



Energy Security and Net Zero Committee

Oral evidence: [Reviewing the electricity market](#), HC 232

Wednesday 24 June 2026

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[Watch the meeting](#)

Members present: Bill Esterson (Chair); Graeme Downie; Melanie Onn; Claire Young.

Questions 1-78

Witnesses

[I](#): Chris Matson, Partner, LCP Delta; Tom Luff, Energy Strategy and Policy Expert, Energy Systems Catapult; and Katrina Salmon, Research Fellow, UCL Centre for Net Zero Market Design.

[II](#): Jason Mann, Senior Managing Director, FTI Consulting; Helen White, Head of Commercial Asset Management, Ocean Winds UK; and Rob Gross, Director, UK Energy Research Centre (UKERC).

Written evidence from witnesses:

- [Energy Systems Catapult](#)
- [UCL Centre for Net Zero Market Design](#)
- [FTI Consulting](#)
- [Ocean Winds UK](#)

Examination of witnesses

Witnesses: Chris Matson, Tom Luff and Katrina Salmon.

Q1 Chair: Welcome to this morning's session of the Energy Security and Net Zero Select Committee and the start of our inquiry into reviewing the electricity market. Welcome to our first panel; please introduce yourselves.

Tom Luff: I am Tom Luff, and I am the head of policy and business model innovation in the Energy Systems Catapult.

Chris Matson: I am Chris Matson and I am a partner at LCP Delta, where I lead our power-market modelling work.

Katrina Salmon: I am Katrina Salmon. I am a research fellow at University College London in the Centre for Net Zero Market Design.

Q2 Chair: Thank you. You are all very welcome. We are looking forward to hearing your evidence in this keenly anticipated inquiry. It is very timely, given many things that are happening, not just in the UK but around the world, and we will come to the impact of events in Iran during our discussions.

We have had lots of people telling us that the electricity market is not designed to meet today's systems needs, particularly the shift from fossil fuels to renewables generation. Chris, can you start by telling us what the market was originally designed to deliver, and who was it designed for? Was it designed for industry, consumers or investors—all of those, some of those or none of those?

Chris Matson: I think it was designed for all of those. The context is that the system was very different from what it is now. You had relatively few large thermal generators, predominantly coal and gas, that were able to generate essentially as required to meet a relatively predictable demand profile. That generation tended to be located relatively close to demand, and often close to coal mines and those sorts of things as well. It was designed to ensure that the lights were kept on, enough investment was placed in those sorts of power stations and they were getting the required return on investment.

We are moving to a world now where the system looks extremely different. You have lots of intermittent renewables being built, often a long way from demand—where it is particularly windy is often a very long way from demand. A system that ensures that those assets are built in the right places and that enough of them are built is a very different one to what the original system was designed for.

The other thing is that we are looking to roughly double the size of the power system over the next 20 to 25 years as we head to net zero, as the wider economy electrifies, so lots of stuff needs to get built, and built in places that are a long way from demand. So there is a need to make sure that investment is efficient, that the system operates efficiently and that the right things are generating at the right time.

Q3 Chair: Thank you very much. Tom, to what extent is the current market design fit for today's objectives, including decarbonisation, energy security and affordability? Also, can you tell us what the shortcomings are?

Tom Luff: Building on what Chris was saying, I think a big change or a big difference between then and now is that we now have lots of renewables that are intermittent. The implication of that is about controllability and flexibility, but alongside that we also have a very different type of demand coming up, which is a controllable, flexible demand in the form of lots of electric vehicles and batteries and so on.

On your question, prices are high—they are too high—and part of the reason for that is inefficiencies in the system. It is undeniable that renewable energy is coming on to the system really fast and it is a great thing, and costs are coming down, but we are not integrating it as well as we could. Inherent in a renewable system is the need to better match when and where the electricity is produced with when and where it is actually used.

The problem is that the market and the system has not caught up with that reality, so there are shortcomings in the market. The signals and incentives are not providing the right incentives for as much efficiency as we could get. Also, if we can get those signals better, we could unlock innovation, which ultimately can drive better solutions and drive down costs for consumers.

Q4 Chair: Thank you very much, Tom. I think that sets out very well the areas we will explore over the next 50 minutes or so. I am tempted to ask you straight away whether you can spell out what needs to be done to better match the when and the where, but we will pick that up later. Before we do, I mentioned the Iran crisis in my opening comment, Katrina; to what extent do external pressures, whether around Iran, Ukraine or other geopolitical activities, strengthen the case for reform?

Katrina Salmon: We have had a good explanation of what is starting to go wrong in the system, and I think there is a growing consensus that the current system is not working. We see that in rising constraint costs and consumer costs. However, the problem is that we do not entirely know yet how bad things will get, which makes it very difficult to argue for when we need reform and how quickly we need it. There is growing consensus that we are moving from about 10 GW of operational CfDs to over 50 GW in the next four years. We really don't understand what that will do to the system and we don't know yet how the market will look. We do not have a vision of what the market will look like when we get to net zero.

Not having an understanding of where we are going and what we are aiming for means that we ultimately are very reactive. Every time there is a new crisis, there is the gut instinct to respond very quickly with something that is often a quick fix or a patch, which the system is full of, but we do not necessarily know the implications of those patches or how long they will be needed in the system. We end up in a situation where

we might be adding loads of patches on top of patches, which we might have to unwind in the next few years if we are able to conduct more significant market reform. It is that inefficiency that defines the system currently.

Q5 **Chair:** Would it be fair to say that your advice up front is to take the time to get the reform right?

Katrina Salmon indicated assent.

Q6 **Chair:** That is very helpful; thank you very much. Tom, why was REMA delayed, and what has been the impact of the delays?

Tom Luff: Why was REMA delayed? First, it was a really important bit of work, and we in the Energy Systems Catapult pushed for a long time to have a more fundamental look at how the market works. I think the analysis in the initial publication was really good. They got to the heart of what the problems were and when they consulted, I think 80% of respondents said the current system is not fit for purpose. They were talking about 2035 at that point, but it is not fit for decarbonising the electricity system. There was a real consensus there.

I think where it fell down, or rather, not fell down but got delayed, was in trying to bring the various different stakeholders on board and come to a consensus. That is very difficult. They were balancing some really big trade-offs. Ultimately, I would call them costs to consumers versus cost of capital, but ultimately you could argue that the cost of capital gets put back on to consumers. That big trade-off was hard, and it therefore took a long time for them to work out what they thought the right solution would be.

Q7 **Chair:** Okay; thank you. Katrina, going back to your earlier point, is there ever a perfect moment when we can implement reform?

Katrina Salmon: I think the answer is no. I know that some analysis was done during the REMA process that said that if we wait until we get to clean power 2030, and we build a lot of the transmission that has been lagging, there will be this moment where we can pause and afford to potentially disrupt investment slightly and undertake more significant reform. However, if you look at the NESO scenarios, there is not some perfect moment when everything is in harmony, we have everything we need and we can afford to massively disrupt the system.

If anything, REMA has taught us that reform needs to bring everybody along, and maybe it needs to be more incremental and gradual to ensure that all the stakeholders are aligned, or at least aligned as much as possible. The idea that you will get some perfect moment when you can do all this reform is just flawed. The problem is that if we had a current system that worked really well, you could afford to sit and wait, but we don't, so the idea that you can simply wait means that you have mounting problems in the current system, with costs associated with that.

Q8 **Chair:** Chris, what is your sense of the learnings from the REMA process?



Chris Matson: I have worked in the UK electricity sector for 14 years, and I think this was the single decision that had the most debate, the most consultation, the most analysis associated with it. You could argue that is a good thing, because they were making a major decision on whether to go with zonal pricing or not, assuming that that is the key decision that was made under REMA, so I would not necessarily call that a failure. These sorts of things are always going to be delayed, but these are important decisions. Although there is no perfect time to make these sorts of reforms, this was a very important time to make that crucial decision. We are looking at huge amounts of investment required over the next five years to reach the clean power 2030 target. To get that decision wrong more quickly would have been much more costly than the delays we saw.

Q9 **Claire Young:** As if we don't have enough heat in the room already, I am going to go into more depth on the question of LMP versus RNP. Tom, given that other countries have adopted locational pricing, why has the UK chosen not to implement it?

Tom Luff: You are right that lots of countries have adopted locational pricing. To be clear, there are two types broadly: a nodal type, which is where you get really granular, so maybe 1,000 nodes across the country, maybe more; and zonal, where you have regions, perhaps 12 or so in the UK. Around the world, a lot of major economies have one of those two systems—for example, most of the states in America, New Zealand, Singapore and other countries. On the zonal side, you have some European countries, including in Scandinavia. It is a very established thing and more and more countries are moving that way. Ontario recently, I think last year, shifted over to nodal pricing.

One of the main reasons put forward for why we did not—because I think all the analysis was pointing towards it being the right thing to do eventually—was that we had a real urgency to deliver renewables. We have a 2030 target; heads down, let's just deliver that. The 2030 target has been really great in galvanising support for building renewables and also hopefully building the grid. The thing we have to look out for is whether it is putting off decisions—a bit like Katrina was saying—that would be better for the longer term and, crucially, thinking about whether we are bringing the demand side along with the supply side. We are getting lots of great renewables built; are we getting the flexible demand, such as EVs and potentially heat pumps, to go alongside that to make the system work well?

Q10 **Claire Young:** Katrina, does LMP only provide theoretical benefits? In practice, you can use things like a strategic plan to deliver energy production in the right place.

