Government of **Western Australia**
**Energy Policy WA**

# Minutes

## Transformation Design and Operation Working Group – Meeting 37

**Time:** 9.30am – 11.30am
**Date:** 22 June 2021
**Venue:** Online meeting via teams

**Attendees:**

| Name | Organisation | Name | Organisation |
|---|---|---|---|
| **Aditi Varma** | EPWA | **Mark Riley** | AGL |
| **Adnan Hayat** | RCP Support | **Mike Chapman** | Western Power |
| **Antonia Cornwell** | Synergy | **Patrick Peake** | Perth Energy |
| **Brad Huppatz** | Synergy | **Peter Huxtable** | Water Corporation |
| **Clayton James** | AEMO | **Rajat Sarawat** | ERA |
| **Dimitri Lorenzo** | Bluewaters | **Oscar Carlberg** | Alinta Energy |
| **Donna Tedesco** | ACAPMA | **Rebecca White** | Collgar |
| **Dora Guzeleva** | EPWA | **Rhiannon Bedola** | Synergy |
| **Erdem Oz** | Independent | **Richard Cheng** | ERA |
| **Erin Stone** | Point Global | **Richard Peppler** | Western Power |
| **Gavin White** | ERA | **Rob Chandler** | Western Power |
| **Greg Allen** | Hydrostor | **Robert Pullela** | ERA |
| **Greg Ruthven** | AEMO | **Simon Middleton** | AEMO |
| **Glen Carruthers** | Western Power | **Simon Orne** | Sapere |
| **Harry Street** | Entego Advisory | **Stacey Fontein** | AEMO |
| **Ignatius Chin** | Energy Market Consulting | **Stephen Eliot** | ERA |
| **Irina Stankov** | ERA | **Tim Robinson** | RBP |
| **Jake Flynn** | ERA | **Wendy NG** | ERM Power |
| **Jacinda Papps** | Alinta | **Sarah Graham** | EPWA |
| **Jenny Laidlaw** | RCP Support | **Toby Price** | AEMO |
| **John Nguyen** | Perth Energy | | |
| **Jo-Anne Chan** | Synergy | | |
| **Judy Hunter** | Western Power | | |
| **Katie Franklyn** | Clear Energy | | |
| **Kang Chew** | AEMO | | |
| **Kaur Sumeet** | Shell | | |
| **Kristian Myhre** | Transalta | | |
| **Laura Koziol** | RCP Support | | |
| **Kei Sukmadjaja** | Western Power | | |
| **Kylie O’Keefe** | Minter Ellison | | |
| **Luke O’Callaghan** | Lavan | | |
| **Manuel Arapis** | ERA | | |
| **Mark McKinnon** | Western Power | | |

Meeting minutes should be read in conjunction with meeting slides.

