GRID ACCESS REFORM PROJECT

COGATI PUBLIC FORUM

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MS MOLLARD: Welcome everyone to the first public forum of our grid access reform project in 2020. For those of you who don't know me, I amm Victoria Mollard, Acting Executive General Manager of the AEMC Security and Reliability team.

We hope you're all staying safe in these very unusual times and we know there's a lot on at the moment in the energy space so we very much appreciate your attendance today at this forum.

Your attendance here will help us to provide, with critical stakeholder input, to the process of developing grid access reform for the NEM to help us ensure the cheapest, fastest and fairest path to a lower emissions future as the generation mix continues to evolve.

Today's forum is intended to provide you with the opportunity to share your experiences and perspectives on locational marginal pricing, or LMPs, and financial transmission rights, otherwise known as FTRs, in overseas markets. In these overseas markets elements similar to these have been in place and regulators, as well as market participants, have had the opportunity to see the reforms in action and to experience the operation firsthand.

We know that a lot of you have many other questions to do with the project. We've been hearing them through the consultation that we've been doing so far this year or emails that we've received prior to the forum. For example, what's the next steps on the NERA modelling that's specific to the NEM; how are we going to assess the implementation costs of the reform; and, what are the interactions and interdependencies with other reforms being contemplated in the ESB's post 2025 NEM design project or the ESB's interim REZ work?

These are all really great questions and ones that we're working really hard on along with all of the other market bodies and we're going to be chatting to you about these over the coming weeks and months. There's going to be plenty of opportunity to provide input and thoughts into these matters and many others including detailed design issues about what the model might end up looking like.

We're planning at least two other public forums. So the first will cover the costs and benefits of implementing the reform and the NEM. As some of you would know, NERA Economic Consulting have also been engaged to carry out this modelling of the costs and benefits specific to the NEM.

The second public forum will be discussing a simplified model of how locational marginal pricing and financial transmission rights will operate in practice. There's more detail on our website about those two upcoming forums or how to register and there may be others. We will keep you posted.

The two upcoming forums we have prioritised, have been a response to stakeholder feedback on the need for looking at NEM specific modelling and understanding of the reform. All of these public forums, the modelling, will all be inputs into our thinking, along with other research analysis and, most importantly, all of the stakeholder feedback that we're receiving through forums like today, our technical working group, bilateral meetings, upcoming forums and all of the various emails and chats that we have with many of you on the phone today, all of this will be taken into consideration as we move towards developing the draft rules for the COAG Energy Council by the end of 2020.

Having said all of this, as well as wanting to recognise our current unique circumstances where many people are working from home, we wanted to kick off by having a series of short, sharp two-hourly forums focused in on a particular topic.

So the topic today we're wanting to focus in on is on international experience of markets with locational marginal pricing and financial transmission rights. These two elements are key aspects of the model that we have proposed and while they're new to Australia they have been successfully in place for decades in many overseas jurisdictions including New Zealand, many areas in North America and Singapore.

As some of you might know, we have commissioned NERA Economic Consulting to assess the cost and benefits, and key learnings from introducing LMP and FTRs in international jurisdictions. NERA's report, which is published on our website, provided an estimate of the expected costs and benefits of the reform based on the evidence gathered from other jurisdictions.

We are the first to recognise that the NERA report itself cannot provide us with all of the answers that we want about international experience; for example, many of the international studies NERA reviewed only provided ex ante assessments of what was expected, rather than an ex post assessment of what actually happened and NERA, themselves, recognised that in their report.

We also realise that comparing jurisdictions is always difficult given everyone has different market structures, underlying dynamics, government policies and different starting points. We recognise that and that's why we think today is important. We have talked to a couple of stakeholders about this idea and they also agreed that it's good to get those practical experiences. So we're really wanting your input and comments today to help us supplement the NERA report. We want to understand if you've operated in overseas jurisdictions, what your experiences were and what your reflections are on the report. We are really hoping you will participate today and share your views. There's going to be lots of opportunities to do that but if you would prefer we are happy to have follow up discussions or receive your feedback offline after the event.

So, to kick us off, I will introduce you to the COGATI project team who are in attendance today. Thanks, James. In addition to myself, we've got the following two key COGATI personnel presenting to you as well as answering questions. Tom Walker, who will be providing some of the context behind the COGATI review, and Russell Pendlebury, who will provide the context for the modelling work undertaken by NERA and the objectives of the report.

We also have the rest of the COGATI project team – James Tyrrell, Jessica Scranton, Orrie Johan and Tom Meares. They're all listening and will be taking notes and helping facilitate with the Q and A behind the scenes.

Finally, we also have some of our consultants on the call. We're lucky to have Will Taylor, who is the director for NERA in Australia, who will summarise the conclusions of the NERA report for forum participants and be able to answer questions, and special thanks to Will. We very much appreciate having him here today. He is joining us all the way from New Zealand, so joining our little COGATI bubble here.

We have also got Ella Pybus who is a consultant embedded in the COGATI team from CEPA who is working on the detailed technical elements of the reform who some of you also know.

I would also like to say a big thank you again to the wide participation here in the forum. We've had over 200 registrations so it's great to see that there's so such interest with a really wide variety of people here – industry, consumers, networks, governments, some overseas jurisdictions and academia participants. We really appreciate your engagement with the review.

So that brings me on to the format for today, so just a little bit of housekeeping. Today, as we've said, is an opportunity for you to provide us with input and ask us questions, as well as share your comments and experiences. We're going to open the forum with some brief presentations on the context, background and findings, but we're hoping that the majority of the time will be devoted to the questions and comments.

So we've got the six sessions throughout the forum which is devoted to Q and A. You have the option to make comments or ask questions by the Q and A function which you should all see on the right-hand side of your screen. We ask that when you're making comments please relate them to the purpose and scope of the forum and also please indicate whether you're asking a question or making a comment and then add your remarks. Then, finally, please include your name and organisation at the end.

Where possible, and time permitting, we're going to invite some participants to present their comments, so if you actually want to be able to talk to present your comments because you've got a lot of reflections and there is a 256 character limit in the box, please write that in the box as well and we will take your mic off mute and you will be asked to make your comment. I will be moderating each of the Q and A sections and we will make that clear each time.

We are going to attempt to answer all of the questions in this session but if we don't get to answer your question we will follow up after the event, either through, as I said, a follow-up meeting, an email, or if there are questions that we don't get to we might put up frequently asked questions on our website.

We hope that in raising questions and comments participants conduct themselves in the same respectful way that they would at an in-person public forum. We're also recording the meeting, just for minutes' purposes, and we will have presentation materials published on our website next week after the forum.

So if we just move to the agenda slide. I just thought it was worthwhile talking briefly through what the plan for the rest of our two hours together is. So we're going to start with a quick overview from Tom Walker on what is COGATI, where we are at, what are the next steps and, most critically, how is it now forming part of the ESB's 2025 work. We're then going to move on to the context for the NERA modelling and outcomes of the NERA report and that's where we are going to get into this Q and A section. That bit will be facilitated by Russell and Will presenting and then each of the Q and A sections.

I encourage you to send through your questions and comments while people are talking. If you hear something that you think, "That's a good question," or, "Here's something I could share about that," please do so as people are talking and we will then facilitate that session at the end of each section.

So, I will now hand over to Tom Walker who is going to provide you with a bit of background on what COGATI is all about and why these reforms have been developed for the NEM. Thank you, Tom.

MR WALKER: Thanks, Victoria. Hi, everyone. Great to see so many people in attendance. There's so much invested in this and I hope everyone is keeping well in these strange times. So I'm just going to provide a little bit of a context about the problems we're trying to address, the purpose of the reforms and, as Victoria said, our process.

So this slide is what is the problem that needs to be addressed? On the left, obviously, a map. This is taken from AEMO's integrated system plan which shows a dramatic change in both the quantum and type of generation stock expected over the next 20 years and that we think the NEM will replace most of its generation stock by 2040.

Given this change in generation mix, the signals about where to locate in the transmission network are more important than they used to be. We're essentially moving from a market, or we expect to be moving from a market of a small number or a relatively small number of relatively big generators to a large number of small and geographically dispersed generators so it's crucial that we have market arrangements in place that facilitate this change at least cost.

If I could go on to the next slide please. So this is going to just give a bit of an overview about the current arrangements and the access model that we have in mind. So, ignoring the impacts of losses, just because it keeps the explanation more simple, every location within a region receives and pays the same price. This price is known as the regional reference price. The regions are essentially the state boundaries and yet with the change in the generation stock discussed a moment ago it's increasingly important that the price reflects the underlying marginal value of supplying electricity at a particular location in the network at a particular time and this is why we're proposing, first of all, the introduction of what's known as locational marginal pricing, or LMP, which best reflects the value of electricity at specific locations and specific times, and we're proposing that this would apply to most generators and storage units while non-scheduled market participants, that is the majority of loads, would continue to face a regional price.

Now, locational prices vary from one another in the presence of congestion and transmission losses. Congestion on the transmission network and losses on the transmission network are normal everyday occurrences of an appropriately sized transmission network because building out all congestion in a network is prohibitively expensive. So it's inevitable that the underlying value of electricity varies between locations and what we're suggesting is this variation is accurately reflected and priced in the market.

