Rachel Cary

Head of policy, Review of Electricity Market Arrangements (REMA)

CC: Rob Hewitt

Deputy director, electricity market reform

Re: Priorities for the next phase of REMA

Dear Rachel, Rob and the REMA team,

As the REMA process enters into the final stages of the first round of consultation and policy development, we would like to summarise Regen's current thinking and position on key areas of market reform. These are Regen's views, informed by our own engagement with our members in the renewables and storage industries, as well as our discussions with other stakeholders, networks, trade bodies, NGOs and consumer advocacy groups.

Firstly, we should say that we have found the REMA process and engagement with your team to have been valuable and constructive. We have very much appreciated the openness of the REMA team and your willingness to have impromptu bilateral meetings, as well as the more structured workshops and forums. There is a strong sense that we are all on a journey to develop market and policy options for a resilient net zero power system and we have benefited from our engagement with DESNZ and the other REMA participants.

We recognise that there are still a range of policy options in play and that we should continue to explore and discuss how the programme of REMA reforms could develop. However, it appears that industry thinking is coalescing in a direction of travel, and some conclusions for next steps are emerging from this.

We have set out below our recommendations for where the REMA team should work with industry to develop the vision for a dynamic GB energy market enabled by a smart, digital and flexible energy system. This letter covers the following recommendations:

In summary, we do not believe that a complete change in market arrangements, for example to nodal or zonal LMP or a split market, is warranted or would be constructive at this stage in the net zero transition. We do, however, believe that there is an emerging package of reforms which would significantly improve the operation of the energy markets, while at the same time delivering greater value to the consumer and helping to secure the investment and economic transition needed to achieve the UK's net zero and energy security strategy.

Rather than portray incremental reforms as less ambitious, we are excited at the prospect of building on the strengths of the GB trading market, which has enabled the UK to move ahead in power decarbonisation at both small and large scale, while enhancing its performance, flexibility, market competition and system operability.

1. Rule out a shift to nodal or zonal LMP as not right for the GB market

We have spent a lot of time researching the basis of an LMP market design. This has included our study of the operation of LMP in the US, our analysis of locational signals in the current market and the LMP impact analysis done by our associate, Simon Gill, with his colleagues at Strathclyde University. We have attended the various ESO and Ofgem LMP workshops and have taken the time to understand the cost benefit modelling that has been produced by their consultants, FTI, feeding back our comments and concerns to Ofgem.

From our analysis we have concluded that neither zonal or nodal LMP would be beneficial to the GB energy system, either today or for the foreseeable future. This conclusion may have been different twenty years ago, when England and Wales had a single price, central pool dispatch arrangements and very low levels of renewable energy, but we do not believe that LMP is a suitable market arrangement today.

Our view, which we believe is shared by many in the industry, is that a shift to LMP (nodal or zonal) would be a major distraction, and a backward step, which would not enable the UK to achieve its net zero and energy security targets. The benefits of LMP have been overstated by use of some extremely hypothetical and, frankly, dubious modelling assumptions, particularly about the re-siting of projects in the theoretical, LMP-modelled world. Meanwhile the risk to investment and the cost/complexity of implementation has been downplayed.

There could be some operational benefits from LMP coupled with centralised dispatch, especially in relation to the operation of interconnectors (which is clearly a problem area), but these benefits could be achieved by other means without the damaging impacts that LMP would have on the operation of GB's trading market and the risk to future investment.

We have highlighted some of the areas of concern in Appendix A, and would be happy to discuss these further with your team, but these are now arguments that you will have already heard from many in the industry. For example, recent reports from Cornwall Insight[1], Prof. Michael Pollitt[2] and AFRY[3] support the view that LMP would be a very high-risk design option and that the benefits claimed for LMP are very much in doubt.

"Any move to a locational market runs the risk that the small overall welfare gains are overshadowed by the scale of wealth transfers between parties and the myriad of other uncertainties between now and 2035." AFRY – Review of electricity market design in Great Britain, 2023.

"We conclude that while the theory and modelling behind LMPs is strong, their wider theoretical rationale is less clear cut and the evidence on their impact in use is surprisingly weak." Michael Pollitt – Cambridge University, Locational Marginal Prices (LMPs) for Electricity in Europe? The Untold Story.

"The introduction of Locational Marginal Pricing and the creation of a split market are two of the most revolutionary options in REMA. They would present significant uncertainty and complexity of implementation that risks jeopardising the acceleration of renewable deployment that is needed to achieve the target of decarbonising the power sector by 2035." Cornwall Insight – REMA: Reform to support Mass Low Carbon Power, insight paper for Renewable UK, Scottish Renewables and Solar Energy UK.

Recommendation 1

Our recommendation is to now drop LMP as a design option from the REMA programme. This applies to both nodal and zonal options. Maintaining LMP as a possible option would create ongoing uncertainty for investors. Zonal LMP may seem attractive as a form of middle-ground compromise but so far we have not seen a positive case for zonal LMP that would outweigh the investment risk it would bring.

We also recommend dropping the idea of a split market. A viable split market design hasn't been developed and, although popular in the media during periods of high gas prices, it remains a theoretical market design with significant flaws. Removal of the split market option would help to focus the REMA programme and industry on viable options. As an alternative to the split market, resource and attention could then be given to the development of long term PPA markets and potentially to the development of multiple 'green pools' for local energy, industry sectors and, potentially, a social tariff.

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[1] Cornwall Insight https://cdn.ymaws.com/www.renewableuk.com/resource/resmgr/media/cornwall_insight_rema.pdf

[2] Michael Pollitt Cambridge University Energy Policy Research Group https://www.eprg.group.cam.ac.uk/wp-content/uploads/2023/07/text-2318-revised-180723.pdf

[3] AFRY https://afry.com/sites/default/files/2023-09/afry_brochure_energy_market_report_phase_two_key_messages.pdf

2. Refocus REMA to achieve core and strategic market objectives

Inevitably a lot of engagement time has been spent considering the radical change options such as LMP and a split market. In our view, this focus on radical market redesign has distracted from the original market reform aims set out in the Energy White Paper of 2020[4] and the good work was done to develop the Smart System and Flexibility Plan[5]. As we stated in our consultation response, part of the challenge for the REMA team is that the case for change has not been well articulated and this, coming alongside the energy price crisis, has led many to presume that "the current market is broken".