<table>
<tr><th>Item No.</th><th>Issue</th></tr>
<tr><td>Slide 1 - 2</td><td>Aditi Varma (AV) opened the meeting and noted this is one in a series of WEM Rules related TDOWG – with today's focus on Tranche 4B.</td></tr>
<tr><td>1.</td><td>Under Frequency Load Shedding Section 3.6 – Aditi Varma (EPWA)</td></tr>
<tr><td>Slide 3</td><td>AV gave overview of draft UFLS rules
<ul>
<li>Set of draft rules presented in the Exposure Draft that will replace existing section 3.6 of the WEM Rules – which currently relates to Demand Control:
<ul><li>Contains a few rules around responsibilities of system management and network operators when UFLS has to take place</li></ul></li>
<li>With separation of system management and Wester Power (WP) these responsibilities are no longer clear enough – UFLS rules written to replace this section</li>
<li>This section focuses on providing clear obligations for AEMO and WP (the only network operator at this point in time)</li>
<li>AEMO required to prepare/publish an UFLS requirement document which will set out aggregate UFLS requirements for the SWIS (taking into account SWIS Frequency Operating Standards)</li>
<li>Networks Operators required to design/develop USFLS specification document – setting out how they will meet UFLS requirement document
<ul><li>Specification sets out how network operator will design and implement various UFLS schemes</li></ul></li>
<li>Rules also contain requirements for AEMO/Network Operators to consult with each other – when requirements and specifications documents are being prepared/modified</li>
<li>Additional rules that outline how coordination must happen between AEMO/Network Operator when load shedding must take place</li>
<li>Commencement date will allow time for AEMO/WP to prepare relevant documents and ensure processes are in place</li>
</ul></td></tr>
<tr><td>2.</td><td>Change Management for Specified WEM Technical Standards – Sarah Graham (ETIU)</td></tr>
<tr><td>Slide 5</td><td>Sarah Graham (SG) gave overview of change management framework for WEM Technical Standards
<ul>
<li>Set of draft rules in the exposure draft – sit within the rule change process and provide a change management framework for WEM Technical Standards.</li>
<li>The Taskforce have proposed that in the future the Coordinator will govern a centralised PSSR Standards Framework with advice from a Reliability and Security Advisory Panel (consisting of WP/AEMO, consumer & industry representatives).</li>
<li>We are proposing an interim framework which was endorsed by the Taskforce with rules that:
<ul><li>ensure that where a rule change proposal relates to a WEM Technical Standard, the Coordinator must seek information or advice from AEMO/WP as the primary entities responsible for managing system security and reliability.</li>
<li>prevent frivolous/ill-conceived proposals from impacting these essential standards which maintain PSSR.</li></ul></li>
<li>New clause requiring WP/AEMO to consult with each other before submitting a proposal to the Coordinator.</li>
<li>Intent is to place clear obligations on parties, avoid over-prescription and ensure the Coordinator has appropriate engineering/technical advice when proposals are progressed.</li>
</ul>
Questions
<ul>
<li>Mark Riley (MR) noted that some standards don't commence until start of the new rules – does this imply that standards that apply to the provisions are currently correct and don't require any review or consideration?
<ul><li>AV answered that standards that have commenced already are the ones that we seek to subject to the change management framework, including quite a few standards that have only just commenced. The only item that commences at market start is the Technical Envelope.</li></ul></li>
<li>MV asked whether the framework should be considered pre-market start
<ul><li>AV answered yes – the standards have either commenced or waiting for commencement and the intent was to put in change management framework and allow standards to be captured by this framework as they commence.</li></ul></li>
</ul></td></tr>
</table>

