Government of **Western Australia**
Energy Policy WA

Meeting Agenda

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Meeting Number:	2022_07_14
Date:	Thursday 14 July 2022
Time:	9:30 AM to 11:30 AM
Location:	Online, via TEAMS.

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	5 min
2	Meeting Apologies/Attendance	Chair	Noting	2 min
3	Minutes of Meeting 2022_06_16	Chair	Decision	3 min
4	Action Items	Chair	Discussion	5 min
5	Project Timeline	RBP	Discussion	3 min
6	BRCP for Peak Capacity Product	RBP	Discussion	30 min
7	BRCP for Flexible Capacity Product	RBP	Discussion	25 min
8	Covering the Duration Gap	RBP	Discussion	40 min
9	Next Steps	Chair	Discussion	5 min
10	General Business	Chair	Discussion	5 min
	Next Meeting: TBD			

Please note this meeting will be recorded.

Government of Western Australia
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	16 June 2022
Time:	9:30am – 11:30am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Rhiannon Bedola	Synergy	
Oscar Carlberg	Alinta Energy	Proxy for Jacinda Papps
Peter Huxtable	Water Corporation	
Dimitri Lorenzo	Bluewaters Power	Proxy for Paul Arias
Mark McKinnon	Western Power	
~~Wendy Ng~~	~~Shell Energy~~	
Patrick Peake	Perth Energy	
Toby Price	AEMO	Proxy for Manus Higgins
Richard Cheng	Economic Regulation Authority	Proxy for Matt Shahnazari
Noel Schubert	Small-Use Consumer representative	
Andrew Stevens	Clear Energy	
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	
Rebecca White	Collgar Wind Farm	
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Ajith Sreenivasan	RBP	
Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	
Shelley Worthington	EPWA	

Apologies	From	Comment
Paul Arias	Bluewaters Power	

Apologies	From	Comment
Manus Higgins	AEMO	
Jacinda Papps	Alinta Energy	
Matt Shahnazari	Economic Regulation Authority	
Dale Waterson	Merredin Energy	
Wendy Ng	Shell Energy	

Item	Subject	Action
1	**Welcome** The Chair opened the meeting at 9:30am.	
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minutes of RCMRWG meeting 2022_06_02** Draft minutes of the RCMRWG meeting held on 2 June 2022 were distributed on 13 June 2022. Mr McKinnon asked to include his comment that 41°C may no longer be appropriate as a basis for the Reserve Capacity Mechanism (**RCM**). Mr McKinnon noted that 41°C is not only the basis for assessing generation capacity but also for setting the RCM Limit Advice. Ms Koziol requested that any further comments on the 2 June 2022 minutes should be provided by close of business 16 June 2022. The RCMRWG accepted the minutes as a true and accurate record of the meeting, pending the amendment to reflect Mr McKinnon's comment and any further comments provided on 16 June 2022. **Action: RCMRWG Secretariat to publish the minutes of the 2 June 2022 RCMRWG meeting on the RCMRWG web page as final.**	**RCMRWG Secretariat**
4	**Action Items** The paper was taken as read.	
	The slides for agenda items 5 to 8 are available on the webpage for the RCM Review (https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group).	
5	**Project Timeline** Mr Robinson presented the timeline.	
6	**Updated System Stress Modelling Outputs** Mr Bowmaker presented the options for assessing resource adequacy (slides 8 to 28). The following issues were discussed:	

Item	Subject	Action
	Government announcement about plant retirement • Mr Bowmaker noted that, on 14 June 2022 the WA Government announced its plans to: o retire Synergy's coal fired power plants by 2030; o assess network augmentation; and o invest in wind energy and storage capacity including long-term storage. • Mr Bowmaker noted that the R1 scenario of the system stress modelling is now obsolete but the R2 scenario is still relevant as it incorporates the announced retirements. • Mrs Bedola suggested to revise the R1 scenario to reflect the announced retirements. • Mr Bowmaker noted that because the R2 scenario reflects the announced retirements, R1 will only be adjusted for the economic modelling in step 5 of stage 1 of the review. • In response to a question from Mr Carlberg, Mr Bowmaker clarified that, under the R2 scenario, all baseload thermal generators including coal and gas fired baseload plants will be retired by 2030 but other gas plant will still operate. • In response to a question from Mr Schubert, Mr Bowmaker confirmed that the Government's announcements about investments in renewable generation and storage will be taken into account in the next round of modelling. • Mr Schubert noted the 2022 WEM Electricity Statement of Opportunities (**ESOO**) is about to be published and asked whether the modelling assumptions for the RCM Review will be updated to reflect the ESOO. Mr Robinson indicated that the 2022 ESOO will be reviewed to assess whether it is consistent with the RCM Review assumptions or whether there are any significant differences. **Updated system stress modelling** • Mr Robinson clarified that the capacity needs identified by the system stress modelling are based on the specified expected unserved energy (**EUE**) and that additional capacity may be needed to satisfy the peak demand limb of the Planning Criterion. • Mr McKinnon clarified that, in reality, the operational load will never become negative and suggested to use different terminology. Mr McKinnon asked whether the projected demand will be affected by the measures taken to address the negative load. • In response to a question from Ms White, Mr Sreenivasan clarified that the assumptions include optimisation for charging of electric vehicles (**EV**) at times of system peak for the 2030 and 2050 scenarios and that the effect of EVs on system load is small in the 2030 scenarios because of the small number of expected EVs.	