In our view, calls for radical market change often stem from a lack of knowledge of how the current market actually works and the nature of the bilateral trading arrangements that were introduced through NETTA and BETA at the start of the century. It has been stated that the "current market is not designed for net zero" without a systematic analysis of what that statement means and what the real points of issue are. Often, what have been described as market issues are actually the result of the UK's poor record of strategic planning and infrastructure investment, and the need to improve operational functions in areas like constraint management and dispatch.

We are, therefore, pleased to see that the REMA teams has proposed to reshape the second consultation around four key objectives, which we understand to be:

- investment to create a renewable based system at pace;
- passing the value of lower cost renewables to the consumer;
- transitioning away from unabated fossil fuels to a flexible, resilient, decarbonised electricity system;
- operating and optimising a renewable based system cost effectively.

We agree these are the right objectives with a focus on securing investment for net zero and flexibility as well as consumer value and energy system operation and resilience.

Recommendation 2

Continue to refocus the work of REMA around core strategic objectives for GB market design, with a focus on securing investment, decarbonisation, consumer value, creating dynamic markets, greater use of flexibility, operational efficiency and maintaining resilience.

[4] BEIS Energy White Paper "Powering our net zero future" https://www.gov.uk/government/publications/energy-white-paper-powering-our-net-zero-future
[5] Smart System and Flexibility Plan 2017 and updates 2021 https://www.ofgem.gov.uk/publications/upgrading-our-energy-system-smart-systems-and-flexibility-plan-progress-update

3. Put in place a net zero energy delivery plan, supported by a dynamic market enabled by a smart and flexible energy system

There is an emerging consensus from the industry that an incremental or evolutionary approach to market reform is the preferred option. Unfortunately this approach has not had the same level of attention as has been given to the more radical options. An incremental approach should not be confused with maintaining the status quo – significant and far-reaching reforms and enhancements are needed.

Regen believes that a package of reform, building on the strengths of the current market arrangements but with a willingness to implement far reaching and meaningful reform, could have just as impactful an outcome as the more radical options claim. Moreover, such an approach could be implemented more quickly and with greater alignment with wider GB energy policies in areas such as retail reform, digitalisation, smart systems and flexibility. In our consultation response we referred to this approach as "radical incrementalism".

a) A net zero energy delivery plan

If there is one thing that everyone involved with REMA can agree on, it is that the UK desperately needs an integrated net zero energy delivery plan. At present we have elements of a plan, some target setting for key technologies (but without a credible delivery plan), and some areas of progress, for example, the moves towards a more holistic network design.

However, even though it is fairly clear what is needed to decarbonise power by 2035, we do not have a coherent and integrated plan for delivery of a net zero energy system. The outcome of the recent CfD AR5 auction is a good example of the current UK's lack of strategic planning and leadership.

This is important for market design. There has been a tendency to argue that energy policy should not 'pick winners' but it should be clear by now that, during a period of fundamental energy transition, the market alone cannot perform the function of strategic planning. With a plan in place the market can mobilise resources and investment; it can deliver efficiency and competition to reduce costs, but it cannot set the direction of travel or determine strategic outcomes.

There have been a number of positive policy shifts in the direction of strategic planning over the past year including the prime minister's recent commitment to develop a Spatial Energy Plan for the UK[6]. The OTNR and Holistic Network Design (HND) for offshore wind has begun to establish a better process for network investment planning aligned with strategic outcomes. However, HND is only a partial approach and needs to be widened across all transmission and interconnector

[6] Rishi Sunak speech 20th Sept https://www.gov.uk/government/speeches/pm-speech-on-net-zero-20-september-2023

planning. Ofgem and DESNZ are now proposing a Centralised Strategic Network Plan (CSNP)[7] aligned with a more accelerated investment approval process[8]. The CSNP, coupled with an accelerated delivery process for network investment, potentially reducing lead times by half[9], would go a long way to ensure that there is sufficient network capacity which, along with other operational reforms and the new expanded role for the Future System Operator(FSO), should address high constraint management costs and enable net zero investment.

Other positive developments include the proposal to restructure the UK Future Energy Scenarios into what should become a central net zero delivery plan and to develop Regional Energy System plans (RSPs) which should then be supported by local energy plans and distribution network investment plans

b) Enhancing the dynamism and innovation within the GB electricity market

At the start of the REMA process many stakeholders argued the current GB energy market is 'broken' or not fit for purpose to achieve net zero. These assumptions were partly driven by the occurrence of high constraint costs and the volume of redispatch actions in the balancing mechanism, and partly because of a belief that electricity prices, and the revenues for low marginal cost nuclear and renewable generators, were too closely tied to the price of gas during the 2021/22 energy crisis.

The challenge of constraint cost management, the operation of the balancing mechanism and the need to share the value of lower cost renewables with the consumer are still priority issues that need to be addressed. In our view, the REMA workshops and engagement have shown that much could be done within the framework of the existing market arrangements and that these arrangements could, with meaningful reforms, address these issues and form the basis for a future electricity market.

One of the key strengths of the existing market is the diversity of trading options that have been created by the GB's bilateral trading arrangements. It is sometimes claimed that the GB market has a single market price. This is incorrect and misses the key point that electricity can be traded over multiple time periods via long term contracts, bilateral trades and market exchanges. Such diversity has created an extremely versatile and dynamic market ecosystem with a myriad of trading options, from long term Power Purchase Agreements to inter-seasonal and weekly trades to day ahead and intra-day trading. According to Ofgem statistics, the average unit of electricity is traded 2-3 times between generator and consumer.

Other markets also support forward markets and bilateral trading, including those which operate with central pool arrangements (as GB used to do) and those with LMP. But compared to the GB

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[7] https://www.ofgem.gov.uk/publications/centralised-strategic-network-plan-consultation-framework-identifying-and-assessing-transmission-investment-options
[8] Such as developed under the Accelerated Strategic Transmission Investment (ASTI) framework
[9] See Winser Report on network investment https://www.regen.co.uk/the-electricity-network-commissioners-transmission-report-going-far-enough/

market these markets feature relatively complex and clunky financial trading arrangements which run in parallel to the main energy market. This limits market access, increases risk and increases transactional costs. Generators with experience of LMP markets, for example, have told us that LMP trading arrangements bring significant transaction costs and higher trading risks which would tend to increase energy costs, penalising smaller generators and those without a portfolio of projects and/or vertical integration to hedge with.

