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NZMR Phase 4 Webinar Q&A

Table 1: ESO answers to questions from stakeholders during our NZMR webinar on 4th July 2023

No	Question	Answer
1	If locational marginal pricing is not in place until 2035 how much of the £51bn value case from the FTI analysis is wiped out (as it assumed that LMP would be in place by 2025)?	The answer to this question is impossible to know without re-running the analysis. Then again, it would be worth keeping in mind the world does not end in 2040 or even 2050. LMP is about putting the plumbing in to support enduring operation of a high-renewables system. So while the benefits would be delayed, there would also be benefits materialising after the horizon ends.
2	Can you outline how much of the congestion shown over 2020 - 2022 period is due to lack of transmission capability in terms of both investment in line with known connections and shortfall in availability due to various issues?	In all electricity systems, there is always an efficient amount of congestion, where any additional network reinforcement would be more costly than the congestion it resolves. The ESO Network Options Assessment recommends investments on this basis. It is ultimately the transmission owners' responsibility to deliver the recommended investments. Outturn congestion will inevitably differ from that modelled in the NOA process due to imperfect foresight of economic market factors.
3	I can see how locational pricing can give signals for operational timescales but how would you give clear long-term (investment timescale) signals in advance of build, connection, and related transmission investment?	Wholesale pricing in operational timescales has always underpinned investment decisions for merchant plant and this was a key message in our presentation. Market participants run fundamental market modelling to forecast national wholesale prices. In the same way, locational wholesale pricing can be modelled over project lifetimes to forecast revenue. Unlike current locational signals in the form of TNUoS, such forecasts would not be subject to regulatory risk due to methodology changes. The basis risk would also be more hedgeable than current locational signals due to the symmetrical nature of locational pricing between supply and demand, with a myriad of strategic options including Financial Transmission Rights, geographical portfolio diversification, co-location and even vertical integration. Layered on top of this is investment policy, which may be needed to bring forward investment you don't think the market would bring forward for whatever reason.
4	Do you agree with argument that nodal/zonal pricing was only successfully introduced in a time when markets were still largely dominated by fossil fuel assets and conventional generation and doesn't really work in this scenario?	The very first implementation of LMP was actually in a hydro dominated system (New Zealand). It is correct that most historical examples of locational pricing implementation have not been in renewable dominant systems. However, this is simply because other electricity systems are only now becoming renewables dominant. We believe that locational pricing is even more valuable in renewable dominant systems due to the need for accurate behaviour of flexible resources in near real time. Our assessment of nodal markets indicates they are managing curtailment of renewables significantly better than the current GB market. Certainly, we find today that perverse flows from some assets results in unnecessary RES curtailment and goes against the trilemma objectives.
5	Have ESO quantified what benefit remains if	We have not quantified the effects of grandfathering on the cost benefit analysis of locational pricing. The details of any grandfathering

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	grandfathering is taken into account following a transition to locational pricing?	arrangements are uncertain would be subject to extensive consultation prior to any transition to locational pricing. While grandfathering arrangements would essentially be a wealth transfer from consumers to producers, they can be designed in a way that does not hinder the overall efficiency gains that can be achieved with locational pricing. While they might offset some of the benefits modelled in the Ofgem/FTI study, bear in mind that the study only looks out to 2040 and net benefits will continue to accrue after this date.
6	On BM reform - could/should this also include consideration of long-term balancing services? Like long term constraint services?	While we believe that LMP is by far the most efficient way to address constraint costs, we acknowledge it will take several years to implement. Therefore, we are considering all options to reduce balancing costs in the short term. Long-term contracts for constraint management are under consideration, but the negative effects of such contracts (e.g. impacts on competition, market liquidity etc) must be weighed up against the benefits.
7	Can you please publish the recording? Are you able to share a copy of the slides that you've showed today?	The slides, recording and Q&A document are now all available on our NZMR website.
8	Has NGESO examined alternatives, for example incentivising curtailment where persistent constraints exist?	The BM already incentivises curtailment where persistent constraints exist. With respect to longer-term constraint contracts, examples such as Local Congestion Management (LCM) and intertrip schemes will be utilised in the short/medium term. But we do not believe ancillary service markets are either efficient or sufficient on an enduring basis, as they are associated with negative impacts on competition, wholesale market distortions, risk of gaming, baselining problems, and impacts on market liquidity. Wholesale market price determine default asset dispatch for most of the market and how key assets, such as interconnectors flow. It is crucial that wholesale market prices in operational timeframes are accurate.
