AEMC

TRANSMISSION ACCESS REFORM

PUBLIC FORUM EDITED TRANSCRIPT

Results of NERA modelling on the impact of access reform in the NEM
Thursday, 17 September 2020

Introduction and admin

MS MOLLARD: Welcome everyone to our public forum on transmission access reform. I probably know most of you on the call now, but for those of you who I don't, I'm Victoria Mollard. I look after the security and reliability team here at the Commission. I hope you're all staying safe at the moment and we know there's a lot on in the energy space at the moment, particularly with the ESB 2025 consultation paper out, of which transmission access reform is a key component. So, we certainly appreciate your attendance today at this forum.

Today's forum is an opportunity to engage on our quantitative analysis on the impacts of transmission access reform in the NEM which is something we've prioritised in response to stakeholder feedback from you all, that you really want to see some of this analysis. So, in terms of an agenda, if we just go to the next slide please Orrie. I just want to run through quickly what we'll be doing today. So, firstly we'll shortly hear from Merryn York, our acting chair who will welcome us all. We'll then hear from Russell Pendlebury who's the project leader for the reform, to talk about what we've asked NERA to model and some of our preliminary cost work.

And then we'll hand over to George Anstey and Will Taylor from NERA Economic Consulting, who will talk us through their methodology, assumptions and then the modelling results, and there'll be lots of opportunities to ask questions throughout that section. We'll be pausing periodically to have a bit of a facilitated discussion and finally I'll hand to Allison Warburton for some closing remarks and next steps. So, just to quickly introduce you to the other COGATI team on the call, we've got Ben Davis, Tom Walker, James Tyrrell, Jessica Scranton, Orrie Johan and Tom Meares. So, thank you all for being here today.

And again, I'd just like to say thanks to everyone who's here at the forum, because there are quite a lot of you online and we've had a few more registrations, I'm sure a few more people will join. So, it's really great to see that there's so much interest in the topic from such a wide variety of people. Really appreciate your engagement in this. So, before I hand to Merryn, I'll just quickly go through some logistics. So, if we just move to the next slide please Orrie.

So, as I said, today's an opportunity to ask NERA questions. We're very grateful for them to be here. George is in the UK, so it's very early in the morning for him and Will is in New Zealand so it's quite late in the evening for him. But you know this is a great opportunity to ask them questions and understand a bit more about the modelling and if there's questions of 'I don't quite agree with that input assumption', get their take on how that might have changed results and what that might mean in terms of sensitivities.

You'll see on your screen that there's a Q&A function on the bottom. You'll have the opportunity to make comments or ask questions via that Q&A function. When you do make comments it would be great if you could indicate whether you are asking a question or making a comment and then add your remarks, and if you could include your name and organisation at the end, it just makes it easier for us as well.

I did just want to reiterate that we've already started doing some briefings more generally on the project and we know that a lot of you have many other questions to do with the project. So, for example, what exactly does a simultaneous feasibility test look like? What do you think impacts on financing will be? How will that change what banks require? They're all really great questions and ones that we want to continue to chat to you about. But I did just want to highlight there's going to be plenty of other opportunities to talk to us about that and provide thoughts on those matters.

So, I would just ask you to bear that in mind and focus questions on the NERA modelling. We're very lucky to have George and Will here, so we should try and get the most out of the session. As we've done in previous forums, if possible and time permitting, we'll invite some participants to present some of their comments. So, if you actually want to be able to talk to your comments, and there is a character limit in that box, it would be great if you could just write that in your question and we will take your mic off mute and ask you to make your comment.

I'll be moderating each of the question and answer sessions and make that clear each time. As always we'll try and answer all of the questions in the session but if we don't get through everything, we will follow up after the event, either through a follow up meeting, an email, or we might put something up on our website. I just ask as well that we hope in raising questions and comments, participants conduct themselves in the same respectful way they would at an in person public forum. We're also recording the meeting and we'll publish the transcript and presentation materials on our website next week. And I think that answers one of the questions that's come through from someone.

Yes, the presentation and a transcript will be made available on our website next week. So that was it from me. So, I'm now just going to hand over to Merryn who will make some opening remarks.

Opening remarks by Merryn York

MS YORK: Thanks very much Victoria. Can everyone here me? Someone nod. Victoria's nodding for me so thank you. I'd just like to start off by welcoming you all to this forum. It's really great to see so many people interested. I'd also like to acknowledge the traditional owners of the land on which everyone is located, wherever they are, participating in this forum. And also, reinforce that I hope you are all staying safe wherever you are. We do know that there's a lot going on and so we're trying also to make our engagement effective and efficient for you, and I think that is part of why it's really great to have the NERA team here, so that we can get you the best information that we can, so you can use the information and the benefits to understand them as best as you can, as quickly as possible, because that will help us all be efficient in the way in which we think about these reforms, all reforms really, and work through that.

So, we're here today to talk about the results of the modelling that the NERA team have done and they'll be here to answer your questions firsthand, so I hope on the way through, or if you haven't already looked at some of the material, that you will actually start to think about the questions that you've got. The modelled benefits are quite substantial and so it is important that we all understand where they come from, how they arise, and that we really do understand what it's sensitive to, so that we can understand what the true benefits of these reforms are.

But before we get into the session with the NERA team to talk about that, I want to touch briefly on the reasons why we think the reform is needed and why it's on the scale that it is. And it really relates not just to this reform but also the reforms that the Energy Security Board are considering in their post-2025 project. And, of course, this transmission access reform is part of that. I hope you've all had a chance to download and have a look at the ESB paper that was published, the consultation paper that was published on 7 September.

It really relates to the very large scale of the change that is occurring in our power system. So, if we look at the registration list that we've got today, pretty much everyone on the list is involved in either generating energy, using energy, or delivering it in some way, or dealing with energy. And so, you'll be familiar with this kind of chart that Orrie has just put up where you can see the massive change that's occurring in the power system. We will have generation that's basically equivalent to the current NEM built or connected to the network in some way, in the next 10 years.

And that's a huge change. And if it took us 40 years to get to where we are, and we're going to have as much generation connect again, in the next 10 years, then I think that it's not that hard to recognise that the arrangements that were suitable when the NEM was established back in the mid-1990s, need to be considered as to whether they are suitable for that different future. And it is a very different future. We know that we will be changing from what are really a relatively small number of quite large generators, to a very large number of geographically dispersed and much smaller generators.

And that's the trend that we're already seeing and the trend that we expect to continue. And so, it's important that we think about are the arrangements that we have suitable for that future? And that we think about, if they need to change that we do that well ahead of time, so that everybody has a picture of what the future arrangements will look like, and that they have time to factor that in, and that allows the transition to be as smooth as possible. And that's really what we've been doing for the last few years in relation to transmission access reform, having a look at the current arrangements, whether they're suitable, and then what they could change to that will deliver better outcomes.

And, of course, the benefits calculation is part of that, to understand whether there truly are benefits from the reform because that's critical to why you're actually doing it. So, if we just think about what the problem is. Our definition of the problem is that there's a really significant change in generation, the size and location and that the current transmission access regime will result in customers paying more and congestion arising, such that generation won't actually be able to be dispatched at lowest cost.

And the proposed solution is something that has been used in many other parts of the world and that's to introduce locational marginal prices where generators receive their local price rather than a regional price, and financial transmission rights to provide a tool to manage congestion risk. So that's the basic premise. We've obviously done a lot of much more detailed work on what that would really look like at a much more detailed level, and the way in which it could be implemented here, taking into account the arrangements we have, the characteristics of the Australian, or at least the NEM states, and the physical arrangements.

And we've done a lot of stakeholder engagement, I guess to refine the details of that model over time, and we've got a fairly comprehensive set of design options that we've published in conjunction with the ESB paper, that you'll all be able to have a look at, and as Victoria said, there'll be plenty of opportunity to talk about those details and give us any feedback on that in other forums, not this one. We were also requested to quantify the benefits of the proposed transmission access regime, and that's why we're here today, to discuss the benefits which are quite substantial.

And that's why we engaged NERA Economic Consulting. I'm sure that the NERA team, as well as the AEMC team will share a little bit of how challenging it's been to come up with both a methodology, as well as the computational analysis to actually do this exercise. So, it's been quite a process to get to this point, but we're really pleased to be able to share the results with you. The benefits that we're seeing are consistent with the kinds of benefits that have been seen in overseas markets when these have been implemented, and they arise largely from more efficient despatch, better locational signalling for investments, so investments occurring in better locations than they might otherwise occur, and of course improved trading between regions, through the FTRs.

But the NERA team will take you through that in detail. I also want to assure everyone that we are coordinating these reforms on transmission access with the other range of reforms that are either occurring or proposed to occur through the post-2025 work. And, of course, one of those critical things is the integrated system plan and how transmission is identified and built, and then how it's used is really part of what this transmission access reform is aimed at improving. So that we make the best use of the transmission that is built and delivered through the integrated system plan.

So, I do want to thank the AEMC team. I know many of you will have had interactions with them, probably on many occasions. I know I speak for the team as well as all of the AEMC commissioners in just appreciating the input that you do provide us, that we listen to that input, we take it into account in the way in which refine the reform that we're proposing to implement. And we're equally interested in your input on this benefits calculation that's been done, and we look forward to hearing your thoughts about the methodology to calculate the benefits, as well as the magnitude of the benefits themselves.

So, thank you, and I will hand over to Russell, who's going to take you through the next part of the presentation.

