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Vattenfall's views on the targeted EU power market reform

09/02/2023

The last year has shown that accelerating the move away from fossil fuels is more important than ever. Decarbonization has become important for both security of supply and climate change mitigation goals. It has also shown that the EU can quickly respond to protect customers and to alleviate burden on those that otherwise could not finance their essential energy needs. It has also made it obvious that the situation in each of the EU countries differs – be it a different degree of decarbonization of the power system, a different preference for technologies or a different industry landscape.

This is no surprise, since EU legislation ensures an internal market in which energy is traded freely between markets in a competitive energy sector. Decision on the energy mix and specific implementation of retail market rules and taxation are left to the Member States by design of the EU framework legislation. However, this creates a major challenge for the announced power market reform. How to unite this diversity?

In our opinion, this can only be accomplished by **creating a flexible framework that provides a toolbox with clear guidelines that leaves the choice of policy instrument to the Member States.** Policy tools are to be used to enable investments, incentivizing energy savings and shifting demand:

The reform should enable investments, rather than hamper them

Vattenfall is prepared to invest extensively in fossil free energy. We need the prerequisites and market conditions to do so. This includes a reliable and efficient market design as well as fast, efficient, and reliable permitting processes. Grid development needs to be stepped up in tandem.

Choice of long-term contract should remain voluntary
Three different long-term contract instruments are currently prominently discussed to drive investments and reduce exposure to short-term volatility of prices: contracts for difference (CfD), power purchase agreements (PPAs) and forward market contracts. It is important to look at the three instruments holistically and in relation to each other as they all have different merits and can influence each other as well as short-term markets. Generally speaking, the strong use of one instrument decreases the demand for the others.
Design details matter and need careful consideration. Rightly designed each of them can deliver reduction of consumer exposure to short-term market volatility & effective investment signals. While still leaving incentives to respond to price signals e.g. by shifting or reducing demand.
All three hedging tools should be available to market participants in the future and the choice for one or the other should remain with the market participants. Likewise, governments should remain free to decide if they want to provide public support measures in line with their needs and EU competition rules.

Limiting the revenue of inframarginal units creates uncertainty for investors
Investors in fossil free capacity have helped drive rapid decarbonization of the EU's electricity system, while delivering significant reductions in technology costs.
Emergency measures such as the revenue cap for electricity producers create uncertainty that increases costs and hampers the rollout: if investors do not know how they will get paid, investors will hesitate or look elsewhere. Doing so could damage long-term investor confidence needed to deliver the projects that will enable the decarbonization of the EU's electricity system.
It is vital that retrospective changes to the market do not negatively impact assets built in good faith. The revenue cap therefore should remain an emergency measure and not become permanent.

Consumers should be protected and empowered

The hardships caused by high prices do not go unnoticed. We share the interest of consumers and decision makers to make our energy system future proof and ensure mechanisms are in place to protect (vulnerable) customers from sustained periods of soaring prices as seen in the crisis. Unfortunately, there is no quick fix to the energy crisis - after all, the fundamental problem is not that the market is not working, but that the gap between supply and demand has sharply increased caused by the disruption of gas supplies. However, providing new capacity at the scale needed will not happen overnight. Nor in six months or a year. It will happen continuously over several years. That is why prices most probably will continue to be volatile.

- We have seen that the high prices have led to unprecedented consumer reaction to prices, and that more flexible demand has proven to be the quickest way to reduce high electricity prices. This shows that it remains important to have visibility on prices to allow customers to react to them.
- Public intervention in the price setting for the supply of electricity e.g. by defining an obligation to offer fixed price contracts at certain price levels, should be targeted to energy poor and vulnerable households as foreseen already today in EU energy legislation. Only essential energy needs shall be covered by such measure.
- All customers should have all necessary information on their contracts, including the risks attached to them prior to contract entering. In competitive retail markets, this will allow customers to choose the appropriate contracts for their engagement levels.
- Suppliers should advise customers on variable tariffs how to avoid "bill shocks" in case prices increase – e.g. by advising consumers without a smart meter to increase their monthly payment to avoid too high overall cost levels at settlement.
- We need a plan to adjust demand in case of supply shocks. To create a safeguard, the demand reduction measures from the emergency regulation should be put into EU legislation and accompanied with a trigger level for when to activate the demand reduction measures. The need for such safeguard could decrease with increasing consumer responsiveness to prices.

The only long-term way to overcome the current situation and solve Europe's energy crisis is to reduce dependence on natural gas, oil, and coal imports and to move away from fossil fuels.

Providing prerequisites for new fossil free capacity and grid build out while incentivizing a more flexible demand is the most effective and sustainable way to reduce high electricity prices.
The reform proposals therefore should:

- **Ensure a technology-neutral approach** e.g. by ensuring easier access to different revenue-stabilizing instruments for all fossil free technologies
- **Put more emphasis on demand flexibility** by ensuring that customers can be responsive to prices. Demand response might be a niche today, but we are convinced that it will be an integral part of the future electricity system. The electrification of transport and industrial processes proves this: In our Hybrit project, since processes had to be planned from scratch, the process will now have hydrogen storage that can deliver / store up to one week of intermittent renewable energy.
- **Foster cross-border trade** and an increase of transmission capacity as we need to be able freely move electricity throughout Europe.