Katrina Salmon: I am not necessarily the best-placed person to answer that. My team did not conduct analysis on the impact of zonal, so I cannot speak to what it would have looked like in practice. But it is important to note your initial framing of RNP versus LMP. It is important to remember that while that is the context we are sitting in now, at the

time the decision was made, we did not really know what RNP was. It took DESNZ nine months after the decision was made to come out with a delivery plan for what RNP would look like. The July update from last year was very high-level. The point is that it is unclear what the counterfactual was—what DESNZ was evaluating LMP against to say, “We think something else is going to be better than LMP,” or, “LMP’s costs are significantly higher than what else?” We have not seen the cost-benefit analysis that DESNZ used that was promised to be announced last July.

As Tom said, there are many ways that countries have implemented nodal and zonal pricing that have been successful. There are probably ways that would have been true in the UK too, and I am sure there are ways that would not have been as well. It would all come down to the design of the precise market and the way that DESNZ, had it chosen to do it, would have implemented it.

- Q11 **Claire Young:** On investor confidence and so on, you are concerned about the delay that happened, but we still do not know what they were evaluating against.

Katrina Salmon: No.

- Q12 **Claire Young:** Chris, is there a case for revisiting LMP later, or has the window now closed and it is not going to be practical to introduce it?

Chris Matson: It depends on what you mean by later, but right now I don’t think it would be a good idea. The last thing the industry needs now is to reopen the zonal debate. A huge amount of consultation, analysis and debate went into that debate. I think what we need to do now is get on with building things. Any re-litigation of that zonal decision would inevitably take time and inevitably result in delays to investment, potentially even cancellations of investment, or capital moving from the UK to other markets.

- Q13 **Claire Young:** Are we at risk of doing things now that will preclude moving to LMP later?

Chris Matson: There is always a possibility in the future of going back to it, but in my personal opinion, on balance, the decision not to go ahead with zonal pricing was the correct one. I think the risks and the costs outweighed the benefits. I am not saying that there are not theoretical or efficiency benefits to be gained by having a zonal market, but at the moment that decision was being made, the real focus needed to be on instilling confidence in investors to deploy a huge amount of capital into the UK power sector.

- Q14 **Claire Young:** How can you make that assessment if, as Katrina says, we do not actually know what the counterfactual is—we don’t have the details of it?

Chris Matson: We did some analysis for DESNZ that looked at the system benefits and consumer benefits of zonal pricing. We had to run different scenarios on what that counterfactual was and how efficient you can get a national market to be.



There are two reasons why you would move to zonal pricing. One is investment efficiency, so providing the right signals to investors of where to locate. I believe that can more or less be provided, potentially more effectively, through network charges. One of the problems with having zonal pricing as an investment signal is that you have to be able to predict what your zonal prices will be over the 30 years of your asset being online, which is extremely hard to do.

I think the better argument in favour of zonal pricing is the operational efficiency, which is the fact that you need to make sure the right things are generating at the right times. At the moment, it is very difficult for NESO having to redispatch everything after the national market takes place to be 100% efficient, particularly with respect to interconnectors—the connections to other countries. It is very hard to have arrangements in place to redispatch those very close to real time.

Overall, I think there are potential reforms that can improve both those areas.

Q15 Claire Young: What are those potential reforms, briefly?

Chris Matson: We have a network charge at the moment, which is an investment signal for locational decisions with TNUoS. I think there are some obvious flaws in the way that TNUoS is set up, but there is no reason why we cannot improve that and basically make it more predictable, more cost-reflective, and in many ways a locational signal would be more effective, in my view, than zonal pricing.

The operational efficiency is a bigger challenge. You are trying to do two things there. One is that you are trying to make sure the right things ultimately generate. The second is that you are trying to make sure the consumer is not paying a huge amount of money to get you to that situation. At the moment, NESO is having to do a lot of that redispatch, very close to delivery. Moving some of that to earlier in the day would potentially save costs by allowing access to cheaper options.

Q16 Claire Young: Tom, do you think RNP will incentivise the investment in infrastructure that we need? What will it mean for consumers?

Tom Luff: There are some good things in RNP and I do not want to relitigate the zonal debate again. I don't think any of us has the emotional energy for it. I do not think we have solved all the problems. We have some really sensible incremental changes, and I think you would do most of them anyway—they are no-brainers, making things more efficient—but there is a value in saying that we need a date in the future when we will say, "This is our vision for where we want to get to and when," so that we can all try to align stakeholders and avoid the same situation where, in five or three or two years, we get desperate and say, "Right, we just have to do it straight away," and again have this big debate and perhaps put a dent on investor confidence because it is done too quickly. Having a clear sense of where we are trying to get to by when, and a route to get there, would be really sensible.

Q17 Claire Young: Katrina, is RNP a mañana policy, or will it deliver

meaningful outcomes by 2030?

Katrina Salmon: To the investor confidence point, I think that RNP can deliver potentially well for big assets—for the large wind farms—but it is not clear what will happen to smaller assets in respect of flexibility, and whether they will get appropriate signals.

On the operational side, we hosted a large workshop in the fall with about 60 different stakeholders from across the energy industry, and we discussed what we knew about RNP at that point. I don't think there was a single person in the room who had a brilliant idea about how to improve operational signals without locational pricing, and we have not seen anything out of RNP yet that would send clear operational signals. The balancing reforms are about giving NESO greater ability to operate the system, which is not the same as sending those signals to generators.

On the question of whether RNP is a mañana policy, it is my understanding that part of why REMA was rejected was the question of deliverability. Was it going to be possible to deliver in the system? Would you really get the benefits that had been modelled? But I think there is a risk that we are underestimating how difficult RNP is to implement. As Chris said, there are issues with TNUoS currently, but reforming TNUoS is an incredibly difficult proposition, and not one that Ofgem plans to be able to tackle before 2029.

There is a risk that maybe we have not learned enough from what went wrong in REMA to be able to correct and ensure that RNP is deliverable on the timescale that is needed and deliver a significant benefit for consumers. The investment-inciting component is anticipated to deliver a reduction in bills of £20 to £40 per household by 2040, and I think that is frankly too little, too late.

Tom Luff: I will add one thing to bring to life the operational signal thing, because sometimes we use that and it is not always intuitive. Let's say you have a really windy day up in Scotland, and lots of wind comes on the system and it drives down the price of electricity across the whole of GB. I am in London. I don't have an EV but if I did, I think, "Okay, great, prices are cheap, I am going to charge my car now," but the electricity cannot get down. What happens is you put on a gas-fired power station down in the south so that my neighbours and I can charge our cars. At the same time, because electricity is cheap, we are exporting it to France in the south, making even more need for gas in the south. That operational challenge is a really big one.

Q18 **Chair:** Thank you very much. You have all touched on the difficulties and, one way or another, all of you have made the point that in the end we are trying to make life easier for consumers. We are trying to get to the bottom of what that might look like, so what do you all think should be in RNP to make life better for consumers? I will start with Katrina—sorry.

Katrina Salmon: Not a simple question.

Chair: No pressure.

Katrina Salmon: A bunch of electricity nerds in a room could debate for hours what the specific here and there of RNP could be and should be, but I think what is important is some of the things that we have lost from REMA. For example, REMA looks really clearly at CfDs and the growing challenges that we would begin to encounter with CfDs, but we have not seen anything happen on CfDs. We have been using very much a similar design to before REMA and there is not a clear timeline for when we might see reform to CfDs. So I think in some ways—

Q19 **Chair:** I am sorry to interrupt, but how would that work? What difference would that make?

Katrina Salmon: There are ways that we could send better operational signals to CfD assets by reforming the CfD scheme. You could also send better locational sighting signals through the CfD itself rather than broader system reform.

Q20 **Chair:** I am trying to get it so that it is understandable to not just those of us in the room who do not have your levels of technical expertise but to the public who definitely do not have levels of technical expertise. Is there a way of explaining what you just said about the redesign of CfDs?

Katrina Salmon: One of the main challenges of CfDs is that they do not send a sighting signal and are not intended to. We build CfD-supported assets in the areas that are sunniest and windiest, which has been okay up to now, but we have had increasing issues where we have transmission constraints.

Chair: It is about putting generation closer to demand.

Katrina Salmon: You could incentivise generation to locate in areas that are better for the grid, where we have more ability to transport that power, so we do not end up turning on as much gas to charge EVs in London.

But perhaps the bigger issue is that CfDs incentivise generators to bid into the market in the same way. Everybody is trying to make sure that when NESO closes the market, they are chosen to generate, and they often bid zero prices or negative prices to ensure that they are selected, because their CfD then makes them whole at the end of the day. If you have growing volumes of generators doing that, we start to lose market signals within the actual system. That then means you do not necessarily have appropriate signals for flexibility to operate in the right way, or you start to lose more investment signals within the market, creating greater need for the Government to intervene and support other types of generation that is not seeing an appropriate investment signal through the market itself, creating greater and greater need for intervention.

My point is essentially that the narrowed scope of RNP is understandable, but there are other parts of the system that have been lost along the way that we need to be paying attention to as well.

Q21 **Chair:** Okay; thank you for that. Chris, when you were talking before about designing a system that minimises cost to consumers, did you

mean CfDs or something else?

Chris Matson: I think best way to bring down consumer bills is to build more renewables, and that is from two perspectives. One is to bring down the actual cost of the bills that you would expect to see in an average year but, extremely importantly, what happens in a bad year? At the moment, as we are all seeing with the Iran crisis and the Ukraine crisis before that, consumers are very exposed to international gas prices. The best way of reducing that exposure is through building more renewables, and the best way of building more renewables is through something like a CfD scheme.

The wholesale CfD that is being proposed is another good policy tool. I don't think that is technically part of RNP, but that takes some of your existing renewables and nuclear and other plants and puts them on a similar fixed-price contract, which would further protect consumers against gas price shocks.

Q22 **Chair:** Tom?

Tom Luff: I could be here all day, but I will try to be brief.

