year ahead probability in year 10 to have a severe cold spell (or very low wind or the outage rate of generation units) is also already known by the investor in year 0 (and by the investor in year 10). These (expected) probabilities do not change much over the lifetime of the asset."

The modeler then needs to build the distribution taking into account the difference is risk between class A and class B variables. CREG (2020) sketches an approach for this. While the approach is clearly a potential scenario an investor could consider, it is not the only one. The suggestion by CREG (2020) thus seems a confirmation of the hurdle rate approach. Irrespective of the base scenario considered, there are always other scenarios. The economic viability assessment must not ignore this model risk both at the stage of translating the observed risk under the base scenario into a hurdle premium neither at the stage of adjusting for policy and model risk.

In conclusion, our framework and the discussion by CREG (2020) seem fully aligned. We do not use a mathematical function to link the risk under the base scenario to a hurdle premium and we emphasize the importance of adjusting for alternative assumptions when calibrating the hurdle premium. This includes that, if two projects have the same expected return, but the first one benefits more from risk reduction through hedging than the second one, then the hurdle rate of the second one should be higher than the first one.

6.4. Tentative and conditional calibration of the hurdle premium per technology[36]

In this section, for several considered technologies an indicative estimation of a reasonable hurdle premium is provided. The estimations are based on the principles and methodology developed throughout this study and are also linked to the considered modelling setup for the economic viability assessment. 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).

As mentioned earlier in section 3.2, no direct mathematical relationship can be established between the different identified risks and uncertainties and the level of the hurdle premium.[37] 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 permissible interval between the minimum and maximum 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.

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 $\frac{1+5\%}{1+1.6\%} - 1$ = 3.3465%. 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.

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.

[36] This tentative calibration excludes the impact of the Project Debt Risk Premium (see Appendix C)

[37] We refer the reader also to Appendix D for an overview of risk factors determining the cost of equity. In case of non-normality and multiple risk factors, the compensation per unit of risk taken is in general unknown.

6.4.1. Keeping an existing CCGT in the market without refurbishment: Hurdle premium of 1.5%

Given that the downside risk is negligible, the revenue distribution and downside risk parameter has limited impact on the hurdle premium. Note also 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. The economic viability check for the refurbishment of existing CCGTs looks only 1-year ahead, during which the asset's output can be fully hedged on the forward markets.

Existing CCGTs are subject to some extent to model and policy risk (e.g. impact of the merit order, implicit and explicit price caps, model risk related to forward hedging etc.). The model risk that the assumed distribution under the base scenario is different than the actual one requires a compensation which we quantify at 1.5%. The compensation is below the minimum hurdle premium of 3.35% given the short investment horizon.

6.4.2. Keeping an existing CCGT in the market with refurbishment: Hurdle premium of 4%

Revenue distribution and downside risk: Very low. A small top-up is given to compensation 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. There is model risk attached to this, given that average returns take into account the simulated spot prices, whereas there is no perfect one-to-one link between the forward prices and the spot prices (see section 6.4.5 for further explanation on the impact of forward hedging for CCGTs).

Model and policy risk: Low. The investment horizon is three years implying that by the time the refurbishment is finished and the existing CCGT is in operation, the conditions of the base scenario may no longer hold. There can be a lower price bound, 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 minimum value of hurdle premium compensation for model and policy risk.

6.4.3. Investment in new solar installation: Hurdle premium of 4.5%

Revenue distribution and downside risk: Very low. The analysis in section 6.2 has demonstrated that the revenue distribution and downside risk is "very low" for solar installations. Therefore, this parameter has limited impact on the hurdle premium. Its availability is obviously fully dependent on the weather conditions. It follows from the simulations, that it has less potential to benefit from price spikes.

Model and policy risk: Low. The profitability of an investment in new solar installations can be impacted by the use of different scenarios (e.g. change in the merit order or higher assumed costs). The impact for solar is more limited compared to other technologies. 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.

6.4.4. Investment in a new wind installation: 4.5%

Revenue distribution and downside risk: Very low. The analysis in section 6.2 has demonstrated that the revenue distribution and downside risk is "very low" for wind installations. Therefore, this parameter has limited impact on the hurdle premium. Its availability is obviously fully dependent on the weather conditions. It follows from the simulations, that it has less potential to benefit from price spikes.

Model and policy risk: Low. The profitability of an investment in new wind installations can be impacted by the use of different scenarios (e.g. change in the merit order) or higher assumed costs. The impact for wind is more limited compared to other technologies.

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. In addition, market parties have pointed out that a market with increased RES penetration and very volatile prices (i.e. periods of low to even negative prices alternated with periods of price spikes) increases the profile risk (i.e. the inverse correlation between wind production and market prices), negatively affecting the investment case for wind projects.

6.4.5. Investment in a new CCGT: Hurdle premium of 6.5%

Revenue distribution and downside risk: Very low. The analysis in section 6.2 has demonstrated that the revenue distribution 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[38], 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.

While without taking into account the effect of such risk-mitigating opportunities the revenue distribution and downside risk would have been assessed higher, its effect results in a 'very low' assessment on this risk parameter for new CCGTs.

Model and policy risk: Very high. The profitability of an investment in a new CCGT is highly impacted by the use of different scenarios. For instance, the impact of the use of a coal-to-gas versus a gas-to coal scenario, as well as different capacity mixes on the investor's business plan is significant. It is very hard to assess how the fuel and CO_2 prices will evolve as those are globally set at regional/world level (and hence depend on geopolitics, global demand/supply, …) or driven by policies/ambitions combined with supply/demand effects (CO_2 prices, …).

