Enhancing a decentralised Economic Viability Assessment Approach: Incorporating Balancing Reserve, Heat Generation, and Capacity Mechanisms

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Abstract—**Economic viability assessments are used to estimate future capacities within the power system. As a possible source of revenue, the focus is often on revenues from the scheduled energy market. However, there are additional markets from which revenues can be generated, including the balancing reserve market, the heat market and capacity mechanisms. These are challenging to model, particularly due to limited data availability and a lack of transparency. This paper therefore first shows how demand and revenues can be calculated for each of these three revenue streams based on public data, and then how these can be integrated into an existing decentralised economic viability assessment approach. The results show that the majority of revenues are generated on the scheduled energy market; nevertheless, the consideration of the other markets has a decisive influence on the profitability of the capacities.**

Index Terms--**Economic viability assessment, Energy security of supply, Investment in liberalised energy markets**

I. INTRODUCTION

The EU Commission's goal of achieving climate neutrality necessitates a transformation of the European power system. This involves both the expansion of renewable energy sources (RES) and the reduction of fossil fuel-based electricity generation. However, the weather dependency of RES increases the risk to resource adequacy, making dispatchable capacities essential to compensate for volatility in renewable generation. Despite this need, limited revenue streams and high uncertainties may hinder the necessary investments in dispatchable capacities. To assess whether current market mechanisms and regulatory frameworks can ensure sufficient dispatchable capacities, Economic Viability Assessments (EVA) are conducted. EVA can be approached from either a centralised or a decentralized perspective. While the centralised approach determines the overall system optimum, the decentralized approach allows each market participant to optimize its own decisions - providing a more realistic representation of market behaviour. Given that the European regulator ACER ruled in 2024 that only decentralised approaches are adequate for analysing investment uncertainties, this study focuses exclusively on the decentralised perspective [1].

The economic viability of capacities depends on their ability to generate sufficient revenue from various markets. While scheduled energy markets play a central role, dispatchable units often participate in multiple markets to ensure profitability. To provide a more realistic assessment, it is therefore essential to consider a broad range of revenue streams. Possible revenue streams to consider are the renumeration of the participation in balancing reserve markets, heat markets and capacity mechanisms.

Existing studies analyse only selected additional revenue streams. For instance, publications such as [2] consider revenues from capacity mechanisms, where market participants bid for capacity payments to cover their costs. [3] extends the EVA by incorporating revenues from the heat market, achieved through the inclusion of combined heat and power (CHP) plants and an exogenous heat market model that determines feed-in time series and heat prices. Although the model simulates balancing power provision, contracted capacities for this purpose are excluded from the EVA, meaning potential revenues from the balancing reserve market are not fully accounted for. The models in [4], [5], [6] integrate revenues from both the balancing reserve and heat markets. Like [3], they include CHP plants to capture additional revenue streams, and they also account for remuneration from balancing reserve market participation. However, except for [5], these studies apply a centralised approach and are therefore not relevant in light of ACER's decision.

It becomes evident that no existing decentralised EVA approach comprehensively considers a broader range of revenue streams. Therefore, this paper aims to provide an overview of how additional revenues from participation in the balancing reserve market, heat market, and capacity mechanisms can be integrated. Since harmonised, Europe-wide data on these revenue streams is often unavailable, the analysis relies on a methodology based solely on publicly available data. Section II presents the methodology of the economic viability assessment, with a particular focus on the incorporation of additional revenue streams. A more detailed description of the underlying model can be found in [7]. Section III follows with an exemplary investigation analysing the impact of each revenue stream. Finally, a conclusion is formulated in section IV.

II. METHODOLOGY

The developed model for assessing the economic viability of capacities is due to the iterative character divided in two stages. The initial stage comprises an electricity market simulation, while the second stage is an EVA. Figure 1 shows the implemented procedure. The iterative character enables to model the requirements of market dynamics and numerous market participants. The given modelling approach does not initially account for uncertainties. To reflect the uncertainties the power system is exposed, e.g., fluctuating feed-in of renewable energy sources (RES) or power plant failures, the deterministic model is developed into a probabilistic procedure by implementing a Monte-Carlo-Simulation. Instead of performing the two stages with only one set of input data, the market simulation can process various n weather and m power plant outage years in the form of time series. Derived from historical data, a distinct pair of weather year and outage year form a new Monte Carlo year. Therefore, the model simulates $n \cdot m$ Monte Carlo years.