Coupled with the introduction of LMPs would be the introduction of what is known as financial transmission rights, or FTRs, which market participants would be able to acquire to manage congestion and loss related risk. These FTRs would pay out when the price differences occur between locations and, as a result, this would enable market participants to manage the risk of congestion and losses which would materialise in different prices across the network.

The funds to pay for these FTRs would primarily come from the money that accrues as a result of the differences in the prices being paid to generators and the prices being paid by load.

While LMPs and FTR markets have these above core features the detailed design decisions that we're working through this year will need to be made and these design choices will need to reflect NEM specific characteristics and so will be aimed at facilitating the new regime in the context that we have here in the NEM.

If I could go on to the next slide please. Thank you. So the benefits of the reforms, firstly, locational marginal prices are a more efficient price signal, as I have alluded to in the previous slide, than the existing regional prices which should result in generation and transmission infrastructure savings, lower fuel costs and lower emissions. Financial transmission rights should be able to provide investors and generators and market participants an improved means to manage congestion and loss related risk.

Market participants who have purchased the FTRs, other than those that are grandfathered, would, by purchasing the FTRs, generate revenue and the proceeds of this process would primarily go to consumers directly lowering bills. So the outcomes for consumers are more affordable prices through lower infrastructure costs, more efficient dispatch and the direct offset in the bills. It will integrate new technologies into the national grid in a way that's reliable and secure and it will be integral to Australia taking the cheapest, fastest and fairest path to a low emissions future.

The next slide. Thank you. Undoubtedly locational marginal pricing and financial transmission rights will be a big change from the current arrangements in the NEM. We recognise that, but actually these types of arrangements are well‑established overseas in a variety of different contexts and settings. All of the US markets have progressively introduced these reforms. The white areas on this map on the left-hand side are not markets. They remain vertically integrated utilities.

Many of the reforms were brought in a long time ago, 24 years, in 1996 in the case of New Zealand, and incrementally over time in the US. The earliest in the US being 1998 in PJM and then incrementally into the mid-2010s. Indeed, Ontario, up at the top, the IESO, is considering the implementation or looking to do the implementation by 2023.

The fact that these reforms have been implemented overseas successively gives the Commission greater confidence about the appropriateness of our reforms. So I acknowledge there's no drive in these markets to revert to a zonal pricing model.

These markets have arrived at a wide variety of different market designs in other aspects of their market design and market structures, geographies, network layout, generation technologies and so on, and yet they have all seemed to have successfully implemented locational marginal pricing and financial transmission rights. These reforms, therefore, appear adaptable to any future market design and resilient to these factors and the fact that Ontario is making these changes, seems to indicate the reforms viability in their transitioning sector.

Of course one of the things we will hear today, or the main thing we are here today is to hear your experiences of operating in these kind of markets and we will get to that shortly.

Next slide. Not only have they been implemented overseas, they are widely regarded as successful in these jurisdictions. I won't go through all of these quotes but just a few of them. The very top left-hand one is from the International Energy Agency:

Locational marginal pricing (LMP) is the electricity spot pricing model that serves as the benchmark for market decision – the textbook ideal that should be the target for policy makers.

The US Federal Energy Regulatory Commission in 2002 said:

LMP – should encourage short-term efficiency in the provision of wholesale energy and long-term efficiency by locating generation, demand response and/or transmission –

And I would add to that, storage in today's context –

at the proper locations and times.

That really is going to the heart of the benefits that I was describing a moment ago. The Parer Review of the NEM in 2002 noted that:

The long run solution to the various transmission inadequacies, particularly the issue of providing clear locational signals for investment, lies with full nodal pricing.

Which is another way of talking about locational marginal pricing. Next slide. So what I have talked about so far is transmission access reform. I've not really talked about other related projects. I think that's an important thing to do and I think it's actually important to note what access reform doesn't do. So what this project doesn't do, in and of itself, is result in substantial changes to the transmission planning or investment processes. This is covered by the rule changes that will action the integrated system plan.

So what we're proposing is a two-part solution. The first part facilitated through the integrated system plan is to facilitate investment in the transmission that appropriately balances the costs of that transmission with the benefits that arise from that transmission. Then the second part of the two-part solution is the access reforms being discussed through this project so that transmission investment that is there in the existing transmission infrastructure that's already there is used in the best possible way by incentivising generators and storage to locate more efficiently and both of these levers are fundamental if we are to keep power prices trending down and to realise the full value of the transition that we are going through.

The next slide. Thank you. So just the final slide from me about the interactions of this project with ESB post 2025 market design process. As many of you would be aware, the COAG Energy Council tasked the Energy Security Board with developing advice on a long-term fit for purpose market framework to support reliability that could apply from the mid-2020s, and in that light, by the end of 2020, the ESB has been asked to recommend changes to the existing market design, or, indeed, alternative market designs to enable the provision of the full range of services to customers necessary to deliver a secure, reliable and lower emissions electricity system at least cost.

The ESB, in addressing this task, has developed seven market design initiatives, which you can see on the left-hand side of this slide, of which the coordination, generation and transmission investment project is one of them and the ESB has flagged the central importance of the COGATI reforms to the market design of the future.

The AEMC has taken the lead on this particular MDI, consistent with its work to date on this topic, and we have been tasked by the Energy Council with providing draft rules by the end of 2020.

I might just stop there and hand back over to Victoria. I have not been monitoring whether we've got any questions that have come in so we will see whether there are.

MS MOLLARD: Thanks, Tom. We have, Tom. Thank you for that. So there's a few kind of questions and comments in. So I might just note that we might pause here if anyone does have any questions or comments on what Tom just talked through.

A few things. David Headberry has asked if the slides will be published after the event. Yes, they will. So the slides and a record of minutes of the meeting, so kind of capturing the feedback provided by participants will be published on our website next Thursday. Thank you for that question, David.

Tom Geiser from Neoen has awesomely said he's got lots of in-depth comments from Neoen's developers in the US, so we should definitely make some time to hear from you, Tom, later in the presentation. We might just go through a couple of the sessions with NERA and Russell first and then we can hear your comments in light of what NERA have concluded and presented, but thank you for offering to share that. That's awesome.

Now, there's a couple of questions. One from Ken McAlpine and another from Katie Barnett from the Clean Energy Investor Group, both asking questions around the lines of what's the problem? What other solutions have we considered? How have we ended up on the journey to get to LMPs and FTRs?

So, again, that's a good question. COGATI, itself, is something that we have a standing terms of reference from the COAG Energy Council to carry out. We have to look at these issues every two years, and we have been looking at these issues for a few years. We have explored some other options but, effectively, when we have looked at other answers or overseas markets it often comes back to the most common model is having some form of LMP and FTRs. There's lots of different details of how those models work that adapted within each of the markets to recognise those differences but they do fall to having those features of LMPs and FTRs.

I guess the other thing we would say is that in terms of another option is just building out all of the transmission infrastructure. Building out all of the congestion, I'm sorry, and while we appreciate that we do need more transmission, as Tom talked about, there's always going to be an efficient level of congestion. I think here I would just like to read out a comment from Andrew Richards from the EUAA who notes that:

A market-based approach to this issue, such as is being proposed here, is preferred over a highly regulated approach where consumers pay all costs through a TNSP RAB or via AEMO interventions.

I think that would be similar with why we see an LMP/FTR regime having benefits. So some good stuff in there and definitely something that we're happy to explore more on a separate session as well.

We've got a few other questions coming through here. So, as I said, if we don't get to each of these questions we will answer them after the forum. There's a detailed question about the technical design which we might take offline, from Andrew Richards again, and there's a few questions around how this might work in other markets which we might get to as we continue through the presentation.

So, if we haven't read out your questions so far, we will try and get to it. I think there's a few places later on where that will make sense to get to. If not, as I said, we will follow up afterwards. I might just hand over to Russell to start us off on the first section of international experience.

MR PENDLEBURY: Thanks, Victoria, and hello everyone. In this section I'm going to cover the context for the commissioning of the NERA report, the benefits and costs they addressed and the different global markets they reviewed as part of the study. If we could go on to the next slide please.

In January this year the AEMC engaged NERA to conduct detailed cost benefit analysis of grid access reform in the NEM. The work was divided into two stages. Stage 1, a benchmarking study of the costs and benefits of similar reforms applied overseas ran from January to March. Stage 2, specific modelling of the reforms as applied to the NEM is being run from April through to the middle of 2020.

The purpose of stage 1 is to broadly define the size of the overall benefits of grid access reform and also to help inform the specific NEM nodal modelling we're conducting in stage 2. Stage 1, while based on international examples, was carefully extrapolated to the characteristics of the NEM wherever possible. The differences between these markets and the NEM were also carefully set out and taken into consideration in drawing any conclusions and the limitations of the conclusions were recognised in this context.

Stage 2 is intended to address the impact of the reforms in the specific context of the NEM and the focus, as we have mentioned, of this workshop is the outcome of stage 1, understanding the international experience, and as Victoria has mentioned, there will be a further workshop looking to address the modelling conducted in stage 2 of the work.

