Merredin Energy Pty Ltd
ACN 124 273 025
C/O- Palisade Asset Management
Level 26, 140 William Street
Melbourne VIC 3000
john.delicato@palisadeassetmanagement.com.au

PO Box 203
Collins Street West VIC 8007
Telephone +61 3 9044 1123

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Mr Matthew Martin
Director Wholesale Energy Markets
Public Utilities Office / Department of Treasury
David Malcolm Justice Centre
28 Barrack Street
PERTH WA 6000
Matthew.Martin@treasury.wa.gov.au

Dear Matthew,

Response to Consultation Paper: Improving Reserve Capacity pricing signals – alternative capacity pricing options

1. Introduction

Merredin Energy Pty Ltd (MEPL) owns and operates the 82 MW open cycle gas turbine power station in Merredin, Western Australia. The plant (known as "MEPS") is connected to the South West Interconnected System (SWIS) via a single circuit 132kV overhead transmission line to Western Power's Merredin Terminal north of the power station.

The financial performance of the plant is highly dependent on the revenue earned by providing Capacity Credits under the Reserve Capacity Mechanism (RCM). Proposed reforms that change network access arrangements, capacity certification processes and Reserve Capacity Prices (RCP) have the potential to significantly impact the profitability of the Merredin Plant.

Given the above, we have a significant interest in proposed reforms and provide this submission to ensure that the policy makers consider the impact of proposed reforms on existing Market Participants and put in place new arrangements that maintain the viability of the Merredin Power Station and ultimately ensure sufficient dispatchable generation capacity remains in the market to maintain a reliable and secure electricity system in the South-West of Western Australia.

2. Proposed Reforms of the Reserve Capacity Mechanism

Merredin Energy is strongly opposed to the introduction of a capacity auction to set capacity prices in the Wholesale Electricity Market (WEM). Some of our arguments were outlined in our submission to the Economic Regulation Authority in 2017.[1] Our updated arguments opposing the introduction of a capacity auction in the WEM are summarised below:

- A capacity auction (as proposed by the Energy Market Review[2]) is too complicated and would provide uncertain outcomes in a small, isolated and relatively peaky electricity system (such as the SWIS). Adopting capacity auction models from electricity markets in Europe (e.g. UK, France) and North America (e.g. PJM[3]) that are many times the size of the WEM[4] is inappropriate and not likely to be efficient.
- The PJM has approximately 33 times the amount of generation capacity of the WEM[5]. In a large market like the PJM, capacity market auctions are not likely to have a significant impact on the overall supply and demand balance in any one year (and hence capacity price outcomes). In the WEM, the retirement of a major unit (e.g. 400 MW coal fired unit) or investment in a new plant (e.g. 500 MW of wind and solar farms) can cause the market to be out of balance rapidly, with the result that capacity prices could vary erratically from year to year (assuming a steep capacity demand curve).
- The capacity pricing paper indicates that the RCM needs to be robust given the current structure of the market. That is, Synergy will have control of a significant share of both retail and wholesale markets (i.e. Synergy purchases around 80 per cent of energy produced in the WEM).[6] This implies that an array of market power mitigation measures need to be put in place to ensure that auctions are competitive. This is an expensive overhead for a small market like the WEM and proving misuse of market power can be highly contentious and problematical.
- Given uncertain outcomes with an auction mechanism in a small market like the WEM, it is very unlikely that the RCM would be bankable on a project finance basis. Steepening the capacity demand curves to facilitate an auction and resulting in potential significant changes in capacity prices constitutes an unfair risk allocation between generators and consumers. This is especially the case for generators that are investing in long-lived capital equipment (e.g. 25 years). Creating price volatility will deter private sector investment in peaking plant that will be increasingly required in the future to help maintain supply given likely future investment in intermittent plant (e.g. rooftop PV, wind and solar farms). Merredin Energy expects that at least another 1000 MW of intermittent generation will enter the SWIS by 2022.
- If a capacity auction was implemented, future private sector investment in the SWIS would be limited and would require the State, by default, to continue to underwrite new generation (via Synergy). This is a further burden on the balance sheet for the State, which already had a total public-sector net debt of $33.8 billion at 31 December 2017.[7]

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1 Merredin Energy, Submission to the Economic Regulation Authority, 2016/17 Wholesale Electricity Market Report, 30 August 2017.

