Council of the
European Union

Brussels, 22 July 2022
(OR. en)

11398/22

ENER 366

INFORMATION NOTE

From:	General Secretariat of the Council
To:	Council
Subject:	Any other business Proposal for a power market design in order to decouple electricity prices from soaring gas prices - Information from the Greek delegation

Delegations will find in the Annex an information note from the Greek delegation in view of the Extraordinary Transport, Telecommunications and Energy Council on 26 July 2022.

ANNEX

Proposal for a power market design in order to decouple electricity prices from soaring gas prices

Non-paper by Greece

Executive summary

The current dramatic increase in electricity prices has proved the inadequacy of the current market design of the electricity market, mainly based on the marginal cost of the most expensive source which now is natural gas. This market design was adopted to enhance the development of renewables when the latter were at an initial stage. Now, however, the energy crisis has underlined the need to decouple electricity prices from soaring gas prices and to adopt a new market model which distinguishes between resources that operate when available and not on-demand and on-demand resources, based on their respective contribution to the electricity mix. This could ensure roughly 50% of lower electricity prices, given that on-demand sources (such as natural gas) have only a one third share of the electricity mix, a share that will continue to decline as the energy transition accelerates.

The need for redesigning the market model

Since this summer of 2021 the unprecedented hike in natural gas prices in Europe has dramatically increased electricity prices. During the winter 2021-2022 natural gas prices remained five times higher than in the previous years. In consequence, the wholesale electricity prices more than quadrupled during the same period without any clear sign of de-escalation in the near future.

Power generation from natural gas in EU Member States (MS) represents less than 20% of the total, nonetheless, natural gas constitutes the main marginal price setter. Since gas-based generation is necessary most of the time to balance the system and to provide ancillary services, the most expensive generator (hence the price setter) depends on natural gas. Thus, in more than 2/3 of cases, the wholesale electricity market clearing price reflects the natural gas cost. For example, for a natural gas price of 100 EUR/MWh and 80 EUR/tCO_2 EU ETS, the wholesale market electricity price is around 220 EUR/MWh.

However, the real total average cost of electricity is significantly lower. Nuclear, renewables and hydro, producing almost two-thirds of the total power in EU MS, have a total levelized cost, including capital costs, below 100 EUR/MWh. Any revenue above such total costs constitutes an extra profit, which would not have been paid in a well-functioning market. In other words, the total average cost of power generation is systematically roughly 50-60% less than the marginal cost. Nonetheless, it is the latter that drives market-clearing prices and final customer payments.

The “low or zero marginal cost power resources” cover the largest part of power generation already today and this situation will considerably increase in the coming years. These resources cannot generate power on demand, i.e. they generate power when they are available, and cannot respond to market signals. Also, they are usually built based on public or private power purchasing agreements, meaning Contracts for Differences (CfD) remunerating the power technology at their total levelized cost over a sufficient period in the future. In this way, they get the lowest possible cost of capital, which is important since their financial structure is almost exclusively capital expenditure. Therefore, the extra profits they may get from wholesale markets, as happened last year, due to the uncertain and volatile price setting of natural gas, will hardly facilitate additional investments in such technologies.

Therefore, remunerating all resources (including those with zero marginal costs) based on natural gas prices entails an unnecessary additional cost for consumers and an inefficient market. The current electricity market design fails to incorporate the developments in the renewable energy sector, because, contrary to the long-lasting cheaper gas-based power generation, from now on electricity generated from renewable energy sources (RES) will be much cheaper. It is evident that a market designed to apply marginal cost pricing does not fit the purpose when the system is dominated by low carbon and zero marginal cost resources. This leads to a systematic market failure: marginal costs persistently stay above total average costs and there is no way to make them converge, which is exactly what a well-functioning market must do.