The way out of the energy crisis is through investments in fossil free energy and grid build out. A decarbonized power system is also a system more resilient to external shocks. Finding the right balance within the market reform will be key to keeping the transformation at high speed.

EU Electricity Market Reform
Vattenfall consultation response

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Making Electricity Bills Independent of Short-Term Markets

Power purchase agreements

Do you consider the use of PPAs as an efficient way to mitigate the impact of short- term markets on the price of electricity paid by the consumer, including industrial consumers?
Please describe the barriers that currently prevent the conclusion of PPAs.

Currently, most SMEs cannot access the PPA market due to stringent credit requirements (investment grade credit rating). Offering a fixed-price PPA will allow an asset owner to swap merchant risk with credit risk, hence prudent PPA sellers will only consider credit-worthy counterparties. This is where the state (or the ECB) can come in by providing governmental credit guarantees. Increasing the buyer pool in the PPA market, and therefore increasing the volumes in the market, might make the market attractive for financial companies, insurances and other risk-takers to offer standardized risk-hedging products. This opens up more options for asset owners to finance their projects and for industry to engage in PPAs.

Ongoing regulatory interventions need to be communicated as clearly as possible. Uncertainty around measures adds complexity to bids, transactions and valuation, which in turn will lead to higher transaction costs and negotiation time.

Complex financial PPA accounting rules currently keep the market from fully reaping the benefits of financial PPAs. In Europe, financial PPAs are, according to IFRS (international financial reporting standards), to be treated as financial instruments and lead to profit and loss and/or balance sheet fair value swings, which lead to more complexity accounting-wise. At the same time, financial PPAs have lots of benefits to both corporate buyers and asset owners:

- Financial PPAs are more simple as they function as a contract for difference/financial hedge, rather than two back-to-back contracts for the sale of power.
- Stacking multiple financial PPAs is easy.
- Financial PPAs are also easier to handle for non-electricity specialists: no physical flow of electricity to manage, no interference with existing power sourcing, no balancing complexity
- Cross-border PPAs are made possible – allows corporates with facilities across Europe to meet needs in multiple markets

Do you consider that the following measures would be effective in strengthening the roll-out of PPAs:

(a) pooling demand in order to give access to smaller final customers,

(b) Providing insurance against risk(s) either market driven or through publicly supported guarantees schemes (please identify such risks),

(c) promoting State-supported schemes that can be combined with PPAs

(d) supporting the standardization of contracts,

(e) requiring suppliers to procure a predefined share of their consumers' energy through PPAs

(f) facilitating cross-border PPAs.

Additional comments

One of the main barriers to broadening the PPA offtake basis is credit risk – the risk if one of the parties fails to deliver on contractual payment obligations or defaults. Within the proposals for the EU Renewable Energy Directive the issuance of credit guarantees is already envisaged possible for renewable energy projects. To ensure a technology-neutral market framework and not losing sight of our climate commitments, such credit guarantees should also be available to other fossil free energy technologies, like nuclear. Smaller final customers will also benefit from these credit guarantees, while we do not see the need for a central governmental pooling of demand and rather see it as something that will naturally develop based on consumer demand.

Standardization of contracts can help, while industry initiatives for this already exists and we do not see a need for regulatory engagement. We do not see an added value in obliging suppliers to procure energy via PPAs as the demand for such PPAs strongly depends on the volume and length of fixed price contracts in the suppliers customer base which can frequently change if customers choose to switch. Commercial strategic decisions should be left to the supplier .

A simplification of the IFRS accounting rules for financial PPAs can be an effective means to increase the uptake of financial PPAs.

In addition to the options proposed in question 3, do you see other ways in which the use of PPA for new private investments can be strengthened via a revision of the current electricity market framework? If yes, please explain which rules should be revised and the reasons.

We do not think that further changes than mentioned in the previous question are required to ensure PPA uptake.

Do you see a possibility to provide stronger incentives to existing generators to enter into PPAs for a share of their capacity? If yes, under which conditions? What would be the benefits and challenges?

The PPA market today is a sellers' market which means that it is not the generator side that is not participating sufficiently in the market. We therefore do not see a need for additional incentives to enter in the PPA market. We do, however, see a risk that a preference for mandatory contract for difference schemes would lead to the PPA market drying out.

Do you consider that stronger obligations on suppliers and/or large final customers, including the industrial ones, to hedge their portfolio using long term contracts can contribute to a better uptake of PPAs?

Hedging is an important tool to mitigate price risks and is naturally pursued by responsible market participants. Which tools the supplier uses for this and to what extent, should not be prescribed by legislation but remain in the commercial decision power of the supplier. Equal applies for industrial and large final customers.

