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RE: DISCUSSION PAPER: 2012 WHOLESALE ELECTRICITY MARKET REPORT TO THE MINISTER FOR ENERGY

Dear Wana,

Thank you for the opportunity to provide comments on the Discussion Paper released by the ERA on 16 November 2012.

Perth Energy (PE) notes from the Discussion Paper that the 2012 WEM report will focus primarily on the Reserve Capacity Mechanism (RCM). This is timely as PE has significant concerns over past and proposed changes to some aspects of the RCM. PE would also like to provide comments on the new Load Following and Ancillary Services (LFAS) market as well as on some other important aspects of the WEM such as metering, dynamic refunds and increased retail competition.

Our main comments and points of concern are summarised below and then explained in more detail in the attachments to this submission.

- **RCM** - From our own experience of providing peaking plant into the WEM, PE believes that investment capital will not be attracted to providing peaking plant (within a 2-3 year capacity cycle) unless the price for capacity is relatively predictable. It is unlikely that investors will commit to 20 year investment decisions based on the low WACC and inherent uncertainty and lack of commercial rationale in MRCP/RCP determination. The current situation could jeopardise the provision of generation capacity in the future.
- PE acknowledges the ERA's concern over excess capacity in the WEM although suggests this results from an oversupply of 'quasi-capacity' rather than 'true' capacity as follows:
    - the awarding of Capacity Credits that are misaligned with the plant's potential contribution to mitigate peak demand, e.g. intermittent plant and Demand Side Management (DSM);
    - ineffective use of the Independent Market Operator's (IMO) discretion to not certify or partially reduce certification of capacity when the plant has clearly and consistently failed reliability benchmark in the Market Rules; and
    - forecasting of the Reserve Capacity Requirement (RCR) based on overestimated load forecast in recent years due to the mining boom, and so contributes to a widening of the reserve margin, which in turn is seen as part of excess supply although the total cost of that supply to the market has remained unchanged in absolute terms and would have been absorbed had actual matched forecast demand.
- Consequently, PE's suggestions for the RCM are to improve forecasting of the RCR to better reflect actual demand load and then ensure a more efficient allocation of Capacity Credits by the IMO to 'true' capacity plant. The pricing of Capacity Credits should be retained as is (with the existing adjustment for excess capacity). This approach will ensure a continued predictability of returns for investors to supply peaking capacity into the WEM and also utilisation of existing market mechanisms to more efficiently award Capacity Credits to existing and planned plant that provide 'true' peaking capacity.
- As referenced above, PE considers that the retention of unreliable generation plant distorts the market given that the receipt of Capacity Credits for this plant is likely to contribute to it remaining in service. If Capacity Credits were better related to plant availability, the number of credits

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allocated to this type of plant would reduce and so influence the economic decision to decommission.

- **Maximum Reserve Capacity Price (MRCP)** - Any discussion around the Reserve Capacity Price (RCP) and RCM should also include the calculation of the MRCP. PE restates its concerns[1] around some of the inputs to the MRCP, in particular network connection costs and the Weighted Average Cost of Capital (WACC):
    - the current WACC methodology is inconsistent with investors' expectations of the risks involved in building and operating generation plant;[2] and
    - transmission network connection costs continue to be volatile and a significant contributor to the overall level of the MRCP.
- PE would prefer to see a transmission connection cost methodology that reflects the location (and degree of constraint present) of the connection on the network and the type of load to be supplied. Such a change would see the connection costs charged to those users servicing the market as a whole being 'use of system' charges while those servicing special discrete loads would be charged on more of a user-pays, deeper connection, cost. This would remove much of the volatility from the resultant MRCP calculation.
- **LFAS** - The significant increase in costs in the new LFAS market is of concern to PE. PE suggests that the inefficient market outcomes predominantly result from technical issues arising out of System Management (SM), namely:
    - overestimation of the volume of load following; and
    - lack of progress in developing SM systems to facilitate generator participation in LFAS.
- Ideally, the start date for LFAS should have been deferred until actual participation by other generators was possible. In the absence of this, SM should be encouraged to address these two technical issues as quickly as possible to facilitate the entrance of other generators into LFAS such that the anticipated cost reductions from increased competition in this market can be realised.
- **Metering** – PE suggests that provision of metering services could be opened up to competition as the current structure of Western Power owning, operating and reading meters is proving inefficient. A move to open up more services (including metering services) currently undertaken by monopoly network service providers, to contestability, was advocated by the recent Energy White Paper.[3] The current inefficiency of metering service provision is illustrated by:
    - some customers now installing a second revenue quality meter behind the Western Power meter in order to obtain the electricity consumption information they require;
    - Western Power is restrictive in providing meter data and charges high fees to provide data over and above current Code requirements; and
    - Western Power is installing 'smart' meters but without enabling/installing the telemetry to make 'smart' operation possible.

