Government of **Western Australia**
Energy Policy WA

Meeting Agenda

Meeting Title:	Market Advisory Committee
Date:	Tuesday 5 April 2022
Time:	9:30 AM – 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	5 min
3	Minutes of Meeting 2021_03_01	Chair	Decision	5 min
4	Action Items	Chair	Discussion	5 min
5	Market Development Forward Work Program	Chair/Secretariat	Discussion	5 min
6	Update on Working Groups			
	(a) AEMO Procedure Change Working Group	AEMO	Discussion	5 min
	(b) RCM Review Working Group	Working Group Chair	Discussion	80 min
7	Rule Changes			
	(a) Overview of Rule Change Proposals	Chair/Secretariat	Noting	5 min
8	General Business	Chair	Discussion	5 min
	Next meeting: Tuesday 17 May 2022			

Please note, this meeting will be recorded.

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Market Advisory Committee (**MAC**)
Date:	1 March 2022
Time:	9:35am – 11:10am
Location:	Videoconference (Microsoft Teams)

Attendees	Class	Comment[1]
Sally McMahon	Chair	
Martin Maticka	Australian Energy Market Operator (**AEMO**)	
Dean Sharafi	AEMO	
Zahra Jabiri	Network Operator	
Genevieve Teo	Synergy	
Paul Keay	Small-Use Consumer Representative	
Noel Schubert	Small-Use Consumer Representative	
Geoff Gaston	Market Customer	
Timothy Edwards	Market Customer	
Patrick Peake	Market Customer	
Wendy Ng	Market Generator	
Jacinda Papps	Market Generator	
Rebecca White	Market Generator	
Paul Arias	Market Customer	
Peter Huxtable	Contestable Customer	
Noel Ryan	Observer appointed by the Minister	
Sara O'Connor	Observer appointed by the Economic Regulation Authority (**ERA**)	Proxy for Rajat Sarawat

Also in Attendance	From	Comment
Tom Frood	Outgoing MAC Member (Market Generator)	Observer
Dora Guzeleva	MAC Secretariat	Observer
Laura Koziol	MAC Secretariat	Observer

Also in Attendance	From	Comment
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	Presenter
Ajith Sreenivasan	RBP	Observer
Apologies	**From**	**Comment**
Rajat Sarawat	ERA	

Item	Subject	Action

1 Welcome

The Chair opened the meeting at 9:35am. She introduced herself as this was her first MAC meeting and noted that she would like to meet members individually.

The Chair continued with an Acknowledgement of Country.

The Chair thanked the outgoing interim Chair, Mr Peter Kolf.

The Chair noted that meetings should only be attended by members, statutory observers and observers with a role in that meeting to encourage effective discussion. Other stakeholders can raise any issues through the appropriate MAC representative or statutory observers.

The Chair reminded members and statutory observers that the MAC must consider the interest of the WEM. The Chair asked members to and relate their views to the interests of the WEM when providing advice.

The Chair welcomed the two newly appointed MAC members Rebecca White and Paul Arias (both representing Market Generators) and the reappointed MAC member Tim Edwards (representing Market Customers).

The Chair thanked the outgoing MAC members Tom Frood and Daniel Kurz for their service.

The Chair advised of two potential conflicts:

1. The Chair is currently the Head of Economic Regulation and Energy Policy at Spark Infrastructure. At this point Spark has no interest and is pursuing no interest in Western Australia. Therefore, the Chair considers that her involvement does not present a conflict of interest.
2. The Chair holds a position as expert panel member on the WA Electricity Review Board. There is a live proceeding between Synergy and the ERA which is yet to conclude. The Chair considered that if the MAC discusses any issues that may be relevant for that case it may present a conflict of interest. The Chair noted that, to manage such potential conflict of interest, she would excuse herself from any such discussion.

The Chair noted that, following the Coordinator's review of the MAC Constitution, the revised constitution has been approved and published on Energy Policy WA's website

Item	Subject	Action
2	**Meeting Apologies/Attendance** The Chair noted the attendance as listed above.	
3	**Minutes of Meeting 2021_12_14** Draft minutes of the MAC meeting held on 14 December 2021 were circulated on 20 December 2021. The MAC accepted the minutes as a true and accurate record of the meeting. **Action: MAC Secretariat to publish the minutes of the 14 December 2021 MAC meeting on the Coordinator's Website as final.**	**MAC Secretariat**
4	**Action Items** The Chair noted there are no open action items.	
5	**Market Development Forward Work Program** The paper was taken as read. The following issue was discussed: • Mr Martin Maticka suggested to close item 22 because most of the issue had been addressed through the changes to the relevant WEM Procedure: Prudential Requirements, that would be discussed under agenda item 6a. Mr Maticka noted that the market mechanisms will change substantially at the start of the new WEM next year. Mr Geoff Gaston considered that item 22 should be left open and be revisited in six months. Mr Gaston noted that the procedure change only addressed part of the issue and that the new market was already delayed by another 12 months. The Chair asked Mr Gaston to specify his concerns. Mr Gaston replied, that addressing the remaining issue will require a complex rule change and that his concern is that such a change would take too long considering that the new market is to commence in about 18 months. The Chair suggested to meet with Mr Gaston and Mr Maticka offline to determine the outstanding issue and amend issue 22 accordingly. **Action: The Chair, Mr Maticka and Mr Gaston to meet to discuss Id 22**	**Chair, AEMO and Mr Gaston**
6	**Update on Working Groups**	
	(a) AEMO Procedure Change Working Group (APCWG) Mr Martin Maticka noted that AEMO received one submission on its Procedure Change Proposal AEPC_2021_04, that sought changes to the WEM Procedure: Prudential Requirements. The procedure change commenced on 28 February 2022 and will apply to AEMO's current biannual credit limit review.	

Item	Subject	Action
	Mr Maticka advised that AEMO has appointed Mike Hales as the new Chair of the APCWG.	
	(b) RCM Review Working Group (RCMRWG) Ms Dora Guzeleva noted that the Reserve Capacity Mechanism Review Working Group that had been established on 2 November 2021, included 15 members and that the two meetings in January and February 2022 had been very effective. Ms Guzeleva advised that Energy Policy WA engaged Robinson Bowmaker Paul to support the RCM Review. Ms Guzeleva emphasised that the intent for the modelling is to test and inform RCM Review decisions and the RCM design and that it is not practical to duplicate the Whole of System Plan within the timeframe of the RCM Review. Mr Richard Bowmaker form RBP presented a summary of the proposed modelling methodology, assumptions and scenarios for the RCM Review. The following key issues were discussed: • Mr Bowmaker noted that he would not present the appendices of the presentation, but would be available to answer any questions on those. • Mrs Jacinda Papps commented that the RCM should be reviewed in conjunction with the Energy Price Limits because she considered this is important for the overall revenue adequacy for generators. Ms White and Ms Wendy Ng supported Mrs Papps view. Ms White asked how the modelling for the RCM Review will interact with Essential System Services (**ESS**) price limits that will be assessed as part of the market power mitigation workstream. Ms Guzuleva noted that Energy Policy WA was about to commence its work on the market power mitigation strategy that included a review of the Energy Price Limits. This project will run in parallel with the RCM Review and Energy Policy WA will ensure consistency between the modelling for both reviews. The RCM Review will be one step ahead allowing the modelling from the RCM Review to inform the market power mitigation work. Ms Guzeleva noted that the Energy Transformation Taskforce made some proposals in regards to price limits for ESS that would be taken into account and that the idea is to always have sufficient room below both the energy and the ESS price limits. Ms Guzeleva noted that Energy Policy WA will consult at least twice on the market power mitigation work through the Transformation Design and Operation Working Group (**TDOWG**) and that the MAC will be fully informed.	

Item	Subject	Action
	The Chair noted that she will discuss documenting the interaction between the RCM Review and the market power mitigation work with Ms Guzeleva offline. • Mr Dean Sharafi noted that system security issues other than generation adequacy should be addressed through the RCM. Mr Bowmaker noted that different types of system stress will be assessed as part of the RCM Review as per slide 11. • Mr Patrick Peak asked whether other financial inputs such as renewable energy certificate costs or government subsidies are considered for the modelling. Mr Bowmaker confirmed that such inputs will be considered. • Ms White asked whether regulatory costs such as market fees and network charges are considered in the modelling. Mr Bowmaker confirmed that these costs will be considered under fixed or variable costs. • Ms Ng asked how the model will decide what type of plants to build and which plants retire. Mr Bowmaker clarified that the model will assess which of a variety of different technologies is the most likely to enter or exit at each point. Ms Guzeleva noted that, as per the scope of works, the review will not look at particular technologies but at the capabilities of technologies that would be required to fill any potential deficiencies. Therefore, any assumptions about retirement and build decisions will not be based on the technologies but on their capabilities. Mr Peake noted that if revenue is not considered adequate by an investor, plant could be moved to a different location. For example Perth Energy's gas turbines can be moved fairly easy if they are not getting the required revenue. Mr Bowmaker noted that from a modelling perspective such a scenario meant the plant would leave the market. • Mrs Papps noted that the certification requirement for Scheduled Generators to demonstrate sufficient fuel contracts and transport arrangements to maintain 14 hours of continuous operation imposes high costs on Market Generators. Mrs Papps considered that it should be assessed whether the 14-hour fuel requirement was still appropriate. Ms Guzeleva noted that the 14-hour fuel requirement will be assessed as part of the development of the method(s) to assign Certified Reserve Capacity (**CRC**). She also noted that the ideal is to design one method to assign CRC for all technologies.	

Item	Subject	Action
	• The Chair asked how the costs of pipeline transport are considered in the model. Mr Bowmaker clarified that the gas prices considered are delivered prices and include the transport costs. The Chair considered that based on the discussion the following issues need to be addressed and documented: • clarification whether the modelling is based on the current, transitional or future state of the industry; • the impact of the RCM Review on Energy Policy WA's market power mitigation work; and • whether all relevant causes of system stress are covered by the RCM Review. Ms Guzeleva noted that: • the modelling will include the current, the transitional and the future state of the industry; • the outcome of the modelling for the RCM Review will feed into the market power mitigation work and the modelling will have to commence to inform a more fulsome discussion on how the two projects relate; and • the RCM Review will assess the various types of system stress outlined in the scope of works and the presentation. The MAC supported the proposed modelling methodology, assumptions and scenarios for the RCM Review. **Action: The Chair and Ms Guzeleva to discuss documenting any interaction between the RCM Review and the market power mitigation work.**	**Chair and Ms Guzeleva**
7	**Rule Changes**	
	(a) Overview of Rule Change Proposals The paper was taken as read.	
8	**Revised Schedule of MAC Meetings for 2022** The MAC approved the revised meeting schedule.	
11	**General Business** Mr Maticka advised that AEMO published the revised timeline for the 2022 Reserve Capacity Cycle and thanked stakeholders who made a submission during the related consultation. The Chair agreed to provide her email address to members and encouraged members to include her in relevant email correspondence with the MAC Secretariat. (Members, please note that the Chair e-mail address is included in the invites for the MAC meetings and published on EPWA's website as part of the MAC membership list here: https://www.wa.gov.au/government/document-collections/market-advisory-committee)	

The meeting closed at 11:35 am.

Government of **Western Australia**
Energy Policy WA

Agenda Item 4: MAC Action Items

Market Advisory Committee (**MAC**) Meeting 2022_04_05

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
1/2022	MAC Secretariat to publish the minutes of the 14 December 2021 MAC meeting on the Coordinator's Website as final.	MAC Secretariat	2022_03_01	**Closed** The minutes were published on the Coordinator's Website on 8 March 2022.
2/2022	MAC Chair, Mr Maticka and Mr Gaston to meet to discuss Id 22 from the Market Development Forward Work Program.	MAC Chair, AEMO and Mr Gaston	2022_03_01	**Open** The Chair, Mr Maticka and Mr Gaston are to meet on 29 March 2022.
3/2022	MAC Chair and Ms Guzeleva to discuss documenting any interaction between the RCM Review and the market power mitigation work.	MAC Chair and Ms Guzeleva	2022_03_01	**Closed** Any interaction between the RCM Review and the market power mitigation work will be documented in the respective consultation papers expected to be published in close proximity in July/August 2022.

Government of Western Australia
Energy Policy WA

Agenda Item 5: Market Development Forward Work Program

Market Advisory Committee (**MAC**) Meeting 2022_04_05

1. Purpose

- To provide an update on the Market Development Forward Work Program provided in Table 1, including:
    - The Chair of the Reserve Capacity Review Working Group (RCMRWG) is to update the MAC on the work done by the Working Group to date – see Agenda Item 6(b).
    - EPWA has identified a preferred bidder for the consultancy services to assist with the Cost Allocation Review and will make an appointment for this consultancy in the near future.
- To provide an update on other issues to be addressed via the Market Development Forward Work Program provided in Table 4:
    - The MAC Chair is to provide an update following a meeting, scheduled for 29 March 2022, between the MAC Chair, AEMO and Mr Gaston to discuss whether Issue 22 has been adequately addressed.
- Changes to the Market Development Forward Work Program provided at the previous MAC meeting are shown in red font in the Tables below.

2. Recommendation

The MAC Secretariat recommends that the MAC reviews and discusses the updates to the Market Development Forward Work Program.

3. Process

Stakeholders may raise issues for consideration by the MAC at any time by sending an email to the MAC Secretariat at energymarkets@energy.wa.gov.au.

Stakeholders should submit issues for consideration by the MAC two weeks before a MAC meeting so that the MAC Secretariat can include the issue in the papers for the MAC meeting, which are circulated one week before the meeting.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
RCM Review	A review of the RCM, including a review of the Planning Criterion.	• The MAC has established the RCM Review Working Group. Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group, including: ○ the Scope of Works for the review, as approved by the Coordinator; ○ the Terms of Reference for the Working Group, as approved by the MAC; ○ the list of Working Group members; ○ meeting papers and minutes from the Working Group meeting on 20 January 2022 and 17 February 2022; and ○ meeting papers for the Working Group meeting on 17 March 2022. • The Chair of the Working Group will update the MAC on the work done by the Working Group to date. The Chair will advise the MAC on the Working Group's review of the reserve capacity mechanisms in other jurisdictions and will give the MAC further opportunity to provide input into the learnings from that review that might be applied in the WEM – see Agenda Item 6(b).
Cost Allocation Review	A review of: • the allocation of Market Fees, including behind the meter (**BTM**) and Distributed Energy Resources (**DER**) issues; • cost allocation for Essential System Services; and • Issues 2, 16, 23 and 35 from the MAC Issues List (see Table 3).	• The MAC has established the Cost Allocation Review Working Group. Information on the Working Group is available at https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group, including: ○ the Scope of Work for the review, as approved by the Coordinator; and ○ the Terms of Reference for the Working Group, as approved by the MAC. • EPWA has identified a preferred bidder for the consultancy services to assist with the Cost Allocation Review and will make an appointment for this consultancy in the near future. • The first meeting of the Working Group will take place in April 2022.

Table 1 – Market Development Forward Work Program		
Review	**Issues**	**Status and Next Steps**
Procedure Change Process Review	A review of the WEM Procedure Change Process to address issues identified through Energy Policy WA's consultation on governance changes.	• This review will commence in mid-2022.
Forecast quality	Review of Issue 9 from the MAC Issues List (see Table 4).	• This review has been deferred.
Network Access Quantity (**NAQ**) Review	Assess the performance of the NAQ regime, including policy related to replacement capacity, and address issues identified during implementation of the Energy Transformation Strategy (ETS).	• This review will be commenced after completion of the RCM Review.
Short Term Energy Market (**STEM**) Review	Review the performance of the STEM to address issues identified during implementation of the ETS.	• This review has been deferred.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
1	Shane Cremin November 2017	**IRCR calculations and capacity allocation** There is a need to look at how IRCR and the annual capacity requirement are calculated (i.e. not just the peak intervals in summer) along with recognising BTM solar plus storage. The incentive should be for retailers (or third-party providers) to reduce their dependence on grid supply during peak intervals, which will also better reflect the requirement for conventional 'reserve capacity' and reduce the cost per kWh to consumers of that conventional 'reserve capacity'.	To be considered in the RCM Review.
3	Shane Cremin November 2017	Penalties for outages.	To be considered in the RCM Review.
4	Shane Cremin November 2017	Incentives for maintaining appropriate generation mix.	To be considered in the RCM Review.
14/36	Bluewaters and ERM Power November 2017	**Capacity Refund Arrangements:** The current capacity refund arrangement is overly punitive as Market Participants face excessive capacity refund exposure. This refund exposure is well more than what is necessary to incentivise the Market Participants to meet their obligations for making capacity available. Practical impacts of such excessive refund exposure include: • compromising the business viability of some capacity providers – the resulting business interruption can compromise reliability and security of the power system in the SWIS; and • excessive insurance premiums and cost for meeting prudential support requirements.	To be considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
		Bluewaters recommended imposing seasonal, monthly and/or daily caps on the capacity refund. Bluewaters considered that reviewing capacity refund arrangements and reducing the excessive refund exposure is likely to promote the Wholesale Market Objectives by minimising: • unnecessary business interruption to capacity providers and in turn minimising disruption to supply availability; which is expected to promote power system reliability and security; and unnecessary excessive insurance premium and prudential support costs, the saving of which can be passed on to consumers.	
30	Synergy November 2017	**Reserve Capacity Mechanism** Synergy would like to propose a review of WEM Rules related to reserve capacity requirements and reserve capacity capability criteria to ensure alignment and consistency in determination of certain criteria. For instance: • assessment of reserve capacity requirement criteria, reserve capacity capability and reserve capacity obligations; • IRCR assessment; • Relevant Demand determination; • determination of NTDL status; • Relevant Level determination; and • assessment of thermal generation capacity. The review will support Wholesale Market Objectives (a) and (d).	To be considered in the RCM Review.

Table 2 – Issues to be Addressed in the RCM Review			
Id	**Submitter/Date**	**Issue**	**Status**
56	Perth Energy July 2019	**Issues with Reserve Capacity Testing** • Market Generators that fail a Reserve Capacity Test may prefer to accept a small shortfall in a test (and a corresponding reduction in their Capacity Credits) than to run a second test. • There is a discrepancy between the number of Trading Intervals for self-testing vs. AEMO testing. • There is ambiguity in the timing requirements for a second test when the relevant generator is on an outage. There is ambiguity on the number of Capacity Credits that AEMO is to assign when certain test results occur.	To be considered in the RCM Review (except that the first bullet may be out scope, in which case it will be added to Table 4).
58	MAC October 2019	**Outage scheduling for dual-fuel Scheduled Generators** '0 MW' outages are currently used to notify System Management when a dual-fuel Scheduled Generator is unable to operate on one of its nominated fuels. There is no explicit obligation in the WEM Rules or the Power System Operation Procedure: Facility Outages to request/report outages that limit the ability of a Scheduled Generator to operate using one of its fuels. In terms of the provision of sent out energy (the service used to determine Capacity Cost Refunds), it is questionable whether this situation qualifies as an outage at all. More generally, the WEM Rules lack clarity on the nature and extent of a Market Generator's obligations to ensure that its Facility can operate on the fuel used for its certification, what (if anything) should occur if these obligations are not met, and the implications for outage scheduling and Reserve Capacity Testing. • (See section 7.2.2.5 of the Final Rule Change Report for RC_2013_15.)	To be considered in the RCM Review (or may be out of scope, in which case it will be added to Table 4).

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
2	Shane Cremin November 2017	Allocation of market costs – who bears Market Fees and who pays for grid support services with less grid generation and consumption?	To be considered in the Cost Allocation Review.
16	Bluewaters November 2017	BTM generation is treated as reduction in electricity demand rather than actual generation. Hence, the BTM generators are not paying their fair share of the network costs, Market Fees and ancillary services charges. Therefore, the non-BTM Market Participants are subsiding the BTM generation in the WEM. Subsidy does not promote efficient economic outcome. Rapid growth of BTM generation will only exacerbate this inefficiency if not promptly addressed. Bluewaters recommends changes to the WEM Rules to require BTM generators to pay their fair share of the network costs, Market Fees and ancillary services charges. This is an example of a regulatory arrangement becoming obsolete due to the emergence of new technologies. Regulatory design needs to keep up with changes in the industry landscape (including technological change) to ensure that the WEM continues to meet its objectives. If this BTM issue is not promptly addressed, there will be distortion in investment signals, which will lead to an inappropriate generation facility mix in the WEM, hence compromising power system security and in turn not promoting the Wholesale Market Objectives.	To be considered in the Cost Allocation Review.
23	Bluewaters November 2017	Allocation of Market Fees on a 50/50 basis between generators and retailers may be overly simplistic and not consider the impacts on economic efficiency. In particular, the costs associated with an electricity market reform program should be recovered from entities based on the benefit they receive from the	To be considered in the Cost Allocation Review.

Table 3 – Issues to be Addressed in the Cost Allocation Review			
Id	**Submitter/Date**	**Issue**	**Status**
		reform. This is expected to increase the visibility of (and therefore incentivise) prudence and accountability when it comes to deciding the need and scope of the reform. Recommendations: to review the Market Fees structure including the cost recovery mechanism for a reform program. The cost saving from improved economic efficiency can be passed on to the end consumers, hence promoting the Wholesale Market Objectives.	
35	ERM Power November 2017	**BTM generation and apportionment of Market Fees, ancillary services, etc.** The amount of solar PV generation on the system is increasing every year, to the point where solar PV generation is the single biggest unit of generation on the SWIS. This category of generation has a significant impact on the system and we have seen this in terms of the daytime trough that is observed on the SWIS when the sun is shining. The issue is that generators that are on are moving around to meet the needs of this generation facility but this generation facility, which could impact system stability, does not pay its fair share of the costs of maintaining the system in a stable manner. That is, they are not the generators that receive its fair apportionment of Market Fees and pay any ancillary service costs but yet they have absolute freedom to generate into the SWIS when the fuel source is available. There needs to be equity in this equation.	To be considered in the Cost Allocation Review.