Revised Market design principles

The fundamental economic principles are twofold:

(a) Remuneration based on CfD (contracts for differences) with prices reflecting total levelized cost is the suitable financial instrument for enabling nuclear, renewables and hydro investment and for bringing up to consumers the low-cost benefits
(b) Remuneration reflecting scarcity and marginal costs is suitable for resources deployed on-demand to balance the system, provide ancillary services and complement the eventual non-availability of renewables.

The resources that require CfD-based remuneration have the following features: (1) Operate *when available*, depending on technical and resource characteristics, *and not on-demand* (2) Capital expenditure dominates their cost structure (3) There are no changes in unit cost when increasing or decreasing their operation. Resources with such features are ***renewables, nuclear, high-efficiency co-generation, and mandatory hydro***. In addition, the same category includes ***electricity storage bundled with intermittent renewables***.

The resources that can be included in a spot market in which marginal costs drive market-clearing prices are the ***fossil fuel plants, hydropower plants operating at peak load times, demand response and electricity storage (unbundled from RES*).** Such resources are *dispatchable* and operate *on-demand.* Also, they incur marginal cost variations when modifying their operation level. Therefore, cost-minimization requires defining a merit order based on increasing marginal costs. Also, the eventual scarcity of resources on-demand (for example in case of shortages) justifies market-clearing prices to be above marginal costs.

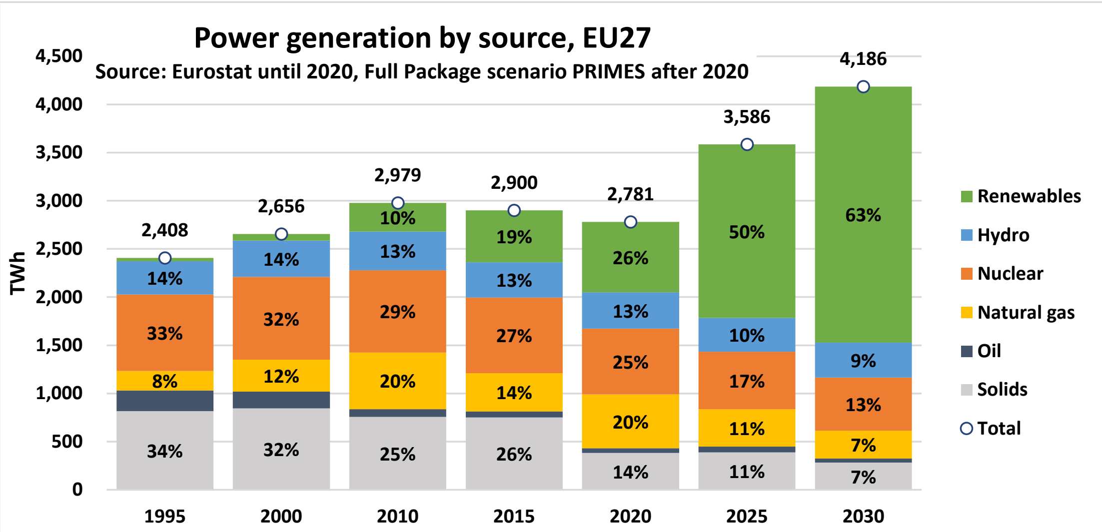
The new market design should be based on the following principles:

- The *resources that operate when available and not on demand* submit volume-based offers in the day-ahead market (DAM), not economic bids. The volume-based offers reflect the best possible forecasts of their operation on the next day. With this offer they assume responsibility for the real-time operation, are subject to deviation costs and can participate in the intra-day and balancing markets.
- For their volume-based offers in the DAM, these resources get remuneration depending on contracts for differences concluded with private third parties or the public sector, regardless of the DAM.
- In case these resources declare no coverage by bilateral or public contracts for differences, they may participate in a non-mandatory pool (green power pool) operated by a public body (or a private body adequately empowered) acting as a single buyer and seller to load-serving entities and consumers.
- The volume-based offers of these resources may correspond to bundled resources that may include storage and possibly an aggregation of RES plants.

