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19 September 2018

Mr Matthew Martin
Director, Wholesale Energy Markets
Public Utilities Office / Department of Treasury
David Malcolm Justice Centre
28 Barrack Street
PERTH WA 6000
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Dear Matthew,

Response to Consultation Paper: Improving Reserve Capacity pricing signals – a proposed capacity pricing model

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. Merredin Energy concerns with alternative capacity pricing approaches

As outlined in our previous submissions to the Public Utilities Office[1], Merredin Energy was opposed to moving away from administered pricing arrangements. In our view, the alternative

[1] Merredin Energy, Response to the consultation paper: Improving Reserve Capacity pricing signals – alternative capacity pricing models, 4 May 2018

approaches considered by the PUO, that is capacity auctions or retailer-led contracting (i.e. retailer requirement to secure capacity credits to meet reliability obligations) would not result in efficient outcomes in the WEM, nor would they be bankable for investors and debt providers to underwrite future investment in dispatchable generation in the SWIS.

The principal concerns that Merredin Energy had with these approaches to capacity pricing were the following:

- 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 high market concentration in the WEM raises significant competition concerns. 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).[5] This implies that an array of market power mitigation measures needs to be put in place to ensure that the outcomes from both capacity auctions and retailer-led contracting 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.
- 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 lack of liquidity and market transparency under retailer-led contracting, and the uncertainty of outcomes under a capacity auction mechanism implies that the RCM would no longer be bankable on a project finance basis. 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.[6]

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.

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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 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.

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

3. Proposed changes to administered capacity pricing approach

Merredin Energy is generally supportive of the preferred approach, outlined in the PUO's paper (August 2018), to retain administered capacity pricing with a modified pricing formula and transitional measures to ensure that enough dispatchable generation remains in service in the SWIS to meet future reliability requirements. Our views on the proposed price formula and transitional measures is outlined in the following sections.

3.1 Proposed capacity pricing formula

The proposed convex capacity price curve will have the following features:

- Price Cap – the capacity value associated with no capacity surplus, to be set at 1.3 times the Benchmark Reserve Capacity Price (BRCP).
- Absolute zero point – the point where the amount of excess capacity is deemed to be sufficiently high for the capacity price to be zero, set at a 30 per cent level of excess capacity.
- Economic zero point – a level of capacity surplus and price at which no additional resources should enter the system under a very wide range of market conditions, set at a capacity price equal to 50 per cent of the Benchmark Reserve Capacity Price and at a level of excess capacity of 8 per cent.

Regarding the Price Cap, the price must be sufficiently attractive to incentivise new investment otherwise risk capacity shortfalls. We agree that at zero excess capacity, prices should be a multiple of the BRCP. Setting a price equal to the BRCP (annualised cost of new entrant plant) may not be enough to encourage investment in a timely manner. Equally, setting a high price (say 1.8 times the BRCP) provides incentives for large, integrated retailers (i.e. own generation) to withdrawal capacity or delay investments in new capacity to drive capacity prices to the Price Cap. In our view, setting the RCP at 1.3 times the BRCP looks too low to incentivise new investment in OCGT plant which is reliant on revenue from the capacity market.

Merredin Energy would be less reluctant about the Price Cap settings if the methodology for setting the BRCP more accurately reflected the cost of new entrant generation.

The BRCP is set with reference to a 160 MW Open Cycle Gas Turbine (OCGT). However, demand growth in the SWIS has been historically much lower on an annual basis and units of this size have not be built in recent years. A more appropriately sized benchmark generating unit should be used (i.e. 30 to 50 MW) in the calculation of the BRCP.

In previous BRCP determinations, the AEMO has used negative real rates of return when calculating the WACC used to annualise the capital costs of OCGT plant. For example, in the 2019-20 price determination, a real risk-free rate of return of -0.26% was used in the calculation of the WACC. A negative risk-free rate of return makes no sense to Merredin Energy given other sectors of the Australian economy are making significant real returns (as reflected by increases in the All Ordinaries stock index in recent times). These methodologies are depressing the BRCP well below the actual cost of new entrant generation and could deter future investment in dispatchable plant in the SWIS.

Merredin Energy strongly advises that these issues be addressed as part of the AEMO's 5-year annual review of the BRCP methodology.

Merredin Energy understands that at high levels of excess capacity the value of capacity to consumers is effectively zero and that a strong signal needs to be provided to market participants not to invest in any additional capacity. However, setting the absolute zero point at (say) 10 per cent excess capacity could result in highly volatile capacity prices, which would not be bankable for existing generators and new generation projects. Equally, not having an absolute zero point could encourage additional investment in new capacity which is not valuable to consumers. In our view, setting the absolute zero point at 30 per cent excess capacity balances these trade-offs and is supported by Merredin Energy.

