Group Manager, Market Development
Independent Market Operator
Email: market.development@imowa.com.au

4 October 2011

Dear Sir/Madam

Five Yearly Review of the Methodology and Process for Determining the Maximum Reserve Capacity Price Submission

Perth Energy believes the proposed change to the MRCP calculation is detrimental to the Market Objectives as it would threaten the long term competitive cost of supply to consumers in the SWIS. Our concerns are due to two main aspects:

1. The proposed change is based on flawed approaches to key cost components of the MRCP. These lead to an unjustifiable 24% reduction in the MRCP that would threaten the credibility of the IMO. Stability and robustness in the MRCP setting mechanism are paramount to maintaining investor confidence in the WEM. The shallowness of the technical arguments in support of the proposed change, and the lack of review and scrutiny at MAC and stakeholder level following the working group period, gives the impression of the IMO either not in control of the process or taking a knee-jerk reaction to its misperception of the capacity surplus situation in the market.

2. The dysfunctional approach to capacity pricing mechanism review where the MRCP setting methodology is proposed to be drastically changed now while other important features of capacity pricing are still under review. If MRCP determination is designed to work within the broader capacity pricing framework to efficiently bring new capacity to market as per Market Objectives, then a comprehensive review should be done before proposing any change. There is no point rushing through some limited modification to the MRCP procedures, but with significant impact on the resulting MRCP, and shocking the investor market when the outcome of the comprehensive review may well point capacity pricing in an opposite direction. This would compound market instability in the near future.

For instance, a fuller review would and should question why capacity pricing still adheres to a 15% discount to the MRCP to derive the first-order Reserve Capacity Price (RCP), with this price being adjusted down further for surplus capacity in the system. If IMO does its job adequately and compiles an accurate MRCP (ie cost based capacity price) in the first place, then there would be no need for an automatic 15% discount to hedge against errors.

On the other hand, in a situation of projected capacity shortage, IMO would go for an Auction as prescribed under the Rules, in which case IMO would pay a full bid price – the MRCP – without discount and for a 10-year term. To protect consumer interest, IMO presumably would prefer to be prudent and try to secure sufficient initial bid capacity without having to go to an Auction and having to offer 10-year term support to Auctioned capacity. An MRCP price shock is then not the way to go about securing initial capacity or Auctioned capacity for that matter.

t (08) 9420 0300 f (08) 9474 9900 w www.perthenergy.com.au
level 4, 165 adelaide tce, east perth, wa 6004 acn 87 386 445

MRCPWG and excess capacity

The MRCP Working Group's objective was to put up a methodology that would 1) provide a reasonable return to a marginal Open Cycle Gas Turbine (OCGT) plant of 160MW as per Market Rules if this plant were to be called through an IMO Auction, and 2) give a reasonable cap price at which the IMO could use as benchmark to call such an Auction.

In this regard, the Group's work result has failed to satisfy the objective due to its limited work on a narrow number of items that make up "reasonable return" to an OCGT.

Further, while the MRCPWG may have been given a certain technical review role, the conclusion had perhaps already been drawn even before the work started that the MRCP might have been too high, based on the expressed IMO concerns over excess capacity in the market at its presentation on 20 July 2011.

Our view is IMO had misunderstood where this short term capacity surplus came from and as a result has been pointing its mitigation effort in the wrong direction.

Network connection cost

The SKM report investigates the DCC charging options with the recommended one being a weighted average of historical costs with more weighting towards more recent years. Adopting this approach would lead to a 58% fall in DCC cost, and if used in conjunction with the lowest cost debt scenario in the PwC report, would lead to 24% fall in the MRCP for 2014-15 compared with current methodology – a purely regulatory risk with little evidence of market factors involved.

A key concern with the existing MRCP methodology was the potential volatility resulting primarily from the method used by Western Power to provide an estimate of DCC. Weighting of network connection costs using several years of data, as proposed by SKM, would reduce the volatility of any movements in network costs.

However, there was only one sharp rise in DCC estimates from Capacity Year 2011-12 to 2012-13. Western Power had stated repeatedly that the transmission network was full and any new 160MW OCGT would have to pay full connection cost. The utility actually produced similar DCC estimates for the following Capacity Year 2013-14 based on its current system planning and ERA approved capital contribution policy. Any attempt now to introduce a simplistic, non-expert formula to "smooth" DCC, with a 58% reduction in these estimates, would be "fighting the last war" and restarting the DCC instability cycle without basis.