- The system operator scrutinizes the volume-based offers from the perspective of forecasting accuracy and system operation possibilities and may accept or curtail the volumes declared. The eventual curtailment follows pro-rata rules.
- In the next step, the DAM considers that the accepted volumes of the above resources that *operate when available and not on demand* are must-take volumes. Thus, the market operator subtracts the accepted volumes from the load declarations. The remaining load (net load) corresponds to the demand that the on-demand resources must meet. Then, the resources submit combined economic and volume offers according to the same rules currently applied and the market is cleared with the same way it is cleared today.
- The load-serving entities and consumers pay at market-clearing prices for the energy purchased in the net-load DAM. They may also buy from the green power pool, if this operates. They also have payment obligations in the context of CfDs which are independently concluded.
- The above points describe a two-stage DAM: The first stage performs the acceptance and aggregation of the volume-based offers by the *resources that operate when available and not on demand*. The second stage performs market-clearing of the net load (after subtracting the accepted volumes from the load) using the bids of *the on-demand resources*.
- The intra-day and balancing markets remain unchanged.
- Although the participants submit bids at the bidding zones, the two-stage DAM performs directly at the level of the coupled markets. The market-clearing of the net load (i.e., second stage) takes into account the interconnection constraints. Thus, the algorithm may lead to different market-clearing prices of the second stage DAM in case of congestion.
- Evidently, the suppliers and consumers pay the weighted sum of the remuneration of *resources that operate when available and not on demand* and the market-clearing price of meeting the net load using *on-demand resources*. The former reflects the total levelized costs of the resources that operate when available and not on demand. The latter corresponds to marginal cost pricing and may reflect natural gas prices.
- Thus, if the first stage of the DAM corresponds, as today, roughly to two-thirds of electricity consumption and for example has an average cost of 80 EUR/MWh and the second stage of the DAM clears at 250 EUR/MWh reflecting gas generation costs, the consumer would pay (2/3 x 80)+(1/3x250)=137EUR/MWh, which is roughly 45% below the cost of electricity when applying the current market design.

APPENDIX

The following figures illustrate the market design concept. The first graphic shows the power generation mix according to Eurostat statistics and its future projection according to the Fit-for-55 scenario, using the PRIMES model. The graphic shows that natural gas generation is only 20% of the total. This share will likely decrease considerably in the next few years, in the context of the carbon emissions reduction policies. At the same time, national plans foresee an impressive expansion of renewables, which, together with nuclear and hydro (resources without marginal costs) almost fully dominate the power system. As a result, the role of gas is reduced in the provision of balancing and ancillary services. The second table calculates the total average generation costs and compares them to marginal costs. It shows two marginal costing cases: the first corresponds to the current market design, where all resources get remuneration at the system marginal costs; the second illustrates the case where the volumes of nuclear, hydro and renewables are not part of the marginal cost remuneration and, consequently, the price of electricity is a weighted sum of average costs while the price of the fossil fuels generation is remunerated at the marginal cost. The table shows that the second combined average and marginal cost remuneration is much cheaper than the remuneration using the marginal cost entirely. The combined average and marginal cost remuneration is a result from the two-stage DAM market design proposed in the previous section.



EU27	2021-22	EUR/MWh		2025	EUR/MWh	
	Mix in %	From	To	Mix in %	From	To
Solids	14%	150	180	11%	150	180
Oil	2%	175	220	2%	175	220
Natural gas	20%	205	260	11%	205	260
Nuclear	25%	50	80	17%	50	80
Hydro	13%	80	80	10%	80	80
Renewables	26%	35	70	50%	35	70
Total average cost		97	130		75	108
Marginal cost (single DAM)		205	260		205	260
Combined average and marginal cost (two stage DAM)		105	142		81	117
Diff. of the two DAM designs on total cost (bn€)		282	335		445	515

Source: Eurostat until 2022, Full Package scenario PRIMES for 2025