2 Final Report: Reforms to the Reserve Capacity Mechanism, Department of Finance, Public Utilities Office, April 2016

3 Installed capacity in the PJM was 183,882 MW in December 2017.

4 Capacity credits issued for the 2018-19 capacity year in the WEM is 4654 MW.

5 There is 183,882 MW of capacity in PJM and around 5500 MW of nominal capacity in the WEM.

6 Even though Synergy only generates 46 per cent of electricity via its own power stations in 2016-17, it also has Power Purchase Agreements (PPAs) in place with many other generators in the WEM (e.g. Bluewaters, NewGen Kwinana, NewGen Neerabup and Emu Downs Windfarm). Synergy effectively controls 72 per cent of capacity credits issued by the AEMO for the 2018-19 capacity year.

7 Government of Western Australia, 2017-18 Quarterly Financial Results Report, December 2017

It should be noted that several market participants (including Merredin Energy) have had trouble refinancing their power stations in the SWIS. Changes to the Reserve Capacity Price formula (increased responsiveness to excess capacity), possibility of future auctions with low capacity prices (which could result from "gaming" by significant market participants), potential loss of firm access rights and general uncertainty have resulted in incumbent generators making more conservative revenue forecasts (e.g. energy and capacity revenue). As a result, incumbent generators have experienced a write-down on asset values (i.e. reduction in equity value of assets). The increased uncertainty has made refinancing of power stations more difficult (required every 3 to 5 years), with the result that interest rates on debt finance have risen for private sector generation assets in the SWIS (this includes Merredin Energy).

The feedback that Merredin Energy has received from financial institutions through its recent refinance is that the cost of debt will rise further if capacity auctions are introduced in the WEM. Debt financiers, that included Merredin Energy's previous lender the Commonwealth Bank of Australia, have indicated a strong preference not to be exposed to any proposed capacity auction scheme. Consequently, Merredin Energy completed a refinance with an alternative financier at a higher financing cost. Capacity auctions are increasing the barriers to entry in the SWIS, which is inconsistent with the purpose of proposed reforms (i.e. reducing capacity costs and encouraging new plant entry to ensure the reliability criteria is met).

Given these arguments, we support the PUO considering alternatives to an auction that are more appropriate for a small, isolated and peaky electricity system.

The two options that are being considered include the following:

Option 1: Administered pricing

Administered capacity procurement arrangement run by AEMO, with a revised capacity pricing formula that more closely reflects the value of capacity at various levels of excess (or shortfall).

Option 2: Retailer led contracting with a bulletin board trading mechanism

A requirement imposed on each electricity retailer to contract sufficient capacity to meet its Individual Reserve Capacity Requirement (IRCR). Significant penalties are put in place for any breach of the obligation by a retailer to avoid supply shortfalls and/or pay for short term procurement of capacity by Australian Energy Market Operator (AEMO) who acts as the provider of last resort.

In effect, there is no central procurement or pricing of capacity and retailers would enter into contractual arrangements with capacity providers (e.g. Power Purchase Agreements (PPAs) with generators and contracts with Demand Side Management (DSM) providers).

AEMO would administer a voluntary trading platform, such as a bulletin (trading) board, to provide price transparency and facilitate contracting, and a means for parties to adjust their contractual positions closer to a capacity year.

This option would require additional regulation to provide contract liquidity and mitigate market power, particularly given Synergy's current dominant market position.

3. Key Design Criteria for Setting Capacity Prices

In Merredin Energy's view, the preferred capacity pricing approach needs to meet the following criteria:

Prices need to encourage demand and supply balance – prices need to move sufficiently to deter new entry when there is excess capacity (price decrease) and encourage new entry if a capacity shortfall is predicted (price increase).

Prices need to reflect the cost of new entrant plant - On average, prices need to reflect the cost of new entrant (CONE) plant. This includes capital and fixed O&M (also referred to as FOM). Failure to ensure this outcome could result in capacity supply shortfalls or short-term measures that incur higher short-term costs (e.g. temporary generation and/or curtailment of major industrial loads). *We agree with the PUO on this approach.*

Prices need to be predictable and not subject to high variability – Investors in peaking generation facilities need to have some certainty about likely future capacity prices. Failure to provide a predictable price path increases risks for investors/debt providers of peaking plant which then increases the cost of funding plant (both new investment and refinancing of power stations). This could cause upward pressure on future capacity prices, or if capacity prices are too low, result in plant exiting the system if they cannot recover higher financing costs.

Capacity market prices can be locked in to encourage new entry – in certain circumstances, new entrant plant should be permitted to lock in capacity prices beyond one year. This can arise if project financing is difficult due to economic factors (e.g. recession, Global Financial Crisis), proposed market changes (e.g. introducing constrained network access) and/or policy changes that make future outcomes highly uncertain (e.g. emission reduction targets).

Capacity market prices need to be transparent – To encourage investment and further development of the market, prices need to be published so that both existing participants and new investors understand market trends, key drivers and future risks. This will help to facilitate new plant entry to ensure the capacity target can be met.