Table 4 – Other Issues

Id	Submitter/Date	Issue	Status
9	Community Electricity November 2017	Improvement of AEMO forecasts of System Load; real-time and day-ahead.	Consideration of this issue has been deferred.
22	Bluewaters November 2017	Prudential arrangement design issue: clause 2.37.2 of the WEM Rules enables AEMO to review and revise a Market Participant's Credit Limit at any time. It is expected that AEMO will review and increase Credit Limit of a Market Participant if AEMO considers its credit exposure has increased (for example, due to an extended plant outage event). In response to the increase in its credit exposure, clause 2.40.1 of the WEM Rules and section 5.2 of the Prudential Procedure allow the Market Participant to make a voluntary prepayment to reduce its Outstanding Amount to a level below its Trading Limit (87% of the Credit Limit). Under the current WEM Rules and Prudential Procedure, AEMO can increase the Market Participant's Credit Limit (hence increasing its prudential support requirement) despite that a prepayment has already been paid (it is understood that this is AEMO's current practice). The prepayment would have already served as an effective means to reduce the Market Participant's credit exposure to an acceptable level. Increasing the Credit Limit in addition to this prepayment would be an unnecessary duplication of prudential requirement in the WEM. This unnecessary duplication is likely to give rise to higher-than-necessary prudential cost burden in the WEM; which creates economic inefficiency that is ultimately passed on the end consumers.	Action Item 2/2022 from MAC_2022_03_01 was for the MAC Chair, AEMO and Mr Gaston to meet discuss and to advise if this item has been adequately addressed. This meeting is to occur on 29 March 2022. An update will be provided by the MAC Chair at the 5 April 2022 meeting. AEMO is considering this issue via Procedure Change Proposal AEPC_2021_04. AEMO will discuss this matter under Agenda Item 6(a). At its meeting on 21 September 2021, the MAC agreed to keep Issue 22 open until it is clear whether AEMO's Procedure Change Proposal to amend the WEM Procedure: Prudential Requirements will address all of Issue 22.

Table 4 – Other Issues			
Id	**Submitter/Date**	**Issue**	**Status**
		Recommendation: amend the WEM Rules and/or procedures to eliminate the duplication of prudential burden on Market Participants. The resulting saving from eliminating this unnecessary prudential burden can be passed on to end consumers. This promotes economic efficiency and therefore the Wholesale Market Objectives.	

MARKET ADVISORY COMMITTEE MEETING, 5 April 2022

FOR NOTING

SUBJECT: UPDATE ON AEMO'S MARKET PROCEDURES

AGENDA ITEM: 6(A)

1. PURPOSE

Provide a status update on the activities of the AEMO Procedure Change Working Group and AEMO Procedure Change Proposals.

2. AEMO PROCEDURE CHANGE WORKING GROUP (APCWG)

	Most recent meetings	**Next meeting**
Date	30 November 2021	TBC
Market Procedures for discussion	Market Procedure: Prudential Arrangement	TBC

3. AEMO PROCEDURE CHANGE PROPOSALS

The status of AEMO Procedure Change Proposals is described below, current as at 5 April 2022. Changes since the previous MAC meeting are in red text. A procedure change is removed from this report after its commencement has been reported or a decision has been taken not to proceed with a potential Procedure Change Proposal.

ID	**Summary of changes**	**Status**	**Next steps**	**Indicative Date**
None				

Government of Western Australia
Energy Policy WA

Agenda Item 6(b): Update on the RCM Review Working Group

Market Advisory Committee (**MAC**) Meeting 2022_04_05

1. Purpose

- The Chair of the Reserve Capacity Review Working Group (**RCMRWG**) is to update the MAC on the activities of the RCMRWG since the last MAC meeting, including the outcome of the review of international capacity mechanisms.
- The MAC is to provide any additional comments on aspects of the review of international reserve capacity mechanisms that should be taken into account in the RCM Review.

2. Recommendation

That the MAC:

(1) notes the minutes from the RCMRWG meeting on 17 February 2022;

(2) notes and discusses the update on the RCMRWG meeting on 17 March 2022, including:

  (a) the RCMRWG's discussion of the review of international capacity mechanisms;

  (b) the RCMRWG's comments on the international review; and

(3) notes that the Energy Security Board (**ESB**) released a report summarising similar international case studies of reserve capacity mechanism following the RCMRWG meeting;

(4) provides any additional comments on aspects of the review of international reserve capacity mechanisms that should be taken into account in the RCM Review.

3. Process

- The MAC established the RCMRWG to support the Coordinator's review of the Reserve Capacity Mechanism (**RCM**) under clause 2.2D.1 of the WEM Rules.
- On 20 January 2022, the RCMRWG discussed the structure of the RCM Review (outcomes were discussed at the 1 March 2022 MAC meeting).
- On 17 February 2022, the RCMRWG discussed the modelling methodology, assumptions and scenarios for the RCM Review (see **Attachment 1** for the minutes of this RCMRWG meeting) and the MAC supported the modelling methodology, assumptions and scenarios at its meeting on 1 March 2022.
- On 17 March 2022, the RCMRWG discussed outcomes from the international review of reserve capacity mechanisms and the detailed modelling assumptions (see **Attachment 2** for a summary of the international review outcomes and the RCMRWG discussions).

- The main part of Attachment 2 will be presented at the MAC meeting on 5 April 2022. The purpose of this presentation is to:
  - inform MAC of the outcomes of the research;
  - inform MAC of the comments made and discussion held in the working group; and
  - provide an opportunity for MAC to provide additional comments, if desired.
- The Appendix in the slides will be taken as read. The slides contain a significant amount of information – MAC members are expected to have read these slides before the meeting and will be invited to provide comments/views during the presentation of the main part of the slides.

Further information on the RCM Review is available on the RCM Review webpage at https://www.wa.gov.au/government/document-collections/reserve-capacity-mechanism-review-working-group.

4. Background

The Terms of Reference for the Reserve Capacity Mechanism review included a literature review:

> *Review of RCM arrangements in other markets and what they aim to address, which problems their electricity systems are facing or are expected to face in the future, and whether/how these arrangements and issues relate to the WEM. Jurisdictions to be investigated include: UK, PJM, and any other jurisdictions identified by the MAC or Energy Policy WA.*

Since the last MAC meeting, the RCWRWG met on 17 March 2022 to discuss the outcomes of the international review of reserve capacity mechanisms and the detailed modelling assumptions.

The RCMRWG provided feedback on the international review and the detailed modelling assumptions. Attachment 2 provides an update to the MAC on the progress of the RCM Review since the last MAC meeting.

The Chair of the RCMRWG is seeking MAC's comments on the international review.

The MAC is also asked to note that, on 25 March 2022, the ESB released a report summarising similar international case studies of reserve capacity mechanism. A copy of this report is provided to the MAC for information (**Attachment 3**).

5. Attachments

(1) RCMRWG 2022_03_20 – Minutes of Meeting

(2) Reserve Capacity Mechanism Review – MAC Update

(3) Energy Security Board – Capacity Mechanism – Summary of International Case Studies (March 2022)

Government of **Western Australia**
Energy Policy WA

Minutes

Meeting Title:	Reserve Capacity Mechanism Review Working Group (**RCMRWG**)
Date:	17 February 2022
Time:	9:35am – 11:20am
Location:	Microsoft TEAMS

Attendees	Company	Comment
Dora Guzeleva	Chair	
Dimitri Lorenzo	Bluewaters Power	Proxy for Paul Aires
Rhiannon Bedola	Synergy	
Oscar Carlberg	Alinta Energy	Subject matter expert (**SME**) Until 11:00am
Manus Higgins	AEMO	
Sumeet Kaur	Shell Energy	
Sam Lei	Alinta Energy	SME
Mark McKinnon	Western Power	
Wendy Ng	Shell Energy	To replace Sumeet Kaur in the future
Patrick Peake	Perth Energy	
Jacinda Papps	Alinta Energy	
Toby Price	AEMO	SME
Matt Shahnazari	Economic Regulation Authority	
Noel Schubert	MAC Small-Use Consumer representative	Observer
Andrew Stevens	Clear Energy	
Dev Tayal	Tesla Energy	
Andrew Walker	South32 (Worsley Alumina)	
Dale Waterson	Merredin Energy	
Rebecca White	Collgar Wind Farm	
Richard Bowmaker	Robinson Bowmaker Paul (**RBP**)	
Isaac Grumbrell	RBP	
Ajith Sreenivasan	RBP	

Tim Robinson	RBP	
Stephen Eliot	Energy Policy WA (**EPWA**)	
Laura Koziol	EPWA	

Apologies	From	Comment
Peter Huxtable	Water Corporation	
Paul Arias	Bluewaters Power	

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_01_20** Draft minutes of the RCMRWG meeting held on 20 January 2022 were circulated on 4 February 2022. The Chair noted that a revised draft of the minutes showing some changes was distributed in the meeting papers. The RCMRWG accepted the revised minutes as a true and accurate record of the meeting. **Action:** RCMRWG Secretariat to publish the minutes of the 20 January 2021 RCMRWG meeting on the RCMRWG web page as final.	**RCMRWG Secretariat**
4	**Reliability, resource adequacy and the RCM** Mr Tim Robinson presented a slide on grid reliability. The following key points were discussed: • Mr Robinson noted that the lack of flexibility could be addressed by incentivising flexible facilities. The question is if such incentives should be facilitated via the Essential System Services (**ESS**) market or the Reserve Capacity Mechanism (**RCM**). Mr Matt Shahnazari noted that capacity mechanisms conventionally aim to address system adequacy, not flexibility and indicated that it is questionable whether the conventional approach should change. Mr Shahnazari cautioned against using a single market mechanism to address different services. The Chair noted that the scope of the RCM Review included assessing the potential lack of flexibility and whether it should be addressed through the RCM.	

Item	Subject	Action
	Mrs Jacinda Papps noted that the ESS markets do not currently include a ramping service or fast frequency response and that those services need to be captured either in the ESS or in the RCM. Mrs Papps considered that the RCM would provide more long-term certainty for investors. Mr Shahnazari commented that the WEM Rules allow for the addition of new ESS, including ramping services, either through proposing new services or procuring those services through the supplementary ESS mechanisms. • Ms Rebecca White suggested adding resource location to the elements of resource adequacy.	
5	**Modelling methodology** Mr Richard Bowmaker presented the proposed modelling methodology. The following key points were raised: • Mr Bowmaker clarified that changes in demand including those driven by climate change would be considered as part of the underlying demand forecast. Mr Bowmaker clarified that the RCMRWG will discuss the assumptions for adjusting historic demand to derive future demand profiles before the modelling is commenced. The Chair noted that it is intended for the modelling to test and inform RCM Review decisions and that it is not practical to repeat the Whole of System Plan or to predict the outcomes of multiple scenarios based on multiple future drivers (i.e. climate change, electrification, etc.) within the timeframe of the RCM Review. Ms White noted that different scenarios for charging electric vehicles (EVs) may lead to very different outcomes. Mrs Rhiannon Bedola noted that the behaviour of distributed energy resources (DER) would largely be driven by the tariff structure. The Chair emphasised that the timeline for the RCM Review would not allow modelling of all permutations of plausible scenarios. The Chair noted that the objective is to assess how the RCM can cope with a small number of key scenarios. However, demand will play an important role in the analysis. • Mr Manus Higgins noted that AEMO is preparing a document for the working group to provide detailed insights into the system stresses that AEMO is observing. • Mr Bowmaker indicated that start-up times will be considered when setting the modelling inputs and assumptions.	

Item	Subject	Action
	• Mr Bowmaker clarified that the system adequacy modelling will assess if there is sufficient capacity for each Trading Interval and the dispatch model will then look at the availability of types of capacity on an interval-to-interval basis. • Mr Patrick Peake noted that the objective of the RCM Review is to find a mechanism to ensure the required reliability. • Mr Lei noted that any modelling using historic generation data will need to be adjusted for any dispatch of the Generator Interim Access (**GIA**) facilities. • Mr Bowmaker clarified that the goal of the analysis is to identify the system needs based on the demand forecast and then to assess how much of the needed capabilities are available and how to model them. The model will assess each type of facility separately without any grouping. • Mr Lei suggested to include a scenario with extremely high volatility in DER / demand, not only scenarios with extremely high peak demand. Mr Robinson noted that DER was modelled separately from underlying demand. • Mr Shahnazari suggested that the RCM Review should first define the capacity product and then assess how the capacity of the current fleet would address the identified system stress events. The other question is if the system stress events can be addressed while meeting the net zero emissions target. • The Chair noted that one objective of the RCM Review is to define the required capacity product. • Mr Peak noted that year-to-year Reserve Capacity Price fluctuations may disincentivise investment. Mr Robinson noted that an option that may be investigated is to allow new facilities to lock in a price for several years. • The Chair clarified that the analysis will be based on current policy. Therefore, a proxy carbon price will not be considered.	

6	**Modelling assumptions (including scenarios)**
	Mr Bowmaker presented the modelling assumptions and scenarios. The following points were made:
	• The Chair clarified that:
	    ○ the references to solar and wind generation should be replaced with references to low-emissions generation; and
	    ○ any references to storage did not necessarily mean batteries but could include any type of storage.	

Item	Subject	Action
	• Mr Bowmaker confirmed that all assumptions and inputs will be adjusted to reflect the latest information available. • Mrs Papps considered that the certification requirement for Scheduled Generators to demonstrate sufficient fuel contracts and transport arrangements to maintain 14 hours of continuous operation imposes unnecessary high costs on Market Generators, as run-times are currently shorter. Mrs Papps asked if this requirement would be assessed as part of the review. • The Chair noted that the 14-hour fuel requirement will be assessed as part of the development of the method(s) to assign Certified Reserve Capacity (**CRC**). The Chair noted that the ideal is to design one method to assign CRC for all technologies. • Mr Bowmaker noted that the modelling would assume that any needed transmission network augmentation will be built as required, so it will not need to be modelled. • Mrs Papps indicated that Alinta is willing to confidentially share with EPWA some of the recent experience about the costs of connecting a new facility to the network. • There was discussion about different studies on the value of lost load (**VOLL**). Mr Mark McKinnon agreed to report Western Power's assumptions about VOLL from the recent access arrangements to EPWA. Mrs Papps noted that the Brattle Group had published a relevant report few years ago. Mr Shahnazari noted that the Public Utilities Office had published a relevant report a few years ago. Mr Shubert noted that the political value of lost load is different than the economic value of lost load.	
	Action: Mark McKinnon to share Western Power's assumptions about VOLL from the recent access arrangement submission with the MAC Secretariat.	Mark McKinnon (March 2022)
7	**Modelling tools** The RCMRWG agreed to ask any questions regarding the modelling tools offline.	
8	**Next Steps** The RCMRWG agreed to hold a meeting on 17 March 2022 to discuss the outcome of the international review and an update on the detailed modelling assumptions.	
11	**General Business** No general business was discussed. The next RCMWG meeting is scheduled for 17 March 2022.	

The meeting closed at 11:30am.

Government of **Western Australia**
Energy Policy WA

Reserve Capacity Mechanism Review Working Group

MAC Update

April 2022

Working together for a **brighter** energy future.

Purpose of this Session

The Terms of Reference for the Reserve Capacity Mechanism review included a literature review:

> *Review of RCM arrangements in other markets and what they aim to address, which problems their electricity systems are facing or are expected to face in the future, and whether/how these arrangements and issues relate to the WEM. Jurisdictions to be investigated include: UK, PJM, and any other jurisdictions identified by the MAC or Energy Policy WA.*

The purpose of this presentation is to:

- Inform MAC of the outcomes of the research
- Inform MAC of the comments made and discussion held in the working group
- Provide an opportunity for MAC to provide additional comments, if desired
- Present information, not solutions

Agenda

Item	Item	Duration
1	International review scope	10 min
2	Considerations for the WEM	60 min
	Appendix – market summaries	

1. International Review Scope

Scope and Purpose

Review selected capacity markets to identify:

- What issues they aim to address
- Issues they are facing or expected to face in the future
- Identified solutions
- How these issues relate to WEM

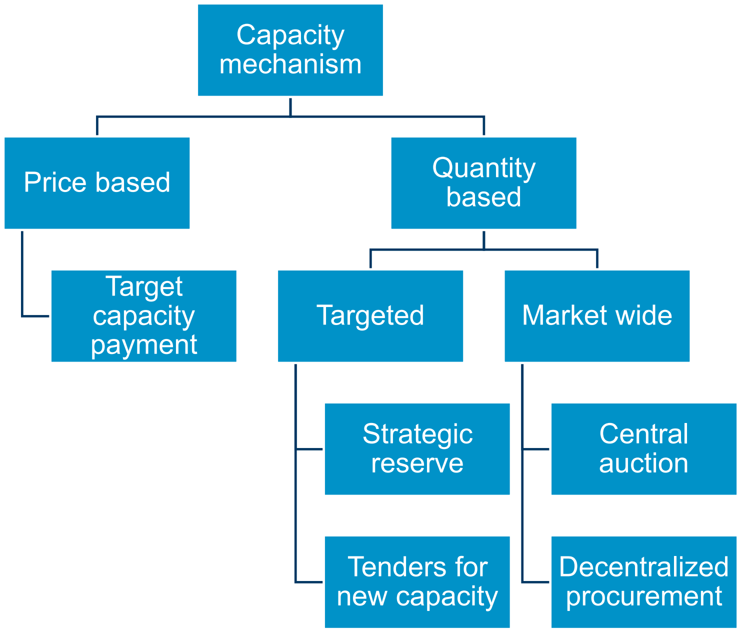
Capacity markets reviewed:

- PJM
- ISO-NE
- France
- Colombia
- UK
- Ireland

Also:

- NEM design options
- Hawai'i "load build" service

Types of Capacity Mechanisms



Mechanism	Description	Jurisdictions
Target capacity payment	The regulatory authority determines fixed prices for proponents that build new-capacity of a specific type	Spain, Portugal
Strategic reserve	A centrally identified quantity is held back from the market and only dispatched when all other services have been exhausted	Belgium, Finland, Sweden, NZ
Tenders for new capacity	Tenders are run by the regulator and/or market operator for participants to offer to develop new capacity	Bulgaria, Croatia
Central auction	Central body determines overall capacity requirement, auction determines the amount of capacity each resource is allocated and the price at which it is procured.	ISO-NE, PJM UK, Ireland, NEM (possible)
De-centralized procurement	LSEs determine their own capacity requirement and procure to meet it. Auction may be run, but no central purchaser.	France, CAISO, NEM (possible)
WEM	Central allocation of obligation, mixture of centralised and decentralised procurement	WEM

Selected Capacity Markets Reviewed

Why Consider these Markets?

- **PJM** and **ISO-NE** are among the most sophisticated wholesale energy markets in the world, using a centralized auction with locational pricing and interties with neighboring markets
- **UK** was explicitly identified in the project Terms of Reference, introducing its capacity market in 2014 with a central auction and non-locational pricing
- **Ireland** is a small market (though with interconnection), with high renewable penetration and locational considerations
- **France** uses decentralized capacity obligations, introducing its current mechanism in 2017
- **Colombia** is one of the few markets which seeks to address reliability over a longer period, mainly due to hydro risk
- **NEM** design is currently underway
- Bonus: Hawai'i has no interconnections and severe mid-day trough issues like WA, using a defined 'load build' product to address this issue

2. Considerations for the WEM from other Jurisdictions

Key Themes from the Review

See appendix for summaries of each jurisdiction reviewed, including their aims, issues faced, and any solutions identified

Four key issues faced that are relevant for the WEM:

1. PJM, UK and Ireland have faced issues where capacity market settings work against decarbonisation
2. PJM and ISO-NE are finding that single-dimension reliability criteria do not work as well in high intermittent penetration environments
3. PJM, UK and ISO-NE are investigating or using new methods to better approximate capacity contribution of intermittent resources: UK uses Equivalent Firm Capacity (EFC), PJM uses Effective Load Carrying Capacity (ELCC). ISO-NE is investigating
4. ISO-NE, France, Colombia and Ireland have faced problems from a non-diverse generation fleet.

In addition:

- There are a variety of other design features of potential interest
- The WEM demand curve is a lot shallower than those in other markets. This is out of scope for the review, but noted here for completeness.

1. Capacity Mechanism Settings can work against Decarbonization Objectives

WEM Context

The WEM is undergoing an energy transition from fossil-fueled generation to renewable generation. Other places around the world are at various stages of the same transition.

The WA government has expressed a goal of being net carbon zero by 2050. This goal requires continued transition in the electricity sector.