9	Will the low marginal price in the North of Scotland (NoS) force closure of existing assets/stranded assets?	Negative prices reflect that the energy generated at that time can't be used. We see periods of negative prices today, both in the wholesale market and in Balancing Mechanism bid prices. Under locational pricing, this reality would be clearer to the market. While it is possible that some areas would have persistent low prices, it would be expected that low prices would attract the deployment of large demand clusters (e.g. hydrogen electrolysis plant) which would exert upward pressure on prices. We are already getting significant interest from large demand users who wish to locate behind constraints where they can mitigate congestion. From the perspective of many assets/investors, what will matter are the **average** prices over the investment timeframe and whether support policy exists and how it is designed. If forecast average prices are considered to be too low to attract investment, then indeed investment is not needed in that particular locality and other areas with higher prices would be more attractive. If an asset or assets exit in a locality with low average prices, then this would put upward pressure on prices. For storage assets that derive value from price volatility, increased price spreads due to more frequent low prices will enhance returns from price arbitrage. As discussed in the webinar, we are supportive of transitional arrangements such as grandfathering to protect existing investments.
10	Did NGESO LMP modelling include estimates on level of	We have not yet modelled LMP impacts.

	subsidies necessary to avoid pushing renewable generators in Scotland out of the wholesale market?	We are engaged with the various modelling exercises considering nodal prices in different locations in GB, and it is helpful that these exercises assume different CfD designs and exposure to nodal prices. FTI modelling for Ofgem did account for the impact on CfD payments required to keep parties whole and results found that increased CfD payments did result in reduced consumer benefits, but not nearly enough to negate benefits from either nodal or zonal pricing.
11	It seems efficient dispatch of interconnectors and other flex is the biggest operational driver for LMP. Is there a minimum disruption policy change which tackles most of that problem with fewer of the headaches associated with a full transition to LMP?	By 2035, the total capacity of assets with two way flows, such as interconnectors and storage, will likely be double the total current dispatchable capacity. It is therefore absolutely critical that these asset flows align with system needs. While we are supportive of interim measures to mitigate constraints, the role of the wholesale market is critical to determining efficient flows of these key assets up to gate closure, reducing costs. So long as the wholesale market does not accurately reflect system needs, there will always be significant need for costly redispatch the Balancing Mechanism. The Balancing Mechanism , which is procuring for many other services in compressed timescales, is not the right market for managing the high levels of congestion we see at the end of this decade in addition to its various other products.
12	What will be the share of nuclear generation to total electricity demand in 2050 as GW and % of total?	The share of nuclear in the system by 2050 will depend on a number of factors including Government policy. The focus of our assessment has been how to ensure policy can complement the wholesale market in delivering on optimal power mix. In my presentation today, I outlined the challenges that centralised contracting will need to overcome in order to achieve an optimal power mix and how policy can be better aligned with markets so the latter can contribute as much as possible to an optimal outcome. According to Figure ES.10 in FES 2023, in 2050 nuclear generation will provide between 2.8% (Leading the Way) and 5.16% (Falling Short) of total installed generation capacity (GW). The share of nuclear generation to FES' ACS Peak System Demand for 2050, is between 10% (Leading The Way) and 14.1% (Consumer Transformation).
13	Government is proposing the Energy Intensive Industries Exempt Scheme (EIIs) do not pay network charges. Will the benefits of LMP not be lost if the customers are protected from any cost, lets along marginal costs?	The proposed compensation scheme for EIIs applies specifically to network charging, rather than to locational differentials under LMP. A market design with LMP offers a whole range of options of demand exposure to the locational price signal. International experience shows different jurisdictions have implemented different degrees of consumer exposure. It is typical that industrial and commercial consumers are exposed to the locational price while residential consumers have a degree of protection. ESO has not yet developed a view on recommending a level of consumer exposure. FTI modelling for Ofgem explored the impact of protecting consumers from price signals in one of their sensitivities. Further detail can be found in their presentation and upcoming report.
