Transformation Design and Operations Working Group (TDOWG): Meeting 2

DATE/LOCATION: 9 September 2019, Level 45, 152 St Georges Terrace, Perth

TIME: 9.30 am

MEETING ENDED: 12.00 pm

PRESENT:

Attendees	Organisation	Attendees	Organisation
Aditi Varma	ETIU (Chair)	Jenny Laidlaw	Rule Change Panel Support
Adrian Theseira	ERA	Julian Fairhall	ERA
Ashwin Raj	ETIU	Kate Ryan	ETIU
Brad Huppatz	Synergy	Kristian Myhre	TransAlta
Clayton James	AEMO	Leon Kwek	AEMO
Daniel Kurz	Bluewaters	Martin Maticka	AEMO
David Martin	ESC Solar	Matthew Bowen	Jackson MacDonald
Dean Frost	Western Power	Matthew Fairclough	AEMO
Dermot Costello	Clean Energy Council	Neil Hay	Oakley Greenwood
Donna Todesco	ERA	Noel Schubert	Individual
Drew Harris	Simcoa	Peter Huxtable	Water Corporation
Elizabeth Walters	ERA	Rebecca White	ETIU
Geoff Gaston	Change Energy	Rod Littlejohn	Tersum Energy
Geoff Glazier	Merz	Sabina Roshan	Western Power
Glen Carruthers	Western Power	Scott Davis	Australian Energy Council
Greg Ruthven	AEMO	Shannon Hewitt	CleanTech Energy
Greg Thorpe	Oakley Greenwood	Simon Middleton	AEMO
Iulian Sirbu	Kleenheat	Stephen Eliot	Rule Change Panel Support
Jacinda Papps	Alinta Energy	Sue Paul	RBP consulting
Jai Halai	Perth Energy	Troy Santen	Stellata Energy
Jas Bhandal	AEMO	Wendy Ng	ERM Power
Jason Froud	Synergy	Yadi Kaler	Alinta

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1.	Opening remarks	The Chair opened the meeting and introduced the meeting agenda. The Chair also informed the TDOWG that the ETIU and PUO had both recently moved to Energy Policy WA, a new sub-department of the Department of Mines, Industry Regulation and Safety. Energy Transformation discussion papers were now available at www.energy.wa.gov.au instead of the Department of Treasury website.		
2.	Market Settlement	Rebecca White (RW) from the ETIU presented on Part 1 of the Settlement workstream, covering settlement intervals, settlement timelines and the allocation of settlement residues. Part 2, covering uplift payments (a new term for constrained-on payments) and changes to the settlement of energy, ESS and RCM consequential to changes made in other work packages, would be discussed with the TDOWG at a later date. • The foundation market parameters paper had identified 5-minute settlement (5MS) intervals as an area for consideration in light of the move to 5-minute dispatch. • The ETIU had identified other measures that could improve efficiency and decrease administration costs, relating to settlement timelines and the allocation of settlement residues to the notional wholesale meter. • If 30-minute settlement was retained after the move to 5-minute dispatch, the misalignment could dilute investment signals, incentivise disorderly bidding behaviour and cause inaccuracies in the calculation of uplift payments which may also lead to disorderly bidding, and ESS cost allocation which would dilute the signals to generators to improve their performance to maintain power system security. To minimise these adverse economic consequences, the ETIU proposed aligning the dispatch and settlement intervals to 5 minutes. • Jacinda Papps (JP) from Alinta Energy raised a concern with the costs of implementation of 5MS and noted that the incentives for disorderly bidding could also be addressed with late rebidding rules. • Wendy Ng (WN) from ERM Power noted the WEM's low price caps relative to the NEM, which would blunt the incentive for disorderly bidding, and asked whether such bidding was really such a problem in the WEM that it required a change to the settlement intervals. RW replied that in addition to disorderly bidding, the misalignment between dispatch and settlement intervals would cause inaccuracies in the calculation of uplift payments and allocation of ESS costs. • WN stated that the NEM had operated for 20 years with misaligned settlement and dispatch intervals without problem and was only now being changed. Sue	Hold one-on-one discussions with market participants on 5MS implementation issues. Hold a TDOWG session on weekly settlement timeline outlining the timing of various NSTEM components, adjustments and other relevant matters.	ETIU ETIU