Objective: Ensure any changes to the RCM do not inadvertently work against decarbonization policy objectives

1. Capacity Mechanism Settings can work against Decarbonization Objectives

International Experience

Jurisdiction	Issue	Experience	Identified Solutions
PJM	Minimum Offer Price Rule (MOPR) may disadvantage low carbon generators	Intended as a market power mitigation measure. Has resulted in new state supported renewable plants offering their capacity at artificially higher prices while plants close to end-of-life and fossil generators can offer their capacity at low prices.	Adjusting MOPR to improve consistency
UK	Higher emission incumbent generators favoured	Distribution network connected resource where several diesel generators and OCGTs cleared the capacity auction as they were able to bid at lower prices when compared to other resources.	Environmental/emission regulations
UK	Demand response disadvantaged	Demand response is only provided 1 year contracts while other resources are provided longer term contracts preventing investment in demand response technology despite this being the most efficient decarbonisation option.	Work in progress
Ireland	Class based capacity allocation reduces participation of renewable / intermittent / DSR	DSR, intermittent and renewables need to pay back the price for the volume promised if failed to deliver during period of stress. Some intermittent generators choose not to participate in the capacity mechanism to avoid the risk of not being able to deliver their (centrally set) capacity quantity at those times	Work in progress

1. Capacity Mechanism Settings can work against Decarbonization Objectives

Considerations for WEM

- We need to consider whether RCM settings could work against policy to decarbonize existing resources
  - Capacity payments generally act to extend the life of existing higher emission facilities
- Current arrangements mean
  - Suppliers earn capacity payments up to a capacity surplus of 30% (high internationally)
  - New lower emission entrants are likely to be allocated NAQ only when locating in unconstrained areas
- This has the potential to temper the competitiveness of new renewable capacity in the SWIS
- In the UK where incumbent non-renewable generators had an advantage, strict environmental and emission requirements within the capacity mechanism helped address the issue

1. Capacity Mechanism Settings can work against Decarbonization Objectives

Comments – RCM Review Working Group Meeting

- Locational pricing signals will be too complex given the size of WEM
- Need to ensure there is adequate transmission taking into account fuel source for wind/solar

2. Future Reliability Criteria must be Multi-faceted

WEM Context

- The WEM planning criterion drives the capacity requirement
- The current planning criterion has two limbs. There must be enough capacity to avoid:
  - Any unserved energy in a 1-in-10-year peak load event, including an allowance for outages and essential system services
  - Unserved energy across the year of more than 0.002% of total demand
- Historically, only the first limb has ever bound, but analysis for the second limb has found USE is increasingly likely to occur outside the peak periods
- The previous RCM review (2012) recommended the second limb be dropped

Objective: Ensure WEM planning criterion can accommodate different types of system stress

2. Future Reliability Criteria must be Multi-faceted

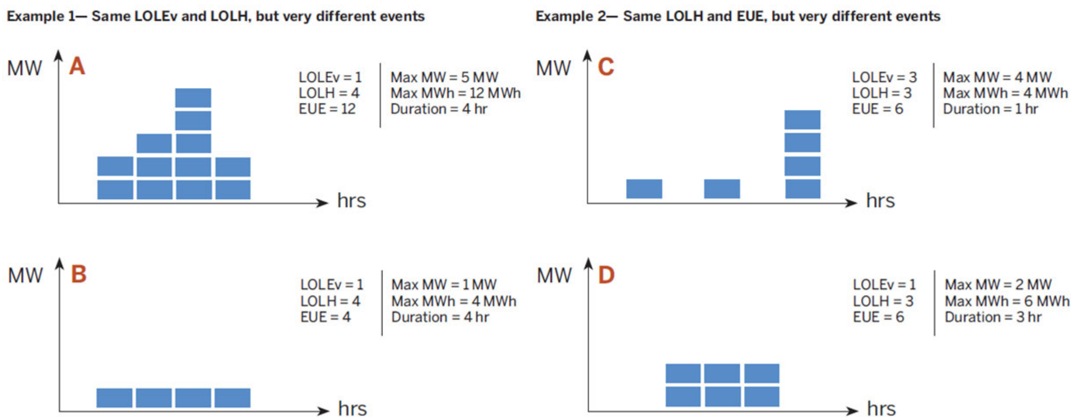
International Experience

Other markets use a single metric reliability criterion. This made sense when the only power producers could provide power 24 hours a day. PJM and ISO-NE have determined that with more intermittent resources, this reliability standard might fail to appropriately reflect all system stress events and is investigating a new standard

No other jurisdiction considers low load support in its reliability criterion

Jurisdiction	Reliability criterion
PJM	0.1 events per year
ISONE	0.1 events per year
France	LOLE of 3 hours per year
UK	LOLE of 3 hours per year
Ireland	LOLE which is 8 hours for Ireland and 4.9 hours for Northern Ireland
NEM	Currently <0.002% unserved energy (interim off-market RRO <0.0006% USE)

Building Blocks of Resource Adequacy Metrics

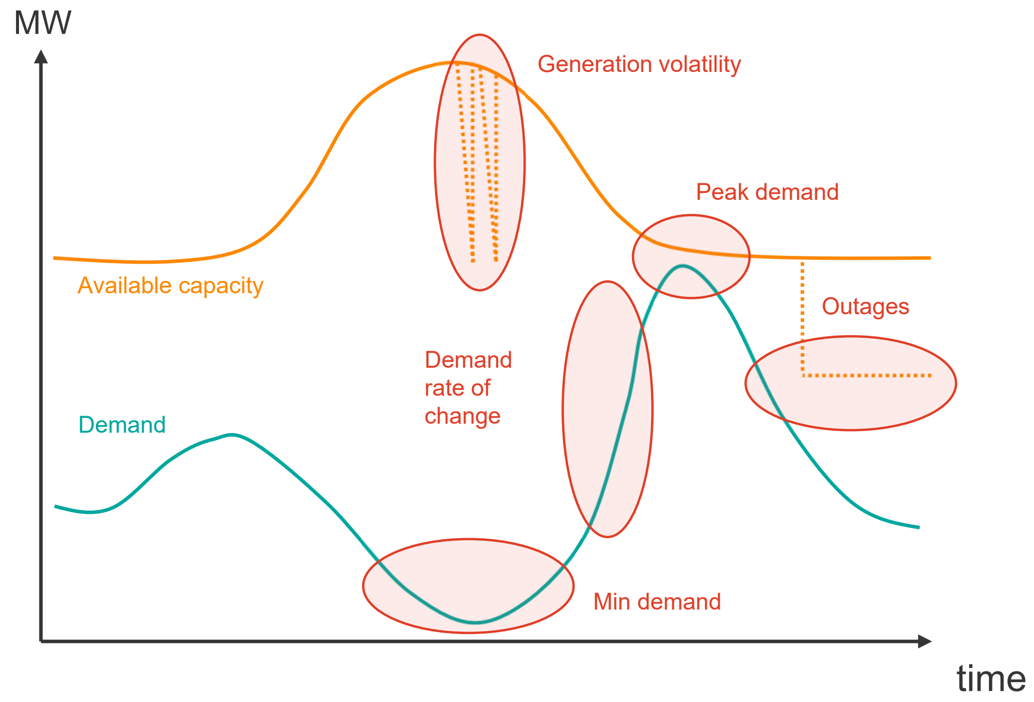


Each block represents a one-hour duration of capacity shortfall, and the height of the stacks of blocks depicts the MW of unserved energy for each hour. A: a single, continuous four-hour shortfall with 12 MWh of unserved energy; B: a single, continuous four-hour shortfall with 4 MWh of unserved energy; C: three discrete one-hour shortfall events with 6 MWh of unserved energy; D: a single, continuous three-hour shortfall with 6 MWh of unserved energy.

2. Future Reliability Criteria must be Multi-faceted

Considerations for WEM

- A reliability criterion focused solely on a 1 in 10-year event is unlikely to be flexible enough to cope with new fleet characteristics.
- The two-limbed WEM approach is already more flexible than other markets, accounting for two of the three dimensions of unserved energy (number of events, total load not served)
- No other markets consider low load in their reliability criterion, and none of these jurisdictions were considering it as an issue – though they were concerned about the afternoon ramp. Hawai'i does have this issue, and treats response as an essential system service rather than a capacity feature.



2. Future Reliability Criteria must be Multi-faceted

Comments – RCM Review Working Group Meeting

- WEM could be the first market to address a minimum operational demand issue
- The LOLE metric is a measure to calculate the required amount of reserve capacity and has an impact on fuel requirements. This means a higher LOLE target (more hours of outage) lowers the reserve capacity requirement but potentially lengthens the amount of fuel/storage required in terms of hours. [Note: not necessarily]
- We may still need to identify some "defined energy shortage risk" events as part of our studies as well as EUE
- It is important to review the purpose of reserve margin and whether it is the best way to manage the effect of outages as it creates a free riding problem. Other jurisdictions use reserve margin for a different purpose

3. New Methods for Certifying Capacity are Available

WEM Context

The WEM RCM certifies reserve capacity using different methods for different technologies.

- Thermal facilities get nameplate
- Storage facilities get nameplate adjusted for storage capacity
- Intermittent facilities get capacity based on historic output during periods when there is the highest quantity of non-intermittent generation
- Demand Side Programmes get capacity based on their historic demand during periods with the highest total generation

Objective: use a single method for all technology types, if possible, but not at expense of simplicity and a clear signal

3. New Methods for Certifying Capacity are Available

International Experience

Other markets are recognizing that current approaches to assigning capacity are out of step with the actual resource contributions to security of supply, and are actively exploring new methods for assigning capacity.

Jurisdiction	Experience	Identified solutions
PJM	Capacity certification does not reflect the actual contribution of the resource during periods of system stress. Historical performance of the intermittent, and energy efficiency resources during stress periods does not actually reflect the contribution of intermittent resources. Assignment to thermal facilities does not account for slow ramping or long start-up times.	Uses Effective Load Carrying Capability (ELCC)
ISO-NE		Developing Marginal Reliability Index (MRI) and ELCC
UK	In UK, capacity credits are assigned for a class of resource instead of individual generating units.	Intermittent derated by Equivalent Firm Capacity (EFC)

3. New Methods for Certifying Capacity are Available

Considerations for WEM

- Using different methods to assign capacity to different technologies and doing so without considering output correlation or lack of correlation means that CRC (particularly for renewables) does not necessarily reflect the actual contribution to system reliability
- ELCC method looks promising, using the marginal reliability value of the resource instead of its nameplate capacity or just capacity during periods of typical system stress
- ELCC can be extremely complex, making it difficult for prospective participants to assess their likely credits

Considers the availability of renewables during each hour of the day for the capacity year

Allows consideration of correlation of output or contingency for factors like location, weather conditions, and time of day

Allows consideration of the size and flexibility of the resource (start time, ramp ability)

Allows impact of storage resources to be based on not just the size of the resource, but also the factors like availability of intermittent, charge-discharge rates, etc.

3. New Methods for Certifying Capacity are Available

Comments – RCM Review Working Group Meeting

- IRCR is currently limited to summer, this may not be appropriate as system stress events move away from summer
- PJM estimates the capacity value of scheduled generators based on historical performance during system stress period. It uses Equivalent Demand Forced Outage rate to derate the installed capacity of scheduled generators. This aligns with the concept underpinning ELCC (effective load carrying capability). In the WEM, we would need to avoid ELCC double counting the network factors that are dealt with by NAQ
- ELCC can be useful as it means capacity is measured where it is needed most. However, if the ELCC method selects too few periods, it becomes too volatile and doesn't send a clear signal for when investors should aim to make capacity available
- Would favor a more approximate method that sends a clearer signal. Avoiding complexity will also be important so that investors can understand how much money they might make. ELCC method is a struggle to explain to investors unless it is approximated
- Agree with the point that we ought to consider the correlation of output of different resources. But correlation can be overstated and its impacts overestimated with too few periods

4. Reliance on one Type of Technology or Fuel Source can be a Problem

WEM Context

- Historically, the WEM generation fleet has been heavily reliant on coal and gas. Even today, gas and coal makes up 80% of the generation fleet
- In recent years, behind the meter solar has become (in aggregate) the largest generator on the power system, with nearly 2GW of capacity
- In future, the proportion of coal and gas will drop significantly, with none left by 2050

Objective: Ensure WEM RCM supports a variety of technologies and fuel sources

4. Reliance on one Type of Technology or Fuel Source can be a Problem

International Experience

Other jurisdictions have had issues where reliance on one type of capacity leads to problems when a whole class of facilities is affected by the same issue

Jurisdiction	Issue	Experience	Identified solutions
ISO-NE	Reliance on NG	NG forms >50% of resource mix. One supply issue with the provision of NG is that several gas generators do not have firm contracts, instead purchasing most of their fuel on the gas spot market.	Securing long term contracts for fuel supply
Colombia	Reliance on NG	Supply shortfall issues due to lack of long term contracts	Securing long term contracts for fuel supply
France	Market concentration	Nuclear forms 70% of generation mix. Recent outage in 5 reactors led to supply shortfall and becoming a net importer of electricity.	Work in progress
Ireland	Market concentration	Market power is high as the small size of Ireland market and the relatively larger size of each generator. Although, the capacity auction in Ireland has secured more capacity at a cheaper cost for the customers, a failure of a single market participant can cause an instability in the market.	Diversifying resources

4. Reliance on one Type of Technology or Fuel Source can be a Problem

Considerations for WEM

- Too much reliance on gas could pose a threat when intermittent renewables are not able to generate enough to meet the demand
- Medium-term fuel security is an important consideration
- Demand side participation will be critical
- We need to ensure the WEM RCM supports a diverse supply fleet

4. Reliance on one Type of Technology or Fuel Source can be a Problem

Comments (1) – RCM Review Working Group Meeting

- Given that fuel diversity/technology diversity was an issue raised in other jurisdictions would we necessarily want to exclude diesel generators? Think timing of this is important
- Given that the size of our market excess is boom or bust, it makes price very volatile. Volatile capacity pricing will not incentivize capacity in a high renewable world. There is significant capacity in the market that does not respond to economic signals and therefore capacity price. This will become even more of an issue if we look to have excess renewable installations to minimize storage and this is a good reason for why we should consider moving away from pricing based on excess

  An alternative is to have different buckets of capacity we need to fill, and turning the tap off when we have enough, and limiting the length of time these capacity types are paid for, potentially to 10 years

4. Reliance on one Type of Technology or Fuel Source can be a Problem

Comments (2) – RCM Review Working Group Meeting

- Reliance on gas might be less of a risk considering the WEM mostly uses long term contracts and has diverse supply points. A solution could be a requirement for storage
- If gas plants are used only to back up intermittent in a low emission mix, this means large quantities of gas will be used for short periods. This could lead to gas contracts being expensive and demand surges could be difficult to handle
- It is not just reliance on a single technology type, reliance on generation in a single location is also an issue in case of outages, congestion, etc.

5. Additional Design Features from Other Markets

Considerations for WEM

Through the review, we identified other design features that could be considered in the WEM:

- Capacity mechanism opt out with extremely high penalties for non-performance (e.g., PJM - Fixed Resource Requirement)
- Resource adequacy standard: onus on retailers to prove their estimated peak load rather than setting centrally
- Dedicated procurement volumes to encourage specific types of supply (e.g. renewables, DSM)
- Temperature dependence for low temperatures as well as high temperatures
- Setting the benchmark capacity price to account for expected energy revenues (CONE/Net CONE)
- Length of guarantees for new build (PJM rate lock is 3yrs, ISO-NE was 7yrs but FERC rejected it as too long, Brazil as long as 15 years in renewable supply auction)
- Obligation timing - all hours; only when SO gives notice; only when energy price goes above a threshold (reliability option)
- Penalty payments distributed to those who overdeliver rather than consumers or other capacity holders

5. Additional Design Features from Other Markets

Comments (1) – RCM Review Working Group Meeting

- The ERA has identified several areas of concern about the risk to the reliability of the system of generators not delivering capacity when needed (including scheduled generators and renewables). A review of RCOQ is also important as the ERA found
- Disagree with derating capacity for outages and considering further penalties for non-supply. Increases risk without improving reliability. Generators have adequate incentives to be available. Derating capacity assumes past outages will predict future ones despite repairs/upgrades. High penalties for non-performance and derating capacity for non-performance may disproportionately impact the generators that run more often and currently have the greatest incentives to be available as these generators are more exposed to outages

  Also, it might double count the impact of forced outages in the reserve capacity mechanism, as the planning criterion already includes a margin for expected forced outages. This would result in unnecessary over-procurement

5. Additional Design Features from Other Markets

Comments (2) – RCM Review Working Group Meeting

- Would also note on the NEM summary that ESB work on options method and is currently contentious and many participants would prefer completely different models than the 3 presented - all evolving through similar working group process – may be worth EPWA and ESB teams syncing up to avoid circular references if both NEM and WEM are adjusting in real time

6. The WEM Demand Curve is Shallower than other Jurisdictions

WEM Context

Note: Amendments to the RCM pricing arrangements (including the demand curve, the option for 5-year fixed pricing, and the refund regime) are not in scope of this review, but the basis for the Benchmark Reserve Capacity Price is in scope.

The WEM sets its Benchmark Reserve Capacity Price (BRCP) based on the capital costs of a 60 MW open-cycle gas turbine facility. The rationale is that such a facility could recover variable costs in the energy market when it runs, and would not need any contribution towards capital costs from infra-marginal rents in the energy market

The BRCP is the basis for the Reserve Capacity Price paid to all capacity providers, and may be more or less than the BRCP depending on whether there is a surplus or deficit of capacity compared to the Reserve Capacity Target. The WEM Rules define a demand curve to translate a particular level of surplus to a price.

6. The WEM Demand Curve is Shallower than other Jurisdictions

International experience

Although other jurisdictions use auctions to procure capacity, they still define a demand curve for use in the auction, with benchmark prices based on a similar principle – estimating the revenue required to recover a contribution to capital costs.

CONE = capital investment costs plus operational and maintenance expenses incurred during the first year of operation of the new entrant

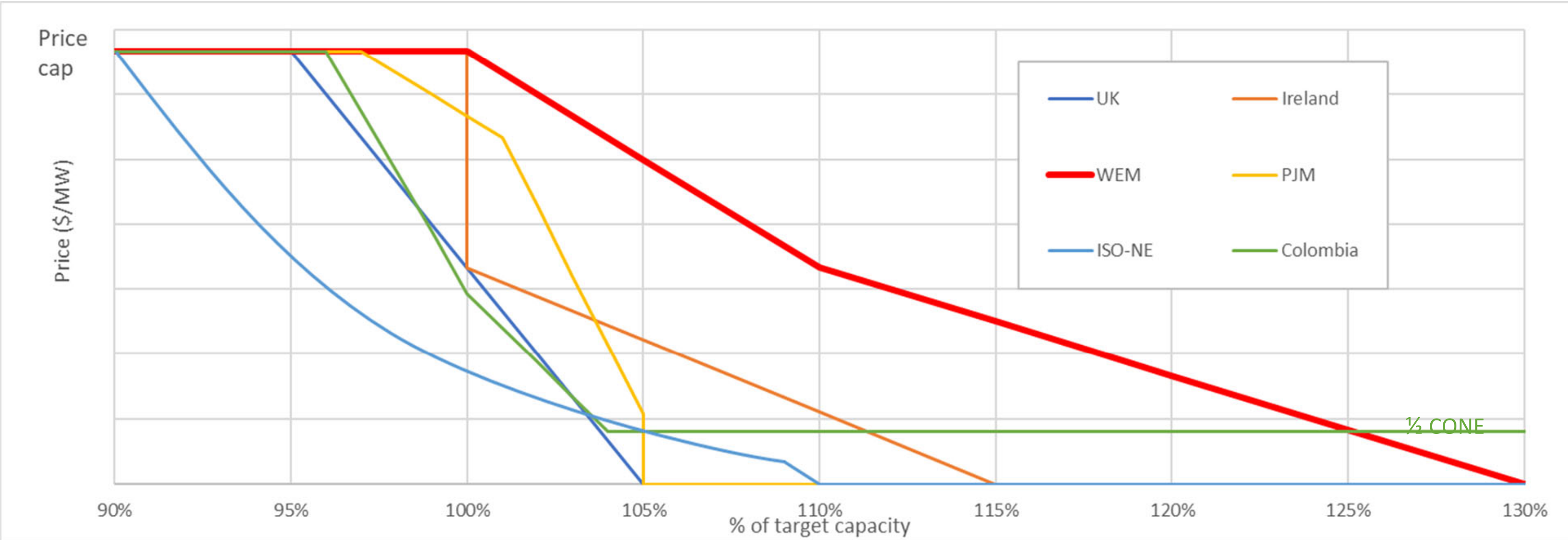
Net-CONE = CONE less an estimate of the energy/ancillary services market profits for the entrant. This measure assumes that the marginal new entrant would receive some contribution to capital costs from the energy market.

Jurisdiction	Price cap	Price floor	Determination of CONE
PJM	$\frac{\text{Max (CONE,1.5 x net−CONE)}}{1 - Poolwide\ Equivalent\ FOR}$	\$0/kWh-month @ 105%	Entry of a Combustion Turbine (CT) generating station, configured with a single General Electric Frame 7HA turbine
ISONE	Max (CONE,1.6 x net-CONE)	\$0/kWh-month @ 110%	Gas-fired simple-cycle combustion turbine, or CT
Colombia	2 x CONE	½CONE @ 104%	Initially set administratively based on a study of the cost of a new efficient peaking unit (gas)
UK	1.5 x Net-CONE	\$0/kWh-month @ 105%	New Combined Cycle Gas Turbine (CCGT)
Ireland	1.5 x CONE	\$0/kWh-month @ 115%	CCGT using GE9FB.05 model turbine

6. The WEM Demand Curve is Shallower than other Jurisdictions

Considerations for WEM

- The demand curve used in the WEM has a shallow slope, meaning that the RCP is still quite high even when there is surplus capacity available.
- Other curves (in chart below) have procurement quantity right-shifted at the price of net CONE. Price caps need to be high enough to reach net CONE on a long-run average basis, and a slope flat enough to mitigate price volatility but steep enough to prevent significant excess quantity.



6. The WEM Demand Curve is Shallower than other Jurisdictions

Comments – RCM Review Working Group Meeting

- Pricing reform is out of scope of this review.
- In terms of load shape, each jurisdiction is different with different generation mix and emission targets. Policies must be formulated such that the capacity market aligns with the long-term market objective.
- With multi-year auctions, the capacity requirement is updated based on the latest forecasts so that the participants can adjust their position accordingly close to delivery period.