[38] Newbery (2020) formulates it as follows: *"the problem is not that there are no futures and forward markets, only that their tenor is not matched to that needed to reassure financiers lending at an acceptable cost of capital"*

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 (e.g. the obligation of a minimum share of “green” fuel). Alternatively, such policies might ban these installations altogether (e.g. in France, it has been decided that no new thermal generations can be constructed anymore). 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 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 “very high” assessment for this parameter for new CCGTs.

6.4.6. Investment in a new OCGT: Hurdle premium of 8.5%

Revenue distribution and downside risk: High. The analysis in section 6.2 has demonstrated that the revenue distribution and downside risk is “high” for OCGT installations, driven by the lower position in the merit order book as compared to CCGT

Model and policy risk: High.

The profitability of an investment in a new OCGT is impacted by the use of different scenarios. For instance, where the impact of the use of a coal-to-gas versus a gas-to coal scenario only has limited impact on the investor’s business plan, scenarios with different capacity mixes play an important role.

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 in section 6.4.5 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 “high” assessment for this parameter for new OCGTs.

6.4.7. Investment in a new DSM 300: Hurdle premium of 8.5%

Revenue distribution and downside risk: Very high. The analysis in section 6.2 has demonstrated that the revenue distribution and downside risk is “very high” for DSM300.

Model and policy risk: Medium-high. The profitability of an investment in new demand response is impacted. An important impact is the risk of a (perceived) implicit or explicit price cap would decrease the asset’s profitability in a detrimental way, given that its business case is driven by the occurrence of price spikes.

The impact of model and policy risk for demand response capacities is considered lower compared to gas-fired installations, given that the economic lifetime is shorter (around 3 years).

The impact of all these different scenarios, combined with the shorter (compared to other technologies) economic lifetime of 3 years, results in a “medium-high” assessment for this parameter for new DSM300.

6.4.8. Investment in a new DSM 2000: Hurdle premium of 9.8%

Under the base and alternative scenarios, the probability of a positive return is so small that a risk-adverse investor would not consider to invest in it. Under our framework this implies setting the hurdle premium to the maximum value in the permissible range, namely 9.8%.

6.5. Implications for economic viability

Given the expected return obtained under the base scenario, the reference WACC and the hurdle premium accounting for policy, model and downside risk, we can now predict the investment decision. Under a setting similar to the one considered by Elia (2019) we find that only existing CCGT investments are economically viable. All other technologies require a change in the base scenario that would increase expected returns and lower risk, as well as a change in the economic and political environment that would reduce model and policy risk.

Technology	Expected return under the base scenario	Hurdle rate accounting for model, policy and downside risk	Conclusion
New CCGT	6.4%	5.53% + 6.5% = 12.03%	Not viable
New OCGT	1.5%	5.53% + 8.5% = 14.03%	Not viable
Existing CCGT (no refurbishment)	195.2%	5.53% + 1.5% = 7.03%	Viable
Existing CCGT with refurbishment	12.5%	5.53% + 4.0% = 9.53%	Viable
DSM 300	-27.5%	5.53% + 8.5% = 14.03%	Not viable
DSM 2000	-67.8%	5.53% + 9.8% = 15.36%	Not viable
Wind	-1.6%	5.53% + 4.5% = 10.03%	Not viable
Solar	-1.7%	5.53% + 4.5% = 10.03%	Not viable

7. Conclusion and suggestions for further research

It is self-evident that, when two investments yield the same expected return, a rational investor will choose the investment with the lowest risk. Also, assuming risk averse investors matches reality. For investments in electricity capacity, the estimation of these decision parameters is characterized by a high degree of uncertainty due to model risk and policy risk. The nonlinear effect of the underlying risk factors on the project return leads to a non-normal return distribution with a variability that is different across technologies.

Risk is a cost that needs to be balanced against expected return. A flexible approach to do so in the context of evaluation the economic viability of investment in electricity capacity is to model the decision as the outcome of comparing expected returns with the investor's hurdle rate. The hurdle rate equals the minimum rate of return required by fund providers to finance investment in the reference technology in the considered geographic area (ACER, 2020). We show how market data, technology characteristics and simulation-based project return distributions give insight for calibrating the hurdle rate modelled as the sum of the weighted average cost of capital (WACC) of a reference investor and a project-specific hurdle premium.

We provide a tentative calibration of the hurdle premium of a selection of technologies under a conditional setting similar to the economic viability assessment in Elia (2019). When market design or technology changes in such a way that revenues become more stable (e.g. through the implementation of a capacity remuneration mechanism with fixed capacity payments), then the hurdle premium needs to be revised downward - and vice versa in case of increases of investment risk.

Suggestions for further research

This paper has contributed to the methodology of analyzing the non-normal returns of investments in electricity capacity under a simulation framework.

Further research is needed to improve the data-driven nature of the framework in a rapidly changing environment. Such an extension is possible along the lines of the author's concurrent research on modelling distributions with time-varying parameters.

A first avenue of research is to quantify concerns about security of supply, policy risk and climate change by monitoring the news media. Algaba et al. (2020) and Ardia et al. (2020) propose to quantify the perceived policy uncertainty and climate change concerns based on news analysis. Their approach selects the relevant news based on keyword relevance scores and extracts the feature of interest using sentiment analysis.[39] The approach can be tailored to the energy market by modifying the article selection and feature selection and using a domain-specific aggregation technique as done by Algaba et al. (2021) for nowcasting consumer confidence in Belgium.