  The lack of timely metering data also affects the IMO's settlement process and so affects all Market Participants.
- **Increased retail competition** –In its review of Synergy's efficient costs and tariffs, the ERA noted that franchise tariffs for non-contestable commercial customers were already above cost reflective levels. As a retailer, PE would welcome increased competition and suggests that contestability for all commercial customers in the South West Interconnected System (SWIS) be introduced as quickly as possible to give these customers a choice of retailer and the possibility of reduced bills as a result. In addition, an indication of the timetable to move to Full Retail Contestability (FRC) in the SWIS, say over the next three years, would be welcomed such that retailers can begin to prepare for this change in the market.
- PE suggests that the residential customer base are already broadly at cost reflective levels. Keeping franchise tariffs unnecessarily high and possibly cross-subsidising the tariffs of the commercial and industrial sectors, which are open to competition, is contrary to efficient market operation, not in the best interests of customers and a serious consideration given the current focus on energy affordability for households and small businesses.
- **Dynamic refunds** – PE supports the idea of dynamic refunds, although not with a suggested 6 times maximum refund multiple nor with the redistribution of refunds to other generators. A 6 times

[1] These concerns have previously been outlined in PE's submissions to the ERA and IMO.
[2] A separate paper on WACC is attached as Appendix B.
[3] Energy White Paper (Nov 2012), p 167

maximum refund retains unnecessarily high project financing costs for no real purpose, and redistribution of refunds to other generators would act to reward generators (again) for a service they are already providing. Instead, PE suggests the ERA looks at 'best practice' in other jurisdictions and allows an outage rate (for example 3% that covers forced outages) below which no refunds would be payable. Anything over 3% would incur refunds which would be payable throughout the year.

- **Ancillary service payment for dual fuel generators** – The Varanus Island gas explosion incident in June 2008 highlighted the importance of fuel security in the supply of electricity in Western Australia. In particular, on that occasion, a significant contributing factor to the continuation of supply in the SWIS was the ability to switch to distillate fuel at dual fired gas / distillate generators. Without that ability, more severe electricity supply restrictions and extended periods of high and volatile wholesale pricing may have been experienced. On the other hand, when supply constraint is caused by factors other than gas supply, continued use of gas at dual fuel peaking plant helps maintain lower than otherwise energy price. Therefore, the ability of a generator to offer dual fuel plant helps with overall system supply security and lower cost to consumers. However, designing and maintaining a dual fuel facility increases both initial capital costs (e.g. certain gas turbine type or feature and additional fuel infrastructure) and ongoing operating costs (e.g. needing to maintain gas transportation contract).

  The current Market Rules do not adequately compensate for the costs of providing dual fuel capabilities. PE proposes a new ancillary service payment for the provision of dual fuel capability. Facilities that qualify for dual fuel status, as per the current criteria contained in the Market Rules, would be eligible to be paid the dual fuel ancillary service fee from System Management.

More detailed comments on the RCM and the Discussion Paper in general and our individual responses to each of the 11 Discussion Points raised by the ERA are listed in the attached Appendix A. We have also attached a separate paper on WACC inputs as Appendix B.

PE may also submit some additional comments on the issues raised in the Discussion Paper under separate cover.

Yours sincerely

Ky Cao

Managing Director

APPENDIX A – Additional comments from PE on the Discussion Paper for the 2012 WEM Report

The Reserve Capacity Mechanism

Prior to addressing each of the discussion points, PE would like to re-iterate its understanding of the objective of the RCM and how it has developed in the first six years of the WEM.

The SWIS is a summer peak system, relatively small, is not interconnected with other networks and does not have a large diversity of generation plant. Consequently, the likelihood of customer curtailment is higher in the SWIS than in larger interconnected systems with less severe summer heat. PE believes that the purpose of the RCM is to ensure there is sufficient generation capacity in the SWIS such that retail customers are extremely unlikely to experience electricity supply curtailment due to lack of generation, particularly at times of peak demand.

For this reason, the WEM design includes the RCM as opposed to being an energy-only market like the National Electricity Market (NEM). From the outset of WEM market design, the RCM has been viewed as:

1) a supply-side mechanism; and
2) an administered process whereby the IMO sets a price for peaking capacity based on a procedure that does not need to consider the total supply and demand balance for capacity in the market.

This is because the WEM is essentially a bilateral contracts market and non-peaking plant can only enter the market commercially under bilateral contracts with Market Customers. The RCP does not (and was not designed to) cover the full costs of running a mid-merit or base load plant.

Being an administered process inherently means that the RCP is not as immediately efficient as a market based outcome. However, for reasons stated above it is believed that the loss of some short-term efficiency is a reasonable trade-off for security in a long lead time industry. In addition, there is already an excess capacity adjustment factor in the RCP procedure to provide adequate price signals to investors. Peaking plant relies on the RCP as its main, if not only, revenue source. Given the semi-regulated return rate accorded investors in the RCM, a relatively small downward adjustment to the RCP can make an investment case unviable for peaking capacity.

PE believes there is some confusion in the understanding of what the RCM is meant to be and this has been driving changes in the Rules governing MRCP/RCP that are not supported by suitable analysis or market feedback.