The GB trading arrangements bring a number of advantages and could, with additional reform and enhancements, provide the basis for a more innovative and dynamic electricity market. A key REMA goal should be to ensure that the wholesale and retail markets (working together) provide the maximum opportunities to harness the value of flexibility, energy storage, interconnection and demand side response. In a high renewable energy system this will be essential to extract the maximum value from abundant low cost electricity, when the wind blows and the sun shines, and to ensure that we have the resilience to manage energy security when there is a supply imbalance.

The ability to establish long term contracts but still be able to trade and re-trade electricity in short term markets and via bilateral agreements is a key strength. So the answer to the workshop question of whether the GB market should be characterised by long term contracts or short term marginal cost trading is definitely BOTH. The future business models for storage, green hydrogen, interconnectors, EV charging and agile consumer tariffs, and a variety of energy market innovations that we have not seen yet, will rely on the ability to trade over long term horizons and in near real-time dynamic markets.

Matching market dynamism with operational efficiency

However, it should be recognised that the diversity and dynamism of the GB market will create additional challenges for system operations. We are already seeing this happening. Current system operations are heavily dependent on the ability of the ESO to plan operations based on a day ahead forecast and to execute balancing and operational actions within a narrow one hour redispatch window, while still being heavily reliant on relatively inflexible large CCGT plants and semi-manual processes. The clunkiness and limitations of the current system operation processes has been highlighted by the industry and especially by flexibility providers who are seeking to enter the balancing market[10]. The result has been higher constraint management and balancing costs.

Higher balancing and operational costs could understandably produce a knee-jerk response to try to limit or corral the market. An example of this would be moves to make generators give a financially firm day ahead commitment, as most LMP markets do, or to limit intra-day trading by, for example, bringing forward gate closure. These options have come up in workshop discussions about how the market may respond unpredictably during the periods of oversupply and negative pricing which will become commonplace.

[10] See for example the Electricity Storage Network Open Letter to the ESO on the subject of skip rates and access to the BM. https://www.nationalgrideso.com/document/285011/download and ESO response https://www.nationalgrideso.com/document/285016/download

The negative price conundrum is a good example of the challenges REMA faces and the perceived opposition between operational efficiency and market dynamism. Clearly it is right to look at how subsidy schemes may be distorting market behaviour, producing an uneconomic response, but it is nevertheless true that when renewable energy is in abundance there will be commercial opportunities we want market participants to take advantage of, both to exploit the value of low cost energy and to ensure that the consumer benefits, even if this produces greater system balancing volatility.

While a sudden volume of GB electricity capacity coming back online during a (day ahead) negative price period, as occurred on 29th December 2022, may create forecasting problems for the system operator, it is not the result of a broken market per se, but could be the result of traders seizing an opportunity to trade GB energy into a higher value export market, a hydrogen electrolysis plant switching to higher production or an energy supply company promoting an agile tariff.

Rather than curtail the market, the answer to improve system operation requires two compatible approaches: a) to create and expand markets for operational and flexibility services that will provide the ESO with additional price-competitive tools to manage the system and b) to invest in building up the ESO forecasting, dispatch and balancing capability especially through IT, digitalisation, system modelling and automation.

Both of these approaches are on the ESO's agenda[11] and we are pleased to see that they are being given a priority focus.

Recommendation 3

The UK must adopt a clear plan for net zero delivery at both a national and regional/local level. This would then allow market reform to focus on how the energy markets can support and enable the delivery of strategic goals, including through investment support, rather than trying to develop market solutions that would somehow try to set goals and fill the gap in strategic planning. It is right to target areas of market distortion, for example those caused by subsidy schemes, but in looking for solutions the REMA team should consider those options that promote greater market efficiency, dynamism and innovation to exploit the value of renewable energy and flexibility.

A more dynamic market will create additional operational challenges but these should be met by enhancing and investing in system operation capability, and flexibility services, not by limiting or corralling the market as has been proposed.

[11] See ESO markets development strategy, enhancements to the BM local constraint management markets, and initiatives like the Control Room of the future digital twin etc.

4. A progressive reform agenda that targets the core REMA objectives

From the workshops and industry engagement there is an emerging reform agenda which would significantly improve and modernise the operation and efficiency of the GB energy markets. We believe that a package of innovative reforms could be aligned with the four core REMA objectives.

The exciting and positive outcome of the initial REMA consultation is that there are plenty of reform ideas and opportunities for the team to explore. The section below highlights some of the areas for reform that have been identified.

1) Investment to create a renewable based system at pace

The key enablers to create an attractive investment environment include the adoption of a strategy delivery plan for net zero linked to an industrial strategy and integrated infrastructure investment plans. Speeding up deployment and delivery through the approval and planning systems is also vital.

Market reforms within the scope of REMA can then be developed to ensure that there are sufficient investment incentives to support the deployment of renewables and investment in grid, storage, flexibility etc.

This will likely focus on enhancing the CfD mechanism for renewables and addressing some of the issues of price cannibalisation. Separate support arrangements will then need to be developed for low carbon dispatchable generation, storage and interconnectors.

Specific reforms could include:

a. Extension of the CfD mechanism to support greater levels of renewable investment
b. Changes to the CfD to reduce the risk of negative pricing and price cannibalisation e.g. consideration of revenue deeming
c. Changes to the Capacity Market to support investment in low carbon generation, storage and flexibility
d. New revenue support mechanisms to support long duration storage and dispatchable generation

2) Passing the value of lower cost renewables to the consumer

It is essential that the consumer sees real benefits from the increased deployment of lower cost renewables and that these are not retained as excess profits by generators, retailers and trading companies. A key part of this is to enable the procurement of energy on long term contracts that enable consumers to hedge against high price periods and exchange lower prices for greater generator revenue certainty.