If we could go to the next slide. Thank you. The benefits and costs addressed by NERA. So this slide covers the key categories of impacts that NERA addressed in the stage 1 study and that they will also be covering in stage 2. These categories are as follows. Firstly, changes to dispatch through the introduction of LMP and FTRs. Secondly, changes to investment decisions or a different capital cost development pathway for generation and transmission investment as a result of LMP and FTR implementation. Third, competition effects. Also, potential cost of capital changes.

NERA were also asked to look at the distributional impacts of the reforms or how value or compensation in the market should shift from one group of participants to another as a result of the implementation of LMP and FTRs. The impacts on contract market liquidity was also a key question NERA were asked to address and, finally, the costs of implementing grid access reform were a key focus of the study.

The markets looked at in compiling the report, where NERA considered a total of 10 markets that have implemented some form of LMP and FTRs across the globe and also have published and available literature on that implementation. This includes seven of the key electricity market areas in the US, as Tom showed earlier on the map. So that includes the PJM market on the east coast; the CAISO market, so covering California; ERCOT, covering Texas; the IESO is the Ontario region of Canada; and, also New Zealand and Singapore.

In most of these regions, as Tom mentioned, LMP and FTR was implemented some time ago. The Ontario market is the exception. It's implementing an LMP regime in 2023. Cost benefit studies of these markets were available in most cases, the exception being the PJM market, the New England market and also Singapore. As you will see from the load under each of these markets, some of the markets are similar in size to the NEM, although there are different characteristics. So the Southwest Power Pool, the CAISO market, the Ontario market and the New York market are quite similar, whereas others such as the Mid-Continent, the US market, New Zealand and Singapore are quite different in size. This set of research forms the broad evidence base that NERA used to conduct their analysis of the costs and benefits over these markets. James, if we could move to the next slide. Thank you.

So now we're going to the interactive, the five key interactive sessions of the forum covering the findings from the NERA study. At the beginning of each segment we will introduce the topic by looking at some of the questions and comments we think participants might want to raise. These questions are just a guide and the purpose of these sessions is for you to present your issues and questions. Once I have introduced those questions and issues I will hand over to Will from NERA who will summarise the findings from the NERA study and following that we will look to address your comments and questions. Please feel free, while myself or Will are speaking, to send your questions and comments through for us to address at the end of each segment.

So in this first segment, the impacts on dispatch, we've focused on hearing about your experience of these markets in relation to operational decisions and the operation of dispatch and also any observations you have of the impacts on other market participants and the market as a whole. For example, what are your experiences of the impacts of grid access reform on the efficiency of dispatch in these markets and does bidding behaviour behind constraints differ to what you have observed in the NEM and if so, in what way? With that I will hand over now to Will to talk through the NERA findings.

MR TAYLOR: Yes. So in terms of our findings on dispatch, I guess to start off just with the context of what we did. We view this exercise of the benchmarking as kind of the start of the journey of confirming the benefits and costs of introducing a reform, rather than being the definitive answer, and, of course, I think as Victoria highlighted at the beginning, recognise that these markets are very different from the NEM so you need to take any transfer of those numbers to the NEM with a very, very large serving of salt which is why we think modelling the actual situation in the NEM is very critical. So just to set that caveat out upfront.

So, on dispatch, conceptually in terms of what the benefit is here, it's the fact that if you have zonal pricing and an average price across the zone but congestion within that zone, that can result in the wrong plant being dispatched and that can raise costs in the form of higher fuel costs. The reason this happens, I imagine everyone on this call is familiar with the term of "race to the floor bidding" and the issue around people being unavailable. Another issue which I will come back to very quickly in relation to the US – and this is something we are particularly interested to hear people's feedback on – is how congestion is actually managed when you have this kind of disconnect between zonal prices but nodal dispatch.

So we found five CBAs, cost benefit analyses, that looked at this issue of what is the benefit of more efficient dispatch in terms of lower fuel costs and we translated that to the NEM using estimates available in those CBAs of the impact on variable cost of more efficient dispatch, and that ranged from 0.6 per cent to 2.6 per cent which translates roughly to 30 to 109 million dollars per annum.

A study by IESO, so in relation to Ontario, it didn't look at things in terms of variable costs. They just had dollar amounts and so we translated that across using the size of the NEM, in terms of generation, and that gives the upper bound of the numbers we came up with of 137 million per year.

So, as I alluded to at the beginning, the caveats around these numbers, when you think about whether they apply to Australia, the first one is that most of these markets had firm access so the race to the floor bidding problem that we have in Australia isn't really an issue. There's no incentive for that type of behaviour so you might think that, therefore, those numbers would understate the benefit in the NEM because they don't have the same problem. But, on the other hand, they don't manage congestion as well. Prior to the reforms they didn't manage congestion in the same way that happens in the NEM where there is redispatch in real time that tries to simulate how a nodal market would work. So, in that sense, you might think that the benefits from those markets would overstate what we would get in the NEM.

Then, just the other main issue is that the benefits of this more efficient dispatch are very dependent on the level of congestion and also the generation mix in the different markets. So that's just the health warning when translating these benefits across.

Just reiterating what Russell was saying before, I guess the purpose of these sessions is really to focus on the questions that Russell has raised in the beginning. So Russell is going to raise questions at the beginning, I'm going to give a quick overview of what NERA have found, but then we're very interested to hear people's experiences in relation to Russell's questions. So, at the end of my little quick summary I'm going to then throw back to Victoria, which I will do now, who will manage any Q and A on this topic.

MS MOLLARD: Great. Thanks, Will, and thanks, Russell. So, yes, a few questions coming in. Some of the questions that are coming in relate to sessions that we're going to do later so I might just kind of hold some of them until later. There's one from Panos around implementation costs so we will get to that, but I might just start off with one for Tom. This is from Josh Stabler. He's asked:

Based on substantial growth in household solar, if there's a large scale uptake of residential batteries does that make it easier for LMP and FTR to be implemented?

Now, I know this is more about kind of international experience of that but I wondered if you just wanted to talk briefly about the benefits we saw for large‑scale batteries from this type of reform, how we might take into account residential consumers, and then I might pass after that to Will to see if he had any reflections on that question from anything from the overseas jurisdictions he looked up. So, Tom.

MR WALKER: Thank you, Victoria. Now, that's a good question. I appreciate the question was directed primarily to the concept of uptake of residential solar and batteries but in just indulging me I think one of the key benefits of these reforms may well lie in improved incentives for grid scale transmission connected batteries.

The current arrangement, the current regional pricing arrangements means that effectively batteries can only choose between one of the five regional prices, whereas under a local marginal pricing regime where they locate they would be able to pick their location which has, for example, larger price differences over time at that particular location and that would, you know, suit their business case because essentially batteries are able to arbitrage those price differences by storing when the prices are cheap and obviously exporting when the prices are higher.

You can envisage, therefore, that this would encourage batteries to locate in parts of the network that are constrained, for example. So if there is, for example, a large amount of solar energy being produced behind a particular constraint, the local price will then, at that location, will go quite low. One would expect the batteries would be able to, or the storage device would be able to effectively top up the solar energy which would otherwise be spilt and would do so and would be incentivised to do so by the low prices at that location and when the sun sets or it becomes cloudy the transmission constraint is alleviated, the local price then returns more similar to the region wide price or the prices elsewhere in the region and the battery is then able to discharge at a higher price and arbitrage that price difference.

Those kinds of incentives don't exist under the existing regional pricing model. The battery is not incentivised specifically to locate in these constrained parts of the grid, but I appreciate your question was more around residential uptake of solar and storage. What we're really talking about with these reforms is at the transmission level and so it's not apparent, to us at any rate, or it's not apparent to me at any rate, that it would make things easier or harder or the case stronger or weaker to do the reforms we're suggesting at the transmission level, but the AEMC is considering the impact of the uptake in solar and batteries in our ENERF project, which I confess I just say the acronym so often I've forgotten what it stands for, but our ENERF project is what is looking at these issues at a distribution level.

MS MOLLARD: I think it's the electricity network economic regulatory review which we do annually. Was there anything? I just might pass to Will. I don't know if there was anything that you came across that related to markets where there was a higher take-up of residential solar PB and whether that had any impacts. I'm not sure whether you came across anything or not?

MR TAYLOR: Not off the top of my head, no.

MS MOLLARD: Great. Thank you. There's a couple of questions here which I guess are more around the scope of the works. We might just take them on now. So there was one from Jasper Noort, "Did you look at the impacts of grandfathering?" So the answer on that is I think there's a chapter in the report which we're going to cover later. We were asking NERA to look at the impacts on this type of reform on the WACC. So, as I understand it, NERA did take into account the kind of theoretical impact of grandfathering into that but there wasn't any consideration of grandfathering in the international review context part of the report.

Ben Skinner has also asked a question. I'm sorry. Bear with me. There's lots of questions here. One for you, Will, from Ben Skinner, from AEC. "Did you look into the stakeholder acceptance in those markets before and after the change or not?"

MR TAYLOR: No. So I guess we were focused on – and, again, part of this is just this being the beginning of the journey and thinking about how we do our quantification. We were focused on studies of the costs and benefits where they existed.