As outlined in our earlier submission to the PUO (May 2018), Merredin Energy was supportive of a convex capacity price curve. The PUO has suggested that the inflection point (i.e. change of slope for the curve) occurs beyond 8 per cent excess capacity. Having a steep capacity price curve provides incentives for participants to withdrawal or delay investment in new capacity, while a flat curve provides incentives for participants to keep investing in capacity when it is not required.

In our view, an 8 per cent level of excess capacity is highly likely in the WEM for several reasons.

Firstly, the WEM is a relatively small market and new investment in generation or DSM facilities can make a substantial difference to the demand and supply balance in the WEM. Significant investment in new capacity and incorrect demand forecasts (i.e. demand is lower than expected which has been the case for many years in the WEM) could result in the 8 per cent level being exceeded.

Secondly, permitting DSM to participate in the RCM and additional investment in renewable energy in response to the Large-scale Renewable Energy Target (LRET), implies that at least 1000 MW of new capacity will enter the market by 2023-24. This could result in around 450 MW of additional capacity credits being created. In the absence of plant retirements, this could result in the level of excess capacity exceeding 8 per cent for several years, with prices falling below 50 per cent of the BRCP. At these prices, MEPS would no longer be financially viable in the WEM and the plant would have to be decommissioned or re-located to a higher value market in Australia (e.g. South Australia).

Thirdly, the capacity price elasticity for some capacity investment types is highly inelastic. DSM facilities are typically the cheapest type of capacity in the market. These facilities are likely to be able to participate in the market even if capacity prices are below 50 per cent of the BRCP (e.g. $75,000/MW/annum). In addition, renewable energy and baseload facilities earn the bulk of their revenues from environmental (e.g. sale of large-scale generation certificates or LGCs) and energy markets. Future investment in this type of plant is not likely to be highly responsive to capacity prices.

In our view, the inflection point can continue to occur at 8 per cent excess capacity, but the resultant price at this point should be around $100,000 per MW (i.e. EZ BRCP Factor of 0.65, not 0.5) to ensure that the only generation that is highly sensitive to capacity prices (i.e. dispatchable peaking plant) is not incentivised to exit the market.

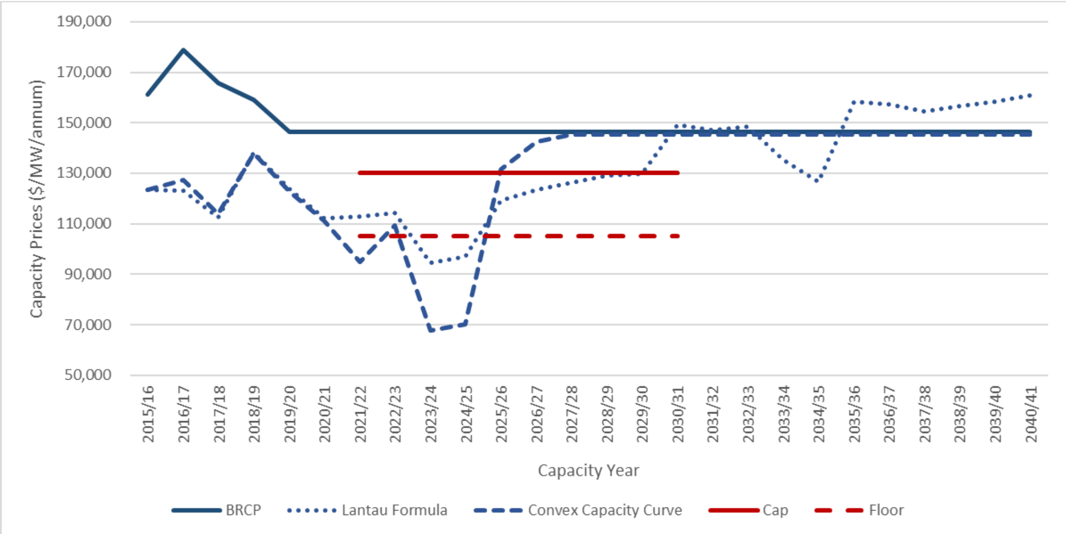
3.2 Transitional arrangements (price band)

The PUO has acknowledged that the proposed capacity price curve does impose additional risks on incumbent generators and has recommended that transitional arrangements be put in place for 10 years. The transitional arrangements involve establishing a price band for existing generation facilities between $105,000 and $130,000 per megawatt (Consumer Price Index (CPI) adjusted) for a period of ten years. It is our understanding that the price band would be mandatory for incumbent generators – i.e. they can't opt for a "floating" capacity price.