Capacity market needs to be liquid – capacity credits are currently a standardised product (i.e. do not vary based on the unique characteristics of each provider of capacity credits e.g. baseload, peaking, DSM facilities etc). Having a standardised product facilitates trade in the WEM and increases retail competition. That is, smaller retailers can procure capacity credits directly from AEMO without having to enter long term PPAs with capacity providers. This is important given that the PUO has deemed the current industry structure (e.g. Synergy's market position) is out of scope for this review of capacity pricing options.

Capacity credits are technology neutral but must be dispatchable – a provider of capacity credits must meet the minimum requirements for having their capacity certified. This includes availability, duration and reliability. For example, if DSM facilities remain in the RCM, they should have the same requirements as dispatchable generation. Intermittent generation should not be certified to supply capacity credits because it cannot be dispatched to address unusually high demand or a plant outage. Instead, both DSM and intermittent generation can be used to reduce a retailer's IRCR. Only facilities that can be dispatched should earn capacity credits which would include conventional generation or intermittent generation combined with energy storage (e.g. batteries).

In the following section we assess each of the alternative options to a capacity auction using the above-mentioned criteria.

4. Summary Assessment of Alternative Options to a Capacity Auction

Provided in this section is a summary assessment of Administered Pricing and Retailer led contracting using the criteria developed in Section 3. The detailed assessment is provided in Section 5.

Table 1: Assessment of Capacity Pricing Options

Criteria	Administered Pricing	Retailer led contracting with bulletin board
Prices encourage demand and supply balance	A capacity price curve can be designed that ensures sufficient price signals are provided to limit oversupply or encourage new entry. A compartmentalised capacity demand curve (with different slopes) may be appropriate for the WEM.	The obligation is on retailers to build or procure sufficient capacity to meet their forecast IRCR. Prices do not play a role in ensuring the demand and supply balance. The level of penalty payments will determine whether retailers procure sufficient capacity.
Prices reflect CONE (on average)	A capacity price curve can be designed to ensure the recovery of the annualized cost of an OCGT plant (i.e. CONE). Ensuring that the capacity price exceeds CONE when the market is short will be important in this regard.	Capacity prices typically reflect the costs of different technologies that underpin long term PPAs. A PPA for peaking energy will typically reflect the annualized capital cost of OCGT plant.
Price Certainty	Provided the capacity demand curve is not too steep, can be designed to ensure that capacity price outcomes remain with an acceptable range for investors/debt providers of power plants in the SWIS.	Underlying capacity prices will be bound up in PPA contracts with retailers and via outcomes with the capacity bulletin board.
Price Lock-in for New Entry	Can be designed to ensure that new entrant capacity providers can lock in (at least) 10 years of capacity prices if required to facilitate investment in dispatchable generation.	Capacity providers can achieve price lock-in via long term PPAs.
Transparent Prices	Both the BRCP and RCP would be published and would provide useful information to market participants and potential investors in power generation in the SWIS.	Bulletin board provides a summary of price/quantity outcomes on capacity credits that are traded in a year. However, market volumes could be low if most energy is traded via bilateral contracts.
Market Liquidity	Capacity credits are a homogenous product under the RCM and can be traded between market participants. Smaller retailers do not need to enter long term PPAs to meet capacity obligations (IRCR), which increases competition in the WEM.	Market liquidity would be substantially reduced as retailers are typically entering into long term PPAs. Can trade around their contract positions via the bulletin board. However, incumbent retailers would have an incentive to minimize trade in capacity to limit competition in the WEM (i.e. squeeze out smaller retailers).
Technology neutral, but dispatchable	Capacity credits should only be issued to dispatchable facilities (e.g. OCGT, CCGT, coal, distillate plant and intermittent plant with storage). Issuing capacity credits to plant or DSM facilities that may not be available or able to meet supply shortfalls can reduce the reliability of the SWIS. However, DSM and intermittent generation (without storage) can be used to reduce a market customers IRCR.	Same as for Administered Pricing Regime.

In Merredin Energy's view, capacity pricing should continue to be set based on Administered Pricing Arrangements. This will help mitigate market power concerns (i.e. Synergy's role in the market) and will help promote a competitive wholesale market (i.e. transparent and liquid market). Administered pricing can also provide more certainty of price outcomes, which will be important for encouraging future investment in dispatchable plant in the SWIS.

5. Detailed Assessment of Options

5.1 Market Power Considerations

Having invested in merchant plant based on future outcomes in the RCM, Merredin Energy fully understands the importance of establishing prices which reflect economic fundamentals and are not subject to manipulation by dominant players in the WEM. If the market was not highly concentrated (i.e. Synergy's control of generation in the WEM) then capacity auctions and retailer led contracting would be viable alternatives to an administered pricing approach.