Forward Markets

In your view, what prevents participants from entering into forward contracts?

In general, the forward market liquidity has been negatively impacted by the lack of transmission capacity within Europe and the resulting smaller bidding zones. At the same time, buyer demand for longer duration contracts is limited, as e.g. suppliers face uncertainty around their long-term consumer portfolio which explains the comparable high liquidity up to three year contracts which is then decreasing further out. In addition, regulatory uncertainty creates hesitance to enter long-term contract as the underlying of the contract is not considered stable. The ongoing crisis has shown the need for more usage of hedging tools like the forward market. Still, collateral payments have led to market parties exiting the forward markets.

In your view, would requiring electricity suppliers to hedge for a share of their supply be beneficial for consumers and for retail competition?

Hedging is an important tool to mitigate price risks and is naturally pursued by responsible market participants. Which tools the supplier uses for this and to what extent, should not be prescribed by legislation but remain in the commercial decision power of the supplier. Equal applies for industrial and large final customers.

Do you consider that the creation of virtual hubs for forward contracts complemented with liquid transmission rights would improve liquidity in forward markets?

We do not see how the introduction of virtual hubs will increase liquidity. Priority should be given to transmission built-out which also benefits society in other timeframes as resources can be more efficiently shared across Europe.

In case you have experience with the existing virtual hubs in the Nordic countries, how do you rate this experience?

Historically, the introduction of the system price in the Nordics has been reasonable in light of the number of small bidding zones and the limited liquidity within them. However, with the grid constraints increasing, the model at some point collapsed and did not offer a good hedge for all market participants anymore.

In your view, what would be the possible ways of supporting the development of forward markets that could be implemented through changes of the electricity market framework?

In line with the reasons for lower liquidity outlined in our earlier responses, we think the following needs to be addressed:

a) Ease collateral regulations in forward markets, by widening the types of non-cash collateral accepted, such as non-collateralized bank guarantees.

b) Create visibility on the regulatory frameworks and ensure that the market reform and instruments promoted within it do not further negatively impact forward market liquidity. For instance, the notion of mandatory hedging requirements (either forward market or PPA) risks obstructing the natural balance between sellers and buyers. Equally, mandatory contracts for difference schemes for all new investments would deplete the forward market.

c) Address the barriers to investments in transmission capacity and review the rules on bidding zone reviews with a view to ensure that also broadening of bidding zones is within the scenarios investigated instead of just continuously proposing the split of zones

Contracts for Difference

Should new publicly financed investments in inframarginal electricity generation be supported by way of two-way contracts for differences or similar arrangements, as a means to mitigate electricity price spikes of consumers while ensuring a minimum revenue?

We would like to note that generally CfDs do not directly affect the prices in the short-term markets. In addition, it could be argued that CfD schemes facilitate additional investments in fossil free generation leading among others to a growing share of zero-marginal cost renewables in the power system which will have a downward effect on wholesale power prices. While the latter is true for higher zero-marginal cost technology penetration in general, regardless of how it was financed.

Rightly designed, two-sided CfDs can provide revenue stabilization as well as a reasonable expectation on returns to customers. Still, solely relying on governmental steered auctions for new investments will never be a key driver for innovation. Equally, the choice of public support instruments should be in the discretion of the member state and not prescribed on EU-level. CfDs should therefore be voluntary and combined with the possibility for merchant investments.

What technologies should be subject to two-way contracts for differences or similar arrangements and why?

Two-way contracts for difference or similar arrangements should not be mandatory in the first place. They should be pursued in parallel to merchant development. In general, they should be open to all inframarginal generation and for all projects within a given technology. For flexible assets they do not seem to be necessarily fit for purpose, as they would take away the incentives to run when the value is the highest since the strike price would prevent capturing higher spreads.

What are the main risks of <u>requiring</u> new publicly supported inframarginal capacity to be procured on the basis of two-way contracts for difference or similar arrangements, for example as regards of the impact in the short-term markets, competition between different technologies, or the development of market based PPAs?

CfD design parameters have known impacts on short-term markets. In particular, the risks are a) continued production when the price is already zero or negative and b) limited incentives to sell at different markets (day-ahead, intraday, balancing). Therefore the design needs careful consideration. While not asked, CfDs also impact forward market liquidity as volumes are taken off the market. A decoupling from output and payments should be investigated.

Furthermore, CfD design parameters can decrease incentives for generators to make the most system-friendly design, dispatch, and location decisions. Also, the volume risk is in current CfD designs largely uncovered.

Even if not mandatory for all new investments, CfDs risk crowding out the PPA market as PPAs are subject to higher counterparty risk and do not benefit from potential other advantages of supported projects, like grid connection or accessing land.

What design principles could help mitigate the risks identified in question 4, in particular, in terms of procurement principles and pay out design? Should these principles depend on the technology procured?