Over the past six years, a significant amount of private sector investment has been made in the SWIS, on the premise of existing Government policy and on the understanding that the RCM was an administered process for peaking capacity procurement and that the price for that capacity would be relatively predictable by investors according to the Market Rules.

- **PE firmly believes that the RCM should stay as designed until such time as industry and Government are able to agree on clear parameters to move the WEM to a different structure (e.g. an energy only market).**

PE views the current proposals before the Reserve Capacity Mechanism Working Group (RCMWG) to make the RCP 'responsive' to supply and demand pressures as confirmation of the confusion of views over the purpose of the RCM and, if adopted, would only further undermine investor confidence in the WEM.

This loss of confidence is more acute in light of the proposals being, in essence, a subjective judgement as to what the elasticity of the RCP should be. This is evidenced in the unscientific determination of the 'price curve' with the proposed adjustment factor of 3.25-3.75 depending upon a determination of 'surplus capacity'. It is unclear to PE why this band would be preferable to the current proportional change to RCP as illustrated by the excess capacity adjustment factor.

Not only does the proposed adjustment factor not have a rational basis, it is also being proposed in the context of an artificial 'excess capacity' situation. Most of the so called excess is made up of 'quasi-capacity, mainly DSM loads and very old unreliable and fuel inefficient generation capacity that has consistently failed, or cannot be ascertained to meet, reliability criteria as contained in the Market Rules. The ERA has found evidence of such unreliable capacity in the Discussion Paper.

- **PE suggests that the IMO should focus on rectifying the allocation of Capacity Credits to this 'quasi-capacity' instead of advocating for wholesale change in the MRCP/RCP methodology.**

PE's concerns are that when real market conditions are properly reflected to market participants, e.g. through a summer crisis that would expose the false surplus, pressure to amend the MRCP/RCP derivation process will arise again, with all the attendant uncertainty thrown into the market.

General comments on the Discussion Paper

True excess capacity (as opposed to the 'quasi-capacity' discussed above) is not necessarily an extra cost to the market. The generation market is a lumpy investment market for long run cost efficiency reasons and short-term humps are to be expected. SWIS demand has historically grown, on average, by 3-4% on peak and 2-3% off peak[4]. This is equivalent to 100-150 MW peak and just under 100 MW off peak per year.

To take advantage of scale and cost per MW built, a base load power station can easily exceed these growth levels in any given year. The excess capacity will then be absorbed over several years. The point to note is that such short term 'excess' is already accounted for in the current RCP regime by the surplus capacity adjustment factor. This means that, even if the excess is due to a base load plant coming on stream, the RCM is flexible enough to provide signals to investors that further peaking capacity is not needed.

Furthermore, the current surplus capacity adjustment factor provides a cap on the total cost of certified capacity for any given year. Table 1 in the Discussion Paper clearly shows that the RCP is adjusted for the excess capacity in a year.

The ERA has used an example and made an assumption about how much a retailer should/could bilaterally trade capacity. The decision to bilaterally trade capacity is a commercial decision and as such should not be used to prescribe outcomes in the market.

Because the RCP adjusts for excess capacity, it is important to look at the other part of the cost equation. Each year the IMO sets the Reserve Capacity Requirement (RCR) based on its approved forecasting methodology and reliability criteria.[5] However, due to expectations generated by the mining boom, the outcome for the past three years has been a significant overestimation of the load forecast. This is due to large discrete loads such as the Mid-West magnetite projects not being delivered on time. This has resulted in existing customers having to pay for a reserve margin in excess of 50% against the actual system load. In more typical systems, the reserve margin is closer to 30%.

- **PE suggests that the over-forecasting of RCR, along with the inclusion of quasi-capacity (such as DSM and unreliable capacity that should have been decertified or decommissioned) is what has resulted in a significant cost increase to consumers in $/MW and $/MWh.**

In addition, it is worth noting that Western Power charges have increased by around 80% over the 5 years to 2011. As these charges make up 30-50% of total retail price depending on the loads' size, they represent a significant driver of electricity costs in the WEM.

Taking this view means there is no excess supply of 'true' capacity over and above the RCR. The focus on amending the MRCP/RCP methodology in the mistaken belief that this would rebalance market supply/demand conditions is likely to cause damage to the RCM in the years ahead.

Over the cycle of 2-3 years the RCM has worked well through an iterative process that reflected market conditions while avoiding short-term price shocks to investors, which is the whole purpose of a capacity market. The change in MRCP/RCP methodology instigated by the IMO in 2011 for determination of the October 2014 Capacity Year's RCP is, in PE's view, causing potentially a lasting confidence crisis in the market.

There is unrealistic assumption now that the RCM could still encourage suppliers to make 20-year investment decisions based on an annual price adjustment with steep variations and without a price floor. Investors are somehow expected to only be able to make a regulated return that reflects the return on State-owned, revenue guaranteed (in both levels and term) infrastructure assets.