| 3. | Transitional AGC Dispatch – Clayton James (AEMO) |
|---|---|
| **Slide 6** | Clayton James (CJ) gave overview of Transitional Clauses: 1:49<br>• Follow on from things taken to previous WRIG regarding SCADA point and SCADA control point changes for SCED<br>  ○ Included implementing some of the automated dispatch capability prior to market start - the idea being to help prepare earlier and de-risk<br>  ○ Follow up conversations with participants who expressed interest – looked at transitional rules with EPWA to allow this to happen<br>• Small set of rules that allows AEMO to consult with participant who is wanting to do AGC based dispatch in the new market and agree on a set of control signals to implement pre-market start.<br>• Idea is still to dispatch as per the balancing market and according to balancing instructions – however AEMO would do this through AGC ramping rather than the facility doing ramping themselves<br>• This allows AEMO/participants to implement control system changes ahead of time – and test before market start<br>• Opt-in approach not mandatory, AEMO can discuss with individual participants the timing and when changes may be implemented<br>• Compliance arrangements remain the same – only a change in control mechanism<br>• Will be discussing this further through other WRIG sessions |
| **4.** | **Amendments to GPS Appendix 12 – Clayton James (AEMO)** |
| **Slide 7** | CJ gave overview of Amendments to GPS Appendix 12<br>• These changes are fixes to GPS Appendix 12 – AEMO and WP in preparing for GPS and monitoring plans identified things that could be interpreted incorrectly – as well as a few typos<br>• Credible Contingency Event definition – modifications to make it clearer and link through to the planning set of credible contingencies not the operational set – intended to be more of a fixed set<br>• Settling Time definition - correction of a few typos to ensure correct interpretation<br>• Voltage and Reactive Power Control – increase clarity in tables describing performance requirements – some definitions pointed to things that were not yet explained<br>• Active Power Control – clarifying generator ramping and difference between ramping conditions<br>• Inertia and Frequency control – largest set of changes:<br>  ○ A lot of duplication between ideal and minimum standards<br>  ○ Improved definition of Droop<br>• Disturbance ride through – ensuring it is clear when there is an approved tripping standard – this is not considered a breach<br>• AV noted that these clauses have all commenced – the changes in Tranche 4B will commence soon after Gazettal (1 August)<br><br>Questions<br>• Oscar Carlberg (OC) - given these are clarifications do you anticipate any of these changes will require generators re-review any aspects of their GPS performance (for the new GPS fields) in their draft templates?<br>  ○ CJ answered he does not believe so – these items are more clarifications and are more relevant to new generators seeking to understand how they would meet new requirements to connect rather than existing generators understanding compliance<br>• Mark Riley (MR) – is there a standalone glossary for the WEM rules?<br>  ○ AV answered yes - Chapter 11 contain the glossary and there is a word version of the WEM Rules of the ERA website |
| **5.** | **Calculation of Not-in-service Capacity and refund quantity for ESR Capacity Shortfall – Mike Hales (AEMO)** |
| **Slide 8** | Mike Hales (MH) gave overview of Calculation of Not-in-service Capacity<br>• At TDOWG 36 not in-service capacity refund introduced – a refund for a facility holding capacity credits or has RCOQ at interval will be required to make capacity available in-service where the pre-dispatch schedules indicate they will be required to be dispatched.<br>The WEM Rules have introduced settlement calculations - new clause to calculate that quantity<br>• The quantity will be published at the end of the dispatch interval<br>• In summary, the calculation quantity will be determined at the dispatch interval, but the settlement amount will be determined at the trading interval<br>• AV noted changes to commence at market start |
| **Slide 9** | MH gave overview of Refund quantity for ESR capacity shortfall<br>• Second refund discussed at TDOWG 36 was the refund for ESR capacity |

