AEMC

AUSTRALIAN ENERGY MARKET COMMISSION

PUBLIC FORUM ON AEMC REVIEW OF ENERGY MARKETS IN LIGHT OF CLIMATE CHANGE POLICIES

HELD AT

PERTH

ON

8 MAY 2009

(WEM ISSUES)

CHAIRPERSON: JOHN TAMBLYN

The ex-tempore character of this discussion has been preserved in the transcript taken from a recording of forum proceedings. Please note that, due to faulty recording equipment on the day, some portions of the transcript are missing.

SESSION 1
OVERVIEW OF THE REVIEW
JOHN TAMBLYN, AEMC

JOHN TAMBLYN: Ladies and gentlemen, can I have your attention, please. Good morning, everybody. I think we'll get under way. We've got a few people that are still to arrive, but I think it's worth getting started. Can I just welcome you to this AEMC forum dealing with our review on the effect of climate change policy on the energy markets. I'll just introduce myself. I'm John Tamblyn, the chairman of the AEMC, and Colin Sausman, at the front table there, is the project leader of this review and is doing a very solid job with his team. We've got a number of AEMC staff members here that will be available to assist during the proceedings.

Could I also note that this is the second public forum we've had. We had a public forum last week in Melbourne, which was very well attended, and now this important forum here in Perth. We will be recording the proceedings, so a transcript will go on our website and you'll be able to refer to that if you want to recall what you said as well as what other people said. So I would ask you, if you speak - and I hope you will - during proceedings, to identify yourself and your organisation so that the recording can acknowledge that.

So that's the introductory remarks. Can I then just talk about why we're here. Climate change is obviously going to have a very significant impact in transforming the structure and behaviour, and outcomes achieved by the energy market, and this is occurring at a time of fair stress on energy markets. In the east, as well as here, there's a fairly tight supply and demand situation. Input costs are rising, demand continues to grow. There's a significant investment task out there for replacement and augmentation and, on top of that, we've got climate change policy coming over the top, putting considerable stress on the energy markets that we have at the moment.

For this reason, the MCE has asked the AEMC to look at the likely impacts of climate change policy on the energy market - its structure, its behaviour, its performance - and to answer the question, "Are the designs of the markets adequate to manage this transition smoothly and keep the lights on, keep costs and prices efficient, or are there some reasons why we might need to change or vary the design to better accommodate the pressures of climate change policy?" So that's the very important context that we have, hence the review that we're undertaking.

Can I also just say a few quick things about the AEMC. Many of you will know who we are, but we're one of the two new national energy market institutions; the other one was the Australian Energy Regulator. Our role, sitting under the MCE, the Ministerial Council on Energy, is to vary the rules on application from any person - it can be the MCE, market participants, consumer organisations - can all put rule change proposals forward. We assess them and, where they meet the test for rule change, we approve them. As well, we conduct reviews for the MCE. Where they see emerging issues in the market and they want analysis, consultation and advice on solutions to those emerging issues, they can send a reference to the AEMC, and this reference on climate change policy is one such review.

We also give advice to the MCE; we can initiate advice where we see issues that we think they should be made aware of. We're doing a range of reviews in addition to this one: demand side participation in the national energy market, we're looking at reliability in the context of extreme weather events, and a range of other reviews of that kind as well as a number of rule changes.

Let me then go to this review. As I've said, the terms of reference require us to review the frameworks, the market design frameworks, for both electricity and gas in all jurisdictions and to consider the question, "Are they adequate and resilient to manage the transition from climate change policy or do they need change?" and that's what we are about. We issued a scoping paper in August. The reference came, by the way, in July of last year. Last August, we issued a scoping paper, and received submissions and comments on that.

In December, we issued our first interim report, which really indicated the issues we thought were material and needed consideration, and those issues which we'd looked at identified, but felt the market design and framework were going to be adequate to manage the transitions. We received submissions on that paper; we've had regard to those submissions, we've conducted further analysis, we have a reference group, we're also consulting on all these issues. We've had regard to the views we've had from the reference group and a number of sub-groups operating under that reference group, and now we're having a couple of public forums to indicate the thinking we have at this stage about the issues that will need attention.

We put out a discussion paper for the purposes of this forum and the Melbourne forum: we want to discuss with you our current thinking and test that thinking with you, and get your comments back today. We will invite you, if you hear things today where you would like to make a further submission, to put a quick submission back to us. We'd like it within the next week or ten days, and I'm talking about an email-type one-pager, basically, rather than a long one.

Our next stage is then we have to put out our second interim report at the end of June, 30 June, back to the MCE, and that will indicate the policy positions and conclusions that we've come to about those issues that need serious adjustment to meet the consequences of climate change and those issues we don't think need any further change, and our reasons for that. Then, on 30 September, our final report will also include reaffirmation of those conclusions. There will be a chance for comment, of course, on the second interim report. We'll consider those comments, reaffirm or vary our conclusions, but also indicate the changes to law or rules that need to be made to implement the changes that we recommend.

So that's our process. I should mention there are a couple of constraints on our process. First of all, the terms of reference make it clear that we are not reviewing or commenting on climate change policy itself. The policy issues, the parameters of those policies, they are givens, and we're taking as our point of departure the framework that was set down in the white paper of late last year, together with the recently announced prospective changes to that framework which the government is now negotiating with other parties. So we're not reviewing climate change policy; we are reviewing the effect of the announced policy on the energy market and the need for change.

So you might bear that in mind today. You may have views of various kinds about climate change policy, and the way it's been announced and managed; that's not a matter that we can comment on or deal with.

After the morning tea break, Colin will take us through brief introductory presentations on the three key issues we think, in the west, will need some attention, after which we'll have comment from three different West Australian people with knowledge on those issues, after which, for each item, we'll have some open discussion from the forum floor. So that's our structure of business for today. Thank you for listening to me. Before I close, are there any clarifying comments or questions anyone would like to make about what I've said or what we are hoping to achieve today? If there are not, thanks for listening, and I'll hand over to you, Colin, to take us through the first session.

SESSION 2
REVIEW OF AEMC FIRST INTERIM REPORT
COLIN SAUSMAN, AEMC

COLIN SAUSMAN: The purpose of this first session was to basically explain the different issues that we look at in the review as a whole. We tried to characterise them at a level which was generic enough to be analysed in the context of the NEM, in the context of gas markets and also in the context of the WEM. So deliberately generic as a means of providing some structure around what was obviously a very wide-ranging and pretty complicated set of issues.

So of those eight issues, we distilled them down a bit in the context of WA. The eighth issue, which was to do with the size of the financing task in general, we didn't think was specific to WA; it was a much wider position. So we're not going to talk about that one here. And we felt that issue 2 and issue 3 in the list on the previous slide, to do with the management of reliability in the short term and in the long term, could be combined because of the way the capacity mechanism works here. So we've essentially got six issues in a WA context that we're going to step through.

So in terms of how we've ordered them, we're going to start with the ones we felt were most significant first and then go through ones where we concluded that the frameworks we felt were sufficiently robust to manage any consequences. And I suppose a point to note is our filtering process tried to identify issues which, if you continued with the existing frameworks, would demonstrate signs of stress and would drive on economic outcomes. The costs of the policies we're talking about, because of the CPRS and the expanded RET, it isn't a general review of, "Are these things good ideas? Do we want to redesign the market?"

We've been asked a much more focused question, which is, "There's a perturbation to the market which is two big policies; they will change the economics in the market quite significantly. Purely because of those effects, are there any problems with the frameworks?" So I think it's quite an important constraint. It's not a general review of everything; it's actually quite a specific review, and the effects need to be attributable to the policies.

So the first issue that we identified in the WA context as a big issue was system operation with intermittent generation. So the basic driver here is the RET, so the RET will stimulate investment in wind farms, wind farms are intermittent - this means that the output comes and goes with the wind - and having a large proportion of intermittent generation connected to a power system creates difficulties in terms of system management. It's the ability to manage the potentially large and unexpected changes in output in very short time frames.

So, in a relatively small network like in WA, this can cause particular problems, and we looked at existing arrangements and felt that it was already exhibiting signs of stress with relatively small amounts of intermittent generation on the network, and if you leave it up to that volume of generation, then it would exacerbate these effects. And it revolves around the way balancing occurs, and the obligation on Verve, if you like, as the balance of last resort and how that works.

And I think the point is, when we say "signs of stress", we mean technical issues - you know, what technically are the risks to the power system - and also economic issues: are the incentives that drive inefficient outcomes drive unnecessary costs if you go along with these arrangements. Technically, it might be quite robust to continue with the arrangement of Verve being a balance, sort of, last resort, but if that's driving large, unnecessary costs, then you should really consider alternative ways of doing it, but at least be aware of those costs in confirming that, "Yes, that is the way we want to do it."

So another aspect that seems to contribute to this issue is the treatment of intermittent generators and their ability to spill onto the network, and this idea that - more a question - "Should intermittent generation be more constrained in terms of how it operates?" This was a very similar issue in the NEM, and a series of changes have been made in the NEM to essentially introduce a degree of controllability to the output of intermittent generation.

So what did the submissions say? The submissions agreed this was a significant issue, and there was a range of views on what you should do with this observation in terms of recommendations for change. Our updated position, rather unsurprisingly, is we still think it's a material issue, that we intend to focus on this going forward. We're beginning to talk in a bit more detail about options for change, and hopefully we'll have some of that discussion in the second session.

Another issue which we felt was material was connecting remote generation. Another feature of wind farms is they want to locate where the wind is, and that isn't necessarily where transmission is. So if you are seeing lots of demand for new connections in remote parts of the network, how do you manage the process of building the transmission to connect? So it puts an additional stress on the connection application and management process, and in a WEM context we felt there were already some pressures which made this quite a complicated process and quite a lengthy process, and if you increased the volume of connection applications, that would only get worse.

So the punchline, if you like, is we recognise the bilateral negotiation framework and in many ways it has some strengths, but it doesn't look like it's going to be able to cope with lots of relatively small connection applications in the same area. Possibly more importantly, the possibility that new waves of generation in the same area will come along over time, so you might build a transmission link to connect the first tranche of generators and then, if a subsequent tranche of generators comes along, you know, have you built a too small connection and is that unnecessarily costly?

So this question of how do you allow for future growth and efficiently oversize the initial connection seemed to us a big issue. And ultimately consumers pay the cost of connection; it's just rolled into the costs of it being a generator. So if costs of connection are unnecessarily high, it just means unnecessarily high bills for consumers.

Submissions said yes, this is an issue. The connection process is challenging, and if you have lots of new connection applications in remote areas, it will be even more challenging. In the NEM context, we actually put forward a model to say, well, here's a way you might actually operate this - make this change, and some people expressed some views on whether that was a good idea or not - some reservations, some support - and we've been busy building that into our thinking. So we do think it remains a material issue; it's another issue that we think we're going to advice the MCE on, the need for change. Our current focus of work is to work through the detail of how these models will work, and try and identify the best one.

The third issue which, in a WEM context, is tightly related to the previous issue about connection is essentially the efficiency of the transmission planning arrangements and the transmission network development. The point we made in the first interim report was the implicit approach of a non-constrained network, which is referred to in a WEM context, can lead to inefficient over-investment. I mean, the simple argument here is it might actually be cheaper, more economically efficient, to accept a level of network congestion and manage that in other ways, than build up the congestion, and I think this is particularly an issue if you connect lots of intermittent generation to the network.

If you build the network to be capable of the maximum output of all wind farms at all times, then most of the time the network that you build will be under-utilised because you don't see it at maximum outputs very often. So it kind of focuses and magnifies the problem. If you build enough transmission capacity to give farm rights to everyone, it's pretty expensive, and if lots of generation is intermittent in nature, it's arguably even less value. So the question is, "Should you accept an efficient level of congestion and how should that be managed, and how does that translate into how you invest in a transmission network?"

So submissions were pretty strong on this one. It was probably the strongest view that came through all the issues that we consulted on. There was unanimous agreement that it is a significant issue, and the unconstrained planning approach wasn't seen as sustainable, recognition that it wouldn't actually be efficient to build out all congestion. But it was also a recognition that this is actually a complicated part of the market arrangements in any market. The interface between a competitive sector and a transmission sector is inherently fraught and complicated, so any change in this area is likely to be reasonably complicated also.