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		Paul (SP) from RBP Consulting replied that the NEM had not harmonised the settlement and dispatch intervals in the first instance only due to technological limitations, and that attempts to harmonise the intervals since had largely been blocked by the owners of slower-responding plant that benefitted from the misalignment. SP noted that the misalignment disincentivises the participation of demand side resources (DSR) that are capable of responding over a 5-minute horizon but won't know the price until the end of a 30-minute settlement interval. • WN asked whether DSR would be required to bid in to the market. The Chair replied there would not be a mandatory requirement for DSR to bid in to the market, although they would be able to bid in if they chose to do so, provided they could demonstrate a stable demand baseline and the ability to curtail demand if required. • JP asked whether the dispatch rules would then be changed to allow DSR to be dispatched ahead of other generators. The Chair replied that where DSR is able to provide controllable consumption into the market, the new market rules would allow them to be dispatched. The Chair noted that more detail on DSR participation in the new market was also outlined in the Energy Scheduling and Dispatch paper published on the Taskforce website. • WN asked why the settlement interval would be changed to allow a 5-minute price for DSR if they may continue to be underutilised by the market. The Chair replied that 5-minute settlement was not being considered solely to benefit DSR, but also to facilitate the participation of other technologies such as storage (especially given the increasing need for fast response to address system security challenges) and to reduce the consequences of inaccurate uplift payments and ESS cost allocation. • JP asked whether 5-minute settlement was a settled decision. RW replied that it would be proposed to the Taskforce in late September. JP asked whether there would be more consultation on the topic. RW replied that any feedback received at the meeting would be considered by the ETIU before going to the Taskforce for endorsement, after which a discussion paper would be published to which stakeholders could provide further feedback. • The Chair noted that the ETIU considered 5-minute settlement to be a good policy direction from an economic efficiency perspective, but would still need to consider any potential implementation complexities before recommending how and when it could be implemented. JP noted that the cost of implementation in the NEM had initially been estimated at around $12-15 million, but would now cost over $100 million, and up to $700 million including the additional costs for		

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		market participants. JP noted that the planning stage had taken 3 years, with a further 3 to 4 years for implementation, and stated that the imposition of 5-minute settlement could put the October 2022 market start date at risk. • JP also stated that market participants such as Alinta would have difficulty ensuring their equipment was capable of complying with 5-minute settlement by October 2022. SP asked whether this would be caused by a switch to 5-minute metering, and stated that SCADA could be used as an alternative. JP replied that using SCADA would weaken the case for 5-minute settlement. The Chair noted that the discussion had now moved into the implementation stage, and that the ETIU would consider both 5-minute metering and SCADA profiling for the implementation of 5-minute settlement, in collaboration with AEMO and Western Power. The Chair also acknowledged the concerns raised by retailers, and other potential concerns raised by other market participants, needed to be factored into the planned work on implementation challenges. • JP stated that these measures should also be assessed against alternatives such as rebidding rules and gate closure. The Chair agreed, and noted that while the ETIU considered 5-minute settlement to be an efficiency improvement at this stage, it would still need to consider the implementation costs and timeframes before endorsing implementation. WN noted that sophisticated customers would likely be unhappy if SCADA profiling were implemented, due to its relative inaccuracy. RW replied that the 5-minute settlement proposal being taken to the Taskforce was simply a policy decision, and that potential implementation complexities would be considered later following further consultation. • RW stated that the 2 implementation options currently under consideration were mandatory 5-minute metering and SCADA profiling. Under the SCADA profiling option, customers would still be free to upgrade to 5-minute metering if they preferred. Simon Middleton (SM) from AEMO noted that such a dual solution would be more complex and costly, and AEMO would be unlikely to support it. • WN reiterated her concern with the inaccuracy of SCADA profiling, even at the household level. SP replied that the 5-minute approximation was still based on 30-minute data, and even if the profile was incorrect the total error would be relatively small. SP added that the same profiling was used by AEMO to monitor system security. Matthew Fairclough (MF) from AEMO clarified that AEMO used the SCADA profiling for the system in aggregate, which is very accurate, but at the individual level there can be greater inaccuracies. Similarly, while the 5-minute estimates were generally quite accurate for generators, they could be less reliable for customers.		