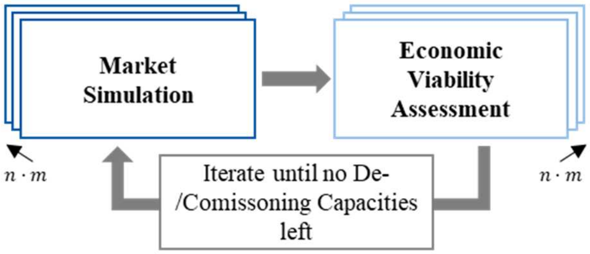

Figure 1. Stages of the methodology

A. *Market Simualtion*

In the first step of the methodology, the deterministic market simulation calculates the optimal use of available resources for each Monte Carlo year to meet the demand for electrical energy by simulating the day-ahead market. The model is a linear optimization approach aimed at minimizing total system costs. These costs include fuel and CO_2 costs for electricity generation, curtailment costs, costs for Demand Side Response (DSR), and costs associated with unserved energy. To reduce model complexity, renewable energy sources (RES) are aggregated for each bidding zone. The power plants are represented at the unit level to ensure a more realistic depiction.

B. *Economic Viability Assessment*

1) *Determining Dispatches of Comssioning Candidates*

Due to the stepwise structure of the developed the utilisation of commissioning candidates is determined exogenously after the market simulation. Based on the scheduled energy market prices, a gas-fired power plant is dispatched at its maximum power in each timestep if the market price exceeds its marginal costs. The dispatch of large-scale battery storage systems is determined using the top-bottom-four method. Assuming perfect foresight, the storage is charged during the four hours with the lowest prices in the next 24 hours and discharged during the four hours with the highest prices [8]. The dispatch of DSR is also determined using perfect foresight, identifying the hours with the highest revenue potential within the next 24 hours.

2) *Considered Technologies within the EVA*

Following the market simulation, the EVA is conducted. Market prices and capacity utilisation are used to assess the profitability of existing capacities and prospective candidates for expansion. Due to exogenous factors, not all generation technologies are assessed in terms of economic viability within the EVA. Technologies whose (de-)commissioning is primarily driven by political factors are excluded from further consideration in this context. Therefore, pumped storage plants, nuclear power plants, and RES are not included in the EVA.

The EVA includes thermal power plants, large-scale battery storage systems, and DSR technologies. It should be noted that not all thermal power plants are considered for commissioning due to the EU's CO_2 emission limits and 2050 climate neutrality target. Only gas-fired power plants are considered due to their potential to utilise carbon-neutral (green) hydrogen in the future. Coal-, oil-, and gas-fired units are assessed for decommissioning. Moreover, DSR (up to its predicted expansion potential in each bidding zone) and large-scale battery storage systems are considered in commissioning decisions due to their potential to stabilise the residual load and reduce peak demand.

3) *Determination of the Inframarginal Rents*

The inframarginal rent (IR) of each unit is derived from its dispatch and the corresponding market prices in each timestep t. It is calculated as the sum of the IR from all individual revenue streams (1). For conventional power plants, the IR includes revenues from the scheduled energy markets $IR_{scheduled,t}$ and balancing reserve markets $IR_{balancing,t}$. For CHP plants, the IR is additionally extended by revenues from heat markets $IR_{heat,t}$. Since the methodology for determining the dispatch of new large-scale battery storage systems and DSR currently focuses solely on electricity prices, additional revenue streams do not influence the commissioning decision. The following section is structured into three parts, each presenting one of the considered additional revenue streams.

$$IR_{capacity,t} = IR_{scheduled,t} + IR_{balancing,t} + IR_{heat,t} \quad (1)$$

a) *Revenues from the Balancing Reserve Market*

The market simulation models the day-ahead market and the balancing reserve market in an hourly temporal resolution. As a result, it does not distinguish between the frequency containment reserve (FCR) and the frequency restoration reserve (FRR). Additionally, it does not account for balancing energy activation, which occurs in real-time operations. To address these limitations, an activation factor $a_{activation}$ is introduced to describe the ratio of activated energy to reserved capacity for the respective time period. Furthermore, by using the ratio of the needed FCR and FRR k_{FCR} in each Bidding zone, the revenues can still differentiate between these two types.