A second avenue of research could be in terms of account for the time-variation in the distribution when modelling economic viability and forecasting electricity capacity and price risk. Algaba and Boudt (2017) propose an equity premium calibration that learns from recent examples to obtain timely

[39] Daily flash estimates of economic policy uncertainty for Belgium are available at www.sentometrics-research.com. The official monthly numbers (used in the Covid-19 dashboard by the National Bank of Belgium) can be downloaded from www.policyuncertainty.com/belgium_monthly.html.

expected return estimates that are robust to changing market circumstances. Bouamara et al. (2020) and Boudt et al. (2020) propose a factor model for estimating the higher order comoments. For time series analysis of market regimes in risk, short-term prediction of load and joint analysis of spot and forward prices of electricity, we refer to the MSGARCH and GAS package of Ardia et al. (2018, 2019). Understanding the interaction between normal and non-normal drivers of electricity transaction price data can be done using the highfrequency software package of Boudt et al. (2020).

References

ACER (2020). Methodology for calculating the value of lost load, the cost of new entry and the reliability standard. Available at : http://www.acer.europa.eu/Media/News/Pages/ACER-sets-the-methodologies-to-assess-electricity-resource-adequacy-in-the-EU.aspx

Algaba, A., Borms, S., Boudt, K. and Van Pelt, J. (2020) The Economic Policy Uncertainty Index for Flanders, Wallonia and Belgium. BFW digitaal / RBF numérique 2020/6.

Algaba, A., and Boudt, K. (2017). Generalized financial ratios to predict the equity premium. *Economic Modelling*, *66*, 244-257.

Algaba, A., Borms, S., Boudt, K., & Verbeken, B. (2021) Daily news sentiment and monthly surveys: A mixed–frequency dynamic factor model for nowcasting consumer confidence. NBB working paper series.

Ang, A., and Bekaert, G. (2002). International asset allocation with regime shifts. *Review of Financial Studies*, *15*(4), 1137-1187.

Ang, A., Chen, J., and Xing, Y. (2006). Downside risk. *Review of Financial Studies*, *19*(4), 1191-1239.

Ardia, D., Bluteau, K., Boudt, K., & Catania, L. (2018). Forecasting risk with Markov-switching GARCH models: A large-scale performance study. *International Journal of Forecasting*, *34*(4), 733-747.

Ardia, D., Bluteau, K., Boudt, K., Catania, L., & Trottier, D. A. (2019). Markov-switching GARCH models in R: The MSGARCH package. *Journal of Statistical Software*, *91*(4).

Ardia, D., Bluteau, K., Boudt, K., & Inghelbrecht, K. (2020). Climate change concerns and the performance of green versus brown stocks. *National Bank of Belgium, Working Paper Research* (395).

Ardia, D., Boudt, K., & Catania, L. (2019). Generalized autoregressive score models in R: The GAS package. *Journal of Statistical Software*, *88*(6), 1-28.

Arnold, U., and Yildiz, Ö. (2015). Economic risk analysis of decentralized renewable energy infrastructures–A Monte Carlo Simulation approach. *Renewable Energy*, *77*, 227-239.

Artelys (2015). France-Germany Study Energy transition and capacity mechanisms. Available at https://ufe-electricite.fr/IMG/pdf/france-germany_study_report-2.pdf

Baker, S. R., Bloom, N., & Davis, S. J. (2016). Measuring economic policy uncertainty. *The quarterly journal of economics*, *131*(4), 1593-1636.

Bessembinder, H., & Lemmon, M. L. (2002). Equilibrium pricing and optimal hedging in electricity forward markets. *the Journal of Finance*, *57*(3), 1347-1382.

Biais, B., Bossaerts, P., and Spatt, C. (2010). Equilibrium asset pricing and portfolio choice under asymmetric information. *The Review of Financial Studies*, *23*(4), 1503-1543.

Bouamara, N., Boudt, K., & Vandenbroucke, J. (2020). Predicting and Decomposing the Risk of Data-driven Portfolios. *Edhec working paper series.*

Botterud A., Kristiansen T., Ilic M. (2009). The relationship between spot and futures prices in the Nord Pool electricity market. Energy Economics, Volume 32, Issue 5.

Boudt, K., Cornelissen, J., Kleen, O. Payseur, S. and Sjoerup, E.. (2021). highfrequency: Tools for Highfrequency Data Analysis. R package version 0.8.0.1.

Boudt, K., Cornilly, D., and Verdonck, T. (2020). Nearest comoment estimation with unobserved factors. *Journal of Econometrics*, *217*(2), 381-397.

Boudt, K., Peterson, B. G., and Croux, C. (2008). Estimation and decomposition of downside risk for portfolios with non-normal returns. *Journal of Risk*, *11*(2), 79-103.

Brealey, R. A., Myers, S. C., Allen, F., and Mohanty, P. (2020). *Principles of corporate finance*. Tata McGraw-Hill Education (13th edition).

Caporin, M., Jannin, G. M., Lisi, F., and Maillet, B. B. (2014). A survey on the four families of performance measures. *Journal of Economic Surveys*, *28*(5), 917-942.