Item	Subject	Action
	• In response to a question form Mr Price, Mr Sreenivasan clarified that the charging scenario from the 2021 ESOO was used for the base case and that additional charging optimisation had been applied. Western Power's assumptions on EV charging are reflected to the extent that they align with the assumptions in the 2021 ESOO. • In response to a question from Mrs Bedola, Mr Bowmaker clarified that the demand response in the scenarios does not refer to the effect of Demand Side Programs referred to in the current WEM Rules. • Mr Carlberg considered that the 2021 ESOO's peak demand forecast is too low because the 10% probability of exceedance (**POE**) of peak demand had been exceeded several times. Mr Carlberg considered that peak demand may increase quicker than forecast in the 2021 ESOO due to climate changes. Mr Robinson noted that it will be assessed whether the RCM Review assumptions are consistent with the 2022 ESOO. Ms White asked whether the Planning Criterion should be moved to cover 5% POE to address the increasing peak demand. The Chair noted that a 5% POE peak demand target would be too expensive and that the focus should be for an appropriate forecast of the 10% POE peak demand. • In response to a question from Mr Tayal, Mr Robinson confirmed that the modelling assumptions included that the generators would meet their availability obligations. The Chair noted that generators are subject to Reserve Capacity Refunds if they don't meet their availability obligation. • In response to a question from Mr McKinnon, Mr Bowmaker clarified that: o the ramping needs assessed are based on the modelled operational demand, which includes assumptions about generation from distributed energy resources (**DER**); and o only ramping from Trading Interval to Trading Interval is considered, not intra-interval ramping caused by the fluctuation of intermittent generation, which is assumed to be met by the Essential System Services (**ESS**) market. • Mr Robinson noted that the current proposal is to include a flexibility product. Mr Robinson considered that if sufficient ramping capacity is available to address demand ramping, it will also be sufficient to address intra-interval variability of intermittent generation. Mr Robinson noted that this will be further assessed to confirm the assumption. • In response to a question from Mr Price, Mr Robinson noted that the numbers for the needed capacity in the table on slide 20 refer to absolute capacity and not additional capacity needed.	

Item	Subject	Action
	• In regards to the charts on slide 21, Mr Carlberg asked whether the high number of loss of load hours (**LOLH**) at 9:00pm are caused by the assumption that electricity storage resources (**ESR**) will not be required to be available at that time because this is outside of the Electric Storage Resource Obligation Intervals (**ESROI**). Mr Schubert considered that the assumptions on EV charging will drive at what time the modelling identifies LOLH. In response to a question from Mr Cheng, Mr Robinson confirmed that the results indicate a need for long duration storage. • Mr Schubert considered that EV charging during the evening peak will be an indicator that the incentives to move charging from the evening peak are insufficient. The Chair agreed that introducing automated staggered EV charging will be important. Mr Robinson noted that some EV charging decisions will be made by consumers and some by aggregators and that some of the charging can be shifted by demand response incentives. Mr Robinson noted that the modelling assumptions were between assuming no measures and perfect measures to shift EV charging after the peak hours. The Chair considered that the modelling should include an assessment of what will happen if there are no measures to shift EV charging to after the peak. Mr Robinson agreed to model this as an additional scenario and noted that there are already incentives for retailers to shift the EV charging to after the peak, such as the Individual Reserve Capacity Requirement (**IRCR**). Several RCMRWG members considered that tariff changes to shift EV charging is unlikely. The Chair considered that the introduction of standards and automation will be important to address timing for EV charging. • Mr Schubert considered that the current IRCR may not incentivise Synergy to reduce consumption during peak. Mrs Bedola noted that customers with distributed PV (**DPV**) are reducing system peak demand while shifting system peak to later in the day but they get no benefits in terms of a reduced IRCR. • Ms White asked if changes in the ESROI would materially affect the modelling results. Mr Sreenivasan noted that, for 2050, the modelling was assuming different ESROIs based on the observed operational demand. The Chair noted that the length of the ESROI can be increased following the relevant review prescribed under the WEM Rules. Mr Schubert considered that long-term storage should be available by 2050.	

