Questions	Answers
If the market is not at equilibrium, wouldn't there be still profitable investments (or unprofitable existing plants)? How will you know, you reached a point where all plants stayed in the market and no additional one's would come online?	In a full long-term equilibrium with all capacities optimised, all units would reach the theoretical 'zero-profit' equilibrium. This is the optimum the global optimization would find. However, the EVA is also not fully free to optimise all variables, as several technologies are fixed and driven by policy. Thus, the zero-profit condition is not expected to apply for all technologies.
In case the approach with variousness dispatch simulations and subsequent individual economic evaluation of individual plants being chosen, how will smaller/different plant sizes be considered? E.g. if a 400 MW CCGT unit is not profitable anymore, a 50 MW unit might still	Decommissioning and investment decisions are modelled linearly in EVA. Thus, thermal units are aggregated in the EVA process and there is no detailed distinction on the size of the units.
"If there is overcapacity, the EVA will identify it and find a more equilibrated Central Reference Scenario outcome" --> but the EVA will yield a different solution depending on whether the National Estimate has excess capacity or insufficient capacity.	The EVA should lead to an optimal mean cost solution. Hence it could either reduce excess of capacity, or increase capacity if additional capacity is viable.
Is the capacity already contracted with CM considered, in both scenario with and without CM, as existing and giving their adequacy contribution for all the life of the contract, because it is already supported by the contract awarded?	Yes, capacity with awarded valid contracts for CM (over the studied horizon) is considered in both scenarios. This is valid for CMs in the form of capacity markets, while capacity reserves (*eg* strategic reserves) are not included in the scenario w/o CM (only capacity available in the market is considered).
If a heat only boiler was to fill the gap once a CHP unit is not profitable anymore, this investment would need to be considered as a cost when retiring the CHP unit.	In ERAA 2022 the heat market is not explicitely modelled. Therefore pure heat demand and the costs for heat-only generators are not included in the optimization.
How are the macro regions being selected? Is this based on an analysis of how often there is congestion between two zones?	The macro-regions used in ERAA 2021 followed the TYNDP 2020 approach. However, this approach will not be followed in ERAA 2022.
Commodity prices: do you have any thoughts about how to capture current uncertainty for future prices?	We acknowledge the complexity of capturing the current uncertainty of future prices. A proposal was presented during the webinar. We welcome stakeholder feedback on this topic through the ongoing call for evidence (https://consultations.entsoe.eu/entso-e-general/eraa2022-call-for-evidence-preliminary-data-inputs/).
Can you elaborate a bit on what you mean by harmonisation of CONE values?	For the countries which have official published CONE studies, the latter will be used. For the countries which do not have published CONE values following an official methodology, an average value based on the available published CONE studies will be used.
What WACC do you use for peak plants?	WACC values are sourced from the published CONE studies per country/per technology. As for countries without a CONE value an average value per technology based on the available published CONE studies will be considered. Technology-specific hurdle premiums will also be considered, following the same methodology as in ERAA 2021.
Capex for batteries seems very variable. Looking for additional inputs might be useful.	We welcome any feedback from stakeholders on this topic.
Do you model power flows and impact on grid congestion on EVA? A greater amount of RES and congestion will have an impact on volume risk.	We consider power flows and congestions either through Flow Based Market Coupling (if applicable) or through Net Transfer Capacities on interconnectors between bidding zones. In both cases the N-1 and other operational security rules are taken into account.
Will emergency State aid or price regulation measures introduced by MS following the Commission's toolbox be factored in, or too late for 2022 assessment?	If Member States provide a clear guidance through the current call for evidence, these might indeed be taken into account. After the closure of the call for evidence, the final modelling.
Which Max. values would you consider more appropiate instead of the 15000€/MWh?	The ERAA 2022 methodology for deriving the price cap for each target year will account for the impact of the current market rules regarding the automatic increase of the technical bidding limit of the day-ahead market.
How are you going to consider that the price cap in the intraday markets is 9999 EUR/MWh	The volume traded in day-ahead is around 80% to 90% of the total wholesale electricity market. Therefore, the day-ahead price cap [currently at 3000 EUR/MWh] provides the most relevant market signal for the EVA decisions in the EVA model of ERAA.

Is RES curtailment assessed under different scenarios? this has implications in EVA for renewables and can have implications on the EVA of storage.	RES generation follows the historical climate scenarios provided in the PECD. In EVA of ERAA 2022, RES are considered as policy technologies and not investment candidates. Nevertheless, batteries will be considered as expansion candidates in ERAA 2022.
Solar and Wind will dominate the expansion in the coming years. Is it not a major drawback if it is not included as expansion candidate?	Solar and wind investments are currently (mostly) driven by direct or indirect government subsidies, which vary at member state level and are expected to change over time. These are hard to account for in ERAA models. For this reason RES are treated as 'policy' units, and the expected expansion of solar and wind is included in the data provided by TSOs based on national government policies and climate objectives (e.g. Fit for 55).