We shouldn't lose sight of the role of locational signals to generators. In a sense, transmission is responding to the actions of generators, and if generators aren't well incentivised to locate in the right place, then there is a risk that efficient transmission investment chases inefficient generation decisions around the place, and the overall outcome is unnecessarily expensive. So there's two sides of this point; I think it's important to be aware of that and think about options for change.

So our updated position is - well, if anything, it's stronger than our position in the first interim. We think this is definitely an area to focus on; it's something we should advise the MCA. Our current focus of work is to step through the options of different approaches, and pros and cons, and also think about process. I mean, to make changes in this area is quite a complicated thing, so you can't just jump to the answer; you need to think about principles and process, and how it might evolve over time, and point a process in the right direction.

So the final issue that we flagged up as significant in a WEM context is retail price regulation. The issue here is CPRS in particular will drive large and possibly quite volatile cost increases, at least in the first years of the scheme. Now, there is a series of issues already in WA..(fault in recording)..issue will compound those problems if it's not addressed. We felt the particular risk is if - ideally, you want price regulation which is reflective of the underlying costs, and that's necessary to facilitate competition and all those things.

If you try to allow for the cost of carbon or get it wrong, which is essentially the task that faces the regulator, then you might end up with price caps which are very non-cost reflective, and that could go either way: price caps could be unnecessarily high or unnecessarily low. There's a potential disruption to the market, so if price caps are suppressed too low, you see..(fault in recording)..the question is how do you make price regulation of retail tariffs smarter, what kind of approaches can you use. We felt this needed to be looked at. We need to be aware there's a framework for jurisdictional regulation in this area, so any approach we adopt needs to be consistent with what individual jurisdictions do, what we felt was - you know, there's principles that can be looked at, and general approaches that can be assessed as to whether we're going to handle this risk.

Submissions agreed that this is also a significant issue. Now, I think this particular issue is probably the one most impacted by the recent policy announcements, because the risk that we had characterised was primarily driven by volatility of carbon prices in the early years of the scheme. So if a regulator needs to set a price path starting in July 2010, then before this policy announcement there would be a high degree of uncertainty about what the carbon price is going to be over that period. That uncertainty has been removed to a degree, so if there is no carbon price until 2011, then 2010's price cap is obviously an easier thing to do.

The proposal is to cap the carbon price at $10 in 2011, so again that reduces any volatility, because you know exactly what the carbon price is going to be: it's essentially a tax of $10. So the problem has been removed in the short term, but will appear in 2012. If you are thinking about how do you set a price path in 2012, if you don't have a deep and liquid forward market in carbon before you need to set the price path, then you do face this risk that you make an assumption and it turns out to be very wrong. One of the risks here is the linkage to international permit prices, so the ability of the Australian scheme to import permits creates an additional volatility, if you like. So if prices tank in Europe, which has happened recently, then under the design of the Australian scheme the price would also tank in Australia because you wouldn't abate locally, you would just buy permits.

So that kind of volatility risk is there, and might well still be there even though the scheme has actually been delayed. So it just makes price regulation more difficult and the question of “are the tools and the ability to respond” going to turn out to get the tariffs very wrong on the basis of an assumption on carbon price, "How does the framework actually respond to that?" So we're focusing on analysing the risk in a bit more detail. We're working with the jurisdictions, individually and collectively, to try and develop some guiding principles, if you like, and approaches that might be adopted that would make retail price regulations smarter to this particular risk.

We're now on to the issues where we conclude that the energy market frameworks, as they stand, could probably cope. One of the issues that we talked about and had a number of submissions on was this issue of convergence between gas and electricity markets. The argument here is - and it's probably a stronger effect in the east than it is in the west - that CPRS will drive a shift from coal to gas, and that will obviously increase the demand for gas, so, are the mechanisms for trading gas and capacity on pipelines sufficiently flexible to allow for these different types of gas consumers and, if not, why not?

I suppose another driver for the forward investment in gas-fired plants might be to complement the intermittent wind plant. So if you are buying energy and you want certainty that capacity can be delivered at peak, and wind farms can't offer that certainty, if you want to manage that risk, you might want to contract with a peaking generator, and the peaking generators might well be gas. So that's another driver for investment in gas-fired generation, which has a particularly peaky profile in terms of its demand for gas. So, again, another pressure on these arrangements.

PAUL DAVIES: Can I comment there?

COLIN SAUSMAN: Sure, yeah.

PAUL DAVIES: Paul Davies; I've just set up a consultancy called Elite Green, but I've worked with Verve Energy and SEC for 38 years, so I'm well familiar through the process of the gas disaggregation of the pipelines and the electricity industry. One of the big problems that we have at the face at the moment is that peaking generation can't actually get cheap gas, because you have to pay for your pipeline capacity 24/7, 365 days a year, whether you use it 1% of the time or 90% of the time. Consequently, for peaking generation, you will find that most of it is now on distillate rather than on gas. That's my comment.

COLIN SAUSMAN: We'll get on to this, but I think the issue we're trying to grapple with is, is there anything in the frameworks themselves that drive inefficient outcomes. It might well be the case that the investment in peaking plant to complement this stuff is going to be very expensive, because that's the economics of gas pipelines, and if you build peaking plants but have an underutilised pipeline, then it's going to be expensive. Now, that might be a natural outworking of this kind of dynamic. Whether there's anything you can do that will improve that situation by changing the frameworks for how markets operate is a different matter, and that was the bit we concluded we couldn't see an obvious flaw in the framework.

Sure, that's economics, and the economics might drive higher cost investments, but what can you do by changing the frameworks that can make that better? So that's the question we were grappling with, and in the first interim report we said we felt the tools were there for people to trade gas and trade capacity, and on that basis there wasn't a barrier within the frameworks themselves. So that was essentially the conclusion we reached in the first interim report. The submissions obviously questioned this - sorry, can we take another question?

TREVOR ST BAKER: Trevor St Baker from ERM and NewGen. On having raised that point, it's a classical problem that the market has resolved, in the NEM and in the WEM, the market is a better solver of those issues (fault in recording)

COLIN SAUSMAN: (fault in recording) We felt, in the first interim, that what specifically was the barrier that stopped people buying gas and capacity, and if they were faced with the real cost, then it might drive people to do other things like, if you do need to invest in storage, you can do. I mean, is there any barrier for that happening? So I think we kind of agreed with the point you made, that this is something that markets can cope with. You might not necessarily like the answer; the answer might imply it's a higher cost than it otherwise would have been, and maybe that's one of the cost implication of a policy like the RET.

Now, that's just a symptom of the policy; that's the effect it has. It's not necessarily a flaw in the energy market frameworks, and arguably you'd be actually making poor public policy if you responded to the economics that result by trying to, you know, engineer another solution through regulation. I don't think our chairman would be particularly comfortable if that was his remit, to try and reverse engineer some of the impacts of the RET. I think it's more appropriate to - you know, if the market can operate, then let it operate.

JOHN TAMBLYN: Could I just say that I think Colin has - this has been an issue on which there has been debate, particularly in the west. If you think we are missing something and there is a flaw or a barrier, or an obstacle in the frameworks that could be removed to more smoothly address this, tell us about it. But our current thinking, having looked at the frameworks, is it's not a market framework design issue; these are some of the realities of the market. So I think, rather than perhaps taking it much further, we've come up with a..(fault in recording)..

COLIN SAUSMAN: ..(fault in recording)..in both the short term and the long term. You know, the punchline here is there is a capacity mechanism; it's designed to make sure there's sufficient capacity presented to the market to serve the needs of demand. It seems to be working pretty well. There are some questions around the edges, around the allocation of capacity credits to intermittent generation; there's a process for dealing with that. This is not a - you know, this is a framework that can sustain the reliability in the light of the changes. Stakeholders agreed--

JOHN TAMBLYN: Just a quick point. As Colin said, we're not here to question capacity markets versus energy only markets. This is the market design in Western Australia. It is working, and we don't see a need, on reliability grounds, to change it because of CPRS or RET.

KEN BROWN: Ken Brown, System Management, Western Power, and I agree the capacity market mechanism is working well. The issue that you mentioned on a few slides earlier was the transmission constraints and/or whether you should run an unconstrained system or a constrained system. There is quite a big relationship between an unconstrained transmission network, if you're going into a capacity market world where you're adding up every single generator and assuming it's totally available for summer. If you've got a whole pile of transmission constraints, they won't be available for summer, so we've got to make sure we don't move in one world on the transmission constraint world or unconstrained world, and not realise that it might have an impact on the capacity world.

COLIN SAUSMAN: Yes, that's a good illustration of why transmission reform is complicated, and that's one of the issues that you'd need to tackle head-on.

KEN BROWN: Yes.

COLIN SAUSMAN: So submissions broadly supported our view that the WEM was robust - sorry, a question.

TREVOR ST BAKER: Trevor St Baker again. On your earlier slides..(fault in recording)..has over a long period of time, in the NEM especially and here, made it difficult to bring on what everyone would objectively see as necessary transmission developments, and they've lagged because of the obstacles created by the regulatory test as it stands. But to then, on a different issue to that, imply that - in the NEM, for example, are building all of the wind generation..(fault in recording)..all the load east of Katoomba as though that's not the responsibility..(fault in recording)..else has to come in and do it. It has the classic implication that people can go on investing in remote location renewables on the basis that someone else will solve the connection problem.

And it seems to me that, while..(fault in recording)..least of all because, arbitrarily, government falling for the lot of connecting thousands of kilometres of remote generation to the load raises the question that those committing to invest in that by governments investing in it, are denying the possibility that could be closer renewables to the market anyway. So once again, was there an implication in those earlier slides that the regulatory test principles are going to be overthrown?

JOHN TAMBLYN: No. Could I suggest that particular issue, the whole transmission, connection, and augmentation and congestion management sort of issues we'll discuss in further detail in our next session. The implications are not what you are raising, but I think we'll plunge into a very detailed discussion if we deal with it. So let's note the point, and we can clarify that after the tea break.

COLIN SAUSMAN: Okay. So our updated position on this particular issue is we don't think it needs to be progressed. It's not something we will be advising ministers on in September, and therefore we're not looking at issues, you know, options for change. So a very quick summary of how this all relates to where we concluded on the NEM issue. There's a high degree of overlap on..(fault in recording)..issue of how you connect remote generation, there's the issue of transmission, network investment and locations signals to drive efficient generation, investment, retail price regulation. They're all common issues across the two markets.

Short-term management of reliability in the NEM context is an issue that we are looking at. There is a very tight supply and demand balance in the eastern states, or some of them, and we are looking at the tools that a system operator has to manage that tight supply, particularly in the event where there's forecast shortfalls: what is NEMMCO's role, does it have the right tool kit? Now, this is not an issue in the WEM context, but it's actually quite an important and quite an interesting issue in the eastern states. Some of the issues that we are re-examining, if you like, on our view on materiality is system operation with intermittent generation. It's actually one of the biggest issues in the WEM context.

We concluded the framework is very robust in the NEM, and a couple of people have challenged some of those findings, and we need a bit more work, particularly to do with ancillary service markets and the implications of having lots of intermittent generation and retirement of some of the large thermal plant - you know, the implications of those two things for ancillary service markets and technical standards. Also on the convergence of electricity and gas markets, there was a particular issue that was highlighted by the AEMO system operator around how do you manage emergencies. So if there's scarcity such that you're looking at interruption, then how do the gas market and the electricity market interface. So do you keep the gas on for consumers but keep the gas off power generation, and live with the consequences in the electricity market, or do you not?

The rules as to how that happens and whether there's any kind of systematic bias in the way the maximum prices are set in those two markets drive the right or the wrong answer. So the AEMO raised some questions around that, and we're getting some further analysis. I think that was all the points I wanted to raise about where we're up to on the materiality of issues. I think the next stage in the agenda was to open that up for further comment.

