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Revenue Adequacy for Generators in the WEM

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A Marsden Jacob Report

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Acronyms and abbreviations

AEMO	Australian Energy Market Operator
BRCP	Benchmark Reserve Capacity Price
CCGT	combined cycle gas turbine
DSM	demand side management
DSP	demand side participation
DWP	dispatch weighted price
CONE	cost of new entry
EBITDA	earnings before interest, tax, depreciation, and amortisation
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
FCAS	frequency control ancillary services
FOM	fixed operations and maintenance
GJ	gigajoule
GW	gigawatt
GWh	gigawatt hour
HHI	Herfindahl–Hirschman Index
kW	kilowatt
kWh	kilowatt hour
LCOE	levelised cost of electricity
LGC	large-scale generation certificate
LRET	Large-scale Renewable Energy Target
LRMC	long run marginal cost
MW	megawatt
MWh	megawatt hour
MRMC	mid run marginal cost
NEL	National Electricity Law
NEM	National Electricity Market
OCGT	open-cycle gas turbine (heavy frame units)
OCGT-Aero	aeroderivative open-cycle gas turbine
PJ	petajoule
PPA	power purchase agreements
PV	photovoltaic
RCM	Reserve Capacity Mechanism
RCP	Reserve Capacity Price
RET	Renewable Energy Target
SRES	Small-scale Renewable Energy Scheme
SRMC	short run marginal cost
STEM	short term energy market
VOM	variable operations and maintenance
VRE	variable renewable energy
WACC	weighted average cost of capital

Executive Summary

Background

Marsden Jacob Associates (Marsden Jacob) was appointed by the Australian Energy Council (AEC) to undertake an assessment of the current and proposed revenue streams for generators in the Wholesale Electricity Market (WEM) and whether they provide revenue adequacy to support the industry as it transitions. Recommendations on measures to send the right investment signals are provided.

Future Challenges for the WEM and Key Attributes of an Ideal Power Market

Australian commitments to net zero emissions by 2050 will drive the WEM to high levels of intermittent generation sources. This has adverse consequences for inflexible generation plant in the South West Interconnected System (SWIS) which is experiencing reduced generation outputs, increased cycling, and periods of negative prices in the Balancing Market and Short-Term Energy Market (STEM).

The current generation fleet is not optimal given the current and future load duration curve in the WEM[1]. There is increased variation in both demand (due to behind the meter generation) and supply due to the increased reliance on intermittent generation sources. The current WEM generation fleet of coal and gas is above current requirements with high capacity (MW) and high energy resources (MWh). These additional costs must be absorbed by either customers or generation asset owners.

The optimal future electricity system will require flexible and dispatchable energy resources such as storage and OCGT aeroderivative units[2] to manage these variations. The likely plant mix will have high capacity but limited energy resources (i.e., energy from storage facilities).

In effect, the SWIS is transitioning from a relatively low capacity (MW)/unconstrained energy system (MWh) to a high capacity/limited energy system. Governments are intervening in electricity markets to support this transition to a more flexible generation fleet in the National Electricity Market (NEM) with underwriting of gas generation and storage projects. The WEM is currently undergoing a reform program to encourage flexible technologies while providing some transitional arrangements to support existing generation.

Overview of the WEM

The WEM is a 'capacity plus energy market' which relies on authorities to co-ordinate long term planning and procurement to ensure that sufficient capacity resources are available to meet the

[1] See section 2.3
[2] Open Cycle Gas Turbine Aeroderivative

targeted level of supply reliability. This is very different to the NEM which relies on 'scarcity' prices to drive investment in sufficient capacity resources to meet the targeted level of reliability. Investors tend to prefer capacity markets because revenue risks are lower, but they can cause surpluses of capacity. The reverse problem occurs in energy only markets, whereby governments and policy makers intervene in the market to avoid shortages of capacity and high energy prices.

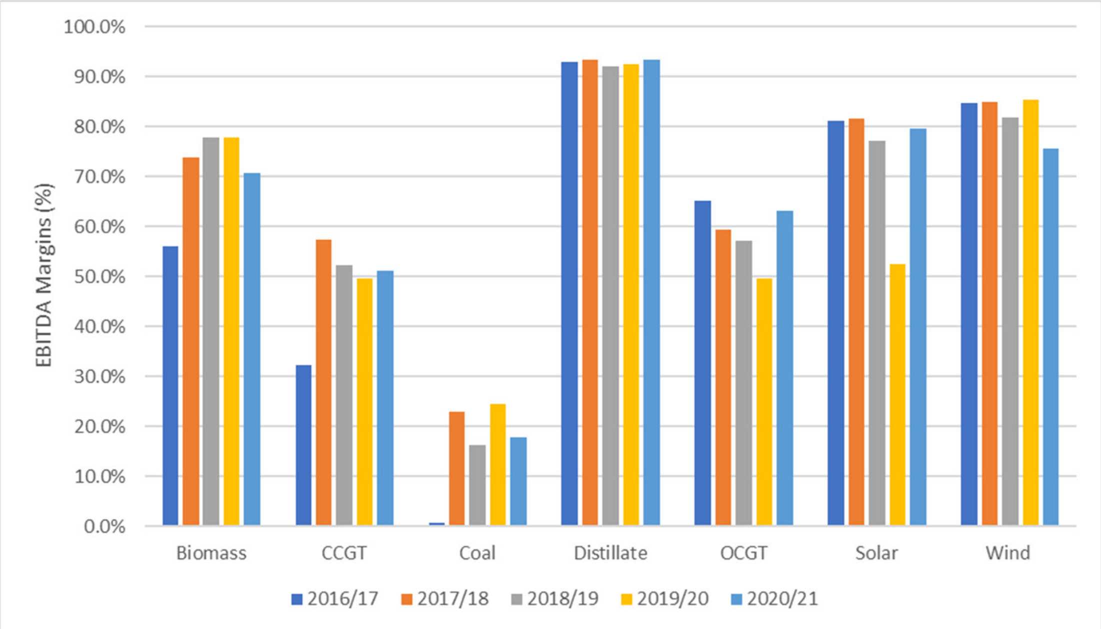
The WEM's current reliability criteria solely focuses on ensuring sufficient capacity to meet peak demand. This doesn't account for the future challenges of low output from solar and wind generation for substantial periods of time. Long duration storage will be required to support the WEM's energy resources as it transitions.

Generator Revenue Adequacy and Market Power in the WEM

Current Revenue Adequacy

Over the period 2016/17 to 2020/21, the WEM has provided adequate revenue to permit existing plants to continue operations with positive EBITDA margins[3]. A positive EBITDA does not imply that generators are making financial returns and covering all capital costs, but it does suggest that generators are at least recovering their variable costs and contributing to capital cost recovery.

ES Figure 1 EBITDA Generator Margins in the WEM by Financial Year (based on June 2021 dollars)



Source: Marsden Jacob 2022

However, there are some notable trends from the analysis of past EBITDA margins:

- The EBITDA margins are lowest for coal plant and increasingly variable operating conditions (i.e., increased number of starts, operating at minimum generation levels) will worsen profitability.

[3] Earnings before interest, tax, depreciation, and amortisation. Formula for EBITDA margin is provided in Section 4.1.2.

- EBITDA margins are second lowest for Combined Cycle Gas Turbine (CCGT) plant. EBITDA margins were lower in 2016/17 due to reduced energy market revenue. EBITDA margins then recovered in 2017/18 but have been declining, in part, due to the 18% reduction in annual generation in 2020/21 compared to 2016/17.
- EBITDA margins for OCGTs was also on a downward trend but increased in 2020/21. It is likely that future coal plant retirements and subsequent increase in capacity factors of gas plant will help increase EBITDA margins for this plant class.
- EBITDA margins for renewable plant are high as they have relatively low variable costs (zero in some cases).
- EBITDA margins for distillate plant are also high as this plant earns sufficient revenue from the capacity market to cover Mid-Run Marginal Costs (MRMCs).[4]

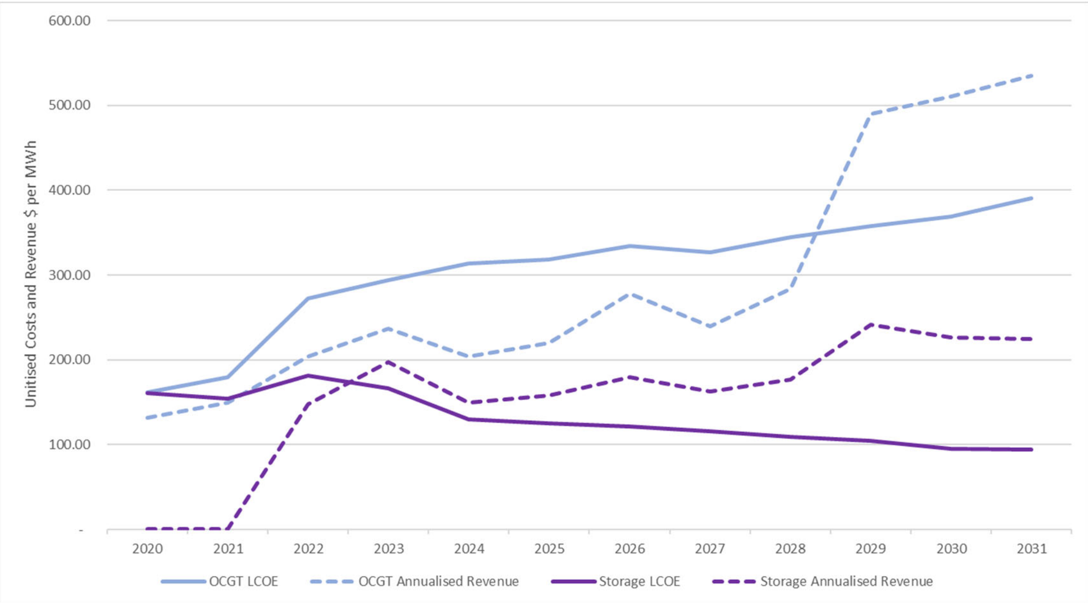
In summary, the WEM has provided sufficient revenue for most plant types. However, EBITDA margins for coal plant are relatively low, and if revenue continues to decline, it is likely that EBITDA margins will become negative for this plant type.

Future Revenue Adequacy

Based on current WEM revenue forecasts, new entrant coal and OCGT heavy frame units are not economic. CCGT and OCGT aeroderivative units are marginal with revenue just sufficient to cover costs. Four hour storage (shown below), wind and solar generation are economic; the latter is only economic if LGC revenue is included.

The comparison of levelised revenue and cost of energy for OCGT and 4-hour storage is shown below. Other new entrant plant comparisons of levelised revenue and costs are provided in Section 4.1.3.

ES Figure 2 Levelised Revenue and LCOE for Peaking Plant in the WEM (June 2021 dollars)



[4] Mid-run Marginal Costs are Fixed Operations and Maintenance (FOM) costs plus Short Run Marginal Cost.

Source: Marsden Jacob Analysis 2022

The above results are impacted by the low-capacity price forecast. If we assume that the variable RCP increases to $159,000 per MW per annum by 2024/25[5], then OCGT and OCGT aeroderivative units plus 4-hour storage facilities are all clearly economic post 2023-24. This highlights the importance of the capacity price in ensuring revenue adequacy in the WEM for new plants that will be required in the transition to a low emission electricity system.

The problem is the amount of excess capacity in the WEM and the fact that capacity price floors for incumbents will slow down the exit of inflexible plant, while subsidies for behind the meter rooftop PV and large-scale renewable generation will continue to encourage more intermittent plant entry. Market balance will only be restored by market participants retiring plant within the coming decade.

Market Power in the WEM

In the WEM, three generators accounted for 90% of electricity generated.[6] The transformation of the market from large thermal generators to more modular sources can reduce market concentration.[7] However, until this occurs, it is likely that market power mitigation measures will be required to avoid anticompetitive behaviour.

A market power mitigation framework is being developed by Energy Policy WA (EPWA), which follows on from the initial approach outlined by the Energy Transformation Taskforce in March 2021.

Learnings from Electricity Markets Elsewhere

In developing recommendations for changes to market mechanisms in WA, it is important to look at the development of other electricity markets internationally. Some of the key learnings include the following:

- Traditional capacity markets of northeast USA have been challenged by the growth of variable renewable generation and the lack of real time price signals. For example, PJM operates a centralised capacity market, but introduced an operating reserve market in 2017 to better reflect shortage pricing when reserves are low.
- ERCOT (energy only market) has included a price adder (operating reserve) to ensure that energy prices incorporate a capacity value.
- Comprehensive market power mitigation frameworks are a key element of international electricity markets. This includes pivotal supplier tests (ERCOT, PJM etc), bidding rules and bid price caps, prohibitions on certain behaviour (anti-competitive conduct), policies and guidelines for treatment of fuel costs and Variable Operations and Maintenance costs in bids, and the option for market participants with market power to develop voluntary market power (VMP) mitigation plans.

[5] Marsden Jacob estimate of the Benchmark Reserve Capacity Price for 2024/25.

[6] Economic Regulation Authority, Report on the effectiveness of the Wholesale Electricity Market 2020, 28 August 2020, p.12.

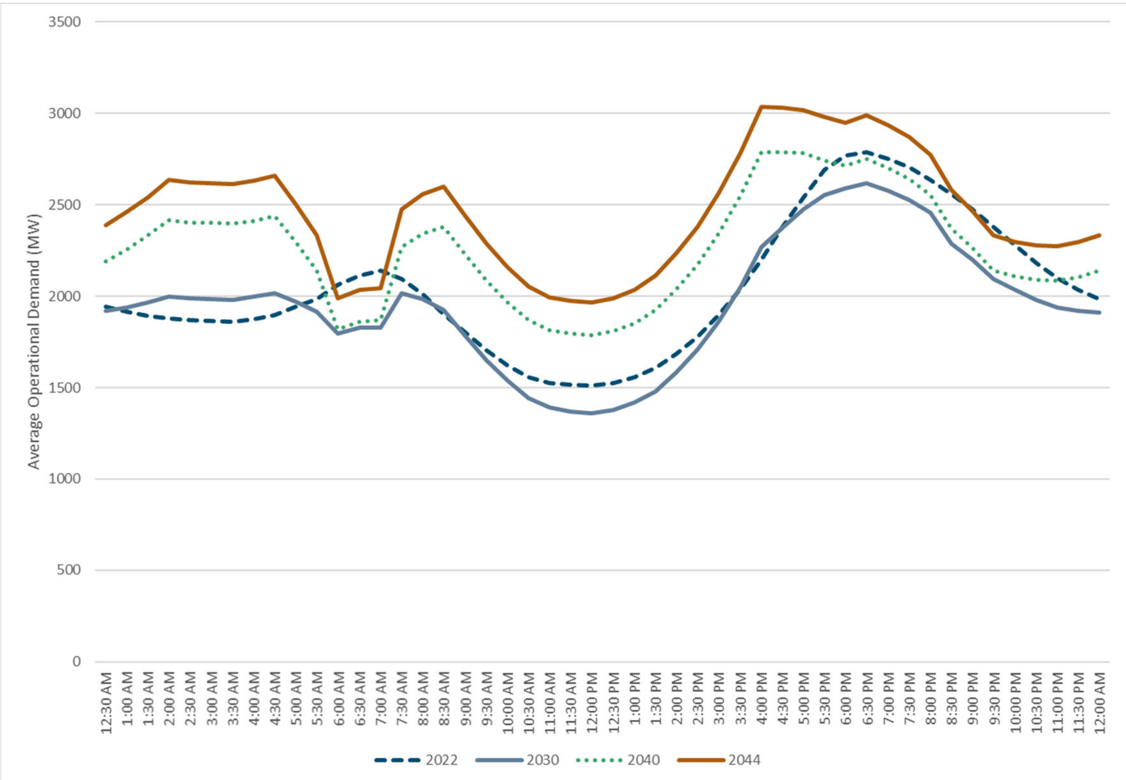
[7] https://www.energycouncil.com.au/media/ar0leqfx/20181213-final-report-advice-on-nem-structure-in-light-of-technology-change-stc.pdf

Analysis and Recommendations

The WEM is moving towards high levels of intermittent generation and will require flexible generation and storage to maintain reliability standards. However, our analysis shows that there may not be adequate revenue to encourage flexible generation and storage. The "missing money" is being caused by low and variable capacity prices for new entrant generators. This can be corrected by providing long term capacity contracts with prices that reflect the costs of new entrant (CONE) capacity.

Under the new capacity rules in the WEM, the Electric Storage Resources (ESR) Obligation Duration is set at four hours, which means that a storage facility that can provide 4 hours of continuous supply will be accredited for Capacity Credits at 100 per cent of the facility's nameplate capacity. This means that an 8-hour storage facility will only get the same capacity market revenue as a 4-hour battery, even though we expect future requirements for storage will exceed 4-hours. As highlighted below, average peak demand in the SWIS is around 4-hours today (4 PM to 8 PM based on Operational Demand that is >90% of peak demand in that year). However, in 2040, average peak demand will be around 5-hours (2:30 PM to 7:30 PM). On some peak days in the WEM, peak demand can occur for up to 6-hours (e.g., in 2022 and subsequent years).

ES Figure 3 Operational Demand for Selected Years – Peak Day Analysis (1 February) – Base Case



Source: Marsden Jacob Analysis 2022

To ensure that both flexible short and long duration generation and storage is incentivised to enter the WEM, we considered two potential approaches to increase revenue for these technologies:

(a) differential capacity prices (based on Gross and Net CONE), and
(b) shortage pricing (in energy and ESS markets).

We conclude that moving to a technology specific net CONE capacity pricing system for determining the Benchmark Reserve Capacity Price (BRCP), and consequently capacity prices, is not necessary for flexible generation and storage facilities, provided that only 4 hours of storage is required in the latter case. A separate capacity price based on net CONE may be necessary to encourage long duration generation or 4 to 8 hour storage.

In theory, adopting scarcity pricing in the WEM could also replace the requirement for AEMO to establish the ESR Obligation Duration period to ensure that there is sufficient dispatchable storage to meet peak demand in the WEM.

However, application of scarcity pricing is unlikely to address the fundamental issue of incentivising new entrant generation to enter the market, since investors are typically looking for stable income flows from the WEM to justify the investment, not the infrequent occurrence of potential capacity shortages and scarcity prices. In addition, scarcity prices also provide incentives for participants with market power to withdraw capacity to drive higher prices.

The proposed reforms of the WEM will require commensurate adjustments to the current market power mitigation framework that achieves its intent without prescribing outcomes and allowing markets to clear at efficient levels. We present three regulatory options for the WEM and suggest that Option b) Safe Harbours for participants and high penalties for unacceptable trading conduct, strikes the right balance in terms of mitigating market power and allowing for efficient outcomes in the WEM.

Achieving net zero emissions in the SWIS by 2050 will require significant investment in both small-scale and large-scale renewable energy power systems. The connection of large-scale renewable energy power plants will require the creation of Renewable Energy Zones (REZs) in the North Country, East Country, and Muja regions of the SWIS and transmission upgrades to ensure that plant is not constrained. While the NEM 2020 Integrated System Plan has highlighted the opportunities for the creation of REZs and transmission upgrades in NEM regions, Western Power's 2020 Annual Plan has indicated that no significant transmission augmentation is required.

In our view, the Western Power transmission planning process needs to be reviewed. Significant network upgrades should be considered to:

- support the creation of REZ's in North Country, East Country, and the Muja region;
- facilitate efficient grid connection; and
- decrease the risk of congestion that reduces generator earnings.

Given that regulatory investment tests for major transmission upgrades have not been conducted for almost a decade, a review of the current approval process for large transmission projects is also recommended.

Provided below is a summary of the reform options that could be used to increase revenue sufficiency in the WEM, our assessment of each reform option in terms of addressing revenue sufficiency and issues that arise from the implementation of this option, and our recommended approach.

ES Table 1 Summary of Recommendations

Initial Marsden Jacob reform option	Issues that this reform could address	Issues that arise with this reform option	Final recommendation by Marsden Jacob
Differential Capacity Prices based on the costs and duration of providing flexible generation and storage	Current capacity prices are set with reference to OCGT Fixed Frame Units. This may not provide revenue incentives for the entry of flexible generation and storage facilities that are required to maintain supply reliability at an efficient cost. In addition, the variability in the current RCP due to the application of the convex capacity price curve, which makes the price highly sensitive to changes in excess capacity, does not support long term investment in flexible generation and storage facilities.	Would need to adopt Net CONE approach to ensure that different technologies are not being over-compensated by differential capacity prices. Marsden Jacob analysis found that if the RCP reflected the BRCP, no additional revenue was required to make flexible generation and storage viable except for long duration storage > 4-hours. The fundamental problem is the amount of excess capacity in the WEM and the fact that capacity price floors for incumbents will slow down the exit of inflexible plant, while subsidies for behind the meter rooftop PV and large-scale renewable generation will continue to encourage more intermittent plant entry. Capacity balance will be restored by market participants retiring some inflexible plant within the coming decade.	Moving to a Net Cone system by technology type is not necessary for the WEM, as there are adequate incentives for flexible plant entry based on the current methodology for setting the BRCP (Gross CONE based on an OCGT plant) provided inflexible plant is retired to reduce excess capacity in the WEM. However, A differential capacity price could apply to long duration storage (> 4-hours) given that this technology type may be required with the future retirement of coal and gas plant, and that proposed market mechanisms will not provide sufficient revenue for this technology type.
Including scarcity pricing in energy markets (and by default Essential System Services markets)	Scarcity pricing could be used in energy markets (and by default ESS markets) to recover any shortfall in revenue created by low variable capacity prices that apply to new entrants. Scarcity pricing may be required in the long term to ensure reliability standards are satisfied with high levels of intermittent capacity and limited energy resources (storage).	Market power remains an issue in the WEM, which creates concerns about scarcity pricing. Relying on forecasts of shortage events in the WEM and how often scarcity prices would apply is not likely to provide an investment case for flexible generation and storage facilities with 25-year asset lives.	Do not introduce scarcity pricing into the Balancing Market and/or STEM (and by default the ESS market) at the current time. However, this approach could be considered in the future if reforms of capacity market do not encourage investment in flexible generation and storage and if appropriate market power mitigation measures were developed.
Long term capacity contracts	To encourage the transition to a flexible generation and storage fleet in the WEM,	AEMO will need to assess offers subject to meeting capacity	Recommend the following:

Initial Marsden Jacob reform option	Issues that this reform could address	Issues that arise with this reform option	Final recommendation by Marsden Jacob
	provide long term capacity contracts for new entrant generation and storage facilities (15 years) at the minimum of their offer price (initial offer price escalated by CPI) or 85% of the BRCP for 15 years.	performance criteria and the maximum quantity of Fixed Price Facilities in MWs. Lowest price offers up to the maximum quantity of Fixed Price Facilities (term now increased from 5 to 15 years) will be accepted.	– Long term capacity contracts for new entrant generation and storage for 15 years at gross CONE or the BRCP based on annualised costs of an OCGT Fixed Frame Unit. – If long duration storage is required (up to 8-hours of storage) to maintain supply reliability, provide a technology-based capacity price based on Net CONE to encourage long duration storage.
Ensuring revenue sufficiency in the WEM	When establishing policies, price limits and measures, policy makers and regulators should be confirming that there is sufficient revenue in aggregate from all market mechanisms to encourage flexible generation and storage to meet future demand and reliability settings.	ERA and EPWA should develop wholesale market models and undertake regular reviews of generator profitability under current market settings, plus committed rule changes, to ensure that the WEM is fulfilling its market objectives (i.e., efficient new entry).	ERA and/or EPWA undertake annual reviews of generator and storage revenue sufficiency in the WEM (rolling 10 year revenue forecasts).
Market Power Mitigation Measures in the WEM	Three approaches were considered: a) Light handed regulation with high penalties for unacceptable trading conduct, b) Safe Harbours for participants and high penalties for unacceptable trading conduct plus elements of Option a) above c) Prescriptive ex ante bidding rules and modest penalties for unacceptable trading conduct plus elements of Option a)	Option c) involves significantly higher costs to establish and administer and has the potential to result in inefficient outcomes if there is an overreliance on prescribed prices and not market outcomes. ERA would be required to undertake wholesale market modelling to understand the potential range of offer prices as a function of the drivers of SRMC under both option b) and c).	Recommended Option b) which includes the following: • Detailed trading conduct obligations for market participants (e.g., good faith offer obligations, prices based on SRMC, market participants have internal controls to prevent use of market power etc) would remain. • ERA would define offer ranges (both energy and ESS markets) for participants deemed to have market power whereby there is a low risk of regulatory noncompliance. • Offer prices can be within a nominated band or "safe harbour" (+ or minus 20%) of a relevant pre-determined reference price calculated by the regulator prior to the

Initial Marsden Jacob reform option	Issues that this reform could address	Issues that arise with this reform option	Final recommendation by Marsden Jacob
			trading period. Penalties for noncompliance would need to remain high to ensure participants act in "good faith".
Revitalise Transmission Planning and Approval Processes	Western Powers Annual Planning Report does not address the significant challenge of supporting the transition to net zero emissions in the SWIS by 2050 Western Power stated that the Whole of System Plan did not indicate any significant investment was required, even though Marsden Jacob has estimated that at least 2100 MW of large scale VRE is likely to be built in the SWIS by 2035. The WOSP assumed that the lowest cost approach was to build VRE in the South West region of the SWIS, which is not practical given alternative land use in this region (e.g., urban, farming and state forest). The current planning processes in the NEM (Integrated System Plan) has identified significant opportunities for the development of Renewable Energy Zones (REZs) and transmission investment to support the transition to high levels of VRE. This is even the case with high levels of investment in DER.	EPWA and ERA need to review current WP planning processes (and relevant legislative frameworks) to ensure that transmission investment is not delayed which is required to support the energy transition to high levels of VRE in the SWIS.	Western Power transmission planning process needs to be reviewed and consideration given to significant network upgrades to support the creation of REZ's in North Country, East Country, and the Muja region to facilitate efficient grid connection and decrease the risk of congestion that reduces generator earnings. Given that regulatory investment tests for major transmission upgrades have not been conducted for almost a decade, a review of the current approval process for large transmission projects is also recommended.

Source: Marsden Jacob 2022

1. Introduction

1.1 Background

Marsden Jacob Associates was appointed by the Australian Energy Council to undertake an assessment of the current and proposed revenue streams for generators in the WEM and whether they provide revenue adequacy. Recommendations on measures to enhance revenue adequacy and market structure to send the right investment signals are provided.

1.2 Detailed study scope

The detailed scope of work for this assignment includes clearly explaining the following:

- The current revenue streams available to generators in the WEM.
- The role of each revenue stream in providing revenue adequacy.
- The extent to which generators now have revenue adequacy.
- The impact of Energy Policy WA's proposed changes to the market power mitigation mechanism will have on revenue adequacy and investor certainty.
- What measures that Energy Policy WA, and the Economic Regulation Authority could adopt to ensure revenue adequacy and minimise investor uncertainty.
- The extent to which the Essential System Services (ESS) market will incentivise retention and investment in system services providing equipment.
- Whether the ESS price should consider scarcity pricing to signal investment.
- What changes could be made to the energy, ESS and RCM markets to promote revenue adequacy and ensure investors receive the right investment signals.
- The potential consequences if generators do not have revenue adequacy.

Marsden Jacob will refer to how these issues are managed in other capacity markets that we consider relevant. This assessment is focused on revenue adequacy in the wholesale market for generators and is not extended to consider revenue adequacy for retailers.

1.3 Structure of Report

The structure of the report is outlined below:

Chapter 1 – Background, project scope and proposal structure

Chapter 2 – Future challenges for the WA electricity system and key attributes of the ideal WA power market

Chapter 3 – Overview of the WEM (current and proposed), role of each service and current revenue adequacy. Current and proposed market power mitigation measures.

Chapter 4 – Current Revenue Adequacy in the WEM. Potential shortfalls in current design to meet future challenges end ensure generator revenue adequacy.

Chapter 5 – How are other jurisdictions meeting these challenges? Relevant learnings for the reform of the WEM.

Chapter 6 – Reforms of the WEM that should be considered to move us closer to the ideal market and ensure revenue adequacy for new generation/storage investment and orderly plant retirements.

Chapter 7 – Provides a summary of the issues that the AEC and key stakeholders wanted us to address in this study.

2. Future Challenges and Ideal Attributes for the WA Power Market

Australian private sector and government commitments to net zero emissions by 2050 will drive the WEM to high levels of intermittent generation sources and firming services provided by flexible generation and storage facilities. The future challenge is managing variations in both supply and demand for electricity, using a plant mix that can be characterised as having high capacity (MW) but limited energy resources (MWh). This is very different from the current power system that has low levels of capacity and almost unconstrained levels of energy supply.

This chapter looks at the challenges facing the WA electricity system and what are the key characteristics of the future power system that are required to achieve secure, reliable, clean, efficient, and affordable energy supplies.