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		• JP stated that while 5-minute settlement may be a good idea in the long run, the timeline was very aggressive for market start. • WN stated that it would be better to monitor the experience as 5-minute settlement is implemented in the NEM to determine its relative benefits before implementing in the WEM. • The Chair thanked the participants for the feedback and noted ETIU would consult with market participants in 1-on-1 meetings as it works through implementation issues. RW presented on changes to settlement timelines (the time taken between the trading period and settlement), which could be pursued independently from the move to 5-minute settlement. Reducing settlement timelines would reduce AEMO's prudential requirements and reducing the number of settlement days would also reduce administration costs for market participants. The ETIU was therefore proposing to change to a weekly settlement timeline. • Jenny Laidlaw (JL) from Rule Change Panel Support asked whether any metering changes would be required for weekly settlement. RW replied that there were currently around 7,500 manually-read meters whose output could be estimated to enable weekly settlement. Changes would likely be needed to be made to the Metering Code and Metrology Procedure to allow for this to occur. Dean Frost (DF) from Western Power noted that there were technical limitations in Western Power's systems in some regional areas, meaning some meters could still need to be manually read. RW replied that the ETIU had been in contact with Western Power and had been advised that any changes required would be relatively minor in nature. DF requested that ETIU discuss in more detail with Western Power before locking in any policy decision. • Brad Huppatz (BH) from Synergy asked whether moving to weekly IRCR would mean a move to weekly Capacity Credit allocation. SP replied that ETIU had been advised that weekly Capacity Credit allocation was not necessarily required to implement weekly IRCR. • Jai Halai (JH) from Perth Energy noted that Capacity Credits are currently allocated on a monthly basis and offset against the NSTEM invoice, and asked how the move to a weekly NSTEM invoice could occur without also moving to weekly Capacity Credit allocation. SP and the Chair replied that Capacity Credit allocation is not necessarily linked to a given week or month, but rather to some period of time in which the week occurs. The Chair noted that exactly how the NSTEM would be treated was still under consideration, and another session		

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		could be held to outline the weekly settlement timeline, including any changes to the timing of various NSTEM components. • RW continued presenting on the use of the notional wholesale meter. Settlement residues were currently relatively small at around $9 million per year, and the costs of implementing the preferred alternative approach of settlement-by-difference would likely outweigh these benefits. The ETIU therefore proposed to retain the use of the notional wholesale meter. • JL noted that around half the market was currently settled based on SCADA. RW replied that participants could use SCADA now if the underlying meter was compliant. Synergy would be subject to grandfathering arrangements. The Chair noted that currently boundary points between Tx and Dx with SCADA but no underlying meter were unable to be used for financial settlement because of legislative framework restrictions. • Glen Carruthers (GC) from Western Power asked whether an alternative approach to allocating settlement residues could be implemented over time. The Chair and RW replied that it could, and that while it may not be an appropriate measure to implement at present it would be considered a market evolution item to be considered going forward.		
3.	Outage planning principles and approach	Jas Bhandal (JB) from AEMO presented on the key principles of the current Outage Management framework. AEMO's initial position on these principles included: • Centralised outage management should be retained. • The availability declaration requirements and definition of unavailability specified in Rule Change 2013_15 should be retained. • The obligation for a generator not to submit a planned outage if it is aware of potential unavailability during the outage period should be retained. • The principle of developing, maintaining and publishing a list of equipment should be retained. 2013_15 rule changes should be retained and possibly expanded. • Non-equipment list generators should retain the requirement to notify AEMO of outages. • The requirement for participants to submit outage information should be retained and modified. AEMO also considered that the key timelines for outage plan submission should be retained. • JP asked whether these timelines would need to be changed along with the change to settlement timelines. RW replied that consequential changes arising	Organise dedicated session on outage management.	AEMO

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		from the change to settlement timelines would be considered in part 2 of the settlement work package. • WN asked whether part 2 of the settlement work would consider the requirement to modify an outage submission with incorrect information. CJ replied that it would need to be considered. JL noted that adjustments to outage submissions were also covered in Rule Change 2014_03. JB continued presenting on AEMO's view on the key principles of the current framework: • The principle of opportunistic maintenance should be retained. • The ability of DSM capacity to count towards available capacity should be investigated. • The principle of the remaining facilities in service meeting ESS requirements should be retained. • The principle of sufficient network capacity being available to maintain security and reliability should be retained. AEMO considered that there would no longer be a need to capture consequential outages to avoid capacity refunds under network constraint situations. • DF asked if this would be because specific constraint equations would be published. CJ replied that it would, adding that under constrained access facilities would be dispatched around constraints and there would therefore be no need for participants to submit an outage for those situations. • JL stated that she was concerned about removing the ability for participants to submit a consequential outage for a few reasons, and provided the example of a generator tripping off mid-interval without a constraint equation being able to neatly describe what had happened. JL was concerned that the ERA would need to go through complex data to diagnose what had happened in such instances, rather than having the consequential outage available as a simple explanation. CJ replied that this was a reasonable point and AEMO would need to work through how to handle such situations, but AEMO would try to minimise the imposition of constructs such as consequential outages on market participants where they were able to use the data available instead. • JP asked CJ to confirm that participants would not be required to pay capacity refunds when they were forced off by a network constraint. CJ confirmed that this was true. A generator receiving Capacity Credits would still be required to bid its full capability, but if the dispatch engine constrained its output it would		