  [Note: In the WEM, allowing participants to declare bilateral trading (without checks and balances), unlike an auction, provides certainty and allows the same position adjustment as provided by year-ahead auctions.]
- Given the size of WA, the impact of each facility being present for capacity purposes is quite large. It makes sense that the curve is shallower to avoid large swings in the capacity price based on the presence of a single facility.
- The price curves used in other markets would be too steep given WA's slim excess - too sensitive and therefore volatile, undermining certainty when we will need more certainty due to increasing intermittent generation.
- An auction will also cause price volatility due to the zero times infinity problem.

How will we incorporate these Findings into the RCM Review?

1. Capacity Mechanism Settings can work against decarbonisation objectives

   Consider in reliability impact analysis modelling – impact on current and future facilities

2. Future reliability criteria must be multi-faceted

   Results of system stress modelling will inform need for additional dimensions

3. New methods for certifying capacity are available

   Include ELCC/EFC as option for CRC methodology

4. Reliance on one Type of Technology or Fuel source can be a Problem

   Consider in reliability impact analysis modelling – assess incentives for demand side participation

5. Additional design features from other markets

   Further discussion with working group at solution stage

6. The WEM demand curve is shallower than other jurisdictions

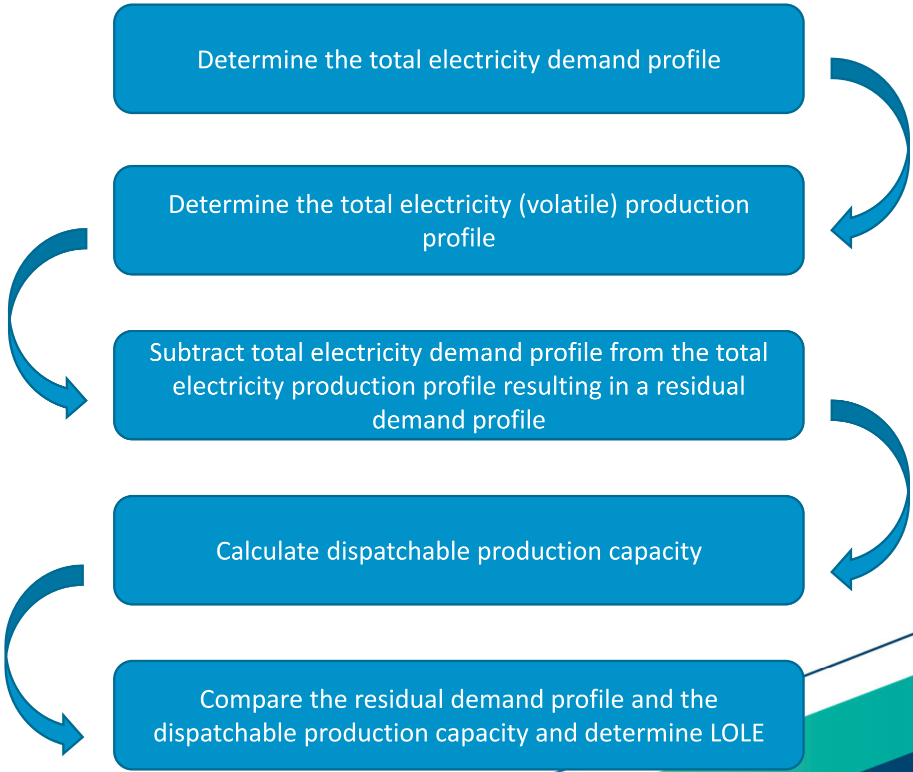
   No changes to price curve in this review.

   Consider CONE/Net-CONE in BRCP assessment.

Appendix

Loss of Load Expectation

- LOLE represents the number of hours per annum in which, over the long-term, it is statistically expected that supply will not meet demand. E.g. LOLE of 3 hours means 3 hours during the year; supply may not meet demand.
- LOLE is a probabilistic approach – that is, the actual amount will vary depending on the circumstances in a particular year, for example how cold the winter is; potential for an unusually large number of power plants to suffer simultaneous forced outage; all the other factors which affect the balance of electricity supply and demand.
- LOLE does not mean power blackouts are expected. It is a metric for Transmission System Operators to use instruments such as temporary voltage reductions or the selective disconnection of large industrial users to prevent blackouts.
- LOLE does not measure the total shortfall in capacity which is measured by Expected Energy Not Served (EENS). LOLE only measures the number of hours supply will not meet demand.



PJM – Market Summary

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	5 minutes
Locational pricing	Yes
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity Market	
Procurement structure	Reliability Pricing Model
Additional features	Bilateral trading
Auction type	Mandatory centralized uniform price auction
Resource adequacy requirement	Systemwide and local requirements set by 0.1 LOLE study (i.e.) 1 event in 10 years
Timeline	3 years in advance. Incremental auctions are held up to the delivery year.
Price information	Sloped demand curve is used based on the system capacity requirement, the net-CONE, and demand reservation prices.
Intermittent in capacity market	Can receive RE support from state as well as partake in capacity market

2019 Installed Capacity vs Peak demand	
Installed Capacity	182 GW
Peak demand	150 GW
Difference	22%

PJM – Capacity Mechanism Overview (1)

Reliability Pricing Model

- **0.1 LOLE (i.e., 1 event in 10 years)**
- Merchant transmission developers can offer transmission upgrades into the capacity market
- Elements of RPM to achieve reliable capacity procurement are
  - **Locational Capacity Pricing** to recognize and quantify the locational value of capacity (**25** Locational Deliverability Areas)
  - **VRR** is the auction mechanism to determine the capacity required and adjust price based on the level of resources procured
  - **Forward Commitment of Supply** to commit supply by generation, demand resources, energy efficiency resources, and qualified transmission upgrades cleared in a multi-auction structure
  - **Reliability Backstop Mechanism** to ensure that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The Office of the Interconnection shall conduct each Reliability Backstop Auction to commit additional Generation Capacity Resource if enough capacity is not procured

Elements of RPM

- Locational Capacity Pricing
- Variable Resource Requirement mechanism
- Forward Commitment of supply
- A Reliability Backstop mechanism

PJM – Capacity Mechanism Overview (2)

Reliability Pricing Model

- **Base Residual Auction (VRR)** - The Base Residual Auction (BRA) is a mandatory centralized forward uniform price auction which is held three years prior to the start of the Delivery Year through a Locational Reliability Charge.
- **Incremental Auctions** – At least three Incremental Auctions (First, Second and Third) are conducted after the Base Residual Auction to procure additional resource commitments. **Conditional Incremental Auction** may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a LDAs to address the corresponding reliability issues.
- **Bilateral Market** – The bilateral market provides resource providers an opportunity to cover any auction commitment shortages

Market mechanism

- Base residual auction
- Incremental auctions
- Conditional Incremental auction
- Bilateral market

PJM – Resource Adequacy

Reliability Pricing Model

- Determines resource adequacy every year for a 11-year future period.
- Reliability depends on – installed capacity of resource and probability that a resource will not be available due to forced outages.

Conventional generation	Wind, solar and storage capacity	Energy Efficiency resources
Nameplate capacity around the year	Unforced capacity calculated as the average hourly output of these resource during expected performance hours in summer (15:00 - 20:00 - June, July, and August) and winter (6:00 - 9:00 and 18:00 - 21:00 - January and February).	Achieve a continuous reduction in energy consumption at the end customer's retail site which will be calculated during EE performance hours (15:00 - 18:00 during all days from June 1 - August 31, inclusive, of Delivery Year, that is not a weekend or federal holiday)

PJM – Issues and Solutions

1. **Reliability criterion needs to evolve**. Current measure is 1-in-10 LOLE or 0.1 LOLE. Does not account for magnitude or duration of the LOLE event. Looking to account for duration and amount of load shed in determining the reliability criterion.
2. **Reliability contribution of renewable resources**. Currently, unforced capacity of intermittent resources is evaluated for a fixed duration in expected performance hours. Lately, performance of units can vary across periods which were previously not considered. Proposed to use Effective Load Carrying Capability (ELCC) (probabilistic analysis which considers the contribution of the resource during hours of high risk).
3. **Minimum offer price rule**. Instituted to stop net consumers from offering capacity into auction below cost, and also used for renewable resources receiving state subsidies. Not so relevant for WEM.

ISO-NE – Market Summary

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	5 minutes
Locational pricing	Yes
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity Market	
Procurement structure	Forward Capacity Auctions
Additional features	Bilateral trading
Auction type	Mandatory centralized descending clock auction
Resource adequacy requirement	Systemwide and local requirements set by 0.1 LOLE study
Timeline	3 years in advance. Incremental auctions are held annually and monthly
Price information	Sloped demand curve is used based on LOLE and net-CONE
Intermittent in capacity market	Can receive RE support from state as well as partake in capacity market

2019 Installed Capacity vs Peak demand	
Installed Capacity	31.5 GW
Peak demand	23.9 GW
Difference	32%

ISO-NE – Capacity Mechanism Overview (1)

Forward Capacity Market

- **0.1 LOLE study (i.e.) 1 event in 10 years.**
- Interties are allowed to participate in the capacity market **(4 zones – FCA 2021)**
- First capacity is procured for meeting system wide requirements followed by the modelled capacity zone followed by monthly and annual auctions for parties to procure/provide resources.
- Three year ahead auction with a bilateral arrangement for trading capacity outside the auction among resource providers and buyers. There are also monthly and annual reconfiguration auctions for parties to procure/provide resources based on the market condition closer to the delivery year.
- FCA is organized in a descending clock format basis where the market is cleared when supply offered by the resource providers (generating resources and demand participants) meets the demand which is based on the resource adequacy requirement.

ISO-NE – Resource Adequacy

Forward Capacity Market

Existing conventional generation	Intermittent	Demand capacity resources
Median of the existing generating capacity resource's summer or winter seasonal claimed capability rating for the previous five years.	• Median of net output in the summer intermittent reliability hours (14:00 - 18:00 between June and September) and winter hours (18:00 -19:00 each day between October and May) for the previous five years • Output also measured during scarcity conditions (when reserve price equals reserve price cap - Reserve Constraint Penalty Factors	• Consists of Load management measure, distributed generation measures, an energy efficiency measure or a combination • Resource's estimated demand reduction value as submitted and reviewed • Reliability measured during historical peak demand or system stress periods

ISO-NE – Issues and Solutions

1. **Method of assigning capacity credits**. Currently, the compensation by ISO-NE for provision of capacity is inconsistent with the marginal impact on reliability. These include conventional generators having low flexibility, large generators whose outage leads to large and more impactful fall in supply, gas units that lack backup fuel, intermittent resources, and energy storage.

   In the calculation of qualified capacity for conventional generators, the following factors are not considered:

   - Lower flexibility of some of the resources due to longer start time and limited operational flexibility. This is not accounted for in the qualified capacity for the unit.
   - The size of the resource is not accounted for in assigning qualified capacity.

2. **Over-reliance on natural gas**. One supply issue with the provision of natural gas is that most of the gas generators do not have firm contracts with suppliers and tend to buy on the spot market.

France – Market Summary

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Net pool
Trading interval	30 minutes
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity Market	
Procurement structure	Decentralized capacity procurement
Additional features	Optional participation with obligation
Auction type	Optional auction
Resource adequacy requirement	Local requirements based on LOLE which is 3 hours per year
Timeline	Market operates on a continuous basis until delivery. Trades can take place in OTC or organized exchanges
Price information	Certificates are traded with a price cap of €60 000/MW (2020)
Intermittent in capacity market	Diminishes RE revenue when participating in the capacity mechanism

2019 Installed Capacity vs Peak demand	
Installed Capacity	96.8 GW
Peak demand	88.5 GW
Difference	9%

France – Capacity Mechanism Overview (1)

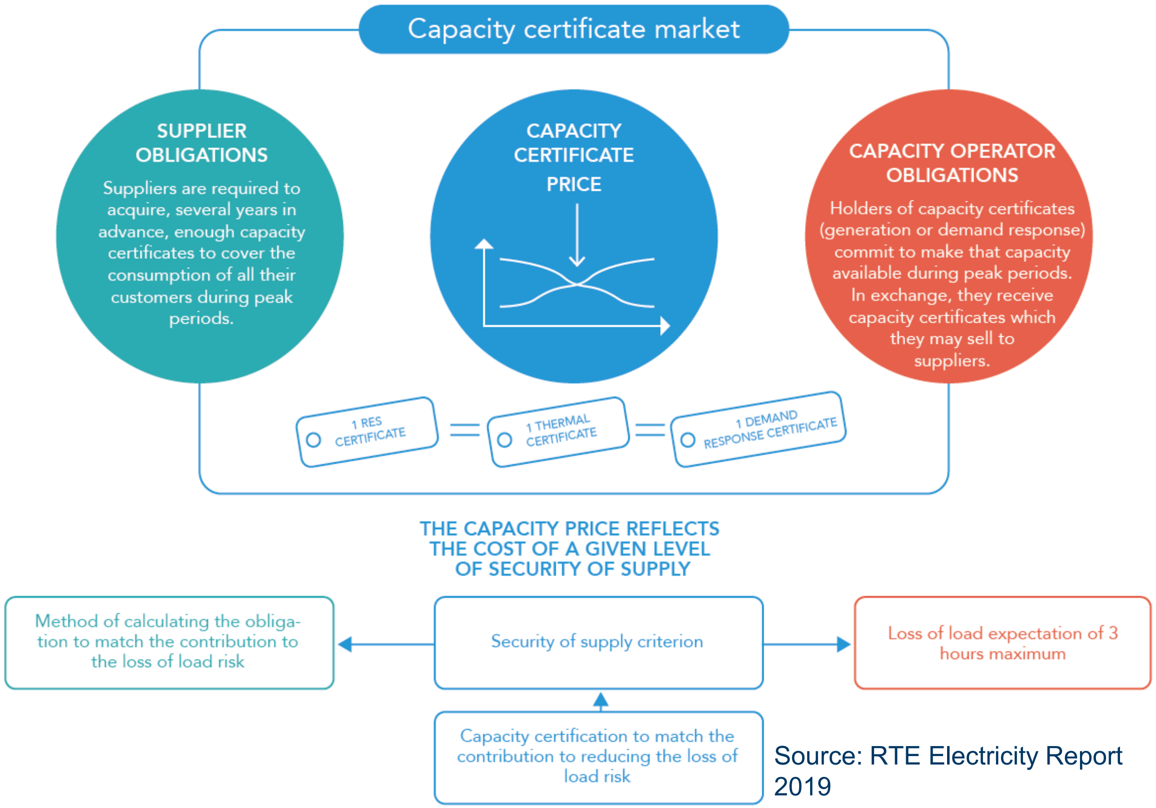
Decentralized Capacity Procurement

- **3-hour LOLE.**
- France's capacity market is intended to meet peak load, not average load.
- Interties are allowed to participate in the capacity market
- Under a decentralized model, it is the actors like suppliers who are responsible for system adequacy for matching the supply and demand instead of a central party.
- Conventional generators are offered 1- year contracts while new low emission facilities and energy storage are offered 7-year contracts.
- The capacity mechanism first creates a capacity requirement which obligates suppliers to obtain energy certificates to meet their expected peak demand based on their end customer energy usage. This way the suppliers are held responsible to contain their peak demand by providing incentives to limit consumption.

France – Capacity Mechanism Overview (2)

Decentralized Capacity Procurement

- Market participants can exchange guarantees either bilaterally on the OTC market or enter auctions organized by EPEX SPOT market.
- During the delivery year, RTE determines the peak demand days the day before for the next day, which is:
  - **15 PP1 days** for suppliers – Jan-Mar, Nov-Dec.
  - **15-25 PP2 days** for generators and capacity operators - 15 PP1 days which are also PP2 days and 0 to 10 days which are PP2 days excluding PP1 days.
- Demand-side response can be used by two different methods: either by reducing a supplier's capacity obligation by reducing consumption ('implicit demand-side response') or by certifying demand-side response capacity ('explicit demand-side response'). The obligations for the two types of demand-side response capacity are different: 'implicit demand-side response' must actually be activated during PP1 hours, whereas 'explicit demand-side response' must be available during PP2 hours.
- PP1 and PP2 days are differentiated based on a threshold of expected demand.



Source: RTE Electricity Report 2019

France – Resource Adequacy

Decentralized Capacity Procurement

- The capacity mechanism does not explicitly distinguish between different capacity sources for providing capacity certificates and there are no locational distinctions.
- RTE issues certificates, calculated on the basis of the original data, together with corrections reflecting the risk of non-availability, for example in the case of wind, hydro or solar generation.
- Suppliers acquire enough capacity certificates to meet the peak consumption of their customers. Producers committed to make their capacities available during consumption peaks are granted certificates, which they can sell to retailers.
- Intermittent energy providers are allowed to participate in the capacity market, but their renewable subsidy is reduced equivalent to the capacity revenue from the market to avoid double subsidization.

France – Issues and Solutions

1. **Market concentration**. In France, nuclear power dominates the electricity mix in terms of energy delivered. Further, all the nuclear generation facilities in France are owned by Électricité de France (EDF) owning a substantial share in the generation portfolio.
    - Recent technical problems in the reactors owned by EDF (5 plants with simultaneous unplanned outage) means that nuclear output has dropped significantly, and France is now a net importer. This issue highlights the importance of diversifying generation sources so that instead of relying on a single large resource of electricity, several small generators can be commissioned to provide the same capacity to minimize the risk of fall short of supply.

Colombia – Market Summary

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	1 hour
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity Market	
Procurement structure	Firm energy obligation auction
Additional features	Call option and bilateral trading through a reliability mechanism
Auction type	Centralized descending clock auction
Resource adequacy requirement	Local requirements set by CONE and LOLE
Timeline	3 years in advance. but this will increase by six months in each successive auction, until it reaches 4 years
Price information	Sloped demand curve with firm energy price having a ceiling of two times CONE and a floor of one-half times CONE.
Intermittent in capacity market	Tenders occur in parallel but do not overlap

Colombia – Capacity Mechanism Overview (1)

Firm Energy Obligation Auction

- Held 3 year before delivery period.
- Initially capacity payment was used to promote new power capacity in order to guarantee security of supply. This was an administrative capacity payment rather than an auction-based market mechanism.
- The capacity price was set conservatively making the generators reliant on energy prices and due to high volume of hydro capacity leading to low prices, investment was subject to uncertain revenue.
- Due to its failure, reliability charge was created. This new market-based mechanism was largely dependent on auctions for new capacity and was designed to guarantee payments to generators for being available when needed.
- A descending clock auction design is adopted for awarding Firm Energy Obligation.
- Bilateral contracts can be agreed between parties to allow trading of obligations, voluntary interruptible demand can participate.

Colombia – Capacity Mechanism Overview (2)

Firm Energy Obligation Auction

- Firm Energy Obligations are allocated and priced in these auctions. Winning Gencos receive a stable and continuous reliability revenue for:
  - Existing plants – 1 year
  - New plants (not under construction during auction) – Between 1 and 20 years
  - New plants (under construction during auction) – Between 1 and 10 years.
- Capacity providers must offer their service during scarcity periods when the spot price exceeds the call price called the scarcity price.
- If the generator produces more or less than the firm energy obligation, it must be settled in the spot market either by purchasing the required energy or get paid for the excess energy generated respectively.
- Safety net include secondary/reconfiguration auctions. Generation assets purely and exclusively used to fulfill Firm Energy Obligations
- Guarantee include contracting fuel supply, and natural gas transportation required to back-up the compliance of obligation.

Element of reliability mechanism

- Firm energy Obligation Auction
- Call option based on spot price
- Safety net
- Guarantees

Colombia – Issues and Solutions

1. **Penalty regime**. In 2015, Hydro power plants were found to generate electricity using their hydro reserves for honoring their bilateral sales commitments and were not conserving water in preparation for dry hydrological year.
   - The appropriate penalties were not in place for under performance. Hydro generators preferred the risk of future non-performance against immediate economic loss which they would have incurred if they had purchased power in the market to meet the bilateral obligations.
2. **Appropriate scarcity prices**. Obligation trigger prices were artificially increased when there was an oil supply shortfall due to higher oil prices and increased demand due to droughts caused by the El Niño event.
   - As the variable costs were higher than the trigger price at that time, CREG had to increase the trigger price to reduce operating losses from fulfilling firm energy obligations.

UK – Market Summary

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Net pool
Trading interval	30 minutes
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity Market	
Procurement structure	Capacity market with auctions
Additional features	Bilateral trading
Auction type	Voluntary centralized descending clock auction
Resource adequacy requirement	Local requirements based on LOLE which is 3 hours per year
Timeline	There is a four-year-ahead auction followed by a year-ahead auction
Price information	Sloped demand curve with a price cap of GBP 75/kW (2014). 95% target capacity at price cap and 105% target capacity where price reaches zero
Intermittent in capacity market	Prohibits RE support when participating in the capacity market

2019 Installed Capacity vs Peak demand	
Installed Capacity	77.92 GW
Peak demand	60 GW
Difference	31%

UK – Capacity Mechanism Overview (1)

Voluntary Centralized Descending Clock Auction with Bilateral

- **3-hour LOLE.**
- Descending clock format with ‘pay-as-clear’ structure.
- Interties are allowed to participate in the capacity market
- First auction for capacity year is held 4 years prior followed by 1 year ahead supplementary auction.
- In the capacity mechanism, a perfect network is assumed to exist where power can always flow across uninterrupted. Hence, locational constraints are not taken into account for procuring capacity.
- National Grid will have the capability to run zonal auctions, if necessary, to manage constraints, but no such zones will be created unless approved by Ofgem

UK – Capacity Mechanism Overview (2)

Voluntary Centralized Descending Clock Auction with Bilateral

Estimation of capacity

Enduring reliability standard set by government

Eligibility/ pre qualification

Generation sources inclusive of DSR and storage

Auction

Descending clock auction to determine capacity price

Trading

Bilateral for adjusting position in private markets

Delivery

Capacity providers commit to provide capacity or face penalties

Payment

Cost of capacity, based on share of peak demand

Source: Adapted from DECC site

UK – Resource Adequacy

- Capacity market in UK is technology neutral in that it does not differentiate between technology types (i.e.) does not seek to procure allocated volumes from specific technology types.
- Intermittent renewable generators cannot participate in the capacity mechanism if they receive subsidies from other state funded schemes.
- Demand response is eligible to participate in intermediate auctions before the main auction to stimulate investment in this types of resource.
- All capacity facilities are derated to account for unplanned plant closure or maintenance. This derating factor is based on the ability of the type of resource and in that season resource to provide during periods of system stress
- Intermittent facilities are assessed based on historical performance.