The aforementioned risks can be partially addressed through different means and tweaks of the CfD design, while most likely they cannot all be removed by one single solution and tradeoffs need to be made. It is therefore important to take a broader perspective and carry out research for CfD design, e.g. deemed generation or financial CfD design concepts should be further explored.

Allocation principles are equally important and should not be looked at in isolation from CfD design parameters.Inflation indexation also needs to be taken into account. This in particular requires a technology-specific approach.

How can it be ensured that any costs or pay-out generated by two-way CfDs in high- price periods are channeled back to electricity consumers? Should a default approach apply, for example, should these revenues or costs be allocated to consumers proportionally to their electricity consumption?

Revenues from the CfD should remain in the power system and should be used where they are needed, e.g. for grid development, energy efficiency, decarbonization or flexibility measures and compensation of vulnerable customers. If paid out to consumers, it should be ensured that responsiveness to price signals e.g. by shifting or reducing demand remains intact.

What should be the duration of a two-way CfD for new generation and why? Should this differ depending on the technology type?

For CfD-backed assets to attract low cost financing and spread this cost over an appropriate period and appropriate contract length is required. The length of the CfD should be connected to the suspected lifetime of the fossil free asset receiving the CfD. For renewables 20 years has proven to be appropriate. We want to highlight that the contract length has a direct impact on the strike price. With shorter contract lengths, the developers' expectation of long-term revenues weighs more strongly and is factored into the CfD bids.

Should generation be free to earn full market revenues after the CfD expires, or should new generation be subject to a lifetime pay-out obligation?

We are not in favor of limiting the amount an operator can earn from the asset as it disincentivizes innovations e.g. extending asset operating lifetimes. Besides, at bidding and investment decision stage, the level of the CfD strike price already incorporates the expected backend market revenues; consequently, if such market revenues are capped, the level of the CfD would probably be higher, resulting in the same cost for society overall.

Without prejudice to Article 6 of Directive (EU)2018/2001[6], should it be possible for Member States to impose two-way CfDs by regulatory means on existing generation capacity? If such possible use of regulated CfDs for existing generation is deemed appropriate, should the obligation apply to all types of existing inframarginal generation or be limited to certain types of generation (and if so, which types)?

Private investors have helped to drive rapid decarbonization of the EU's electricity system, while delivering significant reductions in technology costs. It is vital that retrospective changes to the market do not negatively impact assets built in good faith. Doing so could damage long-term investor confidence needed to deliver the projects that will enable the decarbonisation of the EU's electricity system.

Under what terms and conditions could regulated two-way CfDs on existing generation capacity be imposed?

We do not support the notion of imposing regulated two-way CfDs on existing generation capacity. However, we see merits in exploring voluntary CfDs for existing assets further. It would have to be carefully considered under which conditions existing assets can enter a CfD, for instance for a lifetime extension or repowering.

Offering voluntary CfDs during high-price periods comes with the risk of locking-in high prices for a prolonged period. In addition, key commercial terms, such as start date, price and tenor, the health of the assets and anticipated asset life, and the auction design, all need to be taken into consideration in a careful manner.

Would it be enough for existing generation to be subject only to a simple revenue ceiling instead of a revenue guarantee?

Future market changes should not unduly penalise existing generation. We do not support the proposal of imposing revenue caps nor 2-sided CfDs on existing generation and consider them a retro-active change that jeopardized investor confidence.

What are the relative merits of PPAs, CfDs and forward hedging to mitigate exposure to short-term volatility for consumers, to support investment in new capacity and to allow customers to access electricity from renewable energy at a price reflecting long run cost?

The three instruments have different hedging purposes and therefore score differently in the mentioned dimensions. In the market reform it is important to look at the three instruments holistically and in relation to each other.

CfDs are a proven instrument to support investments in fossil-free capacity. They effectively lower the cost of capital for new investments and with their generally long tenure, they provide long-term revenue stabilization and can closely reflect the long-term cost of renewables. However, a high degree of CfDs will reduce liquidity in the forward and PPA markets and will not necessarily mitigate customer exposure to short-term price volatility (this depends on the redistribution mechanisms).

PPAs can be an effective instrument to provide revenue stability for new investments as they provide revenue stability for a significant part of an asset's lifetime and reduce cost of capital compared to merchant investments (but less so than CfDs). They are a direct contract between developers and consumers and therefore directly mitigate exposure to short-term price volatility for participating parties. However, they are currently primarily accessible for larger (industrial) parties, therefore limiting their impact for smaller consumers.

Forward hedging is an effective instrument to mitigate exposure to short-term price volatility that is accessible by both supply and demand side actors. However, liquidity for forward contracts with longer tenure (>3-5y) is low and it therefore provide less long-term revenue stability for new investments and does not directly reflect the long-run marginal cost of renewables.