Carhart, M. M. (1997). On persistence in mutual fund performance. *The Journal of finance*, *52*(1), 57-82.

Conine, T. E., McDonald, M. B., and Tamarkin, M. (2017). Estimation of relative risk aversion across time. *Applied Economics*, *49*(21), 2117-2124.

CREG (2020). Nota als reactie op de openbare raadpleging georganiseerd door ELIA over de methodologie, de basisgegevens en -scenario's voor de studie van de bevoorradingszekerheid en de behoefte aan flexibiliteit voor het Belgische elektriciteitssysteem voor de periode 2022-2032. Available at: https://www.creg.be/sites/default/files/assets/Publications/Notes/Z2154NL.pdf

Driver, C., & Temple, P. (2010). Why do hurdle rates differ from the cost of capital?. *Cambridge Journal of Economics*, *34*(3), 501-523.

Elia (2019). Adequacy and flexibility study for Belgium 2020-2030. Available at https://www.elia.be/en/electricity-market-and-system/adequacy/adequacy-studies

Fama, E. F., and French, K. R. (1993). Common risk factors in the returns on stocks and bonds. *Journal of Financial Economics*, *33*, 3-56.

F. T. I. (2016). Assessment of the impact of the French capacity mechanism on electricity markets, FTI CL-Energy. *Available at* https://www.fticonsulting.com/~/media/Files/us-files/intelligence/intelligence-research/the-french-capacity-mechanism.pdf

Kraus, A., and Litzenberger, R. (1976), Skewness Preferences and the Valuation of Risk Assets. *Journal of Finance*, 31, 1085–1100.

Goltz, F., and Le Sourd, V. (2011). Does Finance Theory Make the Case for Capitalization-Weighted Indexing?. *Journal of Index Investing*, *2*(2), 59-75.

Graham, J. R., and Harvey, C. R. (2018). The equity risk premium in 2018. *Available at SSRN 3151162*.

Helms, T., Salm, S., and Wüstenhagen, R. (2020). Investor-specific cost of capital and renewable energy investment decisions. Chapter 4 in *Renewable Energy Finance: Funding The Future Of Energy*. Imperial College Press, London (second edition).

Holdermann, C., Kissel, J., & Beigel, J. (2014). Distributed photovoltaic generation in Brazil: An economic viability analysis of small-scale photovoltaic systems in the residential and commercial sectors. *Energy Policy*, *67*, 612-617.

Holt, C. A., and Laury, S. K. (2002). Risk aversion and incentive effects. *American Economic Review*, *92*(5), 1644-1655.

Jamasb, T., and Pollitt, M. (2000). Benchmarking and regulation: international electricity experience. *Utilities policy*, *9*(3), 107-130.

Jondeau, E., and Rockinger, M. (2006). Optimal portfolio allocation under higher moments. *European Financial Management*, *12*(1), 29-55.

Jondeau, E., Poon, S. H., and Rockinger, M. (2007). *Financial modeling under non-Gaussian distributions*. Springer Science & Business Media.

Jurczenko, E., and Maillet, B. (Eds.). (2006). *Multi-moment asset allocation and pricing models*. Hoboken, NJ: John Wiley & Sons.

Mauldin, J. (Ed.). (2011). *Just One Thing: Twelve of the World's Best Investors Reveal the One Strategy You Can't Overlook*. John Wiley & Sons.

Markowitz, H. (1952). Portfolio section. *Journal of Finance*, 7, 77-91.

Markowitz, H. (1959). Portfolio Selection. Efficient Diversification of Investments. John Wiley & Sons.

Maronna, R. A., Martin, R. D., and Yohai, V. J. (2019). *Robust statistics: theory and methods (with R)*. John Wiley & Sons.

Martellini, L., and Ziemann, V. (2010). Improved estimates of higher-order comoments and implications for portfolio selection. *The Review of Financial Studies*, *23*(4), 1467-1502.

Meier, I., and Tarhan, V. (2007). Corporate investment decision practices and the hurdle rate premium puzzle. *Available at SSRN 960161*.

NERA (2015). Electricity generation costs and hurdle rates. Lot 1: Hurdle rates update for generation technologies. Prepared for the Department of Energy and Climate Change (DECC). https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/566809/NERA_Hurdle_Rates_for_Electricity_Generation_Technologies.pdf

Newbery, D. (2020). Capacity Remuneration Mechanisms or Energy-Only Markets? The case of Belgium's market reform plan. *Energy Policy Reserach Group, University of Cambridge.*

Oum, Y., Oren, S., and Deng, S. (2006). Hedging quantity risks with standard power options in a competitive wholesale electricity market. *Naval Research Logistics (NRL)*, *53*(7), 697-712.

Peña, I., Azevedo, I. L., & Ferreira, L. A. F. M. (2014). Economic analysis of the profitability of existing wind parks in Portugal. *Energy Economics*, *45*, 353-363.

Redl C., Haas R., Huber C., Böhmer B. (2009). Price formation in electricity forward markets and the relevance of systematic forecast errors. Energy Economics 31,356–364.

Ross, S. (1976). The arbitrage theory of capital asset pricing. *Journal of Economic Theory*, *13*(3), 341-360.

Salm, S. (2018). The investor-specific price of renewable energy project risk–A choice experiment with incumbent utilities and institutional investors. *Renewable and Sustainable Energy Reviews*, *82*, 1364-1375.