There is no reason to believe DCC for 2014-15 will be less than the previous 2 year's DCC as quoted by Western Power in the MRCP process, especially when the marginal 160MW OCGT is assumed to be able to be placed at any location in the SWIS, not just confined to the lowest cost location. Western Power has stated as much throughout the MRCP review exercise.

The proposed approach is backward looking and is bound to be inaccurate given the step change in DCC estimates that has been made. It is also bound to miss the business cycle – either its result would be too high or too low but never matching actual DCC. The proposed methodology creates risk that at any point the allowance for network connection costs will differ substantially from actual costs. If the estimate of DCC does not parallel its reality, the estimate would become irrelevant and so would be the MRCP.

If attempt at reducing DCC volatility would cause a sharp decline in, and therefore a sharp rise in instability of, the MRCP procedure then adopting such a DCC estimation approach would be self defeating, especially with the ongoing risk of the DCC estimates increasingly diverging from the actual DCC, compounding volatility in the MRCP over time.

Reform in the electricity market over the last 10 years has focused on getting price signals right. Industry and Government have worked hard to get to this ultimate result that the cost of generating and supplying power be reflected truly and accurately to consumers. Adopting the proposed change in DCC would set back cost-reflective pricing years.

Capital expenditure issues

The PwC report considered whether the existing assumption about the timing of the capital expenditure was correct. Currently, the implicit assumption in the MRCP procedure is that all of the capital costs are incurred two years prior to the commencement of Capacity Year. The PwC report attempts to show that using first principles, the likely "allowance for funds used during construction" is close to that given by a "rule of thumb" that assumes a linear capital expenditure profile, with an effective compensation period of 6 months.

This is out of touch with real project financing and construction. A simple check with any generator that has delivered projects in SWIS since WEM start would show financing cost is front-loaded and construction and delivery of a peaking power station has been 2 years and baseload much longer, with payments also skewed to the front end.

Our own experience is that capital expenditures are usually three-quarters spent by half mark, ie end of first year with one year to go, since deposit and then full payment for plant and equipment, which make up more than half the total cost of a power station, have to be effected early in the order and manufacturing process.

The plant delivery time frame and front-loaded capex schedule require the effective compensation period to be at least 14 months.

The 11% discount applied to the full cost of a power station as a result of one component, the inlet air cooling, being included while ignoring all other technology-versus-cost changes to a total power station package is inappropriate.

There are revisions year on year to the cost of a "standard" GT package and the full cost of such a package needs to be compiled each year as it stands. Eg, past packages would have included full external electrical cabling for the control system while new packages do not anymore. Taking one component and assigning a single change to the total cost of a past package is the wrong way to determine the full cost of a package at any point in time. If there are supportable changes to the full cost, they will as a matter of course show up in the process of IMO costing a new 160MW OCGT for a particular year's MRCP.

This 11% discount is not justifiable as a stand-alone item and should not be adopted as proposed.

On the other hand, the following areas need addressing:

- Fuel infrastructure and (fixed) transportation costs covering both gas and liquid fuels for a dual-fuel power station. A dual-fuel power station provides better security of supply to the system by providing a higher certifiable capacity level on gas but is certified only on liquid fuel capacity that is lower than gas based. Lower emission when a dual-fuel plant is run on gas is of further value to the market. A Market Objective is to avoid discrimination against technologies that deliver lower emission to the market.

- The WACC as currently applied is low. The risk premium for equity is shown in the PwC report to less than the risk premium for debt, resulting in the cost of equity being 10.57% against cost of debt of 10.84% on a pre-tax basis. There is no basis for this or for thinking that equity could be obtained for less than 15% in SWIS. While the WEM Capacity Market provides a level of security in revenue, the other side of the coin is that it carries high risk in price volatility and capacity refunds, which could concentrate significant losses within a short period of time. This could cause irreparable damage to a power station's earnings in a full year with ramification for the plant's long term viability. IMO should be mindful of these real market risks, which have manifested themselves in the SWIS, before stripping any simplistically perceived margin from generation projects by deliberately driving the MRCP down.