Generally speaking, the strong use of one instrument decreases the demand for the others.
Design details matter and need careful consideration. Rightly designed each of them can deliver reduction of consumer exposure to short-term market volatility & effective investment signals. While still

leaving incentives to respond to price signals e.g. by shifting or reducing demand.
All three hedging tools should be available to market participants in the future and the choice for one or the other should remain with the market participants. Likewise, governments should remain free to decide if they want to provide public support measures in line with their needs and EU competition rules

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Accelerating the deployment of renewables

Do you consider that a transmission access guarantee could be appropriate to support offshore renewables? Please explain and outline possible alternatives.

It should be noted that the outlined volume risks relate to offshore hybrid renewable energy projects which are to be placed in offshore bidding zones – so to renewable generation that is connected to an interconnector which connects two or more transmission systems. In contrast, radially connected projects are addressed through the curtailment rules provided for in the EU Electricity Regulation. Generally, we are of the opinion that the 70%-rule should not be applying to offshore hybrid assets, as these serve dual functionality in comparison to classic Interconnectors. The 70%-rule should only be applied to the residual capacity, that is capacity not forecasted to be used by offshore generation. The assumption of offshore hybrid assets automatically being moved into an offshore bidding zone, we therefore do not share.

Still, to ensure a level-playing field with radially connected offshore projects that do not face relevant volume risks from grid-unavailability, we are supportive of the usage of TAG. TAG compensation should equal: Max(reference bidding zone price – OBZ price, 0) x total offshore generation available to the market + spot price in OBZ x total offshore generation prospectively curtailed. In this way, TSOs are kept incentivized to offer as much IC capacity as possible. While this approach would address the volume risk, it does not necessarily address the inherent price risk of separate offshore bidding zones. A CfD scheme decoupling output from remuneration should be investigated for this purpose.

Do you see any other short-term measures to accelerate the deployment of renewables? If yes, please specify

The political intentions outlined with the RePower EU permitting proposals which also are reflected in the proposals for the EU Renewable Energy Directive need to be shared on authority level to lead to a true step change in permitting. Staffing and interpretation of EU legislation still lead to lengthy processes. The electricity market integration should be pursued, especially by making a maximum amount of cross-border interconnection capacity available to the market.

How should the necessary investments in network infrastructure be ensured? Are changes to the current network tariffs or other regulatory instruments necessary to further ensure that the grid expansion required will take place? (4000 characters)

We believe that the revenue regulation for the distribution level needs to be further developed at EU level to ensure investments in necessary network infrastructure to meet the accelerated electrification. The three key points for a successful revenue regulation are to be predictable, long-term and stable. To be able to attract capital, the investors need a return on the investments in parity to the risks. If one also considers socio-economic aspects and cost-efficiency the reasonable solution ends up in a predictable revenue regulation with long-term and stable conditions. In such regulation the applied models are widely known and used in the financing world. Furthermore, the models reflect the lifetime of the network assets. A predictable, long-term and stable regulation will lower the risk and therefore attract needed capital to a lower price.

Limiting revenues of inframarginal generators

Do you consider that some form of revenue limitation of inframarginal generators should be maintained?

In shorter perspective, the revenue cap will cause significant reductions in revenues for assets across the EU. Both internal and external assessments show that the effect of a prolongation of the cap at the current level will be noticeable in the coming 4-5 years and then, assuming “normalized” or detached gas prices in the long term, decrease to moderate impact in the long-term.

Although diminishing long-term effects, the investment climate might be influenced by a prolongation of the cap adding additional uncertainty and pressure on profitability, this on top of already facing cost increases caused by inflation, including higher CAPEX, financing and O&M costs. In addition, current uncertainties from the volatile power and commodity market as well as uncertainty of the outcome and implementation of the EU reform for the power market design, are all factors contributing to investments becoming more cautiously approached.

Based on implementation experience, so far, we notice high administrative burden for generators with regards to tax reporting, calculations of actual income and un-realized income as well as unclear treatment of fixed price PPAs. In case of prolongation it is very important that there are clear guidelines and that reporting of the tax takes place in such a way that the administrative burden is eased for the companies to the greatest extent possible.

The effects of a deteriorated investment climate is by extension reduced competition and a reduced security of future fossil-free capacity buildout as well as unachieved climate goals. Given all other mentioned challenges we are currently phasing, it should be looked into other solutions than limiting revenues for generators when mitigating consumer price impact.

Against this background, it is vital that retrospective changes to the market do not negatively impact assets built in good faith. The revenue cap therefore should remain an emergency measure and not become permanent. Should a continuation be considered, the rules should be complemented with opt-out options for member states, e.g. when instead imposing a time-limited corporate tax increase, windfall profit taxation or other means.

Should the modalities of such revenue limitation be open to Member States or be introduced in a uniform manner across the EU?

Rules on EU-level shall ensure that the measure is not negatively impacting dispatch decisions and a minimum degree of harmonization is accomplished. The rules should be complemented with opt-out options for member states, e.g. when instead imposing a time-limited corporate tax increase, windfall profit taxation or other means. The measure should remain limited in time.