2.1 Environmental Policies Driving Change in the Generation Mix

Policies driving changes in the electricity plant mix in Australia include the following:

- 20% reduction in emissions by 2020 (Large-scale Renewable Energy Target (LRET) scheme) driving investment in large-scale renewable energy plant,
- Explicit and implicit subsidies to customers driving investment in "behind the meter" solar generation,
  - Capital subsidies under the Small-scale Renewable Energy Scheme (SRES)
  - Generous Feed-in-Tariffs for early solar PV adopters[8]
  - Lack of cost reflective tariffs with an over-reliance on energy prices driving good paybacks in investment for solar PV (under 4 years)
- Learning curve effects that have and are reducing the capital cost of both small and large-scale solar and battery technologies.[9]
- Threat of carbon taxes on our mineral and energy exports and shareholder environmental activism is driving companies to set emission reduction targets and underwrite renewable generation. Many companies are building or contracting renewable energy facilities and

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[8] Many of these generous FIT arrangements have now concluded and been replaced with FIT prices that are more reflective of the value of energy exported to the grid.

[9] Since 2010, there has been a 64%, 69%, and 82% reduction in the cost of residential, commercial-rooftop, and utility-scale PV systems, respectively. (https://www.nrel.gov/news/program/2021/documenting-a-decade-of-cost-declines-for-pv-systems.html).

surrendering the LGCs, which further increases the LGC price and promotes further renewable energy projects.

The Commonwealth Government has committed Australia to achieving Net Zero Emissions by 2050.[10] However, there are currently no new financial or market mechanisms to achieve the target, with the Commonwealth Government relying heavily on technology change (learning curve effects) to achieve the target.

2.2 Distributed Energy Resources and Embedded Power Systems

Distributed energy resources (DER) are renewable generation and/or battery systems that are located "behind the meter" i.e., electricity is generated or supplied 'behind' the electricity meter in the home or business. Common examples of DER include rooftop solar PV units, battery storage, thermal energy storage, electric vehicles and chargers, smart meters, and home energy management technologies.[11]

Embedded Networks are private networks (typically apartment blocks, retirement villages, caravan parks and shopping centres) where the electrical wiring is configured in such a way as to enable the owner of the site to sell energy to all the tenants or residents based there. Instead of buying grid supplied power, owners of embedded networks are planning to install generation and/or storage facilities on site.

Surplus electricity from either DER or embedded networks may be exported to the grid and can potentially provide both network and wholesale market services.

Distribution Network Service Providers (DNSP) have begun trials on determining the network services that can be provided by DER in the future. This includes Project Converge in the ACT and Project Symphony in WA.[12]

The Energy Transformation Taskforce (ETT) developed the DER Roadmap[13] to facilitate the integration of DER into the power system and ensure customers can realise benefits from small-scale solar systems and other technologies such as storage. The actions have been developed to permit DER to export power to the grid, and through an aggregator, provide network and wholesale market services, including energy arbitrage and frequency control ESS.

Both DER and embedded networks, when combined with energy storage, could provide additional sources of dispatchable generation in the SWIS. Investment in these technologies could reduce the need for further investment in large-scale dispatchable generation/storage facilities. In developing our Base Case wholesale market scenario (Section 4.1.3), we have included assumptions on how

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[10] https://www.minister.industry.gov.au/ministers/taylor/media-releases/australias-plan-reach-our-net-zero-target-2050

[11] https://arena.gov.au/renewable-energy/distributed-energy-resources/

[12] Project Symphony is outlined in https://arena.gov.au/news/composing-a-distributed-energy-symphony-in-western-australias-largest-energy-grid/ and Project Convergence is outlined in https://arena.gov.au/projects/act-distributed-energy-resources-demonstration-pilot-project-converge/

[13] Energy Transformation Taskforce, Distributed Energy Resources Roadmap, December 2019

much DER is likely to be installed behind the meter and reduce future operational consumption and demand.

2.2.1 Stand-alone power systems and microgrids

Stand-alone power systems (SPS) and Microgrids are off-grid systems (the latter could remain connected to the grid) that operate independently from the main electricity network. Typically, they consist of a renewable energy supply such as solar panels, battery energy storage system (BESS) and, where necessary, a backup generator. Both SPS and Microgrids are a subset of DERs.

Western Power is committed to developing SPS for regional customers and Microgrids for regional communities since they can improve supply reliability, especially in fire prone areas of WA, and reduce investment in the transmission and distribution system in the SWIS.

Western Power installed 52 SPS units in 2020 and expects to install another 88 in 2021/22. Western Power has indicated that 6000 SPS units could be deployed over the coming decades.[14] There are currently 4 microgrids in WA: Kalbarri, Perenjori, Bremer Bay and Ravensthorpe.

While both SPS and Microgrids will reduce grid demand further, Microgrids can potentially also provide network and wholesale market services if they remain interconnected to the grid (like DER projects discussed previously). Microgrids could compete with large-scale generation and storage facilities to provide wholesale services.

2.2.2 Distribution Connected Batteries

As part, and in addition to microgrids, Western Power is rolling out distribution connected batteries. There are currently three types of batteries being deployed, which includes large network batteries that form part of a microgrid (like at Perenjori), community batteries located in suburbs, and PowerBank batteries installed in Meadow Springs, Falcon and Ellenbrook that allow customers to store their excess solar energy and use it later when energy demand is high. Western Power has been actively converting community batteries into PowerBank batteries.[15]

Western Power announced it had plans to install an additional 50 MW of batteries in 2021.[16]

2.3 Consequences for the Large-scale Generation Sector

Due to the installation of DER and improved appliance energy efficiency, operational consumption (i.e., electricity that will be supplied from wholesale generation facilities) has been falling and will continue to fall, reducing sales and revenue for large-scale generators. Some of the implications for generation include the following:

- Solar "duck curve" is reducing minimum demand and causing negative prices which results in generators having to shut down and restart more often. Generators incur more costs and get less revenue.

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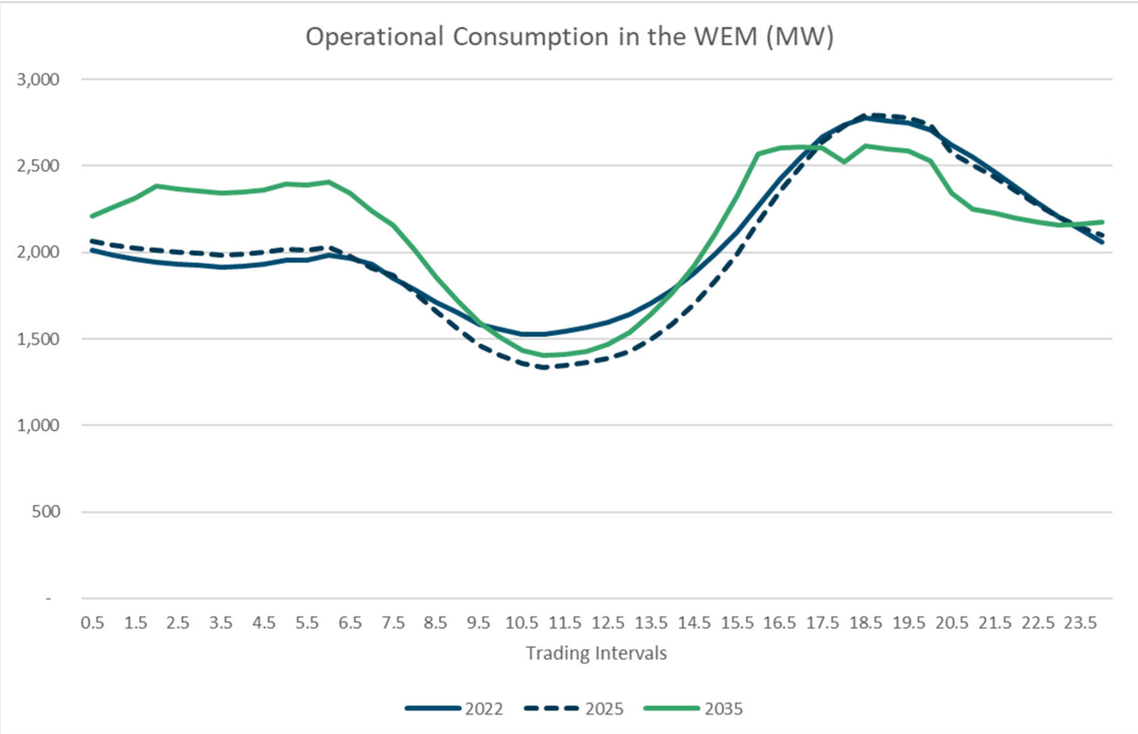
[14] https://www.westernpower.com.au/our-energy-evolution/grid-technology/stand-alone-power-system/
[15] https://www.westernpower.com.au/our-energy-evolution/grid-technology/battery-energy-storage/
[16] https://www.westernpower.com.au/community/news-opinion/50mw-of-extra-battery-storage-planned-for-the-swis/

- Increased frequency variations caused by intermittent plant necessitates generation to be more responsive (real time) to help restore frequency to the desired range. More fast response generation must be in-service in the future.
- Fast response generation needs to ramp up quickly to meet evening peak demand when solar generation output is reduced.
- Less baseload generation is required and with falling revenue, decreased sales, increased number of starts and shutdowns, and increased ramping of generators, baseload gas and coal plant are likely to retire sooner.
- Less synchronous generation on the system, which makes it more difficult to maintain system frequency and system strength (voltage waveform).

The average daily load curve for the WEM is shown for a Base Case scenario developed by Marsden Jacob for three years (Cal 2022, 2025 and 2035). The 'duck curve' is clearly visible and highlights the disparity between average daytime demand of 1400 MW and the evening peak of 2750 MW. With the reduction in output from rooftop solar systems in the early evening, demand increases rapidly, which implies that generation plant will have to ramp up quickly to meet evening peak demand.

Figure 1 Operational Consumption in the SWIS – 50% PoE



Source: Marsden Jacob Analysis 2022

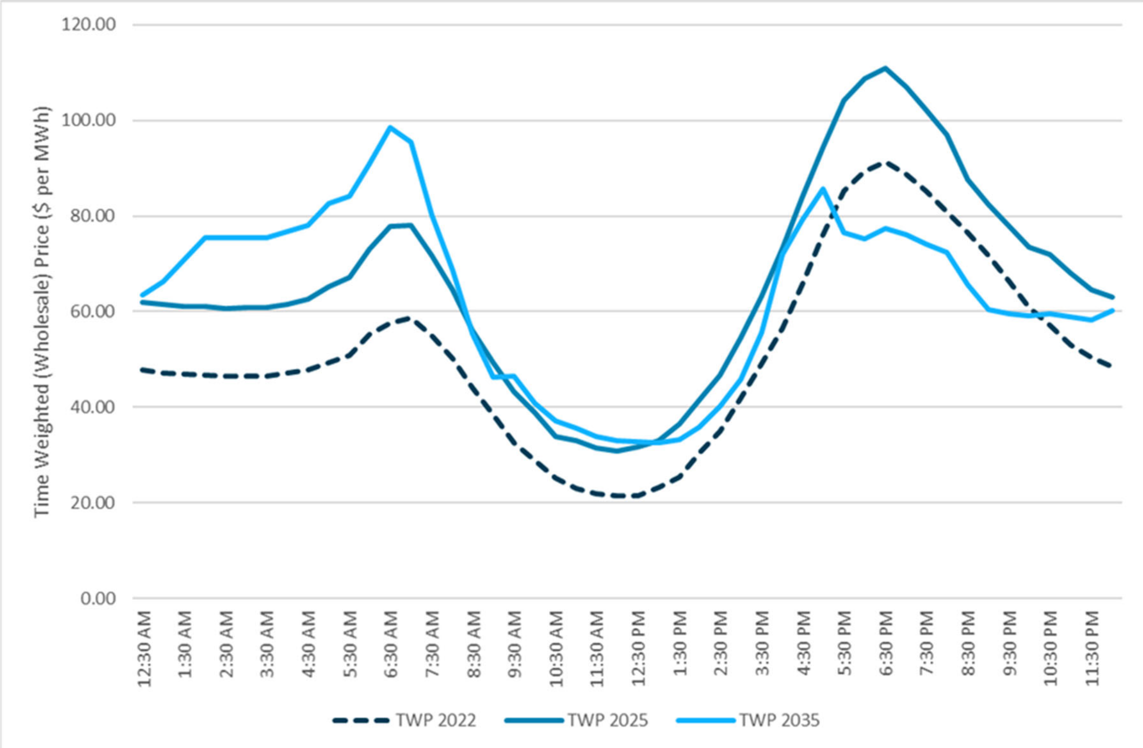
The shape of daily operational consumption drives a significant spread in wholesale market prices (time weighted price). In 2022, the average prices during the day reduce to $20 per MWh and then rise quickly to $90 per MWh in the evening (6:30 PM). The short run marginal cost (SRMC) of baseload coal and gas plant is expected to be around $40 to $55 per MWh, which implies that this plant is making a loss if operating at these times (and most likely will be operating given minimum generation requirements for these plants). On the other hand, peaking gas plant that is typically only on to meet the evening peak will be running profitably since their SRMC is typically around $65 per MWh and prices are above this level from 4:30 PM to 9:30 PM.

However, in the future, the wholesale price spread is expected to reduce. This is because operational demand during the day will likely increase due to the impact of the continued electrification of the WA economy. Electrification will be driven by the:

- Declining cost of renewable energy and storage technologies that will increase the penetration and output from these sources and reduce behind the meter and grid connected electricity supply costs relative to conventional generation sources.
- Battery storage holding surplus power during the day to avoid negative wholesale prices and dispatching at times, typically in the early evening period, when demand and wholesale prices are high.
- Relative decline of retail electricity prices relative to natural gas due to declining renewable and battery costs and increased electricity demand which can reduce per unit network charges (if price incentives are provided to ensure peak electricity demand is managed via dispatch of storage facilities).
- Increased penetration of Electric Vehicles (EVs) due to declining capital costs and likely future increases in liquid fuel costs. Cost reflective electricity tariffs would need to be implemented to provide incentives for the charging of EV's at off peak times on the grid and discharge of electricity from EVs (could potentially act as storage facilities) at peak times on the grid.
- Increased electricity demand due to the production of hydrogen, which could be used by business, blended into natural gas networks, and exported to South East Asia.

Many of these above drivers have been incorporated into our Base Case forecasts which show that after 2022 increased rooftop solar penetration reduces prices during the day further, but after this, daytime prices increase due to the recharge of behind the meter batteries and EVs, while evening demand reduces due to the discharge of behind the meter batteries. In effect, behind the meter storage helps reduce the wholesale price spread.

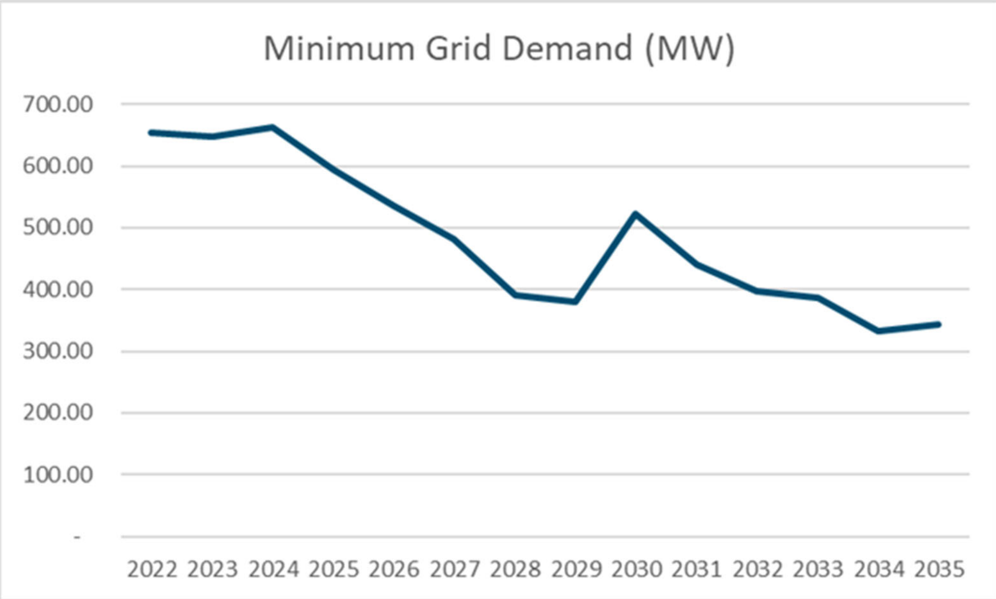
Figure 2 Future Pattern of Wholesale Prices in the WEM ($ per MWh, June 2021 dollars)



Source: Marsden Jacob Analysis 2022

The problems for baseload and mid-merit generation are further exacerbated when you consider what future extreme minimum demand levels could be in the WEM (above analysis was based on average demand, not maximum or minimum demand days). Based on the Base Case scenario, we have forecast that extreme minimum demand on the grid could reduce to less than 400 MW in 2029. That means that at these times, baseload coal and gas plant will have to shut down. Once shutdown, it can take several hours for coal plant to be able to recommence operations, which implies that it does not contribute to meeting peak demand in the evening on those days when it is required to shut down. Additional costs are incurred in the shut down and restart process, which includes additional wear and tear on these coal units. To avoid these issues, many coal and gas units bid the minimum STEM price (-$1000 per MWh) which can drive Balancing Market and STEM prices to negative levels, which is highlighted in Figure 4 below.

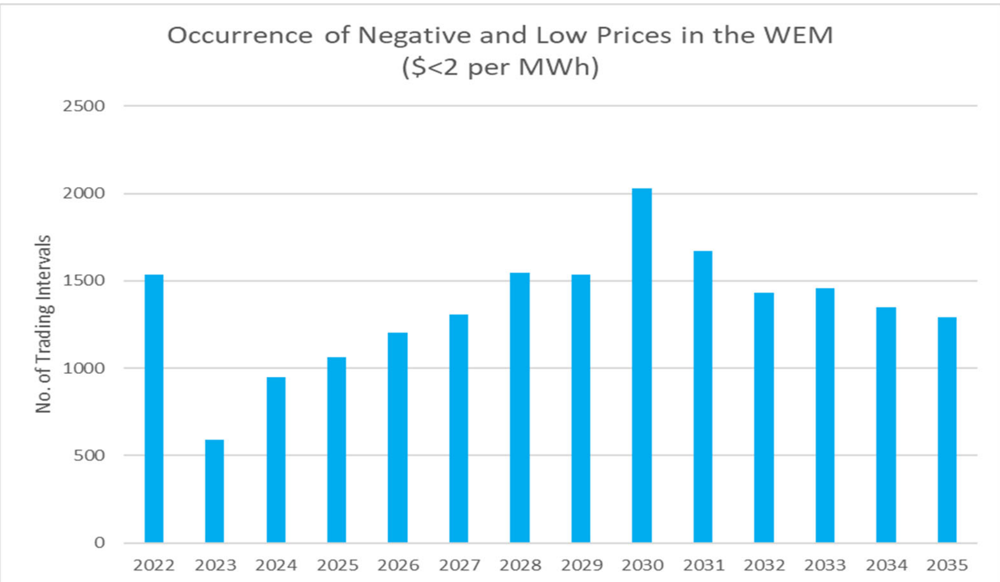
Figure 3 Minimum Demand in the WEM



Source: Marsden Jacob Analysis 2021

In the WEM negative and low prices (<$2 per MWh) are forecast to occur in 1500 trading intervals[17] for the 2022 calendar year.[18] The incidence of negative and low prices is forecast to fall in 2023 with the retirement of Muja C Unit 5 but is then expected to rise again with increased penetration of rooftop solar systems, despite the retirement of Muja C Unit 6 in October 2024.

Figure 4 Occurrence of Negative Prices in the WEM



Source: Marsden Jacob Analysis 2021

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17 Trading intervals in the WEM are currently 30 minutes but will be reduced to 5 minutes in 2025.

18 Negative prices in the Balancing Market represented 7% of all trading intervals in Q3 2021 according to AEMO, which is over 300 trading intervals in Q3 alone. Negative or zero prices for Q4 2020 to Q3 2021 occurred in 1350 trading intervals.

In Figure 5, we categorise the current generation fleet into various operating cycles (i.e., baseload, mid-merit, peaking, reserve). We have overlaid a load duration curve developed by Marsden Jacob for the 2022 and 2030 calendar years over the actual capacity credits of generation by operating cycle in 2022 and the expected capacity credits of generation/storage facilities in 2030. Renewable generation has been classified as mid-merit plant given that they have capacity factors in the range of 26% (solar) to around 45% (wind).

What this figure shows is that, assuming AEMO's POE10 and Reserve Capacity Requirement forecasts are accurate, there is currently a surplus of generation capacity in all periods in 2022, with an overall surplus of Capacity Credits exceeding the Reserve Capacity Target of 9.9 per cent in the 2021/22 Capacity Year. However, the figure shows that the surplus of plant is most acute for baseload generation (i.e., coal, biomass, cogeneration, and combined cycle gas turbines) when compared to Mid-Merit Plant. Average baseload capacity is 77% higher than average base load demand, whereas Mid-Merit Plant capacity is 55% above average mid-merit demand. Peak capacity is also high in the WEM (68% above peak load demand) because it was expected that peak demand would grow in the WEM and this justified investment in new capacity (i.e., distillate and Demand Side Management (DSM)). However, actual peak demand in the past 5 years has been lower than the highest demand of 4004 MW achieved in 2015-16.[19]

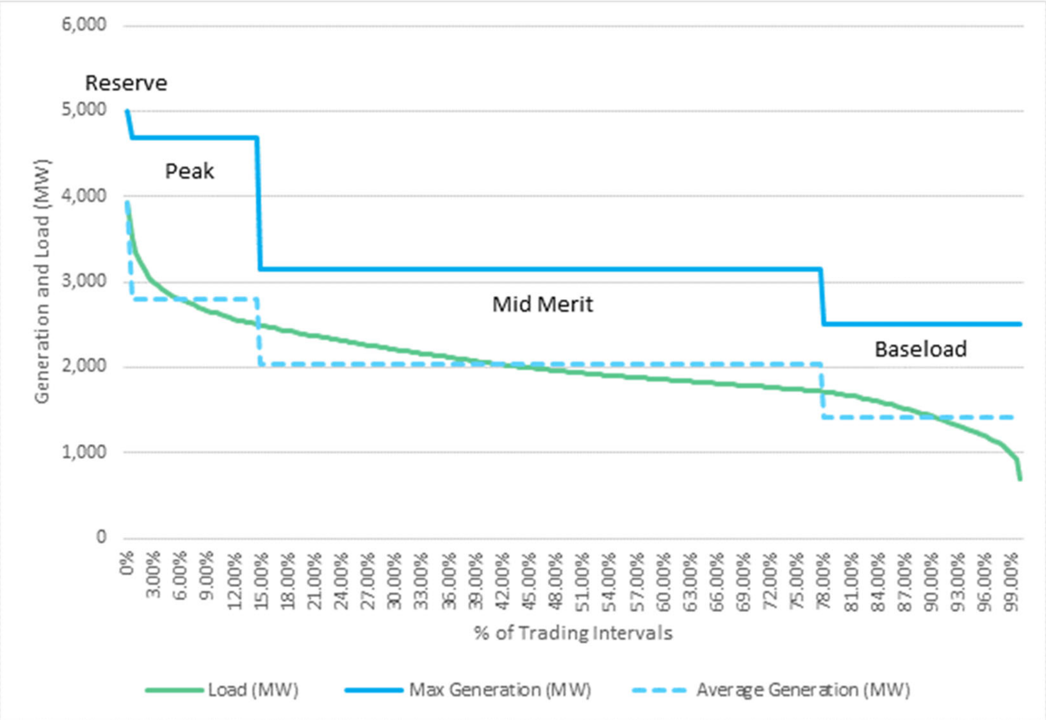
Marsden Jacob has analysed the likely plant mix in the WEM compared with expected demand (50% PoE level) based on announced retirements, such as Muja C in late 2024, and expected future plant retirements, likely new investment in renewable plant to meet renewable energy targets, and investment in dispatchable generation and storage to meet the reliability target in the WEM.

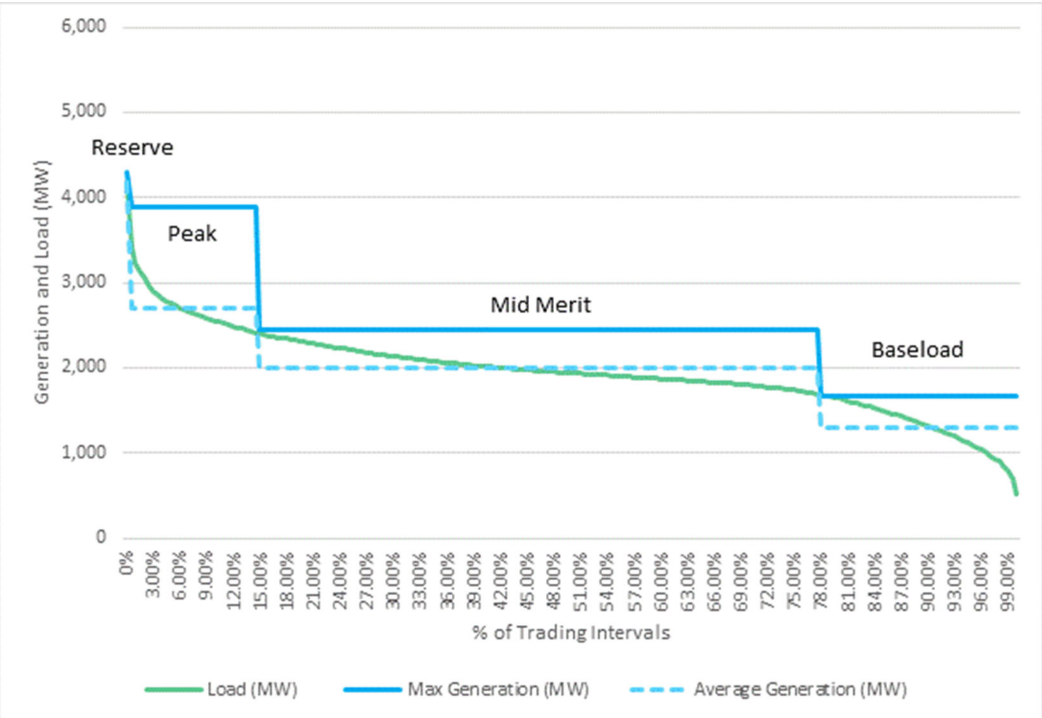
Through this analysis we forecast that plant surplus will reduce to around 2.5% (i.e., Capacity Credits exceeding RCT). However, the plant mix will also change with Baseload generation capacity credits reduced to around 1670 MW (surplus of only 28% of average demand) compared to around 2500 MW in 2022. Mid-merit plant capacity credits will also reduce from 3142 MW to roughly 2450 MW in 2030, and peak capacity credits also reduces from 4683 MW to 3880 MW by 2030.

What is clear from the above analysis is that the generation fleet we have today is not the most appropriate mix to meet future requirements. The current WEM generation fleet can be characterized as having high capacity (MW) and plentiful energy resources (MWh) – i.e., the potential output of generators using coal and gas in the SWIS is significantly above current requirements. Having high capacity and high availability of energy resources incurs additional costs which must be absorbed by either customers (if passed through) or generation asset owners if there is insufficient revenue adequacy in the WEM (this is discussed further in Chapter 4).

[19] Peak Demand on 19 January 2022 (3982 MW) almost exceeded the record demand level set in 2015-16.

Figure 5 Generation Capacity by Operating Cycle and Load Duration Curve for CAL 2022 (top) and CAL 2030 (bottom)





Source: Marsden Jacob 2022

2.4 Transitioning to the Future Energy System

The energy system of the future may comprise of the following:

- Distributed energy resources – behind the meter PV and storage, community batteries, electric vehicles that can both recharge and discharge to the grid, mixture of controllable and uncontrollable technologies,
- Variable renewable energy (VRE) generators – onshore and offshore wind farms and solar farms,
- Large-scale dispatchable generators – aeroderivatives, gas plant running on biogas or hydrogen,
- Large-scale storage – 2-to-8-hour battery systems, compressed air energy storage and pumped hydro systems,
- Synchronous condensers – voltage management (system strength)
- Demand response – customers reducing loads in response to financial incentives (beginning of two-sided energy markets),
- Electrification of households and business – will be partially offset by energy efficiency and PV take-up but electricity demand is likely to increase substantially in WA due to gas to electric conversion.

In the following table, we compare the current generation fleet with the likely future generation fleet that is required to achieve emission reduction targets and meet the reliability criteria, while minimising wholesale costs. Significant new storage capacity needs to be available to meet demand and maintain supply reliability for only a few hours of the year, and to firm up supplies from large-scale intermittent plants. There is a significant reduction in dispatchable generation capacity for all plant types (i.e., Coal, OCGT and CCGT), except for OCGT Aeroderivative plant which is required to provide Essential System Services in the WEM. Additional Demand Side Participation (DSP) resources are also required to help ensure supply reliability for several hours a year.