However, the PUO has indicated that the RCM will need to be designed on the assumption that the current market structure remains in place. This implies that if alternative options are considered then additional reforms will be necessary to help mitigate Synergy's market power and provide contract liquidity for smaller buyers to purchase (or sell) capacity credits.

In effect, these alternative market designs for the WEM are flawed even before they begin and then require complimentary measures to ensure that prices reflect competitive market outcomes. *That is, we are hoping for the best outcome and then planning for the worst outcome.*

Consider the likely market outcomes under retailer led contracting. Dominant Firm A is required to procure additional capacity to meet its capacity obligations. The cheapest market option would be for Firm A to underwrite the construction of a 100 MW OCGT.[8] However, annual growth in the market is only 50 MW, which means that there may be excess capacity for around 2 years which could be utilised by smaller retailers in the market to win electricity customers. Instead of investing in a 100 MW OCGT plant and creating excess capacity for 2 years, Firm A only invests in a 50 MW OCGT plant resulting in some additional excess capacity for up to 1 year only. This has several consequences:

- Economies of scale are not realised because participants are wary of creating excess supply in the market which could depress capacity prices and result in a loss of retail market share if competitors can access this spare generation through a bulletin board arrangement (would be compulsory otherwise participants may not offer the capacity into the market). This is not an efficient outcome for the market;
- Capacity prices will typically be higher as a participant with market power will attempt to ensure that the market is *short* capacity or close to market balance. Higher capacity prices will be passed onto to retailer customers which causes upward pressure on retail electricity prices.

It is hard to see how this behaviour could be prevented by developing a market mitigation measure. Would the market operator/regulator have to calculate the least cost investment path for the SWIS and then dictate which generation investment profile is best for the market and then instruct Dominant Generator A to build a 100 MW OCGT? If so, this then looks remarkably like an administered price approach whereby the market operator currently establishes capacity prices based on the benchmark plant for the WEM (e.g. 160 MW OCGT plant).

8 For example, we have estimated that the capital cost of a 100 MW OCGT would be around $1,430/kW in the SWIS, while the costs of a 50 MW OCGT would be around $1,707/kW. Given this cost difference, it can be shown that the costs of building a 100 MW OCGT plant is cheaper (on a present value basis) than building two 50 MW generators. However, in this example, it is likely that the Dominant Player A will attempt to inflate capacity costs in the market by building smaller plants.

As we outline in Section 5.3, the current administered pricing approach has not to date resulted in any shortage of capacity credits and deliberately inflated capacity prices and has helped to increase competition in both wholesale and retail electricity markets in the south-west of Western Australia.

Currently, there is not much *"science"* in the determination of the benchmark unit size as it does not relate to likely peak demand growth (closer to 70 MW per annum in the AEMO Expected Case for the SWIS) or the unit size that is determined from a least cost planning study of the SWIS. For the SWIS, it is likely that the optimal size of future plant that should be considered will be smaller (around 80 to 100 MW) rather than the current 160 MW benchmark unit size.

5.2 Capacity Price Discovery

The PUO is concerned that an administered pricing approach does not result in *"market discovered"* prices. That is, actual prices should be set based on results of a capacity auction, a long term PPA (which is not easily discoverable by the market operator) or a short-term bulletin board for capacity. Merredin Energy disagrees with this.

Consider a capacity auction approach such as the PJM. Under this approach, the market operator sets a "variable capacity target" (downward sloping curve) and then sets the price based on a competitive response by bidders (e.g. generators or DSM providers). In the WA RCM, a downward sloping demand curve for excess capacity is established and the Reserve Capacity Target is set. The Reserve Capacity Price is then established based on AEMO's understanding of what capacity additions and retirements will occur in the 3-year capacity cycle. In effect, the resulting RCP set by AEMO will reflect a competitive response by market participants.

If the Benchmark Reserve Capacity Price (BRCP) is set too high (exceeding new entrant generation costs for peaking units), then this may encourage more investment in generation capacity than required which then reduces the RCP to competitive levels (given the downward sloping demand curve for capacity). If the BRCP is set too low, then there may be less investment which results in a shortage of capacity (requiring a capacity auction to take place under current WEM rules) or low levels of excess capacity which results in higher prices (prices that may exceed the BRCP if the capacity demand curve is designed correctly). The administered mechanism ultimately results in *market determined* prices due to a competitive supply response by market participants.

In effect, a capacity auction with a variable capacity target (PJM) and the WA RCM with a downward sloping demand curve for capacity and both result in competitively set capacity prices. However, the administered price is less likely to be subject to manipulation by a dominant market player.