| | |
|---|---|
| | • ESR storage facility needs to ensure it has enough capacity/charge status remaining to meet its RCOQ if dispatched.<br>• Simple calculation that takes into account SCADA readings of charge status – compares to RCOQ for the interval – if the charge status is greater than the RCOQ than there is no refund<br>• AV noted changes to commence at market start<br>Questions<br>• OC asked – for storage facilities co-located with another scheduled facility – would that RCOQ be able to be met by the other co-located facility<br>  o DG noted that EPWA will take this away for further consideration, as the original intent was to declare this as a forced outage but needs further thought.<br>  o DG further noted that the problem here is, though a storage owner may have the best intent to declare a partial outage – we have given AEMO ability to control this facility by putting some constraint equations around storage and the input into these equations would be the charge level of facility. Removed from participants this dispatch function.<br>• Rebecca White (RW) – useful to better understand how SCADA relationship works in relation settlement – and asked whether there is opportunity to have more flexible arrangements around reserve capacity obligations for the hybrid facilities. E.g. wind farm and battery each with 10 RCOQ – if wind happens to be blowing more but battery not as charged – there would be a net benefit to the system if capacity sent out in aggregate.<br>  o DG observed that intermittent generators do not have RCOQ and they cannot be relied upon for capacity, and even if the other facility was gas, they would have to meet their own RCOQ over the day or at that point in time.<br>  o In the above example, as the intermittent generator does not have RCOQ, very difficult from system perspective to rely on them to provide capacity. Policy decision not to allow facility to swap RCOQ as this would cause system reliability issues.<br>• MR asked whether in a situation where facility installed a small diesel behind the battery to provide supplementary charge, would this be a problem as this is a non-market generator to assist battery to meet its obligations.<br>  o DG referred back to the fist principle, the fact facilities do have RCOQ and due for refunds if they don't meet the RCOQ, it is their purpose to ensure they are available when AEMO requires them. Anyone without capacity credits behind the meter, they cannot be relied upon to pick up obligations on the facility. Ensure facilities paid capacity credits by consumers are there when they are required.<br>• OC – if we have a gas peaking facility co-located with a battery, and the battery is bidding for contingency reserve raise, is called for all of it and lost all of its capacity just before RCOQ intervals for that battery. In this case the battery would have to bid a forced outage, and gas peaking facility could not cover for the battery.<br>  o DG answered a market participant with storage would have obligation over short period of time, exception of this RCOQ obligation is if they are directed by AEMO to run. In some situations they may prefer to bid in the ESS market instead of being dispatched, if this would outweigh the disadvantage of refund.<br>• RW noted that Mark's example was worth exploring more – if behind submeter there was storage and diesel, is it relevant how the electrons are delivered through the sub meter? Would this not support the system?<br>  o DG noted the need to clarify the policy intent here to avoid confusion – additional behind the meter capacity without capacity credits cannot be relied upon to top up storage. The idea of refunds if that those facilities that do have RCOQ and receive reserve capacity payments – are there to be dispatched to ensure system reliability. The storage concept in the RCM is to recognise that storage facilities can be there for only short periods of time – recognising the fuel availability issue they need to be there for the intervals they're required for.<br>  o RCM provides for the reliability of the system generally. AEMO were eager to have real-time SCADA available to understand what is available from storage facilities. Allowing for an unregistered facility to top up storage with no regard for charge levels of the storage facility would be hard to rely upon.<br>• Jenny Laidlaw (JL) asked what happens if there is a problem with the SCADA measurement of the charge (e.g. temporarily not available)?<br>  o AV noted in the rules AEMO is allowed to estimate value if SCADA not available – e.g. looking at last available data.<br>  o DG added that this is a very specific circumstance where AEMO looked at charge level in deciding when facility should be dispatched. If SCADA was unavailable, AEMO would need to make assumptions. Need to consider this further. |