Table 1 Current and Future Wholesale Market Capacity

Nameplate Capacity (MW)		
CAL Year	**2022**	**2035**
Biomass	93	93
Coal	1,574	530
CCGT	939	854
OCGT	1,760	1,148
OCGT_Aero	200	600
Wind	966	2,111
Solar	177	1,211
Distillate	122	122
DSP	100	300
Storage	65	1,613
Total	5,996	8,582

Source: Marsden Jacob 2022

In summary, the future electricity system will have flexible energy resources (i.e., storage, OCGT_Aero) to manage variations in both supply and demand for electricity, and the likely plant mix will have high capacity (MW) but limited energy resources (MWh).

In effect, we are transitioning from a low capacity/unconstrained energy system to a high capacity/constrained energy system.

The electricity system will have to transition rapidly to achieve emission reduction targets and ensure supply reliability but will need to retain legacy generation technologies until the transition is completed.

Governments and policy makers have not fully trusted market mechanisms to achieve this transition, with the result that government intervention in electricity markets is extensive in the National Electricity Market (NEM). Both State and Federal Governments are underwriting large-scale renewable generation, gas generation and storage projects in the NEM.

The more interventions in the market, the more likely that market mechanisms will not deliver on all the outcomes we would anticipate from a well-designed energy market, i.e., reliable, affordable, efficient, secure, and clean electricity supplies.

Interventions can cause subsequent interventions to correct the adverse consequence of the initial intervention.

Some transitional arrangements have been put in place to ensure legacy generation remains in service to provide firming and ancillary services. These include a capacity price floor and ceiling, the Network Access Quantity (NAQ) framework[20] and the System Security Transition payment to Synergy of $300M over 5 years. However, some participants are concerned that these measures simply delay the transition of the generation fleet that is required to meet future demand.

2.5 Consequences of not Transitioning to a Flexible Generation and Storage Fleet

Given continued investment in intermittent plant to meet emission reduction targets and a current plant mix which is inflexible, the consequences of not investing in a flexible generation and storage could include the following:

- Increased likelihood of unserved energy in some trading periods due to inflexible plant not being able to ramp up sufficiently to meet demand. Alternatively, additional inflexible plant may need to be operational out of merit order in the energy market to provide Essential System Services, which increases costs to the market and ultimately to customers,
- Increased incidence of negative prices when output from solar installations is high and storage systems are not available to store this low value energy,

[20] NAQs also provides certainty for new entrant generation and storage facilities that qualify since they are protected from the "unhedgeable" risk of new generation facilities connecting to the grid and increasing transmission constraints that apply to all generators in that region.

- Increased intervention by regulators when the frequency of energy market at the market cap occurs,
- Increased use of Demand Side Management resources to address supply shortfalls, which can be expensive as they are typically only used as a last resort measure in the WEM (i.e., have high fixed costs and low variable costs),
- Increased energy and ESS prices if inflexible plant exits the system (due to age or low economic returns) and is not replaced with flexible generation and storage systems.

3. Overview of the WEM

The WEM is a 'capacity plus energy market' which relies on authorities to co-ordinate long term planning and procurement to ensure that sufficient capacity resources (quantity approach) are available to meet the targeted level of supply reliability. This is very different to the NEM which relies on 'scarcity' prices (pricing approach) to drive investment in sufficient capacity resources to meet the targeted level of reliability. Investors typically like capacity markets because revenue risks are lower (guaranteed minimum levels of revenue), but frequently suffer from chronic surpluses of capacity, which requires policy makers and governments to intervene regularly in the market to reduce the surplus. The reverse problem occurs in energy only markets, whereby governments and policy makers intervene in the market to avoid shortages of capacity.

There are two fundamental approaches to market design – energy and capacity markets, and energy only markets. We discuss some of the key aspects of each design in meeting market objectives. We also look at how reforms of the WEM are attempting to overcome some of the inherent flaws of the current energy and capacity market design.

3.1 Approach to valuing capacity in energy markets

The Electricity Market Review (EMR) of the WEM considered the merits of retaining the "energy and capacity" market design or moving to an "energy-only" market like the NEM.[21]

Some of key aspects of the NEM energy-only market design (or price driven approach) include the following:

- Setting an energy market price cap at a level (such as the NEM's $15,000 per MWh) that is high enough to avoid curtailment of customers,
- Using forward coordination mechanisms (such as the NEM's Electricity Statement of Opportunities, Projected Assessment of System Adequacy, Retailer Reliability Obligation) and facilitating forward contracting to reduce risks and impact of significant under-investment in resources that would otherwise cause a lower-than-expected level of reliability.

In a market with high energy price caps, to hedge high price events, retailers' contract with generators for the supply of cap products ($300 price caps) that then provides them with a revenue stream for investment in new generation and storage facilities.

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[21] Public Utilities Office, Electricity Market Review, Options Paper, December 2014, p.53.

Despite the Options paper from the EMR indicating that electricity costs and prices would be lower under a NEM-style "energy-only" approach, the WA Government retained the energy and capacity market approach.

A Capacity Market (or Quantity Driven Approach) involves the following:

- Setting the market price cap at a lower value sufficient to recover short-run marginal cost of generators and add penalties for being short of energy or ancillary services at an administered cost of non-supply.
- Establishing targets for required capacity of plant in the market (e.g., 1 in 10-year peak demand with loss of the largest generation unit) and running a procurement process (auctions in many markets) and/or obligations on retailers for the purchase of capacity units (Capacity Credits in the WEM).

Numerous models of capacity markets have evolved worldwide: decentralised (retailer reliability obligations only), a centralised market (PJM, UK etc), and a strategic reserve (Europe). The WEM is a hybrid system with centralised coordination (AEMO establishes a Reserve Capacity Target, accreditation of capacity credits, and uses administered pricing to establish market prices), with responsibility for retailers to procure sufficient capacity credits to meet their loads (plus reserve margins).

The principal attractions of the Capacity Market approach are that:

- policy makers can be assured there is enough supply to meet demand for a time horizon;
- energy price volatility is reduced; and
- reduced concerns about the use of market power, especially in tight demand and supply conditions.

The trade-off is that customers must make capacity payments even in situations of excess capacity - although the new WEM capacity price formulae (see Section 3.4.2) has been reformed to ensure that customers don't pay more when an excess occurs.

Significant and regular energy market price spreads can provide a basis for investment in high duration storage (e.g., pumped hydro). However, given that energy price caps in the WEM are set at relatively low levels (based on SRMC of highest cost plant) compared to energy-only markets, there is limited incentives for long duration storage in the WEM that will be required to replace coal plant that is likely to be decommissioned over the next 10 years. Additional payments from the capacity market would be required to make high duration storage viable in the capacity and energy market design.

The new WEM capacity price formulae have created significant price risks for investors in new capacity in the WEM (incumbents are protected by the capacity price floor until 2031), which will encourage proponents to enter bilateral contracts to secure new capacity. Unlike previous versions of the RCM, it is now very unlikely that merchant investment in the WEM will occur based on the current capacity price formulae that is only applied to new entrant facilities.

Potential problems with capacity markets are well known:

- WEM – oversupply due to the significant over-forecasting by AEMO and the entry of DSM resources. Capacity price was not highly responsive to the level of excess capacity so didn't provide a strong incentive for plant retirements to correct imbalance. Subsequently, DSM was treated differentially (separate capacity pricing model), and WA government announced plant retirements (Muja C and some gas turbines) to help correct the market imbalance.
- Concern's that Britain's capacity market had not attracted sufficient new capacity with payments mainly going to incumbent generators. The capacity auctions were meant to bring forward large flexible gas-fired generation (which it has not).
- The PJM capacity market has experienced chronic oversupply of generation which is primarily due to setting the cost of new entry (CONE) well above new generation costs. With net CONE set too high, prices in energy and ancillary services markets are reduced, which then doesn't provide incentives for flexible generation and storage resources to enter the market, which is what is needed with high levels of VRE.
- State based subsidies for nuclear power plants and low emission plants in the US is also impacting capacity price auctions in the PJM. PJM cancelled its 2019 capacity auction after FERC refused to make the changes PJM proposed to the rules for the capacity market to account for state subsidies (Minimum Offer Price Rule or MOPR).

In the WEM, DSM, generation and storage facilities can be accredited Capacity Credits based on the expectation of how many MW of capacity a facility can provide at peak times in the SWIS. Once the peak contribution of each facility type is determined and Capacity Credits allocated, each type of capacity is regarded as being the same in terms of its contribution to meeting peak demand. However, in practical terms, different types of capacity are treated differently in terms of both obligations and remuneration:

- Dispatchable resources must demonstrate sufficient fuel for 14 hours of operation with one day resupply,
- Batteries can receive 100% certification of capacity for providing 4 hours of energy supply (i.e., 100 MW / 400 MWh configuration),
- DSM is accredited based on the lesser of:
  - the fifth percentile of the top 200 system peak hours in the previous Capacity Year; and
  - the sum of all Individual Reserve Capacity Requirement (IRCR) contributions of the DSP's associated loads.
- All facilities except for VRE are financially penalised for non-performance (excluding planned outages).
- Incumbent generators receive the price floor when the RCP is low (when excess capacity is high), and price cap when the RCP is high (when in slow excess or shortage)
- DSM and new entrant generators receive the RCP based on the administered price formula, which exposes merchant plant to considerable price volatility, and incentivises them to seek long term bilateral contracts with off takers.

Capacity markets are not perfect, and experience tells us that they can require adjustment to deliver the required mix of plant to ensure supply reliability at an efficient cost (i.e., minimising excess capacity in the market).

The challenges for the Reserve Capacity Mechanism in the WEM include the following:

- Are the reliability criteria still relevant when we transition to high VRE generation with limited energy resources (2-to-4-hour battery)? Solar is impacted by cloud cover (can occur for periods of up to 24 hours) and wind droughts can last for several consecutive days.
- If a 4-hour battery is accredited at 100% of its capacity under the Linear De-rating Method and is paid a capacity price based on a fixed frame OCGT ($1200 per kW), how does long duration storage (8 to 10 hours) or baseload energy plant enter the WEM to firm up energy supplies post the retirement of coal-fired generation? Long duration storage may have a capital cost of around $3000 per kW (pumped hydro or 8-hour battery).
- If you maintain price caps (moving to a single price cap based on SRMC of most expensive unit currently $500 per MWh), and requirements to bid at SRMC in the STEM/Balancing Market, there will not be sufficient energy arbitrage opportunities for long duration storage to enter the market (or for CCGT).
- Essential System Services (ESS) will partially make up the shortfalls in the energy market as frequency regulation grows (85 MW to 200 MW by 2030). But it is likely that several large-scale batteries will be used to provide this service in the future, which reduces revenue streams to gas generators.

As highlighted below, cloud cover can reduce rooftop PV system generation to only 10% of nameplate capacity for 8 hours. That implies that if we have 2000 MW of rooftop solar PV, we need to have sufficient generation capacity to cover 550 MW of lost rooftop generation for at least 1 day a year (most likely in winter).[22]

Low wind years can see the output from WA wind farms reducing by 8% per annum. However, the drop on a particular day for an individual wind farm over 3 days is 95% compared to average generation levels. This highlights the importance of maintaining wind diversity in the SWIS to help avoid this situation.

3.2 The problem of managing storage in a capacity market

Energy-only markets provide strong incentives for storage providers to ensure that energy is available to meet tight demand and supply conditions, since prices may achieve VOLL[23] at these times. In the WEM, energy price limits restrict energy arbitrage opportunities and there is little incentive for storage providers to retain energy for tight demand and supply conditions given inadequate price signals. In these circumstances, the market operator has to co-ordinate the

[22] While the nameplate capacity of rooftop solar output is 2000 MW, it does not produce this level in winter due to lower irradiation levels. Typical output level is only 550 MW in winter months.

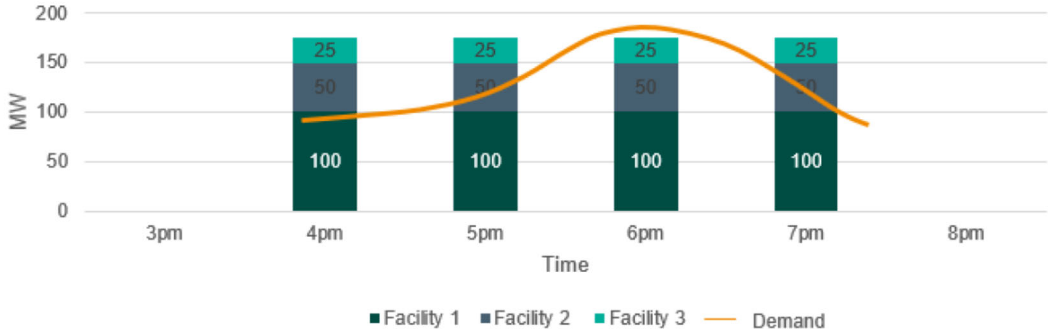
[23] Maximum price in the NEM ($15,100 per MWh from July 2021) is based on a proportion of the Value of Lost Load, which can be as high as $30,000 per MWh.

dispatch of storage facilities. In the WEM, this will be achieved by the AEMO establishing four-hour dispatch windows (ESR Obligation Duration) for Electric Storage Resources (ESR).

For a 100 MW / 400 MWh facility, this would mean offering 100 MW in every hour for the four-hour ESR Obligation Duration (Facility 1 in the figure below).

The ESR Obligation Duration applying to a Capacity Year will be published in the Electricity Statement of Opportunities. AEMO will also have the flexibility to change the window of time (but not the length of the window) at shorter notice, by 8.30am on the Scheduling Day, to enable AEMO to respond to changing or unexpected market conditions.

Figure 6 ESR Obligation Duration

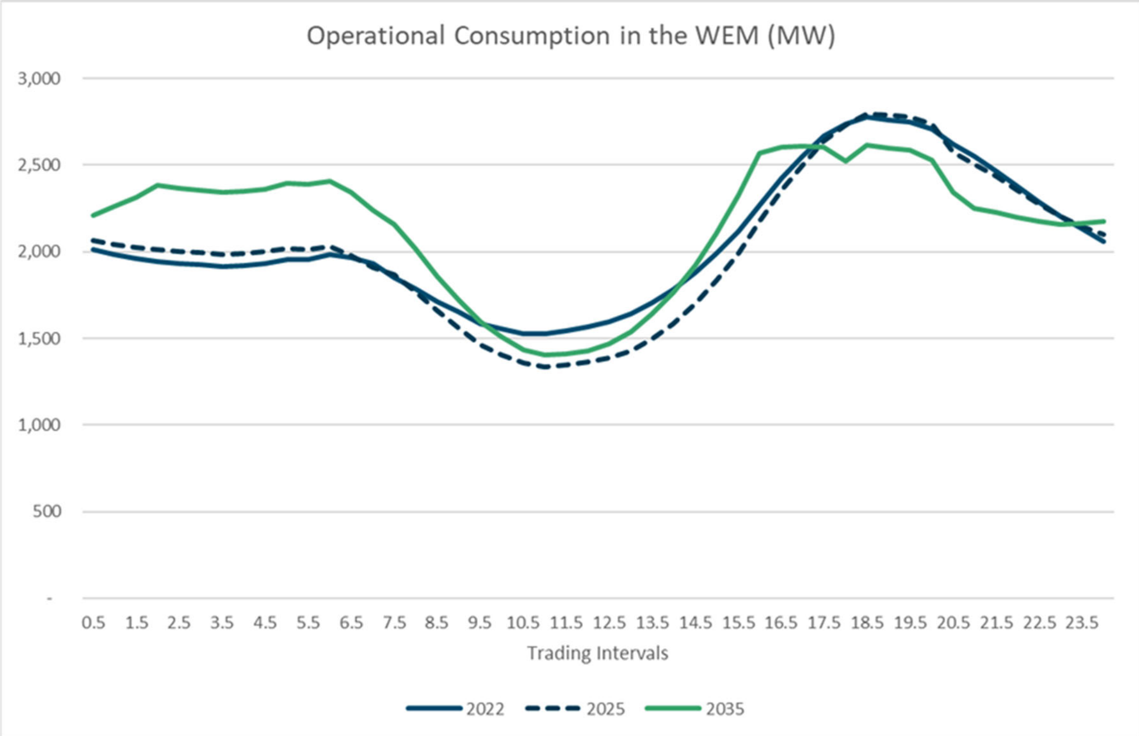


Source: Energy Transformation Taskforce, Reserve Capacity Mechanism, Changes to support the implementation of constrained access and facilitate storage participation, Information Paper, May 2021

In effect, the ESR Obligation Duration (quantity approach) replaces the price-based approach used to determine the dispatch of plant in energy-only markets such as the NEM.

Currently AEMO has determined that the peak period for storage facilities is only 4 hours. However, as more storage is deployed in the SWIS, it is likely that AEMO will have to extend the ESR Obligation Duration to avoid creating new peaks in demand. This can be clearly seen below, whereby the peak period in 2022 is currently 3 hours from 5.30 PM (17.5 interval) to 8.30 PM (20.5 interval), but then changes to 4.5 hours from 4 PM (16.00 interval) to 8.30 PM (20.5 interval) in 2035 (note this could also result from behind the meter storage being dispatched as well). This implies that the 100 MW battery (Facility 1) will have to increase storage by 50 MWh to ensure that it continues to be accredited for 100 MW of Capacity Credits.

Figure 7 Operational Consumption in the SWIS – 50% PoE



Source: Marsden Jacob Analysis 2022

This implies that AEMO and the Coordinator of Energy will need to conduct regular reviews (currently planned for 5-year reviews) of the effectiveness of the certification of Reserve Capacity for ESR to ensure it is consistent with the likely future changes in Operational Demand in the SWIS.

In effect, the responsibility for ensuring storage resources is available to meet peak demand now and, in the future, will be the responsibility of market operators and policy bodies. If these settings are wrong, some mechanism may need to be put in place to compensate owners of storage facilities. For example, if the dispatch window does not coincide with peak Balancing Prices, then ESR many need to be compensated for the loss of any energy or ancillary services revenue. If AEMO forecasts that the dispatch window will increase to 6 hours, but remains at 4 hours, how will an investor in a 6-hour storage facility be compensated for the fact that they do not receive any additional capacity revenue when compared to a 4-hour storage facility?

3.3 How do we address these challenges?

Can we address these issues with incremental changes to the WEM (further product unbundling – inertia services, long term storage services, administered pricing and price caps, 5-minute market settlement, reform of the Capacity Mechanism etc.) or does the WEM require fundamental change (e.g., dynamic energy and ESS prices that reflect scarcity values, less reliance on administered pricing through capacity mechanisms etc.)?

If efficient outcomes can be delivered through incremental changes to the new WEM, what are those changes that you would like to see?

If efficient outcomes can only be delivered though fundamental changes, what is the nature of the change and the key mechanisms that need to be developed?

Much of the reforms developed by the Energy Transformation Taskforce, and will be continued by Energy Policy WA, has been concentrated on wholesale market reforms and the introduction of constrained network access. There has been insufficient focus on other reforms such as ensuring that Western Power is incentivised to invest in transmission to alleviate congestion/constraints and permit transition to VRE generation in regional areas of the SWIS (e.g., North Country, East Country, South Country)? The inaugural Whole of System Plan (WOSP) did not any indicate significant amounts of transmission upgrades in the SWIS and assumed that new generation build would occur in regions of the SWIS that had spare transmission capacity and/or any constraints could be alleviated by the installation of energy storage systems.

Market power is likely to be a concern in a small isolated market, like the WEM, and the current market power mitigation rules and regulations will need to be reviewed and amended to ensure they are appropriate. It is important that any market power motoring regime is efficient and does not add unnecessary regulatory burdens and costs to the market.

3.4 WEM Market Mechanisms

The WEM is a 'capacity plus energy market' where capacity and energy generation are traded separately. In addition, there are ancillary service markets and administered mechanisms that will be replaced by Essential System Services in the future.

3.4.1 Energy Market

The WEM was designed under the assumption that most energy would be traded via bilateral contracts. That is, a market participant would typically have a zero net contract position (bilateral contracts or physical generation would supply the majority of a retailer's load). As a result, the markets were designed to facilitate trade or manage imbalances around market participant's net contract positions. These markets include the following:

- Short Term Energy Market (STEM) – enables participants to purchase or supply energy the day before the trading day – effectively a short-term hedge.
- Balancing market - accounts for imbalances between a market participant's net contract position (after STEM nominations) on the scheduling day (day before trading) and their actual position on the trading day.

The Balancing Market will be renamed the Real Time Energy Market under the reforms and its primary purpose is to ensure the efficient dispatch of generation (and storage in the future) to meet demand in each trading interval (currently 30 minutes, changing to 5 minutes). Focus of this market is to ensure that prices reflect variable costs of supply from each supply source, to ensure variable cost recovery for each resource participating in the market and provide variable price signals to retailers (ultimately customers). However, because the Balancing Market (and STEM) price in each 30-minute trading interval is determined by the most expensive unit cleared in the market, generators with lower variable costs can earn additional revenue which can contribute to the recovery of fixed costs (i.e., capital and Fixed O&M).

Actual participation via price-based dispatch in the Balancing Market is mandatory for generating Facilities with a sent-out capacity of 10 MW or more. Generation plant is dispatched on the merit order of bids, with cheapest generation plant dispatched before more expensive plant as necessary to meet the load in a trading interval (although there are deviations from merit order dispatch due to network constraints).

While there are similarities to the NEM, the differences in the WEM have been and are significant. These differences include:

- Synergy currently bidding as a single entity (facility bidding starting 2023 with the new market) and AEMO managing Synergy plant subject to guidelines
- Gate closure (which is moving to zero gate closure period)
- Energy and frequency control ancillary services are not currently co-optimised (starting 1 October 2023)
- Coal plant have not provided frequency control services
- Stricter rules on participant bidding (i.e., prices must reflect SRMC if market power is evident)

The balancing prices are a reasonable reflection of efficient short-run marginal costs (and hence "competitive prices") since they are made up from the offer curves of all significant generators in the WEM. Market settlement for energy is based on 30-minute trading intervals (same as the NEM), although the NEM moved to 5-minute settlement on 1 October 2021. The WEM will move to 5-minute settlement in October 2025.

Energy Price Limits (EPL) apply both to the STEM and Balancing Market. Shown below are the current price limits (Maximum STEM Prices were developed by Marsden Jacob on behalf of AEMO).

Table 2 Energy Price Limits in the WEM (2021/22)

Name	Units	From Date	Value
Maximum STEM Price	$/MWh	01/09/2020	$267.00
Minimum STEM Price	$/MWh	01/07/2012	-$1000.00
Alternative Maximum STEM Price	$/MWh	01/11/2021	$511.00

Effectively the Maximum STEM Price (which is also the maximum for the Balancing Market as well) is based on the highest SRMC for an Open Cycle Gas Turbine (OCGT) running on natural gas, while the Alternative Maximum STEM Price is based on the highest SRMC for an OCGT running on distillate.

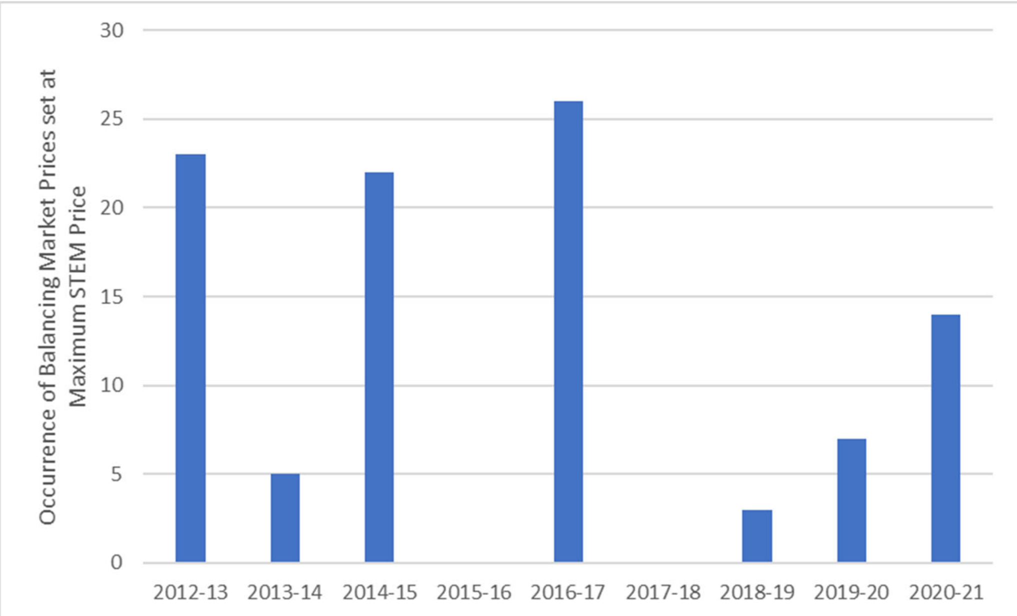
The Minimum STEM Price has not been reviewed since market start and is not based on numerical calculations or a formula.

The purpose of the Maximum STEM prices is the following:

- Protect market customers from high prices that could result from generators exercising market power in the STEM and Balancing Market,
- Provide incentives for new generation investment (i.e., peaking generators),
- Enable existing generators to cover the costs incurred in providing peaking generation so that they are encouraged to provide their capacity during high price periods.

To a large extent it rarely does any of the above. Actual occurrence of maximum prices in the Balancing Market is rare. As shown, the occurrence of the Maximum STEM Price in 2020-21 was 14 trading intervals. In some years, there is no occurrence of prices set at the Maximum STEM Price (although prices above Maximum STEM Price did occur in 2019/20).

Figure 8 Occurrence of Maximum STEM Price in the Balancing Market



Noted: For 2019-20 have included prices set above Maximum STEM Price (at Alternative Maximum STEM Price).

Source: Neo, Final Balancing Price (extracted 9/11/2021)

It is unlikely that new entrant generators will be relying on prices set at the Maximum STEM Price to underwrite their investment. New entrant generators will be looking at overall revenue from the Balancing Market/STEM, Reserve Capacity Mechanism and Essential System Service Markets, and green certificate prices (LGCs) if they are a renewable energy generator.

3.4.2 Reserve Capacity Mechanism

The Reserve Capacity Mechanism (RCM), effectively an administered capacity market, is designed to ensure that there is adequate generation capacity available in the system to meet forecast peak electricity demand plus a margin to allow for forecast errors or plant failures. Under the RCM, generation plant and DSM facilities are certified and allocated Capacity Credits. Electricity retailers are required to procure Capacity Credits in proportion to their share of the electricity load in periods of peak electricity demand. The retailers may meet this obligation by either purchasing Capacity Credits directly from generators under bilateral contracts or procuring Capacity Credits via the AEMO at the resulting administered price (known as the Reserve Capacity Price or RCP).

Because generators receive a separate revenue stream for providing capacity, this removes the need for the energy market to be subject to high and volatile energy prices like the NEM. High price events in NEM (such as prices at or near the price cap of $15,000/MWh) are not necessary to provide revenue for peaking facilities and to trigger new investment. Instead, energy prices are capped at lower levels ($511/MWh for plants running on diesel; $267/MWh for all other plant)[24], with the RCM contributing to generator capital costs. The RCM may fully fund the capital costs for peaking facilities and contribute towards a base load unit's capital cost.

The WA Government have implemented changes to the RCM in recent years. The objective of these reforms is to reduce the amount and cost of excess capacity in the market (which was 23 per cent in the 2016/17 capacity year).

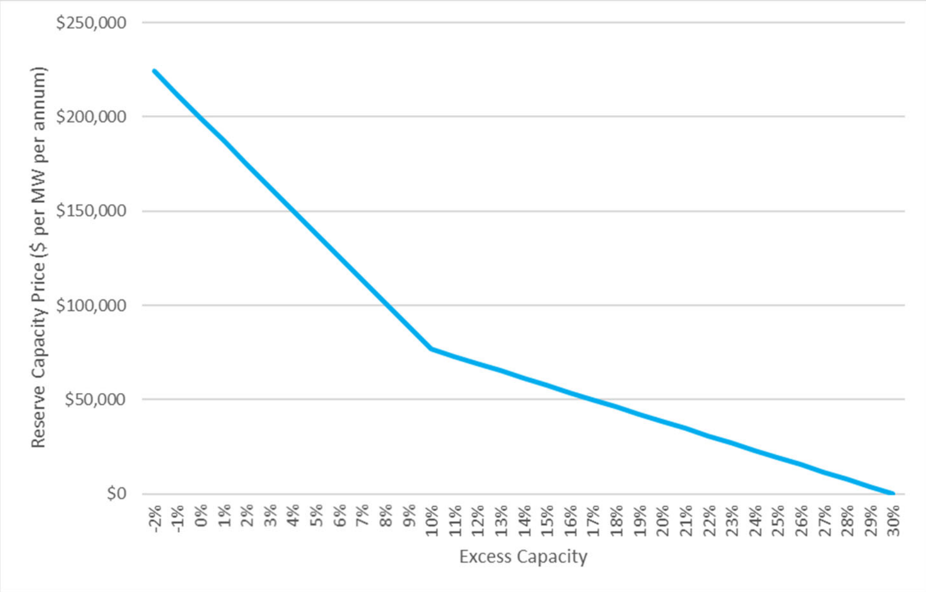
A recent reform was the introduction of a new capacity pricing model that commenced for the 2021-22 capacity year with the following features:

- The RCP excess demand curve will be set at 1.3 multiplied by the Benchmark Reserve Capacity Price (see discussion of BRCP in next section) when excess capacity is 0 and will reduce to 50 per cent of the BRCP when excess capacity is at 10 per cent (effectively a convex capacity curve)
- Beyond 10 per cent excess capacity, the RCP will fall to 0 when excess capacity reaches 30 per cent, and
- A transitional cap and floor price band is applied to transitional generators for 10 years. The cap price is set at $140,000/MW/annum, while the transitional floor price will be set at $114,000/MW/annum (both in 2021 dollars).