Fuel Type	Winter Availability	Summer Availability
Coal (and Biomass)	87%	61%
Gas CCGT	86%	69%
OCGT[17]	77%	63%
Gas CHP	86%	89%
Hydro	92%	84%
Pumped Storage	95%	95%
Nuclear[18]	83%	71%
Oil	81%	47%
Wind	20-22%	11%

Adjusted every year based on historic performance

Wind availability calculated using Equivalent Firm Capacity (EFC) method

UK – Issues and Solutions

The two major issues that were identified were over-procurement of capacity due to low clearing prices and the dampening of on-peak load pricing in the wholesale energy market which is the main source of income for demand-side management technologies.

1. **Favoring incumbent generators**. Several OCGT and diesel power plants connected to the distribution network cleared the market as they avoided paying (TNUoS) charge leading to higher emitting resources clearing the auction.
   - While the capacity mechanism was able to procure the necessary capacity at a very low price, the mix of capacity that cleared the auctions were not the most efficient in terms of true economic cost.
2. **Participation of demand response**. New generators are provided longer contracts while demand response providers can bid into the auction for only one-year contract and cannot win a long-term contract.
   - Long contracts provide the required assurance and stability of revenue to build a business case and secure investment in development of new technology. But a shorter one-year contract does not provide the necessary timeframe to develop and install a new demand response technology.

Ireland – Market Summary

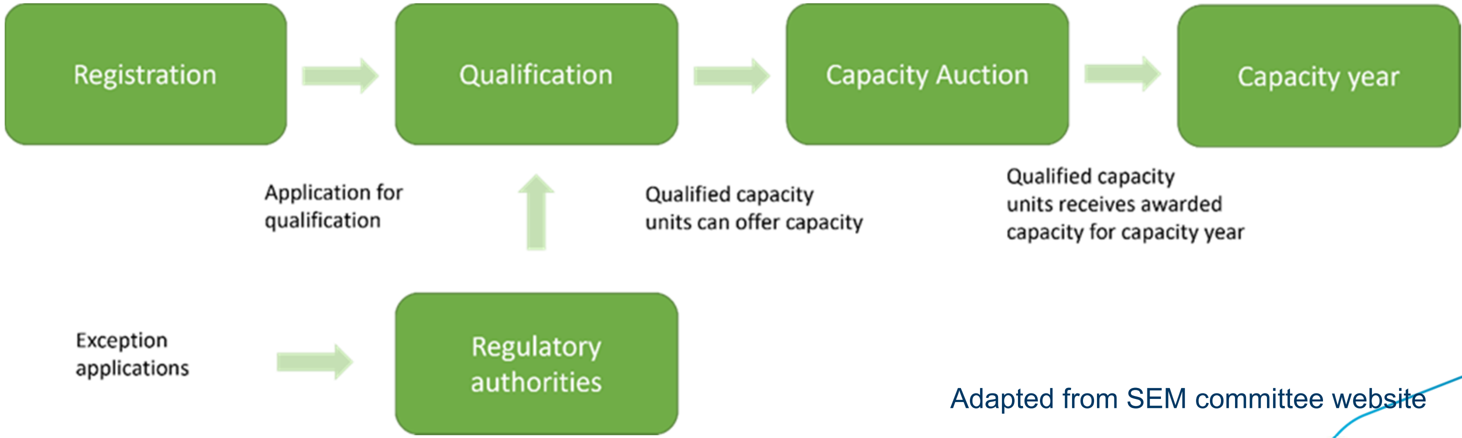
MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	30 minute
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity Market	
Procurement structure	Capacity Renumeration Mechanism – Reliability Options
Additional features	Bilateral trading with reliability options
Auction type	Central buyer uniform price sealed bid auction with locational network constraints
Resource adequacy requirement	Local requirements based on LOLE which is 8 hours for Ireland and 4.9 hours for Northern Ireland
Timeline	There is a four-year-ahead auction followed by a year-ahead auction
Price information	Sloped demand curve with price cap at 150% of CONE. 100% of target capacity at price cap, then target capacity at 100% CONE and finally zero price at 115% target capacity
Intermittent in capacity market	Diminishes RE revenue when participating in the capacity mechanism

2019 Installed Capacity vs Peak demand	
Installed Capacity	16.7 GW
Peak demand	6.8 GW
Difference	145.6%

Ireland – Capacity Mechanism Overview (1)

Capacity Renumeration Mechanism – Reliability Options

- **Local requirements based on LOLE which is 8 hours for Ireland and 4.9 hours for Northern Ireland.**
- Interties are allowed to participate in the capacity market
- Auctions are conducted as a sealed bid combinational auction with uniform clearing price where one participant does not know the other participant's bid.
- First auction for capacity year is held 4 years prior followed by 1 year ahead supplementary auction.



Adapted from SEM committee website

Ireland – Capacity Mechanism Overview (2)

Capacity Remuneration Mechanism – Reliability Options

- CRM is locationally constrained. More expensive and additional capacity may be procured in order to address locational constraints than otherwise would be if the network was considered unconstrained.
- SEM operates with reliability option which is a one-sided Contract for Differences (CfD). Reliability option bundles a call option to each unit the provider sells to the capacity market. The capacity provider is committed to a payment that is the difference between the market price and a set strike price.
- The strike price is set such that it is at or slightly higher than the marginal cost of the peaking plant so that the cash flow captures the scarcity rent that would be earned by the providers with the capacity of the peaking unit is exhausted.
- This means the participants will never earn more than the marginal peaking price in the wholesale or balancing market.

Ireland – Resource Adequacy

Capacity Remuneration Mechanism – Reliability Options

- Derating is based on historic performance data and sometimes expected changes in future performance (based on projections) can be taken account of. Facilities with higher reliability will have a smaller derating, meaning they can offer a larger share of their installed capacity into the auction.
- Interconnectors, demand response, existing capacity, new capacity and storage can bid in the auction. All qualified capacity, except intermittent and new resources **must** bid into the auction.
- For variable intermittent like solar and wind, whose outage pattern is highly correlated, the derating is based on entire class of the resources rather than individual units. Derating is based on technology and **unit size**. The exception is energy storage where de-rating factors have been provided for storage, based on duration as well.

  For all resources except wind & storage: $\{\sum_{unit}\sum_{year} (\text{Annual Run Hours})_{unit} \times (\text{Average Forced Outage Rate})_{unit}\} / \{\sum_{unit}\sum_{year} (\text{Annual Run Hours})_{unit}\}$,

  The **availability of the wind** technology class is based on the actual output of all wind units relative to their installed capacity and defines a profile of wind generation for a year.

  Set of de-rating curves for pumped hydro **storage units** (based on its historical outage statistics) and another set of de-rating curves for other new storage types (such as batteries, compressed air and flywheels) that are based on system wide outage statistics.
- For renewables in the Republic of Ireland, the Renewable Energy support is diminished on capacity revenue generated through CRM while in Northern Ireland, Renewable Obligation Certificate holders cannot participate in the capacity mechanism in order to prevent double subsidization.

Ireland – Issues and Solutions

1. **Market concentration**. Given the very small size of Ireland market and the relatively large size of each generator, the market power each capacity provider in the area holds is quite high.
   - In 2018, one of the largest generators in Dublin did not clear the capacity auction and hence wished to exit the market. Since no new capacity was procured in that auction and the generation unit formed a significant source of supply for that area, it was necessary to keep the generating unit running for ensuring the operational viability in Dublin.
2. **Incentivizing renewable intermittent**. Under the current CRM arrangement, generators are rewarded based on their availability to generate during periods of high demand. If they are not able to provide capacity, they must pay back the entire market reference price for the RO volume promised for that period. Some intermittent generators choose not to participate in the capacity mechanism to avoid the risk of not being able to deliver their (centrally set) derated capacity quantity during those periods.

NEM – Market Summary

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	5 minutes
Locational pricing	5 zones
Day ahead market	No
Real time market	Yes
Capacity Market – emerging design	
Procurement structure	Three approaches under consideration: 1a. Fully decentralised – retailers forecast demand and procure capacity 1b. Hybrid decentralised – AEMO forecasts demand, retailers procure capacity 2. Centralised – AEMO forecasts demand and procures capacity
Additional features	
Auction type	Auction possible under any approach, format TBC.
Resource adequacy requirement	Currently <0.002% unserved energy (interim off-market RRO <0.0006% USE)
Timeline	TBC
Price information	Pricing at same locations as energy market.
Intermittent in capacity market	Derating based on ‘at risk’ periods. TBC whether forward or historic

2021 Installed Capacity vs Peak demand	
Installed Capacity	51.6 GW
Peak demand	31.8 GW
Difference	62%

NEM – Options under Consideration

Option 1a – Fully Decentralised

- Liable entities:
  - Forecast their own load
  - Determine the quantity of capacity certificates they need
  - Procure certificates bilaterally
  - Assessed ex-post based on actual demand
  - Penalties for under-procurement include payment of RERT costs as well as AER enforcement
- Potential for exchange-based trading and/or central auction, but all supply/demand would be determined by liable entities

NEM – Options under Consideration

Option 1b – Hybrid Decentralised

- AEMO:
  - Forecasts load
  - Allocates a capacity requirement to each liable entity
- Liable entities:
  - Procure certificates bilaterally
  - Assessed ex-ante based on forecast demand
  - Penalties for under procurement at various points in time, with 100% coverage not required until one year ahead.
- Potential for exchange-based trading and/or central auction, either with:
  - All supply/demand determined by liable entities
  - AEMO to procure shortfall where liable entities have not procured to meet their allocation

NEM – Options under Consideration

Option 2 – Centralised

- AEMO:
  - Forecasts load
  - Procures capacity in an auction with an administered demand curve
  - Allocates capacity costs to liable entities based on actual demand

Supply Side Incentives

- Two approaches:
  - Explicit penalties for non-performance in ‘at risk’ period (per WEM and elsewhere)
  - Cap contract reliability options, where providers are exposed to difference between spot price and some cap (e.g. $300/MWh). ‘at risk’ periods are implicit, as spot price used instead

NEM – Issues

- Transmission constraints – intra-regional constraints mean challenges for derating
- Market power – decentralized procurement puts pure-play retailers at a disadvantage to gentailers
- Incentives for under- or over-estimation of demand forecast.
- Interplay with extremely high market price caps, and potential scarcity pricing.

Bonus: Hawai'i "Load build" Service

- Service hours 10am-2pm, notified 8 hours ahead
- Events are typically two to four hours and occur only a few times per year
- Managed through aggregators, with automated notification (primarily electric hot water).
- Procured through direct contract with HECO (SO)
- Same portfolio also provides:
  - Load reduce service (5-9pm, notified 10 minutes ahead)
  - Fast frequency response
  - Regulating reserve (AGC response)
  - Replacement reserve (10-30 minute response, 1-2 hour duration)

We're working for Western Australia.

ENERGY SECURITY BOARD

CAPACITY MECHANISM

SUMMARY OF INTERNATIONAL CASE STUDIES

MARCH 2022

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INTRODUCTION

- As part of its detailed design process, the ESB commissioned NERA to undertake case studies of five capacity mechanisms in international jurisdictions to understand, in detail, how they work, and to draw any possible lessons for the NEM
- This pack is designed to summarise NERA's findings to share the important information and lessons from this work
- The jurisdictions studied were: Great Britain, PJM (Pennsylvania – New Jersey – Maryland), Ireland, France and California
- This pack contains a high level summary of each mechanism and a summary of the performance of the regime along with any lessons that might be relevant for Australia
- The appendix contains more detail on each mechanism

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CONTENTS

- Summary and assessment of case study mechanisms:
  - Great Britain
  - PJM
  - France
  - California
  - Ireland
- Appendix – detailed information on each case study

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UK – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- The scheme was introduced in 2014 (first auction, with the first delivery year in 2016) alongside a contracts for difference scheme designed explicitly to support renewables
- Renewables that receive subsidies through this separate mechanism are ineligible to participate in the capacity mechanism
- The British capacity mechanism is technology neutral, but emissions limits were introduced in 2020:
  - There are carbon intensity limits (rate of emissions) and also yearly emissions limits
  - These apply to generators commissioned after July 2019 for all auctions beginning in 2021 and all generators from delivery year 2024/25 onwards
  - This will disqualify coal and diesel from receiving capacity payments from the relevant year
- Electricity is procured bilaterally within an integrated zone that covers Great Britain excluding Northern Ireland, with any uncontracted capacity being sold and allocated via the balancing mechanism. The balancing market has a £6,000 per MWh price cap

Design aspect	Summary of design choices*
Capacity definition	• Capacity providers make capacity available during "system stress events" (defined by the system operator) with four hours of notice • Derating factors differ by technology type (dispatchable generation, storage, interconnectors, demand response and VRE)
Forecasting methodology and determination of capacity certificate demand	• Centrally determined demand curve, set by the Government on advice of the system operator • The system operator undertakes scenario-based modelling based on publicly available future energy scenarios, each of which specify assumptions around peak demand events, generation capacity and interconnectors • Modelling is a "least worst regrets" analysis of the optimal amount of capacity to procure based on the range of forecast scenarios
Certificate trading and procurement methods	• Centralised auctions run at T-4 and T-1 • The system operator deliberately under-procures in the first auction to leave some residual capacity to be procured at T-1 • Existing capacity contracts are one year, with refurbished plant receiving contracts up to three years in duration, and new plant receiving up to 15 year contracts • Secondary trading permitted but rare in practice
Transmission constraints and interconnection	• The capacity mechanism does not account for transmission constraints within the Great Britain system – all capacity is procured without concern for location • Locational constraints are accounted for using a separate mechanism whereby generators near urban areas pay lower annual charges • Interconnectors can participate in the market, with capacity assessed based on net transfers into Great Britain during system stress events. Their derating factors are highly volatile year-on-year
Market power mitigation	• There are bidding rules depending on type of capacity: new build plants and demand response units are "price makers" and allowed to submit bids up to the price cap of 1.5x net cost of new entry (CONE), existing generators and interconnectors are "price takers" which can only submit bids up to a cap of 0.5x net CONE • Existing generation is required to participate
Penalties, compliance and incentives	• Penalties apply to capacity providers who do not perform during system stress events • Penalties are capped at 2x monthly capacity revenue and 1x annual capacity revenue • Over-delivery during system stress events is awarded at the penalty rate

* More detail in appendix

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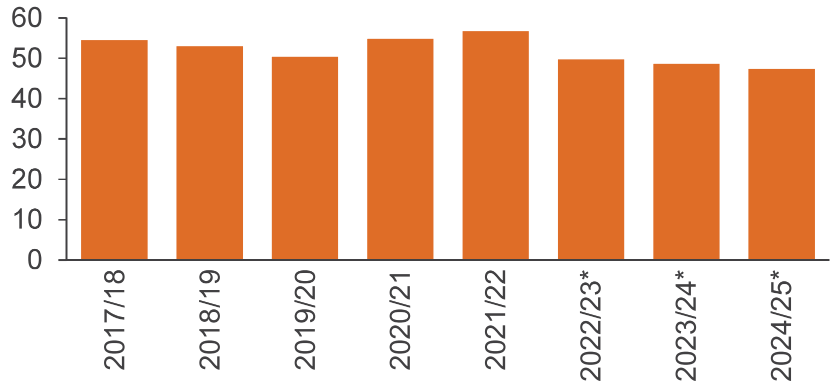
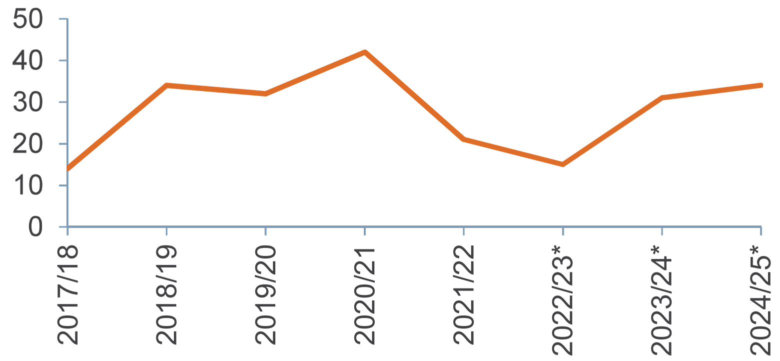
UK – PERFORMANCE OF REGIME

- Despite the investment certainty provided by the longer tenor contracts awarded, new capacity contracted through the auction has not necessarily actually been delivered
  - 1.9GW of capacity (a new CCGT plant) that was secured in the first T-4 auction was never built and the proponent cancelled its capacity contract
- The scheme appears to have achieved its reliability objectives: since the start of operation, there have been seven "notices" but no events in which the system operator would have to disconnect demand
- The scheme has arguably overprocured as loss of load events have been significantly lower than the target amount (under 0.1 hours in 2018-19 to 2020-21 vs a target of 3 hours per year)

Capacity procured in past UK auctions (GW)



Unit price of capacity procured in past UK auctions (A$ per kW)



* T-4 auction results only as T-1 auctions yet to take place

Source: UK Electricity Market Delivery Body (2021), NERA

UK – POINTS OF INTEREST AND LESSONS

- **Sufficient penalties are required in order to guarantee new plant will deliver on contracts:** capacity providers that terminate their contracts have the penalty capped at the capacity revenue – in other words, they are no worse off than if they never had a contract. This is insufficient to guarantee plant actually gets built and as a result, historical projects which have won capacity contracts have not eventuated in the physical market
- **Treatment of demand response is challenging:** the UK system subjects demand response providers to testing requirements which can be difficult to perform (e.g. requiring demand response providers to demonstrate reductions in load when it is not economic for consumers to reduce load), especially for new demand response providers. Derating treatment of demand response has been the subject of successful court challenges
- **Interactions with other government mechanisms can lead to inefficient outcomes:** early capacity mechanism auctions resulted in large amounts of new inefficient diesel-powered generators to enter the market, connected to the distribution system. This happened because the diesel generators benefitted from another government scheme which supported distribution-connected generation. This was remedied in later years
- **The scheme explicitly values dispatchable capacity, with a separate scheme to support renewables, and does not allow any capacity to participate in both schemes:** the British capacity mechanism theoretically includes variable renewable energy generators as eligible participants, but in reality they are virtually all excluded based on their involvement in the separate scheme to underwrite renewables

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PJM – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- Pennsylvania – New Jersey – Maryland Interconnection (PJM) serves all or parts of 13 states in the US
- World's largest centrally dispatched electricity grid
- The capacity mechanism is highly complex, with detailed regulations covering virtually every aspect of the scheme
- 27 local delivery areas, but with a different locational price at every delivery point
- Wholesale energy price offers are capped at US$1,000 per MWh, unless the bidder can demonstrate they have a cost-based reason for an offer above that level, up to US$2,000 per MWh (make-whole payments can be above this if needed, but the market price cannot rise above this level)
- Interestingly, the mechanism is a hybrid decentralised and centralised mechanism: retailers can self-fulfil their resource adequacy requirements (for vertically integrated players) or participate in the centralised scheme
- Rule changes are frequent in the PJM capacity mechanism, as are legal challenges to various aspects of its operation

Design aspect	Summary of design choices*
Capacity definition	• Split into two delivery seasons – summer and winter. Capacity can be sold differently for each season • Derated capacity must be available for emergency events between 10am and 10pm in summer and 6am to 9pm in winter • Capacity providers can include: generators, demand response, energy efficiency, aggregated resources (combination of other resources acting as a single bidder) and transmission upgrades • Derating methodology varies for each resource type
Forecasting methodology and determination of capacity certificate demand	• PJM centrally determines reliability requirements • Requirements are determined on a "local delivery area" level and also at a PJM-wide level • Modelling accounts for non-coincident peak load on a day as a function of calendar events (e.g. weekdays, holidays, etc), weather data and other trends • The projected peak plus a specified installed reserve margin (most recently 14.4%) informs the demand curve • If local delivery areas are constrained, they have a separate reliability requirement
Certificate trading and procurement methods	• Vertically integrated retailers can opt out of the mechanism and "procure" their share of the reliability requirement from within their own portfolio. This capacity must still be certified and derated centrally • Other capacity is procured by the system operator in an auction, with auctions at T-3 (which aims to procure all the required capacity) and 20 months, 10 months or 3 months before if required
Transmission constraints and interconnection	• Transmission upgrades can enter into auctions to increase transmission availability into constrained local delivery areas (they may increase connectedness of a "sink area" with a "source area") • If the transmission is successful in an auction, it is paid the difference in price between the sink area and the source area • Existing transmission cannot participate in the auctions – only new projects
Market power mitigation	• There are extensive rules to regulate bids into the capacity mechanism auctions • "Pivotal suppliers"* are subject to market seller offer caps • New generation is subject to other offer caps which are dependent on the average location-adjusted sell offers • A minimum offer price rule applies to a subset of generation – most recently any subsidised generators*
Penalties, compliance and incentives	• Capacity providers with capacity contracts are subject to non-performance charges (including those that are part of a decentralised retailer portfolio and those who bid into the central auction) • The penalties are awarded as revenue to overperforming resources • Other penalties also apply