MS MOLLARD: All right. Thanks for clarifying that. We've got a comment here from David Dawson who is talking about developing the Philippines WESM. I assume that's the wholesale market. It was noted that incentives around FTRs are critical, which we would definitely agree with, and that FTR incentives may lead to the transmission companies to have incentives either way to invest or to not invest in congested removal. So the whole impact around the structure of the FTRs is something we're definitely alive to as a COGATI team and there's a whole series of work that we're looking into at the moment about how FTRs can be structured, responding to the stakeholder feedback on how can they be as firm as possible.

There's a few others. There's another question around looking, did we look at portfolio impacts. So I think again, as you just kind of articulated, Will, the analysis was really around looking at benefits and costs of the reforms in those markets, not necessarily going into that next granular level of detail. I think that's something we would be particularly interested in and I know we've had comments from other participants about how do these types of reforms impact you if you are a standalone retailer, for example, or if you're a vertically integrated generation retailer. So if anyone has any views on that that would be great to share with us. Awesome. I'm sorry, there's a lot of questions coming through. It's just a bit hard to keep track of them.

There's some questions here. There's one more about how dispatch efficiency would be increased from the introduction of LMP and FTRs. There's a few that relate to that. I might just hand that one to Tom if that's all right. So it's a question from Ron Logan about where generators with the same short run marginal cost locate together. "How does this introduction increase dispatch efficiency if they've got similar locational short line marginal costs? How does that work?"

MR WALKER: I understood the question. Thanks, Ron. So, just to recap the benefits as it would arise. It's that the incentives under the current regional pricing arrangements is for generators to, when they're behind a constraint, to bid to the market full price which is minus a thousand. The dispatch engine dispatches based on bids what underlying costs and it cannot distinguish between identical bids and, therefore, there is some complexity about how it does this. It essentially just pro rates identically priced bids where there's constraints, and, therefore, you might get a situation where, for example, an expensive gas fired generator, for example, is dispatched and pro rated along with zero short run marginal cost generators like say solar, instead of the solar just being dispatched to the full amount of the congestion or the full amount of the constraints which would be the more efficient outcome.

So Ron raises the question, "What happens if both the technologies behind the constraints are zero short run marginal costs?" and in that case you are right; there would be no efficiency gained as a consequence. You're just offsetting one zero short run marginal cost generator with a different short run marginal cost generator.

So in a future where we had a very, very large amount of short run marginal costs generated and nothing else one would expect the benefits to be lower and that's one of the things that NERA are doing when looking into their modelling, but I think a really important caveat to that, an additional point to that to make is one would also expect, or at least conceive of the possibility, that there would also be a large amount of storage in those types of instances and, therefore, it is important to encourage efficient dispatch between storage and zero short run marginal costs generated, so envisage there to be the prospect of benefits in a world with very large amounts of short run marginal costs or zero short run marginal costs generated because in that world we would also have non-zero short run marginal cost generators or entities in the form of battery storage.

MS MOLLARD: Thanks, Tom. That's great. So we've got just a question from Nigel Baker which I think is quite a nice segue to the next section. So he said:

Given the stated benefits relating to dispatch are primarily driven by reduced fuel costs has this benchmarking been considered in the context of the quantities of zero fuel cost renewable energy in the current and future NEM?

Which is a good example of how it is hard to compare different jurisdictions and what the learnings may be. As Tom noted earlier, Texas, ERCOT, and I know there's been a few comments or kind of suggestions that people have some experience with Texas. Matthew Dickie was one of them. We would definitely be keen to hear that. It does have a large number of renewable generators and there has been some evidence there that the introduction of LMPs and FTRs has actually facilitated some introduction of renewable energy, but as kind of Nigel points out, there are a number of other, well, alludes to the benefits relating to dispatch are about reduced fuel costs. We do think there are a number of other benefits or impacts from the introduction of LMP and FTR, one of them being impacts on investments, so we might just move on to that section now. So I will hand back to Russell to talk us through that. Thank you.

MR PENDLEBURY: Thanks, Victoria. So here we are looking at the experience in these markets in relation to investment decision-making in particular, so any observations that you have on the impact on your investment decisions or the investment decisions of other market participants and investment as a whole in these markets. Some of the example questions we have are: to what degree has the LMP/FTR decision influenced your investment perspective in these markets? To what degree have locational prices been factored into your decision-making? Have they impacted locational decisions? Have they impacted the type of technology or combination of technologies involved? With that I will hand over to Will.

MR TAYLOR: Thanks, Russell. So, yes, just to recap what we're talking about here. It's that if you improve the locational signals that plant face – and I guess the key emphasis there is on "improve" – nobody is claiming that there are no locational signals in the NEM, this will improve your incentive to locate plant in the right place. So the benefits that people have quantified around this are reduced costs of investment effectively, in that the capital costs of providing electricity fall if you have fewer but better located plants. Also there's potentially more of an ongoing operational benefit, which gets back to fuel costs which we've just been discussing, if you have better located plant. In essence, if new and more efficient plant that are built are located in better places, they are used more often and that gives you an ongoing additional dispatch benefit.

The only place we found that tried to quantify this – and tried might be liberal – was in New York. So we have taken that benefit and scaled it based upon expected investment in a generation capacity, but there's a very large health warning with this number in that really we couldn't find out how they calculated it and we suspect that it includes a lot of the other things that we have already been talking about like dispatch benefits. On that note I will pass it back to Victoria to facilitate some discussion.

MS MOLLARD: Great. Thanks, Will. So we've got a question from Con Van Kemenade So:

Has NERA looked into the degree of correlation in overseas markets between the prices paid for FTRs as a hedge versus the actual congestion avoided, ie do FTRs represent value for money for businesses?

Now, I don't think NERA have done that but, Tom, do you have any comments to add on that one?

MR WALKER: Yes. That's a very interesting point. So I think this question relates to do FTRs typically pay out more or less or the same as the value or the price at which the owner of the FTRs paid for in the first place? The experience overseas has actually been typically the FTRs pay out quite a bit more than the underlying original price so in that respect it represents good value for the businesses. One might argue that represents poor value for consumers given that the proceeds from the sale of the FTRs are primarily used to offset the consumer's transmission charges, and we actually observed those arrangements or those outcomes, I believe, in the NEM. The settlement residue, the core regional settlement residue auction typically raises less money than the payments from the instruments sold in those auctions.

As I understand it, overseas these markets are looking into why there has been considerable consideration, in both academic literature and amongst the equivalents of the market institutions, as to why is it that the FTRs typically pay out more than they are paid for. Is that a problem and if it is a problem, how might it be rectified?

MR TAYLOR: Just to build on what Tom was saying, there's a section in our report where we set out whether the, I guess the term is whether the auction revenues from the FTRs were fair or not and that's relating to the payouts versus the price paid. There's some evidence there on the fact that in the US the auction revenue has been, quote/unquote, "unfair" and that the payments from those FTRs exceed the revenue that was raised in the auction.

MS MOLLARD: Thank you. We've got another question, probably another few from Andrew Richards again around stating:

LMP and FTRs can manage future congestion but how will it relieve existing congestion or be able to manage existing congestion, maybe especially if existing generators receive grandfathered rights equal to 100 per cent of capacity?

That is always another good thing to throw into the mix, and:

Do we need to invest to resolve existing congestion first?

That's one for you, Tom, I think.

MR WALKER: Look, that's an excellent point. I think it touches on one of the things that I raised in my sort of introductory remarks. It's the need for what we have described as a two-part solution, the first part being – well, in direct answer to your question, "Does LMPs and FTRs alleviate existing congestion?" the answer is no, they don't.

LMP prices congestion and FTR provides a tool to manage that congestion but it doesn't physically alleviate it; therefore, that's why we've suggested that we need the two-part solution with the actioned ISP being the mechanism through which we, with appropriate checks and balances, to ensure that we do not over invest in transmission. The ISP is intended, or the actioned ISP is intended to deliver the appropriate amount of transmission to alleviate some congestion and the appropriate amount of congestion.

We clearly do need to resolve that but the important point is that an efficiently scaled network will never have zero congestion. There is always an appropriate amount of congestion. Congestion is an everyday occurrence in appropriately sized networks and, therefore, it's important that we have LMPs that signal the value of that congestion to market participants and FTRs to appropriately manage that congestion.

MS MOLLARD: Great. Thanks, Tom. There's a few comments here from Matthew Dickie about the importance of taking into account grandfathering in discussing the benefits and has asked whether AEMC needs to take a position in grandfathering before accessing the benefits because otherwise the benefits will be artificially inflated. Yes, absolutely we agree. It's really important to consider grandfathering and that's something that we, you know, is one of the top areas of the design of the model that we are considering. So there will be something on that shortly. So just to flag that, not the subject of today but we are aware that it is quite an important consideration in our thinking about that.

I might just go on to Ron. Ron has talked a little bit about, he's made a comment, so, Pete, I might get you to take Ron Logan off mute, if that's all right, in a second. So, Ron has noted that concerns have been raised in at least PJM with regards to flaws in the design of FTRs and has asked whether further analysis can be provided regarding that. So I just wonder if we could get Ron to speak just to provide a little bit more detail about what those flaws might be. That sounds like it's a useful thing to hear about. So hopefully Ron is off mute now.

MR LOGAN: Hello. Can you hear me?

MS MOLLARD: Yes, we can hear you, Ron.