New generators will have full exposure to the new price formula (unless they contract with a retailer).

[24] 2021-22 nominal prices.

Figure 9 Reserve Capacity Price Curve

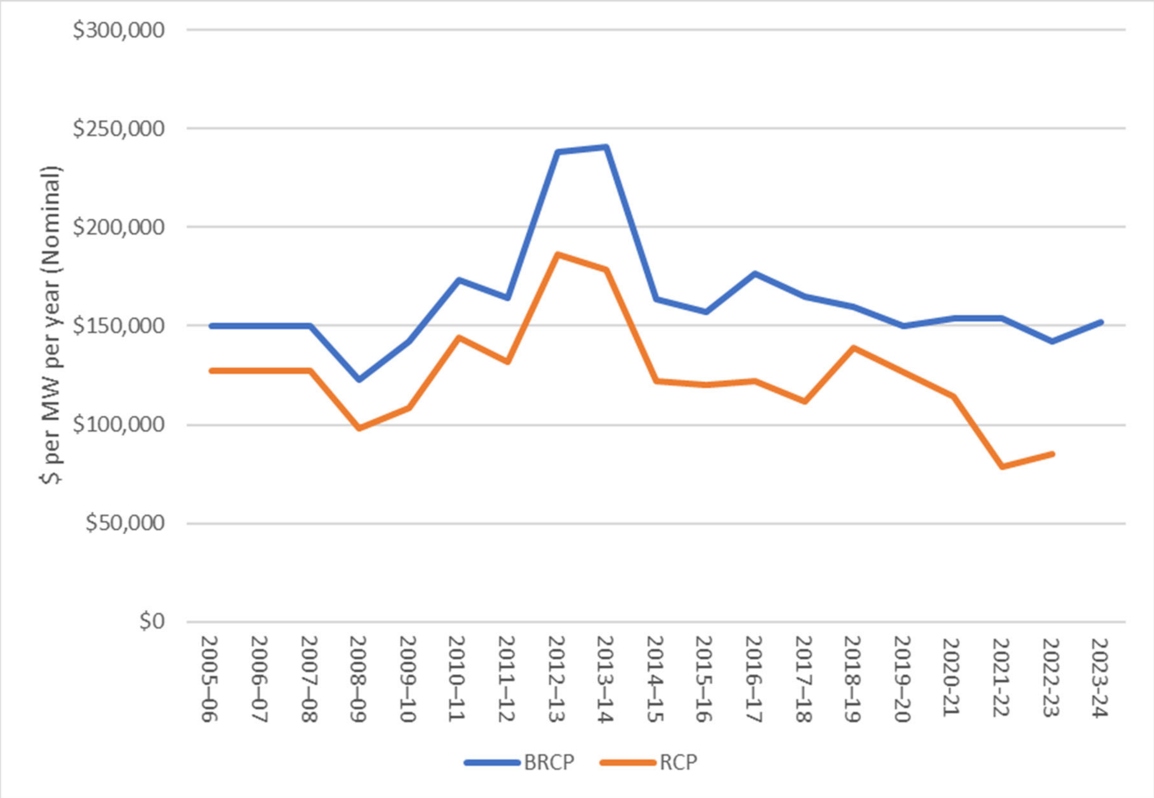


Source: Marsden Jacob 2020

The WA Government has acknowledged that a convex capacity curve may result in increased price variability, which may make the re-financing of power stations difficult in the SWIS. That is the rationale for including the transitional price cap and floor for existing generators. The price floor is currently binding in the WEM given the low RCP in 2021-22 and 2022-23 (~10 per cent excess capacity).

Figure 10 shows the historical BRCPs and RCPs. In most years, the RCP is well below the BRCP due to relatively high levels of excess capacity in the WEM. The divergence between the BRCP and RCP is the largest for 2021-22 and 2022-23 capacity years due to the combination of high levels of excess capacity (~10%) and the new convex capacity curve for determining the RCP.

Figure 10 Historical Benchmark and Reserve Capacity Prices ($ per MW per annum, Nominal dollars)



Source: https://aemo.com.au/energy-systems/electricity/wholesale-electricity-market-wem/wa-reserve-capacity-mechanism/reserve-capacity-price

3.4.3 Benchmark Reserve Capacity Price (BRCP)

The price cap in the RCM is the Benchmark Reserve Capacity Price (BRCP). The BRCP is used to establish the RCP, along with the amount of excess capacity in the WEM, under the current capacity price formula (discussed above).

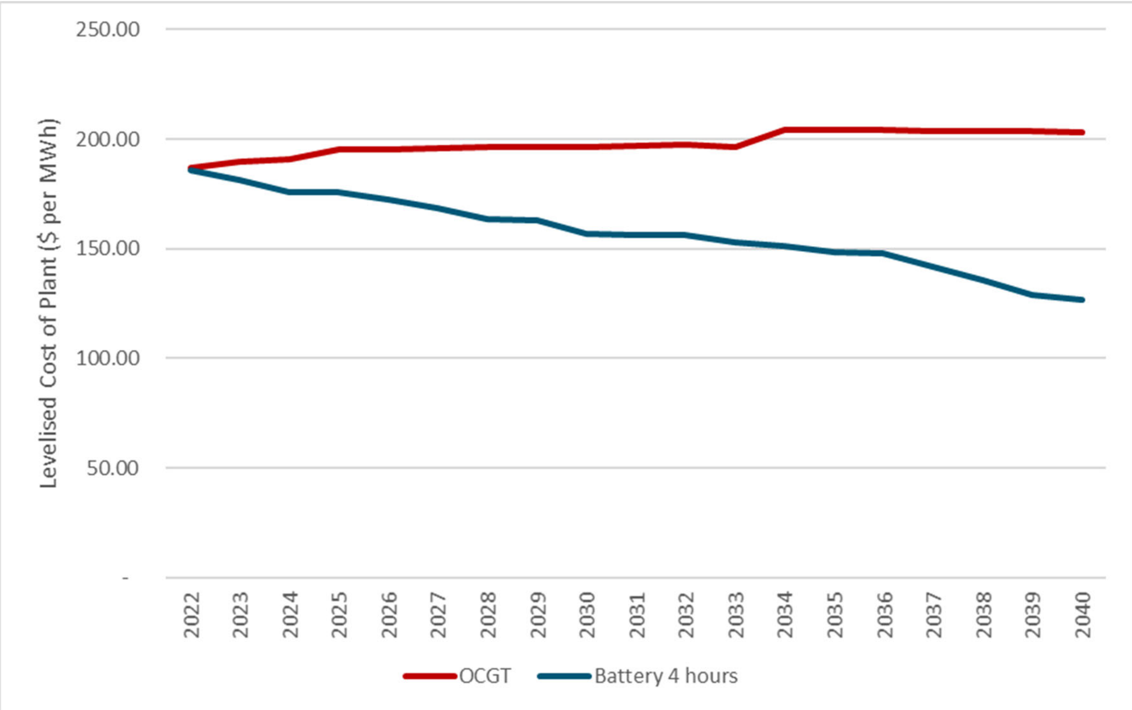
The BRCP is based on the cost of building a new 160 MW open cycle gas turbine generation facility in the SWIS during the relevant Capacity Year. The BCRP is set annually by AEMO after considering changes in the cost of capital, generator capital costs and connection costs for the benchmark generator. The methodology used to determine the BRCP has not changed since 2011 due to the deferral of the five-yearly review of the Market Procedure, despite concerns with the methodology consistently raised by market participants (Marsden Jacob has assisted clients with their submissions to both AEMO and the ERA on these matters). Some of those concerns include the following:

- Annualising generation and transmission capital costs with a Weighted Average Cost of Capital (WACC) that is set well below levels that would be applicable in the funding of peaking generators in Australia. In some years the real after tax WACC has only been just over 5% per annum; and,
- Current choice of the reference generation unit of 160 MW OCGT that is not likely to be installed in a system that has low peak demand growth. By choosing a larger unit that has some economies of scale ($ per kW installed) when compared to smaller units (say a 40 MW unit), the BRCP is not likely to be

high enough to enable the entry of small-scale peaking units in the WEM.

With the future entry of large-scale batteries into the SWIS, it is not clear that the Benchmark Unit for the WEM will continue to be an OCGT plant. Shown below is the levelised cost of an OCGT versus a battery with 4 hours of storage (will be accredited 100% of nameplate capacity for Capacity Credits under the Linear derating method). Based on our estimates, the levelised cost of a battery is lower than the cost of an OCGT.

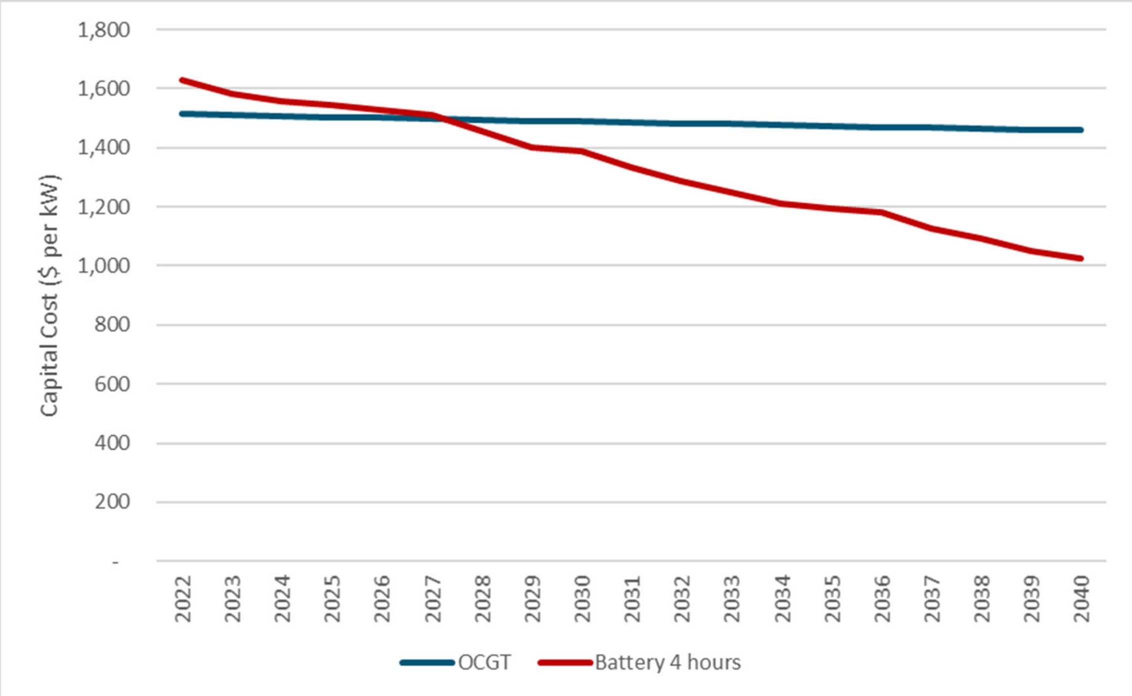
Figure 11 Levelised Cost of Battery and OCGT (2021 dollars, $ per MWh)



Source: Marsden Jacob 2022 and AEMO, Draft 2022 Forecasting Assumptions Update, For Integrated System Plan 2022

If the BRCP is based on the installation cost of a large-scale battery, then initially the BRCP may increase. However, factoring in learning curve effects of battery technologies, we may find that the BRCP reduces rapidly if based on battery technologies as shown below.

Figure 12 Installed Cost of Large-Scale Batteries and an OCGT Plant (2021 dollars, $ per MW)



Source: Marsden Jacob 2022 and AEMO, Draft 2022 Forecasting Assumptions Update, For Integrated System Plan 2022

3.4.4 Essential System Services

Essential System Services (previously known as Ancillary Services) are required to ensure a secure and reliable electricity supply. They are required to maintain system frequency due to a sudden large change in generation or load, as well as providing load following services to balance demand and supply within each 30-minute trading interval. The current Ancillary Services will be replaced by Frequency Control ESS, like the NEM ancillary service standards, and includes:

- Frequency Regulation Raise (currently referred to as Load Following Ancillary Services Up or LFAS Up)
- Frequency Regulation Lower (currently referred to as LFAS Down)
- Contingency Reserve Raise (currently referred to as Spinning Reserve Ancillary Service or SRAS)
- Contingency Reserve Lower (currently referred to as Load Rejection Reserve or LRR) and
- Rate of Change of Frequency (RoCoF) Control Service (no current equivalent service).

It is likely that grid connected battery systems (2 hours) will be able to provide the first four services in preference to coal or gas fired generation over the next decade due to the fact that battery system response times are superior to the response times of coal or gas fired generation, even when the later technologies are operating (i.e., generation units that are operating can ramp up and down quicker when compared to a warm or cold start unit).

The need for a formalised RoCoF Control Service has not been required in the past since most of the generation fleet consisted of large coal and gas units that had provided significant inertia (stabilised system frequency) through normal operations. With the expected retirement of many of these units over the next decade, synthetic inertia will need to be provided by batteries and intermittent plant (e.g., wind).

RoCoF Control Service will perform the following functions[25]:

- To restrict the RoCoF to below a certain level (e.g., 1 to 2 Hz/second); the amount of RoCoF Control Service scheduled to meet this purpose is referred to as the minimum RoCoF requirement.
- To provide a substitute for Contingency Reserve raise; the more inertia there is in the power system at any given point in time, the less contingency reserve raise is required.

AEMO will determine a safe RoCoF limit through appropriate technical studies and include it in the Frequency Operating Standard and the dynamic frequency contingency model used in dispatch. The implication of this service is that higher marginal-cost synchronous generators will need to operate ahead of cheaper intermittent renewable generators.

Maintaining a minimum level of inertia could be achieved by constraining on additional synchronous generators or by commissioning a high inertia synchronous condenser. Some inverter connected generators (e.g., wind farms) and batteries are also capable of providing a synthetic inertial response.[26] Battery energy storage systems can provide a rapid change in the power generated or consumed; this fast frequency response can also help to control RoCoF.

3.4.5 FCESS Price Determination in the WEM

Currently, prices in Frequency Control Essential System Services markets reflect generator variable costs and/or opportunity value foregone in the energy market (i.e., Balancing Market) when these resources are dispatched to provide these services. Analogous to the Balancing Market, Regulation and Contingency Reserve prices are based on the most expensive unit cleared in a trading interval, so can provide a capacity contribution for ESS resources that are lower cost than the resource that determines the price in that trading interval.

Given the inter-relationships between ESS and energy markets, these markets will be co-optimised from 1 October 2023, which could reduce ESS prices in the future given that co-optimisation has the potential to reduce risks for generators participating in ESS markets (i.e., do not forego profitable opportunities supplying energy in the Balancing Market).

Under proposed reforms of ESS, the Economic Regulation Authority will set ESS price limits every three years. The ESS price limits could be based on the higher of either:

I. the energy price cap less the energy price floor – which represents the maximum opportunity cost at times of high energy demand; or
II. the potential costs not recovered in the energy market when running at minimum generation to provide ESS.
III. The ESS price floor will remain at zero as currently gazetted.

[25] AEMO, Market settlement, Implementation of five-minute settlement, uplift payments and Essential System Services settlement, 1 December 2019

[26] The current RoCoF rules do not permit synthetic inertia, but this is likely to be reviewed in the future.

A ten per cent margin will be added to the ESS price limits and then rounded up to the nearest one hundred dollars.

What the above highlights is that ESS bids and price limits are highly related to energy market bids and price limits. As a result, there needs to be consistency in bidding practices and price caps between both market mechanisms. That is, if price caps in the energy market are based on SRMC of most expensive unit in the WEM, then price caps in the ESS market also need to be related to the energy market price cap (for example, energy price cap less energy price floor). Establishing differential price caps in the ESS market would mean that ESS prices no longer reflect opportunity cost of operations in energy markets, which is not consistent with efficient pricing principles (i.e., prices reflect actual cost of resources used or foregone revenue opportunities).

LFAS (Frequency Regulation) Prices

LFAS, or Frequency Regulation, prices are effectively based on foregone generation sales (LFAS Down Service), and additional costs that are incurred if operating out of merit order in the energy market (LFAS Up and Down Service). Currently when providing the LFAS Down Service, gas generators must be operating and have the flexibility to reduce supply. For some intervals, gas generators may not be operating profitably (SRMC>Balancing Market price) and will need to be compensated for these higher costs. If they are operating profitably and must reduce generation, they forego revenue opportunities in the Balancing Market and will need to be compensated for this. For providing the LFAS Up Service, gas generators must be on and their SRMC could exceed the Balancing Market price. When they ramp up, their SRMC may exceed the Balancing Market price and they will need to be compensated for these additional costs.

Currently, LFAS prices are based on the additional costs (SRMC>Balancing Market price) and foregone net revenue (Balancing Market price>SRMC) of gas plant in the SWIS (i.e., OCGT, OCGT-Aero, CCGT and Cogeneration Units). Currently, the energy and LFAS market is not co-optimised, which implies that costs are higher for gas generators providing this service (i.e., risk of foregoing profitable sales opportunities in the Balancing Market are higher).

However, the move to co-optimisation of the energy and LFAS market and Facility Bidding (October 2023) will enable more existing generators to participate in the LFAS market (e.g., potentially coal plant), as well as the entry of energy storage facilities. From the mid 2020's, large-scale renewable plant can also participate in Frequency Regulation Lower Service (i.e., constraining plant output).

As a result, it could be expected that LFAS prices will reduce in the WEM due to new supply sources coming on stream, despite a likely increase in demand for these services due to the increase in the penetration of intermittent plant that makes it more difficult to forecast both electricity demand and supply, implying that the size of frequency deviations will likely increase. This dynamic has been captured in our ESS price forecasts that support revenue adequacy analysis in 4.1.3.

Contingency Reserve prices

Frequency Contingency Raise Service (i.e., spinning reserve) is provided by gas generators in the WEM and by interruptible loads. Generators need to be operating to provide this service so that they can ramp in response to a frequency drop. Frequency Contingency Raise prices are driven by similar market dynamics that drive Frequency Regulation Up regulation services.

FCAS Contingency Lower Service (i.e., Load Rejection Reserve) is provided by generators that are operating and can be ramped down to help to reduce system frequency resulting from the loss of a major load in the SWIS. Frequency Contingency Lower prices are also driver by similar market dynamics that drive LFAS Down regulation services.

For this revenue adequacy study, it is assumed that Frequency Contingency Raise and Lower Services prices are 17.5% of Frequency Regulation Raise and Lower Prices. This is based on the ratio of FCAS regulation and FCAS contingency reserve (60 second) in the National Electricity Market.

3.5 Market Power Mitigation Mechanisms

In March 2021, Energy Transformation Taskforce released the consultation paper "Proposals for changes to Market Power Mitigation Mechanisms".[27] This has been followed up with the release of an Information Paper on the same subject.[28]

Changes to Market Power Mitigation Mechanisms are required given the significant changes to the WEM:

- Establishment of Essential System Services (ESS) markets
- 5-minute dispatch intervals (but not 5-minute market settlement until 2025)
- Move to a zero-gate closure period
- Security constrained economic dispatch (SCED)
- Synergy facility bidding
- Co-optimisation between energy and ESS
- Abolition of constrained-off payments (moving to constrained network access where this risk is borne by market participants)
- Changes to the Reserve Capacity Mechanism (RCM) to recognise network constraints in the capacity credit allocation process with the introduction of a Network Access Quantity (NAQ) regime which will be used to determine the capacity credits a facility gets under the capacity mechanism with a constrained network. The NAQs removes the unhedgeable risk of complete loss of capacity revenue of a new entrant (or later new entrant) locating nearby and increasing transmission constraints on local generators.

[27] Energy Transformation Taskforce, Proposals for changes to Market Power Mitigation Mechanisms, Consultation Paper, 31 March 2021.

[28] Energy Transformation Taskforce, Improvements to Market Power Mitigation Mechanism, Information Paper, 21 May 2021

- Establishment of a Supplementary Essential System Services Mechanism (SESSM) which can be triggered by AEMO (if a potential shortfall of ESS) or the ERA (if prices are regarded by the ERA as being inefficient) and is overseen by the ERA.

It was argued by the ETT that the existing market power mitigation mechanism in the WEM are largely reactive (ex-post) and to some extent unenforceable, given that it relies on compliance with SRMC bidding rules. Generator SRMC is complex, dynamic and requires judgement to determine, which makes it extremely difficult for regulators to understand whether market participants have complied with these rules in retrospect.

Due to these deficiencies in current Market Power Mitigations framework, the ETT have made the following recommendations

- Reference to SRMC will be removed from the Rules
- The Rules will define unacceptable trading conduct as raising prices (and margins) above levels that would have arisen in the absence of market power being exercised.
- The ERA will be required to provide practical guidance on unacceptable trading conduct like that provided by the Australian Competition and Consumer Commission (ACCC) and the Australian Energy Regulator (AER).
- An objective test will be introduced to determine which participants are able to exercise market power. Additional requirements will be imposed on participants which pass this test.
- Price caps will be set for the energy and ESS markets. These limits should be high enough to enable participants to recover efficient costs and Energy Policy WA will need to redesign the relevant market rules to provide for this.

Concerns around the merits of the proposed price limits and the impact such controls will have on the market were raised by the AEC. Specifically, interventions based on arbitrary price limits could lead to services being undervalued and prices being below cost, which risks disincentivising investment in the energy sector. Without capacity mechanisms to support investment in ESS, investment into efficient technologies (i.e., battery storage) is infeasible due to the energy price cap which results in fixed costs not being recovered via market mechanisms.

The new ESS markets (although FCAS market has been in place since 2012), provides dispatchable generators with a third revenue stream. However, in the discussion of the scope of the RCM review, the AEC's WA Working Group broadly agreed that revenue adequacy for generators is a major issue and needs to be considered wholistically including the RCM, and the energy and ESS markets.

4. Generator Revenue Adequacy and Market Power in the WEM

Over the period 2016/17 to 2020/21, revenue from the WEM has provided adequate revenue to permit existing plants to continue operations in the SWIS (EBITDA margins are positive). Based on current WEM revenue forecasts, new entrant coal and OCGT plant is not economic. Flexible generation (OCGT_Aero) and storage (4 hours storage) is marginal (revenue is just sufficient to cover costs), while intermittent generation (wind and solar) is still economic (the latter is only economic if LGC revenue is included). A low-capacity price forecast contributes to the above results.

4.1 Revenue Sufficiency in the WEM

4.1.1 Generator costs

Generator costs consist of the following:

- capital costs (of construction, including connection to the transmission system, and any fuel assets required, such as pipelines)
- fixed operations and maintenance (FOM) costs
- variable operations and maintenance (VOM) costs
- fuel costs, which are a function of the heat rate of a thermal plant (GJ/MWh) and delivered fuel costs (e.g., gas, distillate, coal)
- market costs (market fees and charges from AEMO).[29]

Based on the above cost components, the cost profile of a generator unit is expressed in the following terms:

- Short run marginal cost (SRMC): This is composed of costs that are variable over the short term. For generators, those are fuel costs and VOM.
- Mid run marginal cost (MRMC): This is composed of the costs that would be avoided (assuming no contractual obligations) if a generator unit were to shut down. Those include the costs that comprise the SRMC and all fixed operating costs, such as capital expenditure, fixed operating expenditure, staffing, management, insurance, and licence fees.
- Long run marginal cost (LRMC): This is the total cost of a generator over its economic life. It includes all capital costs and all variable costs. This is the cost that needs to be considered in an investment decision.

[29] Excluded from our analysis

These costs determine the economics of the entry of a new generator (do prices exceed LRMC), the closure of an existing one (do prices exceed MRMC), and how a generator will operate when it is built (only operating when prices > SRMC). These are critical matters in how scheduled generation (new and existing coal, gas and hydro plant) will respond to increasing levels of renewable generation entry.

The relationship between the three cost benchmarks ($ per MWh delivered to the node) are shown below:

SRMC = ($variable\ O\&M$ + ($heat\ rate \times fuel\ cost$)) / $loss\ factor$ Equation (1)

MRMC = Equation (1) + $fixed\ O\&M$ / $loss\ factor$ Equation (2)

LRMC = Equation (2) plus capital costs / loss factor Equation (3)

where:

- $variable\ O\&M$ is the mean variable operating and maintenance cost of a generating unit, expressed in $ per MWh, and includes, but is not limited to, start-up costs,
- fixed $O\&M$ is the mean fixed operating and maintenance cost of a generating unit, expressed in $ per MWh,
- $heat\ rate$ is the mean heat rate at the average capacity of a generating unit, expressed in GJ per MWh,
- $fuel\ cost$ is the mean unit fixed and variable fuel cost of generating unit, expressed in $ per GJ, and
- $loss\ factor$ is the marginal loss factor of a generating unit station relative to the reference node.

The SRMC is the change in total generator costs for a given change in electricity generated (or delivered to the node). SRMC is highly relevant to determining bids in the STEM/Balancing Market, since prices below SRMC can imply that the generating unit is making a variable loss on each unit generated.

MRMC is relevant in determining whether an existing generator should consider closing (whereby prices are consistently below MRMC).

4.1.2 Past Revenue Sufficiency in the WEM (2016/17 to 2020/21)

For each generator in the SWIS, we have determined EBITDA margins (revenue minus MRMC) to assess where there has been sufficient revenue adequacy in the WEM. We have aggregated this for each plant type.

EBITDA is equal to the following:

EBITDA = (energy, capacity and ancillary services revenue) minus MRMC (equation 4)

What our analysis shows is that EBITDA margins have provided adequate returns to permit plants to operate in the SWIS. This does not imply that the generation units are financially viable, since the plants may not recover their full capital costs. However, if the plants can at least cover their avoided costs (MRMC) and contribute to their capital costs, then it is likely that the plant will remain in operation.

We have excluded Large-scale Generation Certificate revenue from the analysis, which indicates that the EBITDA margins would be significantly higher for renewable plant in the WEM

What this analysis shows is that EBITDA margins are positive for all generator classes in the WEM over the period 2016/17 to 2020/21. However, there are some notable trends from the analysis of past EBITDA margins:

- The EBITDA margins are lowest for coal generating units in the WEM compared to all other plant classes. Given that this plant type has high fixed costs (i.e., FOM), a small reduction in revenue will likely result in this plant having negative EBITDA margins. Increases in start-up costs could also increase VOM costs for this plant type and reduce EBITDA margins further. This indicates that coal plant may not earn sufficient revenue to cover costs in the future if increases in intermittent plant erode future sales from coal fired generators.
- EBITDA margins for CCGT are the second lowest of all plant types. EBITDA margins were historically low in 2016/17 for CCGTs, recovered in 2017/18, but have since been on a downward trend. To a large extent, reduced load in the SWIS has contributed to this reduction in EBITDA margins for this plant type. This trend indicates investors are unlikely to consider future investment in this plant type.
- EBITDA margins for OCGTs was also on a downward trend but increased in 2020/21. It is likely that future coal plant retirements will help increase EBITDA margins for this plant class.
- EBITDA margins for renewable plant are high as they have relatively low variable costs (zero in some cases).
- EBITDA margins for distillate plant are also high in the WEM given these plants earn sufficient revenue from the capacity market to cover MRMCs.