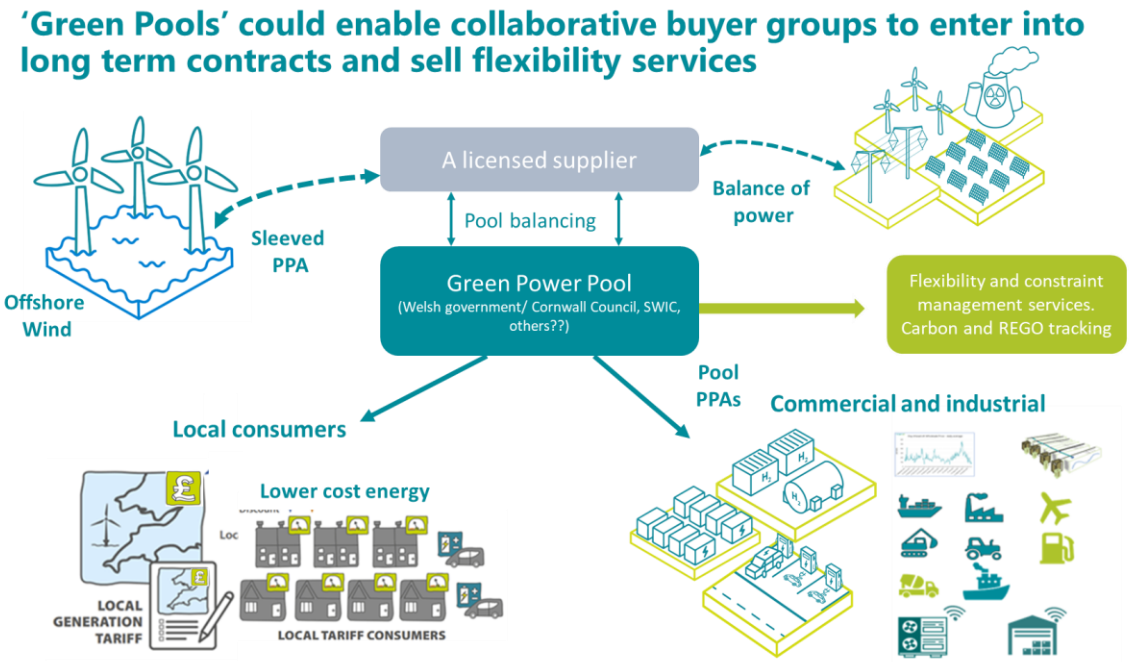
REMA options to ensure a fair value share with the consumer would include:

a) Expansion of the CfD mechanism for renewable generation which has an inbuilt value share via the negative CfD payment, and making this more transparent and auditable for the UK consumer.

b) Offering a form of CfD to existing generators to bring the RO scheme to a close. This was discussed at the start of the energy price crisis and could still be a viable and enduring alternative to the Electricity Revenue Levy which continues to damage UK investment.

c) Measures to support the greater use of long term PPAs including corporate PPAs and local supply agreements, which enable consumers trade with generators directly or via an electricity supplier.

d) Development and support for the creation of 'Green Pools' which can be used to establish collaborative procurement groups for local energy, industrial sectors, public sector and disadvantage/social tariffs.



e) Further support for community energy schemes and projects, including local generation, supply and energy efficiency schemes.

f) Continuing to expand consumer access to provide demand side flexibility services and agile tariffs.

3) Transitioning away from unabated fossil fuels to flexible, resilient, decarbonised electricity system

There are lots of areas of market reform that relate to the transition away from fossil fuels whilst maintaining the UK's energy security and resilience.

Some key areas for the REMA team to address include:

a) The future evolution of the Capacity Market so that it switches support to low carbon and flexibility solutions and especially provides support for hydrogen generation and CCUS. This could be facilitated by moving 'end-of-life' fossil fuel assets out of the CM and into a Strategic Reserve.
b) Adapting the Capacity Market to provide more value to assets that are low carbon and can provide more flexible and responsive system services – either by weighting the CM (via attributes), or establishing split auctions for different technology features/types.
c) Creating appropriate revenue support models for long duration storage and low carbon dispatchable generation. It is critical that these support models encourage appropriate generation behaviour and do not encourage higher marginal cost assets to behave as baseload generators, which would displace lower cost and lower carbon renewable generators.

4) Operating and optimising a renewable based system cost effectively.

Again there are plenty of options and opportunities for REMA, and aligned market development work being undertaken by the ESO and DSOs, to help improve the operability and cost effectiveness of the GB electricity system. The goal should be to support a far more dynamic and agile market, enabled by flexible and smart energy system.

Reforms and enhancements that have been highlighted include:

a) Reform of network charging (transmission and distribution) to send appropriate long term locational signals for generators, demand and flexibility providers[12].
b) The expansion and reform of the balancing mechanism to make far greater use of flexibility and more responsive assets – reducing the dependency on large CCGT plants.
c) Upgrade and investment in the control room and dispatch functions through process redesign, IT investment, automation, digitalisation and greater use of smart systems.
d) Creation, where appropriate, of new or extended flexibility markets, for example, development of local constraint management markets.
e) The role of interconnectors within the energy system should be an area of focus for the second consultation.
f) Dealing with the distortion and operability impacts within the existing markets, including during periods of oversupply and potential negative price periods. This should include the consideration of new approaches like CfD payments for deemed generation, if they can be shown to be cost effective.
g) Support for the ongoing development of the Future System Operator working with regional system planners and the development of Distribution System Operator functions.

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[12] See Regen paper https://www.regen.co.uk/publications/rema-insight-paper-improving-locational-signals-in-the-gb-electricity-markets/#:~:text=Regen's%20recommendations%3A&text=1.,considered%20as%20a%20key%20criteria.

Recommendation 4

Focus the next stage of REMA on a programme of far reaching and impactful reforms that build on the strengths of the GB market arrangements, are aligned with the core REMA objectives and which are aimed to create a dynamic and agile electricity market, enabled by a smart and flexible energy system

5. Continuing to develop REMA as a coherent and integrated package of reform

There is a risk in the current political environment that the REMA programme begins to dissipate and loses its cohesion and focus. This may be more of a risk if REMA results in a number of incremental reforms rather than one big-bang market change.

We would therefore suggest that the REMA team thinks carefully about the ongoing structure and governance arrangements for the programme. Industry colleagues we have spoken to have said that the recent Offshore Transmission Network Review (OTNR) had a good governance framework which could be used as a possible model.