How can it be ensured that any revenues from such limitations on inframarginal revenues are channelled back to electricity consumers? Should a default approach apply, for example, should these revenues be allocated to consumers proportionally to their electricity consumption?

Revenues from any revenue cap, if pursued, should remain in the power system and should be used where they are needed, e.g. for grid development, energy efficiency or flexibility measures and compensation of vulnerable customers. If paid out to consumers, it should be ensured that responsiveness to price signals e.g. by shifting or reducing demand remains intact.

Alternatives to Gas to Keep the Electricity System in Balance

Do you consider the short-term markets are functioning well in terms of:

	Yes	No
a) accurately reflecting underlying supply/demand fundamentals,	**X**	
b) encompassing sufficiently liquidity,	**X**	
c) ensuring a level playing field,	**X**	
d) efficient dispatch of generation assets,	**X**	
e) minimising costs for consumers,	**X**	
f) efficiently allocating electricity cross-border?	**(x)**	

Do you see alternatives to marginal pricing as regards the functioning of short-term markets in terms of ensuring efficient dispatch and as regards the determination of cross border flows?

Marginal pricing for electricity is the most efficient because it directly aligns the price of electricity with the cost of producing it, thus already today keeping the price for the electricity as low as possible for consumers while contributing to the decarbonization targets by dispatching the least carbon intensive units first and providing a price signal for demand reduction. These three elements help to ensure that the market for electricity is operating as efficiently as possible, with the price reflecting the true cost of producing electricity.

Aside from being most cost-efficient, marginal pricing in short-term markets is also essential for the proper calculation of cross border flows. Cross border flows are vital to prevent extreme price volatility in isolated areas and crucial for ensuring security of supply. In case of a demand shortage in country A leading to high prices, cross border flows from country B help mitigate the spike. Were the demand to be caused by unforeseen circumstances, the ability to import from country B would be vital to prevent a brown out.

A market based approach for cross border flows means that dispatch is calculated a day in advance and during the day. A shorter time period is essentially to optimize assets, especially renewable production which is dependent on weather conditions. In doing this optimization, marginal pricing has been a centerpiece in the methodologies used to calculate cross border flows, such as *flow based day ahead.* Their introduction has lead to significant increase in social welfare that could not be maintained under a different allocation regime due to the decoupling from the true cost of electricity. For these reasons, we see no viable alternatives to marginal pricing.

How can the EU emission trading system and carbon pricing incentivize the development of low carbon flexibility and storage? (3000 characters)

The aim of the EU ETS is to drive CO_2 emission reductions in a cost-efficient manner. It benefits all low-carbon (and especially fossil-free) assets, investments and measures.

Do you consider that the cross-border intraday gate closure time should be moved closer to real time (e.g. 15 minutes before real time)? YES

Do you consider that market operators should share their liquidity also for local markets that close after the cross-border intraday market? What would be the advantages and drawbacks YES

Would a mandatory participation in the day-ahead market (notably for generation under CfDs and/or PPA's) be an improvement compared to the current situation? What would be the advantages and drawbacks of such approach? NO

What further aspects of the market design could enhance the development of flexibility assets such as demand response and energy storage?

There are a number of aspects that should be pursued. When having onsite storage at renewable assets, it is essential that the storage asset can both contribute to the renewable generation profile "behind the meter" and make use of (arbitrage / system service etc.) business opportunities "in front of the meter" (or "as if").

Any barriers resulting from e.g.
- eligibility of RE subsidy schemes,
- different tax levels e.g. for self-consumption and feed-in,
- unfavorite grid connection requirements (e.g. pure capacity adding) and similar

should be avoided.

In addition we see merits in: moving grid losses to suppliers, so that they can be charged via the supply contract; More flexible design of ancillary services products, so that a broader range of flexible consumers and producers can deliver; Standardisation of communication for steering of smaller assets; and designing grid fees in such a way that flexibility services (like energy storage and demand-side response) are incentivized, rather than punished.

In particular, do you think that a stronger role of OPEX in the system operator's remuneration will incentivize the use of demand response, energy storage and other flexibility assets?

In general, a shift to more OPEX driven decision would have potential benefits in the forms of a more efficient use of the grid, as the cost and benefit of active operational decisions would be clearly reflected as an alternative to investments in lines. All assuming correct data as input to take (socioeconomic).

Do you consider that enabling the use of sub-meter data, including private sub-meter data, for settlement/billing and observability of demand response and energy storage can support the development of demand response and energy storage?

Data quality of metering values is central for active customers, which implies that meter functionality and high data quality needs to be ensured. If "deducted energy" is applied, using multiple meters, it needs to be clarified how the responsibility of the metering and the metering data is inflicted. A second meter may help to limit the distortive effect of the deduction. However, a meter needs a context if it is to be used outside the customer premise and also a responsible party to handle the result of the measurement. It is unwise to hasten changing the market before stabilization of NBM. It also adds unneeded complexity and increases costs to one of the core processes of the electricity market, where DSO costs will have to be socialized. The responsibilities for faults, maintenance, administration, establishing and de-establishing also need careful consideration as it's cost driving processes. Deducting the production value from the cost of consumption might be a better way but the how's and the who needs to be analyzed carefully

Do you consider it appropriate to enable a product to foster demand reduction and shift energy at peak times as an ancillary service, aiming at lowering fuel consumption and reducing the prices? NO

Do you consider that some form of demand response requirements that would apply in periods of crisis should be introduced into the Electricity Regulation?