Item	Subject	Action
7	**Planning Criterion** Mr Robinson presented the proposal for amending the Planning Criterion (slides 30 to 32). The following issues were discussed: **Reserve margin** • Mr Carlberg considered that the forced outage rate may become less relevant for the reserve margin with a higher share of intermittent generation and Synegy's coal fired power plants retiring. Mr Carlberg considered that the errors of demand forecast and intermittent generation forecast may become the main driver for the reserve margin. • Mr Robinson suggested that a principles based approach could be used to set the reserve margin instead of a fixed percentage. The Chair considered that the reserve margin must strike the right balance between system adequacy and cost to consumers. If the reserve margin is not fixed in the rules, then guidance for AEMO and strict scrutiny rules will be important to ensure the right balance. • The Chair clarified that, at a minimum, the reserve margin should be set by the largest contingency, including network outages, and not by the largest generation unit. • Mr Schubert considered that, when assessing the north country as the largest network contingency, it should be recognised that the north country generators may not have the highest output at times of system peak. • The Chair agreed that the largest contingencies may not happen during system peak demand and suggested that the reserve margin should be set probabilistically based on the largest contingency expected at times of system peak demand. **Introduction of a flexibility capacity product** • Ms White noted that the target for the flexibility product should consider the time difference between daily minimum and maximum demand and not only the MW difference of the two. • In response to a comment form Mr Schubert, Mr Robinson noted that setting the target for the flexibility product may need to be refined to reflect the duration and steepness of the ramp because the difference between daily minimum demand and peak demand may overstate the need for flexibility. • In response to a question from Mr Price, Mr Robinson clarified that the suggestion is to have one requirement for the peak demand and EUE and another requirement for the flexibility product. • Mr Schubert considered that the RCM needs to ensure that enough flexible capacity and enough capacity for peak is procured, but must avoid doubling up on capacity at unnecessarily higher cost. • In response to a question from Ms White, Mr Robinson clarified that the suggestion is to have two capacity products with two distinct	

Item	Subject	Action
	prices and that a Facility that can provide both products will receive the uplift payment for the flexibility product. • In response to a question form Ms White, Mr Robinson summarised that the following capabilities are expected to be part of the defined flexibility product: o fast start capability; o low availability restrictions, such as minimum generation; and o fast ramping capability. • Mr Robinson clarified that inertia is not planned to be included in the flexibility product, as this is expected to be provided through the ESS market. The Chair noted that it is important to ensure that sufficient inertia is available and that the RCM should not de-incentivise the provision of inertia. • The Chair considered that the flexibility product should be remunerated for facilities that provide both the peak product and flexibility to avoid perverse incentives to withhold capacity. • Mr Schubert considered that procurement of the peak product should not be prioritised over procurement of the flexibility product or vice versa to satisfy both requirements at the lowest cost. • Mr Peake considered that it would be ideal to price every required element needed from facilities and optimise procurement of the lowest cost combination but that this will likely be too complex. • In response to a question of Mr McKinnon, Mr Robinson clarified that the modelling does not consider any DPV that is part of a virtual power plant (**VPP**) as part of the operational load. Mr Price clarified that this concept can only apply for VPPs that are a Small Aggregation under the WEM Rules. Mr Robinson agreed. • The Chair considered that reducing the output of DPV should be avoided were possible by charging ESR instead of DPV curtailment. • Mr Carlberg asked whether the flexibility product is envisioned to be based on the needed ramp rate over a certain time. Mr Robinson agreed that this is the current proposal. • Mr Schubert considered that the needed flexibility product may differ depending on how many facilities can provide it. • The Chair noted that the obligations for the flexibility product will need to be carefully designed to ensure that the flexibility is available when needed. • Mr Robinson noted that the economic modelling will assess whether the peak capacity product may be sufficient to incentivise the needed flexibility without adding a flexibility capacity product. • In response to a question from Ms White, Mr Robinson clarified that he considered that the obligation for providers of the flexibility product will likely include obligations to offer the flexibility at certain times and seek outage approval.	