Moving forward into the second round of consultation we would also suggest that the REMA team looks again at the scope of the programme and the interaction between REMA market reform and other key areas of policy development, including retail reform and the changes coming through grid investment and system planning. These must be closely aligned.

Regen will of course continue to work with and support the REMA team and would be very happy to contribute to the development of the REMA programme.

Kind regards,

Johnny Gowdy
Director, Regen

Appendix A:
Reasons not to continue with LMP as a REMA option

This section discusses the key areas of concern regarding LMP in more detail. They are as follows:

1. The increased in investment and development risk

LMP would significantly increase investment and project development risk for renewables, flexibility and other low carbon technologies.

The analysis of LMP to date has paid very little attention to these investment risks except to claim that there is little evidence for them or that they can be mitigated. The base case modelling to support LMP has narrowly defined the investment risk as a relatively small increase of half of one percent in the cost of capital. It is noted that the benefit case rapidly erodes if the cost of capital increase climbs to 1-2 percent, which is entirely possible in today's capital markets.

Regen, and many in the industry, believe that the investment risks are far greater and more profound. An increase in the cost of capital would be one likely outcome in an LMP market but we would also expect to see a reduction in project development activity as developers baulk at the prospect of spending millions in development costs without the certainty of a firm connection agreement, route to market or revenue stability. There is plenty of evidence highlighting that these factors are critical for investment, which is why developers are so keen to secure a grid connection and are concerned about the current connection queue. It is also why developers are willing to give up significant upside revenue to secure a CfD with revenue stability.

The risk impact of LMP is profound and, as well as constraint volume risk and price risk, generators would also face a dispatch risk – a shift to centralised dispatch driven by an algorithm which would be almost impossible to predict or to interrogate. This is analogous to the current tensions around the balancing mechanism and skip rates for flexibility providers.

We have found the claims that investment has proceeded in US and other markets with LMP to be extremely superficial[13]. Texas, for example, has managed to invest in onshore wind but this has been in spite of LMP and has had more to do with their strategic investment in grid capacity for wind and targeted support as part of the West Texas Competitive Renewable Energy Zone (CREZ).

It is significant that, more recently, Texas has struggled to secure investment for offshore wind with, amongst other physical factors, their LMP-based market being cited as one of the reasons. While other LMP markets have secured investment in offshore wind – both New York and New Jersey have an active offshore wind programme – that is because they have introduced market mitigation measures alongside LMP, including the mandated procurement of offshore wind by state utilities under long term PPA contracts and prices. Even these have been difficult to negotiate and subject to revision. The lesson from these markets is that renewable investment can be supported within LMP markets but only by bringing in comprehensive mitigation measures that unpick the main tenants of LMP in order to guarantee a revenue stream, and that these types of mitigation measures will become more difficult to implement as the proportion of renewable energy increases.

As others in the industry have highlighted, the treatment of investment risk within the LMP analysis has relied on examples from other energy systems. We know, however, that the level of risk associated with LMP will vary depending on the circumstances within those markets. This is also a key finding of the Strathclyde University study into LMP impacts.

- A market which is relatively static, with a low level of network constraints, spare capacity and low levels of variable and low marginal cost renewable energy and nuclear, will have a lower risk profile. Implementation risk is also lower if the current market already has centralised dispatch, a smaller number of generators and a single price pool arrangement, i.e. like GB twenty years ago.

- A market that is going through a rapid transformation of both generation and demand, with higher levels of network constraints, rapidly growing levels of renewable energy (and nuclear and interconnectors) and facing a programme of massive network upgrades, will have a higher risk profile. The GB market has the additional complication of having operated as a decentralised bilateral trading market for over twenty years, with significant volumes of generation and storage connected at distribution voltages.

[13] See Energy Systems Catapult https://es.catapult.org.uk/report/rema-international-learnings-on-investment-support-for-clean-electricity/
Also Michael Pollitt working paper https://www.eprg.group.cam.ac.uk/wp-content/uploads/2023/07/text-2318-revised-180723.pdf

Needless to say the GB market falls into the second higher risk category and even supporters of the theory of LMP have suggested that now is not the time to implement such market changes in the UK.

At a basic level the risk posed by LMP is not just that the cost of capital may increase by a few percent, but that investment and project development stops until those risks are removed.

LMP Potential risks would include:

Development risk	Increased risk and loss of value for developers who will no longer have a firm grid connection or ability to forecast future revenues.
Siting risk	Challenge to choose the best site given market uncertainty and the likelihood that the siting decisions of other developers, interconnectors, demand and grid construction will impact future revenues.
Price risk	Increased price volatility and the potential for a generator to experience very low prices due to competition in constrained areas.
Volume risk	Loss of revenue due to volume constraints.
Dispatch risk	In addition to volume risk – the additional risk that even in merit generation may not be dispatched because of the operation of centralised dispatch algorithms and processes. Similar to the current skip rates in the balancing mechanism.
Balancing risk	Increased risk and cost associated with imbalance trading because the ability of participants to manage their balance position is inhibited in an LMP market.
Market complexity	Developers we have spoken to, with experience in LMP markets, have emphasised how much more complex and costly it is to operate in an LMP market arrangement. Trading, especially across nodal areas, has higher transactional costs. Balancing carries a higher risk. Price prediction is more complex. There are tools and products available to deal with these issues but a) they will take time to develop in the UK and b) they are expensive and add to overall costs. A comment from one developer was that LMP markets tend to favour large generators with a portfolio of assets who can afford to pay the additional transactional and financial costs to trade and hedge their generation. Vertical integration between generation, trading and supply also becomes an advantage.

2. The cost benefit analysis for LMP is not credible

We have not yet seen Ofgem's full published report of the cost benefit analysis for LMP which has been modelled by FTI, but we have seen the high-level summary that was presented to industry stakeholders, and some of the numbers that have appeared in various media posts claiming tens of billions in cost savings.

Regen, along with many others in the industry, have fed back our concerns that this cost benefit analysis is not credible and that the modelling should not be described as a cost benefit analysis at all. It is, at best, an extremely theoretical and hypothetical modelling exercise which does not represent a likely outcome of either an LMP implementation or the continuation of the existing integrated market arrangements. It is also notable that recent modelling undertaken by Afrys have produced a much smaller cost benefit from LMP.