Scott, R. C., and Horvath, P. A. (1980). On the direction of preference for moments of higher order than the variance. *Journal of Finance*, *35*(4), 915-919.

Sharpe, W. F. (1964). Capital asset prices: A theory of market equilibrium under conditions of risk. *The journal of finance*, *19*(3), 425-442.

Tversky, A., and Kahneman, D. (1992). Advances in prospect theory: Cumulative representation of uncertainty. *Journal of Risk and Uncertainty*, *5*(4), 297-323.

Willems, B., and Morbee, J. (2010). Market completeness: How options affect hedging and investments in the electricity sector. *Energy Economics*, *32*(4), 786-795.

Appendix A: Taylor expansion of the expected utility function

The utility function $U(x)$ is a non-linear function. We can use Taylor expansions to describe its behavior around a fixed point such as the expected value of $x = 1 + R$, namely 1+μ with $\mu = E[R]$. The first order expansion uses the tangent line:

$$U(1+R) \approx U(1+\mu) + U'(1+\mu)(R-\mu).$$

For risk-averse investor, the utility function is concave. We can take the curvature into account by computing the second-order tailor expansion:

$$U(1+R) \approx U(1+\mu) + U'(1+\mu)(R-\mu) + \frac{1}{2}U''(1+\mu)(R-\mu)^2.$$

Note that the expected value of the second-order approximation of the utility function shows the trade-off between expected return and variance:

$$EU \approx U(1+\mu) + \frac{1}{2}U''(1+\mu)\sigma^2,$$

where $\sigma^2 = E[(x-\mu)^2]$. We have a trade-off since, for risk-averse investors, the utility function is concave and hence $\frac{1}{2}U''(1+\mu) \leq 0$.

The utility function is however not quadratic and project returns are skewed. We can thus improve the approximation by taking higher order terms into account. The third order approximation equals:

$$U(1+R) \approx U(1+\mu) + U'(1+\mu)(R-\mu) + \frac{1}{2}U''(1+\mu)(R-\mu)^2 + \frac{1}{6}U'''(1+\mu)(R-\mu)^3.$$

The expected value of the third-order approximation shows the trade-off between expected return, variance and skewness:

$$EU \approx U(1+\mu) + \frac{1}{2}U''(1+\mu)\sigma^2 + \frac{1}{6}U'''(1+\mu)\zeta,$$

where $\zeta = E[(R-\mu)^3]$. From Theorem 1 in Scott and Horvath (1980) it follows that $U'''(\mu) > 0$. Let's verify this in the concrete case of the CARA and CRRA utility functions.

The expected value of the fourth-order approximation shows the trade-off between expected return, variance, skewness and kurtosis:

$$EU \approx U(1+\mu) + \frac{1}{2}U''(1+\mu)\sigma^2 + \frac{1}{6}U'''(1+\mu)\zeta + \frac{1}{24}U''''(1+\mu)\kappa,$$

where $\kappa = E[(R-\mu)^4]$. The impact of the moments depends on the derivatives of the utility functions. Let's elaborate this in the concrete case of the CARA and CRRA utility functions.

- CARA : $U_a(x) = \frac{1-e^{-ax}}{a}$. Hence : $U_a'(x) = e^{-ax} \geq 0$, $U_a''(x) = -ae^{-ax} \leq 0$, $U_a'''(x) = a^2e^{-ax} \geq 0$ and , $U_a''''(x) = -a^3e^{-ax} \geq 0$. The corresponding value of the expected utility function is

$$EU_a \approx \frac{e^{-a(1+\mu)}}{a}\left(e^{a(1+\mu)} - 1 - \frac{a^2}{2}\sigma^2 + \frac{a^3}{6}\zeta - \frac{a^4}{24}\kappa\right).$$

- CRRA: $U_\gamma(x) = \frac{x^{1-\gamma}-1}{1-\gamma}$. Hence $U_\gamma'(x) = x^{-\gamma} \geq 0, U_\gamma''(x) = (-\gamma)x^{-(\gamma+1)} \leq 0$, $U_\gamma'''(x) = \gamma(\gamma+1)x^{-(\gamma+2)} \geq 0$ and $U_\gamma''''(x) = -\gamma(\gamma+1)(\gamma+2)x^{-(\gamma+3)} \leq 0$. The corresponding value of the expected utility function is

$$EU_\gamma \approx U(1+\mu) - \frac{\gamma}{2}(1+\mu)^{-(\gamma+1)}\sigma^2 + \frac{\gamma(\gamma+1)}{6}(1+\mu)^{-(\gamma+2)}\zeta - \frac{\gamma(\gamma+1)(\gamma+2)}{24}(1+\mu)^{-(\gamma+3)}\kappa.$$

Appendix B: Impact of cashflow distribution on the expected project return[40]

The variance of the underlying cashflows tends to have a negative effect on the project return. In the option literature, they refer to this as negative *vega*: as the volatility of underlying risky asset increases, the value of the financial instrument decreases. Due to price spikes, the underlying asset in case of investments in electricity capacity can have substantial positive skewness. This positive skewness reduces the negative effect of the variance. The goal of this appendix is to shed more insights on this interaction between variance and skewness on the project return. Note that we assume here that the variance and skewness are correctly estimated. In practice model risk leads to uncertainty about these values (and thus their effect on the project performance).

B.1. Analysis using Taylor expansions

The recommended investment rule is to invest when the expected project return exceeds the hurdle rate. The goal of this appendix is to illustrate the importance of accounting for the randomness of the cashflows when computing the expected return.