14	Can ESO expand on its conclusion that LMP is a big win for storage? You indicate that storage will be able to locate to benefit from lower prices. However, new pumped storage locations are pretty fixed and often behind network	Firstly to clarify, one of the ESO conclusions was not that LMP will be a "big win for storage". Rather, we concluded that one of the big wins for LMP was that it aligned assets with two-way flows such as storage with system needs. We recognise that pumped storage is a unique asset type - indeed no major pumped storage project has reached financial close since privatisation. Given specific factors such as high capex and atypically long asset lifetimes, we recognise that pumped storage should be treated as an asset class that may require bespoke support to bring investment forward, regardless of whether locational pricing is implemented.

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	constraints. Furthermore, without network investment, even location-agnostic storage (e.g. batteries) will still not be able to get this stored energy to market if the wires are not there. Can panel or ESO suggest how LMP is the answer to this issue?	We note the Ofgem/FTI study found that considerable storage would locate in front of constraints in order to be able to export in times of scarcity. Ultimately efficient market design would deliver the most efficiently sited mix of assets.
15	Is it possible to choose the best wholesale market structure before the target energy mix has been determined? A market that works for wind+nuclear+storage might be quite different from a market that works for hydrogen+ccgt.	A fundamental premise underpinning electricity markets since privatisation is that, despite their many imperfections, markets have a large comparative advantage over centralised decisions, for multiple reasons: • Market participants, unlike planners, have a direct economic state in the outcome of their decisions. • Private actors often have better (albeit still imperfect) information than central planners, partly because market prices condense huge amounts of information into a readily understood form. • They also generally respond more quickly to new information, especially information about prior mistakes. • Lastly, government decisions often reflect political, rather than economic imperatives. The appropriate starting point is therefore that it is generally more efficient for the market to determine the energy mix, rather than vice-versa, and that a more efficient wholesale market will result in a more efficient energy mix. LMP is working effectively in jurisdictions with very different generation/demand mixes. (E.g CAISO which is solar/ battery dominated; New Zealand which is hydro dominated; ERCOT which is solar/wind/fossil).
16	Can you explain how cost of capital was reduced under EMR but modelling being used to promote LMP is assuming no cost of capital impact? Follow-on question: Can you explain the fundamental difference you outline - the CfD reduced exposure to long term market price uncertainty, LMP increases exposure to Long term market price uncertainty	It would not be appropriate for us to reply on behalf of FTI as we did not conduct this analysis. However, in their analysis, FTI state that they found "limited evidence that moving to nodal or zonal pricing will impact the cost of capital for market participants." We think the change in allocation of risks related to EMR implementation, with the introduction of the CM and CfDs, is fundamentally different to that related to any change in wholesale market design. In our view, EMR and particularly CfDs were designed to reduce cost of capital when low carbon assets such as offshore wind were relatively nascent, and therefore had very different investment profiles to today. While we agree that continuation of some form of govt support is needed for the foreseeable future, the underlying rationale for supporting assets such as offshore wind in this decade has changed somewhat – it's about retaining capital and ensuring continued momentum rather than derisking investment for a new asset class. Concerning the debate on cost of capital and LMP, it is necessary to unpack risks and to consider different risk profiles for different asset types and different investor appetites. We think the impact of uncertainty

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		around REMA outcomes may increase risk premia for some assets – it is for this reason we are advocating a quick decision, clarity on grandfathering and investment policy etc. In our own research, however, we have not found robust evidence that operators in LMP markets face systematically higher cost of capital. Furthermore, assets would be able to manage risk using FTRs, portfolio diversification and futures markets, and would no longer face volatile, unhedgeable TNUoS charges with associated regulatory risk.
17	How do investors forecast locational prices accurately if the bulk of investment appears to be coming via centralised contracting?	Investors will need to forecast locational signals in the future system with significant investment via centralised contracting whether or not we retain national pricing (under which investors need to forecast TNUoS locational differentials). Forecasting of locational wholesale prices (either nodal or zonal) would be free of the complication of regulatory risk associated with frequent, unpredictable TNUoS methodology changes which impact locational differentials. Under any wholesale market design, it will be crucial for the procurement targets (including any locational element) of centralised contracting to be made transparent as far in advance as possible. They can then be taken into account in market participant modelling as early as possible to improve the accuracy of pricing forecasts. It is also important to ensure that investment policy does not create distortions that are difficult to model in price forecasts. Ultimately, as we stressed in the presentation, the share of central contracting should ideally be reduced over time by driving move volume through the market i.e. demand-led contracting, PPAs.