* More detail in appendix

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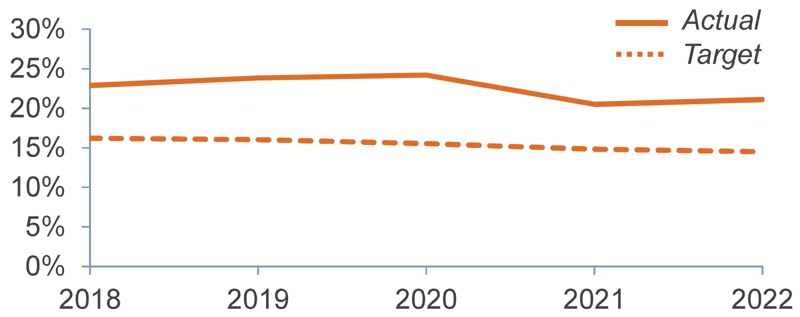
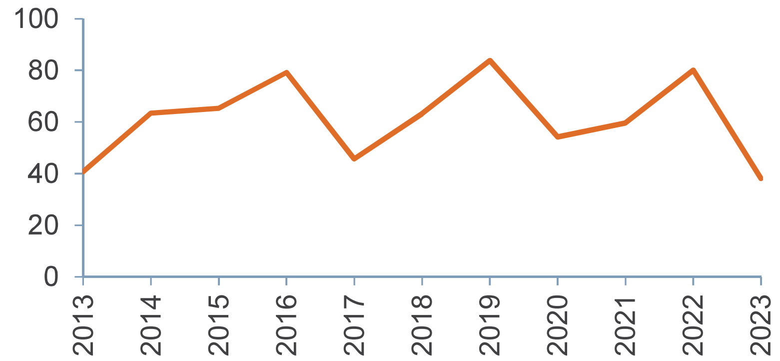
PJM – PERFORMANCE OF REGIME

- The PJM capacity mechanism has successfully procured a large number of new projects over its years of operation (59 GW since 2008), from a variety of capacity sources including: OCGT, CCGT, diesel, hydro, steam, nuclear, solar, wind and fuel cell batteries
- For the 2023 delivery year, almost 9 GW of new capacity has been procured, mostly CCGT
- The capacity mechanism has consistently over-procured relative to the target reserve margin
- Performance assessment intervals have been very rare throughout the operation of the capacity mechanism, suggesting that the level of procurement has been more than sufficient to meet reliability requirements

Actual vs target reserve margin



Unit price of capacity procured in past auctions (A$ per kW)



Source: NERA analysis on publicly available data from PJM

PJM – POINTS OF INTEREST AND LESSONS

- **The hybrid centralised and decentralised system is a point of interest:** it is unusual in a global context as it allows vertically integrated participants to contract for their own needs. This may be an option in Australia, where there are vertically integrated players, however the benefits of such a model are unclear (versus a model that required all generators to participate in the central auction)
- **Transmission upgrades can compete with generation to provide locational capacity:** this is a theoretical point of interest, however no transmission upgrades have actually cleared an auction in PJM
- **Incremental auctions can increase liquidity in capacity contracts:** this may reduce the risk of non-delivery for new capacity by offering an option to “trade out” of their capacity obligations in a delivery year if there are construction delays
- **Permitting a wider range of resources to enter capacity mechanism auctions may be more efficient but also requires much more regulation:** different types of capacity (e.g. energy efficiency and transmission upgrades) need to be derated and monitored differently
- **Competing policy objectives have resulted in issues with operating the mechanism:** tension between competing objectives (e.g. decarbonisation vs undistorted competition) have led to delays in auctions for multiple years, which may undermine the ability of the mechanism to attract long-term investment, particularly if delays continue
- **There are strong incentives to follow through with commitments to build new capacity:** significant penalties for failing to meet targets has incentivised successful delivery of significant amounts of new capacity

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FRANCE – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- Mechanism launched in 2016, with first delivery year in 2017
- Market context:
  - The electricity market is highly concentrated
  - Electricite de France (EDF) is the largest retailer (80% of residential customers)
  - EDF owns ~55% of the capacity guarantees traded through the capacity mechanism
  - EDF also owns distribution and transmission assets
- On the generation side, the market is highly dependent on nuclear, which is large and inflexible plant
- The French mechanism is decentralised, with obligations on both retailers to procure capacity guarantees and capacity operators to provide capacity during peak periods
- There are three separate schemes to support different kinds of capacity: the capacity mechanism, which awards one year contracts to capacity based on contribution to reliability, a separate underwriting scheme which supports demand response and batteries (up to 7 year contracts), and a third which underwrites renewables

Design aspect	Summary of design choices*
Capacity definition	• Market operator certifies capacity • Must perform during defined peak days – on peak days, all periods between 7am-3pm and 6pm-8pm are peak periods • Notice is given the day before a peak day • There are a fixed number of peak days each year, with additional restrictions around how many can be in each season • De-rating uses a combination of historical data (non-dispatchable), calculation of duration of capacity (dispatchable), and a technology scalar (e.g. solar scalar is 0.25)
Forecasting methodology and determination of capacity certificate demand	• Forecasting is done by retailers • Based on consumer demand during peak periods • Compliance is determined ex post, based on the actual average consumption of the retailers' consumers during peak periods, and a "security coefficient"
Certificate trading and procurement methods	• Auctions and over-the-counter bilateral trades • At least 15 auctions cover every delivery year (across T-4 to T-1) • Can be traded during and after the delivery year
Transmission constraints and interconnection	• Capacity guarantees can come from anywhere in mainland France – there is no adjustment based on location • Interconnectors can be awarded certificates, which are held by the network operator and sold on to obligated parties
Market power mitigation	• Requires internal transfers of capacity guarantees (e.g. from a wholesaler arm to a retailer arm) are made at a price representative of auction prices • Requires all trades to be recorded in the capacity guarantees register
Penalties, compliance and incentives	• Ex-post compliance on obligated parties and capacity providers three years after the delivery year • Assessment made in aggregate over a delivery year (overdelivery on some days can cancel out underdelivery on others) • Penalties for underdelivery in aggregate are up to 1.2 times the capacity price for that delivery year, while overdelivery generally receives 0.8 times the price of capacity for the delivery year

* More detail in appendix

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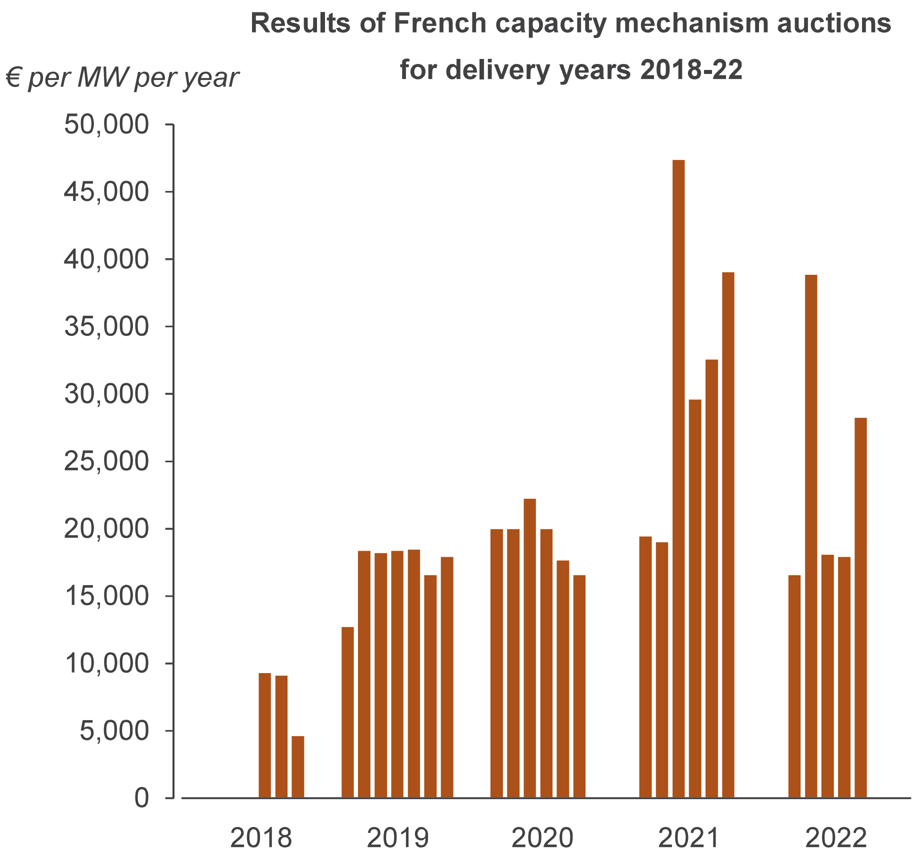
FRANCE – PERFORMANCE OF REGIME

- New capacity is procured through the separate underwriting scheme and awarded multi-year contracts. The scheme is very new and has only awarded contracts to battery and demand response projects
- Prices in capacity mechanism auctions have been volatile and increased on a unit basis in recent years
- Auctions only represent roughly one third of procurement under the scheme (the rest done bilaterally and not transparently), so it is difficult to track the performance of the scheme based on publicly available data
- As the scheme is in very early years of operation, it is arguably too soon to make an assessment of its impact on reliability in the French market



Source: Flexcity 2021, NERA

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FRANCE – POINTS OF INTEREST AND LESSONS

- **Decentralised scheme:** the French scheme places the responsibility and the risk of procuring capacity guarantees on retailers. They are incentivised to procure sufficient guarantees due to a threat of penalties, administered by the market operator
- **Separate mechanisms for long-term and short-term auctions:** the French policy landscape includes a separate mechanism that awards long-term contracts to low-carbon or carbon neutral generation (e.g. batteries). This is similar to the NSW roadmap in that contracts are only awarded to new capacity and take the form of a contract for difference (CfD).
- **Market power mitigation:** During the operation of the French capacity mechanism, market power measures have been introduced, including:
  - Transparency over bilateral over the counter trades to minimise information advantages for incumbents (data is anonymous)
  - Transfer pricing must be based on market prices
  - Regular auctions to promote liquidity
  - Requiring managers of portfolios over 3GW of capacity to offer capacity into the centralised auctions
- **Multiple platforms for procurement:** the mechanism allows both centralised auctions and bilateral procurement

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CALIFORNIA – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- California's mechanism is a decentralised system
- There are three types of retailers ("load serving entities"):
  - Investor-owned utilities (three dominant ones with some minor players)
  - Community choice aggregators (not for profit providers which usually serve a specific, small geography)
  - Municipal utility districts (some municipalities directly own electricity companies)
- The wholesale market is quite fragmented – investor-owned utilities have some generation capacity, but not a commanding share
- There are different types of requirements placed on load serving entities, which must procure:
  - System resource adequacy products
  - Local resource adequacy products
  - Flexible resource adequacy products (which are divided into a further three categories)
- The system is decentralised because the obligation is placed on load serving entities to procure the contracts, but has centralised compliance

Design aspect	Summary of design choices*
Capacity definition	• Contracts are written and assessed on monthly periods • Three types of contracts: system agreements, local agreements (where load serving entities must show they have enough local capacity to meet the required level) and flexible agreements (where resources must be available within a 3 hour ramp period – this is further separated into three categories which each have their own specific requirements*) • Different methods are used to de-rate different technology types. All technology must be certified and de-rated by the system operator
Forecasting methodology and determination of capacity certificate demand	• Forecasting mostly sits with the market operator, which can assess load serving entities' procurement levels at different times on an ex-ante basis • There is a mandated reserve margin over the peak demand forecast (15%, although this increased to 17.5% for summer months in 2021 and 2022) • There are different requirements for each of the types of required agreements (system, local and flexible)
Certificate trading and procurement methods	• Trading and procurement is totally decentralised and can occur at any point up until load serving entities are assessed • There is an element of forced centralised cost allocation through a "Cost Allocation Mechanism", which can occur if the market operator requires the investor-owned utilities to procure new generation on a case-by-case basis. In this instance, all costs and benefits of the procurement are allocated to the relevant customers. This is a separate, but related mechanism
Transmission constraints and interconnection	• The local procurement requirement addresses the issue of transmission constraints because load serving entities are required to purchase capacity in a way that reflects local transmission constraints • Interconnectors are also accounted for under this system because load serving entities can procure system agreements from resources across an interconnector
Market power mitigation	• A "waiver rule" for local requirements where load serving entities can opt out of some requirements if they can demonstrate they did not receive any reasonable offers • CAISO can act as a backstop to directly procure capacity not otherwise contracted (for a fixed rate)
Penalties, compliance and incentives	• Load serving entities face penalties for non-compliance with each of the three separate requirements • Capacity providers who have sold contracts must offer their capacity at the pre-defined times, but do not actually face a penalty for failing to perform

* More detail in appendix

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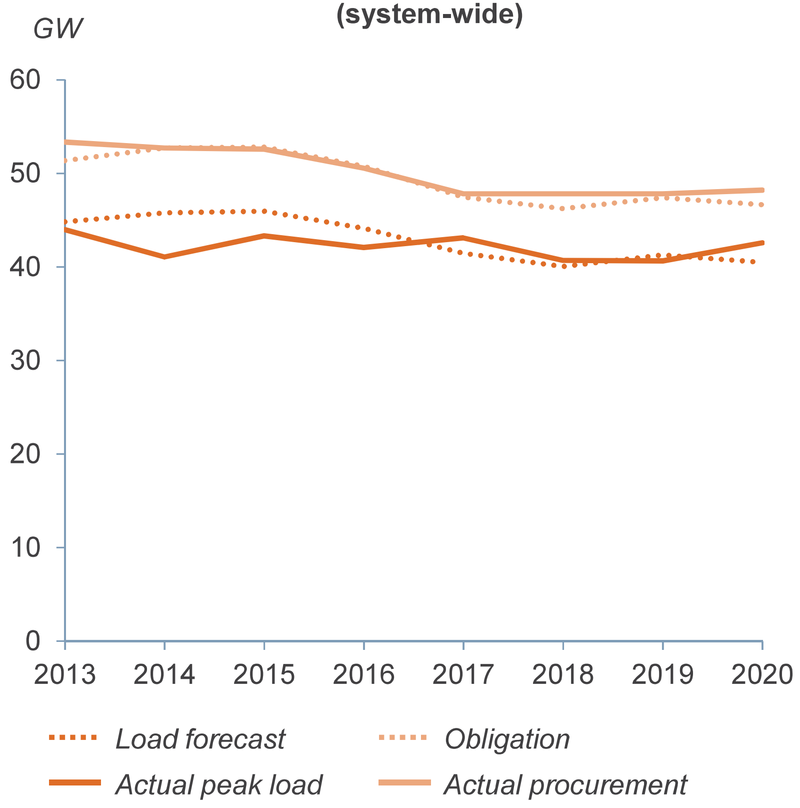
CALIFORNIA – PERFORMANCE OF REGIME

- In 2020, on a system-wide level, the load serving entities collectively met their system requirements, but there were some shortfalls in respect to local requirements
    - In five of the ten regions, retailers would have had to request a waiver from the scheme or pay a penalty, with the remaining capacity procured by CAISO as a backstop
- Even though forecasts have been a good reflection of actual load in recent years, and retailers have covered their required positions in aggregate, (pictured right) the system has faced reliability events in recent years. These have been attributed to extreme weather events, planning targets that have not accounted for the changing grid requirements in transitioning to renewables, and practices in the day-ahead market that exacerbated supply problems

Procurement in capacity mechanism vs peak load (system-wide)



Source: CPUC, NERA

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CALIFORNIA – POINTS OF INTEREST AND LESSONS

- **Difficulty in sending investment signals through a decentralised mechanism:** the mechanism has only recently (in 2020) introduced a requirement for load serving entities to purchase contracts more than a year out from a delivery year. Before this, there was minimal long term capacity contracting (that has been publicly reported). Under the new model, load serving entities must contract 100% of their requirements two years in advance and 50% three years in advance, which is still a shorter investment signal than most centralised mechanisms
- **Clear methodology can mean less technical grounding for decisions:** the methodology for the Californian system is relatively uncomplicated (e.g. penalties for not complying with the system resource agreement requirement are $6.66/kW month, and the local penalties are half that amount), but it is not necessarily based on economic efficient reasoning
- **Different requirements serve different purposes:** the three separate requirements that load serving entities must meet are not co-optimised into one market, but assessed completely separately. This places a compliance burden on load serving entities to procure the minimum amount to meet all three requirements, with no ability to trade-off between them
- **Performance obligations:** the Californian system has no performance obligations for capacity providers. As such, load serving entities can have achieved their required procurement targets, but the system can still face a reliability event. Dispatchable generation is subject to some penalties for not offering into the market, but these do not become steeper in events of actual system need.

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IRELAND – HIGH LEVEL SUMMARY OF MECHANISM

Background information

- Irish market covers Northern Ireland and the Republic of Ireland in an integrated system
- This system uses a “reliability option” model where capacity is incentivised by a market-based wholesale price rather than administrative penalties
- The current mechanism was implemented in 2018, but replaced a more administrative, less market-based system that previously existed to hand out explicit capacity payments
- In 2018, alongside the new capacity mechanism, the integrated Irish system also introduced a day ahead market, an intra-day market and a balancing market
- There is a high concentration of market power
- There are three main zones – Dublin, the Republic of Ireland outside Dublin, and Northern Ireland. Significant transmission constraints separate these zones
- There is a high penetration of renewables
- The system is very small (peak demand <10 GW) so exit or entry of one large plant has a huge impact

Design aspect	Summary of design choices*
Capacity definition	• Capacity is provided by thermal units, renewables, storage or demand-side units. Interconnectors (i.e. to Great Britain) can also participate in the auctions • Each type of capacity is de-rated using a different methodology
Forecasting methodology and determination of capacity certificate demand	• A central operator sets the demand curve based on modelling of future demand scenarios • The central operator also determines how much capacity is required in each zone (Dublin, Republic of Ireland excluding Dublin and Northern Ireland). If the amount procured in the central auction doesn’t meet the requirements, accounting for constraints, in each zone, the central operator will award contracts to additional capacity providers in zones that were short
Certificate trading and procurement methods	• Central auctions at T-4, with additional auctions run in subsequent years if required to fill the capacity demand • Secondary trading is only permitted under certain conditions: if the unit is affected by an outage, if there are fluctuations in the availability of a unit’s primary energy source (e.g. hydro, based on water levels), or if otherwise given an exemption to trade
Transmission constraints and interconnection	• The capacity requirements are set by zone as well as overall to account for the transmission constraints between zones • Otherwise, there is one integrated auction, and the marginal value of capacity in different zones is not accounted for • As discussed above, the market operator separately ensures that enough capacity has been procured to meet the requirements for each zone after the auction is complete • Interconnectors (from Great Britain) are included in the auction and de-rated based on technical availability (i.e. accounting for projected outages) as well as the modelled likelihood of availability of capacity to be exported out of Great Britain
Market power mitigation	• Strict bidding price caps for existing generation. The market has typically cleared very close to these price caps • More lenient bidding restrictions on new generation • All capacity required to offer into the auction unless granted an exemption (e.g. if a unit is planning to close)
Penalties, compliance and incentives	• Incentive built into the “reliability option” style capacity contract – similar to the structure of an Australian “$300 cap” – requiring generators to pay out the difference between the (blended) wholesale price and the strike price when wholesale prices are higher than the strike price • Termination charges apply to capacity providers who exit contracts ahead of the delivery year

* More detail in appendix

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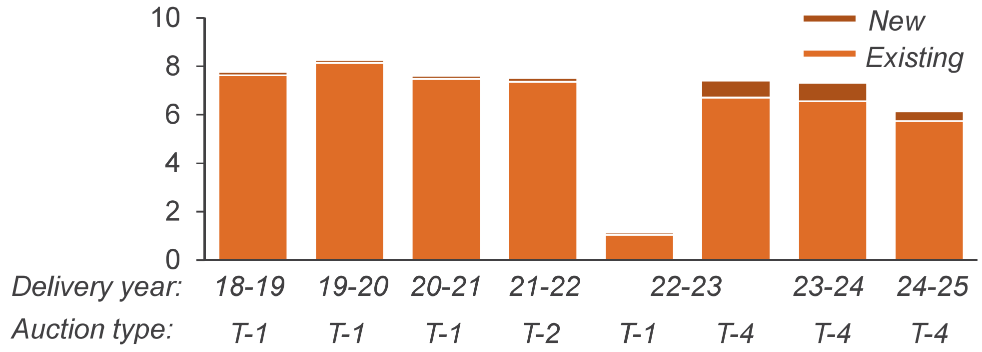
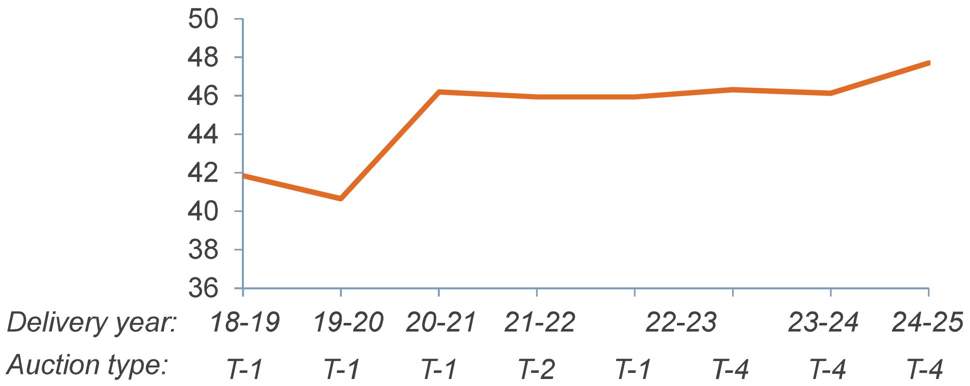
IRELAND – PERFORMANCE OF REGIME

- The scheme was introduced in late 2018 and as such, limited data on performance of the scheme exists
- **Cost:** annual procurement costs are between €300 and €400 million per year, or roughly €40-€50/kW-year.
- **Compliance events:** there have only been two compliance events (where the wholesale price has risen above the strike price) in the operation of the scheme, and neither resulted in a shortfall
- **Overall supply pipeline:** every year since its implementation, the Irish capacity mechanism has overprocured capacity. However, concerns remain about projected resource adequacy, due to:
  - Generation scarcity in Great Britain, and difficulty in accurately de-rating the interconnection capacity four years in advance
  - Closure of fossil fuel plants
  - Growth in electricity demand
  - New capacity failing to deliver (more detail on next slide)

Capacity procured in past Irish auctions (GW)



Unit price of capacity procured in past Irish auctions (€ per kW)



Source: SEM-O data, NERA

IRELAND – POINTS OF INTEREST AND LESSONS

- **Integrating interconnectors has posed a persistent challenge:** interconnector capacity represents a large proportion of the nameplate capacity available to participate in the Irish capacity mechanism, but determining an appropriate de-rating factor is extremely difficult, especially on a T-4 basis. Interconnector owners also do not influence the available flow over an interconnector so cannot respond to the incentives in the capacity contracts, unlike other participants. Additionally, most European interconnectors are subject to revenue caps, so capacity mechanism revenue may not affect investment to promote resource adequacy.
- **If penalties are insufficient, new plant may not actually be delivered:** in the short history of the current capacity mechanism in Ireland, 513 MW of new plant has failed to deliver. While the Irish mechanism has stronger penalties than comparable mechanisms (e.g. UK) within a delivery year and for existing capacity withdrawing from a contract before a delivery year, penalties for non-delivery of new plant appear insufficient. Penalties for early termination for new plants are set at a fixed per-MW fee if the contract is exited more than 13 months in advance of a delivery year.
- **The mechanism was specifically designed to be able to offer a longer-term investment signal:** the committee tasked with the redesign of the Irish capacity mechanism considered it was critical for longer-term contracts to be awarded. The mechanism awards up to ten year contracts for qualifying plant.
- **Locational incentives:** the Irish mechanism attempts to address transmission constraints between zones by procuring additional resources after the auction to meet zone-specific requirements if required. A more ideal design would have separate demand curves to reflect required capacity by zone, even if that resulted in different prices between regions. The current arrangement has resulted in successful litigation by participants that were forced to operate in constrained zones*

* More detail in appendix

APPENDIX 1 - GB

CAPACITY DEFINITION

Product Definition

- Capacity Agreements are a contractual agreement between System Operator and generators, whereby generators will be required to make the contracted amount of capacity available whenever the System Operator gives a Capacity Market Notice of system distress.
- This gives generators 4 hours' notice.
- The generator, in return, receives yearly payments.