Due to the limited availability of publicly accessible data on activated energy, historical data from the German bidding zone in 2023 is used to determine $a_{activation}$ and is applied uniformly across all considered bidding zones [9]. The lack of bidding-zone-specific data also affects remuneration. The underlying price data is again derived from the German bidding zone [10]. Renumeration is differentiated by balancing reserve type into positive and negative reserves and is determined analogously to (2). For FRR, a further distinction is made between in activation $MP_{FRR,provision,i}$ and capacity price $MP_{FRR,activation,i}$.

$$MP_{balance,t} = k_{FCR} \cdot MP_{FCR,t} + (1 - k_{FCR}) \cdot (MP_{FRR,provision,t} + MP_{FRR,activation,t} \cdot a_{activation}) \qquad (2)$$

The IR for existing power plants is derived from the hourly dispatch in the balancing reserve market, which differentiates between positive $Q_{Dispatch,pos,i}$ and negative $Q_{Dispatch,neg,i}$ reserve participation, multiplied by the corresponding profits (4). These profits are determined by the market prices derived from (3) and the associated costs. The costs include variable costs $c_{variable,i}$ incurred when providing balancing capacity, as well as start-up costs $sc_{plant,i}$ (4). The latter may arise if the power plant was not already operating in the balancing reserve market or participating in the scheduled energy market during the hour preceding hour. It is important to note that in timestep t, power plants cannot provide both positive and negative balancing reserve simultaneously.

$$IR_{balancing,t} = Q_{Dispatch,pos,t} \cdot \left(MP_{pos,t} - c_{costs,t}\right) + Q_{Dispatch,neg,t} \cdot \left(MP_{neg,t} - c_{costs,t}\right) \qquad (3)$$

$$c_{costs,t} = c_{variable,t} + sc_{plant,t} \qquad (4)$$

For new gas-fired power plant investment decisions, a similar approach is applied. However, as elaborated earlier, the challenge of absent real capacity deployments arises. To address this, hypothetical deployments are derived under the assumption that new gas-fired power plants will replace older existing gas-fired plants for balancing provision. Thus, the capacity deployment of new investment candidates in the balancing market is aligned with gas-fired plants still in operation within the respective bidding zone at that time. If no gas-fired power plants are participating in the market, this implies that new candidates have no revenue potential under the current market conditions.

b) *Revenues from the Heat Market*

To assess the revenue from the sale of heat from thermal power plants, an exogenous heat market must be introduced, as the employed market simulation focuses solely on the energy-only market. CHP plants act as the interface between the heat and electricity markets, predominantly producing the required heat for district heating networks. The given power plant fleet is therefore expanded to include heat-driven CHP plants, as these prioritise heat production. Electricity-driven CHP plants are not focus of the extension since their heat is considered a by-product. Therefore, their operational patterns and heat sales cannot be realistically estimated in parallel operation.

To determine the installed capacity of heat-driven CHP plants, the share of CHP plants in the total installed thermal capacity is calculated per country using Eurostat data from 2019 [11]. To categorise CHP capacities into fuel types, a distribution is performed according to the fuels used. The CHP capacity is then divided into heat- and electricity-driven, considering only the former. Due to the lack of Europe-wide data for this division, data from the German bidding zone is again utilised [12]. Assuming that heat-driven CHP plants have a higher thermal than electrical output, their share is determined. The installed capacity for each bidding zone is then calculated by multiplying this resulting share with the installed capacities of each power plant type.

The supply obligations of heat-driven CHP plants are represented within the market simulation as a minimum generation time series Q_{min}. The time series correspond to the consumption of end-users connected to district heating networks. Using heat demand as the minimum generation time series means that specific district heating networks cannot be modelled in detail. Thus, generic district heating networks are assumed, where the assigned CHP plant meet the entire heat demand. To determine the demand within district heating networks, local measurements serve as the data foundation, gradually adjusted for broader European application. The fundamental data comes from smart meter readings of 3,021 households in Aarhus (Denmark) from 2019 [13]. To smooth out irregularities, an average time series is calculated over the individual time series. Since district heating networks also supply commercial, trade and service sectors, the data is further adjusted to include a base load of 10 %. The Danish demand time series is normalized using the corresponding 2019 temperature data to reflect the correlation between heat demand and temperature. Finally, the normalized demand is scaled based on the temperature time series of the respective country where the considered CHP plant is located.