Item	Subject	Action
	• The Chair noted that sculpted refunds would be preferable for the flexibility capacity product, similar to the current refund regime for the peak capacity product.	
8	**Next Steps** The RCMRWG noted the outstanding items to be resolved on slide 34. The RCMRWG agreed that, based on the discussion, the MAC should be advised that the RCMRWG suggested the following: • retaining the two existing limbs of the Planning Criterion: peak load and EUE; • change the current reserve margin to the largest contingency on the system and make this change ahead of the rest of the changes to the RCM; • compare the continuation of the current single-product RCM with a two-product RCM with separate targets for peak capacity and flexible capacity; and • only procure a flexible capacity product if the need for flexibility is not met by the capacity needed to fulfill the peak capacity requirement.	
9	**General Business** No general business was discussed.	

The meeting closed at 11:30am.

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Agenda Item 4: RCMRWG Action Items

Reserve Capacity Mechanism Review Working Group (**RCMRWG**) Meeting 2022_07_14

Shaded	Shaded action items are actions that have been completed since the last MAC meeting.
Unshaded	Unshaded action items are still being progressed.
Missing	Action items missing in sequence have been completed from previous meetings and subsequently removed from log.

Item	Action	Responsibility	Meeting Arising	Status
6	RBP is to provide information to the RCMRWG on how the number of continuous LOLH matches against battery profiles	RBP	2022_05_05	**Closed** This was presented under agenda item 6 at the RCMRWG meeting on 16 June 2022.
9	RCMRWG Secretariat to publish the minutes of the 2 June 2022 RCMRWG meeting on the RCMRWG web page as final.	MAC Secretariat	2022_06_16	**Closed** Minutes published on 20 June 2022

Government of **Western Australia**
Energy Policy WA

Reserve Capacity Mechanism Review Working Group

Meeting 2022_07_14

14 July 2022

Working together for a
brighter energy future.

Meeting Protocols

- Please place your microphone on mute, unless you are asking a question or making a comment
- Please keep questions relevant to the agenda item being discussed
- If there is not a break in discussion and you would like to say something, you can ‘raise your hand’ by typing ‘question’ or ‘comment’ in the meeting chat
- Questions and comments can also be emailed to energymarkets@energy.wa.gov.au after the meeting
- The meeting will be recorded and minutes will be taken (actions and recommendations only)
- Please state your name and organisation when you ask a question
- If you are having connection/bandwidth issues, you may want to disable the incoming and/or outgoing video

Agenda

Item	Item	Responsibility	Type	Duration
1	Welcome and Agenda	Chair	Noting	5 min
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10	General business	Chair	Discussion	5 min

5. Project Timeline

Project Timeline

08/07

Stage	Step	Short description	Week ending Analysis	21/01	28/01	4/02	11/02	18/02	25/02	4/03	11/03	18/03	25/03	1/04	8/04	15/04	22/04	29/04	6/05	13/05	20/05	27/05	3/06	10/06	17/06	24/06	1/07	8/07	15/07	22/07	29/07	5/08	12/08	19/08	26/08	2/09
1	Working group meetings		RCM Working Group meetings	WG				WG				WG							WG				WG		WG				WG							
1	MAC meetings		MAC meetings							MAC					MAC						MAC						MAC								MAC	
1	Step 1	Requirements analysis	(a)International Literature review																																	
1	Step 1		Gather assumptions and set up models																																	
1	Step 1		(b)Model system stress																																	
1	Step 1		(c)Analyse the required capacity services																																	
1	Step 2	Review Planning	(d)Assess the Planning Criterion																																	
1	Step 2	Criterion	(e)Assess the ICAP and UCAP Concepts																																	
1	Step 3	Review CRC allocation	(f)Assess CRC Allocation and identify options																																	
1	Step 5	Model CRC allocation	(h)Scenario Analysis - Model CRC allocation options																																	
1	Step 4	Review BRCP	(g)Analysis of the BRCP																																	
1	Consultation paper		Consultation paper																																	

Purpose of this Session

- In this session we will discuss the appropriate method to set of the Benchmark Reserve Capacity Price (**BRCP**) for each of the two potential capacity products.
- We will also discuss considerations around incentivizing capacity that can cover the overnight duration gap.