MR LOGAN: I've heard – and we won't go into them too discretely – but I've heard that in the PJM market there has been raised some concerns around flaws with regards to market power issues and not being suitable in that for the PJM and they are considering alternatives. I noted – I was just concerned that that wasn't in the report and hadn't been noted and I just think it's something that possibly should have been noted and should have been documented in the report.

MS MOLLARD: Thanks, Ron. So I think part of that might be because we didn't necessarily ask NERA to do that but, Tom, do you want to add a bit more around some of the market power issues and if there is more information on that we would certainly be interested in hearing about that? Do you want to talk to that, Tom?

MR WALKER: So I'm not familiar with that – and I'm glad you've raised it because I don't think we are familiar with the specific concerns being raised or that were raised in PJM and, you know, the kind of changes they have made or are considering making. So it's excellent that you've raised it so that we can go away and investigate.

We are aware, and in previous reports have noted, previous AEMC reports have noted the possibility that local marginal pricing will make market power more transparent and may allow it to be exercised in a different manner. I will note that we don't consider that the instances of when localised market power will arise will be any different but it may well be that how that market power is exercised is different and needs to be carefully considered.

In that light one of the work streams that we're progressing at the moment is to look into more detail at the market power mitigation measures that have been put in place in the US and in New Zealand. I believe in one of our earlier reports we had an appendix on this concept or these concepts and we're going into a bit more detail in our analysis. That is still relatively early days in that analysis so I don't think we're in a position to sort of share any findings but in due course we will be keen to feedback on the best approach.

MS MOLLARD: Thank you. Further, it's more the question more about process from Ken McAlpine which is:

Why would we do LMP and FTR now when the necessary transmission has not yet been built? Changes being sent to the Energy Council by the end of 2020 seems quite premature.

So on that one I would say that, you know, we think it's important that now is the time to be working out what access reform would look like. It's important. It's part of the Energy Security Board's 2025 work. There's a difference between when real changes need to be worked out and what the detail looks like versus when it would be implemented, and we have said through our various reports that if it was to be implemented it would be in the order of four years from whenever the final rules were made so we are still talking some time away in terms of if this was to be implemented.

MR WALKER: Can I answer that, Victoria, as well, in that local marginal pricing is more beneficial in an arrangement where, more beneficial compared to regional pricing in arrangements where there are substantial amounts of transmission constraints because that is the time when the local marginal prices differ from one another the most and, therefore, the regional pricing arrangements are most inaccurate.

So, clearly there's a timing difference about now, when this gets implemented, and when the transmission actually gets built out, but to be clear, I don't think it's the case that we need to build the transmission infrastructure in order to make local marginal pricing and financial transmission rights work. They work regardless of the amount of transmission infrastructure that there is and they are most beneficial compared to the (indistinct) of regional pricing in instances where there is a shortcoming in the amount of transmission infrastructure that there is.

MS MOLLARD: Thanks, Tom. That's a really good point as well. So we might just end the section with a general comment from Tim Blackmore who said that:

The payouts to owners could get excessive if congestion keeps building as investment around strong points in the NEM continues to occur. That said, if the investment is encouraged in regions with higher resource now; good.

I think that's interesting. I don't know, Tom, if you want to respond to that reflection or comment. Perhaps that's a good segue into the next section.

MR WALKER: Yes. I'm sorry, Victoria, I missed what you were saying actually. Can you either repeat the question or – well, could you repeat the question?

MS MOLLARD: It's just a general comment about, you know, the payout to owners could get excesses if congestion keeps building as investment around strong points in the NEM continues to occur, but if investments is encouraged in regions with higher resources now, good.

MR WALKER: I assume that comment is the payout under the financial transmission rights. I assume that's what the comment is. So the way it would work is the payouts are the difference between the local price and another price, typically the regional price. So if a generator or an asset is in a part of the network that is constrained and, therefore, either the price is low, typically is lower than it would otherwise have been, or is more frequently lower than the regional price than it would otherwise have been, or the combination of both, then the FTR payout would be more and more frequent, but, of course, the generator at that location will also receive a lower price by virtue of that, through the wholesale market directly by virtue of that lower price.

So the purpose of the FTRs is to mitigate that risk of those lower prices. Yes, the prices are lower but the FTR payout is higher and the two, in broad terms, match, providing the quantity of FTRs of the bulk of participant holdings matches their generation assets or their generation dispatch in question. So I don't think it's a concern that the FTR payouts will become substantial in instances of congestion.

MS MOLLARD: Great. Thanks, Tom. So we might, just in the interests of time, want to make sure we leave some time for Tom Geiser to share his observations at the end. So we might just move on to the next section, so back to you, Russell.

MR PENDLEBURY: Thanks, Victoria. This section covers three areas addressed by NERA in the report: the impact of LMPs and FTRs on the cost of capital; the impact on contract market liquidity and the impact on competition, both in the wholesale and the retail space. In terms of questions in relation to the cost of capital, we would like to hear your view on whether there's been any change in the cost of capital in response to the implementation of LMP/FTRs in these markets. Has LMP/FTR market design been a tool influential in the cost of capital in these markets? To what extent have FTR type products helped to mitigate the impact of locational marginal prices in these markets? Are you aware of any investment being deferred as a consequence of the implementation of LMP/FTRs in these markets?

In relation to contract market liquidity, has the implementation of LMP and FTRs changed your willingness, need or desire to participate in a contract market or the amount of capacity you choose to trade in the contract market? Have you observed any impact on contract market liquidity across these markets as a whole or on the signing or operation of PPAs on longer term contracts?

Finally, what impact do you think LMP/FTRs have had on competition in these markets, both at the wholesale and retail level. With that, I will hand over to Will.

MR TAYLOR: Thanks, Russell. So the starting thing to note on the cost of capital is that none of the studies we looked at considered the issue so we weren't really able to find any evidence of the other policymakers considering this impact.

So the next thing we looked at was whether – and this is kind of moving away from benchmarking, I guess, because we couldn't find any discussion of this specific point – so we looked at what credit rating agencies and equity analysts in Australia have been saying about the impact of COGATI. We also didn't really find any discussion of that which really has two possible explanations, that it's too early to say because this thing hasn't happened yet, or that they don't think it's an issue, and we're not forming a view on why they have or haven't talked about it.

So we've then done some very initial analysis – and, you know, I just want to emphasise that this is initial analysis and there's still a long way to go – to try and think about, from a more first principles perspective, what would the impact on the cost of capital be.

So in terms of the cost of equity, we thought about that using the capital asset pricing model framework that is commonly used by policymakers and regulators. Our view is that constraint risk, which is the key thing you're exposed to under nodal pricing, isn't systematic. So, in that kind of theoretical framework, it doesn't affect the cost of equity.

On the cost of debt, there's quite a lengthy discussion of this in our report where we set out the framework for how COGATI might impact the cost of that because debt holders are concerned with the absolute level of risk rather than systematic risk in that theoretical CAPM world. We set out that the impact on the cost of debt depends on a couple of factors, which are: whether FTRs are firm, the likelihood that you actually get an FTR, which is related to the points about grandfathering which we've been seeing come up in the questions, and also how the auctions work and stuff like that, which goes back to that unfair value point we were also discussing, and then also the relative volatility of the regional reference price versus the nodal price that you would face in the new world.

Based on those four factors our overall conclusion is we don't know what will happen to the cost of debt without doing further work on those specific points. We do set out, there's a number which is on these slides, what could happen to the cost of debt effectively if everything works out perfectly as planned. So, I mean you can kind of view this as the best case if the reforms are really successful, and that's an impact of 30 to 50 basis points on the cost of debt which you would then scale down by leverage to work out the impact on WACC.

I guess the other point is around regulatory risk. So this is obviously an interesting point. The way that we think about this as economists is that change, in and of itself, doesn't create regulatory risk. It's whether the change is unexpected and unjustifiable. So it's something we've taken a relatively high level view on at the moment, but we didn't see the introduction of nodal pricing and FTRs as violating that constraint as such.

So I think, as Russell may have flagged, we've got three different areas and so we're just going to whip through them and then discuss all three of them together at the end, so if we could move on to the next slide.

So the next issue is liquidity and this is really an issue around introducing FTRs and whether that affects people's willingness to contract in the forward markets. When we looked at the studies of introducing nodal pricing and FTRs in general this wasn't really talked about so we didn't really learn much from the studies we looked at on the specific point.

The one thing that we did find is that the distribution of liquidity seemed to change, which really makes sense that if you go from relatively centralised markets with single prices and then you split it up that you then have liquidity moving to those different places, but there was no specific analysis of whether that resulted in the overall level of trading decreasing. It's just that it got split up into different hubs.

There's also, I guess, a big caveat to this in that most of this analysis comes from the US where the downstream retail market structure is very different from what we have in the NEM. We often still have, even in these markets with competitive generation, incumbent retailers who are vertically integrated and have regulated rates where wholesale prices are passed through, so there's quite different incentives to hedge versus the NEM. These are the kinds of things that we're interested to hear people's experiences about. I think, on that note, we will whip through to the next slide before we then have a discussion.