To evaluate the revenues from heat generation, the heat prices MP_{heat} must be determined. The heat prices are given in [14], whereby for not mentioned countries average values from the neighbouring countries are used. Since the heat prices account for thermal energy, a conversion factor c_{CHP} is applied. This factor describes the ratio of generated electrical energy to thermal energy and is assumed to be constant [15]. The inframarginal rent for CHP is given in (5).

$$IR_{heat,t} = Q_{min,t} \cdot \frac{1}{c_{CHP}} \cdot MP_{heat} \tag{5}$$

It is important to note that no additional variable costs are considered. This is based on the assumption that CHP plants do not incur increased variable costs when supplying heat to the heating network alongside power production. The variable costs of parallel electricity production are already accounted for in the calculation of the renumeration of the scheduled energy market.

c) Revenues from Capacity Mechanisms

Currently, capacity mechanisms (CM) are implemented only in a few bidding zones within the ENTSO-E interconnected system. To incorporate these mechanisms into the EVA model, it is necessary to analyse the respective reports published by the transmission system operators. The level of detail provided varies significantly depending on the member state and bidding zone. In the present model, mechanisms from Belgium, France, Germany, Hungary, Italy, Spain, Poland, United Kingdom and Northern Ireland are considered. The given capacity mechanisms can be categorised into two types. The first is the strategic reserve, currently implemented in Germany. Contracted capacities under this mechanism are entirely excluded from the model for regulatory reasons, as they are prohibited from participating in the electricity market during the term of their contracts. The second type is the capacity market, where contracted capacities face no such restrictions. These capacities can participate in both the capacity market and the electricity market and are therefore considered in the EVA.

Due to the lack of unit specific data, it is not possible to include the additional revenues for the capacity market in the same way as the other revenue streams. Therefore, another way of integration has to be made. Unlike the previous mentioned revenue extensions, the implementation of capacity mechanisms does not involve adjustments to the calculation of inframarginal rents. This assumption is based on the premise that capacities receiving payments from capacity mechanisms are inherently profitable due to these payments. Consequently, instead of integrating the additional revenues from capacity mechanisms in the calculation of the inframarginal rents, the revenues are included in a step after the determination of the possible revenue streams. A more detailed description of the integration is presented in the following section.

4) Determination of (Un-)Economic Capacities

To compare the different investment projects, the internal rate of return (IRR) is used. It is described as the efficiency of an investment and enables a comparison of investment projects with different durations or scales. The IRR is defined as the discounted rate for which the net present value NPV is zero. To determine the IRR Eq. (6) has to be solved. Thereby I represents the total costs discounted to the first period. IR are the previously determined archived revenues of the generation units discounted for each year.

$$0 = NPV = -I + \sum_{y}^{TY} \frac{IR(y)}{(1+IRR)^{y}} \tag{6}$$

After this step, there are for each Monte-Carlo year in total $n \cdot m$ IRRs. By using the average of the determined IRRs, the deterministic process of the EVA results in a probabilistic variable IRR^{mean}.

5) (De-)Investment Decision

The final decision-making process regarding the investment in new capacities or decommissioning of existing capacities is based on the previously calculated IRR.

$$IRR^{mean} > \pi_k \tag{7}$$

If the given capacity satisfies the Eq. (7), it is classified as profitable; otherwise, it is considered unprofitable. The variable π_k represents the hurdle rate and serves as a threshold value, to determine the worthwhileness from the perspective of investors.

Based on this classification, the most profitable new capacities are added to the market, while the least profitable existing ones are removed. To account for additional revenues from the capacity mechanisms, the decommissioning process is adjusted. If the model determines that a power plant contracted in the capacity market is not profitable, it is not decommissioned. This exception follows the logic of capacity payments described in the previous section.

The entire process, starting from step one, is repeated until no further (de-)investment decisions can be made. However, for the purpose of this paper, only a single iteration is considered in order to isolate the impact of additional revenue streams.

III. EXEMPLARY INVESTIGATIONS

A. Exemplary Case and Model Assumptions

The following analyses are conducted for the year 2030 and are based on data from the European Resource Adequacy Assessment (ERAA) 2023. The datasets under consideration comprise detailed information on the generation capacities of each bidding zone, load data and exchange capacities between bidding zones. Furthermore, geographically dependent time series on RES feed-in and power plant outage time series are given due consideration. Additionally, the parameters for variable and fixed costs, efficiencies, emission factors and prices for raw materials and CO_2 are taken into account. The modelling encompasses all countries that are connected to the European interconnected grid and have relevant capacities. However, it should be noted that the small island states of Cyprus and Malta have been excluded from the modelling. In total, 33 countries are represented, covering the entirety of the EU as well as several additional European countries. These countries are divided into 45 bidding zones. As already mentioned in the methodology section, the focus is on controllable capacities: Gas and coal-fired capacities, large-scale battery storage and DSR.