The limitations of the FTI modelling are numerous and we would be happy to go into these in more detail, but at a fundamental level:

i. The modelling claims to be a comparison of the outcome of an LMP-based market versus the existing market arrangements. In fact, the baseline market does not represent the current GB market but is based on a single price market, as existed in GB pre-2001 and, notably, in most other markets that made the move to LMP. This is not just a modelling simplification but overstates the benefits of LMP to squeeze out infra-marginal rent and also ignores the opportunities presented by the bilateral trading arrangements over multiple time periods within the GB market. A true counterfactual to LMP should be based on an enhanced and reformed GB trading market.

ii. The modelling claims to show the increase in constraint costs caused by the current market locational signals and how these are reduced under LMP. However, the modelled constraints are not driven by the current market but are a result of using a locational distribution of assets from the 'regional view' of the System Transformation and Leading the Way scenarios from FES 2021, which are not representative of real-life deployment plans and do not consider network capacity. These scenarios are then modelled against an incomplete and misaligned network investment plan as set out in NOA 7 with the addition of the first Holistic Network Design (HND1), which runs only to 2030. Hence the increase in constraint costs in the 2030s and beyond because neither HND1 or NOA have adequately modelled the net zero transition.

   It is clear that if we did build out generation assets without considering network capacity, and without an aligned network investment plan, then network constraints would increase. This did happen between 2015 and 2019, because of delays in network investment, but it is not the result of current market and is not how it is intended to work in the future as we shift towards spatial energy plans, regional system plans and a **Centralised Strategic Network Plan**.

iii. Constraint management costs have been extrapolated from the costs of constraints over the recent past. We would however highlight that constraint costs have jumped since 2021, not because of an increase in constraint volumes but because of the rise in the price of gas and the current dependency on the use of large CCGT plants to provide constraint and balancing services. See Figure 1. As has been well documented elsewhere there are huge opportunities to reduce constraint costs by improving the performance and functioning of the balancing mechanism and greater use of flexibility by, for example, greater use of local constraint markets as recommended in the recent Winser report. [14]

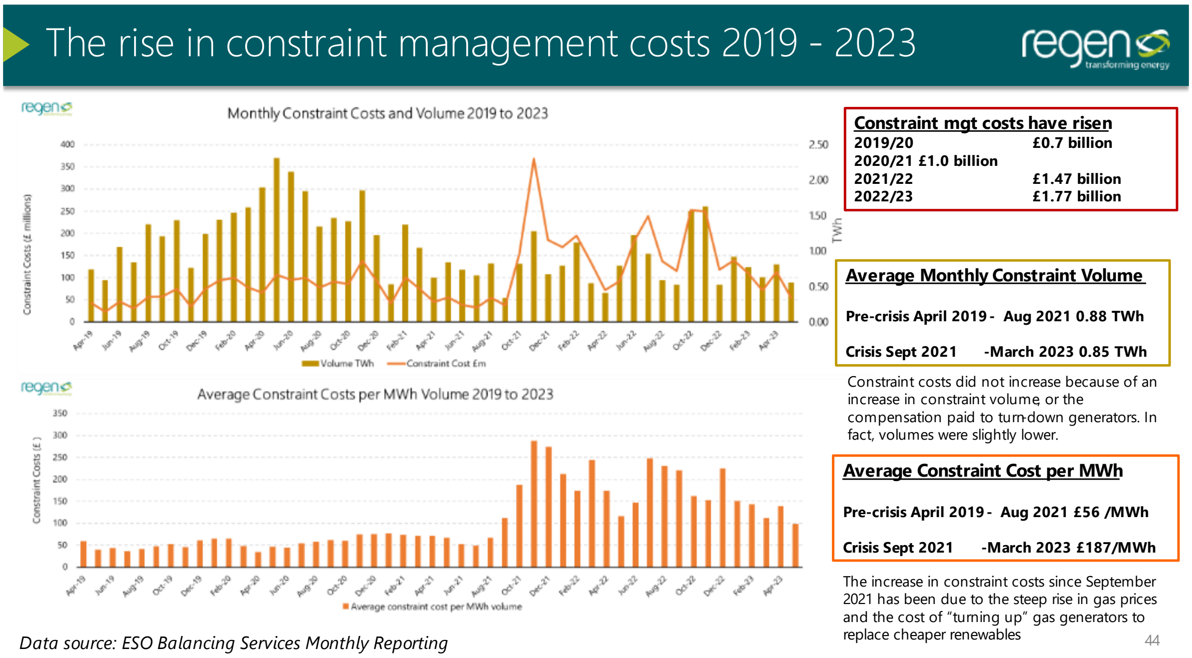

Figure 1 Rise of constraint management costs since 2021 have been due to the increase in gas generation prices and GB dependency on CCGT plants for balancing services

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[14] See also letter from Electricity Storage Network raising concerns about the speed of BM reform and continuing dependency on costly and inflexible CCGT plants https://www.nationalgrideso.com/document/285011/download and ESO response https://www.nationalgrideso.com/document/285016/download

3. The claimed ability of LMP to influence siting decisions is doubtful

A big part of the economic benefit case for LMP rests on its ability to send very strong price signals that would influence the location and siting of both generation and demand to optimise network utilisation and reduce constraint costs.

From the start of our discussions around LMP it has been highlighted that the evidence suggesting marginal price signals can determine, or even impact, long term investment decisions is extremely weak. It takes 8 to 10 years to develop a new offshore wind farm, longer for nuclear and not much less for onshore wind. Major transmission projects currently take 12-14 years, although there is now a desire to reduce this by half.

The key point is that marginal price signals, giving a snapshot of current locational supply/demand balances and constraints, can only send a very limited, and potentially incorrect, signal for long term investments. As we discuss in Regen's Locational Signals paper, these constraint-based signals are already given via the connection queue, lead times and network heat maps.

When we look at the major technologies that are needed to achieve net zero it is clear that investment decisions and asset siting will be much more driven by spatial and energy system planning, whether this is via offshore wind leasing rounds or a more comprehensive Strategic Spatial Energy Plan as recommended by Winser. National plans can then be backed up by regional system plans and Local Area Energy Plans.