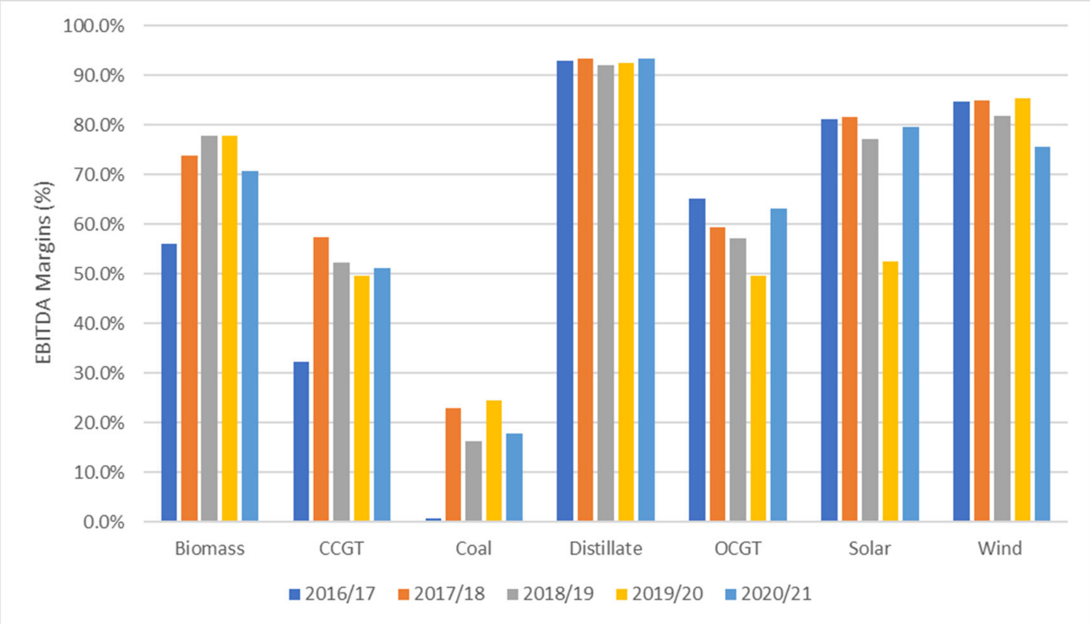
In summary, the WEM has provided adequate revenue for most plant types in the WEM between 2016/17 and 2020/21. The exception is coal plant which has relatively low EBITDA margins and if revenue continues to decline, it is likely that EBITDA margins will become negative for this plant type.

4.1.3 Future Revenue Sufficiency in the WEM (Cal 2022 to Cal 2031)

The transition to zero net emissions by 2050 is gaining momentum with many market participants in the NEM announcing the earlier retirement of coal fired units.[30] To a large extent this is occurring because of reduced grid demand for dispatchable generation and a reduction in utilisation of coal fired units. These same drivers may accelerate the retirement of coal fired units in the SWIS.

[30] https://www.argusmedia.com/en/news/2300504-australias-agl-advances-coalfired-power-closures

Figure 13 EBITDA Generator Margins in the WEM (based on June 2021 dollars)



Source: Marsden Jacob 2022

Given that coal plant retirements may be an efficient response to declining operational demand, will there be sufficient revenue to enable new investment in firm generating sources to maintain future supply reliability? To answer that, we need to consider likely future outcomes in the WEM with new entrant generator costs.

In the following analysis, we have compared the levelised costs of each technology class with levelised revenue over the period 2022 to 2031 for a Base Case Scenario (i.e., ESOO 2021 expected case scenario).

The key features of this Base Case Scenario include the following:

Table 3 Base Case Scenario Assumptions

Scenario Description	Base Case Scenario
Network Access Arrangements	Fully Constrained Network Access by October 2023
WEM Reforms	Facility bidding, co-optimisation of energy and ancillary services, security constrained economic dispatch all commence 1 July 2023 5-minute market settlement in Oct 2025
Capacity Pricing Model	Convex Capacity Price Curve introduced 1 October 2021. Limited reforms of Reserve Capacity Mechanism to accommodate short duration storage and changing nature of peak demand (increased intermittent generation).
Emission Reduction Policy	Zero generation emissions by 2050 in the SWIS Renewable generation forecast by Marsden Jacob to be 58% of total SWIS demand by 2031.
Reliability Criteria	Current reliability criteria is maintained in the SWIS. That is, sufficient capacity to meet the following:
	(a) Peak Demand (10% PoE) and Reserve Margin;

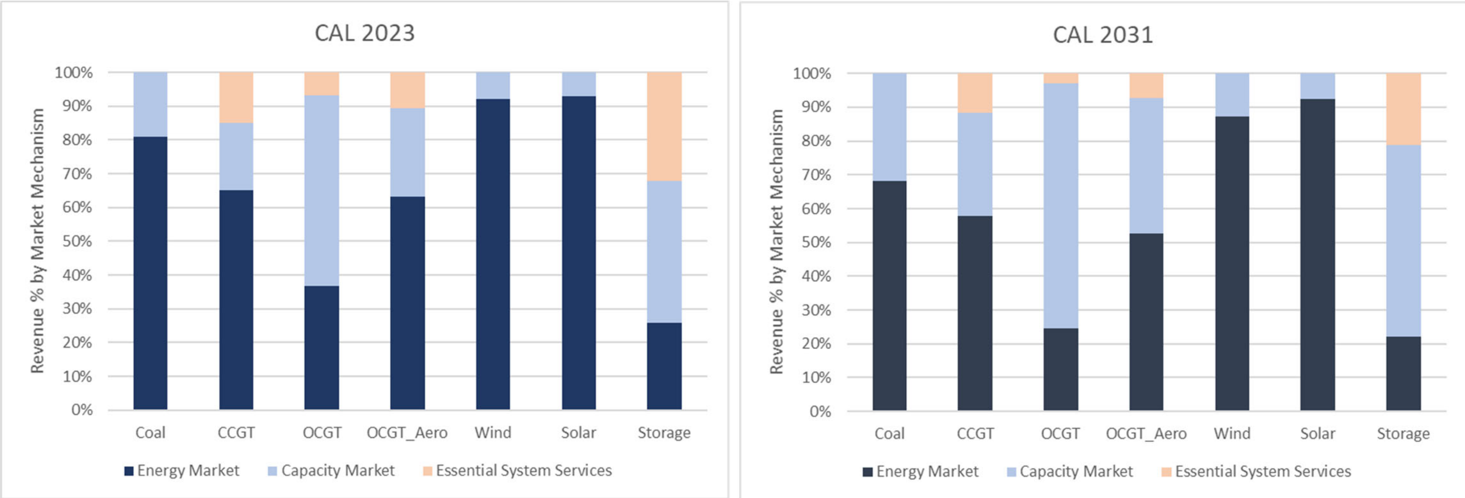
Scenario Description	Base Case Scenario
	(b) Limit Unserved energy to 0.002% in a year.
Weather	10 per cent and 50 per cent POE Operational Demand
Underlying Demand	Profile is based on calendar year 2021 Operational Demand
	ESOO 2021 Expected Projections - 2021/22 to 2030/31 plus new Large Industrial Loads (LIL).
Rooftop PV and Storage Uptake	ESOO 2021 Expected Projections - 2021/22 to 2030/31
Operational Demand	ESOO 2021 Expected Scenario plus LIL
Peak Demand	ESOO 2021 Expected Scenario plus LIL
Fuel Prices	Delivered natural gas price increases from \$6.31 per GJ in 2021/22 to \$7.36 in 2030/31 in real terms. Coal price increases from \$3.19 per GJ in 2021/22 to \$3.65 per GJ in 2030/31 in real terms.
Large-scale Renewable Build	Committed plus sufficient to achieve emission reduction targets.
Plant Retirements	Consistent with meeting LRET and Emission Reduction Targets. Muja C - Unit 5 By October 2022 - Unit 6 By October 2024 Additional 400 MW of coal plant retired by October 2028.
New Build	No new coal plants. Battery storage, CCGT, OCGT aero (preferred) and conventional OCGT all permitted.
Storage	Battery storage is economic to enter from 2020 Synergy Battery (100 MW / 200 MWh) enters on Sept 2022 and is located at the Kwinana Power Station (decommissioned) Alinta Battery (100 MW / 200 MWh) enters on Mar 2023 and is located at the site of the Alinta Wagerup OCGT units (has not achieved FID at this stage) Distribution connected (Western Power batteries) and Behind the meter storage also enters the market
Network Augmentations	Transmission from Northern wind farms limited to 500MW until 1 July 2024. Major augmentation to alleviate constraints from Northern wind farms in 2025. Existing constraints on East Country generators are removed in 2022.

Source: Marsden Jacob 2022

Total revenue includes energy, capacity, and ESS (where relevant), whereas costs are effectively LRMC (see section 4.1.1). Shown below is the revenue stack for each plant type for CAL 2023 and CAL 2031. What this shows is that energy market revenue is a significant revenue source for coal, CCGT and OCGT Aeroderivative units, wind and solar. Capacity Credit revenue is the most important source for OCGT and 4-hour storage as each technology is only operating at a 7 and 10 per cent capacity factors respectively in 2023.

In 2031, capacity market revenue increases substantially for all generator classes because of increased capacity prices (RCP is \$170,000 per MW per annum in 2031 compared to \$83,000 per MW per annum in 2023), while ESS revenue falls due to lower frequency regulation and contingency reserve prices. The higher RCP results from a decrease in excess capacity in the market, while ESS prices fall due to increased competition between gas plant and storage technologies.

Figure 14 Levelised Revenue by Plant Type, Selected Calendar Years (June 2021 dollars)

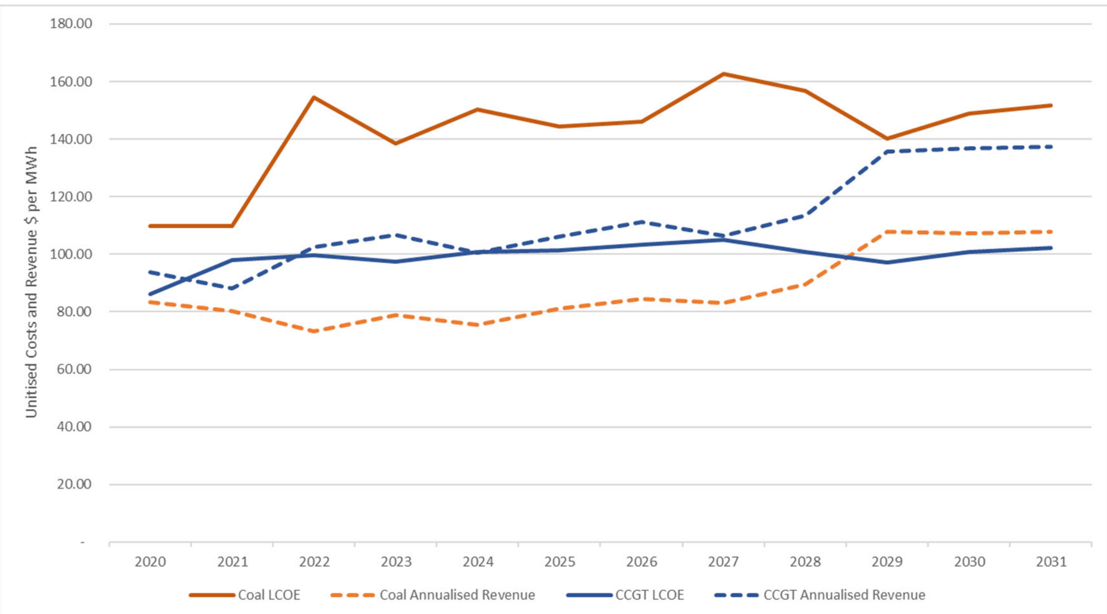


Source: Marsden Jacob 2022

The comparison of LCOE with levelised revenue is shown below for baseload, mid-merit and peaking plant.

Our analysis indicates that the revenue earned from the WEM is insufficient to recover the LRMC of a supercritical coal plant, while the forecast revenue is just sufficient to cover the cost of a CCGT plant. The major factor driving this result is the relatively low capacity factors for each baseload plant type - 57% for coal and 45% for CCGT, which increases the levelised costs of this plant given the high fixed costs associated with these plant types.

Figure 15 Levelised Revenue and LCOE for Baseload Plant in the WEM (June 2021 dollars)



Source: Marsden Jacob Analysis 2022

Regarding mid-merit plant, wind is economic, while OCGT Aeroderivatives are marginal. Large-scale solar is not economic without LGC revenue because of competition with rooftop PV which is decreasing the dispatch weighted price (DWP) for energy delivered in the Balancing Market. Contributing to the marginal economics for OCGT Aeroderivatives is the anticipated reduction in ESS prices (e.g., Frequency regulation up is $20 per MW while Frequency regulation down is $13 per MW over the period CAL 2022 to 2031) which will result from increased competition with new storage facilities and low variable capacity prices (averaging $75,000 per MW per annum from CAL 2022 to 2027) due to persistent excess capacity in the WEM (averaging 10% from Capacity Year 2022 to 2028). Excess capacity persists over this period for the following reasons:

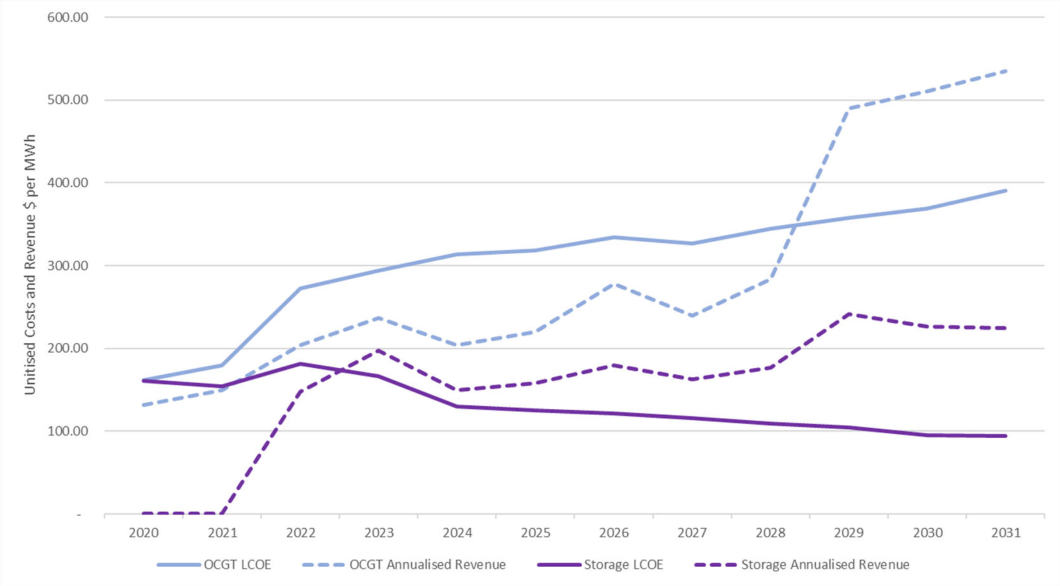
- Whilst the capacity price floor provides revenue stability for owners of incumbent generation, it reduces incentives for the exit of older and less flexible generation units,
- New investment in storage and OCGT-Aero is required to ensure that the reliability criteria can be maintained with the retirement of Muja C and subsequent coal plant retirements,
- New investment in large-scale wind and solar plant to reduce emissions in the SWIS. Solar plant can be economic provided that LGC prices remain higher than $6 to $10 per MWh over the next decade (currently prices are around $46 per MWh).

Figure 16 Levelised Revenue and LCOE for Mid Merit Plant in the WEM (June 2021 dollars)

Source: Marsden Jacob 2022

Regarding peaking plant, heavy frame OCGT units are not economic, while 4-hour storage facilities are economic from 2023. Storage facilities are increasingly economic due to learning curve impacts reducing capital costs and because the price spread in the Balancing Market increases overtime with the retirement of Muja C and other coal units by 2028 and the increasing entry of renewables in the SWIS (price spread of $55 per MWh in 2023 which increases to $75 per MWh in 2029). It should be noted that after this, price spreads in the SWIS decrease to a long-run average spread of only $45 per MWh as the increased penetration of energy storage helps to reduce the price spread (increases daytime charging and reduces peak demand in the evenings). However, continued reductions in storage capital costs will keep storage facilities economic in the WEM.

Figure 17 Levelised Revenue and LCOE for Peaking Plant in the WEM (June 2021 dollars)



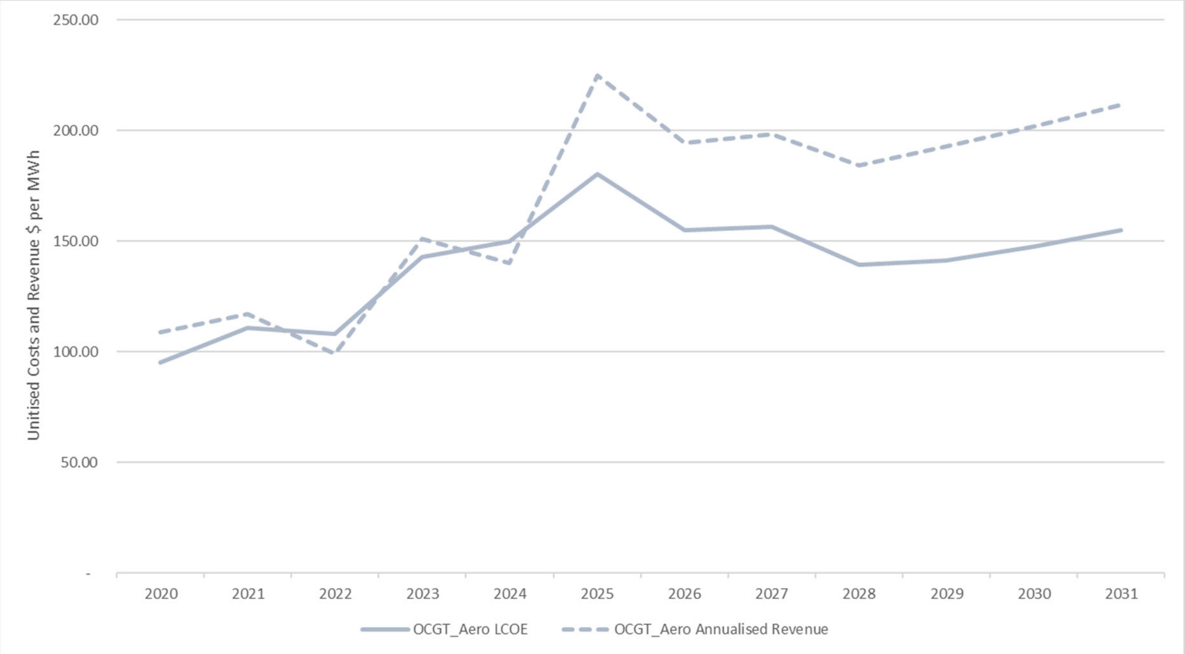
Source: Marsden Jacob 2022

All of the above results are impacted by the low-capacity price forecast. If we assume that the variable RCP increases to $159,000 per MW per annum (our initial estimate of the future BRCP in 2024/25), then OCGT and OCGT Aeroderivative units plus storage facilities are all economic post 2023-24. This highlights the importance of the capacity price in ensuring revenue adequacy in the WEM for new plants that will be required in the transition to a low emission electricity system.

The capacity price floor has been important to ensure dispatchable generation remained in the SWIS to meet reliability standards. There was a real risk that both gas and distillate units would have exited the market (physically relocated to higher value markets) given the new capacity pricing mechanism (discussed in section 3.4.2) that was introduced in October 2021, which results in highly volatile capacity prices. However, the downside of the capacity price floor is that it has reduced the incentive for the retirement of aging generation units, which contributes to relatively high levels of excess capacity and lower variable capacity prices for flexible generation and storage facilities.

In effect, the policy that was implemented to support existing dispatchable generation units to ensure supply reliability in the WEM given the influx of intermittent plant, may also be delaying new investment in new sources of dispatchable plant (such as batteries) that will be required to maintain supply reliability with high levels of intermittent plant connected to the SWIS. The continued reduction in minimum load and increasing uptake of PV suggests that interim measures may be needed to further encourage new investment in storage.

Figure 18 Levelised Revenue and LCOE for Selected Plant with Higher Variable RCP (June 2021 dollars)



Source: Marsden Jacob 2022

4.2 Proposed Review of the Capacity Mechanism

The Coordinator of Energy (Coordinator) plans to review the Reserve Capacity Mechanism (RCM) and to develop any WEM Rules resulting from the review in 2022/23. The RCM Review will incorporate the Coordinator's first review of the WEM Planning Criterion.[31]

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[31] Energy Policy WA, Scope of Works for the Review of the Reserve Capacity Mechanism

The WEM Rules also require the Economic Regulation Authority (ERA) to undertake the following reviews, which may be affected by the Coordinator's RCM Review:

- review of the methodology for setting the Benchmark Reserve Capacity Price and the Energy Price Limits (clause 2.26.3);
- review of the Reserve Capacity Price Factors (clause 2.24.3A); and
- review of the Relevant Level Methodology (clause 4.11.3C).

The assumptions underpinning the RCM review include the following:

- the WEM will continue to have an RCM;
- the purpose of the RCM is to ensure acceptable reliability of electricity supply at the most efficient cost ("purpose of the RCM"); and
- any changes to the RCM should not erode the level of system reliability currently provided for by the WEM Rules.

The following aspects related to the RCM are out of scope for this RCM review:

- the Network Access Quantities regime;
- the Reserve Capacity Price regime; and
- Energy Price Limits

4.3 Impact of proposed changes to the market power mitigation mechanism on revenue adequacy and investor certainty.

4.3.1 Market Power in the WEM

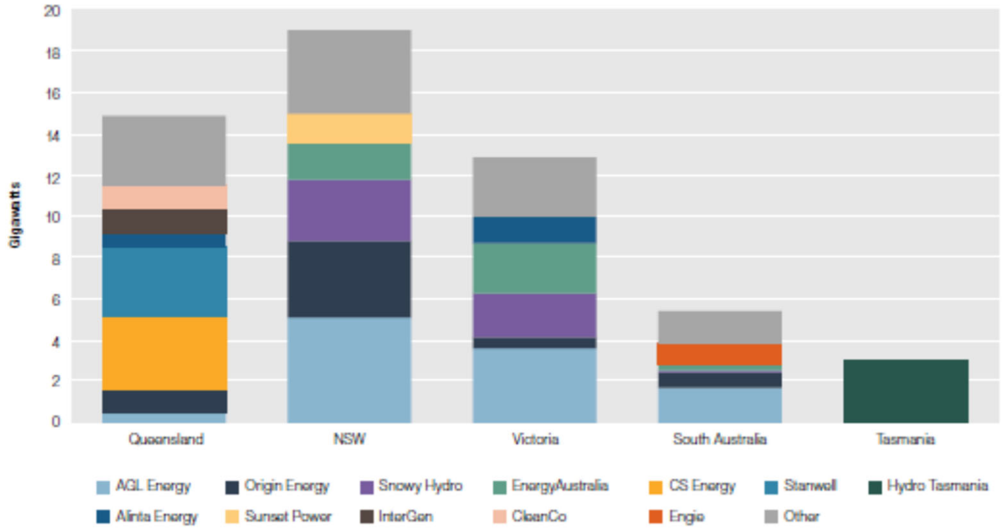
In a competitive energy market, prices should reflect demand and underlying cost conditions. Barriers to entry and exit must be sufficiently low so that investors can respond efficiently to market signals. Relatively short periods of high prices driven by tighter supply and demand conditions can occur, allowing generators to recover their fixed costs and earn a return on their investment. But a sustained period of high prices provides clear signals for new generation to enter the market.

Likewise, a fall in demand relative to supply should put downward pressure on prices and prompt higher cost generators to exit the market, noting that this needs to be a significant and sustained price reduction for long term generation facilities to exit.

High levels of market concentration are a key feature of electricity markets in Australia and overseas. In the NEM, a few large participants control a significant proportion of generation in each region. The two largest participants account for over 40% of total capacity in all regions and 60% of output in all regions except South Australia.[32]

[32] Australian Energy Regulator, State of the Energy Market 2021, July 2021, p.84

Figure 19 Market Concentration in the NEM



Note: Generation capacity based on registered capacity of market scheduled and semi-scheduled generators at 31 January 2021. Market shares are attributed to the owner of the plant or the intermediary (should one be declared to AEMO).

Source: AER; AEMO.

While governments structurally separated the energy supply industry in the 1990s, many retailers later reintegrated with generators, forming ‘gentailers’ with portfolios in both generation and retail. Vertical integration allows generators and retailers to insure internally against price risk in the wholesale market, reducing their need to participate in hedge (contract) markets.

Regulators refer to the Herfindahl–Hirschman Index (HHI) as a measure of market concentration, where the index can range from zero (in a market with many small firms) to 10,000 (that is, 100 squared) for a monopoly. In the NEM, the average HHI is over 2,000 for each region except Queensland, which indicates a moderate level of market concentration.[33]

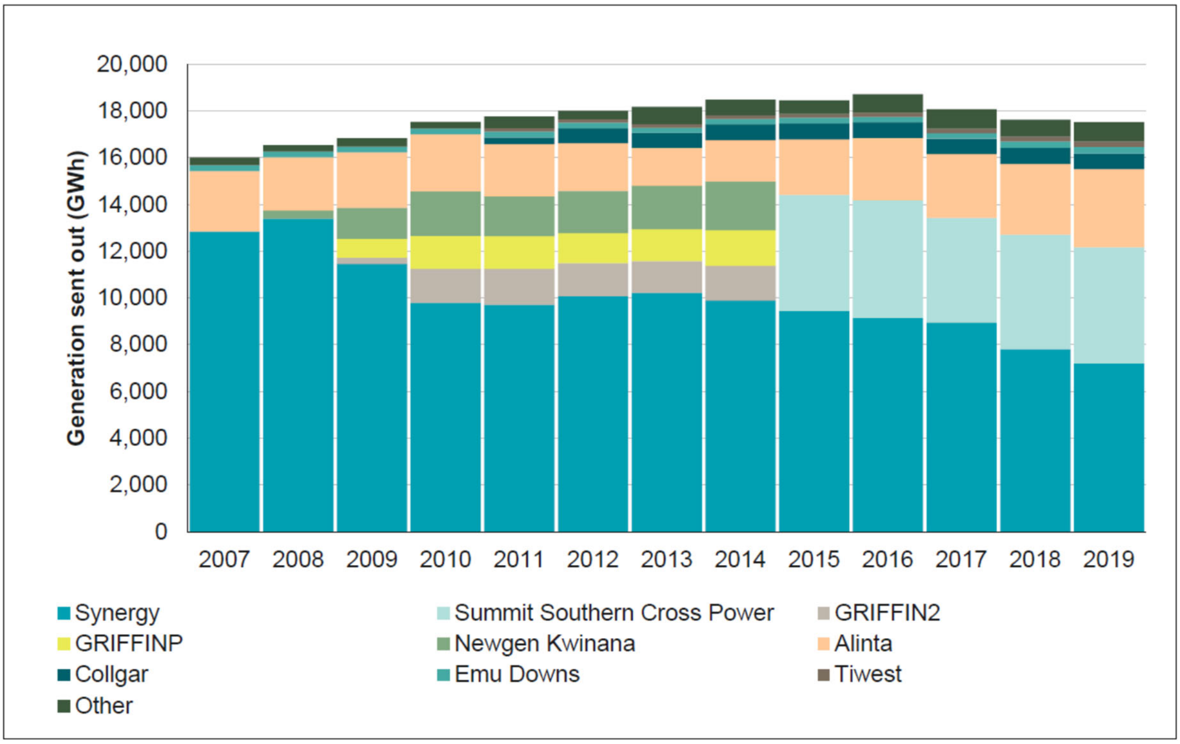
The AER review did not identify any concerning exercise of market power. Reductions in input costs were reflected in lower average generator offers, and short-term price spikes were driven by extreme weather and high demand.[34] The AER monitors the performance of the wholesale electricity market and assesses whether it is effectively competitive.[35] The 2020 performance report found that the transformation of the market from a system dominated by large thermal generators to one that incorporates an increasing volume of widely dispersed renewable generators had slightly reduced market concentration.

In the WEM, three generators (Summit Southern Cross Power, Alinta Energy and Synergy) accounted for 90% of electricity generated and had a HHI of just over 4,500, indicating a high level of market concentration.[36] Like the NEM, the transformation of the market from large thermal generators to more modular energy storage and intermittent power sources has the potential to reduce market concentration, especially with the retirement of coal fired power stations in the WEM. However,

[33] A market with an HHI of less than 1,500 is considered a competitive marketplace; an HHI of 1,500 to 2,500 is a moderately concentrated marketplace, and an HHI of 2,500 or greater is a highly concentrated marketplace.
[34] Ibid, p.
[35] Australian Energy Regulator, Wholesale electricity performance report - 2020, December 2020
[36] Economic Regulation Authority, Report on the effectiveness of the Wholesale Electricity Market 2020, 28 August 2020, p.12.

until this occurs, it is likely that the above-mentioned participants have some degree of market power in the WEM and that market power mitigation measures are likely to be retained.

Figure 20 Generation by Market Participant



Source: Economic Regulation Authority, Report on the effectiveness of the Wholesale Electricity Market 2020, 28 August 2020, p.46.

Currently, the WEM is mainly reliant on ex post market power mitigation measures. The ERA monitors the market, investigates possible misuse of market power, and takes regulatory action if a participant's behaviour is found in breach of the Market Rules. These measures rely on the deterrence provided by enforcement and penalties.