There are rules that would prevent payment of CfD to RES when market prices are affected by oversupply for several hours. Therefore RES investment is not risk free. Is there any entity in Europe responsible for the EVA of RES?	Solar and wind investments are currently (mostly) driven by direct or indirect government subsidies, which vary at member state level and are expected to change over time. These are hard to account for in ERAA models. For this reason RES are treated as 'policy' units, and the expected expansion of solar and wind is included in the data provided by TSOs based on national government policies and climate objectives (e.g. Fit for 55).
Why this skepticism towards scarcity prices? So far we simply haven't seen them yet, as we have no capacity shortage but overcapacities in the EU. If they are allowed to occur regularly, investors will get used to this type of remuneration.	Different investors have different risk appetite. Some are more risk averse, while others are more risk takers. Therefore, it cannot be assumed that all investors will commit to investment decisions which rely on the occurence of very high prices in moments of scarcity.
On Option 1, you say "limited number of climatic conditions", but then you say "single result". Does that mean that you will only do "one climatic year"?	When following a stochastic approach, multiple scenarios are considered simultaneously to deliver a unique optimal solution. However, its complexity may require to reduce the number of total climate conditions considered.
How will you simulate consecutive years in the presence of 4 non-consecutive target years in the model?	In ERAA 2022, the focused target years are 2024, 2025, 2027 and 2030. The approach to consider for the years in-between is currently being developed.
Do you intend to model the effect of regulatory measures to tax profits earned by inframarginal generators?	When the central cost optimization approach is followed, inframarginal generators are remunerated by the EOM market based on the difference between their marginal cost and the marginal cost of the generator setting the marginal price in the merit order. No taxation is accounted.
Are national taxes supported by generators being considered for the EVA?	No taxation is accounted for.
Wouldn't it be more accurately to assume that heat revenues will fill whatever revenue gap there is? Instead of retiring a CHP unit, the district heating network operator would simply raise the heat price	It is assumed that boilers represent an alternative source for heat production. If a CHP unit is retired due to non-profitability, boilers or other heat providers can fill the gap. CHP units that are essential for the local heat system can be marked as "must-run/policy units" by the TSO and are consequently not considered as decommissioning candidates.
Which methodology will be used for the Climate years ?	The clustering approach will be different from ERAA 2021 and based on the total system cost distances.
Why is no V2G considered in the modelling? In 2030 some (conservative) sources are assuming 10% of EVs providing V2G	Improvements towards V2G is anticipated in next editions according to the published ERAA implementation roadmap. In ERAA 2022, EVs will have load-shifting and smart-charging capabilities, but not yet full V2G flexibility.
Why do you not assume a part of industrial load as price-responsive during scarcities? The current situation seems to give us interesting data about this?	Industrial DSR is included in the modelling as "explicit DSR".
Implicit DSR: What criteria will TSOs use to determine the ratio of flexible/inflexible consumers? Will this be set as fixed over the timeframe of the analysis can it vary? How will the analysis take into consideration the effects of new legislation (e.g. AFI and smart charging)?	The ratio of flexible/inflexible demand can vary over the timeframe of the analysis.
Comment regarding V2G you need ev capable for V2G but also charging stations… will not most charging stations be unidirectional?	Improvements towards V2G is anticipated in next editions according to the published ERAA implementation roadmap. In ERAA 2022, EVs will have load-shifting and smart-charging capabilities, but not yet full V2G flexibility.

An existing electrolyser has to produce hydrogen in a high percentage of hours. Wouldn't it be better to model the electrolysers as a set demand volume that can be optimized into the best hours instead of waiting for a strike price?	The current modelling approach assumes that electrolysers are operating if the price is below a certain threshold (~49 Eur/MWh in 2030). The threshold is derived from the hydrogen price forecasted in the respective target year. This assumption ensures that the operator of the electrolyser only operates if profits can be generated. As the price threshold is relatively low in the merit order (e.g. lower than marginal cost of coal, gas and oil generation), it is expected that full load hours are sufficiently
What "must run trajectories" means? Which type of tecnology are included? If there is a termal power plant production, you should risk a double counting...	Must-run units have a predefined minimum generation profile attached to them, to contribute to security of system stability and inertia response as well as provision of heat in the case of CHP units.
About maintenance schedule, will you take account european mandatory terms about compliance with european regulation as emergency and restoration (black start, ILF, power system stabilizer, etc) that could lead to subefficient and suboptimal maintenance schedule?	TSOs can provide restrictions in the maintenance optimization which are taken into account to generate more realistic maintenance pattern. Those constraints can e.g. reflect the minimum or maximum number of unit in maintence at a certain period of the year to account for limited maintenance work force, system stability requirements, regulatory terms or others.
Do you think that whether the National Estimates imply excess capacity of insufficient capacity affects the result of the EVA/ERAA? If so, should you not require that TSOs submit National Estimates that are all developed assuming there is no CM?	If there is overcapacity, the EVA will identify it and find a more equilibrated Central Reference Scenario outcome.
In both scenarios,phase-out of existing capacity market have NO effect on the already contracted capacity,keeping on giving its adequacy contribution,right?Does this mean that,in case of CM phase-out,the mechanisms to manage and guarantee the adequacy contribution (as secondary mkt) should be kept on?	Yes, contracted CM are considered fixed (no exit through EVA) in both scenarios with and without CM. The central reference scenario with CM will calculate how much capacity needs to be added to obtain maintain resliability standards.