6. BRCP for Peak Capacity Product

Current State

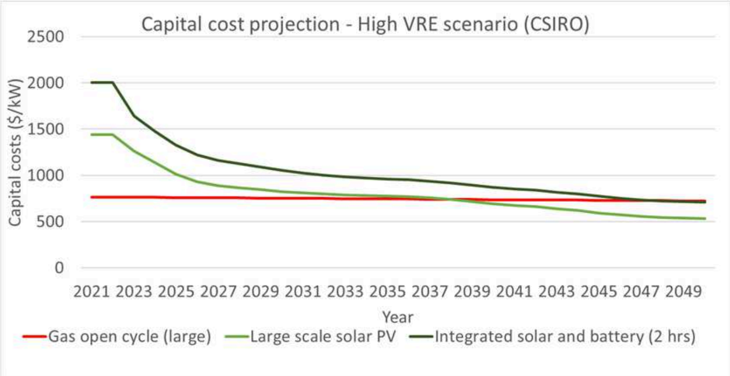
- The BRCP is the anchor for the administered reserve capacity price paid to each provider of capacity.
- Depending on under- or over-supply of capacity, the actual administered capacity price received by each facility may be greater than (up to 130% of) or less than (down to 0% of) the BRCP.
- The WEM Rules used to specify how to determine the BRCP in an appendix, but currently provide little guidance, delegating the method to a WEM Procedure developed and published by the ERA.
- The WEM Procedure defines a specific power station to be used as the basis for the BRCP: a 160MW liquid fueled Open Cycle Gas Turbine (**OCGT**), the configuration of the station, and various commercial and financial parameters that are needed to determine the total capital and fixed operating costs of the facility.
- The capital and fixed operating costs are annualized over a 15 year period, and divided by the expected facility capacity at 41ºC to give a cost per MW of capacity.
- Thus, the BRCP is set at the gross Cost of New Entry (**CONE**) for a liquid fueled OCGT.

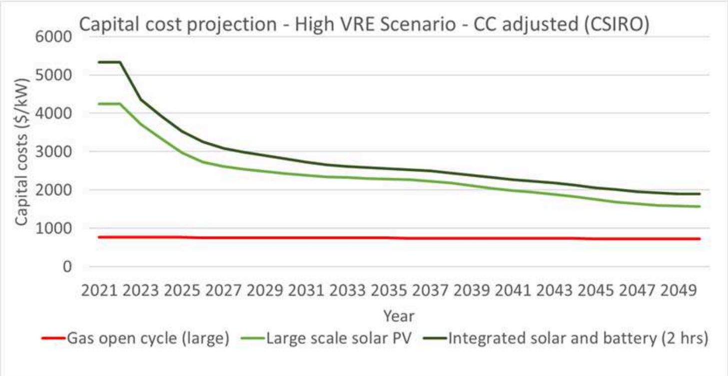
Principles for Setting the BRCP

- The WEM Rules should provide guidance or a high level methodology for the BRCP.
- The details of the BRCP determination can be delegated to a WEM Procedure.
- Together, the WEM market components must provide a means for providers of market services to recover all their long-run costs – including both capex and opex.
    - It does not guaranteed that inefficient participants will recover long-run costs, but there must at least be a clear view to investors on how an efficient provider would get a return on its investment.
- The BRCP should be set based on the marginal cheapest new entrant provider of new *capacity* – which may not be the same as the marginal provider of *energy*.
- The determination of BRCP must align with the determination of market offer and price caps.

What will the Marginal Capacity Provider Be?

- CSIRO forecasts that, while wind and solar have the lowest $/MWh cost, OCGT will continue to have the lowest $/MW cost until some time in the 2030s.
- When adjusting variable renewables to account for capacity derating, OCGT continues to be the lowest $/MW cost capacity provider until 2050, unless something else (e.g. government policy, fuel availability or network congestion in possible locations) means that no new facilities of that type can be built.





- Proposal: the WEM Rules define the BRCP as the per MW capex cost of the new entrant technology with the lowest expected capital cost, with the ERA to set the reference facility every 5 years.
  - This means the reference technology will continue to be set based on OCGT technology until it is no longer credible that a new OCGT could be built in an uncongested part of the network.
  - If BRCP were to be set based on a more expensive technology *while OCGT can still be built*, OCGT would still be the cheapest new entrant, and be overcompensated for its costs.

Gross CONE or Net CONE

- The Market Power Mitigation Review is proposing that the Max STEM Price be set based on the highest short run cost facility in the fleet, with ESS offer caps set at the highest enablement cost for any of the five services, with opportunity cost added for settlement. This would allow this facility to recover short-run costs when it runs, but not get a contribution to capital costs.
- At present, the facility with the highest short run costs is also likely to be the facility with the lowest capital costs: an OCGT. Such a facility will rely on the RCM to recover all of its capital costs.
- This means that, in the WEM, gross CONE and net CONE are the same for the marginal provider of capacity as long as it is also the most expensive provider of energy.
- If the marginal capacity provider does not have the highest short-run costs in the fleet, then it will recover some contribution to its capital costs through infra-marginal rents in the energy market, and setting BRCP at gross CONE would overestimate the marginal cost of new capacity entry.
- Proposal:
    - BRCP should be set based on net CONE of the marginal capacity provider.
    - BRCP can continue to be set based on the gross CONE of the marginal new capacity provider as long as its short-run costs are close to the energy market price cap.
    - Consideration of gross vs net CONE to be included in the 5 yearly review of the reference technology.