4.3.2 Proposed Market Power Mitigation Measures

Due to market power concerns, the Electricity Transformation Taskforce has proposed the following changes:[37]

- Reduce reliance on ex-post investigations (by ERA) and provide guidance as to acceptable and unacceptable trading conduct and imposing ex-ante obligations on market participants to monitor and report on their own trading practices.
- Adopt an objective measure of market power. It is proposed that a simple market power test is applied to the STEM, and RTS and ESS markets. This would ensure that market power mitigation obligations and market surveillance focus only on the participants that meet a threshold defined by that test.

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[37] Energy Transformation Taskforce, Proposals for changes to Market Power Mitigation Mechanisms Consultation Paper, 31 March 2021

A ***three-part market power test*** is proposed, incorporating:

1. Ex-ante: Determining the presence of market power through a "pivotal supplier test":
   - For the threshold to be met, AEMO must dispatch one or more facilities of a Market Participant ("pivotal supplier") otherwise demand cannot be met. A pivotal supplier test could potentially be automated in the AEMO's surveillance systems and applied to the STEM, and real time energy and ESS markets.
   - The ERA would need to establish thresholds (e.g., incidence of offers meeting the pivotal supplier test over a set period) which, if met, would trigger certain market power mitigation obligations and market power surveillance by the ERA.
2. Ex-post: Considering whether the participant is operating within the safe trading envelope; and,
3. Ex-post: Assessing how the market power exercise has affected market outcomes ("an effects test").

Trading conduct obligations for market participants to be included in the WEM Rules and guidelines provided by the ERA, which:

- Build on 'good faith' offer obligations, which already exist in the WEM Rules, with additional guidance from ERA on what constitutes acceptable trading conduct;
- Provide that market submissions must be consistent with submissions that would have been made in the absence of market power, rather than directly requiring offers to be at SRMC as currently required by the WEM Rules; and
- Require participants with market power to have internal controls to support self-monitoring and prevention of potential market power exercise and to retain records to support the rationale for their offers.

ERA to provide ***offer construction guidelines*** that set out how the ERA expects a participant would construct its offers. The WEM Rules will provide clarity on the types of costs that could be included in offers, while the ERA's offer construction guidelines will be required to include examples of efficient variable costs and how they would be incorporated in different situations. For example, the ERA will be required to provide clarity on how it will consider efficient long-term fuel contracts when considering fuel costs. These requirements are intended to ensure that when participants have market power their offers reflect SRMC.

With respect to the ESS markets, the potential for the ERA to publish its internal pricing benchmarks, which once approached or exceeded would prompt the ERA to require AEMO to trigger the SESSM process, to provide additional transparency and certainty to participants.

Introduce a ***safe trading envelope*** that identifies acceptable trading activity for participants with market power, encompassing the above trading conduct obligations and offer construction guidelines. There will also be trading conduct guidelines, which would include a series of examples of conduct that is acceptable or not acceptable. Thresholds for defining unacceptable conduct would focus on the extraction of material super-normal profits via trading behaviour.

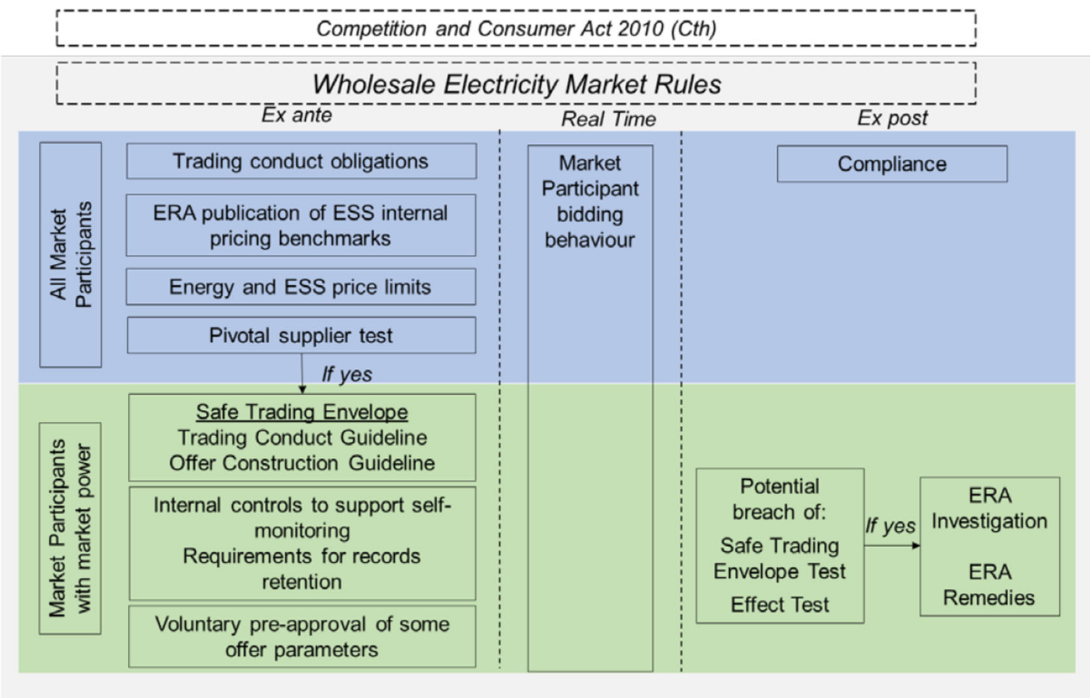
Allow participants with market power to voluntarily seek ***pre-approval of some offer parameters*** (including, for example, their internal market power mitigation controls or their fuel costs) by the ERA. Once a voluntary agreement is struck it is binding on both parties.

Energy and ESS price limits, including:

- The ERA will outline in a WEM Procedure how it will calculate a single energy price cap. The ERA will set and review the energy price limit every three years based on the highest cost (i.e. SRMC) in the fleet. The process for setting the energy price floor will be unchanged.
- The ERA will also set ESS price limits every three years. Despite the SESSM, ESS price limits are needed to mitigate exposure to extreme prices as competitive alternatives may need time to bring to market. The ESS price limits could be based on the higher of either:
  I. the energy price cap less the energy price floor – which represents the maximum opportunity cost at times of high energy demand; or
  II. the potential costs not recovered in the energy market when running at minimum generation to provide ESS.
  III. The ESS price floor will remain at zero as currently gazetted.
- A ten per cent margin will be added to the energy and ESS price limits and then rounded up to the nearest one hundred dollars.
- Market Participants can submit costs to the ERA as evidence price caps or floors should be amended.

The proposed framework and market power mitigation measures are summarised below:

Figure 21 Proposed Market Power Mitigation Framework and Measures



Source: Energy Transformation Taskforce, Proposals for changes to Market Power Mitigation Mechanisms Consultation Paper, 31 March 2021, p.12.

5. Learnings from electricity markets elsewhere

In developing recommendations for changes to market mechanisms in WA, it is important to look at the development of other electricity markets internationally. Many of these markets are facing similar challenges of integrating Variable Renewable Energy into their systems and are having to modify their market settings.

International experiences reveal a trend towards developing energy markets with complementary capacity mechanisms or capacity markets with mechanisms that emulate energy only markets in real time.

5.1 US Markets

The US has a mixture of energy-only (ERCOT) and an energy and capacity market (PJM, ISO New England (ISO-NE), New York ISO (NYISO), and Midcontinent ISO (MISO)).

5.1.1 ERCOT

The Electric Reliability Council of Texas (ERCOT) is the independent system operator for most of Texas, scheduling generation (75,000 MWh) and undertaking financial settlement for the competitive wholesale bulk-power market and administering retail switching. The design of the ERCOT market is net-pool and energy-only with both day-ahead and real-time markets. The Public Utility Commission of Texas (PUCT) is the Independent Market Monitor (IMM) of the wholesale market.

ERCOT is facing the challenge of high levels of intermittent plant (wind) has been working to implement its real-time market to optimize the scheduling of resources to provide energy or operating reserves every five minutes. Real time co-optimization of energy and ancillary services is planned to go live in 2025. ERCOT is also facing the challenge of integrating Energy Storage Resources (ESRs) and Distribution Generation Resources (DGRs). Both technologies are entering the market, with ESRs entering more rapidly as their costs decline.[38]

While ERCOT remains an energy-only market it now incorporates two price adders: Operating Reserve Adder and a Reliability Adder. The Operating Reserve Adder was implemented in 2014 to account for the value of reserves based on the probability of reserves falling below the minimum contingency level. In effect, this incorporates a capacity value into energy only markets. The

[38] Potomac Economics, 2020 STATE OF THE MARKET REPORT FOR THE ERCOT ELECTRICITY MARKETS, Independent Market Monitor for ERCOT, May 2021, p.ii.

reliability adder was implemented in June 2015 as a mechanism to ensure that certain reliability deployments do not distort energy prices.[39]

5.1.2 PJM

The PJM wholesale electricity market has been operating on a competitive basis since 1997. The PJM is a large market, with market participants having installed capacity of 184,722 MW in January 2020.

The PJM has limited vertical integration with only five generators having a modest interest in the retail market.

The energy market operates under a capacity market mechanism and consists of both a day-ahead and real time market. A notable feature of the PJM is that the independent market monitoring function is outsourced to a private company (Monitoring Analytics in the case of the PJM).

Transition to Capacity Performance

Two capacity resource product types were recognised in the RPM Auctions[40]:

- Base Capacity Resource - capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year[41]; however, the resource must provide enhanced assurance to provide energy and reserves during hot weather operations. Since Base Capacity Resources do not provide the same availability and reliability benefit as Capacity Performance Resources, constraints are imposed on the quantity of Base Capacity Resources that can be procured in Reliability Pricing Model (RPM) Auctions (like the concept of Availability Class 1 and 2 in the WEM).
- Capacity Performance Resources - capable of sustained, predictable operation that allows the resource to be available throughout the entire Delivery Year to provide energy and reserves whenever PJM determines an emergency condition exists.

Base Capacity Resources have been phased out (last year was 2019/20). The change was necessary to ensure reliability after a particular cold winter (polar vortex of 2014), when many generators were unable to remain online. However, while 20 per cent of conventional generation was forced off in 2013-14, the change in standards has resulted in a reduction of Demand Response which was not affected by the cold spell. Many seasonal resources, such as Demand Side Management, solar and wind resources were not able to qualify under the Capacity Performance Resource standard.

Scarcity Pricing

Traditional capacity markets of northeast USA have been challenged by the growth of variable renewable generation and the lack of real time signals. For example, PJM operates a centralised capacity market, but it introduced an operating reserve market in 2017 to better reflect shortage

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[39] Ibid, p.1.
[40] PJM Manual 18: PJM Capacity Market Revision: 51 Effective Date: October 20, 2021, Prepared by Capacity Market & Demand Response Operations

[41] A Delivery Year is a financial year (commencing 1 July)

pricing when reserves are low. Reserves are procured according to an Operating Reserve Demand Curve (ORDC) which causes reserves to increase in price the closer the market is to being short. These prices 'cap' at a penalty price significantly above the normal energy market price cap in PJM. As reserves get tight, and especially when they are short, higher prices in the reserve market spill over into the energy prices through co-optimisation. PJM energy market prices can reach or exceed $14,000/MWh in cases of extreme reserve shortages.[42]

Table 4 Maximum Clearing Prices (PJM)

Product	Current Maximum Clearing Price ($/MWh)	After May 1, 2022 Maximum Clearing Price ($/MWh)
Secondary Reserves	N/A	$2,000*
Primary Reserves	$850	$,6,000*
Synchronized Reserves	$1,700	$10,000*
Energy	$3,750	$12,050*

Notes:

(a) No congestion is included.

(b) *Assumes the sub-zone is not modelled for 30 Minute Reserve. In instances when the sub-zone is modelled, the $2,000 penalty factor on the 30 Minute Reserve Sub-zone ORDC would also cascade through the above prices.

Source: PJM, Operating Reserve Demand Curve & Transmission Constraint Penalty Factors, PJM Operating Reserve (online).

5.1.3 Market Power Mitigation in the US

ERCOT

Market power is evaluated from a structural (does market power exist?) and behavioural (have attempts been made to exercise it?) perspective. Like many electricity markets, consultants for PUCT found that structural market power exists in ERCOT, but little evidence that suppliers abused market power in 2020.

ERCOT uses a pivotal supplier test, i.e., a supplier is pivotal when its resources are needed to fully satisfy customer demand or reduce flows over a transmission line to manage congestion. Over the entire ERCOT region:

- Pivotal suppliers existed 22% of all hours in 2020, compared to 24% in 2019.
- Under high-load conditions, a supplier was pivotal in more than 80% of the hours since competing supply is more likely to already be fully utilized.
- These results indicate that market power continues to exist in ERCOT and requires mitigation measures to address it.

The Independent Market Monitor (Potomac Economics) is also concerned with market power being exercised in regions where transmission constraints are binding. In these circumstances, Market rules cap prices apply that restrict the maximum price that suppliers can offer in these cases. As part

[42] PJM Operating Reserve (online).

of the bid mitigation process, a reference price is set by simulating dispatch in the market while only considering competitive constraints. Bid offers are then capped at the maximum of the reference price and the mitigated offer cap, which is an estimate of the marginal cost of a marginal gas fired generator. This bid mitigation has a particularly important role in the context of nodal pricing, where the risk of single firms having control over localised prices is higher.

It should be noted that Bid price regulation is common in capacity markets, particularly in the US, but less so in energy only markets. The ERCOT market is an exception to this rule.

The IMM is also concerned with potential "economic withholding" of capacity that can occur when a supplier raises its offer prices to levels well above the expected cost to produce electricity. The IMM also monitors the "physical withholding" of capacity when a supplier makes one of its resources unavailable for use. Analysis for 2020, showed that economic and physical withholding was not a significant issue in ERCOT.[43]

Other market behavioural regulations that are in place in ERCOT include the following:[44]

- prohibitions on activities by market participants that:
  - adversely affect customers using unfair, misleading, or deceptive practices,
  - materially reduce the competitiveness of the market,
  - disregard the effect on the reliability of the system, and
  - interfere with the efficient operation of the market.
- the option for market participants to enter a voluntary market power (VMPs) mitigation plan to reduce regulatory risk of future actions against them. By the end of 2019, Calpine, NRG and Luminant had active VMPs in place, and
- a condition that firms with less than 5 per cent generation market share are ruled, a priori, not to have ERCOT wide market power.

Capacity Markets US

Ex ante market power mitigations have been developed in many US markets that have capacity markets, as these markets tend to impose more control over the characteristics of capacity that enters the market (i.e., type and level of capacity). This includes PJM, ISO New England (ISO-NE), New York ISO (NYISO), and Midcontinent ISO (MISO).

PJM[45]

Pivotal supplier tests identify times when a small set of suppliers can meet demand, particularly during periods of network constraint. During these circumstances, the system operator implements administered pricing for these generators.

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[43] Potomac Economics, 2020 STATE OF THE MARKET REPORT FOR THE ERCOT ELECTRICITY MARKETS, Independent Market Monitor for ERCOT, May 2021, pp. 91 to 94.

[44] HoustonKemp Economists, International review of market power mitigation measures in electricity markets, A report for the Australian Competition and Consumer Commission, May 2018, p.14.

[45] Ibid, p.16-17.

The three pivotal supplier test is applied in all markets, i.e., real time energy market, day-ahead energy market, regulation market and the capacity market. This enables targeted mitigation of market power in the relevant market.

In the specific case of the PJM, the three pivotal supplier test considers whether the level of excess supply results in an adequately competitive market structure. It measures the degree to which the supply from three suppliers is required to meet the demand for relief of a constraint. This then defines the relevant market. In the energy market, the supply tested is the constraint relief megawatts for a specific constraint.

The use of a three pivotal supplier test is not unique to the PJM, with similar tests also applied in the NYISO, CAISO, New England Independent System Operator (ISO-NE) and Ontario markets.

a) Fuel Cost Policy

All Market Sellers (from generation resources) must have a PJM-approved Fuel Cost Policy, or utilize a temporary cost offer methodology, for each fuel type that they enter a non-zero cost-based offer into the Day-Ahead and Real-Time Energy Market. This is mainly applicable to natural gas generators and the policy requires the Market Sellers to explain the process by which natural gas is procured and purchased Day-Ahead, Real-Time, and Intraday.

The Market Seller's Fuel Cost Policy must pass both the Market Monitors review and a separate review by PJM (consistency with Operating Agreement).

Fuel Cost policies shall include the method used by the Market Seller to calculate:

- Fuel Cost
- Fuel additives, and
- Emission allowance cost (if applicable)

As well as other factors that influence a generator's offer:

- Performance Factor, Heat Rate, or Heat Input information
- Start Costs
- No Load Costs

Market Sellers are responsible for establishing their own method of calculating delivered fuel costs, limited to inventoried cost, replacement cost, or a combination thereof. A Market Seller may elect to calculate fuel cost using actual cost (i.e., contract price), spot price, or a combination of actual cost and spot price.

Fuel costs for energy storage is deemed to be zero.

Fuel costs for pumped hydro is deemed to be real time Locational Marginal Price at the plant node by the actual power consumed when pumping divided by the pumping efficiency.

b) Maintenance and Operating Cost Adders (VOM)[46]

PJM's Operating Agreement allows Market Sellers to include Maintenance and Operating Cost Adders as components of the cost-based energy offer. Market Sellers must submit these adders to PJM, at least annually, for review and they must be changed if they are no longer accurate.

Detailed descriptions of allowable costs are provided in guidelines published by PJM. The allowable maintenance costs include expenses directly related to electric production and must be a function of starts and/or run hours. Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses. Operating Costs are expenses related to consumable materials used during unit operation and include, but are not limited to, lubricants and chemicals.

5.1.4 Generation Offer Reference Levels in ISO-NE

One ex ante mitigation adopted in ISO-NE is to regulate generator offers to a maximum of specific "reference levels." The market monitor calculates a reference level for each facility that reflects their SRMC. This calculation uses data provided by each participant on costs, including expectations of fuel prices, and on the physical characteristics of each facility. Each offer is evaluated for market power and when generators are found to have market power and to be offering above the reference level, the offer is reduced to the reference level.

5.2 UK Market

The United Kingdom electricity market currently operates with a capacity market, energy market and a Balancing (Ancillary) Services Market.

5.2.1 Capacity Market[47]

The Capacity Market was introduced (2018) to ensure that firm electricity supply continues to meet demand as more VRE enters the market. Potential Capacity Market participants can bid for contracts in auctions held four years ahead of the delivery date.

If successful at auction, existing generators and demand-side responders will be offered one-year capacity agreements at the clearing price. Longer term agreements (15 years) are available for new plant, to encourage investment in new generation assets, and three-year agreements are available for refurbished plant.

During the delivery year, capacity providers will receive monthly payments for their agreed obligation at the auction clearing price. Providers are expected to be available to respond with their agreed generation volumes or load reductions when called on by National Grid at times of system stress.

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[46] PJM, Maintenance and Operating Cost (VOM) Adder Review Guidelines, Version 0: 5/20/2021

[47] https://www.engie.co.uk/wp-content/uploads/2016/07/capacitymarketguide.pdf

To notify providers that they will be required to deliver the agreed capacity, a ‘Capacity Market Warning’ will be issued by National Grid through the Capacity Market Portal.

5.2.2 Market Power Mitigation[48]

The United Kingdom’s electricity market relies on ex post mitigation. The market, operated by National Grid Electricity Transmission (NGET) and regulated by the Office of Gas and Electricity Markets (Ofgem).

Ofgem relies on antitrust laws to examine and punish anticompetitive behaviour of electricity generators. Ofgem commences a formal investigation if there are reasonable grounds for suspecting that an action or behaviour infringes the law.

Ofgem’s market surveillance team monitors market prices daily and investigates unusual situations—such as price spikes or periods of low reserve margin—primarily via publicly- or commercially-available data, and sometimes by obtaining output and bidding information directly from generators through its powers under the Competition Act and other legislation.

Ofgem also checks for instances of predatory pricing by applying either a cost-based or avoidable costs test to assess whether a generator is pricing below average variable or fixed (avoidable) cost.

5.3 Ireland (I-SEM)[49]

The Integrated Single Electricity Market (I-SEM) is the wholesale electricity market operating in the Republic of Ireland and Northern Ireland. The SEM has 2.5 million electricity customers (similar size to the Victoria) and has also has the challenges of mitigating market power for a relatively small market.

The I-SEM, which was launched in 2018, includes a Day-Ahead (like the STEM) and Intraday energy market, a balancing market and a capacity market (like the RCM). In parallel, to support the achievement of renewable energy targets, a range of ancillary services functions have been implemented.

Electricity Generators, with over 10MW capacity, are required to sell electricity into this single pool and bidding is regulated by a bidding code of practice, which states that Generators must sell electricity to the pool at the marginal cost of producing each unit of electricity.

Generators in Ireland potentially receive three payment streams:

- Energy Payment- The market price per MW sold per half hour time slot.
- Capacity Payments – Compensation for being available to generate upon instruction from the grid operator.
- Constraint Payments – Compensation for being constrained from exporting scheduled amount of

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48 Department of Finance | Public Utilities Office, Market Power Mitigation Mechanisms for the Wholesale Electricity Market, Information Paper, October 2016

49 EIRGRID, Quick Guide to the Integrated Single Electricity Market, The I-SEM Project, Version 1.

energy onto the system (due to grid stability issues).

Like the current Reserve Capacity Mechanism (RCM) in the WEM, capacity payments are calculated based on the fixed costs of a peaking plant. As a result, the payments generally cover only a portion of the fixed costs involved in building most plants.

Prior to 2017, the Irish electricity market included a traditional capacity mechanism based on administratively determined availability payments. Through the integrated, single electricity market (I-SEM) reform process that began in Ireland in 2007, the regulator determined that an 'enhanced' capacity mechanism was required to reduce the costs of funding capacity relative to their pre-existing approach. The Irish 'capacity remuneration mechanism' (CRM), was introduced to issue Reliability Options to eligible capacity from 2018 onwards. Following an initial transition period of near-term auctions, the Irish CRM runs central auctions four years ahead, issuing one-year contracts to existing generation and up to 10-year contracts for eligible new generation.

The Irish market operator has initially set the contract strike price based on a hypothetical low efficiency peaking unit. The Irish Reliability Options must have physical backing by a specific generating asset – meaning they are used exclusively to contract physical capacity. The Irish model includes a participant qualification process to determine the capacity rating of each unit – capacity is de-rated with a methodology reflecting its anticipated marginal contribution to reliability. All qualified capacity is required to bid into the auction.

6. Reforms of the WEM that should be considered to improve revenue adequacy and market efficiency

There is "missing money" in the WEM that can adversely impact the investment case for flexible generation and storage in the SWIS that is required as part of the transition to a low emission electricity sector. The fundamental problem is low and variable capacity prices for new entrant generators. This can be corrected by providing long term capacity contracts with prices that reflect the costs of new entrant (CONE) capacity.

The WEM is a highly concentrated market, and as such, an appropriate market power mitigation framework needs to be developed that ensures parties are incentivised to behave competitively but does not prescribe outcomes and allows both participants to act commercially and allow markets to clear at efficient price levels.

6.1 Missing Money in the WEM

Our forecasts of the WEM prices and plant operations over the period 2022 to 2031 indicate that there is "missing money" for some new entrant generator types in the WEM (see Section 4.1.3). This included super critical coal plant and OCGT i.e., insufficient revenues for generators to recover their capital costs through market revenues. OCGT Aero and CCGT were marginally profitable (i.e., sufficient revenue to cover costs), while 4-hour battery storage and wind farms were clearly profitable. Solar farms did not earn sufficient market revenues to cover levelised costs, but once you factor in LGC revenue, there would be sufficient revenue to cover costs.

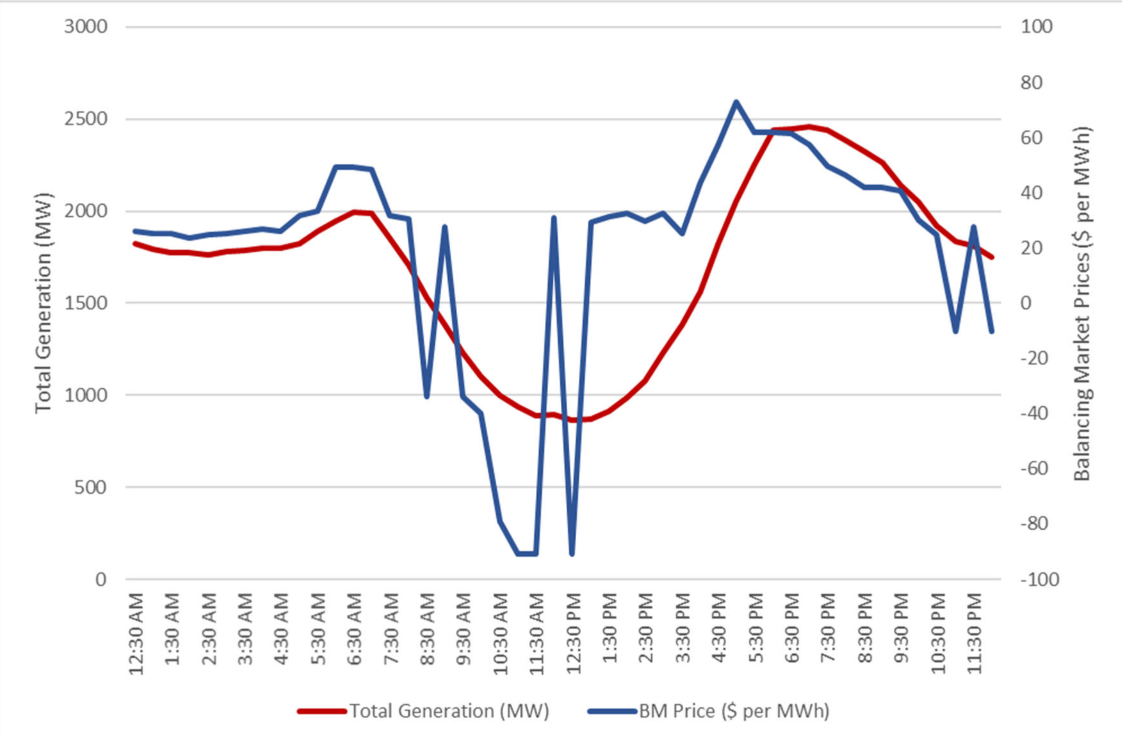
Given that new entrant OCGT is not profitable, and OCGT Aero and CCGT plant are only marginally profitable, there is the potential for under-investment in these generator types if they are not able to recover costs.

The fundamental cause of the missing money is a low RCP caused by the capacity price formula that was introduced on 1 October 2021 and high levels of excess capacity, whilst capacity price floors have the unintended consequence of reducing the incentive to exit for existing generation. Although the capacity price ceilings and floors provide certainty for existing generations over the pricing transition period it may also be reducing the exit signals for some facilities. As the new capacity pricing curve is relatively steep, even with modest levels of excess capacity (~5 percent), the RCP is being significantly depressed for new entrant generation and storage facilities. This suggests that additional measures may need in the short to medium term to further incentivise investment in flexible generation and storage. We outline some options for addressing this in Section 6.2.

Negative energy prices also contribute to the "missing money" problem in the WEM. Negative prices occurred over 1248 trading intervals (624 hours) in Calendar Year 2021, with an average negative price of $28.73 per MWh. The Average Time Weighted Wholesale Price was historically low at $49.87 per MWh. Negative prices contributed to a $2.05 per MWh reduction in the average Balancing Price over CAL 2021.

Shown below is actual generation and Balancing Market prices on 5 September 2021 (highest occurrence of negative prices in a 24-hour period in CAL 2021).

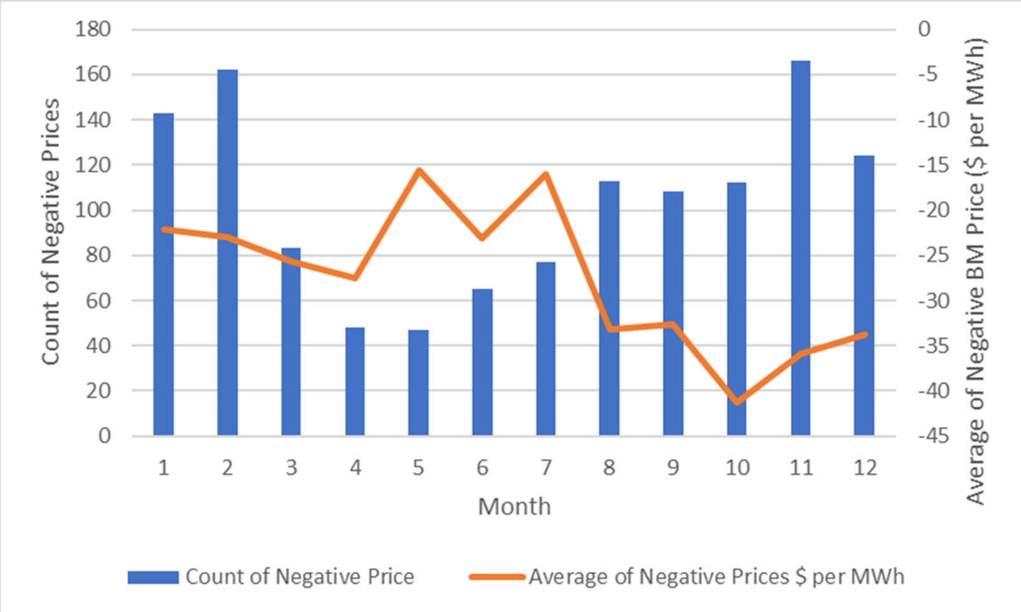
Figure 22 Generation and BM Prices (5 September 2021)



Source: AEMO Market Data

Negative prices typically occur throughout the year on sunny days when the contribution from rooftop solar systems is high. Operational demand is around 1500 MW in trading intervals with negative prices, which is 25% below average demand (2000 MW).