Introduction of the work done by NERA

MR PENDLEBURY: Thanks Merryn. So, I'm just going to provide a quick overview now of the work we asked NERA to do over the course of the year prior to handing over to George to take us through the results. In January of this year the Commission asked NERA to conduct analysis of the benefits of the transmission access reform in the NEM. And the work was divided into two stages. The first stage, which ran from January to March, was a benchmarking study of cost benefit studies conducted on similar reforms overseas. We published this on the website in March, alongside the update paper and we also held a public forum in late May in which NERA presented the results of this initial report.

And the report covered 10 jurisdictions overseas. A number in the US but also Ontario in Canada, New Zealand, and Singapore. The study in benchmarking these benefits to the NEM made allowances for the differences between those markets and the NEM but it also recognised limitations of a benchmarking study. But the study also provided helpful insight to refine the later NEM specific modelling conducted under stage 2. Stage 2, which commenced in April, and ran through to the publication of NERA's report on 7 September, involved specific modelling of the reforms as applied to the NEM. It required the creation of a detailed nodal model reflecting the characteristics of the NEM as well as a model of the functioning of the NEM under the existing market rules.

In the modelling of the NEM, NERA were asked to analyse a number of key impacts of access reform across a number of areas. So, the first of these was changes to dispatch. In particular, the impact of race to the floor bidding on the efficiency of dispatch. And the effect access reform would have on removing any inefficiencies arising in the current market from this type of bidding activity. Secondly, changes in investment decisions or the different capital costs of generation and transmission investment under access reform when compared to the existing operation of the market.

Third, the impacts on competition. And fourth, any changes to the cost of capital as a consequence of the reform. We also asked NERA to look at the distributional impacts or the degree to which one side of the market may be better or worse off when compared to others. NERA was also asked to look at the potential impacts on contract market liquidity. Core assumptions in both a reform world and the existing operation of the NEM were to be taken from other modelling processes in the NEM, specifically the ESOO and the ISP.

And all the assumptions, both the core assumptions in common between the two models and the other assumptions used to differentiate a reform world from the existing world were reviewed with the COGATI technical working group on 18 June, as well as with market bodies. The output of this work, which NERA will present on shortly is a comparison of the costs faced by industry and consumers in the two different worlds. This comparison assumes implementation of the reform in the middle of the decade and assesses the net impact of reform out to 2040.

But before we hand over to NERA, it's important to address the issue of implementation costs. In particular, the system costs faced by the operator and participants in the lead up to and following the implementation of the reform. So, NERA provided benchmarking analysis of implementation costs in their stage 1 work. But in stage 2, their work has been focussed on the operation of the reform in the NEM rather than the cost of implementation. So, in tandem with the NERA work, the AMC has commissioned preliminary work into the IT cost of implementation and further work is planned on the detail of these costs and on additional consultation with AEMO and participants.

To obtain preliminary cost figures to inform the reform design decisions we engaged Hard Software to assess the IT costs of transmission access reform for both AEMO and market participants at a high level. Hard Software assessed IT costs with three different options for access reform, ranging from option 1, shown here, with the least changes implied for the NEM dispatch engine, the regional reference price and loss factors, ranging up to option 3, with a new security-constrained dispatch engine facilitating both the option of VWAP (or volume weighted average pricing) and dynamic losses. I should note the proposed reform design we published on 7 September includes both of these elements and so we'll focus here on the costs under option 3.

The results were published alongside the interim paper and they provide indicative figures of $105 million in total for implementation costs, with over two thirds of this, or $71 million attributable to the market operator and $34 million to participants, taking an NPV over a 20-year period. In addition to this analysis we also carried out a high-level assessment of the potential costs of reopening long-term contracts or PPAs that would not expire until after the implementation period. So, using publicly available information, we estimated that legal costs relating to contract re-openings could total just over $5 million, $5.4 million.

Taken together, these figures suggest implementing access reform could cost $110 million, but we suggest these costs may be a bit low, although they're still a fraction of the benefits estimated by NERA. We will be working with AEMO and participants to obtain more detailed numbers with stakeholder input over the coming months. And now without further delay, I'll hand over to George and Will to take us through the results of the NERA analysis on the impact of access reform in the NEM.

Presentation by NERA on the benefits of reform and Q&A

MR ANSTEY: Good afternoon. My name's George Anstey, I'm a director at NERA in London and I work on a range of topics and regulated industries but particularly specialise in energy market reform and electricity market design. So, this is the agenda for this section of the presentation. We're going to be going through essentially an overview of how the model works and actually in a slight change to this agenda, we're going to have questions immediately following that, and then going through each of the big categories of benefits that we've modelled.

So, first the capital and fuel cost savings, and then we'll have questions on that; the improved dispatch from eliminating race to the floor bidding; the introduction of dynamic losses (and we can take questions on those together); and then, the impact on consumer prices and competition at the end. So, at the high level philosophically, really there are two ways one can think about modelling electricity markets. The first is one can think about strategic models in which people are behaving in a competitive way that reflects market behaviour around all of the imperfect competition that you might see in that world. So, based on commercial rationale and bidding. Those kinds of models tend to require a fixed quantity of capacity in the system.

Or alternatively, you can use essentially models which take the cost minimising results you get out of perfect competition and then apply those to models which then gives you the computing power to think about what the endogenous entry might look like and how the system might evolve over time. And given the nature of this exercise, the need essentially to see what the impact is on different capital investments in the NEM over time, we've opted for a market modelling software that adopts the latter logic, which is in this case PLEXOS.

So PLEXOS is a market leading platform used all over the world for modelling in electricity markets and indeed by AEMO for the electricity statement of opportunities model and for the ISP modelling process. Fundamentally, the assumptions that we feed into our PLEXOS model are those used by the AEMO in modelling electricity markets. So, we take the ESOO assumption book and we're taking those generation information and properties, the capacity of all the generators and the units, demand growth, gas prices, fuel prices, outages, and broadly speaking, all of the technical parameters.

And then we take the central assumptions on the growth and evolution of the system. So, there are multiple scenarios, and we take ESOO's central assumptions. Now the ESOO model is a regional model, reflecting the current regional model of the NEM in setting prices. And it has a bunch of constraints that are programmed into it which reflect to some extent the way that constraints might operate and reflect the underlying structure of the network. So, instead of adopting that network typology, essentially, we have built a network typology independently, which has a series of nodes.

In our case, it's over 1,000 nodes. Each of those nodes have defined voltage properties. We have something like 1,800 lines separately defined in the model. The model reflects reactance and resistance and the load constraints on each of those lines. And the modelling obeys Kirchoff's second law. So, we're trying to build a model that is representing some form of realistic dispatch based on the constraints that would emerge in practice. And actually, to a very large extent, this is where our focus has been in thinking about the compromises that we've made in designing the model.

Whenever you're thinking about modelling electricity markets, the question is really about where you apply your focus and granularity and make trade-offs between the different granularities you can offer on different dimensions, given any amount of computing power and time. And given that locational marginal pricing is really about having lots of prices at lots of different nodes, we focussed a lot on the topology of the network and making sure that we have something that works.

Now in doing that, we've worked closely with the AEMC who provided us with information about where plants are located and the properties of the lines. So, then our fundamental approach is to take the difference between two sets of nodal runs in PLEXOS. A nodal run which has locational marginal pricing and a nodal run which has regional reference prices. Now, PLEXOS's underlying cost minimisation logic doesn't allow one to have a nodal structure and use directly the cost minimisation logic to reflect the current incentives that market participants then face because it's a cost minimisation algorithm – it's not trying to simulate market behaviour in response to commercial signals.

So, in order to create a no-reform scenario essentially what we have done is run a scenario which in some way reflects the distortion imposed by the current electricity market arrangements offering a regional reference price when the value of power may differ by node and that would be our no-reform scenario. And then running our nodal model using PLEXOS’s cost minimisation software which gives you, if you like the reform world. And then benefits are the difference between those two things.

So possibly the last thing to say is that in doing this analysis we've had to take a multi-stage process, largely due to the complexity of the model we're looking at. So, we've really divided it into two types of runs. We've got long-term runs where we allow for endogenous construction and for those, we use a sampling approach. We have about 24 blocks a month which are using PLEXOS's statistical sampling algorithm to identify, if you like, the most representative blocks and weighting them together in order to work out what generation gets brought on, on the system.

And we've run those runs out to 2040. And then we can also run dispatch runs where we do chronological dispatch for all of the half hours from 2020 to 2040, so you've got 17,500 half hours per year, and you're running that chronological dispatch for 20 years. That gives you much more granular information according to prices. And then we use those results, having taken the investment decision from the first run, and the capacity mix from the first run, it's going to show price information and calculate revenues and subsidies and all of those kinds of other things that we use in our later methodology.

Here are the four sorts of categories of things that we really looked at with the model. There's the capital and fuel cost savings from more efficient locational decisions and that's all of the work we did on generation and storage. And then also looking at whether there was a case for adjusting those for the transmission benefits and we can talk about that in a bit. Looking at the benefits of eliminating the race to the floor, the introduction of dynamic losses and what implications that might have, and then also the wealth transfer. So, what essentially happens to prices as a result of that.

And who gets most of those social cost savings? So, the first three are really looking at social costs and then the wealth transfer is really about the change in prices. And then I think we're onto questions.