We need to test this last statement. Can a dominant player manipulate the resulting RCP calculated under an administered pricing approach? In theory, the dominant player could withdraw capacity or refuse to invest in new capacity. If this occurred, other market participants would be required to invest in required capacity for the market. Given that the RCM is in place, merchant capacity could enter the market to meet demand or retailers could underwrite long term investments in new capacity. Under the RCM, both types of investment have occurred in the WEM in the past.[9] This indicates that the presence of a dominant

[9] For example, Merredin Energy (merchant), Tesla Energy (merchant), Alinta Wagerup Peaking Units (internally contracted to Alinta Retail and some merchant exposure) and Perth Energy's Kwinana Swift Plant (internally contracted to Perth Energy's retail arm with some merchant exposure).

player(s) in the market to date (e.g. Synergy and to a lesser extent Alinta Energy) has not resulted in outcomes heavily influenced by the market position of these participants.

If an administered pricing approach results in *market determined* prices and has resulted in competitive market outcomes with little market power mitigation measures in place, we shouldn't need to introduce alternative capacity price options that require significant market power mitigation measures to be developed and administered. In our view, the benefits of moving away from administered pricing approaches in the WEM are not warranted.

5.3 Competitive Market Outcomes

It should be pointed out the RCM has been important in helping to facilitate both wholesale and retail competition in the WEM. The RCM has resulted in plant entering the SWIS that has not been fully contracted to vertically integrated retailers (like Alinta Energy and Synergy) and has enabled smaller retailers (e.g. Perth Energy, Premier Power (Wesfarmers), ERM Power etc.) to win market share from incumbent retailers.

The current RCM facilitates competitive entry and rivalry in the retail market through the following mechanisms:

- Transparent and predictable pricing – The Benchmark Reserve Capacity Price is announced 2 years and 8 months prior to the commencement of the applicable capacity year. Given an administered price formula, parties can calculate what the likely RCP will be in that year (usually to around 1 per cent accuracy) given the information provided by AEMO via the Electricity Statement of Opportunities and other publications. This provides confidence to retailers to provide three-year contracts to customers even if they have not hedged their wholesale position out for the full three years (both energy and capacity).
- Capacity credits are a homogenous product that can be traded - Rather than requiring smaller retailers to underwrite new generation in the SWIS (via ownership or long term PPAs), retailers can obtain capacity credits from AEMO to meet their Individual Reserve Capacity Requirement. This helps to encourage smaller retailers to participate in the market and win market share from incumbent retailers.

Putting in place retailer led contracting for capacity would reduce both retail and wholesale competition. Only larger players would be able to underwrite significant investment in generation plant via ownership or long term PPAs. Capacity prices would no longer be easily discoverable as most capacity contracted in the WEM would be via bilateral contracts. Only a small amount of capacity credits is likely to be traded in the WEM, implying that capacity prices realised in the capacity bulletin board will not be a reliable indicator of market capacity costs.

The retailer led contracting approach would limit the number of off-takers for generation capacity that generation developers in the SWIS would have access to. If these larger players (e.g. Synergy and Alinta) end up with a surplus of capacity credits via bilateral contracting, then market rules would need to stipulate that the capacity credits must be traded (either bilaterally or via the capacity credit bulletin board). The question arises as to what would be an acceptable price for Synergy and Alinta to offer capacity credits to third parties in the WEM?

Clearly, both Synergy and Alinta would have an incentive to offer capacity at higher prices (exceeding CONE). Does that now require AEMO to establish maximum price caps for capacity traded in the WEM? In effect, once the cap is established, is it likely that both Synergy and Alinta Energy will be incentivised to sell capacity credits at the cap price? Would the price cap be related to the amount of excess capacity in the market (most likely outcome) that then results in capacity price outcomes being determined along an administered determined price path?

Merredin Energy sees no real advantage in adopting retailer led contracting approach and believes that this approach will lessen competition in the WEM by reducing price transparency and market liquidity (trade in capacity credits).

5.4 Importance of Price Certainty

The PUO has indicated in its consultation paper (p.2) that the *"the fundamental problem with the Reserve Capacity Mechanism is the lack of a price response to surplus capacity – so that excess capacity is significantly overvalued. Conversely, when there is a looming shortage, it is likely that capacity will be under-priced. This results from a pricing formula that delivers a shallow sloping capacity price curve, rather than a market discovered price from competitive offers."*

As a result, this drives the PUO to develop steep capacity demand curves (administered approach) or to put in place capacity auctions with convex shaped capacity demand curves, and/or no price floors (zero prices are possible). As a result, it is likely that future prices will be much more volatile if these approaches are implemented – could be as high as $200,000/MW/annum or as low as zero.

While capacity prices play a role in influencing the level of generation and DSM investment and efforts by retailers and customers to reduce the demand for capacity credits (IRCR), the role is relatively minor compared to other factors.