18	On herding behaviour slide: Why does this present a challenge as the reduced output is known - which is not the same as a sudden failure of a nuclear plant? *Follow-on question:* Why is it different for 4GW of wind coming off in response to the -ve pricing rule compared to say ~10 GW of CCGTs planning to come off in response to changing DA prices?	It presents a challenge because of the sheer scale of it. For example, on 2nd July, more than 4GW of wind suddenly came off the system and this is much greater than the largest single infeed. We also expect this "herding effect" of aggregate wind reduction at GW scale to occur more frequently than the largest infeed loss. We hold a certain amount of reserve to cope with unplanned loss of the largest infeed. Because it is known that synchronised aggregate wind reduction will occur and it is regarded as being part of normal operation (for example, the frequency should remain inside the operational limit during the change in CfD output), the reserve we must hold to manage it has to be **in addition** to that held for unplanned events and this is very expensive. In addition, we have to deal with error accumulation. With that much generation moving at once, the accumulated error when generators fail to follow their programme (i.e. physical notifications) is large and difficult to manage. Given all of this, it isn't economic to use the same tools to manage it as we would for an unplanned large loss of infeed (e.g. expensive STOR). The key difference is that CCGT plant do not behave in a synchronised way as their economics do not have such a coordinated cliff edge. For plant under CfDs subject to the negative pricing rule, they are fully topped up to a strike price when prices are positive but when prices are zero they receive no subsidies and are exposed when prices turn negative.

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		For CCGTs, they have slightly varying marginal costs, and their strategy is much more complex - as a result they are traded in a less abrupt fashion.
19	How are interconnectors classified as low carbon capacity - what is the direct link to ICs and the carbon emissions of the generation that flows in via an IC.	We appreciate that the flows in interconnectors are not always low carbon. We used the capacity market graph to illustrate the limited low carbon flex resources that have been supported by the Capacity Market, even when including interconnectors in the mix. The carbon intensity of interconnector imports is expected to decrease over time with more ambitious EU targets.
20	You say the CM has not bought forward much low carbon plant. What do you think is missing? Hydrogen, new nuclear, CCUS are all under their own schemes. Did I miss the invention of a magic power plant?!	The Capacity Market has mainly supported existing resources and has brought forward limited new investment. Indeed, some nascent low carbon dispatchable technologies have their own innovation support policies. However as we showed in our Phase 3 report, there is missing money for flexibility in the wholesale energy market and going forward we will need to remove carbon from the electricity markets including the capacity market. So, in the short term, there is a strong case to improve the Capacity Market in order to increase the market share of low carbon flexibility, such as battery storage, hydro and DSR, relative to the share of gas plant. In the longer term, with restoration of missing money for flexibility into the wholesale market, the changing nature of system stress and because innovation support for new technologies will need to be phased out as they mature, we think alternatives to the Capacity Market should be considered.
21	It comes across from the materials presented that the challenge is in operability and shorter term markets. If so, why is the focus on reforming the day ahead market and potentially damaging long-term investment signals? And risking Net Zero. Should the focus not be on BM reform, CfD impact on BM, a more automated control centre etc.	It's true LMP is addressing distortions in the market which are currently particularly manifest in balancing timeframes. It is a mistake to think that short term markets are separable from long-term investment signals. As we stated in the presentation, market expectations of spot and balancing market outcomes also underpin long term investment decisions. The strength of the US nodal design is in the coherency of balancing, forwards and other financial markets.
22	With regards to scarcity adders, it’s been argued that they actually trigger greater price volatility and price spreads (as demonstrated in US). Would these not result in more risk to greater consumer costs?	The objective of a scarcity adder is to restore missing money to the wholesale energy market, to ensure there is appropriate renumeration for assets which can respond in times of scarcity. While this may increase wholesale energy prices, it should in turn remove the need for or at least reduce the revenue that needs to be provided through out-of-market mechanisms such as a Capacity Market. If there are concerns about price volatility impacts or consumer exposure to high prices, then a scarcity adder could be combined with Reliability Options that provide a hedge for consumers and revenue stabilisation for assets that need it.