De-rating

- Dispatchable: 7-year historical average availability during winter high demand periods.
- Storage units: Equivalent Firm Capacity of storage class (by duration).
  - For every block of extra duration provided to a Base Case (0.5-hour increments), simulations calculate how much firm capacity can be removed while reliability standard is maintained.
- Interconnectors: Stochastic simulations of GB and overseas markets run over 5 'Future Energy Scenarios' (FES) to create a country-specific de-rating factor
- DSR: De-rated on the basis of Average Availability of Non-BSC Balancing Services, measured under assessment of committed availability to provide Short Term Operating Reserves over the previous 3 Winters.
- Units in the same technology class receive the same de-rating factor.

Technology Neutral

- The mechanism is aimed at being technology neutral but is confined to some degree by fossil fuel limits put in place following the EU's Clean Energy Package.
- Emissions of a unit must not exceed 550g of CO_2 per kWh installed or 350kg of CO_2 per kW installed over the year
- This applies for all auctions beginning in 2021 for all generating units commissioned after 4th July 2019.
- For units commissioned before 4th July 2019, these emissions restrictions apply for all auctions for delivery year 2024/25 and onwards.

FORECASTING AND DEMAND

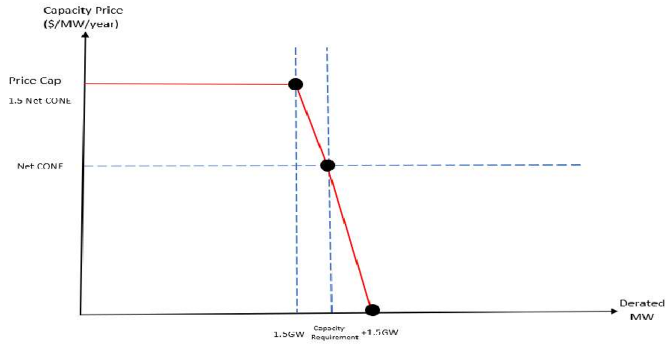
- Forecasting is centralised, the Secretary of State decides the target capacity on advice of the system operator, who publishes a yearly report based on simulated demand scenarios.
- Five Future Energy Scenarios (FESs), generated based on different assumptions about demand conditions.
- Dynamic Dispatch Model (DDM) used to generate de-rating factors and capacity requirements under each scenario
- This method provides i) total de-rated capacity required to meet 3 hours LOLE, ii) de-rated capacity to be secured in the CM auction, iii) de-rated non-eligible capacity expected to be delivered outside the CM, iv) total nameplate capacity split between CM and non-CM, v) de-rated capacity already contracted from previous auctions.
- Least-Worst-Regret analysis used to balance cost of over-procurement against cost of shortfall and select a target capacity requirement that minimises costs, while maintaining 3 hours LOLE standard.

Future Energy Scenario	Energy Demand
Base Case	Demand reduction and decarbonisation continues at a steady pace
Consumer Transformation	2050 net zero target is met, driven by greater consumer engagement in the energy transition. High peak electricity demands managed through flexibility. Low gas demand
System Transformation	Less disruption for consumers, most changes coming from supply-side. High hydrogen demand, produced through natural gas with CCUS
Leading the Way	GB decarbonises rapidly. Assumptions on different areas of decarbonisation pushed to earliest credible dates. Consumers highly engaged. Hydrogen used a lot, produced from electrolysis
Steady Progression	Progress on decarbonisation, however it is slow. Growth in EV means that smart technology is still important

PROCUREMENT AND TRADING

- The operator runs two auctions, one main one at T-4 and a balancing auction at T-1.
- Mandatory participation for existing generators and interconnectors.
    - Can opt out by proving capacity unavailability or failure to meet emission standards
- Price cap for 'price-setters' = 1.5 Net CONE
- Price cap for 'price-takers' = 0.5 Net CONE
    - Unless 0.5 Net CONE is demonstrably insufficient for a plant to remain operational.
- DSR eligible for multi-year contracts following EU ruling
- Descending clock auction
    - Start at 1.5 Net CONE, descend in £5/kW increments

Demand Curve



Secondary Trading

- There are restrictions on secondary trading, transferees of contracts must qualify in much the same way as participants in the auctions and new build must meet progress milestones before qualifying.

Cost Recovery

- Costs are recovered against retailers based on their contribution to total load in the system.
- Monthly charge levied to retailers: (Total annual payments to capacity provider) * (Monthly weighting factor) * (Ratio of retailer's gross demand to total gross demand for all retailers)

TRANSMISSION AND INTERCONNECTION

- No locational pricing in the CM
- Interconnectors can participate in the CM, these have country-specific de-rating factors based on ESO modelling of capacity entering GB in system stress periods.
- This is extremely volatile as modelling for interconnectors is based on selected values from a wide range of sensitive assumptions. e.g. Ireland’s interconnector capacity for 2025/26 is between 10-97%.

MARKET POWER

- No locational pricing in the UK means that local market power is not an issue.
- No single firm can exercise significant market power on a national level.
- All generators are obligated to participate in the auction unless they can demonstrate that their capacity will not be available for the delivery year or that they will be in breach of emissions restrictions.
- Price caps of 1.5 x Net CONE and 0.5 x Net CONE for ‘price makers’ and ‘price takers’ respectively.
- Price caps exemptions may be granted if a generator can prove it is not operational at the price cap level.
- Mandatory participation and price caps prevent generators from withholding or driving prices upwards with high bid prices.

PENALTIES AND COMPLIANCE

- System stress event is defined as 15 or more continuous minutes of demand reduction due to a capacity shortage - Distinct from a network failure or demand disconnection.
- The operator must give four hours' notice that a system stress event could occur and will then make an assessment on whether a demand reduction or demand disconnection has occurred, or it is indeed a system stress event.
- It is during system stress events that generators are obligated to provide their contracted capacity.
- Penalty rate = 1/24th the clearing price for that delivery year. Penalty payments capped at twice the monthly revenue for a single month and for the year are capped at the total yearly revenue.
- Termination for failure to meet construction/financial reporting deadlines either £5/kW or £25/kW depending on reasons for termination.
  - Termination not only incurs a penalty fee but foregoes capacity payments, which are not paid until delivery year.

APPENDIX 2 - PJM

CAPACITY DEFINITION

Product Definition

- Capacity Obligation is a contract to provide 'Capacity Performance'
- Under this obligation, contracted capacity must be made available during emergency events between 10:00 and 22:00 during Summer (May to September) and between 06:00 and 22:00 during Winter (October – April)
- Contract can be held for the entire delivery year or on a Summer/Winter basis, though only approx. 0.5% of capacity is procured on this basis

De-rating

- Rated installed capacity adjusted to reflect the previous 15 years' summer peak (ICAP)
- This is de-rated by a unit's forced outage rate over one-year period.
- New capacity is de-rated in the same way but using the forced outage rate of the technology class as a whole.
- Intermittent capacity and batteries de-rated based on Effective Load Carrying Capability (ELCC) – ELCC models displacement of firm capacity by intermittent/batteries while maintaining the reliability standard.
- DR units are de-rated according to their registered capacity multiplied by Forecast Pool Requirement. (*note: FPR > 1)*
- Energy Efficiency resources qualify on the basis of demand reduction during Summer period (provided Winter load reduction is at least equal to this) and de-rated according to FPR.

FORECASTING AND DEMAND

- Forecasting is centralised and performed by PJM, who release an annual report of fifteen-year monthly load forecasts for each local delivery area called the Reliability Requirement.
- PJM set an administered demand curve as described below

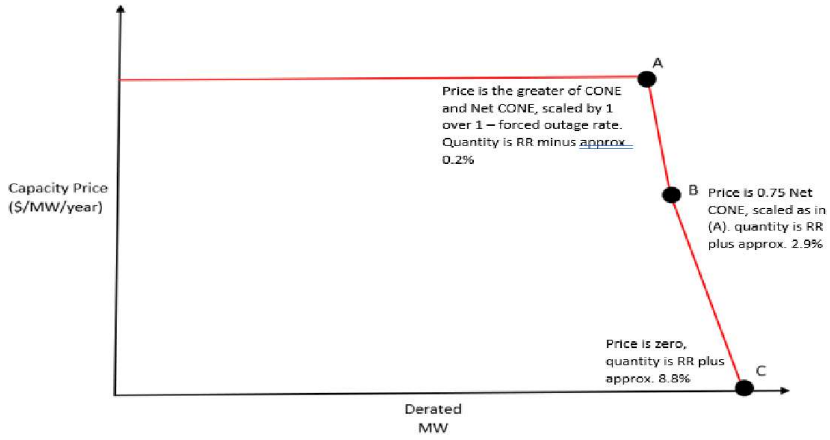
Reliability Requirement

- Econometric model is estimated that can explain non-coincident peak load in terms of calendar effects, weather effects, economic drivers and other related effects.
- Uses these to forecast load using economic drivers and weather simulations based on historical weather data.
- Jurisdiction-wide median load forecasts are allocated across zones in the PJM.
- PJM uses a Probabilistic Reliability Index Study Model (PRISM) to compare peak load forecasts, from which distributions of peak demand are taken for each week of the year, with capacity performance data for existing and new/planned generation.
- LOLE for each week taken and added for the 52 weeks of the year and adjusted to meet the reliability standard (One in ten years/2.4 hours). The difference between total capacity and adjusted demand is the required Installed Reserve Margin (IRM)

LDA-specific Reliability Requirement

- A Local Delivery Area (LDA) is considered constrained if Capacity Emergency Transfer Limit (CETL), the amount of energy the transmission system is capable of importing, is less than 1.15 times the Capacity Emergency Transfer Objective (CETO), the amount of capacity an LDA needs to import to have LOLE of no more than once every 25 years.
- If an LDA has in the past three BRAs had a Locational Price Adder or is the Mid-Atlantic Region, it is also considered constrained.
- Constrained LDAs have a separate Reliability Requirement, equal to local generation capacity plus CETO.

Demand Curve



PROCUREMENT AND TRADING

- Base Residual Auction (BRA) at T-3 and incremental auctions at forward periods of 20 months, 10 months and 3 months.
- Full capacity requirement is procured in the BRA, incremental auctions are for rebalancing purposes.
- All existing generation is required to participate.
- Transmission upgrades are only permitted to participate in the BRA, not in Incremental Auctions.
- Sealed-bid auctions, up to 10 price-quantity pairs can be offered.
- Algorithm used to clear the auction based on demand curve.
- Seasonal bids must be paired, algorithm works this out.

NEPA

- New entrants may be granted a New Entry Price Adjustment, which guarantees a certain price for three years, limited to new generators or upgrades of at least 450 USD/kW.
- If the new entrant capacity is cleared, it must increase the overall capacity for the Local Delivery Area (LDA) from below the LDA Reliability Requirement to approx. 4.9% above it.
- If, subsequently, the capacity, though no longer a new entrant, fails to clear in year 2 or year 3, the participant's bid is replaced with the highest bid that would have cleared and the marginal bidder is replaced. LDA specific clearing price is set on that basis, but the NEPA recipient receives the full price of its bid.

Secondary Trading

- Incremental auctions are used for rebalancing, capacity providers may offer a 'buy bid' to unload some of their obligation.
- Bilateral trading is also permitted

TRANSMISSION AND INTERCONNECTION

- 27 local delivery areas (LDAs), some of which can be designated as constrained LDAs, which may mean those auctions clear with a Locational Price Adder.
- If an LDA receives a Locational Price Adder in two consecutive base (T-3) auctions, a cost-benefit analysis of a transmission upgrade vs. the value of removing the Locational Price Adder. If the transmission upgrade is deemed feasible over ten years, PJM will include the upgrade in the Regional Transmission Expansion Plan.
- Costs of the transmission upgrade will be charged to retailers, prorated to their share of total load.
- External capacity providers may participate but must demonstrate that they have the right and ability to transmit capacity to PJM prior to qualification for the capacity mechanism.
- If an area is expected to have a Capacity Emergency Transfer Limit less than 1.15 times its Capacity Emergency Transfer Objective, PJM can file for that region to be made a new LDA with the Federal Energy Regulatory Commission (FERC).

MARKET POWER

Minimum Offer Price Rule

- Used to prevent state-subsidised generation from depressing the capacity price.
- Until 2018, it only applied to combustion turbines and CCGT but now applies to all state-subsidised capacity except renewable, nuclear technology, DR, Energy Efficiency (EE), or New CCGT.

New Capacity

- New capacity is not subject to MSOC, but if new generation is deemed pivotal, market mitigation measures are used.
- Deemed pivotal if: a) there is only one supplier who submits a sell offer, b) total capacity of new generation offered is less than twice the new entry required to meet reliability requirement, or c) one such sell offer is pivotal.

Market Seller Offer Cap

- Three Pivotal Supplier test is used to determine if capacity from any three generators is required to meet the Reliability Requirement
- Cost-based clearing price – clearing price if all bidders were to bid avoidable costs – is calculated
- PJM works out which bidders could withhold their capacity and in doing so increase the cost-based clearing price by more than 50%
- Pivotal suppliers are then subject to MSOC
- If any two capacity providers are jointly pivotal, then all capacity providers will fail the TPS test.
- MSOC based on Avoidable Cost Rate less projected PJM net market revenues.
- Existing generator bids are replaced with MSOC if a) the bid is above MSOC and b) the bid is either marginal or more expensive than cost-based bid of a marginal unit.
- This mitigation of bids occurs as part of the auction clearing process.
- MSOC previously based on marginal cost of acquiring a capacity obligation, with the assumption of 30 hours of failure to meet capacity obligation - much higher than observed in reality so MSOC was rarely used.

PENALTIES AND COMPLIANCE

- Assessed during Performance Assessment Intervals (PAI), a 5-minute settlement period during which emergency action has been declared.
- Generation and DR resources assessed on the basis of metered output or load reduction plus real-time reserves
- Energy Efficiency resources are assessed on the basis of a post-installation Measurement and Verification Report, submitted prior to the delivery year, thus it is binary, EE is either performing or it isn't throughout the delivery year.
- Transmission upgrades are assumed to have provided full cleared quantity if in service prior to PAI or zero if not.

Expected Performance

- Generators are expected to provide the full contracted de-rated capacity, scaled down if all generators in PJM underperform.
- DR and EE resources expected to provide full contracted capacity.
- Transmission upgrades expected to provide full committed MW upgrade.
- Shortfalls result in Daily Deficiency Rate payments.
- A resource can buy, bilaterally, replacement capacity if there is an acceptable reason why they cannot provide their committed capacity. Replacement capacity must be bought from within the same LDA.

Penalty and Bonus Rates

- Non-performance charge is such that 30 hours' worth of 5 minute intervals, or 360 PAIs, would cost Net CONE for an LDA.
- Penalty is capped at 1.5 LDA Net CONE (45 hours' worth of PAIs)
- Penalties for non-performance are redistributed as a bonus among resources who overperformed.
- Capacity Resource Deficiency Rate is charged to resources who fail to meet committed capacity requirements.
- CRDR is equal to clearing price plus the higher of 20% and $20/MW-Day.
- For transmission upgrades, CRDR = higher of 1.2 times clearing price in LDA and LDA Net CONE.
- Daily Generation Resource Rating Test Failure Rate (failure to prove it can meet capacity requirement) is calculated in the same way.

APPENDIX 3 - FRANCE

CAPACITY DEFINITION

Product Definition

- Generators are awarded capacity guarantees representing 0.1MW each, which can be sold to obligated parties (mostly retailers) at auctions and bilaterally in over-the-counter trades – these guarantees last for 1 year only
- Capacity operators are obligated to make capacity available during PP2 periods, retailers are required to demonstrate they hold sufficient capacity guarantees to meet customer base during PP1 periods.

De-rating

- Non-dispatchable – Average output for PP2 periods over the last 5 years (10 for RoR Hydro)
- Dispatchable – Certified capacity is scaled down based on duration of capacity it could provide, 10 hours a day for 5 consecutive days being considered full credit.
- C parameter also assigned to each technology class as a further de-rating based on likelihood of delivery.

Peak Definition

- Peak hours on days classified as PP1 or PP2 are always 07:00-15:00 and 18:00-20:00
- Must be 15 PP1 days and between 15 and 25 PP2 days in a year, all PP1 days are automatically PP2 days.
- 11 PP1 days must be in the January to March period, 4 must be in the November to December period
- Only business days, excluding Christmas school holidays.
- PP2 days that are not PP1 days can be distributed across any time of the year, except that the sum of PP2 days in March and November must be less than or equal to 25% of the total PP2 days in a delivery year.
- PP2 days cannot fall on weekends or Christmas school holidays.
- RTE decides if a day is a PP1 or PP2 day by running an algorithm that estimates the following day's demand and decides if it is in the *n* highest demand days, based on how many PP1 days remain in the year.

FORECASTING AND DEMAND

- Obligated parties are responsible for forecasting. The demand curve is formed by retailers' demand and the responsibility is on retailers to forecast demand accurately to avoid penalties as well as to reduce load during peaks to reduce their obligation.
- Ex post analysis by RTE three years after delivery year is based on:
  - ‘Reference power’ – actual consumption each obligated party faced during PP1 periods, adjusted for extreme weather. - Equal to sum of reference powers for remote-reading sites (exact consumption discernible), profiled sites (consumption modelled based on load profile) and ‘network loss buyers’.
  - ‘Security coefficient’ – a factor applied to consumption to cover unforeseen externalities (excluding weather). Based on a target LOLE of 3 hours and derived from adequacy studies carried out by RTE.

PROCUREMENT AND TRADING

- Capacity guarantee of 0.1 MW is awarded by RTE to capacity operators and sold to obligated parties.
- Can be sold bilaterally OTC or through organised auctions.
- At least 15 auctions for each delivery year
    - 1 auction in T-4
    - 4 auctions in T-3
    - 4 auctions in T-2
    - 6 auctions in T-1
- Auctions are run by EPEX Spot who publish auction results and supply and demand curves
- Non-fossil fuel capacity (CO_2 emissions < 200 grams of CO_2 per kWh) is eligible for a scheme with the government which offers a contract for difference (CfD) between a guaranteed price and the MC capacity price for up to 7 years
- Renewable energy sources are not eligible for the CfD scheme if they already benefit from a separate scheme that subsidises renewables.
- Obligated parties can trade capacity guarantees during and after the delivery year, this allows for customer churn during the delivery year.

TRANSMISSION AND INTERCONNECTION

- Obligated parties can buy capacity guarantees from any capacity operator in mainland France.
- Two schemes under which an interconnector can be awarded certificates, which are held by RTE and sold to obligated parties.
  - Simplified
    - Country-wide de-rating based on the country's contribution to the reduction of risk of power failure in France
    - Applies when the other country's System Operator has not signed a Cooperation Agreement with RTE.
  - Advanced
    - Individual Interconnector is de-rated based on its contribution to the overall country contribution.
    - Only applies when the other country's TSO has signed a Cooperation Agreement with RTE.