Auction

An Auction scenario as provided for in the Market Rules will unlikely happen in reality. There has not been an Auction in the WEM and there will not likely be one. The current Capacity Certification timeline does not realistically allow for an Auction to ever be called. Generation project developers have to spend about 2 years preparing to take a project to unconditional project finance by July each year in order to apply for Certification. Upon confirmation from IMO by late August, the developer will have to put up security deposit equivalent to 25% of the first year's total Capacity Credit revenue. For a 160MW plant this security deposit would be approx $6 million at current Reserve Capacity Price.

No projects that could be certified within a current year's time frame would hold back from seeking Certification in July in order for project owner to take a punt on bidding into an Auction that might or might not happen, ie that would not be known until after IMO had allocated Capacity Credits for the year.

The project development costs to the point of a July Certification application would have been substantial given the long lead time for land, network access, environmental and various other approvals, and most critically project finance, which needed to be confirmed in order for a developer to obtain the security deposit facility. Such costs would not be incurred on the basis of taking a punt on whether IMO would call an Auction in November or not. A project ready for an Auction would have been bid into the July Certification process to secure Capacity Credit allocation.

At most, if some shortfall in forecast capacity did materialize for any reason, an Auction might be able to squeeze out incremental capacity from existing plants. Under this more realistic scenario, maybe a 10-year contract with IMO for incremental capacity could come to fruition. Otherwise, it is not feasible for a stand-alone 160MW OCGT to be prepared for an Auction, hence the 10-yr contract pricing scenario should not even be considered at all. All debt profiles should be based on the year-by-year RCP revenue, which is exactly what investors have borne since WEM start.

This picture points to 2 scenarios:

1. The improbability of IMO ever carrying out an Auction would make an attempt to set an MRCP for the purpose of providing a cap price for such Auction redundant. The MRCP is in reality a cost based indicator price for investors to make a decision whether to prepare a project for Certification application in July each year or not. It is imperative that the MRCP be set based on true costs. Using an arbitrarily driven process aimed at reducing it in reaction to a short term excess capacity situation in a highly capital intensive market with lumpy investments is fraught with danger.

2. If IMO ever needed to call an Auction, incremental capacity would require full cost MRCP without discount, as a discount is neither provisioned in the Market Rules nor can be realistically considered in a capacity shortage situation. Any attempt to lower the MRCP artificially would not be acceptable to bidders.

WEM not yet truly tested

IMO's concerns over the current (short term in our view) state of surplus capacity should be balanced by a proper look at WEM's capacity composition. WEM has not truly been tested in terms of it being able to bring in private sector investment in large scale generation for retail competition purposes – a key Market Objective.

Up until now the only substantive plant that has been built for and by a stand-alone private entity for retail purposes is Perth Energy's Kwinana Swift power station. All other substantive power stations built in the SWIS under the auspices of the WEM have been done with underwriting by incumbent State utilities or major resources projects that were not that different to those power plants that had been set up to supply mining projects in the old monopoly structure days – the so called self-supply power projects.

The following table evidences this view:

Substantive Power Stations	Underwriter/sold to	Size
Newgen CCGT Kwinana	Synergy	320MW
Walkaway Wind Farm	Alinta	90MW
Kwinana/Pinjarra/Wagerup	Alcoa/Alinta	593MW
Bluewaters 1	Boddington/Water Corp	216MW
Bluewaters 2	Synergy	236MW
Emu Downs Wind Farm	Synergy	80MW
Neerabup OCGT	Synergy	330MW
Kwinana Swift	Perth Energy	108MW
Collgar Wind Farm	Synergy	90MW
Total		2063MW

Of the total 2063MW, 1056MW or 51.2% is underwritten by Synergy, 683MW or 33.1% by Alcoa/Alinta and 10.5% by Boddington, the largest gold mine in the SWIS. Just 5.2%, Perth Energy's Kwinana Swift, is built for general retail purposes by a third party new entrant.

This means the WEM has not been truly tested for new generation entry without being underwritten by dominant incumbent, State owned utilities or the few largest loads in the SWIS. There is no evidence yet that the general contestable market, the SME market, under the current structure, will be able to bring in new substantive generation capacity to enable genuine retail competition to be sustainable.

For this Market Objective reason alone IMO should refrain from making Rule or Procedure changes that could destabilise the capacity market and deprive retail based generation entry. The setting of MRCP cannot be divorced from this reality.