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		not pay capacity refunds. The key difference was that a generator would not alter its bids based on its expectation of a network outage. • WN asked whether, in a scenario where a generator was effectively constrained off by another generator, this would not be considered a consequential outage. CJ replied that security constraints would be handled by dispatch, and the dispatch record of that constraint would be used instead of labelling it a consequential outage. JB noted that AEMO considered that outage quantities would need to be modified. Participants were currently required to submit outage quantities reflecting their unavailable capacity, whereas SCED, pre-dispatch and PASA would require knowledge of the available quantities for dispatch. There were also other complexities to resolve, such as temperature adjustments and partial or overlapping outages. • CJ added that the intention was to align the information required for outage submissions with the information required for dispatch and PASA, to simplify submissions for participants. • DK asked whether temperature adjustments could be accounted for when considering any inconsistencies between 3-month ahead outage submissions and dispatch. CJ replied that while participants would not be expected to exactly match the 3-month ahead submissions, they would still need to make the minimum capacity identified in the submission available for dispatch. • WN asked whether the onus would now be on market participants to calculate their minimum available capacity. CJ replied that it would, based on what the plant may be capable of. WN and CJ agreed to discuss further offline, and CJ added that AEMO would be happy to have separate conversations, or even hold a dedicated session, to discuss the matter further. JB noted that AEMO considered that compensation for participants should be retained where a previously scheduled outage is rejected within 48 hours of the scheduled start, and then presented some additional ideas AEMO had for the future outage process. CJ added that these were only ideas at this stage and asked the TDOWG to send AEMO any ideas they may also have for the future outage process. • AEMO proposed moving to a 1-stage outage process, similar to the NEM, with outage plans being flagged as either “unassessed”, “likely to proceed” or unlikely to proceed”. • JL asked how this would be different to the current process, aside from the final approval stage. CJ replied that participants would not be required to ask for approval, rather it would continue to be assessed and actioned by AEMO.		

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		• The Chair asked whether outage plans would then automatically flow through to pre-dispatch PASA. CJ replied that this would continue to be assessed by AEMO. • AEMO proposed moving to an annual planning approach, similar to Singapore. • DF noted that there would be challenges to implementation, for example Western Power might not know a year in advance when customer connections would plan an outage. • WN asked whether participants would be allowed to submit intra-year. CJ replied that they still would be able to, but AEMO would just like as much certainty as possible. WN noted that ERM currently planned its outages based on what others were expected to do, and annual planning may make it more difficult to do so in future. • JL asked whether AEMO was considering imposing any penalties to incentivise earlier outage submissions. CJ replied that penalties were not being considered. WN noted that there was no need for penalties, as Capacity Credits provided participants with an incentive to make their capacity available. • JL asked what problem annual planning would be addressing. CJ replied that it was just an idea for potential improvement. GC noted that constrained access will make it more difficult to coordinate the planning of generation and the network together, and the longer-term view of availability would make it easier to manage. CJ added that there were benefits for AEMO's engineers too. • JB noted that participants would be able to update their outage plans at a later date if they still wished to plan around other participants. WN noted that to do so participants would actually need to submit an entirely new outage plan. CJ replied that AEMO would consider measures to provide participants with the flexibility to amend their outage plans and avoid locking themselves in to their initial submission. • DK noted that Muja C's outage plan was based on the hours it had run, which would be difficult to forecast a year ahead. CJ noted that some flexibility may be required in this instance and JB replied that they could resubmit the outage plan up to two trading days prior to the day on which the planned outage is scheduled to commence. • Drew Harris (DH) from Simcoa noted that DSM providers would also need to submit outage plans and would require the flexibility to resubmit up to 48 hours beforehand. CJ replied that recent Rule Change had removed the requirement		

