Evolution of the electricity bill structure in Italy and the role of contracts for difference

Riccardo Mario, Gaetano Formato, Ennio Luciano, Francesca Raffo, Fabio Genoese, Luca Marchisio

***Abstract*—The structure of electricity bills in Italy is projected to change significantly by 2030 due to the growing role of renewable energy sources (RES) and the adoption of long-term contracting mechanisms like Contracts for Difference (CfDs). This paper compares electricity bill components between 2023 and 2030, analyzing the potential of CfDs to stabilize consumer prices and promote renewable investments. Using a techno-economic model based on Italy's National Energy and Climate Plan scenario, the study simulates various market scenarios to estimate future bill components. Specifically, within the electricity bill we analyze the energy component and system charges for RES. The results indicate that by 2030, only 43% of these bill components will be linked to gas prices, down from 77% today. For every +10 €/MWh_th increase in gas prices, the energy component and system charges for RES are expected to rise by +12 €/MWh_el, compared to +20 €/MWh_el in a gas-dominated scenario. The findings highlight the importance of expanding CfD coverage, promoting low-cost RES, and ensuring competitive auctions to reduce exposure to fossil fuel volatility and enhance long-term price stability for consumers.**

***Index Terms*--CfD, Electricity bill, Electricity market, Electricity market model, Renewables.**

I. INTRODUCTION

The rapid deployment of renewable energy sources (RES) across Europe has significantly influenced the dynamics of wholesale electricity markets where the price formation is based on a System Marginal Price (SMP) mechanism. As European countries strive to meet their ambitious climate targets, the integration of technologies such as wind and solar power has accelerated, leading to notable changes in market prices and especially in price volatility.

Many studies have analyzed the effect of the energy transition on wholesale electricity prices: while renewable energy can reduce overall electricity prices, the intermittent nature of sources like wind and solar introduces new challenges for price stability and market dynamics.

A recent study conducted by the European Commission [1] highlights that the increasing share of RES in the electricity mix has generally led to a reduction in wholesale electricity prices due to the well-known "merit order effect" [2], i.e. that low marginal cost renewables displace more expensive fossil fuel generation, thereby (ceteris paribus) reducing the wholesale market price. However, the intermittent nature of RES increases price volatility, with periods of very low or even negative prices during high renewable output. Another study conducted by the Joint Research Centre (JRC) of the European Commission [3] highlights that, due to the SMP mechanism, the impact of renewable generation on wholesale electricity prices will vary strongly among EU member states, depending on their mix. Countries with a relatively high share of gas-fired generation will continue to see a substantial amount of hours in which gas is setting the marginal price, despite the overall push towards renewables.

With this paper we would like to offer a broader perspective. Instead of focusing only on the wholesale electricity price, we examine the impact of the energy transition on the structure of electricity bills, which will be shaped by multiple factors, including the future energy scenario, political targets, and regulatory changes, but also by contractual arrangements. A key role could be played by Contracts for Difference (CfDs), a mechanism designed to promote renewable energy development while ensuring price stability for consumers.

A. Future energy scenario: NECP 2030

The electricity bill model is scenario-dependent. For this study, we consider the 2030 scenario of the latest National Energy and Climate Plan (NECP) as starting point [4]. The latest NECP reflects the EU's "Fit-for-55" targets, raising the 2030 GHG reduction goal from 40% to 55% (vs. 1990 levels). To ensure consistency among the various NECPs the European Commission has issued a report with recommended parameters, ranging from macroeconomic assumptions to commodity prices. The document indicates a natural gas price of 32.5 €/MWh_th and a CO2 price of 95.3 €/ton for 2030.

As requested by national regulation, Terna together with the Italian gas TSO prepares a report on future energy scenarios every two years, considering the policy targets defined in the NECP. The latest scenario document has been published in October 2024 [5]. For 2030, the latest NECP targets a share of 63% renewables in electricity consumption (about 227 TWh of RES generation, up from 129 TWh in 2024 [6], see Table 1). Wind and solar capacity will grow significantly, reaching 107.4

GW by 2030, with solar increasing by +42.2 GW and wind by +15.1 GW vs 2024. The scenario also foresees that coal-fired thermal power plants to be phased out completely before 2030. Electricity demand is expected to grow to 362 TWh, up 16% compared to 2024 (312 TWh), driven by electrification, economic growth and new increasing needs for data centers.