MS MOLLARD: We've already got a few questions coming through but if anyone had any questions so far around the methodology and assumptions, feel free to pop them in now. I will kick off with one that I will answer. So, Ron Logan from ERM has asked us why did the stage 1 review only include markets where LMPs and FTRs have been, or are being introduced and not a review of markets where introduction of LMPs and FTRs were considered and rejected, and the reasons for such rejection.

I know this isn't quite related to the modelling question, but I will cover it off because it is a common question that we keep getting asked. So essentially what we asked NERA to do was look at markets where LMPs and FTRs had been seriously considered. So, we're not aware of any markets where it was seriously looked at and then wasn't pursued. So, what NERA's study found was that there was no market or studies that looked at LMPs and FTRs and found that they actually had negative impact on the market. So, if you do have some ideas about where that might have happened, we'd certainly be interested in hearing Ron.

I think the other thing to reflect is that most of the markets in Europe do not have LMPs and FTRs but I would also reflect that those markets typically have generators paying for TUOS, so that is what sends the locational signals in those markets, which is different to what we're proposing obviously but has the same impact of generators paying per share of TUOS in the market. So, I might just move onto a couple of questions, I think for you, George.

So firstly this one from Jasper Noort, who has said, given the benefits to consumers ultimately flow through into prices, don't you think you need to ultimately model how change actually impacts on actual market prices, rather than the least cost implied prices. Do you want to take that one George?

MR ANSTEY: So, when everyone's doing cost benefit analysis and one's making a projection, broadly speaking one is taking two lines - two market outcomes and then taking the difference between them. So, the first thing is then the granularity and adjustments to whatever outcomes we might get from something like a cost minimisation software are only relevant to the extent that they differ materially between the two lines that we see. So if, for example, we think there's imperfect competition and a mark-up on prices in the COGATI world and that mark-up would be the same in the non-COGATI world, then broadly speaking, for the purposes of the cost benefit analysis it doesn't make a huge amount of difference to the overall result.

I think the other reflection to share is, it would be lovely, were it technically possible to design a long-term model that allowed you to generate a consistent pattern of construction and model imperfect competition reliably, based on empirical methods in electricity markets. And broadly speaking, that sort of software just doesn't exist. I mean, frankly, economists find it quite difficult to find an equilibrium in imperfect competition in electricity markets, that is kind of reliable and unique and there's a large literature on supply function equilibrium models, most of which says there are many, many equilibria, and outcomes.

So, what we've done is use a cost minimisation software. That's frankly what a lot of the studies that we've looked at have also done internationally and it's broadly speaking the method that most TSOs use when thinking about long term system modelling and system planning.

MS MOLLARD: And another one, which I think flows on from that, again from Jasper is that near-term prices are less approximately 50 per cent below market prices with the model benefit only comprising around 14 per cent of the difference. How can you be sure that customers actually benefit?

MR ANSTEY: I'm not entirely sure I understand the question, so the question is our model prices are below market prices and then the suggestion is that the model benefit is only about 14 per cent of the difference, so how can we be sure the customers benefit? Well, it seems to me that if the price levels were higher then the implication of the question is that the benefits would also be higher and by a similar proportion. So, I think referring back to my previous question, insofar as we're taking the difference between two line items, if what you're saying is - if one's hypothesis is that the benefit is a percentage of the level of those prices, then higher prices would only help.

MS MOLLARD: And one from Sam, and this is one that I certainly have been asked a lot and some of the implications of this might be worth speaking about now George. But can you provide a bit more detail around how the load is blocked and what the blocks look like in terms of the modelling?

MR ANSTEY: I can provide some. So, the way that we've done the load blocking is essentially to rely on PLEXOS's sampling methodology. So, basically, there is a sample in PLEXOS. It takes samples of the days. Actually, there are multiple ways you can do this in PLEXOS. So, one is that you can use a fitted option and the other one is you can use a sample option. And so, we've used a sample option. And the samples are taken of the days, weeks and months based on a statistical algorithm that PLEXOS has. And the precise operation of that mechanism is buried in thousands of pages of PLEXOS modelling logic. And frankly, is not entirely transparent to most users.

But I think that what one can say about it is it's the sampling method that is offered by the market leading market modelling software. So, in that sense, it's as reliable as market modelling exercises ever are when they take on sampling approaches. And then those sample blocks, which are selected statistically on a monthly basis by PLEXOS's algorithm are then weighted together, to generate essentially a load profile for investment, so that we get the right combination of the base load and peaking plant.

MS MOLLARD: There's a few questions coming through so some I'm just going to hold until we get to the relevant parts of the presentation later. So, there's quite a few around loss factors and how they were calculated, but I'll hold that until we get to that section. But there is another one George, so FTR markets internationally are settled ex ante against day ahead markets. Did the PLEXOS model reflect real time settlement or ex ante settlement?

MR WALKER: I can have a crack at this one if it helps. I think, correct me if I'm wrong George, but it's reflecting real-time prices and you didn't model the FTRs and therefore it's neither, is I think the answer. Perhaps if you could repeat the question, Victoria.

MS MOLLARD: Asking in terms of the modelling, I guess the reflection is that in overseas markets, often LMPs and FTRs are often combined with the ahead markets, which has ex ante settlements, so settlement ahead of real time. What did we model? Was it real time settlement or was it ahead settlement?

MR WALKER: It was real time, I would suggest.

MR ANSTEY: Yes. It is real time. And the reason it's real time is that we don't have separate day ahead markets. I mean, insofar as we looked at

FTRs at all in the PLEXOS model itself. I mean the PLEXOS model itself doesn't have FTRs. The analysis we did of FTRs was a separate offline calculation on the PLEXOS results. We don't have separate day ahead markets and real time markets, so we're using real time prices, and therefore the analysis we did of FTRs was based on real time markets in that sense, because there's just no - all day ahead markets, but there's no stochastic difference between the two, which is, I think, probably the import of the question.

MS MOLLARD: There's a comment here from someone who said, can we upload some reference years, so 2025, 2030, 2035 showing before and after regional reference prices and LMPs. That's an interesting comment. I think we'll take that away and have a think about it. We've certainly been asked by quite a lot of people whether there's more granular information we can share about the modelling. So, we're just working through that at the moment. There's a few questions here, another one from Ron. Again, for you, George, I suspect. The model results and the calculation of a significant wealth transfer due to the difference between a calculated LMP and FTRs – did the calculation include for the impact on financial contract prices, the requirement to purchase FTRs to manage risk to the RRP? So, either that specific question, or perhaps more broadly, how do we take into account FTRs in this modelling?

MR ANSTEY: Yes. So, the wealth transfer is essentially looking at the difference in the LMPs versus the RRPs and the generation - so the generation-weighted prices and the volume-weighted prices. So, essentially the various transfers that we calculate - I mean we'll come to those at the end of this section really but - so it's obviously going to make sense we're going to field that part of the question later. But what we really want to say here is that FTRs don't really feature in that assessment because basically, we're implicitly assuming that FTRs get bought at fair value.

And if FTRs get bought at fair value then it's actually the difference in the underlying prices that reflects the wealth transfers. So, that's the answer to the question.

MS MOLLARD: So, as I said, there's a few other comments in here, you know some questions about how we've calculated the difference between the reform and no-reform, particularly in that first element of benefits about more efficient investment and costs. So, I think that's what you're going to talk about next. So, why don't we go onto that next section George and then for the few people whose questions we haven't answered, we'll get to then later on in the presentation at the relevant sections. Back to you George.

MR ANSTEY: Perfect. So, this slide tries to give an overview of how it is that we go about trying to model the impact of the capital costs of generation and transmission of storage. And really focussing on generation and storage. And then we talk about how we cross-check that on transmission. So, the first thing we do is we have to split our PLEXOS runs into multiple stages and we do that, essentially for feasibility reasons. So, the first run, and also for getting granularity of information. So, the first run here, in the process here set out is that we run a long-term expansion to 2040 to identify optimum system build.

And we actually do that in two stages. The first stage is a kind of zonal model with dozens of zones around the NEM and then we allocate that construction plus any top up required to individual nodes and we do that to reduce run times and simplify the problem to deal with feasibility constraints. Now, that's essentially the first step and that tells you how much capacity PLEXOS says, given the assumptions you've given it getting built in a perfectly competitive cost minimising world, which in this case we're calling reform. And in a world which has a nodal network, a nodal set of constraints and market participants responding to those constraints. And then we run that model twice. We run it with regional settlement and then we run it again with LMP settlement and we run them in a dispatch run. So that's a chronological 17,000 half hours model, to get very granular information on prices and on market outcomes.

And the LMP settlement - so the regional settlement model, I suppose, is the status quo, or no-reform world, given the capacity mix that you get in that first stage. So if we were to build that capacity optimally and then run the market under current arrangements, we would get an outcome that looked a little bit like - I mean a little bit like - exactly like, if all the assumptions are right, exactly like the dispatch run with regional settlement. And so then we're also running it with LMP settlement and that gives you the reform case. Now, the next step is to work out well, what implications does that have for investment.

So how, in the regional settlement run, generators are in constraint nodes, which oversupplied, are earning repeatedly more than they are - than the LMP. And the model, when it thinks about where to build plant optimally, is effectively making decisions based on the LMP at each location. So essentially, in order to get the no-reform case, we need to distort the investment signal that PLEXOS sees to reflect this additional money that generators would be getting commercially with regional settlement.