Future BRCP Review

- For at least the next 5-10 years, OCGT technology has a place in the fleet, and will remain the relevant benchmark for the BRCP.
- At some point, it will no longer be credible that OCGT can be built, or network location considerations may mean that it cannot be built without capacity being derated due to NAQs. When this happens, the BRCP methodology will significantly increase in complexity, to determine the lowest $/MW of capacity on a net CONE basis:
  - after derating for intermittency;
  - accounting for the effect of NAQs; and
  - after deducting expected energy and ESS profits from capital costs.
- Other important considerations may also emerge as the shape and pace of the fleet change becomes clearer.
- The WEM Rules need to provide guidance for the ERA to identify when such a change is likely to be necessary, and the factors that will need to be accounted for – e.g. the size of the representative facility.

7. BRCP for Flexible Capacity Product

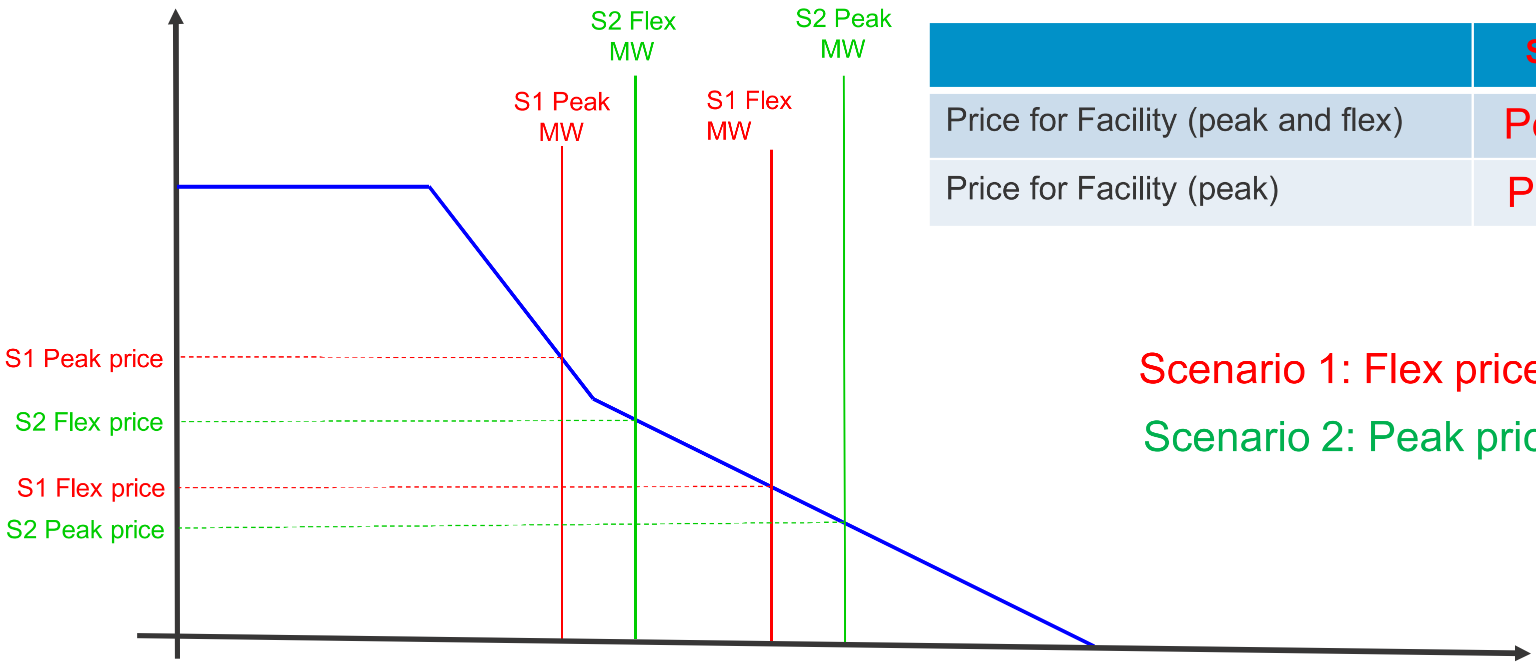
Setting the BRCP for Flexible Capacity Providers