JOHN TAMBLYN: So we'll have some. Noting that we'll be discussing the three key issues in greater depth after tea, are there issues you want to raise on the matters that we think need to be progressed? On the matters that we don't think need to be addressed because the frameworks will adequately deal with them. So over to you. Before you start, can I just re-emphasise the point again that ours is a high-level review of these issues in the west. We recognise that decisions on taking action on these matters will be with the jurisdictional government and/or the responsible market institutions, and implementation of any decisions will be for West Australian bodies to deal with.

So ours is a high-level review in the context of the national approach to these issues, which we hope will be helpful, but we're not telling West Australians how to run their state. So I just want to emphasise that point, and we do know that ERA, IMO, and the policy and department people are conducting a number of important review on matters in Western Australia. So over to you. Any further issues you'd like to raise with Colin or with me.

KEN BROWN: The only issue with gas and electricity markets - and I'm involved with Jason and most of the people in this room, I think, on gas crises type things - is that this state has had a very close relationship between gas and electricity over probably the last 20 years since the pipe was built, and I know there are other parts of the world that have quite a high dependence on gas, and as gas penetrates further into the electricity world - and the issue is, with the gas, gas is almost an instantaneous product. Even though you have line pack, you've sort of got maybe a few hours, a few days or whatever it is, but it then becomes..(fault in recording)..

JOHN TAMBLYN: ..(fault in recording)..right signals for developments and resources, and that the trading and arrangements should bring on both gas and pipeline capacity. A short-term security issue - I'm not sure we've directly addressed--

COLIN SAUSMAN: I think your point is more long-term.

KEN BROWN: Can you get longer-term high..(not transcribable)..

COLIN SAUSMAN: Yes. I mean, that's my reading on your question. It's more to do with long-term energy security and the framework for that, and I think it's fair to say we probably see that as out of scope of this particular review. There are things like should you oblige a new gas plant to, you know, have back-up fuel, stuff like that. No, it's not something we've analysed.

JOHN TAMBLYN: Okay. Anything else arising? Trevor.

TREVOR ST BAKER: Trevor St Baker again. Is it in your area of review to deal with - to sort of touch on another issue where federal and state attitudes in the west have been opposed to each other; that is, the 10% DomGas issue in the west, when the feds in the previous government were absolutely opposed to the state government imposing requirements on the north-west shelf gas producers. But the current premier is very strongly in favour of DomGas as a high-level need for the state to be able to enjoy some of the assets that are owned by the state.

In the east, there's now an abundance of gas in the near term because the gas developments that are necessary to support all of the prospective LNG plants have to start up and be proven to be operating from the coal seam gas people before they could bank the investments in the LNG plants, whereas in the west you've got a puddle of gas down there, and nothing happens until they decided to go ahead and do it for LNG with billions of dollars, and those resource owners aren't interested in talking to Domestic Gas. That's a high-level reality, and it seems that it's very much in the energy area, and it's an area where state and federal governments now - through changes of government, even - are having opposing views that the AEMC may be useful in collating sort of an opinion to bring those two attitudes together.

JOHN TAMBLYN: I think the short answer is no.

COLIN SAUSMAN: Yes, but that's not to say it might not happen in the future, but it's not this review.

JOHN TAMBLYN: Yes. Any other points? Yes, up the back there.

JUSTIN SCOTCHOOK: Justin Scotchook, WA Gas Networks. The issue I have is more from the displacement of gas in the longer term. I know you highlighted, to begin with, the fact that you're signalling a potential increase in the utilisation of gas; I'm looking more further term as renewables come on line, and then there's a switch back to a potential displacement of gas and then the impacts of the investment in gas infrastructure as gas is potentially displaced in terms of potential renewables or alternate fuels. Have you given that much consideration in a longer-term horizon?

JOHN TAMBLYN: Colin?

COLIN SAUSMAN: Well, I think, you know, the framework for how network infrastructure as a regulated bit, and there's also a framework for merchant investment. I guess the risk within that framework of essentially stranding assets in a merchant context is borne by the people who are going to invest. Presumably, they'll bear that contingency in mind when they do the business model for the investment. And in a regulated context - I'm not an expert on the regulation of gas networks, but I understand, if it gets through the regulatory hurdles and there's a degree of revenue certainty there, so they stranded asset risk is borne by the consumer.

But beyond that I haven't really got much to add. The conclusion in the review was that seems to - there are frameworks to support network investment, regulated and unregulated. The fact that you might need to build more investment is a fact, but it doesn't seem to me that the frameworks can't work.

WACOSS: ..(fault in recording)..policy changes from the climate change CPRS and the RET are going to have cost impacts, and there's a whole range of different costs impacts that are discussed in your paper. I'm wondering whether the commission is going to take a role in terms of recommendations about how the regulatory framework should build in transparency about how those costs are passed through to consumers in order for consumers to be able to make well-informed choices and know where their cost pressures are coming from.

COLIN SAUSMAN: Okay, I'll go first.

JOHN TAMBLYN: Let me take that. Look, I think that goes to understanding how the costs will impact upstream. Yes, there will be a carbon price that emitters have to build into their cost structures. That carbon price will make more economic the renewable structures, and we'll see the heavy emitting businesses gradually disappearing from the market. Those costs will be reflected in energy prices. That's the wholesale level, and they'll come through to the retail level. That then goes to the question of how prices are regulated for the small customer, and the kind of approach that regulators will take in satisfying themselves that the costs that are to be passed through and any adjustments that need to be made because of..(fault in recording)..process that sorts that out, and whether you agree with that or not, that's the policy position.

In every other state, there's going to be a regulator that looks at the pass-through of costs to customers. So I don't think can say much more than that. The point that we've raised, making that an important issue, is if that's not done well and accurately over time, the retailers are going to suffer because they won't be able to cover their costs, or customers will be carrying too much. So I think that's the heart of your question: what sort of transparency and process will there be? And I am simply saying that's the issue we've put on the table. By the way, that's the issue that regulators around the country are also thinking about, and the power industry - particularly the retail sector - is also concerned about how this issue is going to be dealt with in the context of regulation.

So I think that's why, raising it now in the context of climate policy - yes, regulation has gone on over the last ten years and it's done its job. Now we've got a big new uncertainty where both the industry side and the consumer side want to understand that this is being done efficiently and fairly, and transparently. So it's still the challenge on the table to do that to the satisfaction of all, but to have efficient cost-reflective prices being passed through.

COLIN SAUSMAN: I think, just to add to that point, one particular issue is, you know, if these policies do generate risks, then who is best placed to manage those risks, and that occurs in a number of issues in the review as we look at it, and in the context of retail price regulation, we shouldn't lose sight of the fact that, if there is carbon risk to manage, then consumers are incredibly poorly placed to manage it, and you want to allocate the management of risk to the people who are most able to manage it. You know, we're still working through the process of what the principles should be. Well, one fairly obvious principle would appear to be you should treat carbon asset controllable cost from the perspective of a retailer.

So when people talk, somewhat unfortunately, about pass-through, they're not talking about whatever the carbon costs happen to be, that's just a straight flow-through, because that removes the incentive on retailers to manage those costs. So the kind of mechanisms you're looking at what John said: trying to capture what an efficient retailer would do, along with the fact that they have some tools to manage those risks; they might not be ideal, but they have some tools and they definitely have more tools than a consumer.

WACOSS: So if I'm hearing rightly, then the role of this review will be more to try and make recommendations about how to be accurate in terms of the pass-through of those costs and how that's managed, rather than making recommendations. You're saying that will be at the jurisdictional regulator level in terms of the transparency that they build into their regulatory frameworks.

COLIN SAUSMAN: Yes.

SHANE CREMIN: Hi, it's Shane Cremin from Griffin Energy. Just following on from that discussion, I just wanted to point out, I suppose, the difference we have here is we have a very strongly bilateral market, rather than a gross pool market, and so pass-through, to use the phrase, is a little more difficult over here. A lot of these regulatory costs are costs that have been borne or put into a market to deliver a particular policy outcome, and in WA we tend to have a lot - especially a lot of the newer generation assets that have come on in the last five to ten years, have come on the back of 15, 20-year long-term burn contracts, supply contracts.

So there is the scope of a lot of these costs being captured somewhere in the supply chain other than going through to the end consumer. It's not just carbon; a host of other regulatory reform that might result out of RET legislation, et cetera. So I suppose the difference being, here in the WEM rather than the NEM - where you have relative efficiencies of different plants in different areas, such as carbon or, you know, of locations, et cetera, that compete against each other in a gross pool - here we have long-term contracts set at a specific point in time based on a whole load of dynamics at that point in time that may have changed due to regulatory inputs going forward. So just something to, I suppose, be aware of here.

JOHN TAMBLYN: Yes. Well, we'll certainly note that point, so thank you.

RAY WILLS: Ray Wills from the WA Sustainable Energy Association. We're the state's largest industry body representing sustainable energy and also Australia's largest state-based body of its kind. I just wanted to offer, I guess, a little bit of a thought challenge. A lot of what we're talking about is business as usual, a lot of what we're talking about is, yes, gas markets will expand, coal will expand, albeit with a price on carbon. I guess the challenge for us is what happens in the case of a disruptive technology, and I'll offer two simple examples.

One is solar thermal is developing rapidly around the world: California is committed to build up to 60 gigawatts of solar thermal by 2030. It's recognised as significant technology. So in that framework it has the potential to actually totally change our energy markets. In the same way, if we crack the back of storage - and storage is the key issue for renewables - then there will significant changes in the energy market as a consequence, including through distributed generation, and the example that's been brought through in the last couple of years is electric cars and vehicle to grid technology that will assist in that storage.

So the question then is, "What if they work?" I guess the second part is very much the modelling in and around renewables is focussing very much on the costs today. But in ten years' time those costs will be reduced, there is no doubt, because it's an emerging technology, and that's what emerging technologies do. The second part of that is that renewables provide a cost certainty, because while we don't know what the price of gas or coal will be in 20 years, we're pretty confident we know what the price of sunshine will be. So, therefore, there is no costs growth in the framework of renewables in that context.

So ultimately, I guess, the question needs to be posed: "What if renewables are cheap? What if there is actually no relevance to the price of carbon because we've found a better way to do it?" I guess the consequence of that is what I'm arguing, I accept, in the next decade isn't highly probable, it's not improbable. And within the context of what we're planning and the pressures that are happening across global markets - and let's pick on $80 billion worth of investment by Obama in the US - to drive these markets, then we may see sudden significant disruptive technology changes there. It's no less probable than us actually developing carbon capture and storage in an effective way.

JOHN TAMBLYN: I'll make a quick comment, and I might get you to elaborate, Colin. In our paperwork, we have said our focus is the transition in the medium term, 2009 through to 2020, and things we can be more confident are the kind of structural changes and investment developments that we're likely to see, and that the medium to longer term developments, we should wait - in other words, there will be a round of changes that we may well recommend to the market to deal with what we can see with some confidence, but with some probability around it, and there will be other developments in the future, including possibly the kind that you have articulated, that we would want to wait and see what knowledge we have about those matters before we start changing fundamental market designs and investment incentives, and so on.

So I think we're saying the future, 2020 and beyond, is an important question, but we don't know enough about it to start making recommendations for policy and market design changes now. But governments, regulators, market operators, participants will be watching these developments, and we need to respond as the future approaches. So I don't know if you've got anything further to say.

COLIN SAUSMAN: Well, just a couple of things to add. I mean, ideally, we want frameworks that are robust to, you know, any kind of technological development. Underlying costs of all sorts of bits of the supply chain change all the time, and we expect markets to manage that and drive the right answer. So the kind of technological developments that you talk about might possibly be, you know, perfectly compatible with the existing frameworks. If they are genuinely cheaper, then they will be able to sell contracts that are cheaper than the next guy, and the transition will occur within a market framework.

We have tried to anticipate different types of futures and characterise ones that are quite challenging for the existing frameworks, but undoubtedly we have missed something, and if there's a technological development that actually challenges some of the findings that we've made, and no doubt we'll be told to look again. It's not a static thing; I think it will be a dynamic thing.

RAY WILLS: I guess the key is, within the framework, to develop a trigger that obviously allows you, as an organisation, to rapidly respond to that.