Chair: We have time.

Tom Luff: One of the exciting things I saw as part of the reform package was something called demand turn-up. This is where there is a lot of electricity, a lot of wind, for example, on the system that cannot be used. Instead of just paying it to turn off, you are giving cheaper electricity in those places. It is just a trial, but that means those consumers directly can get cheaper electricity. That is really exciting. I would love to see it scaling out much more across the country and making more competition. Rather than just paying generators to turn off, we should find other ways of using that electricity really well.

A slightly geeky thing, but I think important, is the settlement time. There is a proposal to reduce settlement time from 30 minutes to five minutes. It sounds very dry, but all that means is you are just making sure that at any time, or much more like any time, you are using the right things. If suddenly you do not have so much wind, then it is a time to use batteries, but you do not wait for that half an hour.

I am going to cheekily squeeze this into the package: levy rebalancing and taking some of the levies off bills. I know you have heard a lot about this in previous hearings, but it seems like that is the single biggest thing you could do with a stroke of a pen. Obviously that has implications for the Government's balance sheet, but that would be really good as a progressive consumer-focused policy.

There is a bunch of other things that I think are beyond this, particularly on networks and retail, but maybe we can come back to that.

Q23 **Chair:** That is very helpful. Katrina, on what you were saying about CfDs, do there need to be better rules for how companies bid into the CfD market? Is that what you were hinting at? We have heard about CfD operators gaming the system, which is potentially some of what you were



describing.

Katrina Salmon: Our focus is on what happens once the CfDs are live and the gaming or strategic bidding that happens then. It does not necessarily violate rules—it is what an economist would expect a CfD holder to do—but it has knock-on effects for the market. I can't speak to what happens in the auction process. My understanding is that it is suitable.

Q24 **Chair:** Tom?

Tom Luff: I will not comment specifically on the rules, but I think one of the challenges is if you have a real need to get lots of generation quickly, you are may be slightly weak in a bargaining position. If you put all your money on the table all at once, are you going to get as good a deal as if you are keeping those pots smaller? I am not an expert in game theory and stuff, but that is a consideration. Do we have the supply chain and the actual industry ready to deliver as much as we can, or are we putting too much money on the table straight away? I am sure others, possibly in the next panel as well, will have thoughts on that.

Q25 **Chair:** You are priming us nicely for the next discussion. Something else comes out of what you have all said so far. We repeatedly hear about the fragmented nature of our network system—the multiple private ownerships and the way the RIIIO agreements have to deal with it; is that a major barrier to the kinds of changes we are discussing?

Tom Luff: It could be, but in the process we have for price controls, there are things that you can probably improve and there are all sorts of experts out there, within Ofgem and outside Ofgem, trying to improve that. Broadly, Ofgem is the gold standard across the world in regulating these kinds of things. There will be inefficiencies and there will be improvements to be made, but as a framework it is probably pretty good.

Q26 **Chair:** What do you make of the changes to the Ofgem system?

Tom Luff: Are you referring to the strategic plan?

Chair: Yes.

Tom Luff: I think broadly it is good. It is suggesting more of a focus on actual outcomes, consumer outcomes, and really focusing on that. Obviously, that is right. There is nothing to dislike about that but, as an example, rather than having an energy retail framework that is one size fits all, so every supplier follows exactly the same rules, it could lead to a situation where you have different levels of regulation for different risks. If you are regulating electricity for an EV, perhaps that is a different risk than regulating for someone to keep their house warm or to keep the lights on. It seems interesting to explore the risk level and, therefore, the commensurate level of regulation needed.

On the network side, the really interesting thing going forward will be how we ration the local distribution grid. If you are getting lots of electric cars coming on the system at the same time, they will all want to charge, possibly at the same time. How do you spread that well across the



network? This is very rule of thumb, but I think about 50% of the local network is latent. It is just headroom. It is not being used and is there just in case there is extra need for it—potentially 50%. Then we are looking in the next three to five years at spending billions and billions to upgrade, to bring on electric vehicles and other stuff. If we could use that much more efficiently, we might not need to spend so much money.

Q27 Chair: I am glad you mentioned the huge potential costs. They are not just potential either, are they? We have already seen that. We have talked about constraint costs already. This is one of the challenges in where we are. Would it be sensible to slow down the roll-out of renewables to avoid an enormous amount of waste of money and inefficiency that stores up longer-term problems, because we are trying to play catch-up all the time?

Tom Luff: I certainly would not say slow down the roll-out of renewables and, anyway, I think it is a bit of a super tanker. You do not suddenly put the brake on and the accelerator on. I saw that when I was an official working on the feed-in tariffs. All of a sudden we cut costs and it had a really damaging impact, and it took quite a long time to regain the confidence. I think you do things gradually but I would not say reduce it. I would say increase opportunities for demand, so really focus in now.

This is a message in the Climate Change Committee's report, which I saw briefly this morning: I think 93% of emissions are now outside the electricity sector. That is a really big statistic. We have to focus on the stuff that is going to use that electricity rather than just generate more. We still need to build more and we need to build more wires.

Chair: Making it easier for people to use it is the answer.

Tom Luff: Yes, exactly.

Q28 Chair: Anything different, Chris?

Chris Matson: No, I agree with that. I think we should not be slowing down renewables. We should be speeding up the ability to use renewables through more network and better access from demand.

Q29 Chair: Katrina, you were nodding. You do not have to give a long answer; yes or no will do, unless you have anything in particular.

Katrina Salmon: I agree. I think in addition to demand, though, are incentives for flexibility—batteries—and ensuring that households are given the right signals, if they choose to opt in, to vary their demand based off time signals. Those types of flexibility will also help to reduce the amount of network we need to build, particularly on the distribution side.

Chair: And presumably, if we are talking about things like batteries and making it affordable for people, that is really attractive.

Katrina Salmon indicated assent.

Chair: Great.



Q30 Graeme Downie: I want to go back to something that Claire brought up and that you mentioned, Katrina, about the evidence base for REMA. You mentioned that there had been no cost-benefit analysis published. I think you also mentioned that we needed a process that brought everyone along with us. Do you think some of the concerns about the evidence base underpinning the decisions and a perceived lack of transparency have hindered that idea of bringing people along?

Katrina Salmon: Yes. Unfortunately, the locational debates in REMA became very contentious. There were jokes about, "Oh, I wouldn't be able to be in the same room as you, because we are on opposite sides of the debate," but there is an underlying kernel of truth to that. The lack of transparency over how DESNZ came to its final decision, and the evidence that it used in making that has, in part, in my opinion, hindered the ability for industry to come together and move on.

In the public domain, the evidence base is slightly not equal, in the sense that we have lots of consultancy reports that were paid for by large generators but we do not have an equivalent evidence base on the side of consumer organisations. Advocacy groups for consumers had less ability to go out and consult, or to pay consultancies to produce vast pieces of evidence that would prove that locational pricing would have benefited consumers. I am not saying that that necessarily would have been the case, but not knowing precisely what evidence DESNZ used has given room to question whether or not the decision was made fairly, and that question should not exist.

Q31 Graeme Downie: Do you have any insight into why the Department chose that approach and why it has not been more transparent?

Katrina Salmon: I could not begin to speak to why DESNZ has made certain decisions.

Q32 Graeme Downie: We have heard about—you mentioned it there—the divisiveness of the process and some of the delays inside the industry. Two questions are linked. Are there lessons for the Department about how they go about future consultation processes? Do you think there has been any damage done inside the industry through the lack of transparency, and in terms of how they might co-operate on future decisions and their implementation, as well as in respect of how the industry might cope the next time we come to a major structural decision, and how we might be able to still work together towards a good decision? As politicians, we are very used to shouting at each other and then often having a cup of tea, but is that a concern for future structural decisions around the electricity market?

Katrina Salmon: Yes, I think it is a concern. The wounds of REMA have not fully disappeared, and I worry that that means it will be harder in future to undertake significant reforms, because everybody is concerned about ending up in a similar almost fist fight over the decision and the topic.

When it comes to questions of transparency, I think that part of what slightly went wrong was that DESNZ left the scope of reform so wide open that it left room for people to interpret reform in the way that they thought it would happen or could happen. That meant that you had the ability to say that locational pricing would be really bad for consumers in all of these ways, when ultimately DESNZ likely would not have chosen to do things in that way.

I was quite surprised to see the term “postcode lottery” in DESNZ’s written evidence to this inquiry. There is no reason why LMP would have needed to have been a postcode lottery. Consumers could have been insulated from locational pricing. As Tom highlighted, we already have different locational signals throughout the system under the current design. The weaponisation of some language like that is a clear sign that something went slightly wrong, and I am not entirely clear that we have really recovered enough or learned enough about how to prevent it in future.

- Q33 **Graeme Downie:** Chris, what does the wound that exists as a result of the process do to the evidence base that would be needed to be brought forward should a future Government want to reopen the decision? Presumably, it makes it much harder to do, and the evidence would have to be very strong indeed. Is there a risk that you end up with stasis on this, or on other decisions, because of the fights that have occurred up to this point?

Chris Matson: I do not necessarily think so on the fights. As Katrina said, the fact that DESNZ did not publish the final cost-benefit analysis makes that next decision harder to do. As she also said, we did not have a clear view of the two things we were comparing: the final zonal design that was being assessed and the final RNP design, or at least an approximation of what those might have looked like. What were we comparing and what was the ultimate evidence or analysis that led to that final decision? That level of additional transparency of publishing more detail would have been useful in putting the issue to bed to some extent. I am not saying that we would necessarily want to reopen the zonal debate, but if we were going to look at something similar in future, I think that would have been better.