The RCM is intended to incentivise peaking capacity to enter the market within a 2-3 year cycle to ensure there is sufficient capacity to meet forecast demand. The Market Rules refer specifically to a peaking plant of 160 MW in size. However, different types of plant have widely different capital, fuel and maintenance costs and the RCM is unlikely to provide the right price signals for all types of capacity or for the optimal plant mix. But the optimal plant mix can still be achieved as base load and mid-merit plant still enter the market and operate on bilateral contracts as originally designed.

The retention of inefficient plant is a two-faceted issue as we need to distinguish between (i) inefficient fuel use and (ii) plant reliability to the market. Refurbishing or recycling of old plant is more cost efficient than building new plant (e.g. the Joint Venture refurbishing Muja A/B has been reported to have cost the parties $150-200 million to provide 220 MW of capacity, which is much cheaper than building a new coal plant or any other type of base load plant) although its fuel efficiency would likely be less than that of a new plant. PE accepts the rationale in Verve Energy undertaking this refurbishment, part of which is to minimise the commitment term (10-15 years compared to 25-35 years for a new plant) for coal generation.

[4] Notwithstanding a fall recorded last year due to the impact of substantial roof-top solar system subsidies for the residential market.

[5] The IMO has recently had both the forecasting methodology and reliability criteria independently reviewed.

What PE considers market distorting is the retention of old unreliable plant such as Kwinana Stage C – as found in the ERA WEM Report of November 2012. This generator is over 35 years old, highly unreliable, fuel inefficient and has caused Verve to be in breach of its 3000 MW fossil fuel capacity cap. Private sector investment in the WEM has been made on the basis of Kwinana C being decommissioned some years ago as per the cap policy.

Consequently, PE believes that the Government should instruct the immediate decommissioning of Kwinana C and the IMO should pay equal heed to plant that cannot satisfy availability criteria as required by the Market Rules.

Moreover, unreliable plant, including DSM that cannot be guaranteed to be dispatched, adds significant costs to the capacity market as it imposes capacity costs for no real capacity value.

- **PE recommends that the IMO should enforce reliability criteria as per Market Rules and be more stringent around what category of capacity should receive the full RCP.**
- **As an immediate step to eliminate the current discrimination between DSM and actual peaking capacity, the IMO should either require DSM to be nominated in the merit order of dispatch like all capacity or pay to DSM a heavily discounted RCP until DSM could be fully equalised with actual capacity.**

Below, PE addresses each of the Discussion Points in turn.

Discussion Point 1

PE does not believe that an auction approach will correct any issues within the capacity market. As outlined in the Lantau Report, the value of excess capacity quickly approaches zero, whereas the value of capacity when there is a shortage can increase quickly to extremely high values. This 'binary' outcome for capacity supply will not be improved with an auction. In addition, the concentrated ownership structure in the WEM and the relatively large size of generation plant could mean that there is a strong possibility of major players 'gaming' in the event that an RCA takes place.

Second, if the Bilateral Trade Declaration were to be made binding, this is likely to make the RCM process redundant. This, in turn, would mean contracted capacity is left to the market to provide, which would be a very similar situation to the NEM. However, without the interconnection also available in the NEM, this could leave the WEM exposed to capacity limitations, and resultant high electricity prices, in the future.

Third, the auction concept would not work in the real world of project financing. In past submissions to the ERA and IMO, PE has suggested reasons why projects that are being progressed for the purpose of applying for certification in July in a Capacity Cycle would not be in a position to withhold that capacity application in order to bid into an auction (should one be called) four months later in November.

A generation project takes years to reach the stage of satisfying the IMO's requirements for certification, including having secured a site, environmental approval, a network access offer and conditional project finance arrangements, or at least substantial progress towards finalising those conditions.

Investors are unlikely to expend millions of dollars in development capital to progress a project on the expectation of missing out on capacity payment as could eventuate through an auction. Instead, investors would invariably apply for capacity certification in July. Only if they failed to be approved by IMO would they then consider bidding into an auction if one were to be called. Even so, in the intervening four months the likelihood of them satisfying IMO requirements for certification under the auction process would not have improved much at all.

Any auction process should be designed to target predominantly existing plant whose Declared Sent Out Capacity (DSOC) could be quickly raised through an incremental change to the power station output. Such plant could result in having, say 90%, of its DSOC paid via the RCP and 10% through an auction once the additional 10% capacity (implemented following a successful bid to an auction) is delivered to market.

Discussion Point 2

PE does not believe there should be a limit on the capacity procured by the IMO. A limit would create the problem of determining which facilities should receive Capacity Credits and why. It would also mean differentiating capacity based on timing, which is at odds with the Market Objectives which seek to avoid discrimination against any particular energy options.

PE believes that the current administered nature of the RCM is meant to ensure there is sufficient peaking capacity in the WEM and that the total cost of capacity in the system does not change in the presence of capacity over and above the RCR because the excess capacity adjustment factor comes into play to adjust the cost of the RCP downwards. Only the cost per unit of MW or MWh would change with factors that are not associated with actual capacity supply as brought on by the RCM.