TABLE I. ANNUAL ELECTRICITY BALANCE IN 2024 AND 2030

Annual Electricity Balance (TWh)	2024 *Actual*	2030 *NECP*
Total electricity demand	312	362
o/w traditional	312	352
o/w for electrolysers	0	10
Total electricity production	263	322
o/w renewables	129	227
o/w conventional sources	134	95
Net import	51	43
Storage losses	-2	-4

The integration of RES is enabled by grid development (see Terna's Grid Development Plan [7]), as well as new storage systems which will be an essential resource to integrate the upcoming wave of renewables, especially solar, into our power system. To this end, Italy is offering a novel, efficient investment framework for storage, MACSE, an auction mechanism to award long-term contracts for storage [8].

Most of the new RES capacity is expected to be contracted via dedicated auctions (so-called FER-X and FER-2), held by "Gestore dei Servizi Energetici" (GSE) starting from 2025 [9], [10]. These auctions will award a two-way Contract-for-Difference. A Contract for Difference (CfD) is a financial agreement between a central buyer (typically backed by the government) and a producer of renewable energy resources, which defines a fixed price ("strike price") for energy produced over a period of 15-20 years. The aim of this instrument is twofold: on the one hand, the long-term contract promotes investments in renewables, because it locks in revenues over a long period, making projects bankable. On the other hand, it is a risk hedging instrument for consumers against volatile wholesale electricity prices, which are and will be heavily dependent on gas prices. In fact, if the captured market price exceeds the strike price, the producer must repay the difference to the central buyer. Conversely, if the captured market price falls below the strike price, the central buyer compensates the producer for the difference.

II. METHODOLOGY

A. *Structure of the electricity bill*

In general, an electricity bill can be characterized by the following structure:

- **Energy Component**. It is the main bill's component and represents the cost incurred to produce and dispatch the electricity consumed. It includes the wholesale electricity cost, congestion rents and ancillary services.
- **System Charges**. This is a tariff to cover the system's long-term investments, such as the renewable incentives (CfDs auctions, existing tariffs), the MACSE and the Capacity Market.
- **Grid Tariffs**. Consists of the remuneration recognized to TSOs and DSOs for the network interventions carried out.
- **Taxes**. They are usually proportional to the energy consumed and may be different for the type of final consumer. In Italy the main ones are VAT and consumption taxes.

For the purpose of this paper, we focus on the Energy Component and the System Charges for RES, as these are the ones most affected by and exposed to natural gas prices.

B. *Modelling approach*

To study the impact of varying gas prices on the electricity bill we performed a series of electricity market simulations using the commercial tool BID3 developed by AFRY [11]. This tool solves the Unit Commitment and Economic Dispatch (UCED) problem by minimizing generation costs while ensuring that load demand is met, considering interconnection constraints - represented by Net Transmission Capacity (NTC) - and reserve constraints (FCR, aFRR, mFRR). While Economic Dispatch (ED) aims to replicate the 'merit-order' logic that governs electricity markets, the Unit Commitment (UC) problem accounts for operational constraints. The objective is to determine the optimal sequence of on/off decisions for all generating units over a given time horizon.

To properly define the specific problem to be solved, several inputs are required, and some assumptions must be made. The most relevant ones are listed below:

1. A perfect market is assumed, meaning that each unit bids at its short-run marginal cost (SRMC), and no market power or bidding strategies are considered.
2. The efficiency of each thermal unit is assumed to be fixed and independent of its loading level, even though efficiency depends on generated power and ambient conditions.
3. Each bidding zone is treated as a copper plate, meaning internal grid limitations within a bidding zone are not considered.
4. Perfect foresight is considered for renewable generation, consumption and unit availability.

For a thermal plant operator, the long-term wholesale prices must exceed the SRMC to recover its annual fixed and capital costs. Historically, wholesale prices include an additional component above the SRMC, referred to as "scarcity rent" or "missing money." In BID3, this component is modeled as a function of the hourly capacity margin (SRT function) and added as a mark-up to the system marginal price. The SRT function has been calibrated based on the Italian electricity market.

The model has been validated using 2018 as a reference year, yielding encouraging results for the key outputs such as electricity prices and power plants' generation.

The electricity market model incorporates a scenario in terms of installed capacity, hourly profiles for electricity demand and RES generation for each of the European bidding zones, including the seven Italian ones. The main results of the model include the hourly generation mix that can meet the electricity demand, as well as hourly wholesale prices and prices captured by RES. The simulation is carried out at the European level, as cross-border flows are not negligible especially for the Italian system. A total of 29 European countries are explicitly modelled, while others are represented through fixed hourly flows based on ENTSO-E analyses. The same modelling approach applies to all included countries, based on the TYNDP scenarios developed by ENTSO-E and ENTSOG.