- Investment in renewable energy plant is driven by Commonwealth policies (e.g. Large-scale Renewable Energy Target or LRET) aimed at reducing emissions in the stationary energy sector. With declining capital costs, increasingly this plant will become commercial and will not require subsidies (Large-scale Generation Certificate or LGC prices) under the LRET scheme (we estimate that LGC prices are likely to be zero around mid-2020s).
- Requirement for base-load generation is driven by demand and whether energy prices are sufficiently high to justify investment in this technology (most likely to be combined cycle gas turbines in the WEM).
- Investment in DSM facilities is driven by costs of lost production for a facility (e.g. smelter), whether a facility has onsite generation and/or whether storage capacity is available (e.g. stockpiles or storage). In many cases, the costs of implementing DSM for a few hours per year is well below the RCP. However, if DSM is required to provide the same level of availability and reliability as dispatchable generation (e.g. 24 hours, 365 days a year), these costs can become prohibitive.

In the above cases, capacity prices are a relatively minor consideration in determining investment from these sources. However, for peaking plant (such as MEPS) with relatively low capacity factors (less than 20 per cent), capacity prices are a critical revenue stream for these technologies. This is especially the case in the WEM where the energy price caps are relatively low.[10]

Typically, peaking (gas or diesel) units have 25-year lives and generation developers will assess future capacity revenue streams over the asset life. Developing capacity pricing approaches that results in high capacity price volatility will result in generation developers making conservative (worst case) revenue projections. As a result, it is less likely that projected plants will not achieve the required financial hurdle rates (i.e. WACC) and will not proceed. This can result in capacity shortages which then results in capacity prices rising

[10] The Maximum STEM and Alternative Maximum STEM Prices in 2017/18 are $351 and $599/MWh respectively.

above the potential costs of new entry. Investment in new plant will eventually occur but is only likely to take place at a premium as investors/debt providers require a higher rate of return to counter the higher price volatility that results from steeper capacity demand curves.

Periodically, existing peaking units need to be refinanced and increasing price volatility can make refinancing difficult as highlighted earlier in our submission. Debt providers have required higher interest rates to refinance plants in the WEM given the uncertainty created by proposed implementation of constrained network access, capacity certification under constrained network access, and steeper capacity demand curves (transitional price formula and proposed capacity auctions).

In our view, making capacity prices highly sensitive to incorrect demand forecasts does not improve market efficiency (i.e. setting low prices for two years in the hope that plant will exit or not enter the market), but does severely punish owners of peaking units that are reliant on capacity prices for recovering the annual capital and operating costs of the plant.

To a large extent, the relatively flat capacity demand curve implemented in 2006 was not responsible for excess capacity in the WEM. Excess capacity mainly resulted from the following causes:

- Incorrect demand forecasts resulted in the Independent Market Operator (IMO) setting Reserve Capacity Requirements (RCR) in the period 2005/06 to 2013/14 that were consistently higher than warranted;
- Allowing Demand Side Management (DSM) to participate in the RCM, and being rewarded on the same basis as long-lived generation assets, despite not providing the same level of availability as generation;
- The Government permitting Verve Energy to bring Muja AB back into service (220 MW of coal fired generation) when forecasts indicated that the plant was not needed to provide energy or meet reliability standards;
- A capacity refunds regime that did not sufficiently penalise old, unreliable plant for being unavailable for considerable periods, therefore not providing an incentive for this type of plant to retire.

Much of the excess capacity that resulted had nothing to do with capacity prices or the price formula. Merredin Energy does not see how the PUO can state the *"fundamental problem…. is the lack of a price response to surplus capacity"* when there were clearly other fundamental problems and drivers. Some of these problems have been addressed (e.g. dynamic capacity refunds and separate pricing of DSM facilities) and have helped to correct the surplus of capacity credits in the market.

Does the PUO want to punish investors in generation plant for market operators getting their demand forecasts wrong (i.e. setting the RCR)? In our view, making capacity prices highly sensitive to incorrect demand forecasts does not improve market efficiency (i.e. setting low prices for two years in the hope that plant will exit or not enter the market), but does severely punish owners of peaking units that are reliant on capacity prices for recovering the annual capital and operating costs of the plant.