JOHN TAMBLYN: Fair point. Lyndon, and then I think we might break for tea, and go into this in more detail.

LYNDON ROWE: LYNDON Rowe, ERAA. I guess I welcome the comments made about the challenge here is to find - what you're looking at is to make sure that the market mechanisms are such that they're not getting in the way of efficient investment.

COLIN SAUSMAN: Yes.

LYNDON ROWE: The focus of your report, therefore, is: if the market is capable of providing those efficient investment, then it ought to be allowed to work. And I guess, in some ways, the CPRS itself is trying to address a market failure and by trying to put a price on carbon, therefore, deal with that market failure. The challenge, I guess, in all this is to make sure that we have the costs allocated correctly, and that whatever the form of generation is, it's accurately reflecting whatever its costs are. In some ways, you actually talked about that in your slide in terms of the capacity payment for renewable energy. But it seems to me, in all of that, if we do have a CPRS that's priced appropriately, then we shouldn't have a RET. I'm just wondering what your view on that is.

COLIN SAUSMAN: I think our view is we don't have a view on that one.

JOHN TAMBLYN: Can I just say that is a very interesting discussion, and I think there are a number of well-informed papers out there, the Productivity Commission, amongst others, has made some comments on that. We are not commenting on it. We've been directed away from it. I think our focus is, if we have a CPRS and a RET of the kind that is being announced by the government, still under negotiation, how do we deal with the energy market consequences. So thanks for the invitation, but--

LYNDON ROWE: I guess the point, though, John - I understand that that's outside your - the point, though, is that it is an issue which will lead to - if the CPRS is priced appropriately, then it will lead to inefficient investment, and you can't ignore that fact, it seems to me.

JOHN TAMBLYN: Now, I guess we are saying a lot of our work, given the RET and given the way it will drive renewables possibly beyond what they would be under just a straight carbon price, there are cost consequences that flow from that. Well, put another way, there are investment consequences that flow from that, with costs attached to them, in terms of the backup generation that's required and the network investments that are needed to link in those renewable generators, many of which will be remote. So we're looking at the consequences. It may be that, in doing so, the cost implications become a bit clearer but, as you know, we'll focus on the energy market design and the consequences, as opposed to the policy position. I don't know if you have anything to add to that.

COLIN SAUSMAN: No.

JOHN TAMBLYN: Look, why don't we just take a break for tea, come back at about 10.30, and we can revisit in a lot more detail some of these issues in the next session. So thanks for that.

SESSION 3a
SYSTEM OPERATION INTERMITTENCY
COLIN SAUSMAN, AEMC
ALAN DAWSON, IMO

JOHN TAMBLYN: …(equipment not turned on) the issues in a bit more detail, then hear from Alan Dawson to give a comment on those issues. The next issue is connecting remote generation and efficient provision of transmission, another little presentation from Colin, and then Gavin Forrest from Western Power will comment. The last issue will be retail price regulation, comment from Colin, and then Jason Banks will make some observations as well. We'll try and keep each of those individual sessions to about 20 minutes each. We've already had some discussion on them, so let's move through them fairly efficiently. But over to you, Colin, to kick us off.

COLIN SAUSMAN: Thanks, John. So the first issue is system operation with intermittency as one of the issues we identified as material. So just to recap, I'm going to step through what the issue is and then talk about the kind of range of options we talk about in the discussion paper, and then leave a few questions that we can come back to. So the main observation here is the arrangements for system operation are already exhibiting signs of stress, both technical and economic, and with a RET and much more intermittent generation, potentially, those will only be magnified.

So some of the features that seem to be causing problems are: the balance of last resort function for Verve and the way in which it has settled, and whether those settlement costs reflect underlying resource costs; the ability for intermittent generators to effectively spill onto the network and for the consequences of their actions to be captured by someone else - this might particularly be a problem overnight, when the load is very low, and some of the costs might be consequently very high - and, again, just the observation that these costs - if there are underlying resource costs to handle these things, then how are they revealed in terms of the level of ancillary service cost and also how those costs are recovered.

So what we tried to do in a discussion paper was identify a range of options, going from the pretty incremental to the quite fundamental. One thing we felt was worth contemplating was just this question of transparency: what information is made available, what balancing actions are undertaken and what are the underlying resource costs of those balancing actions. Our initial view is that it's not particularly transparent what Verve does and why, and how much that costs, and maybe, regardless of doing anything else, it might just be useful to shine a light on what those actions and costs actually are.

The next step is to think about how ancillary costs are recovered. I think this is under active consideration already, and I think Alan is going to talk a little bit about that. Another feature is, well, do you allow competitive balancing, so the idea that Verve would bid into the balancing market in a similar way to the STEM, if you like, with pay as bid, and, a question mark - there are concerns about market power that are reasonably well documented.

There is a framework within the STEM to mitigate those concerns, so why isn't that kind of framework equally applicable to a balancing market? Just an observation there. You could change more generally how settlement occurs in balancing, so you might apply administered prices to everyone or some other cost to everyone; there are a few options within that particular option.

Then there's this question about more actively scheduling into intermittent generation, the idea that a generator would need to notify a position and would face a similar kind of exposure to deviation prices as, say, some other type of plant. Clearly, there's difficulty with forecasting what your position will be, particularly if gate closure is 24 hours ahead. That's obviously an issue which leads on to the next feature of possible options, which is to re-examine gate closure. Possibly, you'd need to take those two things together. If you are exposing people to deviations, then you should probably give them the ability to give a more accurate position that they are being exposed to deviate from. So that's another feature of these kinds of options.

The next feature is looking at how deviation prices are set. So essentially there's a framework of administered prices, taking a price from the day ahead market. That's one administered price; there's other ways you can set those prices..(fault in recording)..price which more..(fault in recording)..and then the final issue is..(fault in recording)..I don't think it's been discussed before, but there's some international precedent for this idea, which is if you are concerned about balancing costs spiralling out of control, then what kind of safeguards can you build in. If you focus on the incentives to manage balancing costs, then there might be some mileage in thinking about, "Is there any way that you can incentivise the system operator to manage those costs a bit more actively?"

We recognise this is quite a large change to the existing arrangements. There's an obvious model in the UK where National Grid is exposed to balancing costs as part of its regulated incentives. There was a great deal of scepticism..(fault in recording)..introduced what the effect would be, and I think the effect has been to reduce balancing costs by orders of magnitude, and I think now even National Grid actually recognises it's probably a good idea. If nothing else, it's actually enabled them to make a bit more money under their regulated revenue framework. So there is a model there. We don't know how applicable it is to this particular set of circumstances. There might be reasons why it isn't, but we think, for completeness, it's worth mentioning

SPEAKER: ..(fault in recording)..Western Power. Just in regards to the last point, National Grid, is that a public or private company?

COLIN SAUSMAN: It's a private company.

COLIN SAUSMAN: Okay. So initial thinking is, "Let's start at the beginning." You know, there's a proposition here which is there's a risk that balancing costs will blow out to be inefficiently high. It seems fairly evident that more transparency in what those costs actually are and what the drivers for those costs are would be a good thing. I don't think anyone can be worse off by having more information. Possibly a relatively low-cost change. Then that would at least provide an evidence base to assess whether more fundamental reform is actually required, so gather some facts first, use those facts to assess the proportional response.

This is trying to embody some principles of, you know, good regulatory design, good regulatory practice, and we think that's probably the way to go. Then, at least, there's an evidence base to then consider whether there's - what the costs and benefits are of subsequent, possibly more fundamental, reform. So that's the nature of where our thinking is getting to. This will all crystallise into some recommendations on approaches, and principles and processes to the MCE. But we clearly value some discussion about the issues that we've put up. We'll come back to these when we open up the discussion, but those were some questions that we felt might be useful to sort of stimulate debate. But another useful mechanism would be for Alan to give his perspective on these issues.

JOHN TAMBLYN: Okay, Alan, can we ask you to make your comment now, and perhaps then join us here for any discussion.

ALAN DAWSON: Thank you. First of all, I'd like to thank John and Colin for inviting me here today, and I'd also like to compliment them on their first report. The section starting on page 61 that covers Western Australia, I thought, was a very - it encapsulated a lot of the issues that we're grappling with here, and it was a good summation of some of the issues that we have.

I thought I'd start off today, rather than going through point by point - because I could be here, and some of you could be here, for many hours talking about these issues - I thought I would address some of the work that's currently being undertaken by the IMO in conjunction with the market participants, and just let you know where we're at with starting to progress some of these issues, and then I'll go through a couple of them and actually highlight some of the thinking that's currently going on.

I think it was recognised long before I arrived in Western Australia that the national climate change policy will impact on our wholesale market, and the IMO started working with the industry to ensure that the regulatory frameworks exist to allow renewable generation to compete and when, with strong drivers to treat all types of generation evenly, and clearly these are going to change the way we operate in our wholesale market.

A renewable energy working group was established, and I think it's referred to quite heavily in some of the papers that AEMC have prepared on 12 March 2008, and assessed the market and system issues stemming from climate change policy. Those are the working scope of that group - I won't go through each one of them - and their intention is to provide analysis and conclusion back to MEC. That's the current membership of that working group, and there are a number of members here today. It would be fair to say I don't think it has made the progress that we would have liked to have seen to date, and we're making some changes to try and push this up the priority list for both the IMO and for the industry.

Two projects that are currently progressing or close to conclusion: first of all looking at the impact of increasing penetration of intermittent generation and SWIS, this is a scoping work which we've undertaken. There is also a review of the treatment of intermittent generation and the capacity market, and that's been undertaken by the Office of Energy. The review of the treatment of intermittent generation really centres on the fact - the level of capacity credits that are currently allocated to intermittent generators.

It has been an area of some concern for some of our stakeholders about the level that we have allocated capacity credits, and now that we have three or four years of experience or data on this, it's probably appropriate that we look at it, considering we seem to be out of step with other jurisdictions on the level of capacity credits we're currently allocating for this generation. The review sought to look at the expected contribution of these generators to reliability, the effect of changes to the capacity credit allocation rules that would better reflect that contribution, and the potential value of diversifying wind farm generation. This work is currently being undertaken by Synergy Econnect, and we expect a report soon.

The next piece of work which probably aligns very well with some of the issues that AEMC have raised as a scope of work has been developed by Sinclair Knights Merz to identify the issues that would be investigated. A works program has been established, a draft one, and it's currently out on our website. I would urge you to have a look at it. It has been heavily consulted with System Management, Western Power, Office of Energy and the Renewable Energy Working Group.

To get some momentum in this, clearly this is a significant piece of work, and I'd just like to highlight to you the fact that we have sought funding in our operational plan for the next year, which is with the minister for consideration at the moment, and have put this in as a special project so that we have the resources to undertake it in the next financial year. This will look at things like overnight load - for example, on Tuesday night, our overnight load was 1300 megawatts. Currently, we have about 190 megawatts of wind; probably doesn't give Ken Brown too much grief at the current levels.

KEN BROWN: Not sure about that.

ALAN DAWSON: But the expression of interest that has just closed for the 2011/12 year has over - we have Griffin, Investec and Verve suggesting that they're going to commit over 400 megawatts - or expressing an interest of 400 megawatts - of wind in that capacity year. So we're fast approaching the issue where the level of wind overnight will become quite a significant system security issue, and the scope of work and the work of that Renewable Energy Working Group will focus on that, as well as some of the other issues that have been raised by Colin in his review.

That review will include looking at things like ancillary services, load following services, how we allocate the cost of those. It may even touch on things like competitive balancing, on which we've started some work as well, and I know System Management and Verve have helped us out with some of that work already.

COLIN SAUSMAN: That is the question. What the answer is, is another matter. We're very interested in what's going on at a working level, and I'm sure Ken has got some views on the direction it should have, and we've highlighted a range of options there that might possibly help address some of those issues, but we're very much in listening mode at this point, I think.