So, the way we do that is we basically take the difference between the dispatch run with regional settlement and the difference and the dispatch run with LMP settlement for these sort of infinitesimal probe generators. So, for each generator type and each eligible node, we estimate the specific subsidy that say a solar plant at a given node would have gotten, were it to be dispatching, based on regional prices as opposed to based on LMP. Now all of this assumes competitive bidding. So, it all assumes cost-based bidding.

We talk a bit later in the kind of race to the floor stuff about distorted bidding, so this stuff is all, at the moment, still assuming cost-based bidding – insofar as it's relying on PLEXOS cost minimisation algorithm. So, the next step then is that we take those subsidies, those differences in revenue and we deduct them from our new annuitised fixed costs of new entrant generators. And so what that does is essentially say, at nodes where there is a very large subsidy, the investors at that node would not invest based on the cost minimising solution for the system as a whole but take into account this additional subsidy that they get and we essentially force PLEXOS's cost minimisation algorithm to treat that as a reduction in cost.

And therefore, to bias investment in favour of those subsidised nodes. Now it doesn't mean that all investment happens at those subsidised nodes. The system's still making cost minimising trade-offs, it's just cost minimising trade-offs taking to account these subsidies. Essentially, the costs that investors see rather than the costs that the system sees. So we go through - with those reductions in fixed costs we then go through this process again. So, we start with the endogenous construction in the zonal model and then we have endogenous construction in a nodal model, taking outcomes from that zonal model as an input.

And then we run the two runs for dispatch in very granular time. And the difference between these two outcomes and the total system cost differences between these two outcomes is the total system benefit, and that's essentially the philosophy of the approach. Now, the bottom right here just shows you what those subsidies look like on average. So what you can see is that basically for the first (well, I mean over time the dollars per kilowatt - these are dollars per kilowatt figures) the dollars per kilowatt subsidy on average, for different technologies rises, and unsurprisingly, especially in the earlier period, it's really wind and solar that are seeing large subsidies under the regional reference price approach.

So largely speaking, these subsidies estimated from the reform case, are showing that there is over supply of solar and wind of some nodes. That means the LMP there is lower than the RRP and that manifests itself as a subsidy in our modelling. And the implications of those subsidies, if we look here at the top right, is that no-reform results in $1.7 billion extra over the modelling horizon. It's just worth saying a little bit about what exactly these numbers mean. These numbers are differences in annuitised total system costs and that's quite important because in practice, Australia will have locked itself into investment decisions for a longer period of time than this.

There will be more costs incurred in the period to 2040 than this, because there'll be overnight investment costs that are quite material ahead of 2040 and those investment costs will be in the wrong place, in an environment where you're not sending the right locational signal. So, this number understates the capitalised benefits if you like from better locational investment decisions. On the other hand, there are a couple of reasons to use these numbers rather than try to calculate what the overnight cost differences would have been. You know, what are the actual cashflows, and capital costs actually incurred and committed before 2040.

Firstly, this is the format in which the total system costs come out of PLEXOS and it's the basis on which PLEXOS makes investment decisions, broadly looking at the annuitised costs over the modelling horizon. And so therefore it's consistent with the PLEXOS modelling logic and with the outputs that PLEXOS automatically provides. And so, you know, one could do some calculations in order to try to convert those into overnight costs, but this is the format that output is available in. And the second reason is that the benefits of those additional investments, because there are benefits of those additional investments, will also be felt later on in the modelling horizon. We haven't got those benefits. Now the costs should exceed the benefits. I mean that's the economic logic of the imperfection in the way the market design currently works.

However, we don't have those benefits either because we're only modelling to 2040. So, this number here is – I think the key thing to say – this number here is understated and that it's an annuitised number rather than a capital cost number and that's the key thing to understand. So, this just gives you a little bit of a sense of really what's going on and what's driving that difference and that quite material difference really in the system of costs. Basically, you can see there are some pretty stark similarities actually between the capital mixes and the capacity mixes in the two different worlds.

Here on the left we have the reform world and there on the right we have the no-reform world with sub-optimal build. And I mean actually the scale of the chart it's not too bad, it's not quite so clear but the ballpark there's about - by the mid-2030s there's about four-gigawatt difference between the left and the right. And then towards the end of the period we get a really big step up in investment in the no-reform world relative to the reform world. And by the end of the period we're at almost 20 gigawatts higher.

And so, what's driving that? Well, I mean essentially what's driving that is that the commercial signal is located in the wrong place. Where you're located in the wrong place, although you do lose some value of output, because there'll be certain occasions when you won't be able to sell your power to the grid. On the other hand, you're getting a regional reference price when your LMP is quite low. And therefore, you're going to be getting the subsidy that I was talking about, that we've identified in the first step.

So, what that means is that we build more capacity because broadly speaking consumers are paying more. Consumers are essentially paying generators as a whole more in the RRP world and therefore there's more money available to generators creating a bigger incentive to invest. And the other thing is if you build capacity in the wrong places then you probably need to build it in the right places too, or at least some of the right places too, in order to meet demand. And the market signals will encourage you to do that because otherwise you get sort of VOLL spikes because you wouldn't meeting load.

So as a result of those two effects, what happens is that you tend to invest in the wrong place and investing in the wrong place means you invest more. And broadly speaking that's what's going on here. Now what you can see really is that difference is relatively - I mean relatively modest compared to the end, it's still relatively large actually, I mean four gigawatts is quite a lot of capacity but what really causes this to kick up is actually when we get a lot of investment needs, and that really happens at a kind of turning point in the mid-2030s when Bayswater retires and we start to lose quite a few gigawatts of coal capacity and that's the point at which we really see this kick up.

Now I should say, we haven't done endogenous retirement, so all of this coal - there's this profile of coal retirement is something that reflects the ESOO and ISP assumptions. It's not something that's sort of endogenously programmed. So, if coal were to retire earlier as a result of this additional investment, then those benefits would get brought forward as well. So, this is just a slide and it gives us a little bit of a sense of what that means for existing plant. So, on the left here we've got the no-reform scenario and the load factors on different types of plant.

And particularly looking at renewables. And broadly what you can see is that the load factors are relatively flat although slowly declining and then by the mid-2030s, we get lots of new investment in renewable plant and the load factors drop off quite a lot as a result of all of that additional production. All of which makes sense, I mean this is essentially what's driving the additional cost for customers is that we've got lots of plant running less than they would otherwise and we've got more capacity on the system than we might optimally need.

And what that means for the differences in load factors after 2032 is shown here on the right-hand panel. So this heat map just shows for each year what the difference is between no-reform and reform and you can see, broadly speaking which types of plant are suffering and that by the beginning part of the period the load factors are lower in reform, the no-reform by a percentage point here or there, apart from for black coal and brown coal plant. But, actually, towards the end of the period, actually there's a really big impact on wind and solar plant, which effectively gets cannibalised because of this investment signal.

Essentially what we're doing is we're overpaying for investment, that investment comes in and then because we're overpaying then the volume shrinks and to a point of equilibrium and that's what the model is broadly trying to get at. So, having done all of this analysis with respect to generation and storage, we then had to make some decisions about how we dealt with transmission. Now in principle one can use PLEXOS to model transmission investment. Doing so, it's not entirely clear that's the right thing to do because PLEXOS deploys transmission based on the cost minimising algorithm.

So essentially it bakes in perfection in the transmission planning process and I'm sure AEMO and the TNSPs have a great many virtues, but perfection is incredibly difficult when it comes to the standard for transmission planning. So, it's not entirely obvious that that would be the right way to think about it in any case, particularly in no-reform where the investment signal and the decisions about transmission investment are not necessarily going to be perfectly aligned because actually the investment in generation is distorted by the use of a regional reference price.

So what we did was to look at whether there was evidence on the back of the modelling that we'd done for generation and storage, to say that we were overstating the benefits of reform and we were doing that because there is at least an arguable hypothesis that transmission investment would substitute effectively for locational marginal pricing and if you built out loads of network, then you don't need LMPs. Sort of a naïve intuition. And that's true, there is a sense in which transmission capacity can substitute for the right locational decisions for generation capacity although at quite some cost.

The alternative hypothesis actually, is that transmission capacity can make things worse because you build to transmission capacity and then that encourages more plant to turn up. So, it's actually not at all obvious which way the effect goes. But we wanted to check this in order to make sure that we hadn't excluded transmission from our analysis and actually as a result of excluding it, we had materially overstated the benefits of reform. So, what we did was take the results of our PLEXOS run and then linearise the problem. So, we then ran the network as though we had resolved all of the transmission constraints and saw what the flows looked like.

And with that, with those two market outcomes, we drew welfare triangles that look a little bit like the ones here on the right. So, the difference between PS1 and PD1 here is the differences in prices that transpires as a result of other fixed volume of transmission capacity QT0 as marked and that's, if you like, our base run. And then we looked at what would happen if you expanded the transmission network so there were not constraints and that gives you QT2, essentially as the outcome. QT2, P2 where prices are equalised as a result of there not being transmission constraints.

And then we do some welfare triangles to say, assuming that there was a kind of linear interpolation between those two points, to say what's the benefits of additional transmission investment. And then we tried to work out what the optimal level of transmission investment was, based on the costs of upgrading each line. So, we had a generic cost assumption of $2,000 a kilometre and then we multiplied that by the geographical distance of each line length. And then from that we could calculate the optimal level, which would be the point at which the height in the triangle between the supply and demandlines here on the right, is equal to the transmission expansion cost on a per megawatt basis.