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		for DSM providers to submit outage plans. JL noted that the requirement did still remain for interruptible loads. • CJ asked for feedback from the TDOWG on the future outage process and stated that there would be extra sessions held on the topic.		
4.	Frequency Regulation modelling	Leon Kwek (LK) from AEMO presented on SWIS frequency regulation (load following) requirements. • The GHD report on ESS requirements had identified that demand forecast errors were currently a much more significant source of frequency error than wind forecast errors. • Noel Schubert stated that more than 500MW of wind generation was expected to come online and asked whether that would substantially change the contribution of wind forecasting errors to overall frequency errors. LK replied that it would increase wind's contribution, but the overall frequency error would continue to be mainly driven by demand forecasting errors. • Synergy were effectively providing a ramping service to the market for free under current market arrangements, as all other generators would ramp as fast as possible to meet their dispatch instructions and Synergy's load following would balance the system load. Under future market arrangements where AEMO would no longer have control of Synergy's portfolio this would no longer be possible. • The system currently operated well within its frequency bands, this was unlikely to continue in future. • With the move from 30-minute to 5-minute dispatch, less frequency regulation service would be required. • Although load following requirements were static currently, historical day-to-day variation showed that the actual requirement for frequency regulation services was quite variable. • CJ noted that regardless of any number identified for the amount of frequency regulation required based on historical data, day-to-day conditions would still vary and AEMO would require the flexibility to vary frequency regulation requirements accordingly. GC asked whether there would be a way to adjust the requirement according to weather conditions to account for solar output, considering the relative accuracy of wind forecasting. CJ replied that GHD had considered it in its paper but AEMO would consider it in more detail. LK added that weather forecasts would likely be included in PASA. • Sub-interval oscillation would likely be addressed by short-term droop control.		

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		• Under current conditions, droop control was effectively shared amongst all generators, leading to a stable system with a relatively negligible effect on each individual generator. • DF noted that current conditions included a relatively large number of synchronous machines and asked what may be expected in future as an increasing number of non-synchronous generators connect to the system. LK replied that modelling would be required to determine that. MF noted that as time goes by AEMO was acquiring more data with higher penetration of non-synchronous machines. CJ added that the intention was for droop response to be spread equitably among all generators where they were able to provide it. Geoff Glazier (GG) from Merz noted that all generators would be required to provide droop response as a base requirement in the new market. • CJ asked the TDOWG to provide any feedback and questions to AEMO.		
5.	RCM update	Ashwin Raj (AR) from ETIU provided an update on the treatment of Capacity Credits in a constrained network. Key issues to be considered in the design proposal included the tenure of capacity rights, the allocation of initial and new rights, and the treatment of competing applications. • The design proposal would be taken to the TDOWG in the week of 23 September 2019, with 1-on-1 discussions with participants in October. • WN asked how access arrangements and charges would be dealt with by the ETIU. AR replied that consultation on Access Code changes would likely occur around November, with a view to implementing Access Code changes by mid-2020. • AR asked the TDOWG to contact him if they had any further questions or feedback.	Provide design proposal to TDOWG on 27 September 2019.	ETIU
6.	WEM Regulation and Rule changes	The Chair provided an update on upcoming changes to the Market Rules and WEM Regulations. • The Taskforce was pursuing changes to the WEM Regulations to enable the Minister for Energy to have temporary rule-making powers to assist the implementation of the Energy Transformation Strategy. The changes were now under the consideration of the Executive Council and were expected to be implemented within 4 to 5 weeks. • The ETIU was drafting a Rule Change on the ability for the Taskforce to access AEMO data to assist with the implementation of the Energy Transformation Strategy.		

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		• WN noted that, regarding 5-minute settlement, a cost-benefit analysis (CBA) had previously been mentioned by the ETIU, and asked whether the CBA could be made available to the TDOWG. The Chair replied it did not yet have the data required to carry out the CBA. WN asked what pricing methodology would be used in the CBA. The Chair replied that a time-weighted average price could be considered, similarly to as had been done in the NEM, although the ETIU would also consider work done in other jurisdictions. • The Chair thanked the TDOWG for attending and closed the meeting, noting that the next meeting of the TDOWG would be held on 27 September 2019 and would be specifically considering the RCM.		