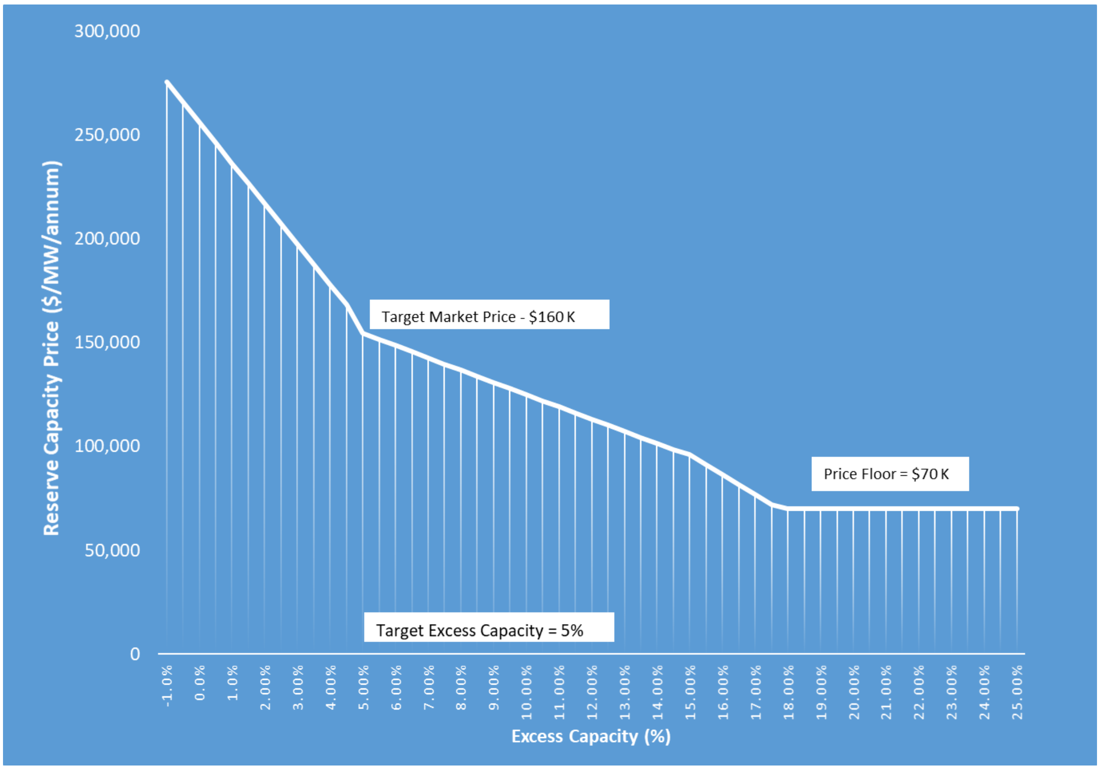
Merredin Energy appreciates that the RCP needs to provide stronger signals regarding the value of capacity when there is a potential shortage and when there is a surplus of capacity. In our view a compartmentalised capacity demand curve (with different slopes) may be appropriate for the WEM. This could include the following:

- The RCP should be able to exceed the BRCP (set at $160,000/MW/annum in this example) if there is a risk of supply shortfalls. For example, if excess capacity is negative (or zero), the RCP can be more than 1.6 times the BRCP (exactly 1.6 times the BRCP when excess capacity is zero).

- We agree with the PUO that the capacity demand curve should be compartmentalised (as outlined below). The slope should be relatively steep until 5 per cent excess capacity (our nominated target level of excess capacity), then should be relatively flat from 5 per cent to 15 per cent, which provides some stability and certainty to market participants. We agree that this would help to mitigate price volatility created by the exercise of market power in this range. Above 15 per cent excess capacity, the capacity demand curve should have a steeper slope to discourage new capacity or encourage plant retirements but should have a price floor set at $70,000/MW/annum. A low price of $70,000/MW/annum should be sufficient to prevent new investment in generation plant or energy storage. It is not necessary to drive prices to zero to achieve market balance.

The following figure shows what are an appropriate capacity demand curve for the WEM could look like that balances price signals for market balance with incentives for plant investment in the SWIS.

Figure 1: Potential Capacity Demand Curve for the WEM ($/MW/annum)



5.5 Technology Neutral, but Dispatchable

As outlined earlier, we agree that capacity credits should be technology neutral but must be dispatchable. That is, the plant can be activated and ramped up or down in response to system operator instructions. Plant that is not dispatchable should not be provided with capacity credits.

The reason we argue for this is that intermittent generation is likely to increase significantly in the SWIS (e.g. rooftop PV, large scale solar and wind). As a result, peak demand for dispatchable generators is likely to change significantly in future years and become less certain (time of day, week and season). In addition, the RCR is also set to accommodate the loss of the largest unit in the SWIS, which could occur at any time and will require plant to be dispatched to ensure supply can be met.