And then the cost of that transmission investment would be the kind of light blue or highlighted square and then the total gross benefits would be the blue trapezium, including the highlighted rectangle and then the net benefits would be the two triangles. And basically, the purpose of this analysis was to check have we left lots of addressable benefits on the table, particularly in the no-reform world. And broadly speaking, what we found was that we hadn't. So we tried this a few different ways and we tried to do it in a way as well that particularly biased the calculation towards finding extra benefits from transmission, assuming things like well you can build a transmission at an annuitised rate and you could build it for a very short period of time.

And basically, we didn't find that there were material benefits particularly material benefits in either case, relatively speaking. And actually the difference between the two cases, in the analysis that we were doing typically was in favour of reform, which was saying the complementary nature of transmission and generation happened to, in benefits terms, happened to exceed the substitutory relationship between generation transmission, although we tended to get slightly more investment, slightly more transmission investment in the no-reform case.

It's as a result of that we essentially did that analysis and said, okay fine there's not evidence here for this analysis, but we need to decrease the benefits of reform. In fact, if anything there was evidence that we should increase the benefits of reform, but we decided to leave those out of the calculation. So that's essentially what we did. So that brings us to our questions on this section.

MS MOLLARD: So again, a few coming through, there are a few questions from Ben Skinner and Ron Logan wanting a bit more detail on how that subsidy was modelled, which I think you gave an explanation of George. But Ben and Ron if you still have questions, just let us know. So, question from Joel Gilmore, have you benchmarked your modified no-reform outcomes against the ISP. I think that's one for you, George.

MR ANSTEY: Yes, not especially formally. And we did look at them and they weren't radically different would be my response. I mean we're not trying to rerun the ISP process, and it gets back to the question, I mean partly because we're not AEMO and shouldn't be making recommendations about planning a transmission system. So, in a sense I'm not terribly concerned if we are a little different. And again, it gets back to this point about the difference between the factual and the counter-factual is really what we're interested in. So, to the extent that we've got assumptions that float both boats, we're not terribly concerned.

So, ballpark I think we were - I mean we did do some benchmarking and we thought we were broadly there or thereabouts.

MR WALKER: Was that with regards to the reform or the no-reform world?

MR ANSTEY: The reform world. Yes. So, the no-reform world - sorry, was the question about no-reform?

MS MOLLARD: Yes.

MR ANSTEY: Yes. So, as I understand it - thanks Tom. Insofar as AEMO is modelling the electricity market, it does so based as we understand, having engaged with AEMO, over the course of this project, talked to them about their modelling process and they're not seeking to model the imperfections in generation deployment decisions, in the way that we are. So, in that sense, we should be very different in the no-reform world because essentially what AEMO is doing is a kind of cost minimisation benevolent planner type analysis. I mean or a perfectly functioning capacity of market type analysis which isn't exactly what we're doing, so in that case we are quite different, and we should be. That's very much the point.

MS MOLLARD: Another one, does the analysis apply the REZ build limit assumptions that were included in the 2020 ISP assumptions. So, can you just talk a little bit about how the REZs were taken into account please, George?

MR ANSTEY: Yes, I can. So, the REZs we used to work out where capacity could be built. So, for renewable capacity we assumed that solar could be built outside of REZs, but we typically assumed that wind could only be built within REZs. There's a question about the REZ capacities. So, can you give me a little bit more on interpreting exactly what the questioner might be after.

MS MOLLARD: So, this one was being asked by Marilyne from Clean Energy Investor Group. I mean I wonder if we might take Marilyne off mute. Pete are we okay to do that and just get her to speak to the question, just to provide a bit more detail for George.

MS CRESTIAS: It follows on from the earlier question really around how close your modelling assumptions are to the ISP and to the REZs that are coming out of the AEMO modelling in the ISP. So, it's really a question around how close you are to that modelling.

MR ANSTEY: So, we have the REZ - we use the REZs in the model to inform the construction of wind plant is the answer. We don't impose formal limits; we rely on the commercial signals to do that. So, I don't think that we've got any additional constraint for a REZ to say, in this particular constraint you can only build - in this particular REZ, sorry, you can only build so much wind. I mean, essentially, we're relying on prices to do that.

MS MOLLARD: One from Simon Brooker from the CEFC. So, in terms of calculating the subsidy where a solar farm receives a regional price rather than an LMP, how are marginal losses taken into account in determining the RRP based revenues versus the LMP alternative case.

MR ANSTEY: Gosh. Could you tell me who this question was from and what time it was, just because the questions are wonderfully precise. Actually, it was really helpful but also quite long, which makes them quite hard to follow. So, it would be really helpful if you could just - - -

MS MOLLARD: This is from Simon Brooker CFC at 3.50 pm. So about halfway down the list of questions.

MR ANSTEY: In terms of calculating the subsidy where a solar farm receives an RRP rather than an LMP, how are marginal losses taken into account in determining the RRP based revenues versus the LMP alternative case. So, what we're broadly doing is we're modelling the electricity market as it currently stands. So, we're taking into account MLFs and regional price events. We aren't - on the RRP and then the LMP alternative case we're using just the locational marginal price. That's right.

MS MOLLARD: If you continue to scroll down there's one from David Dawson at 4.10 which has asked - I'll read it out while you scroll down to that point. David Dawson 4.10. On REZs do you include the new transmission connection investment in the analysis and is this incrementally added or added in one capacity block as needed around 2040 or the end of the model horizon.

MR ANSTEY: So, the answer to the question is all of the transmission investment that we have is - well, it's clearly set out in the report and it's basically the ISP priority 1 and priority 2 projects. So, those are the projects that happen and anything that isn't those things doesn't happen. And that's the answer to the question.

MS MOLLARD: Great. Thank you. So then there is one here earlier, so hopefully you can follow along with this George. So, this is Robert Pane at 3.45 pm. How would the analysis change if we assume investors build to P50 demand rather than P10 and was there any engagement with investors to support the P10 assumption.

MR ANSTEY: Right. So I mean the simple answer is the benefits would - the benefits of capital investment would fall because there would be less of it and if there's less of it and we're not building up to that higher demand curve, then we will have fewer benefits from capital investment. That's right. I mean offsetting that, we would also have more constraints in the dispatch run. So, the dispatch run we had P50, we used a P50 run. So, we would have less capacity on the system, so we would have in the P50 run, we would then have less power around to resolve our problems, we'd have higher prices in the P50 run.

So, the dispatch run we'd have commensurately high prices but you're absolutely right, the benefits of the new investment itself, the capital costs would be lower. Was there any engagement? No. I don't believe that we've - I mean, well hang on, I know that we haven't engaged specifically on whether the P10 was the right number to use. One needs to use something other than the P50 because otherwise you're accepting that in the median case, we're going to have lots of - lost loads is fine and investors would respond to - investors would invest for median demand, which I don't think is reasonable, given the asymmetric distribution you would expect to see in electricity prices.

I mean prices would get really, really high if you start having VOLL, particularly in Australia because you have a very sensible market price cap that's very high. So as a result of that the P50 wouldn't be the right thing to use. The question is what else might one use and in principle one could use another forecast.

MS MOLLARD: Thanks George. And there's another question from Jasper Noort, 4.10 pm, towards the end of the questions, which is similar, talking about how some of the assumptions might change. So, he's asked if there are significantly higher distributed generation given he's saying that the central scenario for the ISP assumptions are quite conservative. How would that change what influenced the results? What would that mean if we were to assume higher levels of embedded distributed generation in the modelling?

MR ANSTEY: If there's significantly higher distributed generation given the central scenario for the December 2019 ISP assumptions - is that the one we're talking about?

MS MOLLARD: Correct.

MR ANSTEY: Oddly enough it seems to have disappeared. I actually see the - I'm sorry, Victoria, I just can't see the question, it's completely - it's sort of disappeared from my list. Is that because it's moved to answered.

MS MOLLARD: That's right. I think we just moved that to answer.

MS CHAN: So my question was just in relation to how REZs are being taken into account, not in relation to capacity, so wind and solar, which George kindly answered before, more in relation to how other reforms are being taken into account in the modelling. So other reforms in terms of actually the ISP and building out REZs. I guess a degree of central planning which will mean that there will be coordination of generation into REZs. Doesn't that mean that then that the megawatt capacity that is built in the no-reform scenario, which is quite substantial at 20 gigawatts, is potentially going to be overstated? Because, in reality, there will be REZs through other reforms to coordinate generation into those areas.

MR ANSTEY: The REZs that we have are only - our modelling in the REZ is only going to affect wind plant, insofar as it is within REZs that wind plant must be constructed. And we don't allow for new REZs, so in that sense we aren't allowing wind to get built in new places that haven't foreseen or declared a REZ yet. And I suppose if that’s the point of your question. then the answer to that would be yes, we are constraining the locations where wind can be built. For solar that's not the case. Solar, we let it get built anywhere, so I don't think it causes a problem.

MS CHAN: It's more a bit of the combination of the analysis you did on transmission, because the transmission appreciates that you basically, I think from reading the report, what you've done is that you've basically built out transmissions to alleviate constraint, that's the kind of a correct characterisation.

MR ANSTEY: No.

MS CHAN: As a separate piece of analysis - - -

MR ANSTEY: Yes.

MS CHAN: Yes. But in the model? But as a separate analysis.

MR ANSTEY: Yes.