- Q34 **Graeme Downie:** We have heard from Octopus Energy, which has told us that the evidence base has actually improved since the decision was taken. What evidence do you think would need to come forward? What strength of evidence would need to come forward to justify reopening the debate or discussion in future, and where would it have to come from?

Chris Matson: I think I said earlier that I do not think we should be reopening the debate.

Graeme Downie: I am not trying to suggest it. I can see the pained expression on your face: “Please don’t make us do this again.”

Chris Matson: It is a good thing for consultants who are doing electricity market modelling. There are some wins out of the debate, but I don’t



know—I do not think any evidence that has not been brought to light would reopen the debate right now. It is probably something that would need to happen five or 10 years in the future, when you have reached more of a steady state for what the electricity transition looks like.

Q35 Graeme Downie: You would not agree that the evidence base, from your knowledge, has changed that much since the decision was taken.

Chris Matson: No, I don't think so. The fundamental things that we were weighing up against each other have not changed. I guess some things have come more into the light than others. The cost of living is probably higher on the agenda than it was three or four years ago, and the risk of shocks to gas prices from international things. Obviously, four years ago they were highlighted as well, but those sorts of things have been brought to the fore a bit more. If anything, some of the costs of different things have increased, but the fundamental drivers that go into that analysis—the fundamental underpinning assumptions—have not massively moved on.

Q36 Graeme Downie: Tom, on the same topic, I think you have expressed concerns in the past about the lack of transparency. Do you have any insight into what happened and why that limited analysis was published? Similar to the question I asked Katrina, do you have any concern about what that points to for the future, either inside the industry or inside the Department?

Tom Luff: I cannot claim to know the ins and outs of why the decision was made. I break it down into two things: the backward looking and the forward looking. If you look back, it was a challenge or, rather, it was a missed opportunity to present a clear bunch of options to bring industry with Government. If you do it incrementally, they get picked off and you end up with the lowest common denominator. I do not think we are finished with that yet, because we are still going to have lots of challenge around TNUoS charging. We have lots of challenge about all sorts of other things incrementally, and perhaps some of the benefits that we have seen from RNP actually will not get delivered—rather than having a big settlement, and saying, “Okay, there are these three options,” and then you agree on one of them and run with it.

But that is the past. Looking forward, the reason why you want to have those two bits of evidence—what would zonal have looked like and what we expect from RNP—is that you can then keep monitoring it as you go forward. You can take a decision about the point at which, ultimately, you are not getting the consumer outcomes you want, and then you say it is time for a bigger change.

I agree with Octopus: things have changed quite materially. On the one hand, constraint costs are continuing to go up. I do not think we have any evidence that grid build is getting faster. Hopefully it will, but it is still a big challenge, and some of the experience of grid build that we have all seen over the years is difficult.



On the idea of postcode lottery, there is a general acceptance that in some parts of the country, if you can get more cheap electricity, why not give it to people for cheaper? It seems like a fairly straightforward thing. The demand turn-up trial will help to show that a bit more—if you have access to cheaper electricity, give it to people. Do not just pay not to produce it.

Q37 Graeme Downie: Do you think some of the evidence base has changed? Similarly to what I asked Chris, what evidence do you think would need to come to light, from where and when, and on what timescale, that would justify the discussion being reopened?

Tom Luff: My view is that it should not be a binary thing. It should not be about saying, "Let's not talk about it until this thing happens." I would say let's keep talking about it, but say there is a long backstop time commitment. The kinds of things we would be looking at are constraint costs—keep monitoring that. Are they coming down? Is the grid building fast enough to keep up with generation to be able to bring them down? Keep doing the trials that show there is a benefit to everyone if you can have different prices in different places, for the individual consumers and for the wider system. It is important to keep tracking and monitoring those kinds of things.

Q38 Graeme Downie: On alternative market designs, you mentioned, Katrina, that it was a very broad option. There were no options put forward. It was very much, "Give us your ideas, bring out your dead, see what happens." What alternatives do you think could have been brought forward between RNP and LMP, and which ones should remain under consideration? I am thinking of things like green power pools or split markets. What options should we be keeping under review or under consideration in our minds as we move forward?

Katrina Salmon: Part of the challenge REMA encountered was that it was never entirely clear on what timescale the reforms were intended to be enacted. Were you reforming for a system to get us to net zero, or was this a design for a net zero system? As a result, you had an incredibly broad array of options put on the table under REMA, and many of them are still very interesting, very viable—things like a strategic reserve for gas—but the question is: on what timescale are you talking about implementing them? It is my understanding that, especially after the clean power 2030 target was enacted, the window for reform options was narrowed to what you could get done in the next few years. In a system that is changing this rapidly but that has such long timescales, we need the ability to think five or 10 years in advance.

My key things in alternative market design would probably just be CfDs again. But also there is a risk. There is a lot of really interesting analysis within REMA, and I am sure within the Department, but also in the industry as a whole. There is a risk that it has become slightly tainted by what has ultimately happened in REMA, when there is really nothing wrong with the analysis. It is just the question of when would we actually do it.



Q39 Graeme Downie: Chris, was the feeling about the process that there was no clear objective in mind? No one said, "This is what we are trying to achieve and let's work towards it." Am I being unfair?

Chris Matson: I think it is probably a little bit unfair. It was a combination of designing a system that gets you to net zero and a system that is fit for a net zero system. It was always going to take five-plus years to enact these reforms. Even if you had made the zonal decision to go ahead with it last summer, it would have probably been 2031 before you implemented it. I think that was even what business itself was saying. It was relatively clear what the purpose of the reforms was.

Q40 Graeme Downie: Do you have any views on why other reform options were rejected, or perhaps not considered fully?

Chris Matson: In general, they were viewed as either too complex or ultimately going to cost the consumer or the system more money. I think they were the main reasons—a combination of those two things. The zonal issue has probably shown us that in the current world we live in, if we are going towards the system we are working in, incremental changes are more desirable than doing a massive reform and moving to split markets or whatever it might be.

Q41 Graeme Downie: Tom, talk us through your view on the alternative market designs that might have been credible?

Tom Luff: It is worth saying that some of them were doing slightly different things. To go back to your overall objective point, the split market was looking to say, "How do you address the issue of marginal pricing, and how do you get the benefits of renewables without losing lots of money because you are going up to the gas price?"

Graeme Downie: It felt a bit like cake-ism. We were trying to get everything.

Tom Luff: I looked at it quite hard and it always got back to the same challenge, which is that, ultimately, in the market it will balance out. If you get cheap electricity from one market and more expensive electricity from another market, in aggregate it will end up with the same thing. That was my take on it. I know that the Government looked at it and they could not quite make it work, so I think it was more of a case of a practical implementation challenge. Conceptually it could have been helpful.

Q42 Chair: Tom, you advocated this very interesting idea of giving consumers electricity when it is going spare. How do you do that without a formal locational system?

Tom Luff: A trial was announced by the Government, I think working with a research agency. At the moment, you might have lots of wind and you are paying because it cannot get on to the system, so you are paying constraint costs to stop it. The trial is looking at exactly that question: how do you implement it so that it can just be used locally at a cheaper



price? Exactly who will use it is something that the trial will address and explore but to my mind, if you can have a bit of industry there that has some flexible demand, if you can have EV owners in the area who can use it, potentially also if you have vulnerable consumers to whom you say, "We are going to give you cheaper electricity and perhaps pay for it from other means in the system," ultimately it is about using that electricity and paying less money for it rather than paying more money to stop it being generated in the first place.

Chair: Okay. So there is a long way to go with that idea.

Tom Luff: I don't think so. I think the concept is there. You could probably implement it very quickly. At the moment it is trialling to understand what the effect would be, how much benefit it would give and so on.

Q43 **Chair:** I like the idea of industry moving to where the electricity is cheap, but that would take a lot of time, and there are moving parts in terms of having the workforce, encouraging people to live there and having somewhere for them to live. Off the top of my head, there are a few issues. It feels like quite a big challenge. The whole point is that you have the constraint in the grid, so you cannot share the electricity much more widely.

Tom Luff: Yes, but there is some stuff that may be beneficial already. There might be industry there that could say, "We could use that cheap electricity, thank you very much, and we would not need to use it another time." In the longer term, though, why not create those incentives to move things like data centres, hydrogen electrolysis and all those other things that are high electricity use? Why not say that over the next five or 10 years, this is where we would expect them to go?

Chris Matson: I think that is right. Being able to provide the right price signals for demand to operate efficiently is obviously desirable. The majority of the constraint cost is not the wasted renewable energy; it is having to turn something else up somewhere else. That needs to be clear.

Katrina Salmon: I think it is a good idea. The risk, though, is that we end up back to my initial point about patches: we see a problem here, we come up with a solution there, we see a problem over there, we have a solution to that. The result is that we end up with a system that is incredibly complicated, and maybe we do not send the signals to consumers clearly enough that, "This is the time when we have a lot of wind, please run your washing machine or charge your EV." Then we end up not being able to see the full benefits for consumers.

Chair: Thank you. That is a very helpful note to finish on, and a reminder of the big points of the discussion. Thank you all for your evidence. It has been extremely interesting. We will now change panels.

Examination of witnesses

Witnesses: Jason Mann, Helen White and Rob Gross.

Q44 **Chair:** Welcome back to this morning's session of the Energy Security and Net Zero Select Committee and our inquiry into reviewing the electricity market. Welcome to our second panel; please introduce yourselves briefly.

Rob Gross: Hello, I am Rob Gross. I am professor of energy policy and technology at Imperial College and director of something called the UK Energy Research Centre, which is a large consortium of universities. I am also one of the advisory commissioners on the clean power 2030 mission unit.

Jason Mann: Good morning. My name is Jason Mann. I am an economist by training and I head up FTI Consulting's global energy team. I lead a team of about 450 people based in London, Europe, North America and Australia, and work globally on the matters that we are talking about today.