In addition, new entrants would have the option to take the floating capacity price in each capacity year or to lock in the price in the year of entry for five years.

In our view, the price floor of $105,000 per MW per annum is likely to be binding for several years. Permitting DSM to re-enter the RCM, committed and likely investment in large-scale generation facilities, with limited future plant retirements in the WEM would result in capacity prices below the price floor for several years. Our future forecast of likely capacity prices is shown below, along with the results under the existing capacity pricing approach (Lantau Formula).

Figure 1: Potential Capacity Price Outcomes under Proposed Approach ($/MW/annum)



As mentioned earlier, several years of capacity prices that are below $100,000 per MW per annum would result in the closure and/or re-location of MEPS. In our view, it would also result in the closure and/or re-location of other diesel and gas plant in the SWIS.

Unfortunately, the price floor which has been set at $105,000 (real 2018 dollars) would not prevent this situation from arising either. The minimum sustainable price to enable MEPS and other diesel and gas plant to operate in the SWIS is between $125,000 to $135,000/MW/annum. This is the level of prices that is enough to pay interest on loans and provide a minimum return to equity investors. Merredin Energy would be happy for the PUO to review MEPS finances to understand the minimum return that is required by our plant to remain in the WEM.

In our view, the price floor needs to be set at around $130,000/MW/annum to ensure that peaking plant remains in the WEM. The transitional price cap should be increased to $145,000 per MW, which is just below the BRCP of $153,600 per MW.

One of the significant disadvantages with the price band is that it will encourage older, inefficient generators to remain in the market for longer, which will then help depress capacity prices when DSM facilities and renewable plant enters the SWIS. Is it reasonable that plant which is over 30 years old, and closer to 40 years in the case of Muja C (currently 37 years old), should be subject to the protection of the transitional arrangements? All debt on the initial investment in these units has been repaid and the avoided costs of retaining these plants in service is relatively low (around $60,000/MW/annum). In addition, Muja C and D are baseload coal plant that earns most of its income from the energy market.

In our view, plant which is over 30 years of age should not be subject to the protection of the price caps. They should be subject to the floating capacity price and will assist Synergy to take a commercial approach to whether existing plant should be retired, while actively investing in large-scale wind and solar farms in the SWIS (e.g. Warradarge wind farm and Greenough II solar farm).

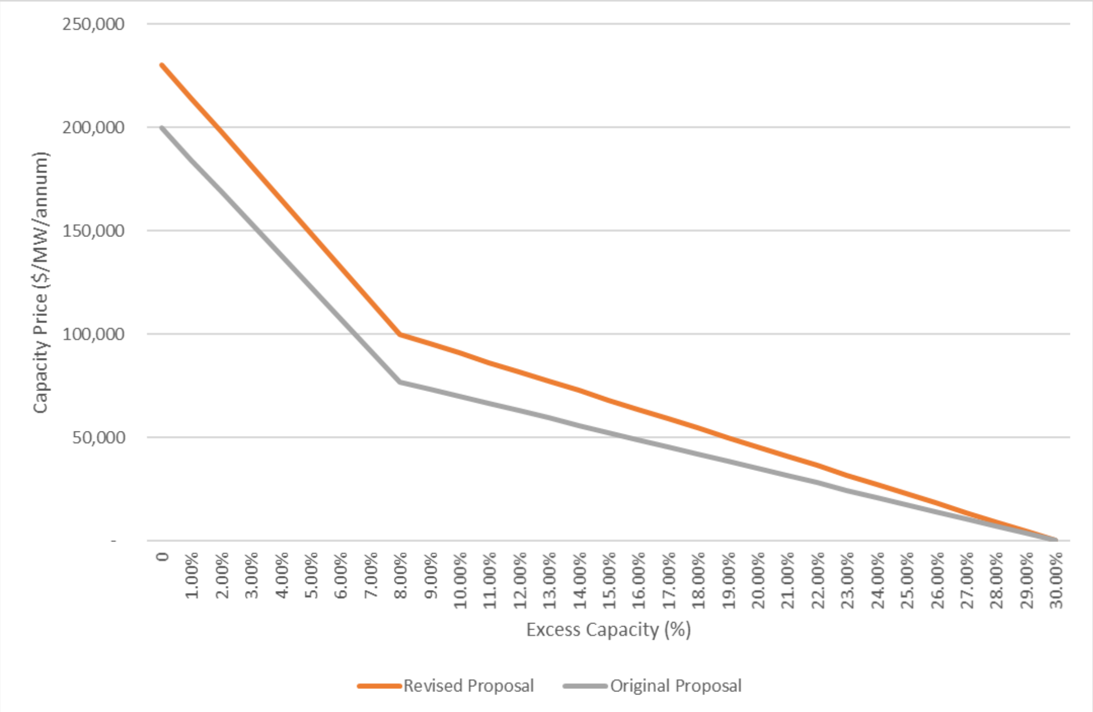
4. Preferred Capacity Pricing Model Parameters