We define the project return as the internal rate of return R such that the net present value of all cashflows is 0. We denote the investment horizon by K, the initial investment is I and the net investment cashflows is for simplicity assumed to be constant within the investment horizon. Without loss of generality we normalize $I = 1$. All variability comes thus from the investment paths.

In the special case of constant cashflow Y/K, we have

$$PV = -1 + \sum_{t=1}^{K} \frac{(Y/K)}{(1+R)^t} = 0 \leftrightarrow -1 + (Y/K)\, \frac{1-(1+R)^{-K}}{R} = 0 \leftrightarrow R = g(Y)$$

where $g(Y)$ is a non-linear function, and hence $E[g(Y)] \neq g(E[Y])$: the expected internal rate of return differs from the internal rate of return computed using expected cashflows.

The function $g(Y)$ is visualized below. The function is of course increasing as the higher are the net cashflows, the higher is the return. The marginal impact of a higher revenue on the return is however diminishing. The function has a concave shape. Numeric differentiation confirms that $g(Y)$ has a positive first order derivative, and (for most points evaluated) a negative second order derivative and positive third order derivative.

[40] This appendix is joint work with Brecht Verbeken (Vrije Universiteit Brussel).

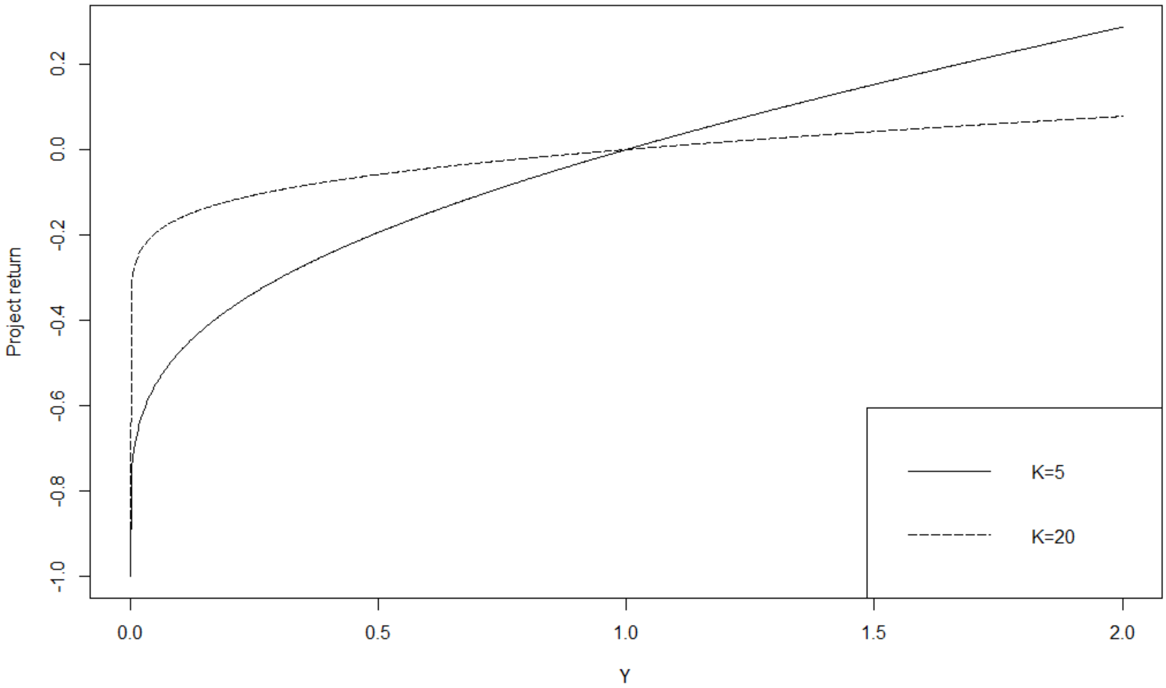

Figure 5 Internal rate of return as a function of total cashflow (yearly cashflow is Y/K)

We can use a Taylor expansion of $h(Y)$ around $h(E[Y])$ to understand the drivers of this difference:

$g(Y) \approx g(E[Y]) + g'(E[Y])(Y\text{-}E[Y]) + \frac{1}{2}g''(E[Y])(Y - E[Y])^2 + \frac{1}{6}h'''(E[Y])(Y - E[Y])^3$

Taking expectations we obtain

$E[g(Y)] \approx g(E[Y]) + \frac{1}{2}g''(E[Y])E[(Y - E[Y])^2] + \frac{1}{6}g'''(E[Y])E[(Y - E[Y])^3].$

Implicit differentiation of $g(Y)$ leads to the following expression for the first, second and third order derivatives

$$g'(Y) = \frac{R\,(1+R)(-1+(1+R)^K)}{Y\,(-1-R-K\,R+(1+R)^K+R\,(1+R)^K)}$$

$$g''(Y) = -\left(\frac{K\,R^2(1+R)(-1+(1+R)^K)\left(2-2\,(1+R)^K+R(1+K-(1+R)^K+K\,(1+R)^K)\right)}{Y^2\left(-1+(1+R)^K+R\,(-1-K+(1+R)^K)\right)^3}\right)$$

$$g'''(Y) = \left(\frac{K\,R^3(1+R)\left(-1+(1+R)^K\right)}{Y^3\left(-1+(1+R)^K+R\,(-1-K+(1+R)^K)\right)^5}\right)\Big(-3\,(-1+(1+R)^K)^2\left(-1+(1+R)^K+K(-3+(1+R)^K)\right)+R\,(-1+(1+R)^K)\big(-4\,(-1+(1+R)^K)^2+K^2(-8-5\,(1+R)^K+(1+R)^{2K})-3\,K\,(4-5\,(1+R)^K+(1+R)^{2K})\big)+R^2\big(4\,K\,(-1+(1+R)^K)^2-(-1+(1+R)^K)^3+2\,K^3(1+(1+R)^K+(1+R)^{2K})+K^2(5-3\,(1+R)^K-3\,(1+R)^{2K}+(1+R)^{3K})\big)\Big).$$