Discussion Point 3

The current RCP formula is reasonably understood by the market. However, some recent changes to the formula inputs, particularly the WACC and network connections costs, are of serious concern to PE. The process is meant to arrive at a MRCP whereby each of the parameters are set to approximate the maximum price. But the MRCP has become more of a Minimum RCP.

The current WACC methodology is not consistent with investors' expectations of the risks involved in building and operating generation plant. Further discussion on the WACC is included in the 'Other Issues' section below and in Appendix B.

Using historical average network connection costs, by definition, is not a maximum, which leads to the conclusion that the current MRCP is not in fact a maximum price. If the current methodology is retained, it should be renamed the Expected Reserve Capacity Price (ERCP) or something similar.

For these reasons, and the fact that there does not seem to be any logical explanation for why it was implemented, PE recommends the immediate removal of the 15% discount factor applied to the MRCP to derive the RCP, in time for the next Capacity Year irrespective of the outcome of the RCM review.

The fact that private sector investment has been encouraged based on the operation of the RCM until recently means that it has been reasonably successful. It is imperative that the ERA maintains market confidence in the RCM by eliminating the unjustifiable 15% discount factor in RCP derivation.

Discussion Point 4

PE does not support Lantau's proposal for making the RCP over-reactive to supply/demand situations. Instead, the RCM should remain as is, with the elimination of the automatic 15% discount in deriving the RCP as detailed in DP3.

Lantau's proposal involves setting values (including an assumption on a retailer's bilateral commitments, which is a commercial decision) in order to derive an outcome. This process should be left to the market to decide.

A large number of PE's retail customers have now gained an understanding of how the RCM operates and are requesting that these costs be passed through. This allows the customer to directly benefit with lower costs if they manage their peak demand. A customer responding to price signals is an efficient market outcome.

Discussion Point 5

PE believes there is a place for DSM in the current RCM. However, the current Rules do not treat DSM equally with other forms of generation and yet DSM is paid the full RCP. PE supports the work of the RCMWG to 'harmonise' DSM with other types of generation especially its inclusion in the Balancing Market.

In addition, there is a need to distinguish if DSM is providing capacity or a frequency control service to System Management (SM).

If it is frequency control service, then SM and the DSM provider should negotiate the terms (including notice period, number of calls, duration, etc.) under a network support contract (NSC).

If DSM is providing capacity, then it should be treated exactly in the same as a peaking plant. There should be no obligation on SM to provide long notices to DSM providers (2 hours instead of 15 minutes for peaking plant) and it should not be reserved to be called only after all other available generation has been used. This would be discriminatory to peaking capacity providers who have invested significant capital and effort into making their plants able to be dispatched at any time and for as long as a supply crisis remains afoot.

Furthermore, if a DSM load is bid at less than the Alt-Max Short Term Energy Market (STEM) price it would not get dispatched in merit order and this would result in an inefficient market outcome.

PE firmly believes that DSM must be included in the balancing merit order. This work should be done in conjunction with any proposed changes to the MRCP/RCP methodology, STEM, Resource Plans and/or Bilateral Submissions. If DSM is not able to be dispatched in exactly the same as true peaking capacity then it should not receive full RCP payment.

Discussion Points 6, 7 & 8

PE would like to reiterate that there is a difference between inefficient plant and unreliable plant. Inefficient plant is a plant that uses more fuel to generate electricity than a comparable type of facility. For this type of plant, it is the commercial decision of owner of the plant whether or not it can profitably continue to operate in the face of more efficient competition.

Alternatively, unreliable plant is not available to provide the capacity service for which it has been paid via Capacity Credits. In the case where a plant experiences an unreasonable amount of forced and planned outages, then Market Customers should be compensated, or the generator should be denied capacity credits. By enforcing the current Market Rules regarding plant unreliability and implementing changes to the capacity refund regime, this problem will be addressed.

Discussion Point 9

The market costs associated with the new LFAS market is of concern to PE. There are no reasonable grounds for the observed increases in costs to the market. PE's view is that inconsistency in key operational decision making between SM and the IMO has contributed greatly to these costs.

At a recent MAC meeting, it emerged that the current amount of load following required by SM has been grossly overestimated. PE understands that the IMO's view is that only a third of SM's load following capacity is deemed required. Consequently, a review of SM's decision making processes should be undertaken in this regard given the significant impact that has been observed to a key market cost component.

Second, SM has, in PE's opinion, been slow in developing its systems to run the new Balancing and LFAS markets and this has contributed to the preclusion of any other generators in participating in the LFAS market. System and market operational related issues should not be the cause of inefficient outcomes in a market. In this regard, the start date for the new Balancing and LFAS regime should have been delayed until SM was ready to support actual participation by interested and able players.

Now that the new Balancing and LFAS markets are in force, Western Power should be incentivised to resolve technical issues as soon as possible to allow all market participants to join the fray.

Discussion Point 10

PE supports the work that has been ongoing to improve information transparency in the market. The changes brought in through the Balancing Market have been a large improvement. The current work by the IMO to improve the transparency of forced and planned outages should be commended and supported.