We need a plan to adjust demand in case of supply shocks. To create a safeguard, the demand reduction measures from the emergency regulation should be put into EU legislation and accompanied with a trigger level for when to activate the demand reduction measures. The need for such safeguard could decrease with increasing consumer responsiveness to prices.

Do you see any further measure that could be implemented in the shorter term to incentivize the use of demand response, energy storage and other flexibility assets?

The main obstacles for consumers today are:
1) Hourly/quarterly metering
2) Fixed price contracts for variable volume
3) Static grid tariffs that reduce or give wrong incentives
4) Levies and energy taxes that are charged by kWh, better to charge these as VAT (percentage) so that the consumer actually benefit from low or even negative prices

Do you consider the current setup for capacity mechanisms adequate to respond to the investment needs as regards firm capacity, in particular to better support the uptake of storage and demand side response? If not, what changes would you consider necessary in the market design to ensure the necessary investments to complement rising shares of renewables and to better align with the decarbonisation targets? YES

Do you see a benefit in a long-term shift of the European electricity market to more granular locational pricing? NO

The textbook logic for more locational pricing is that congestion is managed during the dispatch, whereas is it dealt with after dispatch under a zonal regime. All in all, this would lead to fewer post-market measures and thus increase the efficiency of dispatch in the theoretical model. Importantly, in a fully nodal market, there would be no need for redispatching actions, as the capacity is optimized per node. This would reduce system costs.

However, it is doubtful that nodal pricing, with changing prices over time, does provide long term confidence for investment in new generation. The fact that transmission costs are always fully reflected reduces the incentive for a system operator to proactively invest in sufficient capacity. This could reduce liquidity in the market.

Additionally, the rollout of nodal pricing would come with some practical considerations. A calculation per node would require an IT system that is capable of communicating on such level of detail and that needs the computing power to efficiently optimize the dispatch. The comparatively simpler flow-based capacity calculation already ran into significant computation performance issues. Moving away from the zonal approach as used in the flow-based to a calculation per node would make the calculation exponentially more complex. To be sure, locational pricing has been implemented in some non-EU markets. For instance, Texas is operating a nodal system with around 4000 nodes, but this pales in comparison to the implementation on EU level, which would lead to a much higher amount of nodes.

Given the increased theoretical and practical uncertainty surrounding the nodal implementation, we encourage optimizing the current system instead. In particular, further refinements to the calculations such as PST optimization and more advanced congestion forecasts in the CGMES could be implemented with relatively low costs and with a quicker time table.

Better consumer empowerment and protection

Would you support a provision giving customers the right to deduct offsite generation from their metered consumption?

The deduction would provide an unfair tax break. Deduction would mean that consumers not only save the price of electricity, but also the network fees, including corresponding taxes. This would distort the level playing field in the energy market, providing a detriment for the efficient use of electricity because less efficient solutions behind the meter would be prioritized at the detriment of more efficient solutions that are metered.

Additionally, it can be questioned whether the actual value of the electricity produced equal to the one deducted from the meter. In order for production and consumption to happen in the same market time unit, dynamic contracts in the same market time units are needed. In practice, this is infeasible given the division of the market in different market time units and the challenge to optimize the dispatch of the co-owned production, coupled with the desire to develop fixed long term prices and hedging requirements for electricity suppliers. This would force suppliers to socialize the costs they would have to make from the deduction to their entire portfolio, meaning that those without access to offsite (or onsite) production would contribute to subsidizing those that do have access. Moreover, these developments are conditional on the rollout of smart meters and assigning balancing responsibilities to the customer.

If such a right were introduced:

(a) Would it affect the location of new renewable generation facilities?

YES
NO

Please explain

The deduction mechanism would distort the locational element in the price, because no grid tariffs have to be paid. Thus, there is no incentive to build in the most suitable location.

(b) Should it be restricted to local areas – why?

YES
NO

Please explain
If the mechanism were to be introduced, the concerns about discrimination because of an undue tax break would still hold. However, if the production would be used in a local network area, the distortive effect from network tariff exemption would be limited.

(c) Should it apply across the Member State/control/zone?

YES
NO

Would you support establishing a right for customers to a second meter/sub-meter on their premises to distinguish the electricity consumed or produced by different devices?

In principle, it is of course fine for the customer to have a submeter / second meter if they bear the costs for this and the sub-meters comply with the required technical specifications.

Would you support provisions requiring suppliers to offer fixed price fixed term contracts (ie. Which they cannot amend) for households?