Demand Side Management and excess capacity

The second key restraint on any MRCP methodology change as proposed by IMO is IMO's own mistreatment of DSM capacity.

A large part of the current so-called excess capacity is due to DSM "capacity". Besides 190MW of DSM currently available, another 250MW-odd is being projected to become available in the next few years. But DSM is not equivalent to generation capacity. A power plant is an investment for the sole purpose of generating power, so its alternative value is close to zero. Once built, a power plant is locked into supplying SWIS and will remain open for business as long as it could sell energy and capacity above its marginal cost. Its supply security value to SWIS is absolute since it is a sunk investment for SWIS.

DSM capacity is not generation capacity but industrial and commercial production capacity equivalent. The marginal cost of production is not what it receives from WEM but from its owners' product markets. The marginal value to DSM capacity is its unit revenue from product markets unrelated to power supply and demand in SWIS. The security of DSM capacity is not based on what WEM can offer at the margin but on what its product markets worldwide can offer at the margin. These markets' conditions determine whether DSM capacity will be honoured, hence its supply security value to WEM/SWIS is unknown.

Evidence of this fundamental difference in value could be observed during the 2000 crisis in California, where hundreds of DSM contracts were not honoured by DSM customers as these refused to interrupt their power demand and continued to consume throughout the crisis. Even when the System Manager had the technology to interrupt remotely the DSM loads – a condition that is critically not required in WEM to be classified as DSM – the potential political fall-out in cutting supply to high priority loads such as hospitals and emergency or disadvantaged facilities, or schools and colleges or other "sensitive" customers prevented the System Manager from activating interruptibility.

DSM is an ancilliary service that should be negotiated between the System Manager and DSM owners. The price payable for dedicated power generation in SWIS and that for DSM must differ to account for this critical difference in value to SWIS/WEM.

Further, as DSM capacity can be garnered at much lower cost than developing and building new power generation plant, and can be dispatched at lower cost than that for peaking plant, DSM capacity should be dispatched first before peaking plants are called on in any constrained supply situation.

Mixing DSM with actual generation capacity leads to the lowest common denominator detrimental to the capacity market. By clearly and accurately measuring DSM's value and risk to WEM, a price could be developed to encourage optimal DSM provision in SWIS.

Energy balancing cost for intermittent capacity and excess capacity

IMO has proposed changing the Certification factor for intermittent renewable energy generation capacity due to concerns that wind farms in particular are currently assigned too high a factor. This perceived "generous" Certifiable capacity factor is seen to have caused too much entry of wind capacity.

However, renewable energy capacity entry has clearly been encouraged by the advantages of 1) renewable capacity being given intermittent (non-dispatchable) status, and 2) not having to pay for full energy balancing and load following costs. Changing the way energy balancing and load following costs can be transparently paid for by intermittent generators would make the change in the Certifiable capacity factor redundant in resetting such entry to what the market can actually bear.

This is another example of looking at the big picture providing us with a more accurate diagnosis for "excess" capacity than being panicked in the short term into changing the MRCP methodology.

Wholesome review needed

A skewed change in the MRCP methodology as proposed, with a dramatic negative impact on the MRCP itself, without substantive evidence would cause a backlash in private sector capacity investment, leading to a potential capacity shortage in 2015-16 or 2016-17 given the unlikelihood of the Auction process materialising as discussed above.

This year (2011)'s Certification results show no new material size generation capacity being committed for 2013-14. We expect the same for 2014-15 due to what can now be seen as a serious regulatory risk from this IMO proposal.

Our view is there is no basis for a significant change in the MRCP methodology or that a high MRPC exists that has brought in excess capacity. There is no excess peaking or mid-merit capacity in the system. Excess capacity is due to flawed treatment of DSM and inaccurate cost assignment to intermittent capacity entry.

A potential shortage in conventional peaking and mid-merit capacity can be foreseen a few years out and this would swing the MRCP significantly upwards next year or the year after, leading to a surge in power costs due to higher cost of capital as a result of perceived regulatory risk.

We recommend IMO undertake a full comprehensive review of capacity pricing as a whole, incorporating review of DSM and energy balancing costs for intermittent generation, before making any decision on piecemeal changes.

Yours sincerely

KY CAO
MANAGING DIRECTOR