MS CHAN: But you don't take into account the transmissions that could be built say in REZs through for example state governments, coordinating generation into REZs. So, for example, central west Orana REZ in New South Wales, which is in the final 2020 ISP but not in the draft 2020 ISP.

MR ANSTEY: That would be right. We don't include transmission investment that is not in the draft ISP. So that is true. Yes.

MS MOLLARD: I think that comes to a broader question about how the transmission access reform complements some of the REZ arrangements that are being developed by the ESB and really make some of those REZ arrangements sustainable, which is probably getting a little bit off topic off the modelling. So might hand back to George and we'll go through the next section on the modelling report.

MR ANSTEY: We're talking next about distortions to short run dispatch. I think I'm probably going to aim to do this bit a little bit more quickly than I did the last bit. I think that's probably proportionate. But I'm going to try to do that just because we've got two sections to cover and I'm just aware that I'm already outstaying my welcome, as much as I'm enjoying it. So, this here is just discussing Katzen and Leslie paper. So Katzen and Leslie are obviously academics who've been thinking about this question a bit and have argued that there is a degree of race to floor bidding in the NEM.

On the current access arrangements, if you bid low when the regional reference price is above your costs then you can shift yourself up the merit order and get your capacity dispatched and make more money, even at total higher system cost for the system as a whole. There on the left is a very simple diagram to show what that might look like so you might imagine that the prices that are constrained node with five plant A to E of equal size and rising marginal cost would be set by Plant C and then actually what we see is the A, B, C, D and E would all have an incentive to bid an arbitrarily low price if there were a regional reference price that was above E's costs.

As a result of that, they would share output based on their participation factors and we would get something that looks a little bit like the pattern of dispatch in the bottom panel here on the left. And the difference between those, here in the top right, I've highlighted the differences between those and that's what we try to quantify. And how does that compare to what Katzen and Leslie did, this is just for kind of context. Katzen and Leslie looked at the difference between the overcompensation, which is the difference between the PRN and the price of the reference node and the price of the constrained node. And we look at the difference between the two sets of total system costs.

So, the blue area between the two dispatched merit orders. The next slide talks a little bit about how we do that. So, what we do is we run through a three-step process. The first step is we get all generators to bid, based on their marginal cost. And then we look at the outcome, and we do this for a single year, and we do it for a fully chronological dispatch. So, you've got your 17,000 half hours. And then for each half-hour we look at whether generators would have been better off basically by bidding lower and there are two things we do. The first thing we do is to say generators must bid - if the generator's generating less than their available capacity but they have marginal costs below the regional reference price, then we assume they bid to the floor.

And provided they're not located at the regional reference node for fairly obvious reasons. And the next thing we do is D here, which is basically we say, if you're co-located at a node, with a generator that's race to the floor and your costs are below the system costs, even if previously - sorry, your costs are below the regional reference price, then even though you were fully dispatched before, you'd still race to the floor because you'd anticipate that somebody else would race to the floor and try to leap frog you.

And then having constrained that set of bids, we then run the model again with those distorted bids. And then we compare the system costs in the two worlds to the base case. Now in doing this, PLEXOS - we have a method actually for sharing, based on participation practice by constraints within PLEXOS. And PLEXOS randomises. Unfortunately, PLEXOS would randomise in the same way each time, so basically pick arbitrarily one particular plant on each node. So what we do is we add a tiny infinitesimal adder of thousandths of a cent per megawatt hour to the different generators in order to get – it varies by half hour – in order to get a randomised pattern of dispatch, which is broadly equivalent to getting people to share.

So, then we do this twice. In one world we do this by allowing thermal plant to displace renewables and in the second world we do this by making sure renewables don't get displaced. And so, the second world is the lower bound of results in a lower change in total system costs in that year of $137 million and the upper bound is materially higher than that because of renewables displaced basically by black coal.

So what we've seen is that roughly 90 per cent of the benefits of eliminating race to the floor bidding in the reform world, where the incentive to do that would disappear, come from black coal plant, which bid to the floor, really quite frequently in our modelling. And so, we index those assumed benefits to the variable costs of coal on the system in each year, in order to sort of calculate the difference. And what we see is that the answer therefore declines over time as coal starts to retire on the system.

So that's broadly speaking our method and then the next slide. Because the other thing we looked at was dynamic losses and so the dynamic losses question - I should say that we're explicitly modelling losses for settlement in various places but not for the kind of physics of the system. So, the physics of the system reactance and resistance are all constrained on but we're not modelling losses dynamically in all of our modelling runs, basically because of the processing power it takes. So, the modelling process that we have for measuring dynamic losses really consists of three stages. The first stage is we model the system with the static MLFs and that generates a dispatch pattern assuming the static MLFs are present.

Again, we're doing this for a single year. So, then we impose the dispatch decisions from run 1 onto a run with dynamic losses and calculate the total system costs. And what that results in actually is quite a lot of lost energy, basically because one doesn't dispatch quite enough power, assuming static losses to deal with the dynamic losses that the system actually incurs. So, then essentially, we price up that lost power at the average system costs with the average cost of generating power in that year.

In fact, sorry, the average load-weighted price, I should say, not the cost. The average load-weighted price of producing power in that year. So, it's essentially a measure of the marginal - average marginal cost of power in each half hour. And then we run a third run using, I say, dynamic MLFs, probably really ought to say dynamic losses. But we allow efficient dispatch systems. So basically, run a run that's just optimal. We take the MLFs off of the dispatch decision and we're just running it based on dynamic losses.

And what's the implication of the difference between those two things? Well, the answer is we get a $100 million difference in costs. Now, this number is likely to overestimate the inefficiency that results from not having dynamic losses in the NEM and the reason for this is really this, our modelling is capturing these two potential sources of inefficiency. There's a price effect which is basically we pick the wrong plant because we're using static rather than the dynamic signals and then there's this volume effect which is that we dispatch the wrong volume of demand and then what we're assuming is that we use the load weighted average price to kind of true it all up. That's actually quite a constrained decision.

Now in practice, we understand - we spoke to AEMO about this, AEMO is not doing dynamic loss modelling but it is forecasting demand effectively gross of losses on a nodal basis in order to make sure the system doesn't fall over. And which makes a lot of sense. But doing that essentially mitigates some of the volume effect here that we are capturing, which is that essentially we've kind of got this two stage process if you like, because we've got this under dispatch and then this subsequent true up, that's quite a sort of constrained decision.

But AEMO is not doing that. AEMO has got another method. Fudge is too negative a word, but there's a word somewhere between fudge and method that I think probably reflects what I'm trying to get at, which is it's an imperfect way of thinking about it, because it's not modelling the losses dynamically, but it's implicitly trying to get at the same thing, which is that we need to meet demand at load and that load includes losses. So, that volume effect is something that we wouldn't expect to see benefits from, to the same extent necessarily that we're modelling it. But our modelling doesn't distinguish clearly between these two effects, the kind of price effect, dispatching of wrong plant and the volume effect.

So, there's a fraction of the above estimate and it's a question of judgment as to what extent these benefits would be realised. That is, I think everything we have to say about those two topics, which is good because we only have half an hour left.

MS MOLLARD: So, I will give you a break and there's a couple of questions come through that are probably better directed at Tom Walker. So, one was what consideration was made to the behavioural change once five-minute settlement commences. And would five-minute settlement impact their estimate benefit. And then the second question related to that, are these benefits for disorderly bidding additional to the benefits that you get from five-minute settlement impacts. Tom, do you just want to talk to interactions of five-minute settlement and different types of disorderly bidding please.

MR WALKER: Thanks Victoria. So, George, correct me if I'm wrong but essentially the modelling that you have done, assumes five-minute settlement is already in place. It doesn't attempt to account for the current pricing arrangements, which is an average of six five-minute intervals, which makes sense given we were suggesting the reforms come into effect beyond the time at which five settlement would be brought into place. So, the question about the interaction and the benefits of them, five-minute settlement addresses one particular type of disorderly bidding, disorderly bidding, or incentives to disorderly bid, due to inaccuracies in pricing over time. That's the key concept.

The 30-minute price does not reflect – or the average of five, or the average of six, five-minute prices does not reflect – the individual five-minute price in each individual dispatch interval. And that is the driver of the incentive to disorderly bid. The introduction of LMPs is looking to address the incentives to disorderly bid due to inaccuracies in pricing by location. So five-minute settlement addresses inaccuracies over time, local marginal pricing addresses accurate bidding incentives by location or the inaccuracies in pricing by location.

And so, these benefits, the benefits of introducing locational marginal pricing, are additive to the benefits of addressing disorderly bidding arising due to the existing 30-minute settlement approach.

MS MOLLARD: Thanks Tom. George, we've cleaned up the questions, so hopefully this is a bit easier to see. So, the third question down from Edmund Hon, at 4.23 pm, third one down. So, he has asked, do you need to consider in the model where solar and wind farms signing a PPA and then needing to generate at any price, does that affect your model? Effectively, saying renewable signed PPAs which means they generate at any price, how does that affect the analysis?

MR ANSTEY: Yes. And the answer is, if you believe that's true, and I completely understand that we have that problem everywhere. It's not a uniquely Australian problem. Then the right scenario to be thinking about is a lower bound scenario where renewables never get displaced because they would generate any price, any negative price. Yes.

MS MOLLARD: And then if you scroll down to the very bottom question there it's from Ron Logan. But with regards to dynamic loss benefits, how much of the claim to benefit was due to volume and how much was price.