23	Are we considering multi-purpose interconnectors (MPI) in Investment Policy? I saw we are still talking about Interconnectors and not MPI.	REMA considers the investment policy required to compliment wholesale market revenue for generation assets in a competitive market. Network asset regulation is outside the scope.
24	What proportion of necessary renewable investment are ESO	Renewable capacity targets are determined by HMG, as are the budgets for each CfD allocation round.

	assuming is supported by CfDs?	
25	ESO is currently spending £1.5b/y switching wind off, mainly in Scotland. This will increase to £4b/y (20TWh!) by 2030 so is a better solution to sell back this excess subsidised renewable energy back to the mkt through 5-10y Long-term "demand soak-up" contracts? This will allow low carbon renewable energy to run and lower costs for consumers without the need of more mkt design changes/ distortions would it not?	Currently, demand could do that via short-term market in the BM. Locational marginal pricing can cost-effectively incentivise this type of behaviour by revealing the locational value of energy, which can then lead to market participants voluntarily entering into long-term bilateral contracts. We are exploring potential interim measures to better signal to demand to locate behind constraints; however, such measures much cohere with existing mechanisms such as TNUoS, and are fundamentally less effective than wholesale market reform since constraints are dynamic and dependent on wider market context (e.g interconnector flows).
26	In the past, it was my understanding that strategic reserve had been used by generators to hold the ESO to ransom i.e. give us a strategic reserve contract or we'll close. Have I missed something if ESO are thinking of reintroducing this?	Strategic reserve is just one of several options we are currently considering and would be dependent on other market changes as to its appropriateness. It is under consideration due to the significant risks relating to carbon and costs that we may have to manage. Gaming risks are present and must be considered for any market intervention and the implementation of a Strategic Reserve would need to be carefully thought through to prevent or minimise such risks. We have seen a Strategic Reserve successfully implemented in numerous jurisdictions across the world and the EU Electricity Regulation 2019/943 (Article 22) provides best practice guidance.
27	Would a CfD based on deemed generation or a cap and floor incentivise generators to participate in forward markets and not just sell in the day-ahead market?	Compared to the current design, we would expect a Revenue Cap and Floor (C&F) model to result in more forward/futures trading due to the price exposure – more so for soft C&F compared to hard C&F. For the Deemed Generation model it would depend on how well hedged the generator is relative to the benchmark generator.
28	In slide 28 you mention that centralised direct procurement is required to accelerate investment. Would this be translated into a more geographically granular Capacity Market, or the FSO deciding what, where and when to build capacity and tendering the development to private developers?	We are not advocating a more geographically granular Capacity Market, which is being considered by REMA. Instead, we believe there is a need for more accurate, real-time dynamic locational signals in the wholesale market which would lead to generators siting in more efficient locations.
29	Do you have views on the impacts of LMP on the retail market? Vertically integrated suppliers seem to fair better in nodal markets	The extent of vertical integration in a market depends on market structure and market rules decided by politicians. Locational energy pricing could encourage more vertical integration if market actors use this as a risk mitigation strategy. It would be worth considering experience in other markets with LMP and competitive retail markets (e.g. Ercot, US).
30	Many of the benefits of locational pricing are a	LMP would result in substantial overall socioeconomic gains, in addition to consumer benefit. We believe the system benefits would derive

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	transfer from generators to consumers - why is it then a problem for the return transfer to support assets that support the societal desire for net zero?	predominantly from enhanced dispatch of two-way assets (e.g. storage, ICs). As discussed in the webinar, we are supportive of transitional arrangements that protect low carbon generation assets, including grandfathering arrangements.
31	Is there a potential role for merchant transmission investment?	Any potential role for merchant transmission investment is a question of network regulation and as such is outside the scope of REMA.
32	ESO are in favour of market reform via LMP, and investment reform via changes to the CfD. Are the two workable together? If so, how?	The current CfD design would not be easily compatible with nodal pricing as settling against the system price could give rise to dispatch distortion due to the negative pricing rule. This could be mitigated by settling against the locational price but then the generator would receive no locational signal. But as we explained in the presentation, we think it is time to change the CfD in order to address distortions and to align generators incentives with market signals. Our analysis concludes that both the Deemed Generation and Revenue cap/floor models are compatible with either zonal or nodal pricing.