- OCGT facilities are likely to be able to provide flexible capacity as well as peak capacity. Based on the CSIRO data, OCGT will be the cheapest new entrant provider of flexible capacity out to 2050.
- Setting the BRCP for the flexible capacity product higher than OCGT capital costs while OCGT can still be built would see OCGT overcompensated for capacity provision.
- Given that the flexible capacity product is designed for a world where there are no OCGT facilities, one option would be to bar *new* fossil-fuelled facilities from providing flexible capacity.
    - This would depart from the principle of technology neutrality, and the marginal provider would probably be hybrid intermittent/storage.
    - BRCP would need to be set based on Net CONE for such a facility, accounting for expected revenues from energy and ESS, and accounting for the effect of NAQs.
- Proposal:
    - remain technology neutral, and set BRCP for flexible capacity based on the lowest capital cost new entrant provider which can provide this product.
    - Methodology for OCGT flex BRCP to include any additional cost components needed to ensure that the facility is configured for fast start, fast ramping, and low minimum generation.

Interaction between Peak and Flexible Capacity Procurement

- If a facility provides both peak capacity and flexible capacity, it does not need to be compensated for its capital costs for both products (except where there is additional investment required for flex capacity).
- If the same price curves are used for both products, the product with the higher relative shortfall (or lower relative oversupply) will have the higher price.
  - If the reserve margin for flexible capacity is tighter than the reserve margin for peak capacity, the flexible capacity product would have the higher price.
- Setting the facility capacity price for a facility that provides both products at the higher of the two product prices would avoid overcompensation, preserve the pricing signals for both products, and avoid incentives to withhold capacity.
- This would also lend itself to separating costs of procuring the two capacity products into two categories:
  - costs shared across the two products; and
  - costs specific to the higher priced product.

Pricing for Facilities that provide Peak Capacity vs Facilities that provide Peak and Flex Capacity



	Scenario 1	Scenario 2
Price for Facility (peak and flex)	Peak price	Flex price
Price for Facility (peak)	Peak price	Peak price