Merredin Energy is generally supportive of the proposed capacity pricing approach outlined by the PUO (August 2018). However, to ensure the mix of generation that is both efficient and can maintain reliability of supply in the SWIS, we make the following suggestions:

- The Price Cap should be set at 1.5 times the BRCP.
- The inflection point in the capacity price curve can occur at 8 per cent excess capacity, but the EZ BRCP Factor should be increased to 0.65 (i.e. RCP at this point is 65 per cent of the BRCP). This will help increase resultant prices and ensure that the only generation that is highly sensitive to capacity prices (i.e. dispatchable peaking plant) is not incentivised to exit the market if excess capacity increases to relatively modest levels of 4 to 6 per cent (which is highly likely to occur). The resultant RCP (assuming BRCP is $153,600 per MW) is $132,480 per MW at 6 per cent excess capacity. This is close to the minimum price required by recently installed peaking plant (i.e. OCGT and diesel generators) to meet interest payments to debt providers and provide a minimum return to equity investors.
- The transitional price floor needs to be set at around $130,000/MW/annum to ensure that peaking plant remains in the WEM. The transitional price cap should be set at $145,000/MW/annum, which is below the BRCP of $153,600 per MW.
- Plant that is more than 30 years of age should not be subject to the price band since this would encourage plant to remain in service for longer and further increase the level of excess capacity in the WEM.

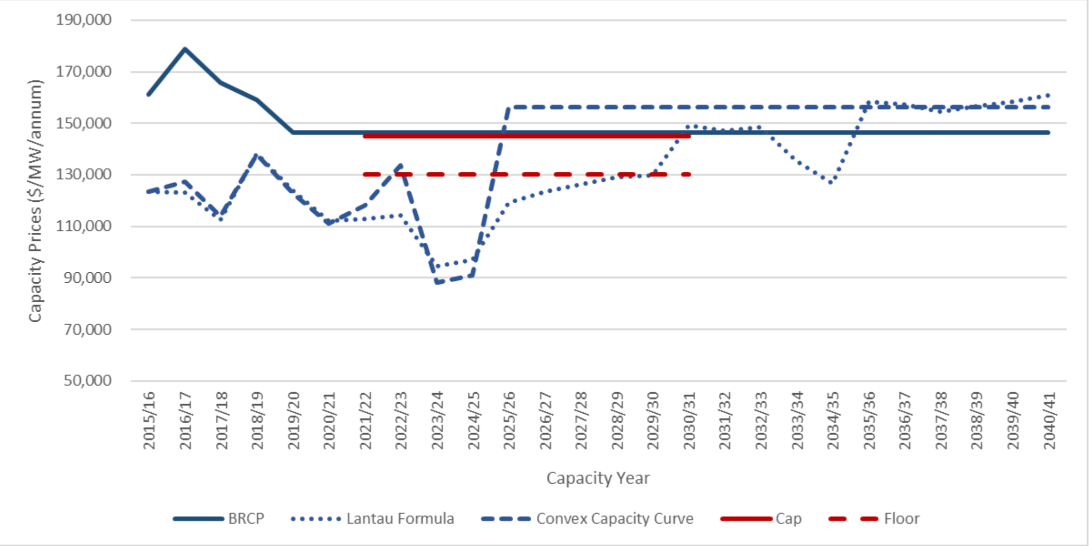
Under our proposal, the likely trajectory of future capacity prices is shown below.

Figure 2: Revised Capacity Pricing Model ($/MW/annum)



Under our proposal, the trajectory of RCPs is shown below assuming the expected demand case under the 2018 ESOO and committed and likely future investments in renewable energy and demand side management facilities occurs (same assumptions underpinning the previous RCP forecast in Figure 1). The major difference between the price forecasts in Figure 1 and Figure 3 is that the long run amount of excess capacity is 4 per cent under this scenario, while it was assumed to be 3 per cent in Figure 1. At 4 per cent excess capacity, the market price is just above the BRCP price of $153,600 per MW – a price that could be expected to occur in the longer term.

Figure 3: Potential capacity price outcomes under Merredin Energy's revised capacity pricing Model ($/MW/annum)



Regards,

John Delicato
General Manager
Merredin Energy