MR ANSTEY: And there Ron lies the rub. So, thank you for the question. That is precisely why we're couching this as an overstatement because we can't distinguish. We haven't come up with a reliable way of distinguishing between those two effects and so this is a combined effect. But I mean it's a very pertinent question.

MS MOLLARD: Thank you. And just one final one from Rimu Nelson before I move on. I suggest this is probably one for Tom, so do the AEMC consider any other tools other than LMP to deal with race to floor issues behind constraints.

MR WALKER: Not in this particular piece of work, no. I think the question of whether other tools could be used has been one that's raised periodically over a long period of time. The Commission for some time has suggested that we think locational marginal pricing is the most appropriate, not just to deal with race to the floor but for all the other benefits that arise that George has been talking about. So that's why we've been focussing our attention, at this kind of later stage, on LMPs.

MS MOLLARD: Great, thank you. I think that's all the questions on that section, so I will hand over George to go through your final slides please.

MR ANSTEY: No, no, no I'm having a cup of tea and Will's taking these ones so - - -

MS MOLLARD: Over to you Will.

MR TAYLOR: So, we thought we'd give you a change in accent for this final section. I'm briefly just going to talk about the consumer benefits, the transfers that we've been discussing and also the competition benefit. So, we've got two graphs here. The graph on the left is showing the difference in GWAP, so the generator weighed average price, so the price received by generators which is what consumers actually end up paying in both the reform and the no-reform world. And as you can see from that graph, for the majority of the period we've analysed, there's not that much difference.

So consumers do pay lower prices but it's between .9 dollars a megawatt hour and .8 dollars a megawatt hour, up until the last five years, at which point the gap gets much bigger and that's because congestion changes quite a lot in the latter part of the period. And the graph on the right is showing the difference between VWAP and RRP and the GWAP in the reform case. And interestingly, this shows that the VWAPs or the volume weighted average price paid by load if that option was chosen, instead of the RRP, is actually moderately higher.

But I guess a point with these two graphs is really that the left one is what matters because what consumers actually pay is GWAP. So, even though VWAP is slightly higher, the kind of matter of fact of reform would still be consumers paying lower prices. So, this was another benefit we were asked to quantify and so this sits outside of the PLEXOS modelling, although we did use the outputs of the PLEXOS modelling to do this calculation. And so we were asked to look at what were the potential benefits of increased retail and generated competition from introducing FTRs in place of the settlement residue auction units.

And so, I've outlined on the slide, we set out four factors that needed to be true for there to be an increased benefit in what we call inter-regional competition. The first being that you needed to think that there was already a competition problem. So, the competition in the generation retail markets could actually be improved. And so, if you read the REPI, you read the AER's wholesale market performance reports and the AEMC's retail energy review, there are concerns in both markets. We haven't independently assessed whether we think they're right. But there are existing concerns by policy makers about the level of competition in both generation and retail markets.

The second factor that needed to hold was the evidence that inter-regional risk was actually distorting behaviour, in that you have generators and retailers co-locating in the same region and not necessarily venturing into other regions. And therefore, inter-regional risk might be limiting the amount of competition that's happening. And so, we looked at where generation and load were locating and we found - I mean at least when you look across the major generator retailers, there is some evidence that they seem to be co-locating. The third thing, and this is particularly on the generation side, is that you actually need room for new competition. You know it's all well and good for there to be a competition problem and a distortion but if there's actually no need for new plant, that makes it a bit harder to get improvement in competition.

And so, I've just set out the stat there that comes from the ISP and I think Merryn mentioned the statistics at the beginning about how much generation is expected to turnover in the NEM. And so that's providing the opportunity for competition to happen on the generation side. And then on the retail side, the REPI found that there were no significant barriers to entry in retail. So, the final factor, which is probably the most interesting one, is that it needs to be the case that FTRs are going to be a material improvement in inter-regional risk management over SRAs.

And we've set out in the report that this is definitely true in theory that FTRs will provide a firmer inter-regional hedge. And that's because of the counter price flows point I've noted there. But the one thing we weren't really able to get a handle on, is how much of an issue is this in practice. You know, is it the case that SRAs are terrible and FTRs are fantastic, or are SRAs a great hedge, but FTRs are a really great hedge. So, the kind of materiality of the improvement was something that we weren't really able to verify. And that goes into what we actually ended up quantifying and the range we took.

So, what did we quantify? Fantastic supply and demand graphs which economists love drawing on the right. So, we calculated what economists call allocative efficiency in both markets. And this is increased consumption due to lower prices, which is the blue area in that graph on the right. So, if prices fall, there is more consumption of electricity that generates more what economists call consumer surplus and that is a social efficiency benefit. We also separately calculated what's called the transfer, which is just the pure existing volumes of electricity bought at lower prices, which is the green rectangle.

And in some ways, this is really a size of pie analysis. So we looked at a range of zero to 0.5 per cent and this compares to when the electricity authority in New Zealand, they went through a similar exercise with a different starting point, which is important I think, in that they introduced FTRs and they did CBA of doing that, quantifying essentially exactly the same thing we're doing here. And they looked at a higher price increase - sorry, price decrease range of 0.5 to one per cent. The other thing we looked at productive efficiency. So, this is where if there is increased competition that would lead to firms being more efficient and having lower costs.

And we followed the same methodology that the EA did and assumed that this would reduce variable costs. And sorry, for both of these, this is in generation and retail. So, we assumed variable costs would fall by zero to 0.5 per cent. And that compares to the assumption that EA took of 0.5 to one per cent. And so, we calibrated a model which basically means we set up a model that replicates that graph that I've drawn on the right-hand side. So, we had to have assumptions around the slope of the demand curve, what variable cost is and that comes out of the PLEXOS model. And then did that over time and worked out what happens if prices fall by zero to 0.5 per cent. And what happens if costs fall by zero to 0.5 per cent.

And so, we intentionally took more conservative assumptions than the EA did in New Zealand due to the different starting points. So, we already have SRAs in Australia, whereas in New Zealand there was not a risk management product like FTRs at the time. And also, another point is that the evidence coming out of New Zealand in terms of the impact, the ex-post studies when they've looked at what FTRs do. It's not super strong, it's really hard to disentangle the improvements that have happened in retail competition, from the other things that have been going on.

And so our results are shown in that table there and probably the key things to take away from this is that the allocative efficiency benefits, so we have the social benefit of lower prices, isn't super large, and that stems from the fact that electricity, and demand for electricity is generally quite inelastic, especially in the short run. So that demand curve's quite steep, so when prices fall, volume doesn't change much. So, it's kind of expected that social benefit's not going to be very large. But it can result in large transfers so that the green rectangle can and is much bigger than the blue shaded area.

And so that comes through both in generation and retail because the two are linked obviously. And then if we go down to the bottom, so the magnitudes of the social benefits versus the transfers are quite different, so we get a very large transfer of 1.6 billion dollars and these are MPVs over the whole period, which is a much smaller allocative and productive efficiency benefits. And in the interests of time I'll probably just keep moving so we can get to some discussion at the end.

And so, this is just the overall summary of all of the numbers we've shown you and I'll probably just highlight a couple of things. I mean the first is that if you look at row 5, that is what we're calling the social benefits so those are effectively the system cost changes and over the whole period we're getting a number of $3.6 billion down to $3.1 billion as a range.

And then row 9 is the - what we're calling the total consumer benefit which adds the transfers to that social benefit which gives \$6.1 to \$8.2 billion. And we have three sets of columns and this is to illustrate that most of the benefits are actually occurring in the final five years.

And that is driven by when coal retires. So, the benefits of this reform relate to primarily improved investment efficiency which you can see on row 2, sorry, no row 1. The single largest benefit and it's all kind of really related to when coal retires and therefore when the system needs capacity. So, if that happens sooner, which could actually be the result of the reform, that would actually bring the benefits forward which would make them larger in NPV terms. And I'll probably just stop there, and we can move on. I think the next slide is the Q&A.

Sorry, one more slide. That final graph, I mean I don't need to talk to it, I'll be very quick. Just compares what we modelled in stage 2 with the kind of benefits transfer benchmarking we did in stage 1. And our bottom up modelling is broadly consistent with the top down benchmarking we did in phase 1. Both in terms of the social benefits and the estimated wealth transfers. But in the interests of time we'll just move straight to questions rather than dwell on the slide, I think.

MS MOLLARD: Great. Thank you, Will. So, one from Jasper which is probably a question for Tom Walker, so is it possible to replace the SRAs, the current SRAs we have, with financial transmission rights but without also introducing locational marginal pricing.

MR WALKER: We think not, although obviously if people have a way to do it then we'd welcome hearing about it. With the introduction of locational marginal pricing, the settlement residue that arises across all the locations is proportional to the FTR payouts. That is payouts out of a quantity multiplied by the price difference. And for this reason, when we introduce the LMPs we can confidently back the FTR payments of these kind of fixed quantity FTR payments with the settlement residue that arises without the introduction of LMPs. The settlement residue is not - well, the settlement residue that arises would not be proportional to some hypothetical FTRs if we were to introduce them.

We can get lots of settlement residue, we can get not a lot of settlement residue, we can actually get negative settlement residue arising in individual dispatch intervals and for that reason that's why - as I understand it, that's the reason why the settlement, the SRA units are designed as they are, which is to simply payout a proportion of the settlement residue that does arise over a period of time.