PE would support, at a minimum, more transparency of the IMO and the IMO's Board decision making process with respect to Market Rule changes. The influence of the current Market Advisory Committee (MAC) role appears limited with no bearing on final decisions carried out by the IMO.

MAC is also a rotational group and this alone could make some participants that are not on MAC unappreciative of the process. PE has recommended in the past that IMO could replace MAC with work groups that could be easily gathered on short notice and on a short-term basis to deal with particular Rule change proposals. These work groups could then be disbanded when Rule change resolution is made. Short-term working groups, such as have been convened by the ERA over the years, are productive when focused on material matters.

In addition, a WEM Rule Committee should be set up by the Minister to oversee and gate-keep any proposed Rule change submitted by IMO. This WEM Committee need only be made up of 3-4 members, including the Chairman of IMO and Chairman of ERA as permanent members, plus two independents on a 2-year rotation basis. The independents must not be employed by a market participant in the WEM.

The WEM Committee does not have to undertake the actual Rule making work. Its role will be to take submissions outside the IMO process to collate the direct views of market participants and then if the WEM Committee is not convinced that a Rule change is valid and aligns with the Market Objectives, it could be returned to the IMO for further work. In this way, genuine and transparent consultation with market participants will be undertaken in the Rule Change process.

Without a MAC, and with a WEM Committee being the arbiter for Rule changes, the IMO would be inclined to consult more effectively and undertake research more thoroughly before engaging in Rule change proposals.

Discussion Point 11

PE believes that the market as a whole is functioning well, with all parties working together towards a better market. Besides more transparency in the IMO decision-making process, PE would like to see better developed settlement systems. This would be of benefit to all market participants.

Current settlement problems can cause large cash flow swings that market participants can do little to change given the timelines set out in the Market Rules.

The role of SM needs to be reviewed to ensure that its sole focus is to enable the market to function properly and not hinder developments that Market Participants deem as good, efficient and commercial outcomes.

The ERA has been proactive in discussing issues in the WEM and does so in a transparent manner. The adoption of this approach by the IMO and a WEM Committee would be to the benefit of the market in general.

PE also offers additional comments under specific headings as follows.

Dynamic Refunds

PE supports the idea of dynamic refunds. However, we do not agree with re-distributing the refunds to other generators as a suitable approach. Fundamentally, Market Customers should receive their money back if the capacity service is provided. Awarding these funds to other generators is rewarding them for doing a job they have already been paid for.

The maximum refund multiple of six times should also be reduced as this is a severe penalty which raises issues with project financing cost and so makes capacity more expensive for no incremental value. It does not result in any greater reliability as flying in replacement parts or engineering teams from overseas to fix a gas turbine will take around a week, regardless of the amount of refunds. Stocking up parts is not practical as this would raise operating and maintenance costs without providing much benefit since there is no way of predicting which parts will fail at any time.

Generators have every incentive to bring a failed plant back on line as soon as possible without any additional penalty above losing the capacity payment. A peaking plant cannot earn revenue other than its capacity payment (except for some minor dispatch occasions for energy balancing or system support where it could earn energy revenue). Unlike DSM, a peaking plant does not have an alternative revenue source so there is no commercial decision between opportunities and a peaking plant must be on line to be financially viable.

PE recommends that the ERA look at best industry practice for generators and allow all a forced outage rate of, say, 3%, under which level no capacity refunds would be payable, but anything over 3% would incur refunds. Refunds should also reflect excess capacity conditions in the market, with excess supply leading to a lower refund multiple.

WACC

WACC is a critical issue for peaking capacity investors in the WEM but it has suffered from the conflicting views of what the RCM was originally designed to provide.

If the RCM, as PE understands it to be, is a market designed to ensure there is sufficient capacity in the market to supply at the reliability level defined in the Market Rules, then the WACC should reflect this purpose. By default and design, the WACC then becomes the WACC for peaking capacity entry, rather than any other form or category of capacity. The Rules give specific conditions as to the type and size of a peaking plant to be costed.

PE has discussed the WACC issues at length and has attached a separate paper (Appendix B) on this issue for the ERA's consideration. We have expressed concerns over the MRCP/RCP methodology change implemented by the IMO last year. The process dismissed all the evidence and contribution by Market Participants on this topic.

Ancillary Services Dual Fuel Payment

The combination of no interconnection to other electricity systems, the relatively high penetration of gas fired generation capacity coupled with high dependency on a relatively small set of gas transportation pipelines and upstream processing facilities make electricity supply in the SWIS vulnerable to any interruptions to the supply chain.

This was evidenced by the 2008 Varanus Island incident when an explosion shut down the gas processing plant for an extended period cutting natural gas supply to the South West by as much as one third. On other occasions, plant failure contributed to temporary energy shortages. The ability of a peaking plant to switch seamlessly between fuels helps avert higher than otherwise energy prices during an emergency. Without that capability, more severe electricity supply restrictions and extended periods of higher wholesale pricing would be faced by the public.