So the final one was whether introducing FTRs might improve competition and the way that this might happen is that if you improve inter-regional risk management that might increase the appetite of firms to either compete for retail customers in areas where they don't have generation, or, conversely, people might be willing to build generation in regional areas where they don't have customers on the basis that previously the best way that they could hedge locational price risk is to just locate your load and your generation in the same areas.

So this was something that was an issue in New Zealand that the Electricity Authority looked at and was one of the main reasons that they looked at introducing FTRs. It's that we had these kind of islands. Well, I mean we have literal islands but there are islands of competition where the main generator in the South Island only really competed for retail customers in the South Island, so the theory there was that if you introduce FTRs you would get people venturing into other regions to start competing.

The way that they quantified this was basically to assume that there was a price decrease, which is a reason that we don't place a lot of weight on this number, particularly because there's not a lot of analysis on why prices would fall by that much or an analysis of showing that there's actually an existing competition problem to then base that assumed price decrease on. So we think that this number needs to be treated with caution. I think that is the end of our quick overview of those three topics so I will turn it back to Victoria to facilitate some discussion.

MS MOLLARD: All right. Thanks, Will. So one from Josh Stabler, Energy Edge. I think for you, Tom.

As the locational prices become more different, so higher congestion, the higher the buyer's risk in the market. That will surely have a detrimental impact on financial market liquidity. Has this been assessed?

Tom, do you want to answer that one?

MR WALKER: That's a great question and one that, in various guises, gets raised quite often. Obviously NERA had a look at the question of liquidity overseas and as well has just said this does not appear to be a heavily considered topic elsewhere. You know, there might be various reasons why that's the case, but it might well be the case that it doesn't appear to be a significant concern now, and that actually is consistent with at least our theoretical understanding of the way this would work.

We are obviously keen to try to understand. This is why we're keen to understand people's international experiences because, you know, we want to understand as much evidence as possible, but our theoretical reason to think that the financial market liquidity would not decline is for a couple of related reasons.

Firstly, only considering locational marginal prices in isolation would, I think, increase the basis risk but that's the purpose of the financial transmission rights. The financial transmission rights are a mechanism by which market participants can manage that basis risk.

The second, I think, important point to note is that market participants already face congestion risk. So the congestion risk they face at the moment is that the quantity of their generation is reduced and, hence, their revenue, and under the arrangements with financial transmission rights market participant can protect themselves against congestion by acquiring these financial transmission rights which makes them largely indifferent to the presence or otherwise of congestion, or more indifferent than the current arrangements.

I think a really important point to think about, and in our analysis, has been not whether locational marginal pricing and FTRs reduce congestion risk to zero because it doesn't. What it does is locational marginal pricing and FTRs, in our opinion, allows market participants to better manage congestion and reduce their volatility of their revenues compared to profits, compared to the status quo arrangements.

This has been a point of, I guess, contention and so we are keen to continue to explore this topic and welcome views as to why we're wrong compared to the status quo essentially.

MS MOLLARD: Thanks, Tom. So just another hopefully quick one from Tom Geiser, "Do FTRs and other markets experience system security constraints?" Tom or Will, do you want to take that one?

MR WALKER: I can. My understanding is that at least in New Zealand the answer is yes. Any system security constraints that are in their equivalent of a dispatch engine influence locational marginal prices and are paid out under the FTRs. That's my understanding anyway. I don't know about all of the US markets. Well, I wouldn't want to speculate.

MS MOLLARD: Thank you. So we've got one here from Panos from Snowy Hydro which might be one for Russell or Will. So:

If there are competition benefits and no serious liquidity issues in New Zealand then to access reform why does New Zealand have market making arrangements to provide liquidity?

Is there some history there that you guys can speak to?

MR PENDLEBURY: Yes, I'm happy, Victoria, to start answering that question. New Zealand's market making scheme was designed, I think, because under situations of quite high stress in the market people were stepping away from contract trading so that scheme, that voluntary scheme was put in place to ensure, during difficult trading conditions, there would be more than one participant in the market to ensure liquidity continued to be present through those difficult circumstances.

MS MOLLARD: Will, did you want to add anything on that?

MR TAYLOR: Just that I mean everybody wants more liquidity and liquidity is quite a complicated and interesting topic. I think an issue with New Zealand around liquidity and why there's this desire for market making is very similar to the debates that have been happening in the NEM about vertical integration and what is the most efficient way for generator retailers to manage the underlying risk. It's not even necessarily nodal. So, in New Zealand we have lots of risk around hydro.

Russell's point about the key concern about marketing making is right. It's when we have long-term droughts that there's a concern that the market becomes very volatile and that that makes the people who are trading futures contracts pull out. So they needed to kind of reform that arrangement.

MS MOLLARD: Thank you. There are a few comments here, and we are after comments as well, so please feel free to provide that. From Josh Stabler noting on liquidity: South Australia is a clear and present danger of low liquidity, which I think all of us here in the NEM, as you say, liquidity is a deep and interesting topic in and of its own right.

We might just quickly move on to the next section because there are a lot of questions coming in, particularly around the implementation costs. That would be good to get to and then provide a few people who want to speak. Matthew Dickie from Innogy Energy, you also noted that you might have some experience from Texas. Could you just confirm for me on the chat, if that's all right, whether you're happy to share that today or whether you would like us to follow up with you? If you could confirm that would be awesome but I might just hand back to Russell to go through distributional impacts. Thank you.

MR PENDLEBURY: Thanks, Victoria. This section, as Victoria says, covers distributional impacts or potential changes in compensation between different market participants as a consequence of LMP/FTR introduction. Some example questions we have are: What price impacts have you seen to your operations, either as a whole or to an asset or a class of assets in particular as a result of LMP pricing that you feel would not have been felt were there to have been regional pricing in place or an alternative market design? Will, over to you?

MR TAYLOR: Thanks, Russell. So, again to start – and this seems to be a bit of a common theme on some of these topics – is that in the assessments that we looked at distributional features didn't feature very heavily.

At a conceptual level, the key change when you go from a regional or zonal price to nodal pricing, is that this results in winners and losers. The two bullets on the slide set out the effect on different situations depending on whether the regional reference price was higher or lower than the nodal price that people end up receiving.

So in a scenario where the regional reference price is higher than the LMP at a particular node, moving to LMP results in effectively a transfer from generators to consumers because generators are now receiving a lower price than they would beforehand and you have the opposite situation where the regional reference prices are lower than the LMP.

So, as I said, nobody looked at these specific distributional impacts. The one thing we did find was that ERCOT looked at the actual price fall and the impact that had on consumers but that's not purely a distributional issue. That's the combined impact of any distributional effects and also any efficiency gains. So, again, there's a number there but that's wrapping up a whole bunch of other things, including the things we've already talked about.

Another key point, I think to look at, is if you were trying to compare the situation in other countries to the NEM that these transfers really depend on how congestion was managed before the reform. That's just another reason that it's really important to look at, specifically, what the situation is in the NEM.

We've also mentioned the work of Gordon Leslie and Matthew Katzen which shows that there is currently overcompensation in the NEM which suggests that, on balance I think, it's a situation where the regional reference price is greater than the LMP, which is why they're finding net overcompensation. I think that's all I had on that one so I think we will kick it back to Victoria.

MS MOLLARD: Awesome. Thank you. So there's a question here from Matthew Dickie again which doesn't directly go to distributional impacts but is somewhat related. So, it's for Tom. The comment is, "Under LMP congestion is good and pumps up the benefits. For generators we had hoped access reform would mitigate congestion." Do you want to talk to that one?

MR WALKER: I'm sorry, can you repeat that please?

MS MOLLARD: Sure. So, "Under LMP congestion is good and pumps up the benefits. For generators we had hoped access reform would mitigate congestion."

MR WALKER: Okay. So I'm not suggesting that congestion is a good thing. I'm saying that congestion is an inevitable thing in an appropriately-sized transmission network and, therefore, it would be sensible to value electricity based on its underlying value at different locations in the network, which is what locational marginal pricing does, and, therefore, the relative benefits of locational marginal prices versus regional prices is higher in a congested network as composed to a non-congested network. It would certainly be completely wrongheaded to think that we shouldn't be building out transmission to the extent it alleviates congestion, where that congestion is inefficient, simply in order to make locational marginal pricing have a higher benefit.

So it's important we build the transmission network to be efficiently sized. Whatever happens, if it is efficiently sized we will still have congestion and it is appropriate that we then price that congestion appropriately. In turn, that will allow for less generation plant needing to be built or more efficiently located generation plants, more efficiently timed and located transmission infrastructure and so on and so forth to flow. I hope that answers the question.

MS MOLLARD: Thank you. So we've got a question here from Sam Stewart asking us:

Is there any evidence of FTRs that are being used to de-risk investment in new generation projects? It seems to be New Zealand's are limited FTR rollout for retail competition purposes rather than locational signals.

So, good question. Thanks, Sam. I think it, again, speaks to some of the stuff we've touched on about the problematic issues of comparing different jurisdictions and the underlying kind of generation mix and different drives and everything that is behind them. So that drives different outcomes of what these might be used for, but I don't know if, Tom or Will, if you wanted to add anything to that in response to that question.