JOHN TAMBLYN: I guess the point of greater transparency to get a focus on what is happening in that context, and what the costs are of that, was our initial point, but if Colin has also mentioned it in the NEM, it may not be applicable here, of course, but the semi-scheduling approach in the NEM, where larger wind generators have to be part of the NEM code dispatch process, and they can be backed off to help manage that kind of issue as well. So I guess what we're saying is we understand that issue. What are the options, or any other options, that we've identified might be feasible here in the west? I wonder if you've got a comment, Alan?

ALAN DAWSON: I have. I think that it's highly likely that the mechanism you suggest about backing off wind is something that will be considered here, given the level of interest from wind developers here. The IMO has highlighted that likelihood in our statement of expression of interest for 2011/12, to highlight it to new investors. We've also highlighted the fact that there's potential to have some sort of load following service that may well be charged back to those wind generators, so both of those have been highlighted to new investors, so that they're aware coming into that process, that this may change, or that structure may change.

I would say that it's also going to mean that, like a lot of other jurisdictions, how the system is managed and how we function, and the types of ancillary services that are likely to change in the next five to seven years. So it's going to be a different world from the, "Let's put on a big coal generator overnight and keep it running, and keep a couple of thermals hot." It's quite a different environment, and who pays and where the costs are shot home, and at what level system security becomes too high a risk to rely on wind is a critical point for this, and I don't envy Ken's job in the next five to seven years, really.

JOHN TAMBLYN: A quick follow-up, and then I think Ken has a comment.

KEN BROWN: Yeah, just a very quick follow-up. One other cost that will be very difficult to identify is when you've built major thermal stations as base load, and you're changing the operation to be load following/two shifting overnight, you're going to increase your maintenance costs, and that will not get reflected in your balancing type costs, not directly, anyway.

ALAN DAWSON: Can I just say, I understand your point. I would to see big thermals compete head to head with wind farm overnight to stay on. If it's really a true cost, those thermals may very well be prepared to bid quite low to stay on, and I hope we see a competitive outcome overnight that is actually an excellent outcome for the consumers of Western Australia.

JOHN TAMBLYN: Ken, did you want to--

KEN BROWN: Ken Brown again. Just with respect to what the NEM does, in the national electricity market - and I know it's in the dispatch engine, or the NEM-DE - it is very much around transmission constraint issues. They get driven back, they put in a semi-automatic bid, or semi-bid, and then they get wound back if the transmission constraint equation constrains them to be wound down, and they have control of wind farms, just like we have control of wind farms. The real issue is that NEM has not got anywhere near the issues of frequency control overnight. They're a long way away from that sort of problem yet.

This state and other very small power systems that have hyper-rotations of wind, are starting to find these problems much quicker than certainly the other side of Australia is finding, and certainly what the Europeans have found. So they're actually constraining it for a different reason, and it's going to be quite interesting when they actually get into pure frequency control, because you have very strict limitations on what you can and can't do with frequency, because it is the one that gets you into really big trouble if it starts moving the wrong way really fast, and therefore that's slightly different than the transmission constraint equation.

I guess the other thing I'd like to comment on, no matter how well we do the balancing - and I've got not problems in being more transparent and getting more balancing, and I'd love to have every generator on the network being able to be part of the balancing game, rather than just Verve - you will still get down to that problem that Paul said, that you will end up taking base-load thermal plant-off, and then you will not be able to get it back the next day, and therefore you're going to run into those security issues that Alan just mentioned, much faster than we'd really like.

So I do agree with getting into a market arrangement, where the price of taking that unit off should be brought in, and therefore it probably would stay on, and therefore you'd wind the wind back, in theory. That's how the practice would work. It's just getting to that level of transparency and knowledge, with some of the rules we have in our existing market, might have to be looked at, such as a short-run marginal cost issue, and how you develop that, and think about that.

JOHN TAMBLYN: While you're there, we've gone through a list of possible options, which we'd like to test, but we've also said, "Look, let's start with transparency; let's understand better what the costs are of the current approach as a basis for moving forward. Is that too conservative? We thought, "Transparency first, and then look at the options in more detail." What would you think about that?

KEN BROWN: I see that as a reasonable option, from a point of view that when we're making decisions on dispatch and unit commitment, and I guess it's the unit commitment that I'm a bit more worried about, and it's overnight. You have 365 nights where we have a spot of trouble. You don't have that much trouble during daylight hours. You'll get to more trouble as you put more and more wind on, but right now with 190, It is a problem on a few nights, and some of the really low days, such as the Good Fridays, and those sort of things. The issue you really have is that you have to start making decisions whether you're taking plant on or off for thermal plant especially, pretty early in the afternoon or evening, because you do want them to come back. Because if they don't come back then, actually your margin has gone down, because you've got to realise that other than the summer where you've got this one in ten years, the other nine, we got lots of plant-out.

We've got about 1,000 megawatts of plant-off now, so we've got a margin on what we think the load is going to be, so if you start finding your big thermal plants being taken off because we think the wind is going to blow, and it doesn't, or even if it does, it often can't get back unless you give them very good timeframes, and what's happening in other parts of the world, I know a couple of jurisdictions have said, "The rule will be, we're not taking thermal plant-off for the wind. We will let the thermal plant come down to as low as they can, and then the wind has clamped down", and - because they're not willing to take that risk, especially with some of the very older plant, that you know are just going to - if it's 20 years old, and it's only got ten years, it's not going to survive coming on and off every night, if he's never really planned that, and I think that's one of the security issues I have, that sort of thought process.

Getting the information out, and getting people to see what it really costs, I guess is more what the generators would have to be prepared to say, "This is what it really cost me to do that." We can give the information on what we did, but what it really cost I think comes from the other participants, and I'm not sure if Andrew wants to say anything from Verve, but that's one of the issues I think we have.

ANDREW EVERETT: Thank you for that, Ken.

KEN BROWN: I put you on the spot.

ANDREW EVERETT: I usually like to sit here and listen, but I think it's a good start. As you say, the more information you have, the better. It's a good start. I think it's possible to identify the costs of providing the service that would otherwise not be incurred, and it's our view that eventually we need to get to competitive balancing, and there's no reason why we shouldn't but it's a iterative process to get there I think.

JOHN TAMBLYN: Thanks. Any other comments? Yes.

MATTHEW FAIRCLOUGH: Matthew Fairclough, System Management. Just a little bit further on that. I do think that transparency is a good way of starting, and one question to Alan on that: it would appear that much of the behaviour is driven by factors outside of the market, that somewhat stem from government policy, such as the Vesting Contract, such as Synergy's policy on procuring RECs solely from local generators. Given that those factors impact behaviour, is the IMO really the right body to be reviewing all of this? Is there something else that should happen as well?

ALAN DAWSON: Yes.

MATTHEW FAIRCLOUGH: Could you elaborate?

ALAN DAWSON: No. No, I think you're right. I think there are behaviours in our market that are driven by externalities, particularly the vesting contract - let's focus in on that - that drive behaviours in our market, that aren't aligned with a competitive outcome in the market, and I currently understand it's under review, and we would welcome that.

JOHN TAMBLYN: I think we'll go over here. I'd like to wrap this session up fairly quickly, so maybe this comment and one other, and then we'll move on.

RAY WILLS: Ray Wills, from WA Sustainable Energy Association again. Just in relation to the comment of externalities, we've got to remember why we're doing this. It's about reducing emissions, and that's the critical point of the design of the market, and within that framework, 20th century, we actually did business without considering externalities. We started bringing in water pollution; we started bringing in air pollution.

This century we've brought in carbon, and this century we will to stop externalising things, and start paying the true cost of things. Carbon is the first step in that for the continuing journey of the 21st century, and I guess along the market design, we have to understand that there will be other things that are added to this, as we realise we're doing damage in other areas. That's a part of the evolution of the market - it should be market based, I agree with that, but we need to keep a mind's eye on why we are making these changes, and I think that that's been missed.

One other quick point: wind. Yes, intermittency in wind is an important thing. As the gas market did finding storage on the east coast, if we do challenge the wind market, the wind market will find storage, and the wind market is finding storage, and we're looking at pump storage - I know with Shane in the room, we're looking at pump storage in WA as well. So there is a range of things that the wind market is innovating too. And I guess finally there's a whole range of renewables out that aren't intermittent. We've got a whole pile of renewables that can provide us with peak load, and there's a whole pile of renewable that can provide us with base load, and they will come online.

JOHN TAMBLYN: Understood. Thanks for the comments. Any other point for this session? Well, if there's not, then why don't we move to the next one.

Colin, just take us through the introductory comments on connecting remote generators and managing network congestion. Thanks, Alan, I appreciate that.

ALAN DAWSON: That's all right, I'll leave you to it.

JOHN TAMBLYN: Good.

SESSION 3b
CONNECTING REMOTE GENERATION AND EFFICIENT PROVISION OF TRANSMISSION
COLIN SAUSMAN, AEMC
GAVIN FORREST, WESTERN POWER

COLIN SAUSMAN: These are two separate issues we identified, that we've conflated in a WA context, because it all revolves around the use and development of transmission network, and how it interacts with the generation sector. That's quite a busy slide. Apologies for that. So what's the issue? There's quite a few framework issues here. The existing framework is based around bilateral negotiation, and if you're looking at lots of connection applications happening at the same time, in approximately the same area, there's this question we talked about earlier on. It makes transmission planning more difficult, there were issues about coordination, and there were issues around how you efficiently size for future development given the large economies of scale in building transmission.

The particular issue in WA is this: unconstrained network planning approach, and what that means, and whether it actually mean you are building out all congestion. Now, when we first looked at this issue, the question was, "Well, where is the unconstrained policy written down, and how is it applied?" and it's a bit greyer than that. We understand that in some instances it's not really unconstrained. There are runback schemes in there, which is a form of constraining generation, so some of those trade-offs are being made around building more transmission, or doing other things, which is a good thing economically, so maybe the issue is more, "How do you give visibility to that, and how is it useful to codify that, so people can see what's going on?"

Clearly there were issues with the amount of time it takes to connect people. It seems to be quite a complicated process to process a connection application, and it's not surprise that queue is emerging, and it looks like under existing frameworks, it will last a long time. That can't be efficient. There might be incredibly efficient projects buried deep in the queue; if there's no means of those projects revealing themselves, then the market and consumers ultimately are worse off.

The other point we clearly have to have in mind is it's not just all about transmission; there's also decisions being made by generators to which transmission is responding. Are generators seeing the right signals to locate in the right places? Are they seeing the costs that they impose on the network? If so, how? And I think there's a whole set of issues that revolve around that, and it's how these things interact. So you get the co-optimised efficient outcome, allowing for generation and transmission as the ultimate goal.

So in terms of options, we think the main point here is we do need to review this unconstrained planning approach or at least enunciate what it is, and I think that will be a part of moving forward. I think we need to be quite explicit in saying, "There is an efficient level of congestion; it needs to be managed; what are the tools for managing it?" and think reasonably creatively about how that occurs.

And the type of creative thinking we should be looking at is, "Should the presumption be that you need to provide a firm capacity right to all generators?" If you do offer a choice between a firm right and non-firm right, that might be a good thing in terms of better suiting the needs of particular generators, but how do you map that kind of choice onto the capacity mechanism, which is a point we've already raised today. Obviously quite complicated, obviously quite difficult, but worth considering to work out whether you can make it work. If the generator is perfectly happy to be serviced with a poorer quality access right, then why shouldn't the framework accommodate that, and be able to manage that? That seems to be a key question.

I suppose the wider set of options is around locational signals. What are the locational signals? What form do they take? Are they robust? Are they stable? Do generators understand them? All these things I think are very important. Where it leads, we're not sure. We've put one possible line of reasoning there, leading to possibly locational capacity credits. That's one route these things might take. We're not saying it's definite, but I think the general question of, "What signals are presented to generators? What form do those signals take? How stable are they? How acute are they?" is a big part of this story.

In terms of the connections queue, is there an issue about speculative applications? Is there an issue about the good project buried deep in the queue, not being able to reveal itself as the good project? Is there a way of prioritising? Is there a way of grouping? Is there a way of managing the queue in a better way? I suppose ideally you wouldn't have this situation, but if there is this situation, how do you better manage it? And I know there's been a few suggestions and ideas already in that space.