Figure 23 Negative Prices by Month (CAL 2021)



Source: AEMO Market Data

It has been argued that the minimum STEM price of -$1000 per MWh contributes to the missing money problem in the WEM. However, our analysis indicates that in 2021 (the 12-month period with the highest occurrence of negative prices in the WEM), the Balancing Market price did not clear at -$1000 per MWh. The lowest price was -$90 per MWh.

In previous years, the minimum STEM price has occurred due to inflexible plant (e.g., minimum load of coal and gas fired generation) and VRE plant that have "run of plant" Power Purchase Agreements (PPAs) and are not exposed to the spot price. However, the latter issue is not a market design problem but a market imperfection (i.e., contractual error) created by those organisations that entered these contractual arrangements. New VRE PPA contracts usually give the off taker the right to curtail the VRE plant if negative prices are likely to occur.

As demonstrated in Section 2.2, the occurrence of negative prices could peak at 2000 trading intervals (i.e., 1000 hours) in the WEM by 2030 and then declines post 2030 as inflexible plant is replaced by VRE and flexible plant and storage.

A minimum price of -$1000 per MWh provides a strong signal for the exit of inflexible plant which is what is required as we shift to a system with high VRE and flexible generation and storage. It also provides a strong signal for contract parities to enter VRE PPA's that permit the curtailment of VRE plants to ensure that the occurrence of negative prices is minimised. In our view, increasing the minimum price is not a high priority issue for resolving the missing money problem in the WEM and provides a strong signal for a flexible plant mix, which is required to manage high levels of VRE plant in the WEM.

6.1.1 Wholesale Market Modelling to Confirm Revenue Sufficiency

For this analysis, we have modelled the likely revenue that different types of generators will earn over the period CAL 2022 to CAL 2031 to understand whether current WEM mechanisms and settings will encourage the optimal mix of generation and storage in the SWIS. Currently, many market settings and parameters (i.e., Energy Price Limits, BRCP, Ancillary Service Parameters) are all set independently and there is no confirmation whether these settings will encourage the right mix of plant in the SWIS. Other markets with capacity mechanisms, such as the PJM, do calculate net CONE by facility type to ensure that there are adequate incentives for plant investment in those markets (refer to our discussion of net CONE in section 6.2.1).

Without undertaking this modelling, EPWA and the ERA are unlikely to fulfill the Wholesale Market Objective to "promote the ***economically efficient***, safe and reliable production and supply of electricity" or "encourage competition among generators and retailers in the South West interconnected system, including by ***facilitating efficient entry of new competitors***".

When establishing policies, price limits and measures, policy makers and regulators should be confirming that there is sufficient revenue in aggregate from all market mechanisms to encourage flexible generation and storage to meet future demand. ERA and EPWA should undertake a periodic review of generator profitability under current and proposed market settings to ensure that the WEM is fulfilling its market objectives.

6.2 Optimising Dispatch of Generation and Storage at Peak Times

Traditional capacity markets are being challenged by the growth of variable renewable generation and the lack of real time price signals to ensure dispatchable generation and storage is available to meet demand.

Given the lack of scarcity price signals in the WEM, Energy Policy WA has opted to rely on capacity refunds regime and the ESR Obligation Duration (quantity approach) to ensure dispatchable generation is available to meet demand at peak times in the WEM.

The responsibility for ensuring storage resources is available to meet peak demand now and, in the future, will be the responsibility of market operators and policy bodies.

The current approach raises several issues.

If the ESR Obligation Duration is set incorrectly, some mechanism may need to be put in place to compensate owners of storage facilities. For example, if the dispatch window does not coincide with peak Balancing Market Prices, then ESR many need to be compensated for the loss of any energy or ancillary services revenue.

The ESR Obligation Duration has currently been set at 4 hours but will likely increase with rising levels of Energy Storage entering the SWIS. This creates considerable uncertainties for investors in storage facilities. For example, an investor in a 4-hour storage facility (100 MW/400 MWh) will receive 100% of its nameplate capacity in capacity credits. However, if the ESR increases to 6 hours, the facility will only be accredited for 67 MW – a reduction of 33 MW or a reduction in capacity revenue of $5.3M per annum (if capacity credits are value at $159,000 per MW per annum).

While we anticipate that the ESR Obligation Duration will increase in time, should we only invest in short term storage (2 to 4 hours) now to firm up renewable energy supplies? While investment in battery storage is modular, investment in pumped hydro is not. Greenfield sites can take up to 10 years to develop. Brown field pumped hydro facility could take up to 5 years to construct. More certainty on the ESR and capacity prices will be required to justify investment in long lived storage facilities (50 years). If not, then battery storage is really the only long duration storage option for the WEM.

The ESR Obligation Duration, the Capacity Price formula and linear derating method does not provide an economic return for storage facilities exceeding 4 hours. The annualised capital cost of 4-hour storage facility is $159,000 per MW per annum, whereas the annualised capital cost for an 8-hour storage facility is $275,000 per MW per annum. If the capacity price is set at the BRCP, then 4-hour storage facilities will be economic (as highlighted in Section 4.1.3). However, an 8-hour facility will not be economic. For example, even if the ESR Obligation Duration increases to 8 hours, the facility will only receive $159,000 per MW per annum on its nameplate capacity. Additional revenue from the Balancing Market will help to cover costs, but the increased penetration of storage in the WEM will likely reduce price spreads (i.e., price arbitrage benefits) post 2031. By this time, it is likely that the ESS market is saturated with storage facilities, which implies that storage facilities will earn no income from ESS markets.

Ideally, the new capacity pricing formula should have provided incentives for orderly plant exit of inflexible plant and encouraged the entry of flexible generation and storage facilities. However, even if the market is in balance and capacity prices increase to the BRCP ($159,000 per MW per annum), long duration storage will not be encouraged by current market settings in the WEM.

6.2.1 Differential Capacity Prices

Currently, the WA capacity market is based on Gross CONE for a 160 MW OCGT. While this could potentially provide incentives for DSP, distillate generators and heavy frame OCGTs to enter the market if the market was in balance, it does not necessarily provide sufficient incentives for flexible generation (OCGT-Aeroderivatives) and storage to enter the SWIS unless there is sufficient revenue to be earned from energy and Essential System Services markets.

Like the WEM, US ISOs typically used simple-cycle combustion turbines as the reference technology for CONE. However, recent proposals in PJM have suggested basing CONE on both the cost of an OCGT and CCGT - ISO-NE now bases CONE on a dual-fuel combined cycle technology. The UK also bases CONE on CCGT plant. PJM still currently bases CONE on a simple cycle technology (dual fuel).[50]

One approach could be to offer differential capacity prices based on the costs and duration of providing flexible generation and storage. That is, we establish differential maximum capacity prices based on service class. However, the maximum capacity price would need to consider all other potential revenues from energy and ESS markets to avoid setting Gross CONE prices that overcompensate investors and result in an oversupply of capacity in each service class. For example, we could establish the minimum capacity, maximum capacity price (Gross CONE) and service specifications for each service class:

50

Table 5 Potential Capacity Service Classes in the WEM

Capacity Service Class	Service Specifications	Candidate Benchmark Units	Gross CONE $ per MW per annum	Minimum Capacity (MW)
Dispatchable short duration	Resources that can only operate for limited periods of time over the day and year (seasonal variation in supply). This would include Demand Side Management (DSM)	50% of the value of BRCP for Dispatchable Medium Duration	$79,500	500
Dispatchable medium duration	Generation facilities must demonstrate an ability to provide a minimum of 4 and maximum of 8 hours of continuous supply per day over several consecutive days. Storage facilities can provide up to 4 hours of continuous supply. Benchmark unit candidates for this class would be OCGT (Heavy Frame), OCGT Aeroderivatives, distillate plant and storage facilities.	OCGT (Heavy Frame), OCGT (Aeroderivatives), Distillate plant and storage facilities (<4 hours of storage)	$159,000	1620
Dispatchable long duration	Facilities must demonstrate an ability to provide more than 8 hours of continuous supply per day over several consecutive days. Storage facilities can provide up to 8 hours of storage. Benchmark unit candidates for this class would be CCGT, Pumped Hydro or Long Duration Storage (8 hours).	CCGT, Pumped Hydro or Long Duration Storage (8 hours).	$275,000	2875
Semi-dispatchable plant	Would include large-scale intermittent plant with storage facilities less than a threshold level. Benchmark Unit for this class is OCGT or Medium Duration Storage Facilities (4 hours).	Dispatchable medium duration	$159,000	0
Non-dispatchable plant	Typically, smaller "must run" units that can't be dispatched by system operator except in emergencies. Biomass generators.	Dispatchable medium duration	$159,000	0

Source: Marsden Jacob 2022

In PJM, the maximum capacity price is the maximum of Gross CONE or 1.5 * Net CONE for the relevant technology type. The formula for Net CONE is the following:

Net CONE = Gross CONE – Net E&AS revenue (Equation 5)

- Gross CONE: levelised annual cost to construct a new resource plus annual fixed operation and maintenance costs
- Net E&AS: expected energy and ancillary service net market revenues (revenue minus variable costs)

For OCGT's that don't run much (low-capacity factors), the Net Cone will be approximately equal to Gross Cone. Whereas the Net Cone will be substantially lower for energy producing plant. We have calculated the Net CONE for each generation type in the WEM as shown below (assuming a 15-year cost recovery period, which is the cost recovery period assumed in developing the BRCP).

Table 6 Net CONE for the WEM (15-year cost recovery period) - $AUD

Plant Type	WEM Net CONE $ per MW per annum	PJM Net Cone (a)(b) $ per MW per annum
Coal	421,402	552,000
CCGT	56,543	117,500
OCGT	119,392	134,000
OCGT_Aero	83,838	0
Wind	84,226	840,136
Solar	240,200	225,000
Storage (4 hours)	68,084	0

Notes:

(a) PJM costs are calculated based on 20-year asset lives

(b) Capacity contribution of solar and wind is estimated to be 42% and 14.7% respectively.

Source: Marsden Jacob 2022, and PJM, Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources, Market Implementation Committee, February 28, 2020

As highlighted above, the WEM Net CONE only needs to be $56,000 per MW per annum for CCGT and $83,838 per annum for OCGT-Aero for these plants to be profitable, whereas the Net CONE for OCGT needs to be $119,392 per MW per annum. However, this analysis assumes that CCGT and OCGT-Aero will earn revenue from the Essential System Services Market. If we remove this revenue on the basis that large-scale storage could saturate this market in the future (which is likely), then we obtain the following Net CONE calculations for WEM generators.

In effect, CCGT, OCGT and OCGT_Aero are only profitable if the capacity price is equal to the final 2024/25 BRCP of $165,700 per megawatt per year. However, it is likely that excess capacity will be around 10 to 13% in that year, which implies that the actual BRCP will be $67,000 to $82,000 per MW per annum for new entrants (incumbents will receive the price floor of $120,088 per MW per annum (nominal dollars)).

Table 7 Net CONE for the WEM generators excluding revenue from Essential System Services (15-year cost recovery period) - $AUD

Plant Type	WEM Net CONE $ per MW per annum	PJM Net Cone (a)(b) $ per MW per annum
Coal	518,870	552,000
CCGT	162,128	117,500
OCGT	165,158	134,000
OCGT_Aero	164,837	0
Wind	70,609	840,136
Solar	69,831	225,000
Storage (4 hours)	147,119	0

Notes:
(a) PJM costs are calculated based on 20-year asset lives
(b) Capacity contribution of solar and wind is estimated to be 42% and 14.7% respectively.

Source: Marsden Jacob 2022, and PJM, Preliminary Default MOPR Floor Offer Prices for New Generation Capacity Resources, Market Implementation Committee, February 28, 2020

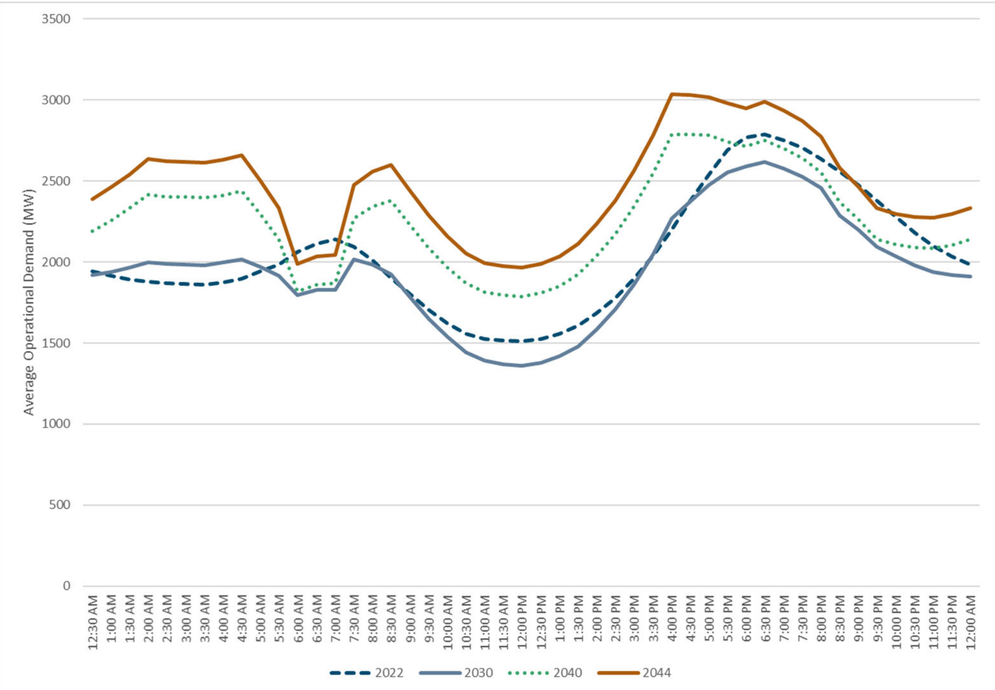
In conclusion, if the capacity price in the WEM is equal to the BRCP for 2024/25 of $165,700 per MW per annum, this provides sufficient incentives for the entry of new flexible plant to enter the SWIS. However, this is unlikely to occur due the fact that excess capacity is likely to remain high in the SWIS.

Moving to a Net Cone system by technology type is not necessary for the WEM, as there are adequate incentives for flexible plant entry based on the current methodology for setting the BRCP (Gross CONE based on an OCGT plant).

The only caveat to this is that a technology-based capacity price may be necessary to encourage long duration storage of 4 to 8 hours.

Modelling by Marsden Jacob suggests that future requirements for storage will exceed four hours. As highlighted below, average peak demand in the SWIS is around 4-hours currently (4 PM to 8 PM based on Operational Demand that is >90% of peak demand). However, in 2040, average peak demand will be around 5 hours (2:30 PM to 7:30 PM). On some peak days in the WEM, peak demand can occur for up to 6 hours, which includes the current calendar year (2022) and in subsequent years.

Figure 24 Operational Demand for Selected Years – Peak Day Analysis (1 February) – Base Case



Source: Marsden Jacob Analysis 2022

A BRCP based on Gross CONE ($165,700 per MW per annum) will not be sufficient to permit investment in long duration storage. Given this facility is required in the future, a specific long duration storage category could be created in the WEM based with prices based on Net CONE to ensure that these facilities are viable.

In summary, the central problem in the WEM is the high amount of current, and likely future, levels of excess capacity, which drives variable capacity prices to low levels and do not provide incentives for flexible plant to enter the market, whilst incumbent inflexible plant are not incentivised to exit the market to restore market balance due to capacity price floors protecting them from downside price risks.

What this suggests is that so long as the capacity market moves in to balance (low levels of excess capacity), investment in flexible generation and 4-hour storage will be profitable in the future. However, additional financial incentives will be required for long duration flexible generation and storage.

6.2.2 Scarcity Pricing

If policy makers are unable to correct the abovementioned market settings to provide incentives for capacity prices to reflect gross CONE for an OCGT plant, one possible alternative approach could be to introduce scarcity pricing in the WEM to provide an additional revenue stream for flexible generation and storage.

As outlined in Section 5.1.2, PJM operates a centralised capacity market, but introduced an operating reserve market in 2017 to better reflect shortage pricing when reserves are low. Reserves are procured according to an Operating Reserve Demand Curve (ORDC) which causes reserves to increase in price the closer the market is to being short. These prices 'cap' at a penalty price significantly above the normal energy market price cap in PJM. As reserves get tight, and especially when they are short, higher prices in the reserve market spill over into the energy prices through co-optimisation. PJM energy market prices can reach or exceed $14,000/MWh in cases of extreme reserve shortages.

Adopting scarcity pricing in the WEM could also replace the requirement for AEMO to establish the ESR Obligation Duration period to ensure that there is sufficient dispatchable storage to meet peak demand in the WEM. This approach puts the onus on AEMO to get the 4-hour dispatch window correct, rather than market participants responding to price signals.

Scarcity Pricing would be required in both Energy and Frequency Control Essential System Services Markets

As outlined in Section 3.4.5, FCESS prices reflect generator variable costs and/or opportunity value foregone in the energy market (i.e., Balancing Market) when these resources are dispatched to provide these services.

Given the inter-relationships between ESS and energy markets, these markets will be co-optimised from 1 October 2023, which could reduce ESS prices in the future given that co-optimisation has the potential to reduce risks for generators participating in ESS markets (i.e., do not forego profitable opportunities supplying energy in the Balancing Market).

In conclusion, ESS bids and price limits are highly related to energy market bids and price limits. As a result, there needs to be consistency in bidding practices and price caps between both market mechanisms. That is, if price caps in the energy market are based on SRMC of most expensive unit in the WEM, then price caps in the ESS market also need to be related to the energy market price cap (for example, energy price cap less energy price floor). Establishing differential price caps in the ESS market would mean that ESS prices no longer reflect opportunity cost of operations in energy markets, which is not consistent with efficient pricing principles (i.e., prices reflect actual cost of resources used or foregone revenue opportunities).

Shortage Pricing in the PJM[51]

If we look at the current features of the PJM Shortage pricing which was implemented in 2012. Shortage prices apply when PJM does not have sufficient reserves to handle the loss of the largest generating unit on the system at the time. Prices are required to provide signals for additional generation and DSM to become available at this time. PJM's shortage pricing mechanism created a new market to price primary reserves. Primary reserves are offline resources that can be activated within 10 minutes.

To some extent, this shortage pricing is very similar to 5-minute FCAS Contingency Reserve Service or RERT service in the NEM[52].

A price cap totalling $2,700 per megawatt-hour for energy during a reserve shortage was phased in between 2012 and 2015, including a $1,700 per MWh cap for reserves alone. The price of primary and synchronized reserves will reflect shortages when either an actual shortage exists or a voltage reduction or a manual load dump emergency action is implemented.

The shortage pricing mechanism enables the market clearing price to increase as a reserve shortage becomes more severe. If emergency resources are no longer available and electricity demand exceeds the capacity that is available to provide energy and meet the required reserves, PJM will use the reserves to supply customers with electricity to meet their demand. This increases the clearing prices of both energy and reserves.

It should be noted that market power mitigations remain in effect during shortage conditions.

Scarcity Pricing in the WEM

When reserves in the WEM are critically low (less than the size of the largest unit online), DSM and non-market generators (e.g., West Kalgoorlie, Mungarra) could be permitted to participate in the Balancing Market at these times and bid up to a price cap of $2000 per MWh. If cleared, this would set the price in the Balancing Market and influence the Frequency Regulation price. This would provide additional revenue to all generators and storage facilities that are cleared in the WEM during the designated shortage period.

[51] PJM Shortage Pricing Fact Sheet (online)

[52] The Reliability and Emergency Reserve Trader (RERT) scheme was designed as an emergency scheme to purchase demand management under critical conditions.

The problem for the WEM is that market power is evident and market participants could potentially withdraw physical capacity to induce a shortage event. While capacity refunds apply and regulatory risk may deter participants from withdrawing physical capacity, the payback of receiving $2000 per MWh for those intervals might provide an incentive for withdrawing this physical capacity.

In addition, scarcity pricing doesn't resolve the fundamental problem of incentivising new entrant generation to enter the market, since investors are typically looking for stable income flows from the WEM to justify the investment. Relying on forecasts of shortage events in the WEM and how often scarcity prices would apply is not likely to provide an investment case for flexible generation and storage facilities with 25-year asset lives.

6.3 Long Term Capacity Contracts

While scarcity pricing is not likely to provide adequate incentives for new investment in the WEM, neither is relying on the current capacity pricing mechanism which only provides annual prices (2 years and 3 months ahead) and can be as low as zero at 30% excess capacity and 50% of the BRCP when excess capacity is 10%.

Investors need to be able to secure long term capacity prices that cover a substantial portion of gross CONE (annualised capital and fixed O&M costs), with the balance provided by energy and ESS markets (and LGCs for renewable generation).

Market Participants seeking price certainty can opt to nominate themselves to be a Fixed Price Facility during the certification process. Fixed Price Facility prices are pegged to the RCP of the first Reserve Capacity Cycle in which they make their capacity available; thereafter, the RCP from that first cycle is increased by the Consumer Price Index for each subsequent cycle. Fixed Prices are only valid for five years.

Current RCPs are 50% of the BRCP (gross CONE) are not likely to increase significantly without plant retirements. Given the prospective variability in capacity prices resulting from the new capacity price formula, it is unlikely that a 5-year fixed capacity price will underwrite investment in new flexible generation and storage in the WEM, given that asset lives are typically 25 to 30 years. Investors who are willing to invest in long lived generation and storage assets in the WEM should be able to lock in a price at or near the gross CONE for a minimum of 15 years or 60% of the asset life.

How could a 15-year price-lock in mechanism work in the WEM?

A new entrant can enter the market and receive the minimum of their offer price (initial offer price escalated by CPI) or 85% of the BRCP for 15 years. AEMO will assess offers subject to meeting capacity performance criteria and the maximum quantity of Fixed Price Facilities (in MW). Lowest price offers up to the maximum quantity of Fixed Price Facilities (term now increased from 5 to 15 years) will be accepted.

If the variable RCP exceeds the Fixed Price Facility Capacity Price each year, a generator or storage facility can then on sell their capacity at the variable RCP price, assuming they have not hedged their capacity at a given price. Hence, the Fixed Price Facility Capacity Price is effectively a floor price for the project.

Fixed Price Facilities will only include new entrant dispatchable generation and storage facilities, and will not include intermittent generation, non-scheduled generation, DSM, and existing generation facilities. The latter would include incumbent dispatchable generation that is subject to the variable capacity price, price ceiling and floor, and all other existing generation that has received capacity credits in the 2023-24 capacity year.

There is precedent for this approach in other capacity markets. New plant can opt for 3-year contracts in PJM, 7-year contracts in ISO-NE, 10 years in I-SEM and 15-year contracts in the UK Capacity Market.[53] Given that the current BRCP (or gross CONE) in the WEM is set based on securing finance for a 15-year period, it makes sense to have a contract term of at least 15 years.

Offering 15-year contract lengths provides significant benefits to the market:

- Investors will be able to secure a lower cost of capital that helps reduce the cost of securing required capacity in the WEM.
- Long term capacity contracts will support merchant plant entry into the SWIS and help reduce market concentration in the WEM.
- Long term capacity contracts reduce barriers of entry to the WEM by eliminating some complexity of the market mechanisms.

This approach may also have the added benefit of lessening the perceived need for market power mitigation measures that severely limit the commercial decision making of participants with market power (perceived or actual).

6.4 Market Power in the WEM

As outlined by the ETT, the reforms may create new incentives for market power to be exercised.[54] The misalignment between the five-minute bidding and the 30-minute Settlement Interval until 1 October 2025 provides incentives for disorderly bidding by participants. The introduction of a constrained network access framework also means that the occurrences of locational or transient market power for a participant operating behind a constraint will increase.

The three largest players have significant market power in the WEM (i.e., Synergy, Alinta Energy and Summit Southern Cross Power) (refer Section 4.4.1) and it is appropriate that Energy Policy WA introduce a comprehensive market power mitigation framework.

A market power mitigation framework has been incorporated in all international markets that we reviewed in Chapter 5 (Great Britain, Ireland, US PJM, US ERCOT etc), including significantly larger

[53] Charles River Associates, What next for the GB Capacity Market? Indications from US experience, July 2016.

[54] Energy Transformation Taskforce, Improvements to Market Power Mitigation Mechanism, Information Paper, 21 May 2021, pp 3-4.

markets than the WEM that have delivered competitive outcomes on a consistent basis (e.g., PJM, ERCOT etc).

In our view, a comprehensive market power mitigation framework needs to be developed that ensures parties are incentivised to behave competitively but does not prescribe outcomes and allows both participants to act commercially and allow markets to clear at efficient price levels. That is, prices that allocates scare resources used to meet consumer demand in the short term (real time, or day ahead) and in the longer term (investment cycles of 5 to 10 years) to deliver secure, reliable affordable, and clean energy.

This does not always mean 'lowest price'. Governments and policy makers intent on minimising energy bills to final consumers have intervened in markets to deliver electricity to customers below cost. All franchise electricity consumers in the SWIS (consuming <50,000 MWh per annum) are currently subsidised by WA ratepayers. Customers installing rooftop PV are currently subsidised by the Commonwealth Government under SRES and implicit subsidies are provided by electricity utilities not implementing cost reflective retail tariffs.

WA is facing an enormous task to re-engineer electricity systems and markets to deliver electricity zero net emissions by 2050. The amount of investment in electricity distribution, transmission and generation will be tens of billions of dollars in the SWIS alone. Inevitably, electricity costs and prices will rise, and the market should attempt to achieve the "lowest possible price", while maintaining existing levels of reliability and lower emissions.

An effective market power mitigation framework for the WEM is discussed in subsequent sections.

6.4.1 Ex ante and Ex post regulation

Both ex ante and ex post regulation measures will need to be employed in the WEM. Development of detailed ex ante measures will mitigate unacceptable trading conduct, and an effective and timely ex post investigation process if there were to be any unacceptable trading conduct and an enforcement of penalties will need to be applied.

6.4.2 Market power test

Energy Transformation Taskforce opted for a ***three-part market power test***, which incorporates a pivotal supplier test (i.e., the participant must dispatch one or more facilities otherwise demand cannot be met). This is an adoption of pivotal supplier tests in US capacity markets, such as PJM and ERCOT. It is highly likely that at least one or more of the top 3 suppliers in WEM has market power and can exercise that market power in numerous trading intervals in a year.

If one participant is deemed to be a pivotal supplier and is restricted in their bidding, then this opens the door for other market participants to exercise market power in a trading interval. Focusing on only one pivotal supplier in a market whereby three participants have substantial market share is the wrong approach.

It is likely that whatever test is adopted by EPWA will indicate that market power exists in the WEM, so the focus should not be on whether there is market power in the WEM, but whether that market power can be exercised under proposed WEM rules.

Fundamentally, market power is exhibited when a participant can vary their market submission (both quantity and/or price) so that resultant prices exceed competitive levels. In ERCOT, the IMM focused on both the "economic withholding" of capacity that can occur when a supplier raises its offer prices to levels well above the expected cost to produce electricity, as well as the "physical withholding" of capacity when a supplier makes one of its resources unavailable for use. Both result in prices exceeding competitive levels.

However, determination of what prices will be in the absence of the execution of market power (not just the presence of market power) is complex. For each trading interval, whereby the pivotal supplier test has been passed, the regulator would need to understand all the requisite information that is required in formulating participant bids for each generator. In essence, this means determining the SRMC of each individual generator that is operated or controlled by a pivotal supplier. This requires information on the following:

- Fuel Cost – spot, contracted, replacement cost or a combination of each;
- Generator performance factors (e.g., minimum generation, maximum generation, ramp rates etc), generator heat rate (GJ per MWh)
- Start Costs
- No Load Costs
- Variable Maintenance and Operational Costs - expenses directly related to electric production and are a function of starts and/or run hours. Allowable expenses may include repair, replacement, and major inspection, and overhaul expenses including variable long term service agreement expenses. Operating Costs are expenses related to consumable materials used during unit operation (e.g., lubricants, chemicals etc).
- Risk factor – inclusion of premium to cover the additional cost of not being dispatched in accordance with what was expected (i.e., only running for 4 hours when the plant was expected to run for 14 hours).
- MLF – marginal loss factors are published.