Scenario 1: Flex price > peak price

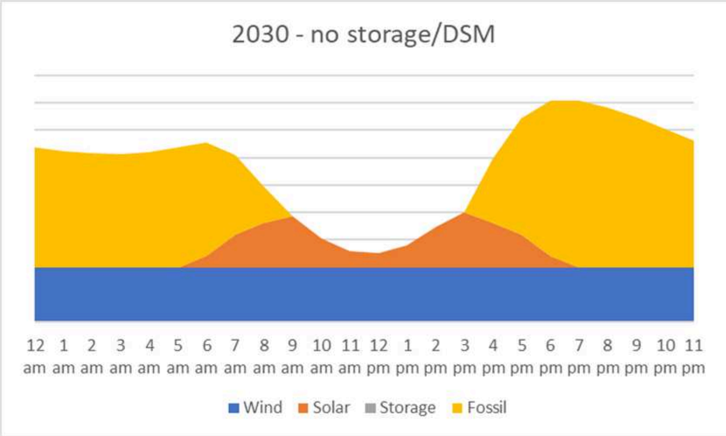
Scenario 2: Peak price > flex price

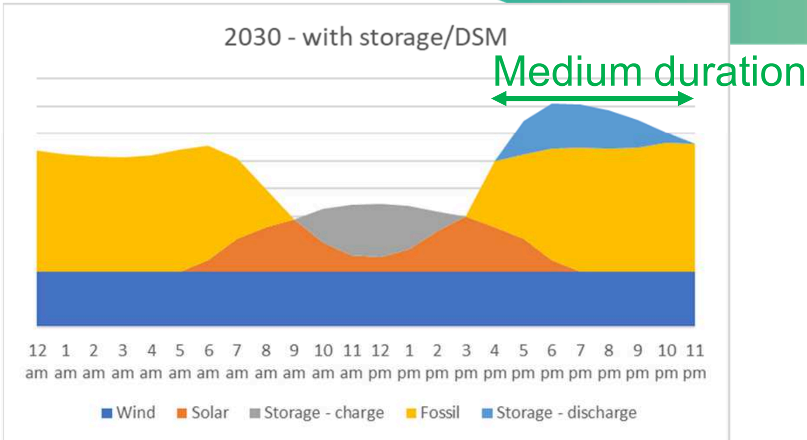
8. Covering the Duration Gap

Recap: Capability Class Proposal

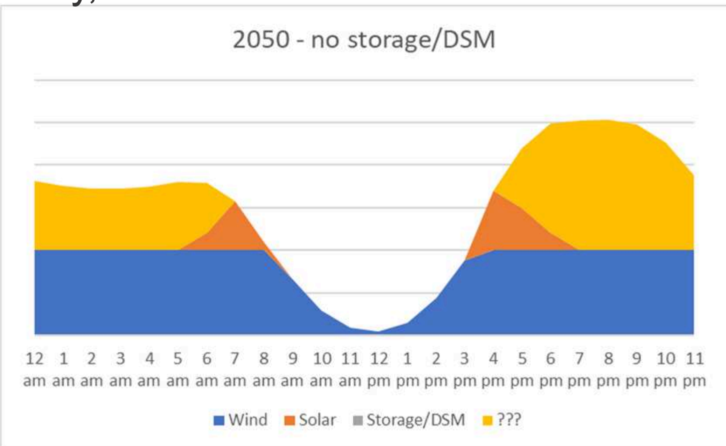
- **Proposal:** Replace availability classes with "capability classes" that better align with firmness of delivery and availability obligations:
  - Class 1: Unrestricted firm capacity (no fuel/availability limitations)
  - Class 2: Restricted firm capacity (fuel/availability limitations)
  - Class 3: Non-firm capacity
- Class 1 and 2 facilities would have availability obligations (and be subject to refunds).
- Class 3 facilities would not have availability obligations, but would expect to have significantly lower CRC than facilities in the other classes.
- Existing and committed facilities in all classes would receive Capacity Credits, but when there is a capacity shortfall, new facilities in lower classes would be preferred to those in higher classes.

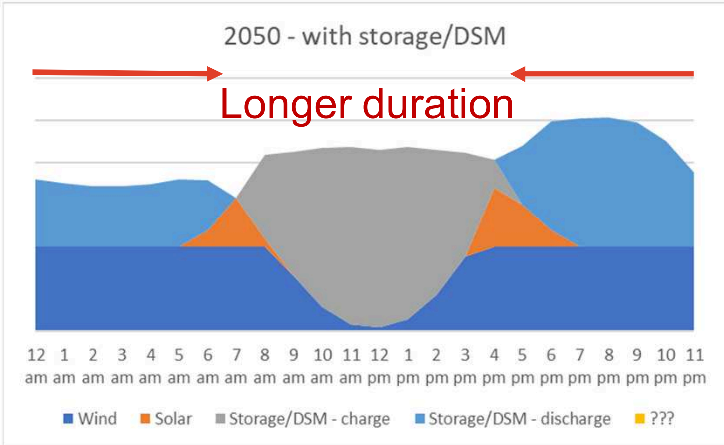
A 100% Renewable Fleet will Operate Differently





Example load shapes and generation output profiles for 2030 and 2050. Illustrative only, does not reflect exact data.





Dealing with the Duration Gap

- System stress modelling showed that – after 2030 – firm capacity duration becomes a key factor in serving load overnight. There will be a 'duration gap' between the end of the evening ramp (when flexible capacity that ramps up to meet the evening peak load may have exhausted its availability) and sunrise (when BTM and grid scale solar ramp up).
- This means that capability Class 2 facilities that cannot maintain output overnight would not be providing the same contribution to system reliability as facilities that can.
- Ideally, the RCM should provide a signal of the needed availability duration as it evolves over the years, and incentive for new entrant facilities to be configured to meet it.
- We can account for availability duration in either the facility capacity price or the quantity of Capacity Credits allocated.

Incentivising Longer Duration Availability

- It is simpler to see a consistent way to differentiate quantities than prices. If not using ELCC method, or only using ELCC for pure intermittent (Class 3) facilities, the RCM would need to specifically address availability duration in capacity certification.
- Proposal:
  - AEMO publishes an availability duration target in the ESOO calculated assuming:
    - Forecast 10% POE day load shape
    - Existing/committed capability Class 1 capacity is fully available
    - Existing/committed capability Class 2 capacity is available per transitional arrangements (next slide)
    - Existing/committed class 3 facilities output per their CRC.
  - Facilities in capability Class 2 are assessed for CRC based on this availability duration, with facilities with less than full availability receiving a prorated CRC (e.g. if target is 10 hours, but facility has 8 hours availability, it would receive 0.8 x CRC).

Does the RCMRWG see better options for incentivising longer duration capacity?

Transitional Arrangements

- Certainty of configuration is important for investment.
- Changing the availability hours after certification can be managed, but extending the expected availability duration after a facility is built would affect the economics of the project by potentially reducing the number of Capacity Credits held.
- To support investment certainty, existing Class 2 facilities within 5 years of commissioning could be allocated CRC based on the availability duration applied when they were first certified.
- These facilities would be accounted for in setting the duration target for future years (previous slide).

9. Next Steps

Next Steps

- MAC discussion on consultation paper content (late August)
- Consultation paper end of August
- Questions or feedback can be emailed to energymarkets@energy.wa.gov.au

10. General Business

We're working for Western Australia.