Helen White: Good morning. I am Helen White, head of commercial asset management for Ocean Winds UK. We are a pure offshore wind JV entity between ENGIE and EDPR.

Q45 **Chair:** Thank you, and welcome. We look forward to your evidence and I am sure you will, between you, pick up on some of what was said in the first session.

Rob, in the first session we touched a bit on how decisions are taken to site projects. What factors should determine where projects are sited? Is there opportunity for locational signals to play their part within the reformed national pricing framework?

Rob Gross: What should determine where projects are sited depends on what projects you are talking about. There are some big strategic assets, mainly on the generation side, but also some options for providing storage, which are quite geographically constrained. Offshore wind needs to be in the sea. Wind resources are stronger in the north. The seabed is shallower around the North sea coast than it is off parts of the west coast.

There are constraints on where you might build a carbon capture and storage plant, due to the infrastructure that you would need and the repositories for the carbon capture and storage. Certainly there are constraints for large nuclear power stations. If you are considering a new pumped hydro storage, you need a large hill to pump water up and down. Beyond that, there are the constraints of the existing grid, the future grid that we intend to build, and at what point it becomes not cost-effective to continue to extend the grid.

Those locational factors have been a feature of electricity ever since electricity was first developed in the early 20th century, when it was city by city, and then we decided to build the first national grid, which we managed to do between 1929 and about 1934. It was done in about five

years, which is a very impressive undertaking. Then we re-engineered the grid so that we could take electricity from where it was convenient to put coal-fired power stations, primarily, to demand as efficiently as possible.

In the context of RNP, clearly we need to send effective location decisions to investors and, in particular, we need to send clear investment location decisions to, for example, offshore wind developers, which are more geographically constrained. We could potentially be a bit more relaxed about onshore wind and solar. We need to make sure that we are putting batteries in the right place. We need to make sure that we do not just continue to build interconnectors potentially coming into the wrong part of the network. I am sure that we will pick up on some of the details.

The strategic spatial energy plan ought to provide us with the information that is needed, but it will not provide the investment signals. That is all in the RNP consultation, and DESNZ has laid out the options. They may draw on some combination of the connections regime and a reformed TNUoS. In my view, they do not give enough attention to the potential of location-specific investment incentives like CfDs, which could be more directive for the location and an effective way of driving it to the right place.

Q46 Chair: You have anticipated some of the other questions I was going to ask, but that's fine. That is a good sign that we are asking the right questions. Jason, what is your analysis of a similar question and of what Rob has said? How might we might apply the question about location to existing assets as well as to new ones?

Jason Mann: First, thank you very much for inviting me here today. I am delighted to be here. For the record, it is probably worth stating that I was strongly in favour of moving to a zonal pricing regime and worked for Ofgem, for example, on that piece of work, looking at the cost-benefit analysis, and have worked subsequently for clients such as Octopus.

On what Rob was saying, of course all those physical constraints apply. The overarching aspect about what should guide investment decisions is what is the value that any particular investment decision delivers to customers. We need to remember all the time, every time we are investing something, that customers will ultimately pay for it. So the most important aspect—the overarching rationale for investing—is what is the overall value to customers, and whether it can deliver lower prices for consumers in the context of the energy transition. I slightly worry that we are on a path that perhaps does not think about that all the time, and as a consequence we have higher electricity prices than we otherwise should. For example, the analysis I did for Ofgem and others subsequently suggested that the cost of retaining the current regime in some format is probably in excess of £100 billion. That is £100 billion that customers are paying.

To go to your question of RNP and what can we do, given that we are where we are, the answer is that RNP in and of itself will not give any locational signals. Almost by design it has a national price. Then you start to ask what we can do to overlay signals on top of that. These are administrative signals, such as TNUoS charging and things of that genre. The slight issue with TNUoS charging is that it has been around for 25 or 30 years and has sought from time to time to be reformed. All of those reforms have become stuck in the mire of stakeholder consultations and being undermined by various winners and losers. The losers in the debate complain a lot about a potential increase in charges, and the winners obviously are not so vocal. Changing that narrative and turning those locational signals through a TNUoS charge seems to be relatively unlikely.

The key point in all of this is that location is not the most important problem; operational signals are the most important problem. All of the analysis done by me and my teams, and others as well, show that only about a third of the issue is an operational issue. Two thirds of the problem is how we operate the system. Two thirds of the problem is that we are operating the system in a way that is wrong. We send the wrong signals to lots of different flexible assets. Rob mentioned interconnectors. They are sometimes flowing out when they should be flowing in. There are sometimes parts of the country where they are flowing in when they should be flowing out. Batteries, for example, are sometimes charging up when they should be discharging. In other parts of the country, they are often discharging on to the system when they should be charging up.

All of these wrong operational signals have a underlying significant further problem, in that it generates the case for further investment. You think, "These things are going wrong. It is perpetuating the constraints on the system, so we need to build more network." That is the narrative that has emerged by virtue of these constraints. But if we use our current assets better by sending the right operational signals, we will need fewer assets, and therefore prices will be lower for consumers.

Q47 **Chair:** How do we send the right signals? Is this about technology and the digitalisation of the grid?

Jason Mann: Operational signals are obviously sent through locational pricing.

Chair: But as we are not doing that?

Jason Mann: In the absence of that, you have a problem. You will have to spend a lot of money building the network—probably another £100 billion. RNP has not come up with any solutions to that problem.

Q48 **Chair:** Helen, what should the balance be between centralised planning and market signals?

Helen White: There is a role for both. We are pleased to see the debate moving forward. What we are looking for as an owner-operator is certainty, particularly over the next five to 10 years when we have a



large pipeline, along with others. From a central planning perspective, there is a key role there to ask what needs to be in place as key infrastructure and when. Then the competitive markets take over and you end up with efficient investment and deployment from the operators that can deliver at lowest cost to the consumer, and who also incentivise the supply chain to invest in the right areas of the UK economy. There is definitely a role for the two. Our main concern is that all the documents that are currently under consultation are aligned, so if there is a recommendation to have generation or strategic demand in a certain area, the network build-out should also reflect that.

I would like to reflect on the talk this morning about constraint costs. Our assets are in Scotland, in the Moray firth. We have 2 GW up there, and we have a further gigawatts pipeline as part of the ScotWind Crown Estate lease. Clearly the point at which the locational signal happened for us was the Crown Estate seabed leasing stage. It makes sense for us that for large assets like offshore wind, that is the point at which you have a locational signal. With the offshore HVDC network, there can be a way to get that power to a different location. The responsibility for that sits with NESO. It has the ability to decide where that power ultimately goes and connects into.

On constraint costs, it was mentioned earlier that the bulk of the constraint cost is the turn-up gas cost. The other thing driving constraint cost is the lack of availability of the grid. What we currently have does not necessarily need to be built out to a huge extent; it just needs to be available. We are in summer now, so availability is low, but the key boundary that will be referenced in constraint costs is the B6 boundary between Scotland and England. That is running at the moment, according to NESO's 12-week lookahead, at about 30% to 40% availability, so the grid we have is not available. As we look into this winter, the more northerly boundary that we sit behind—the B4 and B5, which runs across central belt Scotland—is anticipated to be below 50% availability.

Again, there are operational elements, and I agree with Jason on that. There are operational elements here that can be done to address constraint costs as a separate entity. On locational signals, we are really keen to see early, clear, strong signals for locational investment.

Q49 Chair: Is it your view that some of that grid capacity could be made available under a national pricing system?

Helen White: The grid capacity is available; it has a seasonal profile. Typically in the summer you have outages for line upgrade or refurbishment, and general maintenance, so clearly there will be a fluctuation in grid availability. However, when you have key boundaries that are creating constraints that are not available, that is a problem that needs to be looked at, particularly if those outages then go into the winter months.



Jason Mann: Can I come back on the point about turn-up costs being the major issue of constraint costs? I would suggest that that is not correct, and I know that it is an issue often portrayed, particularly by certain cohorts. I suggest that the overall cost of constraints is driven entirely by the generators behind the constraints. Often, how it is characterised is that when they look at the “constraint costs”, which is the costs incurred in turning down generators in the north of the country and turning up generators in the south of the country, that is typically what incurs the constraint cost. They then say, “We pay a generator in the north of the country x and a generator in the south of the country y. Let’s have a look at x plus y—oh, y has caused the constraint.” That would be the narrative. That is simply not true, because you always need generator Y in the south to meet demand, because otherwise the lights would go off. It also mischaracterises and forgets that generator X in the north of the country has been paid in the wholesale market already.

I happened to look beforehand, because I thought this issue might come up. Ocean Winds, for example, last year generated 2.9 TWh of electricity on to the grid, but also were paid for a further 3.1 TWh for constrained off-payments, and that equated to a further £150 million of wholesale constraint-cost payments. On top of that, they also got paid about another £200 million in the wholesale market. In all, customers paid £350 million for the constraint costs generated by Ocean Winds last year. That is fine, and maybe that is what we think is a sensible policy approach, but it is not caused by turn-up generators in the south. It is caused by virtue of the fact that wind exists in the north.

Q50 **Chair:** I suspect this debate will continue, but I will let you comment on it briefly, Rob, before we move on.

Rob Gross: I feel as though we are in a time machine going back into 2024, and the decision has been made.

Melanie Onn: That is what I said—it’s like groundhog day!

Rob Gross: You had the questions on transparency, which are very interesting and I will come back to. Clearly, Jason is completely right. Of course the generator that is doing the turn-up in the south did not cause the constraint. The constraint is caused because we built a load of generation assets out and did not keep pace with the build of transmission assets needed to get that power away under a system called connect and manage. That was deliberately and purposefully introduced at an earlier stage in the roll-out of wind, when there was much less wind on the network and when we thought we would be able to get the network built to catch up and the constraints were small. The constraints are caused by the absence of network capacity that allows us to get the generation that is already in existence away.