| | |
|---|---|
| | ○ MR noted that most participants would have better access through the battery array even if SCADA not available – participant should be able to provide to AEMO. Rules should allow AEMO to do this.<br>○ DG noted that if SCADA outage – participant would need to take control back. MR added not necessarily, problem could be data memory loss etc, control is there but data not being collected.<br>▪ CJ noted there are a few different ways to get data from participants, and if all else fails AEMO is able to use estimates, there is a generic WEM rule allowing AEMO to estimate. MR noted there needs to be transparency of how estimate arrived at.<br>• DG noted that there is before real-time; and what happens without visibility of charge level, and there is after real-time. Before real-time, EPWA needs to take this away and think about what happens if participant has asked AEMO to manage charge level through constraint equations.<br>• Patrick Peake (PP) said, following up on Oscar's comments, if a storage system is being used to offer frequency control then it probably cannot also ask for capacity credits for its full capacity. Storage operators will need to decide just what their battery is going to offer.<br>○ DG noted that yes – it is the participants choice.<br>• AV clarified point on SCADA vs metering and what can be used for settlement – SCADA values are essentially giving us MW shortfall value – a capacity figure that is used to calculate shortfall. This is compliant with the National Measurements Act as it is not a metering MWh value which is what is used for settlement as opposed to a MW shortfall value which is an input into a settlement calculation<br>○ RW noted that she understood, and that SCADA can be used for regulation cost recovery – this is a similar case to this. AV agreed. |
| **6.** | **Consequential Amendments – Mike Hales (AEMO)** |
| **Slide 10** | MH gave overview of Consequential Amendments under Tranche 4B<br>• Minor amendments – all in Tranche 4B<br>• Needed to update Real-time Market Submissions clauses to include a start-up time for each tranche submission – changes<br>• Changes to RCOQ to allow it to be by dispatch interval<br>• Change to forced outage quantity calculation |
| 7. | **RCM Amendments – Dora Guzeleva (EPWA)** |
| **Slide 11** | DG gave overview of RCM Amendments<br>• These are not major amendments – when Tranche 3 was published in December there were some things that needed fixing related to accommodation of facilities with more than one component<br>• Bilateral Trade Declarations – existing clause requires participants to provide AEMO with total amount of reserve capacity. Proposed amendment was required to accommodate facilities with more than one type of technology.<br>• Publishing CC Information – current rules have an oversight that is being rectified as in the future we are likely to have facilities with more than one component.<br>○ Allow participant 30 days to tell AEMO how they will allocate capacity credits to each component<br>○ The reason for this is in the future the facility may be certified to certain level but when the NAQ calculation is applied – the facility may have a lower NAQ than the certified capacity – so need to allow the participant to decide which component gets how many capacity credits<br>• Capacity Credits for ESR Components – after we published Tranche 3 we continued to talk about facilities with more than one component and one of them always being an ESR. What we realised is that in the future we may have different combinations of components – e.g. intermittent component, storage component and scheduled component and we have to allow for this.<br>○ Therefore, changing clause 4.20.17 and this will be required for several other clauses not listed here to ensure that we can accommodate these different permutations and allow association of capacity credits with all relevant components<br>• Commencement date for these amendments and for the following slide – some amendments will commence on 1 August 2021 and some will commence later depending on which cycle they relate to. For example, the Bilateral Trade Declaration will need to commence before the NAQ cycle.<br>Questions<br>• RW asked if you had a facility with two different types of intermittent components say wind and solar, would they be considered two separate components or would they be a single facility/component |

| | |
|---|---|
| | ○ DG noted that for some purposes they may be considered homogenous intermittent facility but depending on where the Relevant Level Methodology (RLM) lands – they may have to be considered separately, and factors like expert reports would needs to be provided on individual components. Neither of those components would currently attract RCOQ and neither of the components would be tested, but they may still need to meet their required level when they are commissioned. Currently would be certified under the same methodology, but within the methodology some steps may be treated differently.<br>• RW asked whether the registration framework would accommodate this type of facility?<br>○ AV noted that yes – such a facility, depending on its size, would be non-scheduled or semi-scheduled but just to reiterate the point DG made, an intermittent facility would not have an RCOQ.<br>○ DG added that some of the same scheduling and dispatch rules may apply – may be many rules that don't treat facility as component but there may be exceptions. |
| **Slide 12** | DG gave overview of voluntary reduction of Capacity Credits by Demand Side Programmes<br>○ Clause 4.25.4E has been deleted to provide equitable treatment of facilities, particularly Demand Side Programmes (DSP). There are other facilities that are rarely dispatched and should be treated equitably with DSPs in relation to the voluntary reduction of capacity credits.<br>○ The following clause is amended to accommodate the removal of capacity credits for DSP.<br><br>Questions<br>• JL noted that the payback requirement for Demand Side Programmes was for a very specific reason, and asked what the rationale for the change is?<br>○ DG noted that it started with AEMO being of the view that the current clauses were broken, especially in regard to clarity on how the money paid back are distributed. Then the question was asked why we treat Demand Side Programmes differently to generators – no clear answer as to why a different type of facility might apply to have their capacity credits reduced without being due for a refund while Demand Side Programmes are singled out and treated differently<br>○ JL noted that the problem was Demand Side Programmes (DSP) were collecting capacity credits year in year out and were very rarely dispatched and if something happened and they were likely to be called – they could just reduce capacity credits and walk away from obligation. The idea of the clause was at the very least, you would be able to call back the capacity credit payments they had received. The difference was that a generator was unlikely to pack up and go home if they are asked to generate<br>○ DG added that the same could be said for diesel peaking generator. Thinking could have been different when we didn't test DSPs but now that we do it is not clear why DSP would be treated differently. Final discussion was more about equity and noting that we do test DSP and also that there may be other facilities that may not run in any given year.<br>○ MR noted that there's also customer change/movement – and with DSP you're relying on what the customer does and what capability they have and with large customers their businesses change and ability to respond also changes. Different to piece of plant that has a MW output. Demand side management is a lot more volatile.<br>○ DG noted that yes – which is why the rules is providing the ability to apply for reduction in capacity credits – then the question is do we treat them equitably with other generators that may also be marginal.<br>○ MR added that with generators you can go to the plant and look at nameplate rating and testing as opposed to figuring out DPS<br>○ DG answered that now AEMO do test DSP though in the past this was not the case<br>○ Laura Koziol (LK) noted that the testing is one thing to ensure that the DSP are capable of providing the service, but as JL said if there is an event and the likelihood increases that they will be called more often than anticipated when applied for capacity credits than the business of DSP is not necessarily to run that often – so reducing capacity credits could be better economically than the alternative.<br>○ DG answered that the rules only allow AEMO to call on DSP for limited hours in each capacity year which should address the above problem<br>○ LK added that she doesn't think a DSP would account in its business for running for 200 hours.<br>○ DG clarified that if they run for a certain amount of hours – than they reduce the capacity credits to reduce any additional hours they are called on than the DSP would lose the capacity credits for the rest of the. As they are likely to be called during the peak period, i.e. |