Analysis of these derivatives for Y between 0 and 2 indicates $g''(E[Y]) < 0$ while $g'''(E[Y]) > 0$. It follows that, for symmetric distribution of Y , a higher variance always leads to a lower expected rate of return. In case of skewness, we have a trade-off between "good" and "bad" variance with a total effect that is case-specific.

To summarize, the larger is the variance of the cashflows, the more deviation there will be between the expected project return and the return computed using the expected cashflow. The effect depends on the shape of the distribution.

B.2. Effect of skewness on volatility gremlins

The negative effect of variance on compound return is commonly referred to as "volatility gremlins": as volatility increases and returns become more erratic, the compound returns get lower and lower compared to the average returns (see e.g. Mauldin, 2011). The effect follows from the observations that $(1+R)(1-R) = 1-R^2$ corresponds to an average arithmetic return of 0 but the final value decreases as $|R|$ increases.

The above illustration of volatility gremlins takes a symmetric assumption on the periodic return. In order to show the interaction between skewness and variance, consider a generalization of the previous case to $K = L+1$ periods where in year 1 the investor receives a return of R and in the remaining L years a return of $-R/L$. The arithmetic average of the returns is zero. The compound return is negative: $(1+R)(1-R/L)^L \leq 1$. There are two extreme cases:

- For $L = 1$ we have $(1+R)(1-R/L)^L = 1-R^2$. This is the case of symmetry.
- For $L \to \infty$ we have $\lim_{L\to\infty}(1+R)(1-R/L)^L = (1+R)\lim_{L\to\infty}(1-R/L)^L = (1+R)e^{-R}$. This is the case of asymmetry where we have an outlier R compared to the infinitesimal small numbers R/L for $L \to \infty$. If $R \geq 0$ there is positive skewness, otherwise negative skewness.

In the last step we use the well-known result for continuous compounding.

Below we illustrate the convergence of $(1+R)(1-R/L)^L$ to $(1+R)e^{-R}$ for $R = 0.5$ and $R = -0.5$. We can see that positive skewness leads to a higher final value of the investment. In the cases considered here, we find that the volatility gremlin dominates since the final value is below 1.

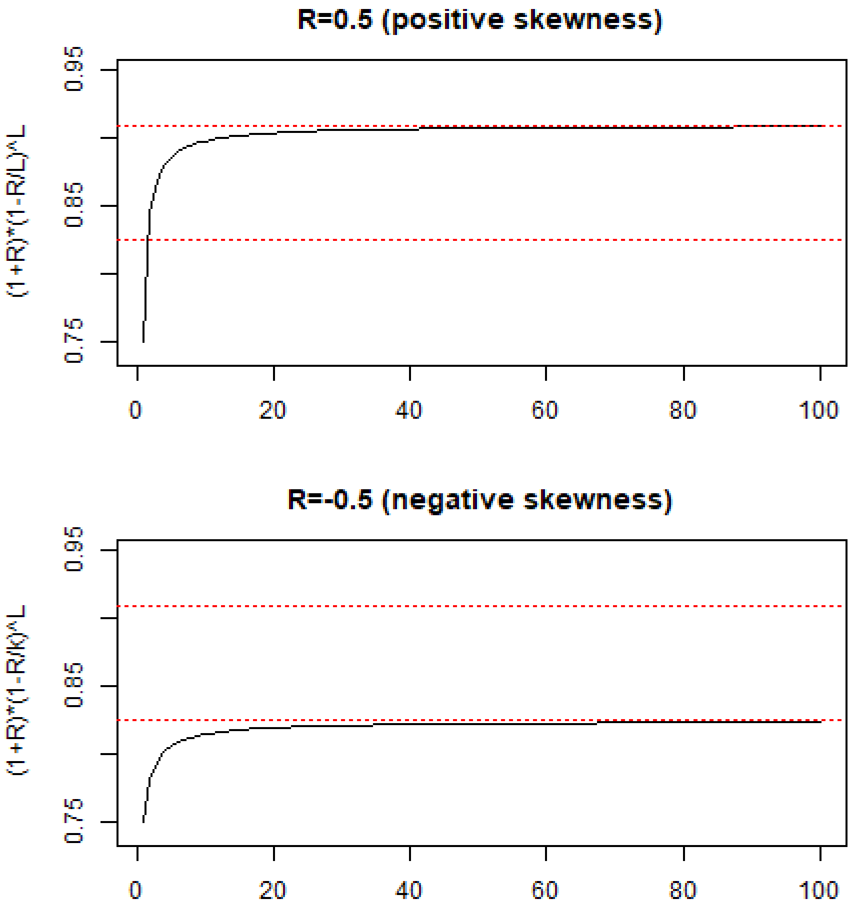

Figure 6 Convergence of $(1+R)(1-R/L)^L$ *to* $(1+R)e^{-R}$ *for* $R=0.5$ *and* $R=-0.5$

Appendix C: Hurdle premium due to deviations between the project WACC parameters and the reference WACC parameters

We do not observe the CoE, CoD, and g of the project. Instead, based on historical data, we can make a good approximation of the cost of equity, cost of debt and gearing ratio of potential investors. Denote these by CoE^*, CoD^*, and g^*, and let $WACC^*$ be the WACC of the reference investor by $WACC^*$.