MS MOLLARD: Thanks Tom. And there is some more detail in our report on that as well. So, if that wasn't a good enough explanation, feel free to let us know and we can email you the exact page reference. Jasper has also reminded me that I did forget to ask one question earlier about batteries, so I might ask this - I think this is one for you George. So, it's the first question on the question and answer screen. Jasper's asking you're assuming that batteries bid at their long-run marginal cost. Why do you think that's accurate? That doesn't make sense because it doesn't maximise their dispatch, given their entire cost is sunk.

MR ANSTEY: Yes, I mean I think that's right. So, it's true that batteries would get more - would have an incentive to be dispatched more frequently. The reason for doing it is really a pragmatic and practical one which is that without modelling batteries as peakers, it's very difficult to get outcomes because of the need to forecast prices at every node in a sort of iterative way, in order to get the kind of opportunity cost of the battery's operation. And we've taken the - as the LRMC it's true that we're basically assuming that there is a given number of cycles per year, I mean 365 cycles, relatively high. So that helps to bring the long-run marginal cost down if you like when it comes to actual dispatch.

But I agree that it would be better were it feasible to dispatch them as batteries with a reflective marginal cost. And one thing I would say is there was some engagement with battery developers about how they think about this and what the variable cost of the batteries were. And I actually, to be honest, I was involved in that but partly that was conducted by some people at the AEMC. And those conversations were broadly leading into answers along the lines of that battery developers do think about capital costs when they're discharging but whether discharging and charging batteries because of the kind of fixed number of cycles really that batteries are capable of doing without degrading.

So, I'm not sure it's quite as poor an assumption as Jasper implies but I believe it is a simplification and that's absolutely right.

MS MOLLARD: Thanks George. And so if we scroll right down to the bottom there's one by Panos, at the bottom, who has asked to understand the competition benefits, did NERA consider the initial disruption on the contract market, which is relevant for investment in the NEM, with impact on the existing contracts and complexity across the market will be a barrier. So, I might hand to George to say how - if you guys considered it in the modelling, and then I might just hand to Tom to talk a little bit about how we're thinking about it. But I'll start with you George. It's the very last question.

MR ANSTEY: Will might be better placed actually but I think the answer's probably no. Will, do you want to field this.

MR TAYLOR: I think you're right. The answer is no.

MS MOLLARD: Easy great. And Tom, do you just want to talk a little bit about obviously we're quite conscious that what we're proposing is different and we have put in place quite a lot of arrangements to support and mitigate some of those effects. Then again, that's something we're really interested in feedback on. But I'll just hand to you, Tom, quickly to talk to that please.

MR WALKER: You're right, Victoria. We've designed - we made a number of design decisions which we hope somewhat mitigates this problem. We appreciate it is a problem. Those design elements include only introducing risk some time into the future. We're suggesting, in the region of four years from when the rule changes are made. We're also very conscious to make sure that it's coordinated with the other ESB related post-2025 reforms, so that any disruptions that might arise as a consequence of those reforms can be sort of not getting the disruption twice as it were.

We are also introducing or suggesting the introduction of transitional rights, which would further limit the disruption to market participants. I may have missed a number of other design decisions or details that would also look to mitigate these concerns, but I think they're the big two, you know, implementation date into the future and transitional arrangements.

MS MOLLARD: And I really highlight as well, in terms of submissions, I know this is going a bit beyond the modelling, but we're really interested in thoughts on any of those mechanisms. Is the date, right? Are the transitional FTR arrangements, right? Should they be longer, shorter, and so on. That's something that we would be particularly interested in. So probably just another quick question. So probably last one, this one's from Ron. So, Ron's asking was sufficient transmission built to ensure that the transmission reliability standards for meeting consumer load were met. So how was kind of the reliability element of transmission incorporated into the modelling. Assume that's one for George.

MR ANSTEY: Yes, explicitly it was not. So.

MS MOLLARD: What's the implications of that then?

MR ANSTEY: I mean, maybe I misunderstood the question. So, the question is when we're thinking about transmission investment, did we make - did we think about the security standards that exist. I mean beyond taking AEMO's ISP decisions, well recommendations I ought to say. Beyond taking AEMO's ISP recommendations, we haven't done anything specifically to take into account any specific security constraints. No, or operating constraints. What's the implication? Not entirely clear to me that it would change very much. I mean what we see is that the benefits of transmission - the transmission is not an effective mitigant, I think is basically what - the conclusions of our analysis on transmission. And therefore doesn't - I mean it seems to me that it would follow that we're not taking into account an alternative expansion of the network in particular ways. Doesn't change very much, it will just increase and decrease the counterfactual by sort of similar amounts.

MR WALKER: Am I right in saying George that that's not to suggest that there would be customer load not being met as a consequence. The customer load is met, it's just being met through investment in generation through the modelling.

MR ANSTEY: Absolutely. And so, our modelling has all of the physics of the system insofar as Kirchhoff's laws relating to reactance and resistance to the lines, those sorts of things. Doesn't have operating constraints in it. So, it doesn't have kind of specific restrictions on synchronicity and things like that. But insofar as what we're doing is making sure that load is met, we're doing that through - exactly doing that through generation as you describe, Tom. So, it's not the case that we're getting lots of load shared, because we're not imposing the right security standard. It's that the model is building as much generation as it needs to meet demand, given those sets of assumptions.

MS MOLLARD: I would say as well, because you're using the base ISP world, and this is relevant to some of the discussion we were having earlier, so that base ISP world, which is - that assumes that the reliability standards are met. So, because you're using the same transmission pathways as what's on the ISP, it's implicitly in your modelling. And then just to go to some of the questions earlier on the REZs, which I think you know Gloria was alluding to. For example, Orana, that's not included in the ISP at that moment. Was that included in your modelling?

Again, what we took as those base assumptions is everything that is in the ISP model. And so, if it had different REZs in it or different locations, then that would have been factored into the model. It was just at that point in time we took whatever was in the ISP and that was the base assumption. So, I might just end there, conscious of time. Someone has asked there have been quite a few questions that we haven't managed to get to in the chat, so we'll have a think about the best way to maybe put something up on our website with some answers to them.

There's also been a lot of questions about whether some of the detailed modelling data could be released. Again, we'll have a think about that. Some people did provide suggestions of particular charts that they'd like to see the data behind, from NERA's report. So if there is anything like that, that you'd like us to consider, please just reach out to one of the project team. But aside from that, I will hand over to Allison, who will close the public forum for us.

Closing remarks by Allison Warburton

MS WARBURTON: Thanks Victoria. Thanks everyone for being here today. We do appreciate you taking the time to engage with our processes and just to reiterate Victoria's comments, there's a lot of questions coming through. I think we're close to about 50 questions and some really good input there. A couple we'll have to chew on a bit. Some good questions around linkages with some of the other market initiatives under consideration. So, that feedback that you give us just invaluable to us. And we want to keep that coming. It helps us make better decisions.

So please do continue to reach out to us with that. In terms of today's discussion, it was very useful, I think, to sort of break down the benefits of the reform and for me, there's probably three key takeaways from today. Firstly, that the benefits of the reform are significant. That they're varied and start to accrue immediately upon the reforms coming in. But for me, probably a really key point is that the faster the pace of change, the faster the benefits and the greater the benefits accrue.

Second point I would make is that clearly modelling the NEM in this level of detail and over the long term is very difficult. So, hats off to George and his team for undertaking what must have seemed like a Herculean task for them at the start. So, we do appreciate that. And probably third takeaway is just this need to get a bit more granular about the costs. And I think we've seen a few questions come in about that. And our thinking on that is quite preliminary, as we said at the start. We really want to get a better handle on that, work with AEMO, work with market participants.

I mean at the moment we're still talking - it's a small, in the order of magnitude compared to the benefits but we do want to understand that much better than we do now. We do appreciate the reforms are not small for generators, in terms of coming to grips with them and how you would operate differently. And we're doing what we can to try and simplify them and streamline them. And you'll see in our report that we've moved quite a bit during the course of the year. So, we're continuing to do that and want to continue to engage with people about how we can make it more streamlined for people.

Victoria mentioned the FTRs as well, that's another area where we're doing some more work. We're proposing that there will be a period of free FTRs for generators, so that they can undertake a learning exercise. Obviously, we need to look at what is the appropriate period. We want to give people enough time to get their heads around it and understand how it works. But not so long, such that you defer the benefits that can flow to consumers. We clearly need to continue to work with participants and our stakeholders, just on the understanding, and again, we're getting the flavour of that from the questions that are coming through today.

We're getting a better handle on the areas where people need a bit more and we've got to do a bit more work to take people through that. To that end, if you're available, I would encourage you to come to our next seminar next week where we're actually going to have a bit of a tool that NERA have produced, so people can get on and have a play and see how this will work in practice. We also would like you to be putting in your submissions due on 19 October and if you’re struggling to reach that date, sing out. We can work around that. We have weekly newsletters and we also have alerts about this project. So, you can sign up to those on the internet or just shoot an email through to one of the team from today.

And if you've got feedback on today's workshop, shoot us a note about that as well. I'm not sure if we've got an official survey form but we'll find out about that. No, we don't. So just shoot us a note about that to the extent that you've got feedback. Obviously, it's a long haul, it's a couple of hours, it's a different format from what we've done in the past and we're still refining and trying to get the new format better for people. So that's probably it from us. Thanks for taking part in the forum, and we very much look forward to your continued engagement.

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