The starting point of the study consists in a batch of electricity market simulations based on the same energy scenario (see previous section), but with a different combination of natural gas and CO2 prices. Starting from the historical time series of these two commodities, a meaningful sub-set of values were extracted to reflect a reasonable range for the combined cycle gas turbine (CCGT) short-run variable cost.

Based on these results we have built an electricity bill model, which quantifies its key components, expressed in bn€ (current currency), each of them covering a specific aspect of the electricity system. For a better comparison with historical data and a clearer representation of results the bill cost will be shown in €/MWh: this value is obtained dividing each bill component (bn€) by the annual electrical demand (362 TWh).

The electricity bill model is composed of several modules, which rely on transfer functions to link the key independent variables (i.e. gas price) to the key drivers of the main bill components (i.e. wholesale electricity prices). The transfer functions are built through a multiple linear regression between key simulation inputs (e.g. set of different gas prices) and key simulation outputs (wholesale price, congestion rent, captured market prices). With this approach, we can estimate how the bill components vary as a function of external variables directly, without having to rerun the electricity market simulations.

Moreover, the model incorporates the legacy costs of the bill (e.g. RES incentives before 2023) and how they depend on the wholesale electricity price.

C. *Module A: Energy Component – Wholesale Cost*

This module calculates the yearly wholesale electricity cost, given the commodity prices as input. From a theoretical point of view, the yearly wholesale cost can be calculated as the sum of the product of electricity demand and zonal price over all bidding zones with hourly granularity (1). Based on this concept, a transfer function was built through a multiple linear regression (2): starting from the simulation results, the wholesale cost was selected as the independent variable, while the value pairs of gas and CO2 prices were used as regressors.

$$Wholesale\ Cost\ =\ \sum_{zones,hours} p_{z,h} * demand_{z,h} \qquad (1)$$

$$C_{MGP} =\ \alpha * p_{gas} +\ \beta * p_{CO_2} +\ \gamma \qquad (2)$$

Where α, β and γ are coefficients obtained from the multiple linear regression.

D. *Module B: Energy Component – Congestion Rents*

This module calculates the yearly value of the congestion rents for Italy, given the commodity prices as input. Since Italy has seven bidding zones and the main RES generation is located far away (South) from the main electricity demand (North), this phenomenon is not negligible. The difference between zonal prices generates a yield, calculated as:

$$Congestion\,rent =\ \left(P_{z_A} -\ P_{z_B}\right) Line\ Capacity \qquad (3)$$

The cross-border congestion rents between Italy and interconnected neighboring countries follows the same rules as the domestic ones, with the only difference being the rents distribution which are equally split between the two TSOs involved.

Following the same approach described for the wholesale cost, a transfer function was built through a multiple linear regression, given the gas and CO2 prices as the regressors.

E. *Module C: System Charges – Renewable Incentives*

This module quantifies the system charges, distinguishing between the new long-term contracts to promote RES development through centralized CfD auctions, and the legacy incentives (before 2023). The CfD module calculates the auction costs derived from the FER-X and FER-2 schemes. These will mainly depend on three variables:

- strike price
- captured market price
- produced volumes (subject to the CfD).

Under the hypothesis of having competitive auctions, the strike price is set equal to the levelized cost of electricity (LCOE), expressed in €/MWh. The module calculates LCOE values per technology per year as a function of the main techno-economic parameters, such as CAPEX, OPEX, WACC and lifetime. All these values are inputs for the model, except the WACC which was explicitly modelled, as a function of cost of equity, cost of debt and gearing, for each year.

Finally, we assume that CAPEX figures decrease over time (ca. 5% per year). The cost and technology mix of CfD auctions will greatly influence the total electricity bill: lower strike prices will be enabled by competitive auctions and by focusing on low-cost RES (e.g. utility-scale solar vs small rooftop installations). The baseline scenario is coherent with the auction volumes of the FER-X and FER-2 schemes, which offer an auction quota of 40 GW for large-scale solar (> 1 MW), 16,5 GW for onshore wind and 3.8 GW for offshore wind. Moreover, up to 23 GW of small-scale solar (< 1 MW) may be incentivized by fixed tariffs, determined ex-ante by the National Regulatory Authority and therefore not subject to a competitive bidding procedure.

The captured prices are derived directly from the hourly simulation results, given the electricity price and the renewable generation at bidding zone level. Using the previously described approach with transfer functions, we can obtain values as a function of varying gas prices.