MR WALKER: Look, I mean I might be handballing this one to Will a little bit but I think, from my recollection, that Texas has seen a lot of investment in generation infrastructure subsequent to the introduction of locational marginal prices and FTRs. I don't know how easy it is to determine that the cause of that investment was as a result of this, as a result of the regulatory change, or that that investment is greater than or less than it would have otherwise have been, but I think that is at least evidence to suggest that locational marginal pricing and FTRs have not been a dramatic brake on investment in the transition that Texas is going through to a lower emissions future. Have I got that right, Will?

MR TAYLOR: I think that's right. I mean I can comment briefly on New Zealand as well if that's useful.

MS MOLLARD: Yes, please.

MR TAYLOR: Yes, so I mean in New Zealand there's been a concern about retail competition. That was part of it but I guess there was a motivation in terms of getting more geographic competition on the generation side as well, so it wasn't just focused on retail, although that's probably where most of the discussion is around.

I mean there has been an increase in, I guess, the geographic spread of generation in New Zealand. Again, it's always hard to make these comparisons because more than 60 per cent of New Zealand's generation is in hydro and it's all in the South Island. So to the extent that people such as Meridian, who is the big hydro generator, are willing to venture out of the South Island, naturally a lot of what they are already doing is there, but we are seeing wind farms pop up in the North Island that, for example, Meridian own. So there has been an increase, I think, but it's not something we've assessed in a methodical way.

MR PENDLEBURY: Tom, just going back to your point on ERCOT. It was actually covered in the NERA report the change in the share of solar and wind generation in the ERCOT market between when the reforms were implemented and where we are today and what you see is a significant increase in the share of that generation in the overall mix.

MS MOLLARD: All right. Thank you. There's a comment here from Sam Stewart on the ERCOT experience. So Sam notes that:

The ERCOT doesn't rely on the limited locational signal of their LMP framework to coordinate generation and transmission investment. In 2008 the PUC decided to invest US$6.8 billion to develop the transmission network to facilitate 18 gigawatts of new wind.

If I can just respond to that. That is right and they did invest in effectively REZs in Texas, although there is quite an interesting case study in terms of what actually eventuated. The demands dropped away and then they discovered gas in those areas where they were building out the transmission network so it kind of was used to facilitate other things as well.

So, it's a good example that in all of these international case studies, as kind of, you know, Will, Tom and Russell have all alluded to, there's a lot going on behind that and there's lots of comments coming through now on Texas, actually, which is awesome. Matthew Dickie. Pete, can we take Matthew Dickie off mute because he has suggested that now would be a good time for him to talk to Texas. So hopefully, Matthew, you are now off mute.

MR DICKIE: Victoria, can you hear me?

MS MOLLARD: Yes. Thank you. Over to you, Matthew.

MR DICKIE: Great. Thank you. So we've got a number of projects in Texas and our regulatory affairs director over there, he's actually a board member at the market operator, ERCOT, over there, and his view on LMP and FTRs over there is that I guess the big build out in renewables occurred not so much because of LMP and FTRs but much more because of that big grid build out to the renewable energy zones, and he also noted that because the losses over there are more socialised there's also not that locational impact that renewable generators are facing. So those have been a couple of the big drivers of build out of renewables there.

But, I guess going to that point, if I can just ask a question on that. I know now that there's work going on with the Energy Security Board on an interim arrangement for renewable energy zones where there could be a level of firm physical access provided as part of a REZ proposal. Do you see any potential for that sort of framework to coexist with a COGATI proposal or the longer term into the future?

MS MOLLARD: Good question, Matthew, and I should also point out that a few people on the chat have also asked similar questions about the relationship between this work and REZs. So, as you alluded, the ESB are doing work on interim REZ development. Some of you might have listened in to a webinar that they ran a few weeks ago on that. As was made quite clear through that webinar by David Swift was that REZs are the interim solution and COGATI is this longer-term solution to access.

As you talked about, the REZs is about creating this type of potential physical access to a small area of the grid. COGATI is about financial access in the longer term and so we see them as being compliments, not substitutes. They can work hand in hand together and we're working quite closely with the ESB on that piece of work.

Yes, we have Jess Hunt on the line who is helping the ESB with this. So, Pete, could we, perhaps, maybe just take Jess off mute to see if she wants to add anything more to what I just said? So, Jess Hunt, hopefully you're going to be off mute in a second.

MS HUNT: Yes. Can you hear me?

MS MOLLARD: Yes. Thank you.

MS HUNT: Great. Yes, hi. Thanks, Victoria. Yes, I agree with everything that Victoria just said. We are being quite careful to try and design anything that happens in the interim framework to be able to peacefully coexist with the COGATI regime. So we aren't looking to introduce anything that would affect dispatch or create sort of financial access rights in the traditional format. More what is under consideration is to provide some sort of protection, more in the planning time frames, so that the REZs would be designed in a way that would sort of give participants in the REZ confidence that they are not likely to have their ability to generate undermined by subsequent generator connections. So it's basically, it's a bit more limited than what would be proposed in the context of COGATI.

MS MOLLARD: Awesome. Thank you, Jess. I might just share a statement from Andrew Richards on that as well before we move on to implementation costs and then give Tom Geiser an opportunity to speak. So, Andrew Richards from the EUAA has just noted that:

The shared cost in risk arrangements being contemplated as part of RES are a welcome development. Consumers should not be carrying the entire burden.

So, good comment. Thank you, Andrew. So, just back to you, Russell, for the last section.

MR PENDLEBURY: Thanks, Victoria. If we could move to the next slide. So, yes, as Victoria said, this is the last section today and we would like to hear about your experience of these markets. In relation to the impact on the cost of your operations has it been harder or easier to operate as a consequence of LMP/FTRs? What cost can you attribute to the operation of LMP/FTR markets versus your operations in the NEM? Have you observed any difficulties for the market operator in operating in LMP/FTR markets? Have you observed any benefits to the market operator? With that, again, I will hand over to Will.

MR TAYLOR: Thanks, Russell. So I guess when we looked at this and the studies that have analysed these costs overseas, the key thing that we found is that a lot of the time LMP and FTRs were introduced in the context of other reforms. So when there were cost estimates they often related to a whole bunch of other things which makes it really hard to disentangle what proportion of this just relates to bringing in LMP and FTRs.

The one that we did find, which was relatively clean in terms of just focusing on LMP and FTRs, was in Ontario in Canada, which is also relatively recent. So we placed the most weight on that estimate given the fact that it is recent and focuses on the same types of reforms.

The other thing to note with the other estimates that we found is that they are often very old and if a lot of the costs associated with this reform would be IT costs then it's really not clear how relevant an estimate of IT costs 15 years ago is to what it would cost to do something similar today, which is the other reason why we placed much more weight on what's happening in Canada at the moment.

The key caveats in talking of these types of numbers is that in general they have been ex ante estimates. So, for example, the Ontario number is what the regulator or the system operator thinks it's going to cost. So this doesn't account for any cost escalation which might occur, which we've seen in some of the other studies of this, for example, in ERCOT where there were cost overruns, and also we think that this number probably underestimates the costs of looking at FTRs given that in Ontario there is already an FTR regime with the neighbouring regional markets. So FTRs aren't a completely new phenomenon like they would be in the NEM.

Also, so, for example, in New Zealand where they just looked at FTRs, and I think it was the SPP as well that split out an FTR number, the numbers that they found were higher than the numbers that the ISO study for Ontario had. So we think that there's a lot of upward risk around this number, even bearing in mind the usual caveats of can you compare what's happened overseas to the NEM. On that note I will kick back to Victoria.

MS MOLLARD: Thank you, Will. So we had a couple of questions on implementation costs earlier in the presentation which I might now just bring up. So one, again, was from Andrew Richards from EUAA:

NERA looked at obviously the implementation costs. Did you look at any differences in operating costs of (indistinct) individual participants that might have changed as a result of introducing the reform?

Do you look at that, Will?

MR TAYLOR: Yes. So I think that under that heading it is includes costs for the individual participants and participating in these markets was accounted for. It was generally, I think, looking at the systems that individual market participants would need to develop to then continue to participate in, for example, FTR markets.

MS MOLLARD: Thank you.

MR PENDLEBURY: It is worth emphasising that some of these jurisdictions, when they did the CBA, they did vary according to the degree to which they take participant costs into account. So I think ERCOT, for example, spent a bit more time doing that but some of the other studies didn't.

MS MOLLARD: All right. Thank you. There's a question here from Panos, I think maybe more directed for you, Tom. So Panos has actually asked, "Is the AEMC concerned that the complexities in Texas could lead to the cost quadrupling in the NEM?" but maybe if we could just talk a bit about how we would take into a cost any estimates of implementation costs and thinking about that. That would be great. Thank you.

MR WALKER: Yes, thanks. So I think my question is alluding to the ERCOT experience which was they did have substantial implementation cost increases compared to their original estimates and, of course, I think it is right to say that the AEMC are concerned that any estimate is exactly that's an estimate and could well be far higher than the ultimate cost. We would obviously need to, as an industry, ourselves, and through our consultation with industry and through the engagement of professionals who look at these type of things, to come to the best estimate we can of the costs and to recognise clearly the upside, or the down and up risk of those costs in coming to, you know, our ultimate decision about whether to proceed.