Would we even want developers to make future investment decisions based on short-run marginal price signals? The LMP price signal may be strong and volatile, but does it represent anything other than the current state of network investment?

A more appropriate economic cost signal can be delivered by a reform of the current network charging methodologies. As our locational paper highlights, a charging methodology for network charging (including TNUoS) that provides a long term, cost reflective, dependable and predictable signal of future network charges would provide an appropriate economic signal for future investment. Future charges need to consider both the cost of the expansion of network capacity AND the greater utilisation of the network as electricity generation and demand grows.

4. The operational efficiency ascribed to LMP could be challenged, and may be achievable within the current market arrangements

It is a commonly held view that LMP would improve the efficiency of operational dispatch.

LMP, it is claimed, would produce a more efficient dispatch outcome because the algorithm would, in near real time, simultaneously optimise the cost of energy merit order (assuming marginal cost bidding), transmission losses, operability, physical network constraints and balancing. It would therefore produce a better systems outcome than the current decentralised market led dispatch with a balancing mechanism for redispatch, constraint management and operability markets.

Supporters of LMP have highlighted the increased volume of redispatch which needs to be undertaken by the system operator as evidence that the current model is not working.

It has been difficult to argue against these assertions since we haven't yet seen what an LMP dispatch process would look like and how it would actually work. This is one of the current design gaps. We need to be careful here not to confuse the operational efficiency of a central dispatch process and the efficiency of the market. We are also entering into the world of modelling where perfect forecast models can produce impressive results, which would not necessarily be attained in the real world

As professor Michael Pollitt comments in his recent paper on LMP:

"We conclude that while the theory and modelling behind LMPs is strong, their wider theoretical rationale is less clear cut and the evidence on their impact in use is surprisingly weak."

In most LMP markets, central dispatch is operated as a three stage process with:

1. A mandated day ahead LMP market were market participants must make a financially binding schedule of commitments for the sale and purchase of energy, like today's final physical notification. This aids operational planning.
2. An intraday LMP market where market participants can adjust their day ahead commitment, usually with some form of adjustment cost/trade such as a 'buy-out' arrangement.
3. Real-time LMP dispatch run by the system operator using an optimisation algorithm.

This type of market arrangement would, in theory, make it easier for system operation and dispatch functions, and especially the efficient use of dispatchable generation.

However, there are a number of questions which need to be addressed:

- Would a centralised dispatch arrangement inhibit or otherwise reduce the benefits that GB has gained through a liberalised bilateral trading market?

- Would a day ahead firm commitment increase balancing risk for generators and suppliers? Will the risk of forecast errors increase?
- How would the LMP algorithm perform with very high levels of zero marginal cost renewables and nuclear?
- How will the thousands of distribution-connected generation and storage assets be handled? Would they continue to self-dispatch or be centrally dispatched?
- How clear and auditable will dispatch processes be, given the challenges that have been raised to the ESO about the performance of the balancing mechanism?

A number of industry representatives we have spoken to have suggested that the outcome from an LMP-based centralised dispatch process may “not look much different to today’s” dispatch process and would be subject to many of the same challenges, for example, there is still a need for balancing. It may make it easier to dispatch fossil fuel generation in a more timely way, whether this is considered a good thing remains an open question. Several have questioned how the dispatch process would work given high levels of renewable energy and the significant volumes of distribution-connected renewable capacity.

Regen, and others, have argued that the inefficiencies in today’s dispatch processes (e.g. the high skip rates whereby higher cost CCGT plants are used ahead of lower cost storage and flexibility) are mainly due to process, IT and resource limitations within the existing dispatch and control room functions. We therefore very much support the steps that are currently being taken by the ESO and Ofgem to improve the function of the balancing mechanism and dispatch processes.

5. The consumer benefit ascribed to LMP is mainly a value transfer

Putting aside the questionable benefits that could be ascribed to project re-siting and more efficient dispatch processes, the remaining consumer benefits which have been modelled as part of the LMP benefit case are in fact value transfers from generators to the consumer and/or system operator[15]. These include the removal of constraint payments and the squeezing out of infra-marginal rents, the 'Producer Surplus' as it is described in the FTI modelling.

There may well be a case that REMA reform should tackle the issue of generation profits to ensure that the value of lower cost renewable energy is passed through to the consumer, but there are better ways to do this while at the same time maintaining investor confidence.

The two most obvious ways to do this would be to:

A) Extend the use of CfDs which have a built-in payback to the consumer during high wholesale price periods – potentially offering a CfD-type scheme to existing renewable generators. The use of a revenue Cap and Floor would also achieve a similar outcome owing to the revenue cap.

B) Encourage greater use of long term supply agreements by developing the PPA market, encouraging more supply companies and larger consumers (including corporate and public sector) to buy electricity on a long term contract terms which would move prices closer to a long run average or LCOE price. The idea of creating 'Green Power Pools' could also support this.

The third option, which we are not recommending, would be to continue with a form of windfall tax like the current Electricity Generation Levy. This is less attractive for investors, but if the objective is simply to move value from the generator to the consumer this would be a lot easier to implement and less disruptive than LMP.

Behind the high-level LMP modelling numbers there are very extreme shifts in value between generation and the consumer and/or system operator. Generators who find themselves in a disadvantaged position, owing to network constraints that are outside their control, would lose significant value.

This brutal reality has been downplayed in the discussions to date and somewhat passed off with a flippant comment that there will be 'winners and losers', but in fact many projects may find their revenue significantly eroded to the point they would no longer be viable. These projects

[15] Depending on the LMP design consumers will, on average, pay more for wholesale electricity while the LMP-based market creates substantial 'congestion rents' which are initially captured by the SO. There is then a question of how these congestion rents are distributed between consumers, generators and/or used to pay for the operation of the LMP system.

would surely demand, and be justified, compensation based on their existing connection contract terms.

The question, and cost, of grandfathering existing projects that will have firm connection agreements has not been addressed. It should be noted that many projects connected at the distribution network will not only have a firm connection agreement, they will also have paid an additional connection charge to pay for the necessary grid upgrades to provide them with a guaranteed capacity. These projects would certainly challenge the removal of their connection rights.