We also need to have regard to the fact that transmission investment is planned within a regulatory framework, and it's how that framework operates, so if you have good ideas that you would like to see processes work, you need to map those across to whether regulation actually supports those new processes, or gets in the way, and whether it causes delays or not, and I think it's - my initial observations, reading into the WA arrangements, are the arrangements around the regulation of transmission are pretty complicated, they seem to imply lots of steps that as an outsider aren't particularly intuitive, but I think there's a general view to say, "Looking at this issue as a whole, what kind of regulatory framework do you need to support the outcome that you want?" and it's not immediately obvious, that framework.

So all this thinking is feeding into our analysis at the moment. We're trying to group it together, and we've got some consultancy engagements at the moment to help us do that, and I think some of you have spoken to our consultants in the last week or so, so thank you very much for that, and we will pull together where our thinking has got to at the end of June, and publish in the second interim report.

The other aspect of this question is this connecting remote generation, which is essentially a subset of this wider question: "If you do have lots of clusters of new generation capacity, do you build big fat wire, or do you build lots of small, thin wires?" Now, the economics of transmission would suggest that it's a lot cheaper to build a big fat wire, if you know it's going to be utilised, so can the framework support that kind of decision, recognising that the case for the big fat wire might actually be predicated on future generation development, which isn't visible to anyone yet, so how do you allow for that possibility?

So the big benefit for consumers here are: large economies of scale and transmission, ultimately consumers pay connection costs through the price as they pay, and if you don't realise there are economies of scale, then obviously costs to consumers are greater than they would be. But there's a question mark about, if you are going to oversize capacity, in expectation of future growth, there's a risk that the growth doesn't happen, there's a technology risk; all sorts of risks. Who should bear that risk? One option is that consumers should in part bear that risk, because consumers will benefit from the economies of scale if you are correct, but precisely how that risk is borne, who ultimately pays for it, how big the risk is, is another design question.

They're all very important considerations, and in the NEM context we're busy developing a model to effectively create hubs to these remote areas, and create a regulatory framework around the pricing and the revenue entitlement for the building of those hubs, and we think it might be applicable to the WEM context as well, and that's a question that we're analysing at the moment. But the problem it's trying to solve is that you build lots of thin wires, when it's actually more efficient to build one thick wire. That's where I wanted to start. There's some key questions that we can come back to, but I think we had another respondent who was going to say a few words before we open it up to the floor.

JOHN TAMBLYN: Then could I ask Gavin Forrest to just come and make a few comments on that, then we'll open it up for general comments. Thanks, Gavin.

GAVIN FORREST: Thanks John and Colin for the invitation to come and speak today. Western Power welcomes the opportunity to come and speak today. Western welcomes the opportunity to engage in this process, and supports the material issues as highlighted in the recent AEMC paper.

Western Power certainly remains committed to the delivery of sustainable energy options going forward to meet the future energy of the WA community, and we certainly believe that Western Australia and the WEM is uniquely placed to capture the benefits of renewable resources, and will be required to respond to those challenges probably much earlier than the NEM that's been raised earlier today. We believe investment in infrastructure, together with appropriate market and price signals, and clear understanding of system security implications will be required to meet these challenges.

On the balance of settling on the right market and policy settings, we should take some care to ensure that we don't add any further distortions, and the right solutions emerge to support choice. Now, what I've done is, I'll probably add another few comments to help frame the discussion, as opposed to respond to anything particularly in the AEMC paper, and I've been asked, as mentioned, to speak to connecting remote generation, and efficient use of transmission. I've probably got four areas of discussion that I'd like to walk us through.

The first one is consideration of alternatives to transmission augmentation, and the planning thereof. The system is currently operating at near capacity, and a number of deep investments are now being triggered in the system, so the question in front of us is, "How do we best optimise these investments for the state, as they are quite significant in scope, and certainly significant in cost?" The opportunity is how we support broader economic development for the state, and meet the policy requirements moving forward.

Western Power is certainly advocating the concept of generation parks, and the AEMC has been commenting along those lines around connection hubs, and that's one and the same process, but getting these off the ground will require significant changes both to our relative framework, and market framework, and the detail of that is still being worked through. They will also have flow on impacts for queuing, connection, and provision of access, and whilst we've made some significant changes to that more recently, we hope that moving in that direction will open that further, and provide some stronger locational signals for the market participants.

I guess the second area of discussion I'd like to introduce is around non-networked solutions, and it has been spoken about a little bit this morning, and certainly raised it. There are two elements I'd like to talk to here: one is promoting further demand-side participation, and I know that's probably outside the brief of AEMC, so I'll leave that there, but it's certainly something we need to consider, and the second being around storage, in the context of climate policy, and we recognise that wind remains as the dominant solution in terms of our renewable technologies, and the associated issues of its intermittent nature.

Western Power's belief is that we need to consider innovative solutions to capture this opportunity, and Western Australia was got a fantastic wind resource, and if you believe the modelling, certainly around the RECs, suggests we'll be a net exporter of RECs arising from that wind resource, and that presents challenge for us, and the opportunity to capture that and mitigate the risks associated with it.

Now, we're seeing some real advances in energy storage, that act as a bit of a dance partner for wind, and can mitigate some of the risks that we see with wind generation on the SWIS, that deals with some of the intermittency issues. Whilst these are still developing, they are showing some real positive benefits to an energy system, and they're things like pump storage, which has been mentioned, and the things like electric cars, and vehicle to grid opportunities.

That takes me to my third point around Smart Grid. Now, we spoke a lot about transmission connection, and transmission networks when we talk about renewables, and particularly wind, but what we're seeing is a real shift to distributed and embedded generation across energy systems worldwide, and they will require changes in the distribution network to allow for bidirectional energy flows, and introduce a level of intelligence to support market and consumer choice, and as DG grows it will have an increasing implication for system and market operations that needs to be considered. Smart Grid certainly is a key platform for Western Power, and its strategy moving forward, and is seen as a key enabler for choice, and embracing more renewables going forward.

The last area I'll put to you is around market and price signals, and some of this has been raised earlier, and certainly the consideration of a constrained planning system has been put to us, and suggested that there's significant benefits both to planning, to investment and provision of access. However, this will require significant changes to our market, and operation of the market and system management, and that's been spoken to earlier by Ken, around the market premised on capacity credits.

The second element is around cost-reflective tariffs, and whilst we've seen some emerging and encouraging signs around the trajectory towards that, they're required to really see the level of change and innovation in products and services to support some of these changes in the market. Lastly transparency: transparency of decision making, and transparency of information to support the operation and connection of intermittent generators and meeting policy outcomes, so that we're adding greater distortions to a market, and it's delivering efficient outcomes.

So as we consider these type of solutions, it's important that they're connected, and that we ensure that they consider the whole of market, and the whole of energy system issues. That's essentially what I wanted to add by way of framing the debate. There were a number of issues put forward in the AEMC paper, and I look forward to the discussion. I just want to acknowledge that there's a number of Western Power in the audience, so they come from various areas of our business, and I'd encourage those people to step forward when questions are raised. Thanks.

JOHN TAMBLYN: Gavin, thanks very much. That was very helpful and very interesting. Could I ask you, without putting a lot of work into it, if you could dot point your comments and perhaps send them to us.

GAVIN FORREST: Sure, no problem.

JOHN TAMBLYN: I think you're putting a broader perspective on the issues, which I found very interesting. Could I just make two quick comments. One, we have just published a paper on demand side participation in the NEM, and it touches on a number of the issues that you were dealing with, so whether there's any learning or applications for the WEM remains to be seen from that work, but we think it is in scope as far as we're concerned to look at demand side participation, and the market response to climate policy.

The second point is that the Energy Network Association has raised this general question with us of smart grids, and interactivity and intelligence in the grid, and whether there aren't market framework implications to encourage and facilitate those developments. We've said, "Well, maybe. What are they?" Is this the development of the market and innovation and improvements, or are there obstacles to these kind of developments in the market framework. We will look further at that second question, as to whether there is something in the Smart Grid area, and imbedded generation, that we need to look at more closely, but the ENA hasn't actually pointed us to the areas that need adjustment, and you might think about that question.

GAVIN FORREST: We'll certainly give some more thought. We're working with the ERA on a number of adjustments to our regulatory framework supports some of the roles that we can play, and I note that are some mechanisms within the market rules to support demand side participation, in addition to those that already exist in the regulatory framework, but there certainly is some more we can do.

JOHN TAMBLYN: Could you join us over here for the comment session. Could I just ask at short notice, Bill Heaps, whether you've got any comments on the network planning investment augmentation side, from the work you've been doing for us? Anything that--

COLIN SAUSMAN: You can say no.

BILL HEAPS: I think what I've been looking at is relating it more towards - you could look at it as a bout of influenza. You could look at the symptoms for the queuing and the access and those sort of issues, and I think the queue itself, and the queuing mechanisms are the symptom, and there are underlying issues, and obviously the first underlying issue is the need for more transmission, and to get more renewables on.

The second one I think is the strong incentives that wind generation has got through the mechanisms, through above capacity mechanism, but also how their rewarded for being constrained often balancing market, so there are strong incentives for wind generators to start to get projects off the ground, or at least announce themselves as a project that's at the inquiry stage, that gets them into the queue.

So what I think has happened there is that speculative projects, because they see such a high value from where they're placed in the queue - a high commercial value, potentially - could be seen as using resources that could be applied more efficiently to projects that have got a high likelihood of going ahead, and give a high value in terms of increased renewables, and hopefully lower cost to consumers.

Let's first of all look at the symptoms, so let's see if we can make it more comfortable, and I think some of the ideas that have been coming out here in some of the options are certainly ones that would help to improve that. I think more assistance around management of the queue, prioritisation, and initially we were under the impression that there was a single queue, and we were looking to say, "Why can't the queues be structured around where constraints are so again you can start to prioritise around those?" and we've found that there is actually a mechanism under the rules that allows that to occur under the access application and queuing code that allows that to occur, and I know Western Power are looking at that actively now, so things like that are going on, because I think a lot of that is about efficient use of Western Power's resources, so you can actually target the projects that really do matter and have got a good chance of going through.

I think then we'll just move onto the transmission areas. What I get out of the efficient utilisation of transmission, before we move onto the augmentation, which comes on next, I think one of the issues for me is there could be underlying free capacity in the system. Western Power do have some non-firm generators connected, so when we looked at this, we thought the unconstrained policy really isn't an unconstrained policy, it is pretty much a constrained policy, because there's generators that are constrained by being denied access. So it's really a firm policy. We looked further at this, and found it wasn't just a firm policy, it was a firm n-minus-one for generators.

So the concept there is that all generators must be able to generate after a single contingence event, so after a line-out, it should still have all generators being able to generate, and that could well - if you change that policy, so that you operate generation on N, potentially it could release a significant amount of capacity. I've just been doing some work to see whether that could actually be the case.

The other concept there of course is connecting non-firm generation, and it's interesting I think that the relationship is being drawn with the capacity market, but there is already non-firm generation. Presumably it's being considered in terms of its capacity credits, but I think more importantly than capacity credits is when the IMO is looking at the reserve capacity that's required, because if you don't take into account that there is non-firm generation on the system, then you could have a more optimistic view of the capacity margin, and I suppose that could lead you into security problems down the track. So I think this consideration of how capacity credits work is really important work, and how that comes about.

What we've noted as well there, is that the non-firm generation is using special protection scheme technologies, so generator run-backs, to actually manage it on the system, so rather than managing it through constraint equations, so in the NEM or in models like PJM - Pennsylvania, New Jersey Maryland - and over in New Zealand, where effectively a network model is used, with constraints, and system constraints; generation is constrained on or off, depending on the outcomes of the model. Western Power use actual flows, so they use current in lines. Where those lines might be constrained by one of the non-firm generators, then the generator run-back scheme is employed, and so if the line reaches its limit, then the generator is pulled back either automatically, or by a system operator telephone call. It seems to me that that's a logical step when you haven't got much wind generation, or intermittent generation on. If it want it on non-firm, then you could use those sort of systems.