Five EVAs are now carried out based on this input data: one EVA does not include revenue extensions, one EVA for each of the three revenue extensions individually, and one EVA that considers all revenue extensions. For each of these EVAs, 20 different weather years are calculated. The subsequent section will present a comparison of the respective calculations and the manner in which the extensions affect the IRR in each case.

B. *Exemplary Results*

In order to analyse the influence of revenue extensions, two parameters are considered: the average IRR across all capacities and the proportion of profitable and unprofitable capacities, as shown in figure 2.

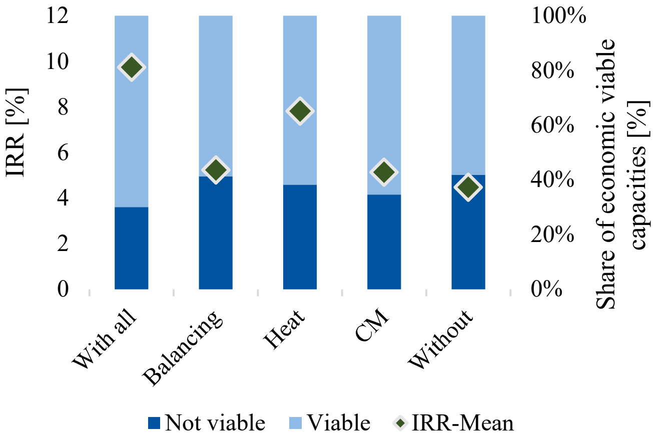

Figure 2. EVA parameters of the respective calculations

The analysis begins with the values derived exclusively from the revenues from the scheduled energy market. Approximately 40 % of the available capacities analysed are found to be uneconomical. The mean value of the IRR is 4.45 %.

1) *Balancing Reserve Market*

A comparison of the share of (un-)economic capacities of the EVA without expansion with the expansion by revenues from balancing reserve reveals only a slight improvement in the ratio. Conversely, the mean value of the IRR has shown a marked improvement, with a rise of 0.8 percentage points. This finding suggests that power plants which are already economically viable are increasing their revenues via the balancing reserve market.

2) *Heat Market*

By comparing the results of the EVA, both with and without revenues from the heat market, a clear increase in the IRR is demonstrated. Conventionally, CHP plants are incorporated into existing market simulations through the utilisation of must-run time series, thereby constraining their optimisation within the scheduled energy market. If the revenues from the provision of heat are neglected in the EVA, this can have a major impact on the economic efficiency, as the results show.

3) *Capacity Mechanisms*

Including capacity markets also has an impact on the proportion of (un-)economic capacities. The share of uneconomic capacities falls from 41 % to around 34 %. These results emphasise the need to introduce capacity mechanisms in the respective bidding zones.

4) *All Revenue Streams*

If all revenue streams are considered in the EVA, the greatest changes can be seen in both the proportion of (un-)economic capacity and the average IRR.

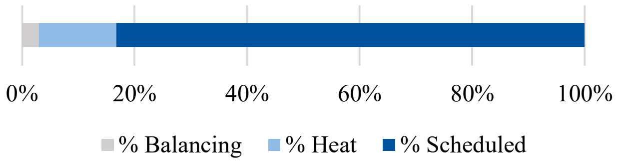

Figure 3. Share of the respective revenue streams in the total IR

A consideration of the mean proportion of revenue from the respective revenue streams in total IR reveals that revenue from the scheduled energy market continues to account for the largest proportion. Figure 3 illustrates that revenues from the heat market account for an average of 10 % of total revenues, and revenues from balancing power for an average of 2 %. However, it should be emphasised that these are mean values, and that there are capacities whose IR consists exclusively of one of the three income streams.

IV. CONCLUSION

When looking at existing EVAs, revenue opportunities that come from things other than scheduled energy are often not considered because of several factors. These include limited data availability, complicated modelling techniques, and a lack of transparency. Nevertheless, the findings of this paper demonstrate that the consideration of each individual revenue stream does have a noticeable effect. However, the most significant effect is observed when all revenue streams are considered. Consequently, EVAs need to include all relevant income streams.

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