It is nevertheless true that more of the payment goes to the turn-up than goes to the turn-down. Jason is right that that does not mean that they have caused the constraint. It is very important, given that we are not



doing zonal pricing, at least for the duration of this Parliament, or for the time being—whether or not we should do it in the future, we are very happy to come back—whether those turn-up payments are inefficiently paid for through the balancing mechanism as a distress purchase, which they are, whether you can do stuff to make that cheaper, which you can, and whether you can do things to alleviate the problem for the—

- Q51 **Chair:** Let's turn back to what we can do something about, which is to take evidence about the system that is happening and the best way of ensuring that it is as effective as possible. Rob, you started to talk about the SSEP earlier. How do we ensure that the SSEP, the centralised strategic network plan and regional energy strategic plans are integrated so that they are as effective as possible? What are the risks if they operate in isolation? Are you confident that they are co-ordinated to prevent the worries of them operating in isolation?

Rob Gross: I am not particularly worried about them operating in isolation. There is a legitimate concern about the extent to which the regional plans—the RESPs—and the GB-wide SSEP will be articulated or connected effectively. I am less concerned about the CSNP, because in some respects the SSEP and the network planning should go hand in hand, because they are both the responsibility of NESO. At the moment, we await the first iteration of the SSEP. I will give NESO, which has hired lots of clever people and already had lots of very clever people to do this, the benefit of the doubt before I prejudge that they have got it wrong. It is a very complex task and it is obviously very important that they get it right.

I will make the very quick comment that I do not think we could do without a strategic spatial energy plan. The absence of such is part of the reason why we are in the situation we are in now. Energy systems can be in a period of relatively steady state, which we were in for most the 1970s through until quite recently, and certainly through the 1990s and early 2000s. We are not now. We are going through a big transition. We need to plan it and try to have the institutions in place to get that right. I have a concern about the institutional arrangements and the three-driver car, with DESNZ perhaps on the steering wheel, but maybe they are also on the gear lever, and Ofgem on the brakes and NESO pressing the clutch or whatever. There is a co-ordination challenge there for sure.

- Q52 **Chair:** Thank you. That is a comment we have heard many times in different contexts. Helen, is the three-year planning cycle sufficiently long, given the 40-year-plus assets on which decisions are being taken?

Helen White: It feels reasonable, as long as with each three-year cycle there are not then retrospective significant amendments that create gains and losses. As long as you are on a stable trajectory, the three-year cycle seems reasonable.

- Q53 **Chair:** Jason, in practice how prescriptive should the SSEP be in operation?



Jason Mann: Thank you for that question. I agree with Rob. We need an SSEP. We need a plan. If you look around the world, all transforming systems have a plan that provides, to some degree of granularity, broad indications of different ways in which they might progress the electricity system. The SSEP at one level might just be something more indicative of the direction of travel we may, as a system, intend to go. You see that in Australia—it is called the ISP. You have one in New York, and you see them in California and all over the world. That is standard.

The question is whether it is an indicative road map or a directional blueprint. If it was a prescriptive blueprint, I would have some major reservations. The major reservations would come from the fact that we may well find ourselves locked into various pathways that in retrospect we might not want to be. We know, for example, that it is a 25-year plan and we know that technology has changed enormously over the last 25 years. I hazard a guess that we all in this room remember 25 years ago, and we remember how much computing power has changed. For example, I checked the other day, and the phone in your pocket now is 25 million times more powerful than a laptop was 25 years ago. We have AI centres, we have quantum computing perhaps not far away. We have huge amounts of demand on the system coming and we do not know where and we do not know how.

Potentially, if we are overly prescriptive about locking in a certain trajectory, I worry that that would set us on a course that in retrospect we might regret, and moreover will have very high prices. So having an ability for the system to respond dynamically to emerging technology seems to me the most important aspect of it, rather than being locked into a plan. I understand the need for certainty, but we live in uncertain times, and we need to be willing and fleet of foot. Otherwise, we are imposing more cost on the system. More cost on the system is higher electricity prices and a less competitive UK economy.

Q54 **Graeme Downie:** Rob, you touched on this earlier; I want to come back to the impact of TNUoS costs on CfD bids and how that affects strike prices. We have seen increasing CfD bids as a result of TNUoS. Can you talk about your views on that and what impact in particular that is having on consumer costs?

Rob Gross: There are two separate aspects to this issue. The first is the unpredictability of the current TNUoS arrangements. TNUoS was designed at a time when principally we had a mix of gas, nuclear and coal assets on the system and we were not going through the major geographical transition that we are going through now, where we are moving more to renewables, offshore wind and so on. The methodology for TNUoS results in uncertainty over what TNUoS charges will be from the perspective of a prospective CfD bidder. The reason for that is they do not know what their competitors will do and they do not know how good NESO and the network companies will be at building networks. They do not know what the TNUoS charges will be, so they will price that into their CfD bids.

Q55 **Graeme Downie:** Is the risk that they price higher because of that uncertainty?

Rob Gross: They will price higher to cover a range of potential and envisionable outcomes. It is widely agreed that TNUoS needs to be made more predictable for that reason, and that it needs to be aligned with what we expect the network to be in the future rather than what it might be now when, as we have already discussed, network build is lagging. But it seems, for various reasons that I do not fully understand, that making changes to TNUoS is very complicated and will take a long time, says Ofgem. I do not have any reason to doubt that it is very complicated; I do not know quite why it needs to take so long. There are issues around it being too unpredictable.

The other thing that is behind your question—which is one of the things Jason and I might agree on—is that TNUoS has the potential to create inframarginal rent when you have a GB-wide CfD price. Do you want me to decode that a little bit? Let's imagine that your marginal CfD bidder, the one that sets the price, is in Scotland, and it is very windy and a very good location for building an offshore wind farm for whatever reasons, but it is paying quite high TNUoS charges. But it just pips it and wins the CfD, and it sets the price for the whole CfD auction. All the England projects that are now being paid that price are paying a lower TNUoS charge, but the CfD price is being impacted and influenced by the fact that CfD prices are set GB-wide.

That is why, in our evidence to the DESNZ RNP call for evidence, we argued that it should be paying great attention to the potential for location-specific CfDs, because then you can avoid that problem. We could have avoided some of the issues we got into with the zonal debate as well, but I would prefer not to go back over that ground now.

The other thing we could consider doing for CfD projects is making the CfD the main location driver and having a volume-based approach to CfDs for different parts of the country. Only allocate up to a capacity that you have decided for a particular part of the country because of constraints, and allow a separate price to form somewhere else. That might be a more efficient way of doing things. If it is going to take a long time to reform TNUoS, in the meantime, have a postage-stamp TNUoS for those projects.

Q56 **Graeme Downie:** Is that more of a market-based solution, rather than having price fixing, which you could almost call an excessive intervention in the market, or a strong intervention in the market?

Rob Gross: All these things are quite interventionist, aren't they?

Q57 **Melanie Onn:** Wouldn't you be asking quite a lot of the Crown Estate in that case? Won't the Crown Estate's role in where they are going impact on CfD pricing?

Rob Gross: There are a couple of things there. First, in the longer term, for big potential offshore wind locations, the whole process should be



made into a one-stop shop. One of the reasons why we have got into a mess is because Crown Estate England is competing with Crown Estate Scotland to try to secure offshore wind bidders. They then subsequently went away and did all their environmental assessments, worked out whether or not they wanted to develop the site, did or did not develop the site, bid for a CfD, did or did not win a CfD, could not get a connection, could get a connection. That whole process seems to me to be nuts.

Q58 Graeme Downie: You are not suggesting that devolution causes problems in energy markets?

Rob Gross: It is not a devolution problem, but it could be about the co-ordination between Crown Estate and Crown Estate Scotland. For now, we already have the sites. What I am talking about is AR8. In AR7 we did a bit of locational CfD already. We have experimented with it, which seems to be quite a good thing to have done. Let's do a bit more.

Q59 Graeme Downie: Jason, what is your view on this? In particular, why is it so difficult for them to look at TNUoS as something to reform or change?

Jason Mann: I have a lot of first-hand experience of this. Essentially, the reason it is difficult to change is that they are trying to meet a number of competing objectives at the same time. You have heard about the desire for predictability and stability in charges; equally there is often a desire to send a cost-reflective signal. That cost-reflective signal, in this case, is ideally going to send a siting signal—a locational signal—to wire that in.

On the one hand you want a cost-reflective signal, and on the other hand you want a predictable, stable, perhaps transparent signal. Those two things are quite at conflict with each other and getting the balance between them is inevitably difficult. A more cost-reflective signal inherently means that it is more unpredictable, and a more predictable signal means that it is less cross-reflective. That is the tension you are facing.

On top of that, why is it difficult to reform it? Given that tension, there is no definitive right place to be on the spectrum. You have various cohorts of stakeholders that benefit under one regime relative to another regime, given you are essentially cutting up a pie for various different stakeholders to pay. Therefore, there is inevitably stakeholder pushback from those that lose out. That is essentially the big problem.

Rob will be pleased to hear that I did agree with him on his locational CfD point. In the context of RNP, it would potentially be a step forward. I think that TNUoS charges are on a long train to nowhere and probably nothing will ever happen. The last thing we want to do is incentivise lots more offshore wind generation in places where we already have far too much. If we can in some ways limit that—it is far more interventionist than I would at all suggest normally, but we are where we are.

For the final point, Rob, when we were looking at how to potentially implement zonal pricing, we did also suggest a zonal CfD, and that would have been very compatible with the zonal pricing regime as well.