The problem then becomes - this is a debate that's going on all around the world in transmission - how many special protection schemes can you actually put on a transmission network before you run into problems, and it was one of the issues that took out the eastern seaboard in the United States a few years ago, that a lot of these systems didn't work as they had been planned. There's also been experience in New Zealand where a similar a lot of inter-trips didn't work as planned, so they have to be very good protection schemes, with the right sort of safeguards on there. Then there's the issue of when you get more of them, how do they interact?

We've found in discussions with system management here, it isn't dissimilar to other transmission system operators, where there are concerns about the limit that you can place on them, because effectively the system manager or system operator feels that they've lost control of the system at a time when they want to see more generation coming on, what they're constrained by is they see generation being backed off automatically on the system. It's a bit like a pilot having to take the hands off the controls when he feels the plane is going down, because the autopilot is on, and it's pretty new and scary stuff for system managers, and it's certainly something that's being looked at all around the world. Again it could bring some more non-form generation on in Western Power.

I think you will reach that limit. There will be a limit to where you can use these schemes, and it takes you then logically to the next one, when you get more intermittent generation on, it brings you to the next point which is, we must actually actively manage constraints, and it may take you to the network constraint model, and in the balancing pool, when the generator or resource plans have been submitted, then you will actually be able to use the model to back off generation where constraints are.

I've taken a bit of time to talk about that, but that's the sort of thinking on the access issues. Yes, you can deal with the queue; there's prioritisation, and more that could be done around the queue to get more local signals as well, coming through. Then there could well be some significant underlying free capacity in the transmission network, if you can bring in the technology and the approaches to release that, and the non-firm capacity, then you would have to look at the capacity market. Then we've been looking at the augmentation issues, and particularly how you could get the augmentation you would need to bring on renewables through the regulatory framework.

JOHN TAMBLYN: Thanks, Bill, for that. It just re-emphasises the point. This is a very complex area, but it's also a critically important area to deal with, and involve policy approaches in. Can I have some general comments on this before we move onto the next session? Yes, Linda.

LINDA GONCALVES: Linda Goncalves from WACOSS. A few slides back, there was a discussion in regard to the cost of risks being passed on to the consumer. Could that be elaborated on a little bit.

COLIN SAUSMAN: So the basic problem is, if you think there's a potential large economy of scale of building a larger extension to a remote area, then who should bear the risk that your assumption about future growth and generation is not right, and the new generators you assume will come along and realise these economies of scale don't appear. The problem is there isn't any easy answer. Ideally you would like the future generators themselves to reveal themselves, and I think there's more things you can do to help people come forward when they are ready, but I think that will take you so far, but there is this residual risk of if you want to build surplus capacity, you need to do it with your eyes open, that it might not actually be the right thing to do.

So you can put safeguards around limiting the risk and the size of the risk, and in a NEM context you can have the national planner or some other body who can look at these areas and look at the prospective growth of new generation, and make some estimates or forecasts to try and limit the overall risk, but you can't remove it. So it's a simple trade-off between the economies of scale available if you get the decision right compared to the cost if you get the decision wrong, and the models we are looking at involve some risk being borne by consumers if - well, the first point is the models we're looking at involve significant protections to limit the risk and seek to minimise it, but some of the models also involve a degree of risk being borne by consumers, and that would reveal itself in higher transmission charges.

Transmission is a relatively small part of the overall bill, but they are still significant investments we're talking about. I suppose another feature of the models we've looked at are, "Is there any way that you can help share that risk between the existing generators and the consumers, or even TNSPs, the transmission companies, so the analysis we're doing at the moment is trying to identify the different ways that risk can be minimised and can be shared out?"

LINDA GONCALVES: Thanks for that, and it's good to hear that risks will be, wherever possible, mitigated, and I understand that in any sort of project like this there will be an element of risk. I guess my concern would be that since it's almost a bilateral negotiation between hopefully the generators to the transmission, then surely an element of risk will be brought on by both of those parties as well, as a fact that it is a commercial transaction.

JOHN TAMBLYN: There was one here.

TIM BRAY: Tim Bray from Western Power. I think just following on from the risk question, it also needs to be recognised that while, yes, there is some inherent risk in the types of planning that you propose, there's also a risk in not having that sort of planning as well, and that could follow through in much larger costs to the market, through an unplanned approach that requires a much larger network investment than you otherwise might require.

JOHN TAMBLYN: That's a very good point, that the risk to the customers of higher costs because the planning not appropriate, or the sizing is too small, is what we're trying to deal with as well, and as Colin said, "What is the appropriate sharing of the residual risk?" is the question on the table for discussion. Yes, over here, and I think there was another one up the back there.

RAY WILLS: Ray Wills again, from the WA Sustainable Energy Association and, I guess, following up on that line. In particular, the development of our energy infrastructure in the last century was a development of infrastructure to where the energy was; that is, where coal was and then where gas is. I guess that network and that technology is mature, and logically if we saw extensions of that, we'd want to see standard market principles apply to it. The challenge for us in the 21st century is that the energy that we need now is somewhere different. So therefore the infrastructure has to be built. The question is, "How do you manage that risk?"

Last century the government built most of that infrastructure to get to the place, and then we had a mature technology. Ultimately, I think, to actually establish a beachhead of renewable energy, we need to see the nation build this stuff as part of its infrastructural planning, and then ultimately, as that process matures, clearly it needs to be handed back to the market, to allow it to do what it does. In context of that, again the planning comments, one of the challenges for us is to know where those best resources are, and so that planning obviously is critical. Some of our wind farms in the state haven't actually been built in the best wind resources, they've been built in really good wind resources, but not the best, and they've been built there because they could get access to land, not because it was the best location.

So I guess the consequence of the sort of generation parks we're talking about, need to build into that model. I guess finally in terms of that, targets and overshoots or undershoots, the reality that we're facing with climate change and with the changes in emissions trading market is that as we talk about this more and more - the targets don't get cut, they get raised - and with some certainty I think we will see even higher targets in the future, so therefore there will be even more need to develop these infrastructures in the right place.

JOHN TAMBLYN: Thanks for that comment. Just a quick observation: governments, for whatever reason, may want to make infrastructure investments. Our task, we think, is to look at how we can best design the market to respond. If governments, based on good planning information, want to make some calls, they can and will do so. It's not part of our frame of reference, rather to get market designed to have the most efficient and timely responses. But I understand all of your comments, so thank you. Any other comments? Yes, down the back again.

PAUL DAVIES: Paul Davies again. I was just going to say that, apart from the network constraints and the generators wanting to get onto the network, the other aspect is that it's very difficult for the generators to get access to the retailers in a sense, because most of the energy is all traded on a bilateral basis, and so unless you've already got a customer who is there, who wants to switch from one form of energy to another, you've got to wait until there is a tender process for somebody wanting, and an additional block of energy.

That may not occur at the same time as your transmission access, and if you're then going into the queue on your transmission access, and there's other people who are above you, they can get in and do the deal with the retailer, because the retailer wants somebody who's got transmission access. So we've got this great big round robin, which is a very congested process: it's not just the two of the generator and the transmitter, it's also the process with the retailers as well.

JOHN TAMBLYN: Any comments on that? I'll take it as an observation.

COLIN SAUSMAN: Just one very minor comment. I mean, this is one of the costs of having a queue; having an administered process to allocate a scarce resource. Ideally you'd want a means for the most valuable projects to reveal themselves as such, and get the priority, and that is the economic concept we're talking about.

JOHN TAMBLYN: Other observations?

GLEN MATTHEW: Glen Matthew from Western Power again. I was just wondering if the IMO could comment on whether they think capacity credits would be an appropriate locational signal.

ALAN DAWSON: No. I think if you moved away from the assumption of an unconstrained grid, the allocation of capacity credits would become significantly more complex; you'd have to probably do some modelling on that, and the allocations would be a little less - there's a direct line between the ability of the generator to generate, and the capacity credits that they currently receive. Clearly, if there were grid constraints in the way, then that would be a different equation that would be used. I'm not sure capacity credits are the way to send a locational signal.

Other markets have adopted the energy price as an appropriate place for a locational signal. I'm kind of in that boat, as well as transmission costs, send a quite significant locational signal to new developers, so that would be my personal preference. Again, with the work that's going on, I'm interested to see the outcomes like everyone else, but I'd be surprised if there was a suggestion that the reserved capacity mechanism would be the way to send a locational signal to new investors of generators.

JOHN TAMBLYN: I'll need to bring this to an end, but one last comment up the back.

SHANE CREMIN: Shane Cremin from Griffin Energy again. Just a quick comment on the issue of the value in the queue. It's been a big issue for some time now, as has been pointed out, and I think some mechanisms that have been put forward to get around this include placing a value on that value. I mean, there's a bit of a tragedy of the commons here, where people are quite happy to try and spuriously put claims on the queue to actually grab some value there. But if you actually place a price on that, then those good projects that you refer to, that perhaps are buried under a whole lot of other spurious projects might actually value that an awful lot higher, and be prepared to pay for it, so whether it be an auction value, or whether you just put a percentage of the expected connection cost on that queue position, I think that would be a fairly good mechanism going forward to actually get rid of a lot of the claims on that queue position, that aren't really going to eventuate.

JOHN TAMBLYN: Thanks very much for that. Now, we need to move on to the last session. Gavin, thanks very much for your contribution, and we'll move on to the retail price regulation and related issue. Okay, Colin, over to you.

SESSION 3c
RETAIL PRICE REGULATION
COLIN SAUSMAN
JASON BANKS, OFFICE OF ENERGY

COLIN SAUSMAN: Okay. So we can probably move through this one relatively quickly. It's a very difficult issue, but it's quite a straightforward issue. The CPRS will change the costs that need to be reflected in retail tariffs, and arguably the estimating of those costs and regulating a tariff will be more difficult because of the volatility in carbon prices, at least in the first instance. This makes retail price setting more difficult.

It's already demonstrating some difficulties in a WEM context in the sense that it was a general recognition that tariffs aren't cost-reflective, and there's various processes to move them in the right direction. This is an added factor that needs to be allowed for in the long-term, to the extent that the retail price regulation exists long-term, having tariffs that are appropriate. But the main aim, if you like, is to have a regime which allows regulated retail tariffs to flex over time to reflect the underlying resource costs. So that's basically the issue.

So I think we can step through this relatively quickly. It's just making the point that the reason we think this is a particular challenge is because the carbon costs aren't like other energy costs that are handled by regimes of retail price regulation in the sense that there isn't a market today; you cannot buy carbon forward, I don't think, in any great volume, for all sorts of sensible reasons, like the parameters for the scheme aren't yet designed, as last week's announcement clearly demonstrated.

Estimating what those costs are going to be in this kind of context is a challenge, and you will inevitably get it wrong. It doesn't matter how accurate your modelling is or how sensible your decision-making is; there just isn't enough information to get this estimate right. So if you do get it wrong, what do you do? I think, for us, that's the main issue that's emerged, and what you probably want to do is introduce a degree of flexibility. So live with the fact that you will get it wrong, and have mechanisms that can kick in to adjust to make it less wrong.

I think there's various approaches to this, and each jurisdiction starts from a slightly different place. I mean, some jurisdictions already have a mechanism a bit like this. An example is, in New South Wales, there's a three-year price path, but every year there's an option to review the energy wholesale cost component of the price path, and adjustments can be made. So one option is to actually allow for that kind of adjustment systematically across all jurisdictions, and possibly ask the question - and this is something where analysis can help - is, "Well, is once a year sufficient?"

If you do see lots of volatility, particularly in the early years, then you might want to do it every six months, or at least have the possibility of doing it every six months. Given that some of these regulations are written into statute, then it's actually quite a difficult thing to change the frameworks, but I think what we're trying to do is sort of enunciate some principles, if you like, that could be applied and made to work to create this sort of flexibility.

So where we are at the moment, we're trying to enunciate what the specific risk is, and we do think it focuses on this short-term volatility - that's the big problem - and to develop some principles that could be applied by all jurisdictions to introduce more intelligence and more flexibility into how retail prices are set. Because if retail tariffs are very wrong, then there are potentially quite large distortions, disruptions to the market: efficient retailers failing is the obvious case, but also customers being charged too much.