Providing dual fuel capability for a generator comes at a material cost. The most common dual fuel configuration is a generator with a gas turbine that can run on both natural gas and distillate fuel. Better design and GTs provide this ability on they fly, ie. switching without having to ramp down or shut down. But having more efficient GTs that could do this, and the dual fuel infrastructure for the plant, incurs additional capital and operational costs.

The major additional capital outlay for providing distillate firing capability relates to the fuel tanks and specific ancillary systems such as a fuel pumping system that will need to be incorporated in the power station design. Having gas capability adds fuel transmission, connection and delivery plant and equipment, which could add up to 4-5% to the capex of a plant. In the WEM, the Market Rules require on-site fuel storage capability for continuous running for at least 12 hours to qualify for dual fuel status (clause 4.10.2). In the "Final Report: Maximum Reserve Capacity Price for the 2014/15 Capacity Year" a value of $3.2 million was ascribed to the fixed fuel cost component of the calculation of the Maximum Reserve Capacity Price. That value included the estimated initial fill of the tank as well to allow 14 hours continuous running for a 160 MW Open Cycle Gas Turbine (OCGT).

One of the most significant ongoing costs of a dual fuel plant is the need to cycle fuel in the fuel tanks from time to time, which may require dispatching the unit at below marginal cost in the WEM. Such uneconomic running is also required from time to time for reserve capacity testing purposes as well as any additional testing that may be periodically required to ensure smooth operation of the unit if called to run using the backup fuel. For gas, it is the cost of maintaining a transportation and commodity contract.

There is currently no specific recognition of the additional costs incurred by owners of dual fuel facilities within the WEM. Investors who are considering constructing a dual fuel facility must weigh up the additional costs against any potential risk mitigating factors or additional revenue streams the additional fuel capability may present. Alinta Energy has made the decision to not continue to certify its Wagerup facility as a dual fuel facility presumably due to the additional expense incurred in complying with the testing requirements and fuel cycling requirements.

The value of the risk mitigation that dual fuel capability presents to the system – the positive externality brought about by dual fuel facilities – as a whole is not captured in the factors that facility owners consider when making their decisions on fuel status for their facilities. The economic value to the WA economy of providing improved electricity supply security at lower cost is not incorporated in the RCP.

PE proposes to introduce an ancillary service in the WEM for the provision of dual fuel capability to mitigate the potential risks of disruption to supply for any reason. Facilities that qualify for dual fuel status, as per the current criteria that exist in the Market Rules, would be eligible to provide the new dual fuel ancillary service and receive that ancillary service payment. The dual fuel ancillary service payment should be set at a level that is sufficient to attract interest from owners of generation facilities to provide dual fuel capabilities at their power stations.

Metering

With increased environmental reporting requirement by government, customers are demanding more timely information on electricity consumption. The current structure of Western Power (WP) owning, operating and reading meters has become inefficient. This is illustrated by the fact that some customers are now installing a secondary, revenue quality meter behind the WP meter in order to get access to the demand profile information they require.

WP has been restrictive in providing meter data and charge a high fee to provide data over and above the current requirements of the metering code. Additionally, when WP installs a new interval meter the associated telemetry is not necessarily installed such that the meter is not 'smart' and instead continues to rely on manual meter reads which only occur once per month and not necessarily in conjunction with the customer's billing cycle.

The lack of timely meter data provision also affects the IMO's market settlement process and therefore all market participants. Due to the IMO's settlement process, the lack of timely and accurate meter data can cause swings in cash flow to market participants to the effect of hundreds of thousands of dollars. Market participants, as per the Market Rules, are obliged to pay the invoices and lodge disagreements which are only rectified, at a minimum, 3 months later.

Synergy cross-subsidisation of business tariffs

PE commends the ERA's report into the efficiency of Synergy's operations but as noted in PE submission on the draft report, further examination of the potential cross-subsidisation across customers should be conducted immediately. In particular, the cost base should be divided between contestable and non-contestable customers. In the contestable (and highly competitive) commercial and industrial customer segment, PE is concerned that Synergy may be able to unfairly subsidise their costs to supply commercial and industrial customer in order to win or retain customers. This inhibits competition and overall increases costs to all retail customers in the SWIS.

APPENDIX B – Examination of WACC Parameters and Related Matters in MRCP Calculation

Contents

1 Executive Summary

The Independent Market Operator (IMO) is required to determine the Maximum Revenue Capacity Price (MRCP) for the Wholesale Electricity Market (WEM) on an annual basis in accordance with the Market Procedure: *Maximum Reserve Capacity Price*.

The MRCP is used to determine an administered Revenue Capacity Price in the absence of a Reserve Capacity Auction, or the maximum bid price in an Auction.

The IMO recently published its Draft Determination of the MRCP (Draft Determination) for the 2013 Revenue Capacity Cycle, which will be effective for the year 1 October 2015 to 1 October 2016, and is seeking submissions on its Draft Determination.

Additionally, the Economic Regulation Authority (ERA) is required to report to the Minister for Energy at least annually, on the effectiveness of the WEM in meeting the Wholesale Market Objectives. To assist this process, the ERA has recently published a Discussion Paper to assist stakeholders make submissions on matters that include the effectiveness of the process used to set the Reserve Capacity Price (Discussion Point 3 of the Discussion Paper).