Q60 Graeme Downie: Helen, can you pick up the points Rob and Jason made, particularly on the issues in Scotland that arise from TNUoS and how that affects bids in Scotland?

Helen White: If you have the concept that everybody pays TNUoS and it is a pie and we are just talking about how we slice that up, that would be an incorrect reflection of what happens. Scottish northern generators pay into the pot; southern generators take out of the pot. Money flows through the charging mechanism and becomes a revenue stream. We are not advocating for retrospective gains or losses as part of any TNUoS reform. We are advocating for grandfathering and transitional arrangements that create a point of investment stability for both southern and northern generators.

The concept that everybody pays is not a true reflection. Some pay; some take out. There are windfall gains for southern generators in the quantum of millions of pounds per annum, whereas I and our projects are looking at doubling our TNUoS rate. At the moment I pay £45 million across my two sites per annum for TNUoS. That will double in the next five years. It is an ineffective locational signal. I cannot move my site; the Crown Estate leased our seabed area. If you build on to that, the impact of the fact that we have a transmission loss multiplier applied to anything that passes our gate again is an ineffective locational signal. We understand the need for transmission charges to be an element of the locational mix, but the fact is that they are now exponentially going up, the windfall losses are significant in Scotland and the windfall gains are significant down south.

On Rob's point on the CfD, we at Ocean Winds are a big supporter of the CfD, and we see that what Rob has just talked about could be a solution. But my role in commercial asset management is to look after my entire route to market, and a large portion of that is corporate PPAs, which would be outside of this particular fix. The corporate PPA market in the UK is thriving at the moment, and there is big demand from large I&C customers and large multinationals.

A fair solution on TNUoS would be to say, "Let's create a system-wide reform." The CfD would deliver relief for those that went for the CfD market, but there is a growing PPA market that is valuable to smaller generators, solar and small onshore wind—that sub-100 MW site—as well. We would advocate for a whole-system approach for transmission-connected assets.

Q61 Chair: I am very interested in what you said about PPAs. How much is it the answer to the challenges of increasing our generating capacity while bringing down bills?

Helen White: PPAs work in a similar way to a CfD, in that we create a levelised price for our power. Some of our assets have CfD, so in winter we pay into the pot, and in summer we draw down. In general, it should be self-balancing. The PPA market essentially takes that responsibility away from a Government mechanism into a private corporate mechanism and creates stability. All our activities in the short-term market, and all our market behaviours about how we respond to oversupply, how we respond to negative pricing, become addressed in a PPA mechanism, so we end up being self-regulating through market signals rather than requiring Government intervention.

Chair: Melanie, do you have more questions on TNUoS?

Q62 **Melanie Onn:** No—I was going to go back to the three-year planning cycle, because my questions have already been covered. On the three-year planning cycle issue we were talking about earlier, and the speed at which technology develops, if you are to do it entirely dynamically, first tech is not always the best tech. Is three years not quite sensible? Would that not work better for developers? It is not immediately dynamic? Jason, I do not know whether you mean dynamic as in—

Jason Mann: Helen can answer that.

Helen White: We work on about a 10-year development cycle before we even get to construction, and the assets range from 25 to 35 years. Clearly, it would be naive for us to expect stability over that length of period. However, because most of our projects tend to be debt financed and they tend to cover 15 to 20 years, that would be the crucial period for us to get this concept of stability. So even as you incrementally eat into that, if there is justification for the three-year cycle being the timeline to allow for some response to grid build-out, and the deployability of renewables, the deployability of grid, and the engagement on strategic demand, essentially that three-year cycle would seem reasonable as long as we are not taking a backward step out of those three years and it was incremental progress.

Jason Mann: Helen was discussing a minute ago the TNUoS charges and the problems with the high charge in the north and the rebate in the south. That goes to the point that at the moment there is some seeking to be cost-reflective in a way, and the costs are perceived to be higher in the north than the south, which is why you have that imbalance of charge. It almost proves the point that stakeholders fight like cats in bags about how to reapportion those sorts of elements.

I hesitate to go back to the dynamic charge point, but I will. I work globally around the world and I work a lot in North America. Texas, for example, is quite a similar market to the UK in many respects—almost an island system with a few DC interconnectors to neighbouring markets. It does not strike you as a bastion of renewables growth and decarbonisation agenda, but in the last three to four years, without any market intervention, it has increased its solar from 0 GW to 30 GW. In

that time, it has also done 12 GW of batteries. No one has told anybody to go and build those batteries; they are just being built. I hate to say this, but the reason why they are doing that is because the markets have moved very quickly. Solar prices have come down astonishingly quickly, and so have batteries.

Also—again, this will sound like a broken record—ERCOT, or Texas, has a nodal pricing system. People are therefore highly incentivised to go and buy solar and buy batteries to take account of that. No one is telling them to do that, and there is no overarching plan; it is just dynamic. If we can get those dynamic price signals into the market, we stand a lot better chance of achieving net zero at anything other than the low cost. The corollary to that is a slow-moving, centralised plan that, in my view, risks loading lots of additional costs on to the system.

Q63 **Melanie Onn:** It does not feel like we are in the same situation as Texas when it comes to solar.

Jason Mann: On the renewables generation we do today—

Melanie Onn: Today is an exception, but on space availability—

Jason Mann: All those things are true, but we still have lots of space. Batteries are really the key point. We have a similar amount of solar as Texas: they have 30 GW we have about 20 GW or 25 GW, so that is not the key differentiator. The key differentiator is that they got 12 GW of batteries delivered in three years and we got 2 GW of grid-scale batteries delivered in a much longer time frame. No one has told them to do that. There is no flexibility commissioner in the Lone Star state telling people to buy things. It just happens.

Q64 **Melanie Onn:** There is room for people to go and innovate and undertake business opportunities without waiting for Government to give permission.

Jason Mann: There would be if there were the signals there to do that. That is my big worry about all this: there are no—

Melanie Onn: You just said there are no signals in Texas.

Jason Mann: There would be if we had locational pricing. They have nodal pricing in Texas.

Rob Gross: That is not the reason why they have invested in lots of batteries, is it? It is because you have a much more straightforward opportunity for time-of-day arbitrage across a sunny part of the world that is sunny a lot of the time. There is a much more straightforward opportunity for those assets to be well matched to solar, as in other parts of the world where it is sunnier. I am not saying that does not mean—it is orthogonal to the argument about zonal pricing.

Jason Mann: I dispute that.



Chair: I am trying to avoid going over the zonal price debate.

- Q65 **Claire Young:** We have already touched on lots of things that I was going to ask about TNUoS. Jason, should demand-side signals, like removing the £0 floor on demand TNUoS, be strengthened to encourage consumption in constrained areas? What are the relative risks and benefits compared to generation-side signals?

Jason Mann: The administrative £0 charge floor is there essentially because it is perceived as wrong to pay people to consume electricity, and that is why they set it at zero. If we are going to stick with the transmission charge and levy it on demand side in some way, shape or form, I see no a priori reason why it should not be negative in some places. That seems to me sensible. Maybe it has some benefit, but I worry about the static nature of the charge relative to a more dynamic charge. That is the big concern with TNUoS.

I also worry about the fact that you get locked into a charge: you create a set of stakeholders and one set of charges and then if you want to evolve it, you cannot. Administering charges and then trying to change them is a very challenging thing to do. But on the face of it, given where we are, and if you want to go down that route, having a free rein to set it in a way that feels more helpful is perhaps a good thing. For example, negative charges in Scotland would be sensible.

- Q66 **Claire Young:** Helen, you are pushing for reforms of the methodology. Would you like to comment on that or on any other specifics?

Helen White: The key thing for the projects UK-wide is the need for transitional arrangements where investments have already been made, whether that is a period of stability and then gradual transition to whatever the future looks like during this period where things will change, and the methodology may be adjusted—the concept of it being cost-effective and stability is clearly one. Does it align with the SSEP, and how deployable is it? How easy is it to implement? They are all key challenges. Industry has tried to put forward suggestions on ways to maybe adjust around the edges through the CCUS process, but to no success. Talking to the broadest system user is the best way forward, but the need for transitional arrangements for existing assets as an investment, and also so that the pipeline can go into AR8 or be securing PPAs this summer to allow deployment in the next 24 months, is important as well.

Claire Young: So it is pretty urgent.

- Q67 **Melanie Onn:** On connection reform, do you think, Jason, that the grid connections regime is in line with the SSEP and can deliver clean power 2030? If not, what further reforms do you think are needed?

Jason Mann: The SSEP or connection reform, or both?

Melanie Onn: Does the connection regime reform align with the SSEP.

Jason Mann: I am not sure; I do not know 100%. The issue with connection reform is that you have set up a system where you have far more desires to connect to the grid than can ever be met and, indeed, ever be needed, and we need a process for weeding those out. The connection reform seeks in some way to weed out those projects that are deemed in some way unhelpful. I hate to have to say it again, but if you had a locational or zonal pricing review, the connection queue would fall by half probably overnight, because half the projects would be uneconomic and you would not want to do that. But the other half would still be there, and you would still need a way to weed those out.

If policymakers want to choose people from the queue to go and do that, that might be one approach. Typically when you have a scarce resource—which is access to the network in this case—you tend to try to allocate it through a price mechanism, because that is more efficient. I would typically be biased towards that, but in the absence of that, the process of selecting projects that you think are particularly suitable is an approach. But as I say, if you did zonal pricing, the queue would halve overnight.

Melanie Onn: You do love zonal pricing.

Jason Mann: It works for customers.

Q68 **Melanie Onn:** Octopus Energy also loves zonal pricing, and it told us that about 62% of the 2026-27 gate 2 projects are delayed. Helen, who do you think is accountable for those delays? Should they have to pay, like a compensation framework?