MS MOLLARD: And that's, I guess, just to add to what Tom was saying, you know, I think that's why it's really important that COGATI is one of the seven MDIs of the ESB's 2025 work because to the extent that reforms can be coordinated and linked to each other then that kind of coordination of reforms and any implementation costs should be more efficient if you can do things together at the same time and have regard to what's going on in other work streams or other reforms that have been contemplated. So that's why it's really important for us that this is one of the seven MDIs of the ESB's 2025 work.

Katie Barnett has just asked a question around costs of implementation for participants as well as transactional costs like grandfathering. "Are they going to be included?" So we are going to do a bit more work on the implementation costs. So NERA are not looking at that. We are doing work on the implementation costs separately and that's something we're going to be working on later in this year. So we will definitely want to take it into account to the extent we can so we will be coming back to you all on the answer to that question.

Then this is a good question from Ben Skinner. So a key question is whether the introduction of locational marginal pricing project includes a network model NEMD, so whether there needs to be changes to the dispatch engine. This was something we recognised in the (indistinct) report that we published in March as well, that assertion and things were flagged might require changes. "Did other markets have to rebuild dispatch engines and should this cost be included in the cost estimate?" Tom, you are probably best placed to answer that and you've taken your hand off mute so clearly you're keen to answer that one. Thank you.

MR WALKER: Well, I don't know whether I might regret that. Look, I will have to confirm but my understanding is they did need to change their dispatch engines. So in the earlier model, in the earlier markets, in the markets which did this earlier, did not have security constrained dispatch in the first place and, therefore, I think this is the kind of benefits that Will was alluding to that it's hard to distinguish different starting points essentially.

Some of these markets, you know, would basically have inferior designs than the current NEM and have sort of, in my view, sort of leapfrogged it, the current NEM, so the question then is, you know, we're trying to assess the benefits of the kind of marginal benefits as a result. So I think they did have to rebuild their dispatch engines, although I'm not exactly familiar with to what extent and so on and so forth.

You then alluded to, well, you then ask should these costs ever be included or even be included in the costs estimate? I'm not exactly sure what you're getting at. Maybe you're alluding to the idea that we might well want to make changes to the dispatch engine regardless, as a consequence of other MDIs and I think that's were Victoria's point was important, which is if we can coordinate these reforms, or as a consequence of coordinating these reforms, these costs that are incurred can be more efficient. Effectively it changes the cost benefits analysis or the ratios of the costs and the benefits change if the costs are essentially shared between multiple projects which have multiple benefits to them.

MS MOLLARD: Yes. Good points, Tom. So that kind of comes back to that different markets have different starting points and so that's why care has to be taken in using those numbers. The NEM actually has a lot of that functionality already in NEMDE but that's where, again, the benefits of kind of coordinating reforms come from. Ben has confirmed, Tom, thank you, that's what he meant so thank you for that.

MR WALKER: I would probably add another point which is that depending on the specific design of these reforms we do not consider that changes would be required to the dispatch engine. So if we retain the existing regional reference node pricing for non-scheduled participants, if we were to retain the statically calculated marginal risk factors, then our understanding is that the dispatch engine, as it currently stands, is able to implement these reforms and that's because the dispatch engine, as it stands, already calculates and has always calculated locational marginal prices in every relevant transmission connection points for every five minutes since markets start. So we already have that information and it would just be a case of utilising those prices that currently are not utilised at the moment.

MS MOLLARD: Thank you. So I've been promising Tom Geiser an option to speak the whole way through so I think now would be a good time to have that. So, Pete, can we please take Tom off mute and hear Tom's views on international experience.

MR GEISER: Can you hear me?

MS MOLLARD: Yes. Thank you, Tom.

MR GEISER: I just muted myself. Thanks, Victoria. So I had a chat with the head of development in the US. Neoen is a pretty new player in the US. So there's an interesting perspective on the competitive environment and how easy it is, you know, sort of how easy it is to break into the market there. So she said to me to get a network access agreement you need to join a project queue. The modelling is run by the TNSP and it's opaque so the generator can't look into it and see what's happening. You have to anticipate other projects near you joining the queue and if those new projects enter the queue it can reopen your application. The application and network study costs can be over a million dollars depending on the jurisdiction in the US and again, depending on the jurisdiction, the costs are uncertain and not necessarily capped. So that's a pretty significant increase in the uncertainty of the development process and the cost of bringing a new generator to market.

On the firmness of access, it is discontinuous, so your rights can vary over time which can have an impact on your ability to contract a PPA or acquire debt. Projects may have to adhere to schedules which is kind of like an operational constraint schedule and you have to pay opex for these schedules as part of access and dozens of schedules may apply to one project.

Bankruptcy is not uncommon for projects and her comment was that investment is highly speculative with projects bought and sold multiple times on the assumption of network access rights and effectively she saw it that there's highly experienced middle men who are the main beneficiaries of the process, not necessarily the new generators seeking access.

So, overall there's risk uncertainty and duration added to development. That's less of an issue for established players and the regulated utilities themselves. So keeping in mind that a lot of these jurisdictions has a centralised body who makes decisions about which generators are allowed to build, which transmission lines are going to be built and how those costs were to consumers.

The other thing, we talked a bit before about FTR payouts and cost of capital. I think it's really worth bringing up the fact that in the US the big lever – and it absolutely dwarfs any of these sort of efficiency things – is the cost of capital is tax incentives for new supply. So renewable projects receive an upfront 30 per cent capital reduction and another – I'm not sure of all of the details but there are certainly lots of incentives for oil and gas production. So what you often see is the capital costs can be relatively high in the US where it brings productivity benefits, so that it's not necessarily the lowest cost of energy without those incentives compared with a market like Australia.

The oil supply incentives have meant that you've got negative priced gas in Texas on occasion so there are strong incentives to invest in generation because you're not allowed to flare it necessarily. So people will build a generator for the purpose simply of burning gas. They don't really care about the market outcome. So we've got to take a lot of this stuff with a grain of salt in terms of whether it's LMP that's delivering these benefit. I definitely agree with Matt Dickie that, you know, bringing in transmission means you can access a better levelised cost of energy.

Just a couple more comments. Neoen intentionally avoid ERCOT because of the above, you know, the things that I've mentioned before. So they have chosen not to play in that market because we saw it as difficult to enter.

On FTR payouts it's worth noting from the customer's perspective it's a pooled risk but from the generator's perspective it's an individual risk, so they are going to wake it in a way that they want to receive a net benefit essentially because if they don't benefit it significantly affects them. So, I'm not saying that's a bad thing. If there's, you know, increase in certainty for a generator is high that leads to cost to capital benefits as alluded to. As long as that outweighs any transfer from customers to generators through FTRs we win.

One more comment. I'm sorry, I've taken up a lot of time. Overall I note that the analysis is very Anglocentric. We're really just looking at New Zealand and the US. Singapore is kind of, I mean it's a city. It's not a 7,000-kilometre long transmission network. Thanks very much. Thanks for your time.

MS MOLLARD: All right. Thanks, Tom, and thank you for those very kind, considered and thoughtful comments. I think that's really useful for us. I think what I would say as well is that one of the things that we're wanting to do is understand what's happening in overseas markets and those experiences so that we can avoid them happening here. A lot of some of those things that you were talking about, in terms of the connections process and context, we actually have a different starting point here in the NEM; for example, you know, we don't have queuing for connections. We have a lot more transparency about modelling. Generators do their own modelling and provide this.

We have made recent rules which are all based around increasing transparency for participants to try and avoid some of those problems with the connection process. You know, we're doing a lot of work in the system security space around do no harm system strength assessments, which, again, kind of suffer from some of those perhaps problems about kind of complexity and lack of transparency.

So kind of as a general comment, all of those other things that make the generators' connection experience are perhaps a little outside the COGATI process but are a different starting point and we have a lot of things that are in the NEM that are very different to what happens in the US, but all of those kind of other points that you went on to make in terms of experience in different markets, risk, uncertainty, all of that stuff is really helpful feedback and so we will definitely kind of mull on that and think about that. I don't know if anyone else from the team wanted to add any quick reflections to Tom's thoughts there. No?

So we might just, in the interests of time, move just to the last slide, James, on next steps. I would like to really thank you all very much for taking two hours of your time to sit through this. Everyone has pretty much stayed on the line the whole time. We've had a lot of interest and a lot of questions, a lot of questions that we haven't been able to get around to answering. Thank you for asking the questions and apologies that we haven't got around to answering them. We will kind of follow up with you all if we haven't got to one of your questions, either separately or on a bit of a response on our website on the project page.

As I mentioned earlier, the presentation material and minutes are going to be published on our website after the forum so look out for that and our newsletter next week. We do have our email addresses there. Russell and Tom as well, so if you do want to follow up on anything or something that someone has said or shared, that that was a thought in your mind, please reach out and chat with us about it.

We do have two more public forums to follow at least. So one is on the draft results of the modelling in July 2020 where NERA will be back to present on that, and then the second, a simplified model of the reforms in action.

We also have our technical working group starting up again next week, which also includes members from the ESB's 2025 working group, given that we are now part of that process.

So, again, just to close. Thank you all very much for all of your participation today. We really appreciate it and thank you. We will see you all soon. See you.

END OF RECORDING