33	What is the timing of the CRO reference price and how do you ensure market liquidity is not detrimentally impacted?	The reference price is the market spot price. The strike price is the level at which an option is activated. The strike price can either be dynamic or static. A static strike price would likely be set through auctions, whereas a dynamic strike price will change throughout the duration of the agreement and would update to reflect the marginal cost of the most expensive market actor. In terms of liquidity, this would depend on the amount of capacity that is procured for a CRO, whether full demand covered and whether the scheme is voluntary or mandatory. We think a CRO could be designed to ensure reliability without significantly impacting useful liquidity.
34	What tangible evidence is there for generators (other than battery storage) considering using locational signals in development plans?	Locational signals have always influenced generators' development plans in the GB market. TNUoS costs are a significant cost component for any financial investment decision. Under a locational wholesale market, locational value would shift from network charges into the wholesale market revenues. LMP simultaneously sends both short-run and long-run signals (i.e. averaged over time)). In a wholesale market that provides more accurate information to inform decision making, market participants will reach better decisions that optimise system costs.
35	Can we learn from NETA - where the efficient market outcome saw the nuclear gencos go out of business? Customers bailing out assets put out of business is a real cost - British Energy was c£700m in 2002.	Major market reform will inevitably involve some distributional impacts. As emphasised in our presentation, however, we recognise that distributional impacts on existing investments can be mitigated by grandfathering arrangements, which is for the government to decide
36	Has full consideration been given to the management of FTRs which would be necessary under LMP?	We have researched into how FTR markets work in other jurisdictions and challenges that are being faced with the decarbonisation of power systems. We are confident that FTR markets offer market participants sufficient hedging opportunities for their locational risk, in combination with other physical hedging strategies including co-location, portfolio diversification and vertical integration. We also think that FTR products typically used in LMP markets today may need to be adapted to the needs of the emerging weather-dependent system. Overall, the ability to hedge locational risks under LMP would be improved by improved symmetry of

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		locational signals across supply and demand and the removal of regulatory risk (as exists for existing locational signals under TNUoS).
37	Recent reports (for example REA, Univ. of Strathclyde,) suggest that there is support for incremental rather than radical reform, partly in order to provide a more transparent, less complex system for developers. Would moving to nodal not cause long term uncertainty? It was mentioned earlier that it is better to go for an improvement that is good rather than a perfect solution. Surely to facilitate that we need iterative change rather than radical reform?	We think the scale of the challenge requires substantive reform to the wholesale market design and incremental reform cannot get us to the same endpoint of efficient system operation and efficient investment. We have not found a compelling alternative to wholesale market reform that addresses the need for accurate locational signals in operational timeframes. Introducing nodal pricing can cause uncertainty during the transition period, hence our emphasis on the need for a quick decision; transitional measures etc.. On investment policy, however, we are proposing incremental change, partly to help market participants adapt to the market design change.
38	The US is constantly used as the example where LMP works, but it has a different geographic spread of resource to the UK. How much work has been done to understand why it works there but might not work in a different geography?	LMP is a market design that has been implemented in Ontario (Canada), Singapore, and New Zealand. It is also being considered as an option in the South of China. New Zealand is a particularly relevant example as its geographic spread is fairly similar with abundant renewable resources in the southern island, and scarcity of transmission capacity in the link between south and north (which is where most demand sits). Also, some of the jurisdictions in the US have some similarities with GB, eg Texas and ISONE.
39	Have you considered the resource-based reasons as to why capacity is built where it is? Nuclear - needs to be on designated sites. Renewables - want to be near resource, availability of land/planning. Low carbon thermal - proximity to carbon stores or available hydrogen. Pumped storage - availability of head and tailpond.	The need for locational signals to incentivise siting decisions is not under debate in REMA – we already have strong locational signals via the TNUoS regime. The purpose of introducing locational marginal pricing is to improve how these locational signals are communicated to the market. i.e we believe that better signals are needed in operational timeframes and that LMP would therefore be more effective than today's combination of TNUoS and the BM.
40	LMP appears to being held-out as providing the efficient locational signal. How can LMP be designed to consider wider system costs and optimisation, e.g. do more than reflect past decisions on network build, and therefore be compatible with	Some form of locational energy pricing, ideally LMP, is indeed essential to facilitate efficient market outcomes for optimal use, transportation and storage of energy across vectors based on true economic costs. Locational signals will be needed in other vectors too. In addition, whole system decarbonisation will require carbon signals that are coherent across energy vectors to incentivise efficient switching between vectors that supports decarbonisation.