| | |
|---|---|
| | early in the capacity year, this would be the majority of their capacity payments. EPWA will take this away and consider the above comments further.<br>• Peter Huxtable (PH) noted that the DSP capacity payments are also locked in. PH added that DSPs are not being treated equally which doesn't happen with respect to the generator's capacity payments – i.e. they get the variable payment |
| **Slide 13** | DG gave overview of Other Minor Amendments<br>• Clause 4.4A.1 – used to say any facility above 10 MW must advise AEMO of planned retirement 3 years before it takes place – changed to say any non-scheduled facility must advise AEMO of planned retirement. It is also proposed to add DSPs to the exclusion from the requirement.<br>• Number of incorrect references – clean up Rules when these items come up.<br>• Additional minor typographical/manifest errors in amended Chapter 4 that are being fixed<br>• Availability class definition – will be refined to be clearer for participants – principle policy is that Availability Class 1 has facilities available during each trading interval and Availability Class 2 will include DSP and Standalone Storage Facilities<br>• Currently a requirement on AEMO to calculate margin values – for purposes of calculating amount of spinning reserve. Provided to ERA before November of each year – who then reviews and provides determination by 31 March of the following year. Now that ERA has ability to calculate these values itself we are proposing to take away role of AEMO to model these beforehand.<br>• AV noted that the updates to clause 3.4.4 and 3.5.5B relate to PSSR:<br>  o Clause 3.4.4 outlines actions that AEMO can take when it has to restore system security. Clarifying existing clause to allow for reasonable consultation between AEMO and WP to ensure that WP has ability to communicate with AMEO how its elements could be directed. Concept of being operated in specific ways has been left open in the rules.<br>  o Clause 3.5.5B requires AMEO to publish details of any directions – including network elements.<br>Questions<br>• PP asked whether DSP should be allowed a time concession on "closure". If they want to be serious players, and receive similar payments, they should be treated as closely to generators as possible. There are serious issues potentially if any capacity provider walks away with limited notice.<br>  o DG noted the point and added that a DSP below 10MW should be treated as a non-scheduled facility and that non-scheduled facilities are currently those below 10MW for generators and below 5MW for storage. Need to consider further whether another exception is required.<br>  o DG noted the point and said this would be considered further. In other markets, a DSP aggregator aggregates a number of loads just before a capacity year commences and this is why we don't require the NMI for each load when they are certified. If they promise 10 MW this may be comprised of various loads which are recruited just before the capacity year. Talking about retirement in this sense is not necessarily analogues to a piece of equipment as the NMI would only be provided at the beginning of each capacity year. There may be single loads of a decent size that could be contemplated for retirement.<br>• MR asked about calculation of margin values – at the moment the process is AEMO calculates and then the ERA reviews. If this is moved to the ERA what will be the process around transparency, auditing of the ERA models etc. to ensure they are staying up to date with AEMOs systems.<br>  o DG noted that the ERA published an issues paper, run the model and made a determination – if AEMO were to do this as well, market participants should arguably not be paying for two entities to do the same process and run the same models.<br>  o MR has the expectation that AEMO would be audited by the Market auditor – with the ERA later assessing it from a different perspective.<br>  o Rajat Sarawat (RS) provided further explanation - the model as referred to – there is not an inherent model of AEMO to calculate margin values. The modeling work used to be largely outsourced and the process is that AEMO would propose values to the ERA and they would conduct analysis on these values. The only difference now is rather than obtaining AEMOs numbers the ERA will now run a model on its own and make the determination.<br>  o MR noted that if AEMO would review outsourced values – which are later reviewed by the ERA. Concerned about lack of review process under proposed changes. Not suggesting that it shouldn't stay with the ERA but is stating that there should be some requirements in the rules on transparency and review.<br>  o RS noted there is an issues paper and a draft – the ERA consult on the model and assumptions made and everything is published as transparently as possible. |