Future modelling needs to show not just the overall shift in value from generation, but how this is distributed across projects and the impact this would have on their financial viability. Modelling must also address the question of how much value transfer is coming from existing connection rights holders and how this would be compensated for.

6. Mitigation measures would unpick much of the LMP value transfer

During LMP workshop presentations it has been said that the increased risks of LMP would be mitigated for new generation projects through, for example, continuation of the CfD scheme or other forms of revenue support such as RAB (for nuclear) and/or Cap and Floor models.

It is not clear however how a CfD scheme would work in an LMP market: this is one of several major design gaps. Modelling to date has assumed that CfD reference prices would be set at a nodal or zonal level which would provide a price risk mitigation, but not necessarily a full volume mitigation for constraint and dispatch risks – which would then lead to higher CfD prices.

Setting CfD reference prices at a nodal level is however extremely problematic and would create further issues in relation to:

- A discriminatory value transfer between consumer groups with some consumers potentially enjoying lower costs of electricity which is being subsidised (via the CfD) by other consumers in high price areas.
- CfD auction processes which would be extremely difficult to compare, budget and manage.
- Potential wholesale price gaming by CfD holders.

Our conclusion, which is shared by many in the industry we have spoken to, is that the entire CfD approach would need to be redesigned in an LMP-based market. This additional layer of risk, change and complexity has not been factored into LMP costs and implementation timescales.

Putting aside the complexity of redesigning existing revenue support models, there remains an inherent contradiction between trying to implement an LMP-based model while at the same time trying to provide increased revenue certainty for investors: the risk created by the new market adds to the risk mitigation that is required and the value transfers created by LMP would then need to be unpicked via other forms of revenue payments and compensation. If done fully this would largely negate the rationale for LMP.

7. The consumer impacts of LMP are uncertain and unfair, and have not been communicated

Proponents of LMP have presented nodal and zonal markets as being more cost reflective and of promoting the value of local energy generation.

In fact this is misleading, the LMP **represents the short run marginal cost of production (MCP) to meet demand at a certain location. The extent to which the LMP price is 'local' (i.e. reflects local MCP) depends on the level of network constraint.** If there is no local network constraint, then the LMP price will not be local – however one defines local. This is an important point to communicate – the attribute of localness is really about constraint not location or proximity.

The winners and losers amongst consumer groups impacted by LMP would be determined by the level of network constraint and whether this is a generation constraint (leading to lower LMP prices) or a demand constraint (leading to higher LMP prices).

Although in a theoretical LMP model it is assumed that consumers may move to areas with lower energy costs, for the vast majority of consumers this is not a realistic option. Hence it is said that the impact of LMP on consumers would be arbitrary and outside of their control.

Alongside constraints, the degree of market liquidity will also play a key role. If there is a high level of competition amongst generators in a generation-constrained area, this will tend to drive down LMP prices, in theory to the marginal cost of production – which could well be zero in high renewable areas. By contrast, if there is less competition in demand constrained areas this would tend to drive up prices to levels that are well above generators' marginal costs. The impact of liquidity leading to above marginal cost pricing has not been modelled but is extremely likely, as we have already seen in the current balancing mechanism.

A further factor adding to the arbitrariness and perceived unfairness of LMP is that the occurrence of constraints, and more broadly supply/demand balances, is expected to change rapidly over the course of the energy transition. Locations enjoying cheaper electricity today may find that position reversed as new network infrastructure is added, and as generation and demand patterns change. This may itself lead to unintended consequences, e.g. consumers campaigning against grid investment in generation areas on the basis that it may in fact lead to higher energy costs for their location.

Consumer advocacy groups such as Citizens Advice and Sustainability First[16] have looked at the consumer impacts of LMP. A report by Citizens Advice[17], while not against LMP in principle, does make an assumption that consumer impacts would be mitigated and that there would need to be a degree of price levelling between different locations. While this may be a reasonable assumption – many LMP markets have introduced measures to protect consumers from LMP price differences –it does beg the question whether it is worth implementing a market design which is then not applied to demand.

A further question, which is identified by Citizens Advice, is where the LMP price risk then sits if consumers are themselves protected. At the moment there is an assumption that the retail market would absorb any additional price or balancing risk introduced by LMP. This may be the case but it would then lead to higher retail tariffs. More broadly the whole question of how LMP with impact the retail sector and the relationship between retail suppliers and consumers has not been addressed and remains a significant design gap.

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[16] Sustainability First
https://www.sustainabilityfirst.org.uk/images/Ofgem_Call_for_Input_on_Locational_Pricing_240622.pdf
[17] Citizens Advice https://www.citizensadvice.org.uk/about-us/our-work/policy/policy-research-topics/energy-policy-research-and-consultation-responses/energy-policy-research/its-all-about-location-will-changing-the-way-we-price-electricity-deliver-for-consumers/

8. The cost, timescales and implementation risk have been underestimated

Concerns about the cost and timescales have been raised on several occasions. It is fair to say that the work to date has only addressed these issues at a superficial level with reference to the time taken to implement LMP in other markets. This has led to a ballpark estimate of around 5-7 years and a cost estimate of around £500 million.

We do not believe that either of these figures is credible. International comparisons can be misleading since markets which have made the transition to LMP have typically moved from a relatively simple single pool market that already has centralised dispatch, to an LMP market. The GB market is significantly more complex, with an ecosystem of existing contracts and trading arrangements – GB is also far more integrated with neighbouring markets than the typical LMP markets in the US.

In addition to the complexity of the GB market it must also be considered that GB is already in the midst of an energy transition with far more generators, storage providers and market participants than would have been the case twenty years ago d. Each of these market participants would have to either exit the market, or incur costs to adapt their contracts, processes and systems to operate in an LMP market arrangement.

The enormity of the change should not be underestimated. To give just one example, if the GB market was to include the use of Financial Transmission Rights (FTRs), this would require setting up a new trading market for billions of pounds worth of financial transactions. In most LMP markets this would be administered by the System Operator or an agency set up for the purpose. The GB ESO is already going through a significant change programme as it takes on the responsibilities of a Future System Operator (FSO), adding new trading functions and LMP market administration on top of already packed change agenda would be highly risky.

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