MARKET POWER

- French Competition Authority highlighted two concerns regarding EDF, who serve more than 80% of customers in France.
    - EDF would internally transfer capacity guarantees from its generation arm to its retail arm.
    - EDF would withhold capacity guarantees from the auctions, raising prices for all other retailers.
- In response, internal transfers must be made at a price representative of the auction for that delivery year.
- All internal transfers must be logged in the Capacity guarantees Register.
- There is a requirement on managers of portfolios of over 3 GW to offer their capacity through centralised auctions.

PENALTIES AND COMPLIANCE

- Compliance is assessed three years after the delivery year
- Retailers are assessed on having sufficient capacity guarantees during all hours PP1 days, capacity operators assessed on making sufficient capacity available during all hours of PP2 days.
- Compliance is aggregated over the full year, i.e. over-procurement during one peak and under-procuring during another would only be penalised if insufficient capacity has been procured on aggregate.
- Penalties generally amount to 1.2 times the price of capacity as cleared in auction the year prior to the delivery year.
- Compensation for capacity produced/procured greater than requirement is typically equal to 0.8 times the price of capacity as cleared at auction in the year prior to the delivery year.
    - Compensation capped at 1 GW above requirement.
    - Penalties increase to 1.6 times capacity price for deficits in procurement/production greater than 1 GW but are capped here.
- If the system has a shortage of 2 GW or more, penalties are replaced by an administrative price set at 60 EUR/kW with no limits.

APPENDIX 4 - CAISO

CAPACITY DEFINITION

Product Definition

- Three types of Resource Adequacy (RA), System RA, Local RA, Flexible RA.
- Calendar delivery year with monthly requirements for each of the three RA types.

System RA

- Monthly requirement on LSEs equal to load forecast plus a 15% margin.
- 90% of system RA requirement for the 5 summer months must be demonstrated to have been procured by LSEs in October prior to delivery year.
- LSEs must demonstrate that they have procured contracts for 100% of the month's system RA requirement 45 days before each month.

Local RA

- RA required to cover an n-1-1 reliability event while maintaining a LOLE of 1 in ten years.
- An 'n-1-1' reliability event refers to 'n', which means all transmission facilities in service, the first '-1' refers to a forced outage or a single contingency event, and the second '-1' refers to the next worst single contingency event.
- This standard must be met in each of all 10 Local Capacity Areas.
- Waivers on obligation fees can be given if an LSE can demonstrate "every commercially reasonable effort to contract for local RAR resources"
- Fees are $51/kW-year
- Local RA requirements must be contracted for three years in advance. In October prior to a delivery year, LSEs must demonstrate they have contracted for 100% of local RA requirement for the following year, 100% of requirement for the following year and 50% for the third year.
- As of 2023, PG&E and SCE will act as Central Procurement Agency (CPE) for Local RA.
- Other LSEs can still procure Local RA capacity which can; be sold to the CPE, contribute to the LSE's System RA requirement, or reduce the Local RA requirement for the CPE.
    - This change does not apply to the SDG&E area, where Local RA exceeds System RA for most months of the year.

Flexible RA

- Based on maximum change in load in a 3-hour period and how much production can be ramped up or down in a 3-hour period.
- In October before a delivery year, LSE's must demonstrate that they have procured 90% of capacity requirement for each month of the delivery year. They must also, 45 days before each month, show that they have procured capacity for 100% of the Flexible RA requirement for that month.

De-Rating

- Dispatchable – Most recent maximum capability test
- Run-of-River or geothermal – average historical production for three years prior to T-1
- Combine Heat and Power (CHP or Biomass – average bid into Day Ahead Market from 16:00 – 21:00
- Wind and Solar – ELCC modelling to simulate how much firm capacity wind/solar can displace and maintain reliability.

FORECASTING AND DEMAND

- Forecasting is performed by retailers who must meet resource adequacy requirements on three different levels.

System RA

- LSEs submit their own forecasts, which the CEC adjusts for plausibility and load migration, as well as a pro-rata adjustment made to the aggregate load forecasts submitted by LSEs in order to achieve a forecast that diverges from the CEC forecast for total demand by less than 1%.
- Forecasts include a 15% reserve margin.

Local RA

- Annual CAISO Local Capacity Technical Study conducted to forecast Local Capacity Requirements (LCRs) for each of the ten LCAs in year 1 and year 5.
- The technical study maps the CEC forecast with CAISO's forecast of transmission constraints and works out how much capacity would be needed locally to cover an n-1-1 event and maintain a 1 in 10 LOLE (same reliability standard as system RA)
- Because the standard is the same, local RA counts towards system RA.
- Data is interpolated between years 1 and 5.

Flexible RA

- Flexible capacity requirement for each month is equal to the maximum 3-hour ramp that would be required 1 in 2 years (50% probability) plus the amount of capacity required to cover a sever, single, system-wide event (assumed for modelling to be an outage of one 1.1 GW reactor at the Diablo Canyon nuclear power plant).
- Flexible RA requirement is met by resources based on resource types.
  - Category 1 - Must be available from 05:00 to 22:00 every day of the year, available for at least 6 hours and able to turn on twice during the day.
    - From May to September, at least 49.6% of Flexible RA must come from Category 1, 39.9% for the rest of the year.
  - Category 2 - Must be available from 07:00 to 12:00 every day from May to September and 15:00 to 22:00 every day for the rest of the year. Must be available for at least three hours and able to turn on at least once every day.
  - Category 3 - Must be available from 07:00 to 12:00 every day from May to September and 15:00 to 22:00 every day for the rest of the year, weekends and holidays excluded. Must be available for at least three hours and able to turn on at least 5 times per month.
    - No more than 5% of Flexible RA.
- Retailers must procure the flexible RA requirement in proportion with their share of peak load.

PROCUREMENT AND TRADING

- Procurement and trading in the CAISO capacity mechanism is entirely de-centralised, there is no central auction.
- Responsibility for procuring Resource Adequacy (RA) is placed on retailers, who must enter bilateral agreements with generators to meet RA requirements.
- RA providers must be accredited and de-rated.
- There is a separate, centralised mechanism called the Cost Allocation Mechanism, which procures a significant amount of new capacity.
- Under this mechanism, CPUC instructs Investor-Owned Utilities (IOUs) to procure new generation, allocating costs and benefits to retailers, while net costs of the contract are paid by the retailers in the IOU service territory.
- This capacity is added to the RA requirement for the IOU and reduces the requirement for non-IOU retailers in the service area.
- Flexible capacity is required to meet RA standards as set out by category in the previous slide and are de-rated based on start-up time and in accordance with how much capacity can be produced within a time frame given their start-up time.
- There is no official mechanism for secondary trading, but it is permitted.

TRANSMISSION AND INTERCONNECTION

- Transmission constraints are built into the RA mechanism by being incorporated into the Local RA requirements.
- The centralisation of Local RA, the designation of two Investor-Owned Utilities (IOUs) (PG&E and SCE) as Central Procurement Entities (CPEs) allows for these two entities to internalise transmission concerns about the trade-off between transmission reinforcement and local capacity.
- This has raised some environmental concerns over these IOUs being able to reinforce transmission rather than opting for potentially greener local capacity,

MARKET POWER

- Waiver rule, which allows retailers to opt out of their Local RA obligations if they can demonstrate that they did not receive any reasonable offers.
- This was put in place to prevent large retailers from dominating the market by effectively capping prices at the waiver rate.
- The rate for waivers was initially $40/kWh but now sits at $51/kWh.
- CAISO can cover shortfalls through its Capacity Procurement Mechanism, the rate for which is $75.68/kW-year, calculated as 20% above marginal costs for a combined cycle resource with duct firing.
- Market power was not much of a concern in the infancy of the RA mechanism due to the lack of retailer-choice that customers had. However, this is becoming an increasing concern as community choice aggregators supply an increasing market share.
- By designating PG&E and SCE as Capacity Procurement Entities CAISO has attempted to address the fragmentation of the consumer base, meaning that in LCAs outside of SDG&E, there is only one buyer of Local RA.
- No entity has a large enough market share state-wide of System and Flexible RA, PG&E is the largest owner with 7 GW to a state-wide peak demand of 40 GW, for market power to be a major concern.

PENALTIES AND COMPLIANCE

- Penalties apply for each of the RA categories
- Dispatchable generators are required through the Resource Adequacy Availability Incentive Mechanism to offer their capacity into CAISO at pre-defined times but have no ‘performance’ requirement that requires availability during system stress events.
- Penalties for retailers who fail to meet System RA requirements are $8.88/kW-month in Summer (May-October) and $4.44/kW-month in Winter. This is a change from the flat rate of $6.66/kW-month that applied prior to 2020.
- Points system, whereby 1% of deficiency in a month accrues 1 point, is in place which dictates that the penalty rate double if 6-10 points have been accrued and triples if 11+ points have been accrued. Points expire after 24 months.
- In 2019, Local RA penalty rate increased from $3.33/kW-month to $4.25/kW-month (1/12th waiver fee)
- Local RA penalties are not additive to System RA penalties. If system RA is deficient, the system RA penalty is paid on the deficiency. If an LSE is deficient by a greater amount in Local RA than System RA, the System RA penalty rate is paid on the system RA deficiency and Local RA penalty rate is paid only on the excess Local RA deficiency.
- Flexible RA penalty rate is $3.33/kW-month (half the average System RA penalty rate) and is likewise with Local RA, not additive to System RA penalties.

APPENDIX 5 - IRELAND

CAPACITY DEFINITION

Product Definition

- Reliability Option – Generator sells a contract to the market operator, under which generators receive a premium but will make difference payments to the market operator equal to any positive difference between the market reference price and the strike price of the option, equal to 500 EUR. This difference payment is owed whether the holder is generating or not.
- If a generator is generating at full de-rated capacity, they receive a net revenue equal to the strike price, large costs can be incurred if a generator is not generating when the market reference price exceeds the strike price.

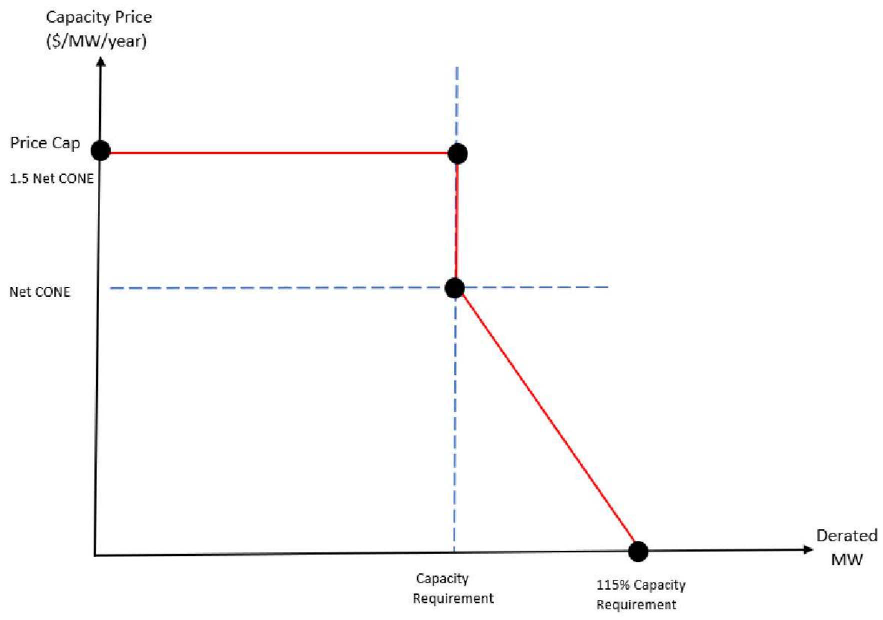
De-rating

- De-rating factors are applied according to technology class
- For non-intermittent generators, de-rating factors are calculated in models that simulate outages in specific technology classes and then calculate how much additional demand the system could manage while maintaining the same reliability standard (LOLE).
- For intermittent generators, de-rating factors are calculated by simulating optimal conditions using thermal generation and calculating surplus to the system when a unit of intermittent generation is added.
- Storage is de-rated by calculating how much firm capacity is required to replace the simulated removal of a storage unit. DR units receive the same de-rating factor as non-hydro storage of the same nameplate capacity and duration.
- Interconnectors are de-rated using the same methodology as thermal capacity, but are then de-rated further using a Monte Carlo simulation of coincident scarcity between GB and Ireland.

FORECASTING AND DEMAND

- Three demand scenarios are forecast by SONI and Eirgrid reflecting different weather effects, economic conditions and energy efficiency uptake.
- Since all capacity is allowed to participate in the capacity auction, there is no mechanism for removing the contribution of intermittent capacity from the forecasted capacity requirement.
- Portfolios of capacity are then randomly generated based on expected capacity and de-rating as outlined in the previous slide.
- Those portfolios that are simulated to meet the reliability standard of 8 hours LOLE are deemed Capacity Adequate Portfolios (CAPs)
- The CAP with the highest capacity requirement for each demand scenario is selected and these portfolios or put through a Least-Worst Regrets analysis, which compares the regret cost of over-procuring (the cost of excess capacity) with the regret cost of under-procuring (a function of VoLL) to determine an optimal demand scenario, which is then used as the forecast.

Demand Curve



PROCUREMENT AND TRADING

- Participation is mandatory in the Capacity Auction, but capacity may apply for exemption
- T-4 auction takes place with the aim of procuring 100% of required capacity, with possible T-3, T-2 and T-1 auctions taking place if the regulator deems them necessary.
- Existing capacity may only win a 1-year contract and has a price cap of 0.5 Net CONE but can apply for a Unit Specific Price Cap which goes up to 110% of estimated net ongoing costs for the unit as determined by the market operator.
- New capacity may win contracts up to ten years in length and have a price cap equal to 1.5 Net CONE.
- All participants bid a flexible or inflexible (whether a partial acceptance of a bid is possible) price-quantity pair.
- Price-quantity pairs are placed in price order by the operator to build the supply curve, the intersection of which with the demand curve sets the clearing price and quantity.
- The operator errs on the side of under-procurement in cases where an inflexible bid crosses the demand curve and the auction is pay-as-clear meaning all winning bidders receive the clearing price.
- Additional ‘out-of-merit’ bidders may receive contracts in order to accommodate transmission constraints into a local area.

Secondary Trading

- May take place for one of the following ‘legitimate reasons’
  - The Unit is affected by outage
  - Fluctuations in availability of primary energy source
  - Any other reason the regulator deems legitimate.

TRANSMISSION AND INTERCONNECTION

- Transmission constraints are incorporated into the forecasting of the capacity requirement.
- Across four jurisdictions (Northern Ireland, Greater Dublin, Rest of RoI, All-Ireland) each has a minimum capacity requirement that is estimated in the forecasting methodology.
- There is no distinction made between generating capacity and transmission capacity, thus it is a sufficient condition that the minimum capacity requirement is met in all four jurisdictions and no consideration is given to the location of a generator.
- The CM acts as a single market with a single clearing price for in-merit bidders (as opposed to out-of-merit bidders which may be awarded contracts to meet local requirements affected by transmission constraints)
- Interconnectors with GB are de-rated using the same methodology as the de-rating of thermal generators, with an additional de-rating based on Monte Carlo simulations of coincident peaks in GB and Ireland.

MARKET POWER

- All generators are required to bid their full de-rated capacity into the T-4 auction unless an application for an exemption is granted by the regulator.
- Price cap of 1.5 Net CONE for new capacity
- Price cap of 0.5 Net CONE for existing capacity, unless they apply for a Unit Specific Price Cap, in which case they may be granted a new price cap equal to 110% of what the regulator estimates are the unit’s on-going (forward-looking) costs.

PENALTIES AND COMPLIANCE

- Reliability Options have a built-in compliance measure in that difference payments, which are owed whenever the spot price of energy exceeds the strike price, are owed irrespective of whether the generator is generating.
- Thus, generators have an incentive to cover those costs during high price periods by selling into the energy markets.
- There is a stop-loss in place which caps difference payments a generator can make in a single delivery year to 1.5 times the total revenue of premiums earned by the generator under their reliability option.
- Termination charges on generators which have cancelled or reduced their contracts apply and increase the closer to the delivery year the contract is terminated.
- Only new generation, which is required to deliver 90% of its contracted capacity before receiving premiums, may terminate their contract, existing generation may not terminate and is liable for difference payments.
- The rates for termination charges is not fixed but have so far remained as:

•Termination more than 13 months before delivery year	10 EUR/kW
•Termination between 13 months prior and start of DY	30 EUR/kW
•Termination at start of DY	40 EUR/kW

Government of **Western Australia**
Energy Policy WA

Agenda Item 7(a): Overview of Rule Change Proposals (as of 29 March 2022)

Market Advisory Committee (**MAC**) Meeting 2022_04_05

- Changes to the report since the previous MAC meeting are shown in red font.
- The next steps and the timing for the next steps are provided for Rule Change Proposals that are currently being actively progressed by the Coordinator of Energy (**Coordinator**) or the Minister.

Indicative Rule Change Activity Until the Next MAC Meeting

Reference	Title	Events	Indicative Timing
None			

Rule Change Proposals Commenced since the Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Commenced
None				

Rule Change Proposals Awaiting Commencement

Reference	Submitted	Proponent	Title	Commencement
None				

Rule Change Proposals Rejected since Report presented at the last MAC Meeting

Reference	Submitted	Proponent	Title	Rejected
None				

Rule Change Proposals Awaiting Approval by the Minister

Reference	Submitted	Proponent	Title	Approval Due Date
None				

Formally Submitted Rule Change Proposals

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Fast Track Rule Change Proposals with Consultation Period Closed						
None						
Fast Track Rule Change Proposals with Consultation Period Open						
None						
Standard Rule Change Proposals with Second Submission Period Closed						
RC_2019_03	17/12/2020	ERA	Method used for the assignment of Certified Reserve Capacity to Intermittent Generators	High	Publication of Final Rule Change Report	31/12/2022
Standard Rule Change Proposals with Second Submission Period Open						
None						

Reference	Submitted	Proponent	Title	Urgency	Next Step	Date
Standard Rule Change Proposals with First Submission Period Closed						
RC_2014_05	02/12/2014	IMO	Reduced Frequency of the Review of the Energy Price Limits and the Maximum Reserve Capacity Price	Medium	Publication of Draft Rule Change Report	31/12/2022
RC_2018_03	01/03/2018	Collgar Wind Farm	Capacity Credit Allocation Methodology for Intermittent Generators	Medium	Publication of Draft Rule Change Report	31/12/2022
RC_2019_01	21/06/2019	Enel X	The Relevant Demand calculation	Medium	Publication of Draft Rule Change Report	31/12/2022
Standard Rule Change Proposals with the First Submission Period Open						

Pre-Rule Change Proposals

Reference	Proponent	Description	Next Step	Date
RC_2020_04	Rule Change Panel	Balancing Facility Loss Factor Adjustment	Consult with the MAC on the priority for development of a Rule Change Proposal	TBD

Rule Changes Made by the Minister and Awaiting Commencement

Gazette	Date	Title	Commencement
2021/212	17/12/2021	Wholesale Electricity Market Amendment (Tranche 5 Amendments) Rules 2021	• Schedule D will commence on 12/04/2022. • Schedule E will commence on 01/07/2022. • Schedule F will commence on 01/09/2022. • Schedule G will commence on 01/01/2023. • Schedule H will commence on 01/10/2023. • Schedule I will commence at times specified by the Minister in notices published in the Gazette.
2021/166	28/09/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 2) Rules 2021	• Schedule E will commence on 01/06/2022. • Schedule F will commence on 01/07/2022. • Schedule G will commence at times specified by the Minister in notices published in the Gazette. ○ The Amending Rules specified in Part 1 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 01/07/2022.
2021/96	28/05/2021	Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 1) Rules 2021	• Schedule D will commence immediately after the commencement of the *Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020* specified in Part 4 of the commencement notice published on 28/05/2021 in Gazette 2021/96, that commence on 01/03/2022. • Schedule E will commence at times specified by the Minister in notices published in the Gazette: ○ The Amending Rules specified in Part 1 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 01/03/2022. ○ The Amending Rules specified in Part 2 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 01/07/2022.

Gazette	Date	Title	Commencement
20201/17	18/01/2021	Wholesale Electricity Market Amendment (Governance) Rules 2021	• Schedule C will commence immediately after the commencement of the Amending Rules in clauses 50 and 62 of Schedule C of the *Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020.*
2020/214	24/12/2020	Wholesale Electricity Market Amendment (Tranches 2 and 3 Amendments) Rules 2020	• Amending Rules in Schedule C will commence at the times specified by the Minister in notices published in the Gazette: ○ The Amending Rules specified in Part 4 of the commencement notice published on 28/05/2021 in Gazette 2021/96 will commence on 01/03/2022. ○ The Amending Rules specified in Part 3 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence immediately after the commencement of the Amending Rules in Schedule D of the *Wholesale Electricity Market Amendment (Miscellaneous Amendments No. 1) Rules 2021*, that commence on 01/03/2022. ○ The Amending Rules specified in Part 2 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 01/03/2022. ○ The Amending Rules specified in Part 3 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 12/04/2022. ○ The Amending Rules specified in Part 4 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 01/09/2022. ○ The Amending Rules specified in Part 4 of the commencement notice published on 17/12/2021 in Gazette 2021/212 will commence on 01/09/2022. ○ The Amending Rules specified in Part 5 of the commencement notice published on 28/09/2021 in Gazette 2021/166 will commence on 06/12/2022.