Helen White: It is a complex topic. It does have commercial implications, because when you are preparing your CfD bid or coming up with a price and applying your tender for your PPA round, you build in an element of risk for grid not turning up on time. Projects experience significant supply chain knock-on effects, where we essentially then carry that cost. The question comes down whether we are the best place to carry that risk at the lowest cost to consumer. Is it better that there is a clearer mechanism for grid connection, delivery, and the requirement for the gate 2 process to be aligned with the SSEP? It passes the risk on to potentially the TOs that have a lower cost of capital and a better place to manage that.

Some of the problems are supply-chain related. We are all competing globally for the same entities to do the same work. Some things are unavoidable, but if there was a clear responsibility and a clear ability to pinpoint whether there was an actual problem sitting with, say, a TO for a grid deployment being late, we would be supportive of that. It is complex timing, particularly when other parallel processors run on and you have to make commercial decisions as well.

Q69 **Melanie Onn:** Rob, do you think that SLoMAs like AI data centres should be prioritised in the connections regime?



Rob Gross: Possibly. It depends on what bit of the network is constraining what asset from being able to connect. It is important to be clear that a lot of the geographical factors that drive generation around can also drive demand around, and are absolutely nothing to do with whether you have zonal pricing or how much electricity might cost. It might be to do with the latency on their digital connection—that is why you get a lot of data centres that want to connect to the west of London—or it might be to do with another demand, maybe where they have the right geographical base, supply chain, skilled workforce and everything else.

Q70 **Melanie Onn:** It would bring down constraint costs, wouldn't it, if they could be an immediate off-taker?

Rob Gross: It has the potential to do so if there is demand from, let's say, data centres. That is a wide category of different types of business. Yes, of course, if there are opportunities to locate particular new demands on the right side of a constraint, that is a good thing. I would never have suggested that—since it seems to be an elephant in the room, ultimately we came down against zonal pricing at this particular juncture, not in principle, but at this moment of the transition. It would have sent a signal to them.

On the connections reform, what has been done already is quite clearly a step in the right direction. It is absolutely right to have reformed the queue, to have got rid of zombie projects and to have tried to align that with the strategic needs of the network and to prioritise it appropriately. That is an administratively complicated thing to do and there is the risk of getting it wrong. However, we have to deal with the realities of the world as it is now rather than as we would perhaps prefer it would have been if things had been done differently in the past, because we do not have a time machine. We are dealing with a connections queue, a lack of network build and all of the things that go with that.

The Government came into office two years ago with a manifesto pledge to do clean power 2030, and they went about doing it. One of the reasons why REMA went in the direction it did was because the REMA predated that election. It was not necessarily focused on the priorities that were concomitant with that election result. One of the great benefits of having a clean power unit—obviously I would say this—is that they can go after and try to find ways to can solve problems. There are problems with the connections regime, there might be problems with whether or not TOs are doing things in a timely fashion and there are many challenges, but it is right to try to fix those things.

Q71 **Melanie Onn:** Would things have been more settled if the Government had published a final evidence base on which they made their final decision?

Rob Gross: That is tricky for me because I am conflicted. I cannot comment on why they did not—

Melanie Onn: Jason, would you have felt more settled if you had known a bit more?

Rob Gross: Sorry—I hadn't quite finished. It has given rise to the sense that there is a conspiracy, which I do not think there is. A great deal of evidence was evaluated by the Department—its own analysis, the analysis done by Jason and others, the submissions from a range of market participants, including Octopus and others on one side, and some of the generators on others, and nuanced positions across that. The idea that it was all about an incumbent conspiracy is completely false. I did see the analysis; I cannot comment on why it was not published. Multiple analyses were robustly—

Melanie Onn: I did not ask you to comment on that; I just asked whether it would have settled things down had it been published. That was the question.

Rob Gross: Yes, I think that you are right.

Melanie Onn: Thank you; that is what I like to hear.

Chair: That is very helpful, Rob. When the Secretary of State is here in three weeks' time, we may ask him.

Q72 **Melanie Onn:** Would you have felt better, Jason?

Jason Mann: I don't know. It depends on what the analysis said, because of course I haven't seen it. To go to your point earlier, it does feel a bit like a conspiracy from the outside looking in. We do not know what it said. We do not know what the analysis was. All the analysis that I have done, not just in this country but around the world, shows massive benefits to moving to a locational pricing regime. *[Interruption.]* It does, Rob. It would be wise to remember—

Chair: You have said that more than three times.

Jason Mann: It is probably wise to remember, when you are thinking about this—and I know you mentioned incumbent conspiracy, which is an interesting concept—that moving to those locational pricing regimes results in very significant transfers of funds between cohorts of stakeholders. Many of these stakeholders have shareholders, and they are protecting the shareholders. For example, SSE, as I put in my note, was—

Q73 **Melanie Onn:** We are going to move on to the next question, because you have already said some of this—thank you.

Helen, how can seabed leasing rounds help to deliver optimal locations? We have talked a bit about that, coming off the back of Graeme's question. What mechanisms would ensure that leasing aligns with the SSEP?

Helen White: If the offshore HVDC bootstrap connectors are deployed in time, that means we have greater freedom for our seabed locations. That

essentially means that no matter where you are in the sea, you have a route to market that will be unconstrained. That is our main objective: to support the progress through the planning and consenting process of those offshore straps from Scotland down to England.

- Q74 **Melanie Onn:** Jason, I am going to ask a question that I already know the answer to because of what you said earlier. Should seabed leasing costs be capped or fixed to try to protect consumers, rather than driven by competition that may inflate prices and Crown Estate revenues?

Jason Mann: I am a bit more agnostic on that point, frankly.

Melanie Onn: I did not expect you to say that.

Jason Mann: In principle, you have a scarce resource and it would make sense to auction that resource in a way that it goes to the third party that values it the most. That is typically the most efficient way of doing it. But there is probably an argument that, given that that feeds into the Crown Estate, which feeds into the taxpayers anyway in some form, do you want to constrain that resource in some way? It is probably reasonable to assume that it would reflect itself in the overall prices. How that balance is struck seems to be something to think through quite carefully. I do not think there is a right or wrong answer, bluntly, on this one.

- Q75 **Melanie Onn:** Rob mentioned earlier CfDs being more directional. Helen, would that be a welcome change for Ocean Winds and similar developers?

Helen White: There are already mechanisms in place within the CfD to allocate minimum amounts into certain pots and technology, so it would be growing on that mechanism. If it is a known framework, the timelines for publication tend to be well known. With the annual CfD cycle, as long as that remains, there is less scarcity of auction opportunities. It is well known if it is within the existing framework. It is also well known to the lending market. They know the CfD mechanism. They know how bankable that contract is. It is known to investors. If you are keeping within that—

- Q76 **Melanie Onn:** In terms of where projects are sited, though, would it help if the CfD mechanism was clearer and there was more expectation in there?

Helen White: If it aligned to the SSEP, absolutely, because what we want is a strong, early signal. With offshore wind, the challenge with waiting for the CfD to be the locational signal is that you are already close to FID, so you have already invested probably another five to 10 years post seabed. I can see that it could be worth while for other technologies that have a shorter development cycle.

- Q77 **Melanie Onn:** It does not seem to me that you are talking about any shorter development and delivery cycles than we had five years ago. The determination from everybody has been to try to shorten some of that.



Helen White: If the SSEP is the document with which everything is aligned, I can see how CfDs fit in with that, and it is another commercial market mechanism to drive competition in the pricing within alignment with the SSEP. If you want to encourage smaller-scale generation that potentially has a shorter timeline, one of the problems with the SSEP is that it has to align with local planning rules and regulations and the devolved control within that area. It would be naive for us to think that it can achieve everything. There is the idea of the capacities and the objectives of the SSEP, and making sure that there is accountability for the attrition rates that would happen within technologies and within geographies as well.

Q78 **Melanie Onn:** Rob, a final question: to what extent are other existing investment mechanisms like the capacity market or the RAB aligned with RNP objectives? Should they be reformed or replaced?

Rob Gross: The principal investment mechanism for the generation assets aspect of the RNP is the CfD, because that is what drives renewables investment. We can talk about the RAB and nuclear and the capacity mechanism. The capacity mechanism could be done to reward flexibility rather than just availability, but that would take us into a separate, not-final-question conversation. There is lots of scope to do more to ensure that you get flexibility for providers where you want them on the network, doing the things that you want them to do, because that is the challenge we have, having not done zonal right. I am sure Jason and I would agree on that.

The CfD is the principal instrument, notwithstanding that there will be some merchant projects that just have PPAs. I do not expect that to do the heavy lifting to 2030, or possibly even beyond. So much airtime was given to the locational pricing conversation and not enough airtime was given to the CfD reform question, and a whole bunch of things that sit around that.

We can do tweaks on AR8 or AR9. I have already said that I think we should make the CfD location specific. There is also a conversation around making the CfD deemed or capacity based rather than being linked to output, and how that might help to improve the operational efficiency. There are definitely things that need to be given more thought to that appear to have been de facto ruled out, and I am not quite sure why. They all have their pros and cons; this is very, very complicated stuff.

I will also say that energy policy is never finished. The idea that this will be a once-and-forever thing flies in the face of every successive bigger or smaller reform to electricity markets that I have seen. We have already seen that we can incrementally improve the CfD as we go along, and we absolutely need to continue to do that. At the moment, we are facing some significant problems, which are not to do with location but are to do with the operation of a system that has lots of variable and inflexible assets that CfD reform could help with.



HOUSE OF COMMONS

Chair: Thank you all very much for your evidence. It was a very interesting discussion and you have given us lots of insights for our inquiry to go forward. That is the end of the session.