I mean, there's a risk that, you know, you can get it wrong by assuming that carbon prices are going to be $25 and it turns out to be 5. This is a real possibility, particularly with international linkages. In those kinds of circumstances, I suppose one protection for consumers is you might see competition. But because there's a lot of headroom, if you assume a $25 carbon price and it's 5, in the absence of competition, should the framework step in to automatically adjust the regulated tariff down? To me, that seems a perfectly sensible thing to do.

So it's how we actually introduce this flexibility, and our focus is on not the specifics of how it works in each jurisdiction - we need to be aware of what that is - but it's more about the principles and the characteristics that you'd like to see in a sensible way of addressing this particular risk. So if our advice can inform the MCE on that, then individual jurisdictions can make sense of what those principles are and apply it to their particular setting in their own way. So that's more or less where we're heading.

JOHN TAMBLYN: All right. Thanks, Colin. Just to re-emphasise that point, this is one policy area which is a jurisdictional responsibility right across the country, not just in Western Australia. So our advice to the MCE is on principles and approaches that might be adopted by individual jurisdictions as they consider how they might work as a matter in their own regimes. Now, can I just ask Jason Banks to join us, and just make a few observations from his perspective, then it will open for general comment. Thanks, Jason.

JASON BANKS: Good morning. Thanks, John, very much for the opportunity to address the group this morning. I guess one of the first things I'd like to do is recognise the work of the AEMC. I think you very effectively engage with Western Australian stakeholders on the issue, and I think it's great to see a national body of the capability and expertise of AEMC drawing its attention to policy matters in Western Australia. So thank you.

I'm from the Office of Energy. We're not a regulator, we're a policy office. One of our roles has been to advise government in regard to retail tariff price settings, both in terms of gas and electricity. Earlier this year, we released a report in regard to electricity tariffs which made a number of recommendations and identified a serious gap between the current tariff levels and the Office's view of where cost-reflective levels sat.

Included in that analysis was allocations for carbon costs. They were obviously preliminary; they were noted as such. Given the changes in the scheme, obviously we can get a bit more precise about those costs in the first year, at least, being $10. But certainly it was keen to flag the issue to the general community in terms of the cost impacts that were coming. Governments responded with a couple of tariff increases which took effect on 1 April and 1 July of this year, and I guess there's a process to be managed there, going forward.

In addition to the actual tariff quanta, the report made a number of recommendations in regard to future tariff-setting processes. There's no formal regulatory framework for retail tariff-setting in Western Australia. I guess we adopted generally what we thought was reasonable regulatory practice around Australia in developing advice to government. The recommendations also included the pass-through of network costs and future carbon costs. The network cost issue is obviously a significant driver of some of the increases going forward, and I guess we'll wait and see, and get a bit more clarity on that later in the year when the ERA makes the determination in regard to works as powers access arrangement.

On the gas tariff front, we've done a review in regard to the regulations. Gas tariffs in Western Australia were historically just escalated, or the caps were just escalated, as a factor of CPI. We did a review of those regulations, found that that tariffs were no longer cost-reflective under that regime and made an interim recommendation last year for a gas tariff increase. We're currently considering whether an increase should be applied from 1 July this year in relation to gas retail tariffs.

A couple of things on the issues identified by the AEMC. I think volatility is a really interesting question. If generators, under the contractual arrangements, are able to pass through carbon costs, then they may not be that incentivised to hedge those costs, and I guess you've also highlighted the fact their capability to hedge those costs at the moment is virtually zero anyway. So if you're going through a monthly auction process where you're getting prices set and, as a regulator, you're trying to determine those prices over the year, there's going to potentially be a big disconnect between those auction price outcomes and what actually you've provided for in the tariffs.

Similarly, given the fact that retailers aren't well positioned to hedge, whilst retailers are used to dealing with variability, and volatility and costs, they deal with that through, obviously, taking hedged positions in the market. If those positions can't be taken, there's not really a lot of risk mitigation that the retailers can enter into.

The other one that I think is really significant and of interest probably is the key factor that it will go into the tariff calculation, and that's emissions intensity. What's the appropriate emissions intensity that a regulator should apply in determining retail tariff settings? Should it be the emissions intensity of the particular retailer or the average emissions intensity of the system as a whole? For example, in Western Australia, Synergy, who is obviously under the regulated tariffs, would probably have a higher emissions intensity than the system average. So should Synergy be paid on the basis of - or should the tariffs make provision for Synergy's emissions intensity, or should it make provision for just the average?

So that's another question I think we probably need to throw into the mix, and we'd appreciate you giving consideration to that. I think it becomes more complicated in the eastern states jurisdictions, where you've got multiple retailers in the one jurisdiction all with alternative emissions intensity levels. Are you going to reward or penalise those retailers that have made historical decisions in regard to their portfolio of contracts? It's an interesting question. Anyway, thank you very much for the opportunity to address this morning.

JOHN TAMBLYN: Join us over here, Jason. Thank you very much. Okay. Well, it's open for comment, observation. So over to the floor. Any points to raise with Jason or ourselves? Linda, yes.

LINDA GONCALVES: More a comment than a question. I guess, where WACOSS is concerned is that, in regard to tariffs, and costs due to the CPRS and to the expanded RET, it's transparent so consumers know what costs have been passed on and why is crucially important. So not only are consumers informed but also advocates, where necessary, can act on their behalf. Also that it's independently assessed by some sort of body, be it the ERA, in this instance, or whoever, that is also crucial, and that it's consistent across jurisdictions would also be something that we think is very important. So no matter what state or territory you're in, in regard to what the composite of your bill is, that it's the same.

JOHN TAMBLYN: Thanks for that. We'll certainly have it in mind. Yes, Bill.

BILL HEAPS: Bill Heaps. Jason, maybe I can ask you - it's really out of the scope of what we're doing, but I'm interested in this because, you know, we've discussed the low night-time load being an issue, so generations being backed off. So essentially there's over-supply. You would expect that, in an efficiently-working market, low prices would be seen to retail consumers to give them to signal to shift load into night-time periods. Are we seeing that in this market?

JASON BANKS: Well, the fundamental issue is the fact that people are on accumulation meters. So until the metering technology changes, then those sort of price signals can't be sent through to small use consumers. Larger consumers that actually have interval metering obviously get those types of price signals, but if you're talking about the broader market, then that's really a technology issue. Along with our study in regard to retail tariffs, we've been working through the Ministerial Council of Energy and also have conducted a study in regard to the roll-out of smart meters in Western Australia, and that's currently being considered by government.

BILL HEAPS: Can I just respond, because I think technology is an issue for detailed smart metering, time of use, tariffs and those sorts of things. But in the - I was just thinking that the 1970s and 80s in the UK had a similar sort of issue with nuclear power stations and coal stations, and low night-time loads, and they needed to keep them warm and running. One thing they did was build a storage power station but the other thing they did was develop Economy 7 and, you know, just split day-night tariffs. They developed night storage heaters - you wouldn't need those here - but, you know, they developed sort of night storage heaters to build up the night-time load. So they gave us - and off-peak water heating.

JASON BANKS: Sure.

BILL HEAPS: So they developed that strong sort of signal. So, again, you'd expect the market to be producing signals to retailers that they should be getting lower prices overnight to this surface generation, and maybe they could be starting to build those sorts of things into their tariffs based on just simple day-night tariffs, and there's technology available for that. Small businesses, commercial properties, using half-hour interval metering, which is pretty cheap now to put in place - you know, you'd expect to see those sorts of things coming through before you have to take the next step into, you know, more complex - you'd expect to see those sorts of things coming through in the contracts as well, you know, with major industrials, giving them very strong incentives that they can shift loading to that night-time period. I was just interested in--

JASON BANKS: So I think that's true for the larger customers, probably not so much true for the smaller customers, in terms of the issues such as, in Victoria, where they have a large penetration of the overnight hot water heating arrangements with the obvious linkage to the meters, I guess. Western Australia has had a bit of a different development in terms of high penetration of gas hot water heating and, obviously, there's government policies around driving that towards the solar, you know.

JOHN TAMBLYN: All right. Thanks.

KEN BROWN: Can I just make one comment on that issue about the overnight load is - Ken Brown again - if you look at the Victorian overnight load, it has this wonderful spike about 9 o'clock and another one at 11.00. But when you get to 2.00 and 3.00 and 4.00 in the morning, it's back to where it was in the old days, because unless you have control of when they start putting these things on, you can't just have a straight, "9 o'clock it's really cheap, and everything comes on, and then by 11 o'clock it's all finished anyway." And that's one of the issues with the Smart Grid and electric cars, and those sorts of things: if you give the control back not so much to the control centre but allow those things to be all charged by 7.00 or 8.00 in the morning, whenever you dial in, but allow them to charge up over a period, rather than everything come on at - because it doesn't actually help the power system operate at all.

If you end up with 2 hours in the middle of the night when it's still back to where it was, it's actually made no difference for us. Everyone thinks it does a great job; from an operator's point of view, it's a pain in the arse, because..(not transcribable)..and, bang, up she goes, you want all your machines up again, and then you know it's coming down. It's actually a nightmare. So if you get it wrong - the wonderful theories, as compared to the practical.

JOHN TAMBLYN: Yes. Thanks, Ken, very much for that. Other comments? Down the back there.

SPEAKER: A question for you, Jason. You started by saying the Office of Energy is a policy office rather than a regulatory body. Could you comment on whether or not there's an appetite within government to transfer that responsibility for retail price regulation from the Office of Energy to a body such as the ERA, which has the responsibility for network price regulation?

JASON BANKS: Yes, sure. That's a question for the government. In terms of the Office of Energy's position, we recommended to government that an independent framework be established, and that they do get transferred to the Economic Regulation Authority. But the appetite issue is really a question for the minister.

JOHN TAMBLYN: Thank you.

RAY WILLS: Thanks, yes, Ray Wills. On load-shifting, I guess the key challenge of the word "base load", the reason we try and shift loads to the night-time is because we've built particular types of power stations that can't switch down, and so therefore instead of actually not consuming energy, we're looking at ways to consume energy. Having said that, I think load-shifting to the times of generation makes a lot of sense. So as we actually build new systems which actually have different peaks - and so, for example, to pick on a solar thermal power station, which can deliver overnight load but can also deliver peak load - then we actually need to look at how we manage the market so that it is shaped to that.

So load-shifting makes sense to the form of energy generation, but we needn't tie ourselves necessarily to the concept of base load, which is a 20th century concept, which is about how low we can turn the technology. We need the energy we need to use, but we don't need more energy than we need to use, and that's what base load actually encourages us to do.

JOHN TAMBLYN: Okay, thanks. Other points to add? Look, if there are not, I think we have come to the end of our forum. So let me just wrap up. Jason, thank you very much. Just a few quick closing comments from me. I would simply like to thank you all for coming along today. Can I just say it's another case where the west has out-performed the east: we had 120 people at our forum in Melbourne, and it was a rather quiet and polite affair; we've had a very strong, interactive discussion. So I really do appreciate the way you've come along and engaged with the issues.

This has been very valuable for us, and I would encourage you, if you think there are points that you want to re-emphasise to us or points you want to comment on that have been raised by others, give us a very quick but brief written submission making those points. But we've heard some things, I think that will help our thinking here today.

All I would then want to say is thank you again. We will consider what we've heard today and your further submissions. We'll put out our second interim report on 30 June. That will indicate where we've landed on these issues for the NEM and for the WEM, and our reasons, but that report will again be open for further submissions and comment. If you think we've missed something or mis-characterised something, or we're heading down the wrong path as a solution, let us know, and we'll refine our final positions in our 30 September paper, and also write down as clearly as we can what the implementation arrangements need to be to give effect to the recommendations that we make.

So that will be any changes to law, if that be necessary, and what rules would be needed to introduce the reforms that we suggest. So thank you once again for coming along today, and keep in touch with our process. I believe the Western Australia reference group will now meet straight after the forum here today, and that will be a chance for some further input from the west. So thank you again, and we look forward to your further participation in our process. Thank you.

oOo