In general, besides the situation of being supplier of last resort, product offerings should be based on consumer demand and hence be as market based as possible.

It should be up to the suppliers to decide whether to include specific products in their portfolio, depending on their market and customer strategies.

If mandatory fixed price contracts are considered, they should be accompanied with either no option to exit prematurely or with a fee that covers market to market position created by the related hedging activities. Otherwise, the risk of customers switching contracts is too high for smaller retail companies which leads to less competition in the retail market. Prior to prescribing mandatory fixed price contracts, a market assessment should be performed. If one or more fixes price offers are available, no intervention should be sought.

If such an obligation were implemented what should the minimum fixed term be?

- **(a) less than one year,**
- **(b) one year,**
- **(c) longer than one year**
- **(d) Other**

We see limited value in defining such minimum terms, as it depends on consumer demand and supplier capabilities. Moreover, national legislation partially already addresses this.

Cost reflective early termination fees are currently allowed for fixed price, fixed term contracts. Should these provisions be clarified? YES / NO

Would you support the establishment of prudential obligations on suppliers to ensure they are adequately hedged?

Hedging is an important tool to mitigate price risks and is naturally pursued by responsible market participants. Which tools the supplier uses for this and to what extent, should not be prescribed by legislation but remain in the commercial decision power of the supplier.

Should the responsibilities of a supplier of last resort be specified at EU level including to ensure that there are clear rules for consumers returning back to the market?

With experience in different European retail markets, we see that the rules are generally in place while enforcement and application differs. Against that background, we do not see an immediate need for further EU clarification in the upcoming reform.

Would you support including an emergency framework for below cost regulated prices along the lines of the Council Regulation (EU) 2022/1854 on an emergency intervention to address high energy prices, i.e. for households and SMEs?

We acknowledge the rationale for the measure and have been supportive in its implementation in the ongoing crisis. However, we prefer a more targeted policy approach offering for a limited time essential energy needs only to those that cannot afford them otherwise. Such measures should be accompanied with investments in grids and e.g. energy efficiency measures.

Enhance the integrity and transparency of the energy market

What improvements into the REMIT framework do you consider as most important to be addressed immediately?

In general, we believe that the REMIT framework in the energy industry has worked well. While it may be developed further where needed to further strengthen it as a sector specific regime, regulatory stability is key for market participants.

- Reduce the implementation uncertainty for Market Participants to facilitate compliance: a key aspect in this sense is the definition of safe-harbor threshold for the definition and publication of inside information for gas and electricity. ACER should be tasked to provide a methodology on how to perform the threshold definition. Ideally, a harmonized level across geographies is developed. Another key aspect is to introduce obligatory public consultations on all guidance from for example ACER. Such guidance, even where it is formally non-binding, sets a standard for what is compliant and can sometimes go beyond a mere interpretation of REMIT and rather create additional obligations. A consultation can prevent confusing or contradictory guidance, as questions and considerations can be raised and managed in the consultation process.

- Adapt the REMIT framework where needed to the markets and practices evolutions: review the definition of markets participants to include Distribution System Operators (DSOs), Storage System Operators (SSOs) and LNG Storage Operators (LSOs) .

With regards to the harmonization and strengthening of the enforcement regime under REMIT: what shortcomings do you see in the existing REMIT framework and what elements could be improved and how?

As a result of the implementation of sanctions for violations under REMIT by the member states, the prerequisites for any criminal liability do not appear to be harmonised. It should be ensured that (only) comparable acts will lead to sanctions in any member state. Discrepancies may particularly arise due to different levels of intent being required e.g. for market manipulation. With this regard, manipulative intent should be a requirement for any criminal liability.
Furthermore, we see a need for a strengthened cooperation between financial and energy regulators to avoid double reporting and to ensure effective data exchange.

ACER should be tasked to provide transparency with technical standards or binding guidance to harmonise the interpretation of market abuse rules in all EU countries. Such development of standards and guidance shall be preceded by public consultations; and a costs/benefits analysis.

With regards to better REMIT data quality, reporting, transparency and monitoring, what shortcomings do you see in the existing REMIT framework and what elements could be improved and how?

Please see also our earlier responses. On data reporting, we would recommend the following measures to simplify data reporting for market participants:
- Request the collection of fundamental data directly from TSOs, LSOs and SSOs. (no double reporting by market participants)
- Avoid double reporting obligations for firms on EU and national level for data which is already reported under REMIT (and EMIR)
- Exclude bilateral OTC contracts for physical energy delivery to final customers

- Allow for single-sided reporting for OTC wholesale energy markets (like EMIR). Direct reporting obligation of OMPs for wholesale energy transactions concluded on orders entered via their venue (no validation by market participants)
- To create one single market integrity regime to facilitate compliance for firms and to reduce complexity and legal uncertainties of oversight from different authorities under different regimes and also to better monitor for and combat cross market and cross instrument market manipulation, Articles 3 and 5 of REMIT should prevail over Article 9 of Directive 2003/6/EC.