The FER-X and FER-2 costs will be the sum of the cost for each auction, and are calculated as:

$$CfD\ component = \sum_{N_{auctions}} (p_{strike} - p_{captured}) \times Volume \quad (4)$$

As can be seen from (4), the CfDs component can assume both positive and negative values, depending on the difference between the strike price and the captured price. In this case, a negative cost would represent savings, which would reduce the bill cost.

The net cost of the existing (legacy) incentives is based on an analysis conducted by GSE for the Asos component [12], which shows the evolution of the net support cost over time and depending on the electricity wholesale market price.

Finally, the energy component is the sum of Module A (wholesale cost) and Module B (congestion rents), while the system charges for RES is identically equal to the Module C.

III. Results

A. Electricity bill structure in 2030 vs 2023

In the following, the main results of the model are reported, starting from the gas and CO2 prices defined by the European Commission for all NECPs. To better understand the exposure of the electricity bill to gas prices, we split the energy component in two parts: (1) covered by long-term contracts, (2) exposed to gas prices. This choice was made because only a share of the bill is directly linked to the gas price, while the remaining part is independent, as a share of the electricity demand is covered by RES secured by long-term CfDs. In particular, the total renewable energy covered by long-term contracts in the scenario is equal to ca. 159 TWh, of which 114 TWh are new contracts and approximately 45 TWh are legacy contracts, while the remaining part of the electricity demand (about 203 TWh out of 362 TWh) is exposed to gas price. It is important to notice that the final consumer is effectively hedged with respect to that volume, since the strike price is fixed and does not depend on the gas price. The results are reported in Fig. 1.

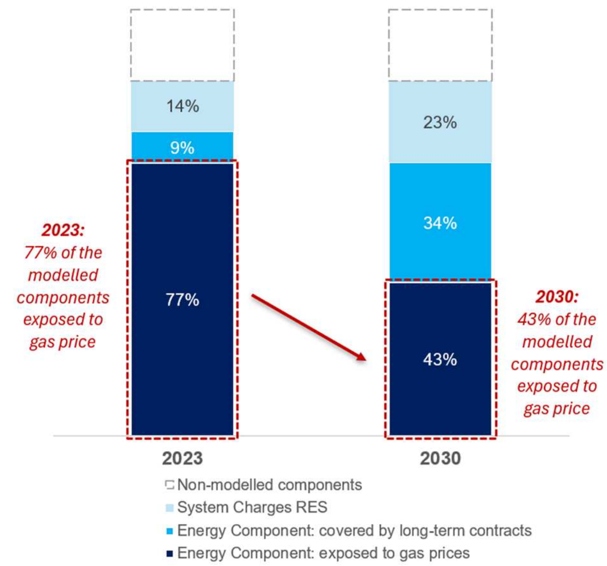

Fig. 1. Exposure of the modelled electricity bill components to gas prices

Looking at the sum of the energy component and the system charges for RES, we can observe that the bill's exposure to gas prices is expected to decline significantly, with only 43% of these components linked to gas, compared to 77% in 2023.

B. Sensitivities: electricity bill as a function of gas prices

As previously shown, contracts for difference applied to renewable sources represent an important tool for hedging the commercial risk of the gas commodity. To further examine this aspect, multiple sensitivity analyses were conducted to assess the model's dependence on the commodity price. Specifically, a range of variation between 10 €/MWh and 100 €/MWh was considered for the gas commodity.

As expected, the sum of the energy component and RES system charges grows with increasing natural gas prices. For every +10 €/MWh_th increase in gas prices, in a hypothetical 'gas-only' system the impact on the bill would be approximately +20 €/MWh_el, assuming that the system marginal price would, on average, be set by a CCGT power plant. However, thanks to the CfD instrument, we found that the exposure of the bill is limited to +12 €/MWh_el for every +10 €/MWh_th of gas price increase. This effect can be explained by the CfD volumes: the share of electricity demand which is covered by RES secured by CfDs is unaffected by the gas price increase, as a higher energy component (linked to the system marginal price) will lead to lower RES system charges. For high gas prices or low CfD strike prices the RES system charges could even become negative, which means that the electricity bill will be reduced.

C. Sensitivities: electricity bill as a function of RES volumes subject to CfDs and strike prices

To further impact the electricity bill, two options can be considered: (a) extend the volumes covered by CfDs to other renewable sources, (b) focus on renewable sources with a lower strike price. Leveraging on model's capability, these two options were investigated.