In addition, the regulator would need to understand what restrictions on the operations of the generation unit were applied in a particular trading interval. That is, partial or total planned or forced outage of the plant. In addition, whether there were fuel supply restrictions (insufficient gas available from the spot market or from storage).

In effect, the regulator would need to construct a pivotal supplier offer curve for each individual generator that applies across the trading intervals in which the pivotal supplier has market power. Run a simulation of the power market to determine what the expected clearing quantities and prices would be based on participant offer curves, and if the pivotal supplier offer curve for a specific generator (or portfolio of generators) deviate from the expected offer curve by a significant margin, trigger a regulated offer (market ceiling or floor price) for the pivotal supplier.

In essence, this is the approach that has been undertaken in US markets. In the ERCOT, market rules cap prices apply that restrict the maximum price that pivotal suppliers can offer. A reference price is established (based on competitive market outcomes) and bid offers are then capped at the maximum of the reference price or the mitigated offer cap – in effect the marginal cost of a gas fired generator.

The overhead for this type of interventionist regulation is high. It requires the procurement of specialist market simulation software, collection of relevant data that is used in bids by all market participants, and expert modellers who can maintain, run, and interpret results from the model. Regulatory and policy bodies are not specifically suited to such specialist tasks or can even gain the requisite skill sets, which has contributed to some major regulators outsourcing their market monitoring and regulatory function to economic specialists. For example, in ERCOT, Potomac Economics act as the Independent Market Monitor, whereas in PJM, Monitoring Analytics act as the market monitor. For a relatively small market like the WEM, this is a substantial overhead that needs to be borne by market participants and ultimately by customers.

Notwithstanding the above comments, market concentration in the WEM means there will still need to be restraints on bidding by market participants. There are several approaches to this:

(a) Light handed regulation with high penalties for unacceptable trading conduct

Under this approach, there would be detailed trading conduct obligations for market participants to be included in the WEM Rules and guidelines provided by the ERA, which includes

- 'good faith' offer obligations with additional guidance from ERA on what constitutes acceptable trading conduct;
- retain the obligation that market prices should be based on a participant's reasonable estimates of SRMC. Understanding the SRMC for facility is a cornerstone for profitable bidding by participants. Requiring participants to make offers based on a what would occur in a competitive market is too vague and open to interpretation.
- Require participants with market power to have internal controls to support self-monitoring and prevention of potential market power exercise and to retain records to support the rationale for their offers.

The ERA would also provide offer construction guidelines that set out how the ERA expects a participant would construct its offers (in the absence of market power). The WEM Rules will provide clarity on the types of costs that could be included in offers, while the ERA's offer construction guidelines would provide clarity on the treatment of fuel costs and variable operations and maintenance costs, in a similar way to how PJM provides guidance on these matters (refer Section 5.1.3 Subsection PJM).

In addition, a participant with market power could enter a voluntary market power mitigation plan with the regulator (applies in ERCOT). These would be bespoke agreements, which has the advantage of being tailored for the specific issues that are likely to emerge for each participant (e.g., fuel position, level of vertical integration, market power in wholesale and retail markets, ownership arrangements etc). Given that there are only a few participants with market power, the cost of this approach is not likely to be high.

In considering the development of a framework for implementing voluntary mitigation plans in the WEM, the ERA would need to consider the following:

- the expected uptake of such plans – penalties for noncompliance or breaches would need to be sufficiently high to incentivise participants with market power to take up a voluntary mitigation plan,
- the types of behaviour that would be covered in a voluntary mitigation plan, i.e., the specific behaviours of market participants that are to be prohibited under the plan,
- the potential reduction in investigations of inappropriate market behaviour, enforcement, and legal costs for both market participants and the ERA that arises by providing clear frameworks that more accurately specify the prohibited activities for specific market participants, and
- the costs of developing such plans and negotiating with market participants as to their content.

Presumably as the regulator and market participants develop and refine these voluntary mitigation plans, the cost of this approach reduces steadily overtime. In addition, this approach is not attempting to prescribe competitive market outcomes, which reduces the incidence of inefficient outcomes that can result when regulators intervene in markets on a day-to-day basis.

(b) Safe Harbours for participants and high penalties for unacceptable trading conduct plus elements of Option a)

A supplementary step to a) would be to define offer ranges for participants deemed to have market power whereby there is a low risk of regulatory noncompliance. That is, offer prices by market participants with market power can be within a nominated band or "safe harbour" (+ or minus 20%) of a relevant pre-determined reference price calculated by the regulator prior to the trading period. Penalties for noncompliance would need to remain high to ensure participants act in "good faith". The focus here would be to ensure that market participants do not extract super-normal profits in trading intervals.

Wholesale market modelling would be required to understand the potential range of offer prices as a function of the drivers of SRMC. Generic fuel prices and VOM costs for SWIS generators would be used in the wholesale market modelling and participants would not be required to provide detailed contractual and commercial in confidence data to the regulator. Generic fuel prices and VOM would be calculated as the regulator is not trying to mimic exactly the offer curve made by market participants with market power, but to develop acceptable price ranges for generator offers.

(c) Prescriptive ex ante bidding rules and modest penalties for unacceptable trading conduction plus elements of Option a)

As outlined earlier, the regulator would need to construct a pivotal supplier offer curve for each individual generator that applies across the trading intervals in which the pivotal supplier has market power. A simulation of the power market is used to determine expected clearing quantities and prices would be based on participant offer curves, and if the pivotal supplier offer curve for a specific generator (or portfolio of generators) deviate from the expected offer curve by a significant margin, trigger a regulated offer (market ceiling or floor price) for the pivotal supplier.

For this approach to work, pivotal suppliers would need to provide detailed information on fuel costs, plant operations (which AEMO will already have) and VOM. This will be the most expensive regulatory approach to implement and operate, with pivotal suppliers having to share detailed contractual and commercial in confidence data to the regulator. This approach, if too rigid, could result in inefficient outcomes if market participants are not able to pass through relevant costs in their bids.

Preferred Approach

In our view, option b), which also includes option a), would be most suited to the WEM given its size and market concentration. Option c) involves significantly higher costs to establish and administer and has the potential to result in inefficient outcomes if there is an overreliance on prescribed prices and not market outcomes.

Energy Price Limits as a Market Power Mitigation Mechanism

It has been argued that ***Energy and ESS price limits***, can also act to mitigate market power in the WEM. Because of the “energy and capacity” market design of the WEM, this has not been a significant issue to date. In effect, the value of lost load is covered by the Reserve Capacity Mechanism. That is, sufficient capacity must be installed to meet the WEM reliability criteria. The role of the energy and ESS markets is not to reflect scarcity values, and hence their role is to reflect the variable costs of supply in each trading interval. Price caps in the STEM/Balancing Market (and effectively ESS market) must reflect the cost of the most expensive resource that will be dispatched in the WEM – which currently are diesel generators. Provided that participants are still required to make bids based on their reasonable expectation of SRMC, then it is unlikely that prices will be set at the maximum energy price in the market (once the single energy price cap is implemented). Thus, moving to a single energy price cap implies that the maximum price is less likely to achieve this level.

Maximum energy prices (and ESS prices) in the WEM do not reflect scarcity values and do not play the same critical role that they do in energy only markets like the NEM.

In essence, it is not the price caps that limit market power in the WEM, but essentially the “energy and capacity” market design of the WEM that means that price bids in each trading interval should only be based on SRMC for each generating unit. Ensuring that the price cap is set to reflect the costs of the most expensive unit in the WEM is really a technical matter and ensures that the most expensive unit in the fleet can achieve cost recovery.

6.5 Transmission Investment in the SWIS

6.5.1 WOSP and Western Power Annual Planning

Much of the reforms developed by the ETT, and that are continuing to be developed by Energy Policy WA, has concentrated on wholesale market reforms and the introduction of constrained network access. Constrained network access would help to ensure that existing transmission capacity is utilised before expansions of the grid are required to accommodate new generation.

While constrained network access may assist at the margin, considerable upgrades of the SWIS will be required to accommodate the likely future investment in large-scale intermittent generation and flexible generation and storage. For example, in our Base Case Scenario, we have forecast that an additional 1100 MW of wind farms will enter the SWIS by 2035, while around 1000 MW of large-scale solar farms will be built. Significant transmission investment will be required to accommodate these new connections and relieve network constraints.

Table 8 Current and Future Wholesale Market Capacity – Marsden Jacob Base Case Scenario

Nameplate Capacity (MW)		
CAL Year	**2022**	**2035**
Biomass	93	93
Coal	1,574	530
CCGT	939	854
OCGT	1,760	1,148
OCGT_Aero	200	600
Wind	966	2,111
Solar	177	1,211
Distillate	122	122
DSP	100	300
Storage	65	1,613
Total	5,996	8,582

Source: Marsden Jacob 2022

It is likely that a significant upgrade of transmission would be required to permit VRE generation in regional areas of the SWIS, such as the North Country, East Country, and Muja (Muja to Albany).

However, Western Power has not identified any significant upgrades of the SWIS to support the transition to zero net emissions by 2050 in its Annual Planning 2020 (February 2021). Some network reinforcement proposals in the Kwinana load area have been considered, but there is very little planning on how large-scale VRE will be integrated into the network.

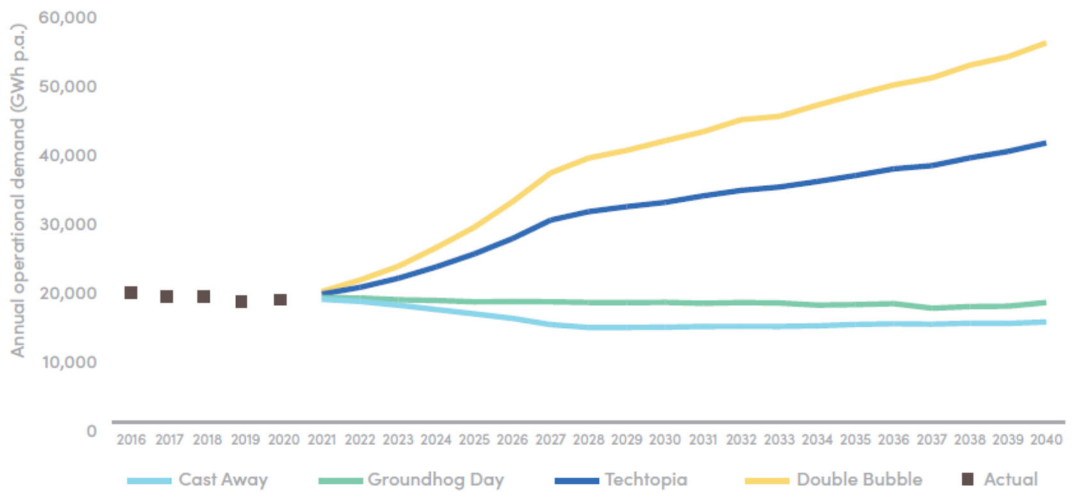
Western Power stated[55] that *"the inaugural Whole of System Plan (WOSP) did not any indicate significant amounts of transmission upgrades in the SWIS and assumed that new generation build*

[55] Western Power, Annual Planning Report 2020, p.45.

would occur in regions of the SWIS that had spare transmission capacity and/or any constraints could be alleviated by the installation of energy storage systems."

The Operational Consumption (net of rooftop PV) trajectory for each scenario that was developed for the WOSP is shown below.

Figure 25 Operational Consumption by WOSP Scenario



Source: Energy Transformation Taskforce, Whole of System Plan 2020, August 2020, p.28.

In effect, Castaway and Ground Hog Day have flat demand due to the high penetration of rooftop PV and as a result there is little investment required in large-scale solar or wind in the SWIS. For example, in the Castaway case, the output of wind and solar farms hardly increases from 2021 to 2030, while the contribution from rooftop PV increases by 260 per cent (see Table 2 below). The assumptions underpinning such a high uptake of rooftop PV would have to include the following:

- electricity tariffs do not become cost reflective (i.e., utilities move away from unit energy charging to a mix of fixed ($ per premise) and capacity charges ($ per kVA)), which reduces the payback for households and business on their investment in rooftop PV
- there is enough roof space for further investment (facing north to maximise solar irradiation)
- households have sufficient capital to make the investment and policy makers overcome the split incentives problem created by rented properties where renters pay the electricity charges not owners who must make the capital investment
- the Western Power network can absorb high levels of rooftop PV and no technical saturation limit is reached

Operational consumption is significantly higher in the Techtopia and Double Bubble cases, which both have lower levels of rooftop PV penetration. In these cases, there is significant investment in both large-scale solar (11 fold increase in generation output) and wind facilities (almost a 300 per cent increase in generation output) in the SWIS. Achieving an increase in wind output of almost 300 per cent would require the installation of around 1500 MW in onshore wind farms assuming a 45 per cent capacity factor. The increase in the output of both large-scale solar and wind is shown below.

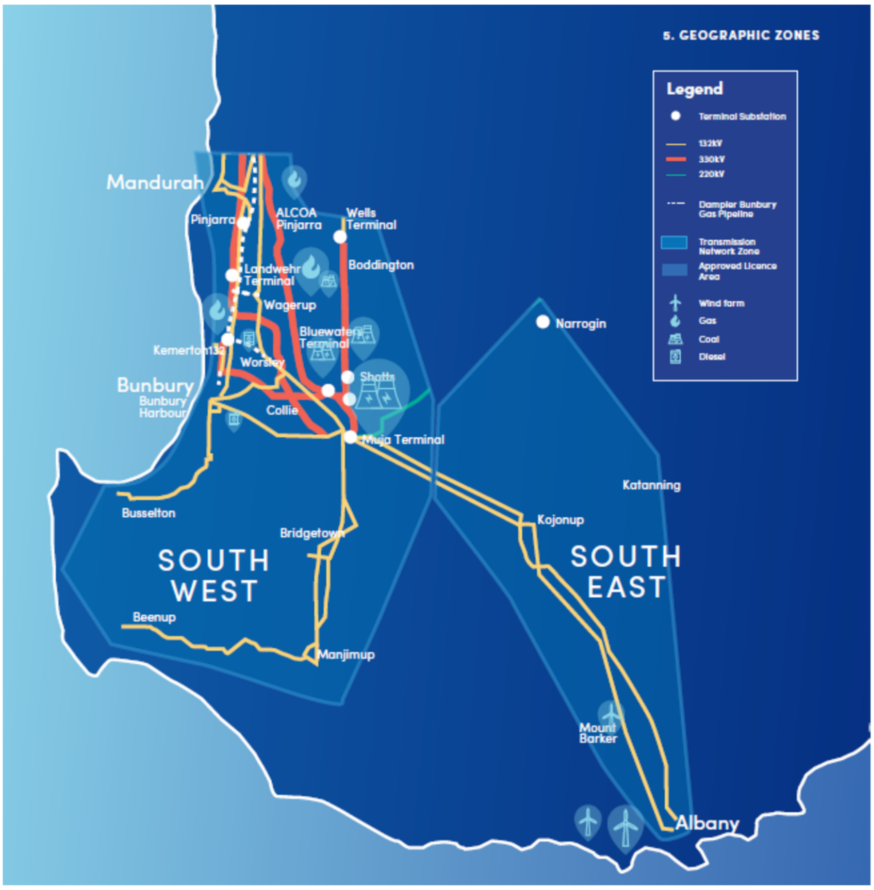
Table 9 Generation (GWh) for Techtopia Scenario, by Technology

Plant Type	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	3,156	3,735	3,919	4,983	5,835	6,962	6,633	8,835	9,633	9,088
OCGT	1,957	1,979	2,208	2,131	2,001	2,032	2,247	2,190	2,211	2,353
CCGT	3,818	3,897	4,518	5,143	6,659	6,901	7,939	7,319	6,924	7,960
Solar	424	424	475	500	579	2,273	4,019	4,212	4,711	4,674
Biomass	174	178	492	754	757	692	736	749	731	732
Coal	10,010	10,322	10,286	10,099	9,685	8,927	9,060	8,589	8,448	8,479
DSM	-	-	-	0	0	0	0	1	-	0
Rooftop Solar	1,807	1,950	2,124	2,343	2,541	2,612	2,918	2,993	3,092	3,163
Diesel	-	-	-	-	-	-	-	-	-	-

Source: Energy Transformation Taskforce, Whole of System Plan, Appendix C.

However, in the Techtopia and Double Bubble cases considerable upgrades in transmission capacity are required to enable wind and solar farms to dispatch into the SWIS once the capacity of the South West transmission network zone is fully utilised. The big assumption in these two scenarios is that wind and solar resources will be built in this zone, even though there are currently no wind farms in this region. Currently all wind capacity is in the South East transmission network zone (40 MW). We have provided a map of the South West and South East transmission zones below.

Figure 26 South West and South East Zones



Source: Energy Transformation Taskforce, Whole of System Plan 2020, August 2020, p.105.

What becomes apparent is that there are significant obstacles to the development of large-scale wind and solar farms in the South West region. This is because:

- Population growth in that region is expected to increase rapidly from 170,000 to 500,000 in 2050.[56]
- A large amount of land is current state forest or prime agricultural land.
- Many areas in this region are popular tourism regions (e.g., Busselton and Margaret River) and resistance to large-scale renewable projects in this region is expected to be high.

For these reasons, there has been little development of large-scale renewable projects in this region to date.

Even if we accept that large-scale wind and solar projects will commence in the South West region, further investment in both large-scale solar and wind farms is still required to meet demand in both the Techtopia and Double Bubble Cases. Because of transmission limits in other regions (e.g., North Country, Mid East etc), considerable investment in the network will be required to support these developments.

Western Power's assumption that operational demand will continue to be flat, and that transmission augmentation will not be significant, is in stark contrast to the findings from AEMO's Integrated System Plan (ISP) that has been developed for planning purposes in the NEM.

6.5.2 NEM ISP

The inaugural ISP was developed in 2018 and was refreshed in 2020 and is currently being updated in 2022. The ISP identifies the most efficient locations for the creation of Renewable Energy Zones (REZ) to support VRE generation and the development of transmission capacity investments that are required to ensure that generation from these REZs can meet various load centre requirements.

The 2020 ISP identified the following development opportunities by 2040:[57]

- While distributed energy generation capacity is expected to double or even triple, over 26 GW of new grid-scale renewables is needed in all but the Slow Change scenario (8 GW in this scenario is required). This is to replace the approximately 15 GW or 63% of Australia's coal-fired generation that will reach the end of its technical life and so likely retire by 2040.
- 6-19 GW of new dispatchable resources are needed in support the development of VRE and maintain supply reliability.
- Significant network augmentations are required and includes the current committed and actionable ISP projects:
  - ➢ Committed ISP Projects included:
    - Western Victoria Transmission Network Project, to support generation from the Western Victoria REZ, including new 220 kV and 500 kV double-circuit lines. The project was on track to be commissioned in two stages, by 2021 and 2025.
    - QNI Minor, a minor upgrade of the existing interconnector, adding over 150 MW thermal capacity in both directions, was on track to be commissioned in 2021-22.

[56] http://www.swdc.wa.gov.au/media/230871/sw%20blueprint_final_web.pdf

[57] AEMO, 2020 Integrated System Plan, July 2020.

- Actionable ISP projects included:
  - Project EnergyConnect, a new 330 kV double-circuit interconnector between South Australia and New South Wales aimed at unlocking stranded renewable investments, for expected completion by 2024–25.
  - HumeLink, a 500 kV transmission upgrade to reinforce the New South Wales southern shared network and increase transfer capacity between the Snowy Mountains hydroelectric scheme and the region's demand centres. Project completion expected by 2025-26.
  - Central-West Orana REZ Transmission Link, involving network augmentations to support the development of the Central-West Orana REZ as defined in the New South Wales Electricity Strategy, and transfer capacity between the Central-West Orana REZ and major load centres of New South Wales. The project completion is due in 2024-25.
  - Project Marinus – a proposed 1,500 MW capacity interconnector between Tasmania and Victoria to allow increased exports from Tasmania's renewable energy and storage resources
  - the Victoria to NSW Interconnector (VNI) West to allow for additional renewable generation in north west Victoria and address grid congestion and system strength issues.

6.5.3 Revitalise Transmission Planning in the SWIS

As highlighted by the Australian Energy Regulator[58]:

"Transmission investment tends to lag behind generation investment, often resulting in delays between the completion of a generation project and the network being ready for the plant to connect. These lags create uncertainty for generation proponents and may delay efficient investment."

Typically, the lag in transmission investment arises because network operators require compelling evidence. This can be challenging because a cost-benefit assessment without all potential benefits included may not meet the required hurdle rate and this will adversely impact Financial Investment Decision approval. Only when generation or load projects achieve Final Investment Decision, or all benefits can be easily quantified in a cost-benefit assessment, do the projects obtain approval from the Economic Regulator.

In Western Australia, the last major transmission upgrade occurred in 2014 with the construction of a single circuit 330 kV transmission line from Neerabup to Eneabba to support the Karara magnetite mine in the mid-west. There has not been recent experience in undertaking cost benefit assessments of major transmission upgrades in the SWIS since that time.

The current Western Power Annual Planning Review is not fit for purpose and does not adequately address the challenge of moving to net zero emissions in the SWIS by 2050. Selectively picking two scenarios (i.e., Ground Hog Day and Castaway) from the WOSP and then claiming that no significant upgrade of the transmission system in the SWIS is required is not a good example of detailed and co-

[58] AER, State of the Energy Market 2021, p.58.

ordinated planning, especially given the likely investment in large-scale renewable generation that will be required to achieve the 2050 target.

In our view, the Western Power transmission planning process needs to be reviewed and significant network upgrades to support the creation of REZ's in North Country, East Country, and the Muja region needs to be considered to facilitate efficient grid connection and decrease the risk of congestion that reduces generator earnings. Given that regulatory investment tests for major transmission upgrades have not been conducted for almost a decade, a review of the current approval process for large transmission projects is also recommended.

7. Summary and Conclusions

In this chapter we outline the key issues that the AEC wanted us to address in this study (refer Section 1.2) and the key findings from our research, discussions with key stakeholders and our analysis. We have also referenced the relevant section(s) of this report where our analysis and findings are discussed in more detail.

Table 10 Key Issues and Study Findings

Issue	Description or Finding	Relevant Section of Report
The current revenue streams available to generators in the WEM	In this study we have focused on the following mechanisms in the WEM: • Energy Market - Balancing/STEM • Capacity Market - Reserve Capacity Mechanism • Essential System Services Market: ▪ Frequency Regulation Raise/Lower ▪ Contingency Reserve Raise/Lower ▪ RoCoF Control Service (no current equivalent service).	Refer to Section 3.4 for a brief description of these mechanisms. We have modelled the revenue streams for all generator types in the WEM based on past and future projections of Balancing Market prices, capacity prices and prices for Frequency Regulation Raise/Lower and Contingency Raise/Lower (see Section 4.1) There are other services, such as Blackstart and Network Control Services, but these have been lumped into a single charge and not allocated to individual generators for this study.
The role of each revenue stream in providing revenue adequacy	Primarily the role of each revenue stream is as follows: Reserve Capacity Mechanism – to provide a significant contribution to the recovery of the capital cost of the plant that is required to meet the last increment of demand in the WEM (which has deemed to be OCGT plant but could be storage facilities in the future). Currently is based on the gross CONE for an OCGT unit. Balancing Market (i.e., Real Time Energy) /STEM - Ensure the efficient dispatch of generation (and storage in the future) to meet demand in each trading interval (currently 30 minutes). Focus of this market is to ensure that prices reflect the current variable cost of marginal supply (each participant is compensated for variable costs incurred). As the Balancing Market (and STEM) price in each 30-minute trading interval is determined by the most expensive unit cleared in the market, generators with lower variable costs	Refer to Section 3.4 for a brief description of these mechanisms.

Issue	Description or Finding	Relevant Section of Report
	can earn additional revenue which can contribute to the recovery of fixed costs (i.e., capital and Fixed O&M). Essential System Services (Frequency) - To ensure that system frequency is maintained within the required band. Focus of these services is to ensure that generator and storage providers are compensated for the variable costs incurred and/or market revenue foregone in energy markets for providing these services. Can potentially provide a contribution to fixed costs for resources that have lower costs than the resource which clears the frequency regulation and contingency reserve markets.	
The extent to which generators now have revenue adequacy.	Based on current WEM revenue forecasts, new entrant coal and OCGT units are not economic. CCGT and OCGT Aeroderivative units are marginal (revenue is just sufficient to cover costs), while 4-hour storage, and intermittent generation (wind and solar) is clearly economic (solar is only economic if LGC revenue is included). Shows that efficient investments are economic and that increasingly inefficient technologies are not	We have modelled the revenue streams for all generator types in the WEM based on past and future projections of Balancing Market prices, capacity prices and prices for Frequency Regulation Raise/Lower and Contingency Raise/Lower (see Section 4.1)
The impact the proposed changes to the market power mitigation mechanism will have on revenue adequacy and investor certainty.	The risk of proposed market power mitigation framework is that the measures prescribe outcomes and do not permit market participants to act commercially and allow markets to clear at efficient price levels. A highly prescriptive approach will be costly in terms of market efficiency and monitoring (regulator will require wholesale market modelling systems and specialist resources), and the market monitor will need to ensure that price bidding controls are correct across a range of scenarios.	Detailed discussion on these matters is provided in Section 6.4.
What measures that Energy Policy WA and the Economic Regulation Authority could adopt to ensure revenue adequacy and minimise investor uncertainty.	When establishing policies, price limits and measures, policy makers and regulators should be confirming that there is sufficient revenue in aggregate from all market mechanisms to encourage flexible generation and storage to meet future demand and reliability settings. Just establishing price limits, policies and measures in isolation does not result in incentives for the optimal supply portfolio. ERA and EPWA should undertake an annual review of generator profitability (10 year rolling forecast) under current market settings, and committed rule	Refer to Sub-Section 6.1.1.

Issue	Description or Finding	Relevant Section of Report
	changes, to ensure that the WEM is fulfilling its market objectives (i.e., efficient new entry).	
The extent to which the Essential System Services (ESS) market will incentivise retention and investment in system services providing equipment.	Based on current WEM forecasts and provided that capacity prices are set at gross CONE for an OCGT (2024/25 BRCP of $165,700), there is sufficient revenue adequacy for flexible generation and storage in the WEM. The fundamental problem is the expected continuation of excess generation, which results in low capacity prices for new entrants.	Refer Section 4.1.3 on future revenue sufficiency in the WEM.
Whether the Energy and ESS price should consider scarcity pricing to signal investment.	The introduction of scarcity pricing in energy and ancillary services that have complimentary capacity markets has occurred in PJM. Scarcity pricing could be used in the WEM to recover any shortfall in revenue created by low variable capacity prices that apply to new entrants. Scarcity pricing may be required in the long term to ensure reliability standards are satisfied with high levels of intermittent capacity and limited energy resources (storage).	Refer to discussion in Section 6.2.
What changes could be made to the energy, ESS and RCM markets to promote revenue adequacy and ensure investors receive the right investment signals.	If the WA Government and policy makers will not make further amendments to the pricing formulas of the RCM (which has only recently been implemented), then the following should be considered: – Long term capacity contracts for new entrant generation and storage (15 years) at gross CONE (or the BRCP). – Provide a technology-based capacity price for long duration storage based on Net CONE. – Continue with implementation of a single energy market price cap to be based on SRMC of the most expensive unit to be dispatched in the energy market. Do not include scarcity prices into the energy market at this stage but monitor whether it needs to be included at a later stage.	Refer Section 6.3 for discussion on long term capacity contracts and Section 6.2.1 for the discussion on differential capacity prices. Refer to discussion on Energy Price Limits in Section 6.4.2.
The potential consequences if generators do not have revenue adequacy.	As highlighted in this report, flexible generation and storage is either uneconomic (OCGT and long duration storage) or marginal (OCGT aeroderivative units and 4-hour storage) based on current WEM forecasts. The consequences of not investing in flexible generation and storage is the following:	See discussion in Chapter 2 on Future Challenges and Ideal Attributes of the Future Power Sector and in particular a summary of consequences in Section 2.5.

Issue	Description or Finding	Relevant Section of Report
	– Increase likelihood of unserved energy in some trading periods due to inflexible plant not being able to ramp up sufficiently to meet demand or alternatively, increased running of inflexible out of merit order to provide ESS, – Increased incidence of negative prices when output from solar installations is high and storage systems are not available to store this low value energy. – Increased intervention by regulators in the market due to more frequent price spikes and low reserves, – Increased energy and ESS prices if inflexible plant exits the system (due to age or low economic returns) and is not replaced with flexible generation and storage systems.	