| 8. | Feedback Period - Dora Guzeleva (EPWA) |
| --- | --- |
| **Slide 14** | • Consultation closes on 30 June 2021<br>• AV highlighted that the consultation email has changed – please provide feedback to energymarkets@energy.wa.gov.au<br>• Feedback incorporated as necessary and intent is to take Tranche 4B to the Minister for Making – by mid-July. Tranche 4B will also contain the System Restart rules which have been previously consulted on at TDOWGs.<br>• Commencement dates available in the exposure draft<br>• Commencement notice – included remaining clauses in Chapter 4 that have not yet commenced<br>• Urgency around Tranche 4B is that some changes will need to commence by 1 August 2021 (for the 2021 reserve capacity cycle)<br>• AV highlighted that new rule book issued on 1 July 2021 so participants should ensure they are aware of rules commencing<br>• EPWA will also update the Companion Version of the WEM Rules and publish on the Coordinator's website |
| **Slide 15** | DG gave WEM Implementation Update<br>• ETIU no longer exists – the team is back within Energy Policy WA<br>• In practice nothing is changing – implementation of rules and Procedures to complete the reform process and implement the last set of the Taskforce decisions remains with EPWA. These rules will still be made by the Minister for Energy.<br>• EPWA is retaining both TDOWG and WRIG – for anything WEM reform related<br>• The Rule change process and Market Advisory Committee will handle all other changes<br>• The Taskforce at its final meeting made a number of decisions<br>    ○ Market Power Mitigation – more work to do on basis of feedback including consultation that should continue. It may be not practicable to commence new regime at market start but EPWA will continue to work with the ERA to strengthen the current regime.<br>    ○ PSSR Framework – Tranche 4B has some additional interim arrangements (e.g. change management process, UFLS rules, system restart rules. Still intent to have centralized PSSR Framework but this will require primary legislation changes.<br>    ○ Non-Cooptimised ESS Framework – taskforce decision made and currently drafting the rules for inclusion in Tranche 5<br>• Tranche 4A rules gazetted<br>• Currently having a deep dive into intermittent loads<br>Questions<br>• RW asked will the tranche 5 amending rules also include compliance related things - e.g. details of the amnesty and any transitional arrangements?<br>    ○ DG noted regulations need to be amended for ERA civil penalties provisions<br>    ○ AV answered yes – AGC dispatch rules and likely to see a few more transitional arrangements as currently being worked through with AEMO<br>    ○ Compliance amnesty – still being considered. |