In the NECP 2030 scenario, there are approximately 227 TWh of RES generation, of which 160 TWh covered by CfD. Assuming that contracts for difference are extended to approximately 40 TWh of hydro generation (25 TWh of run of river and 15 TWh of reservoir hydro), the exposure to the gas price of the observed components would drop even further, from 43% to 36%. Furthermore, the "gas coefficient" of the bill would be reduced from +12 €/MWh_el to +10 €/MWh_el of extra cost for every +10 €/MWh_th of gas price.

Apart from the "volume effect", there could also be a "price effect" on contracts for difference. The model shows that a lower strike price would not lead to a lower dependence on the price of gas, but to a reduction in the cost of the bill. In practical terms, a strike price reduction may be achieved by focusing on more mature technologies, such as large-scale solar power plants instead of small-scale ones.

IV. CONCLUSIONS

This paper shows how the structure of Italy's electricity bill is set to evolve by 2030, thanks to the energy transition and the contractual arrangements. In particular, we expect a reduced exposure of the bill to the volatility of natural gas prices, enabled by the increasing role of long-term contracts such as Contracts for Difference (CfDs). Our modelling results show that CfDs applied to renewable energy sources effectively act as a hedge against fluctuations in natural gas prices by fixing the remuneration for RES generators, thereby insulating a significant portion of the electricity bill from wholesale market volatility. From a quantitative perspective, we focus on two key components of the electricity bill: the energy component (related to the wholesale electricity price) and the system charges related to the promotion of renewables (legacy and new contracts). For these two components, the share that is directly exposed to gas prices is expected to drop from 77% in 2023 to around 43% in 2030, significantly improving price stability for end consumers.

To further reduce this exposure, two strategies can be considered: (1) expand the volume of renewable energy covered by CfDs, ensuring that a larger share of electricity demand benefits from price stability, and (2) prioritize renewable technologies with lower strike prices and/or ensure highly competitive RES auctions, as this would decrease the cost of the system charges component or even lead to net revenues in the future, especially once the legacy contracts from 2008-10 have ended. Our sensitivity analysis confirms that even moderate changes in gas prices have a strong impact on electricity costs, making the adoption of effective risk-mitigation strategies essential.

Beyond the technical and economic considerations, this study also raises a broader policy question regarding how to finance the energy transition. Currently, system charges - including CfD costs - are embedded in the electricity bill, effectively shifting the financial burden onto electricity consumers. While this approach may be perceived as fair at the electricity sector level, because the contribution to the system transformation costs is proportional to the electricity consumption of a customer, it also risks making electricity a less competitive energy carrier compared to others (gas, oil). In contrast, one could assess whether to cover these costs through general taxation or a levy on all energy carriers rather than the electricity bill only, distributing the financial burden more broadly across the economy. This difference in approach has significant implications for the competitiveness of electricity as a vector for decarbonization and warrants careful consideration in future policy decisions.

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Riccardo Mario holds a M.Sc. in Energy Engineering from Politecnico di Milano. He currently works as a power market analyst in the Market Strategy team of the System Strategy Department at Terna, the Italian Transmission System Operator. His work focuses on assessing national energy storage needs (MACSE), modeling demand-side flexibility (e.g. EVs, heat pumps), and conducting advanced simulation of the Italian ancillary services market.

Gaetano Formato Degree in Mathematics and Computational Engineering from Università di Milano and Lappeenranta University of Technology (LUT), specialized in analytics for the energy sector since 2018 and currently working as analyst for the Italian System Operator (Terna).

Ennio Luciano Bachelor and master's degree in Energy and Nuclear Engineer at Politecnico di Torino, PhD in Fluid Mechanics at the University of Zaragoza; working for the Italian Transmission System Operator (Terna) since 2018.

Francesca Raffo Degree in Industrial Engineering at Università La Sapienza in Rome; working for the Italian Transmission System Operator (Terna) since 2008. She currently leads the Market Strategy team, which develops energy and ancillary service market simulations to provide quantitative analyses supporting market evolution proposals. Her work focuses on enabling flexibility resources (e.g. storage) in medium to long-term scenarios.

Fabio Genoese Degree in Physics and PhD in Energy Economics at the Karlsruhe Institute of Technology (KIT); working for the Italian Transmission System Operator (Terna) since 2017 where he currently manages the Strategy team.

Luca Marchisio Degree in Mechanical Engineering with a long-standing career in the energy sector. He is currently Head of the System Strategy department at Terna, leading long-term scenario development and market adequacy assessment. With extensive experience at Enel and Tirreno Power, he has held key roles in energy management, power plant operations, and marketing.