In the past, most of the capacity credits have been provided by dispatchable generation (e.g. coal, gas-fired and distillate plant) and with excess capacity in the market, there has been plenty of dispatchable generation on hand to deal to with unexpected demand increases or loss of generation plant or transmission assets. This is not likely to be the case in the future as intermittent generation makes up a higher proportion of WEM capacity and changes to the RCM ensure market balance on average. In this scenario, managing variations in demand and/or supply will become more difficult and the system operator will need plenty of dispatchable generation to deal with these contingencies.

Obviously, there is some capacity value associated with DSM facilities and intermittent plant that helps reduce peak demand (i.e. 1 in 10-year peak demands). But in the future, this type of capacity will provide less value in managing variations in demand and supply. Instead of awarding this technology capacity credits, these technologies could be used to reduce a retailer's (or customer's) Individual Reserve Capacity Requirement in the same way that energy efficiency or rooftop PV reduces peak demand for retailers. Demand reductions by some major customers at peak times in the SWIS are currently being used to reduce IRCR's in the WEM.

Intermittent facilities in combination with energy storage may be entitled to earn capacity credits since they are dispatchable. This would provide an added incentive for renewable developers to look at options to firm-up energy supplies, which helps to improve energy security and reliability in the SWIS.

6. Our Response to Specific Issues Raised by the PUO

1. **How the pricing approach would provide value for the consumer?**

   Our preferred approach of administered pricing arrangements will help mitigate market power concerns in the WEM and reduce entry barriers for generator and retailers in the WEM. As outlined in our submission (Section 5.2), administered pricing can also result in *"market discovered"* prices in the same way that capacity auctions result in market prices.

2. **How the pricing approach would replicate a competitive price for capacity?**

   The Benchmark Reserve Capacity Price (BRCP) is based on AEMO's understanding of the costs of new generation technologies (usually informed by engineering consulting studies). This can provide an accurate estimate of the cost of new entry (CONE). A downward sloping capacity demand curve can be used to signal to capacity providers (via the RCP) that additional capacity is valued less that the BRCP and provide incentives for plant retirement or deter new plant entry.

3. **How the pricing approach would operate in scarcity and surplus capacity situations?**

   A compartmentalised capacity demand curve can be designed (see Figure One in Section 5.4) that would be used to signal the high value of capacity when excess capacity is low and used to signal that capacity has a relatively low value when excess capacity levels are high.

4. **How would the pricing model attract capacity when additional capacity is required and discourage capacity when capacity is not required?**

   A compartmentalised capacity demand curve as shown in Figure One in Section 5.4.

5. **How would demand side capacity resources participate under the pricing approach? How should these resources be priced?**

   DSM and intermittent generation should not participate in the RCM unless they can meet all of the same obligations as dispatchable facilities. This should include:

   - Able to provide capacity at any time on the grid (24 hours/7 days a week);
   - Able to provide 14 hours of continuous energy to the grid on a given trading day;
   - Able to deliver energy for a minimum of 3 consecutive trading days;
   - Meets minimum outage requirements for a class of generator;
   - Multiple pathways for power to be delivered to load centres on the Western Power Network (i.e. not vulnerable to network failures);
   - Has a network access contract in place that permits the plant to operate at its maximum capacity when called upon by the market operator. This could occur at any time due to the changing nature of peak demand in the SWIS (e.g. peak for dispatchable generation is moving into the early evening due to the increased penetration of solar plant in WA) and potential energy infrastructure disruptions (e.g. generator, transmission, gas supply infrastructure etc.).

   However, DSM facilities and intermittent plant (without storage) can be used to reduce a market customers IRCR. This is effectively what retailers are doing when customers are curtailed to reduce peak demand (either to reduce contract network demand or their IRCR) and when customers install rooftop PV.

6. **What would be the advantages and disadvantages of the pricing approach compared to the current Reserve Capacity Mechanism pricing arrangements?**

   Merredin Energy supports continuation of administered pricing arrangements. In a small, isolated and peaky electricity system, centralised pricing and trading arrangements have the following benefits:

   - Mitigate misuse of market power by incumbent suppliers (e.g. Synergy)
   - Reduce entry barriers for smaller retailers (don't need to procure capacity on long term contracts)
   - Promote transparency and liquidity in the market, which is important for encouraging future investment in dispatchable plant in the WEM.
   - Capacity demand curve can be designed to encourage market balance (i.e. compartmentalised capacity demand curve) without the volatility that may result from an auction process – especially if incumbents have substantial market power.

7. **Would this pricing approach provide sufficient transparency regarding the capacity price?**

   This is one of the principal advantages of a centrally administered pricing arrangements.

8. **Would this pricing approach promote sufficient market liquidity to support new retail entry?**

   As argued above, centrally administered RCM can encourage market liquidity (trade in capacity credits) and reduce barriers to entry for new entrant retailers in the SWIS.

Regards,

John Delicato

General Manager

Merredin Energy