We use these numbers as reference values to define the project equity and debt risk premium as[41]:

$CoE \quad = CoE^* + PERP$ [PERP: Project Equity Risk Premium]

$CoD \quad = CoD^* + PDRP$ [PDRP: Project Debt Risk Premium]

In addition we have that the project gearing ratio differs as banks may be more or less reluctant based on the project uncertainty[42]:

$g \quad = g^* + PGRD$ [PGRD: Project Gearing Ratio Difference]

We can then establish the following relationship between the project WACC and the reference investor WACC:

$$WACC = \frac{1 + \left[(CoE^* + PERP) \cdot \frac{1-(g^* + PGRD)}{1-t} + (CoD^* + PDRP) \cdot (g^* + PGRD)\right]}{1+i} - 1$$

$$= \frac{1 + \left[CoE^* \cdot \frac{1-g^*}{1-t} + CoD^* \cdot g^*\right]}{1+i} - 1$$

$$+ \frac{\left[PERP \cdot \frac{1-(g^* + PGRD)}{1-t} + (PDRP) \cdot (g^* + PGRD)\right] + \left[(CoE^* + PERP) \cdot \frac{-PGRD}{1-t} + (CoD^* + PDRP) \cdot (PGRD)\right]}{1+i}$$

= $WACC^*$ + hurdle premium

[41] Note that this notation follows the framework of ACER (2020) for introducing a country premium in the WACC calculation.

[42] The optimal gearing ratio $g = D/(D+E)$ is such that the Weighted Average Cost of Capital (WACC) is minimized and financiers consider the amount of equity as a sufficiently high buffer to protect them in case of insolvency.

Appendix D: Cost of equity models

The project cost of equity has two components: (i) the risk-free rate (expressing the opportunity cost of investing at no risk) and (ii) the risk premium (expressing the compensation for the risk taken). Financial theories like the modern portfolio theory of Markowitz (1952), the Capital Asset Pricing Model (CAPM) of Sharpe (1964) and the Arbitrage Pricing Theory (APT) of Ross (1974) formalize the central paradigm of finance that rational investors optimize their portfolio by maximizing expected returns and minimizing risk. If two portfolios have the same expected return, the rational risk-averse investor chooses the portfolio with the lowest risk. Since risk is multidimensional, there are many plausible candidates to be used as risk measure. A general view is therefore to include several risk factors in the cost of capital equation, each having their compensation for risk. Suppose there are K risk factors f_i, then the cost of equity capital equals:

$$k = r_f + \sum_{i=1}^{K} \zeta_i f_i,$$

where r_f is the long-term risk free rate, and ζ_i is the compensation in terms of expected excess return per unit of exposure to risk factor f_i taken.

Markowitz (1952) uses the portfolio return variance as risk measure. His modern portfolio theory states that mean-variance efficient investors only invest in portfolios that offer the highest expected return for a given level of risk. The collection of all these portfolios is called the efficient frontier.

Sharpe (1964) extends the framework to asset pricing and uses the stock's beta as the relevant risk measure in determining the value of an asset. Under the proposed Capital Asset Pricing Model (CAPM) the expected return of an investment in excess of the risk free rate equals the investment's beta multiplied with the market expected return (μ_{MKT}) in excess of the risk free rate:

$$k_{CAPM} = r_f + \beta(\mu_{MKT} - r_f).$$

The investment's beta is the covariation of the investment return with the market portfolio return, divided by the variance of the market return. Extensions to the CAPM include the three-factor and four-factor models of Fama and French (1993) and Carhart (1997).

The above models assume that the return distribution is symmetric. In practice, investment returns for energy projects tend to be skewed and heavy-tailed. Markowitz (1959) recommends using semivariance as a measure of downside risk. Modern investors heavily rely on value-at-risk and expected shortfall as measures of downside risk.[43] Boudt et al. (2008) show how downside risk measures like value-at-risk and expected shortfall can be estimated for non-normal distributions.

Kraus and Litzenberger (1976), among others, extend the CAPM to account for the higher moments of the return distribution. They conclude that investors not only care about the covariance between the project return and the market return, but also the coskewness. Bawa and Lindenberg (1977) define the downside beta as the covariance between the stock return and the market return, conditional on the market return being below its average, divided by the corresponding conditional variance of the market return. Irrespective of the downside risk measure used, there is the consensus that agents who are averse to losses demand greater compensation, in the form of higher expected returns, for investing in projects with high downside risk (Ang et al., 2006). The disadvantage of these alternative risk measures is that there is no readily available number to express the market-based return compensation per unit of risk taken.

[43] Popular downside risk measures are the Value at Risk and Expected Shortfall at loss probability α (typically 5%). Let Q_α be the α −quantile of R, then: $VaR_\alpha = -Q_\alpha$ and $ES_\alpha = -E[R|R \leq Q_\alpha]$.