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	stimulating whole system investments across the range of vectors (which have their own infrastructure limitations and constraints)?	
41	What are your thought regarding Wind FTRs?	We think that FTR products typically used in LMP markets today may need to be adapted to the needs of the emerging weather-dependent system.
42	The introduction of LMP shows no correlation to decarbonisation in international markets. GB would have one of, if not the highest intermittent renewable mix of any LMP market. Is this worth the risk at the same time as trying to decarbonise? note that hydro is not intermittent	We believe that LMP is key to cost-effectively decarbonising a power mix based on weather-dependent renewables as it enables the efficient coordination of supply and demand/2-way resources (i.e. interconnectors, storage), so reducing the need for carbon-intensive dispatchable plant. We also note that ERCOT has about the same capacity of wind as GB today, in addition to a much stronger pipeline of battery storage.
43	What are your thoughts regarding where any Trading Hubs may be located?	Trading hubs have arisen organically and have been set up by system operators where nodal prices have tended to coalesce. We have not looked in detail at this stage into where trading hubs should be located in GB, but would be interested if stakeholders have views on this matter.
44	Studies have from LMP in other jurisdictions shows that efficient signalling requires the network to be fully developed. The UK transmission is not there yet, and so implementing LMP early would disadvantage generators and investment in Scotland and it does not appear to deliver investment into the areas where network reinforcement is required. Furthermore, these generators would be at a disadvantage due to decisions made by the ESO whether to build network or pay constraint costs. Given the known leasing rounds, is the plan to use cheap energy from constrained generators to kick start the hydrogen market? The alternative would be renewables on CfD, in which case the true liquid market would be very limited.	We fully advocate significant and accelerated investment in GB's transmission network (as seen with our HND and work on a Centralised Strategic Network Plan). It is important context that locational signals exist in the current market (via TNUoS and the BM) – moving to LMP changes the style of these signals, making them more transparent, but not the underlying principle that the location is an important factor in the value of electricity. We are exploring how constrained energy may be utilised for green hydrogen before a more to locational energy pricing. For example this project is exploring the economic and technical considerations around using hydrogen for constraints under the status quo market design: https://smarter.energynetworks.org/projects/nia2_ngeso036/
45	Can we please stop talking about LMP, its not	We are working across the ESO to reduce constraints in the short, medium and long term through:

	the Holy Grail, even if it took less than 6-10y to implement. GB has put the cart before the horse and we need solutions NOW like location "long-term" constraint markets that can reduce the £1.5b/y consumers are currently paying to switch wind off. Surely this will provide LT investment signals in the interest of consumers?	- New ancillary service markets for constraints - Long term contracts - Improvements to network planning and dynamic network utilisation We are also continuing to explore new ideas to resolve constraints outside of market reform, including long term contracts for demand behind constraints, and are part way through an innovation project exploring hydrogen for thermal constraints: https://smarter.energynetworks.org/projects/nia2_ngeso036/ While these interim measures are crucial to reducing constraint costs in the medium term, we do not believe they are sufficient for the scale of congestion we expect in the early 2030s and consider wholesale market reform is needed to provide coherent and transparent signals in a way that is accessible across the market and does not fragment liquidity.
46	What are the next steps?	As set out at the end of our NZMR programme to date presentation, our next steps include: 1. Final conclusions on investment policy will be set out in our autumn publication, taking into account stakeholder feedback from the webinar 2. ESO best-view reform package that coherently combines investment policy and wholesale market design, will be set out in our autumn publication 3. In depth assessment of centralised and decentralised scheduling ongoing; stakeholder engagement will start in Autumn We continue to work with government and Ofgem on REMA, advising from unique System Operator viewpoint.
47	Slide 15 shows a very heavy reliance on storage. How many GWh of storge (not GW) will be required and what might be the cost? Over the past three years wind had failed to supply 20% of demand for between 3600 and hours in the year although the nameplate capacity is more than 90% of average demand.	In FES2023, we modelled between 43.6 GWh (falling short (FS) scenario) and 130.2 GWh (leading the way (LW) scenario) of storage in 2030, and between 91.3 GWh (FS) and 337.2 GWh (LW) of storage in 2050. This is shown in Figure FL.12. We do not publish the costs associated with these forecasts.