The paper sets out Perth Energy (PE)'s submission on a number of issues that are relevant to both the IMO's Draft Determination and the ERA's Discussion Paper; principally

- the effectiveness of the Reserve Capacity Price set using the administrative formula in the Market Rules with reference to the MRCP and the Excess Capacity Adjustment; and
- the IMO's approach to calculation of WACC and the incentives that it delivers for investment in reserve capacity and hence the implications for achieving Market Objectives.

This paper explains the basis of PE's view that the effectiveness of the Reserve Capacity Price set using the administrative formula in the Market Rules is impaired by the approach adopted by the IMO to calculating WACC for the MRCP. The Capital Asset Pricing Model used by the IMO, if applied appropriately and calibrated against wider evidence, has the potential to be effective. However the approach currently adopted by the IMO does not meet Market Objectives of:

- promoting the economically efficient, safe and reliable production and supply of electricity and electricity related services in the SWIS; and
- encouraging competition among generators and retailers in the SWIS, including by facilitating efficient entry of new competitors;

because the WACC and MRCP that result from the IMO's approach:

- does not result in an economically efficient price for the efficient, safe and reliable production and supply of electricity services in the SWIS; and
- consequently does not provide pricing that facilitates efficient market entry and hence competition in the generation sector.

The IMO's approach to setting a Reserve Capacity Price includes applying a weighted average cost of capital (WACC) to a benchmark asset base. The WACC is a critical component of the MRCP, profitability for generators providing reserve capacity and hence incentive for generators to participate in and provide an efficient wholesale market.

The IMO uses the capital asset pricing model (CAPM) to determine WACC. This is a widely accepted model for determining benchmark rates of return for both commercial and regulatory purposes. It provides a reasoned transparent approach, but its calculation requires commercial judgment to determine a number of its critical parameters, and it is by no means an exclusive means of determining returns. It can be complemented and corroborated by comparisons and financial analysis such as financability testing. These further methods are briefly described later in this summary.

A key intent of the CAPM is to identify returns that match the risk characteristics and investor expectations of different kinds of businesses. The different parameters that feed into the CAPM account for different risk characteristics. The provision of reserve generation capacity requires investors to bear risks particular to that activity. Not all of those risks and hence CAPM parameters will be necessarily unique to the provision of reserve generation capacity, but there are a number of characteristics and risks that strongly distinguish such a business from others.

In applying the CAPM approach to determining the WACC for the MRCP, the IMO has relied on and narrowly referred to, precedents and parameters set by regulators of monopoly businesses.

The IMO's approach of following regulatory precedent may not be unreasonable, but the rationale for its approach of apparently so rigidly and restrictively following a relatively narrow band of regulatory precedent using the parameters of network business and the Western Australian electricity network sector in particular, is unclear. Generation may share some risks by virtue of participating in the same market as network assets, but it is not reasonable or realistic for the IMO to assume that the risks are identical and to exclude from consideration a wider body of regulatory and pricing precedent. The consequences are that the IMO:

- has developed WACC for the MRCP by including parameters and risks that are not relevant to the provision of generation capacity, which inevitably leads to distortions in both pricing and signals for efficient investment;
- does not seem to have followed an internally consistent approach to applying the CAPM to the MRCP; and
- has not in its Draft Determination cross checked the outcomes of its assumptions and approach to determining WACC to other availability data or undertaken financial analysis to test the business impact of its Draft Determination.

Examples of these consequences are summarised below.

Inappropriate WACC parameters

Section 2 of this paper explains that there is a wide range of information and regulatory precedent that is more relevant to the derivation of WACC parameters for generation businesses, than the narrower precedents to which the IMO has referred. Section 3 illustrates how this has led to the IMO's WACC being significantly misstated. For example, Section 2 illustrates that the IMO's approach appears to have materially misstated:

- the risk free rate;
- equity beta;
- the debt risk premium;
- gearing; and
- gamma.

The IMO sought advice from PriceWaterhouseCoopers[6] (PwC) to inform its determination of WACC parameters. However, the terms of reference for advice it provided to PwC restricted the research to three WACC parameters[7] and to regulatory decisions made by regulators subject to merit reviews[8]. Accordingly, PwC was obliged to ignore regulatory decisions made by other economic regulators which may be appropriate to consider in the context of the decision on the MRCP. It seems important that the IMO should consider all information to ensure that the decision making approach is appropriate for the MRCP.

Internally inconsistent WACC parameters

The IMO approach includes parameter values carried over from previous reviews as well as parameters that are recalculated annually. Although, perhaps inconsistently with this approach, one of these "fixed" parameters, the gamma, was reviewed by PwC in its report due to a recent Australian Competition Tribunal (ACT) decision, which changed the value used by other Australian regulators.

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[6] PwC, 19th October 2012, Summary of regulatory decisions related to the WACC used in the Maximum Reserve Capacity Price

[7] The risk free rate, the debt risk premium and the gamma.

[8] Such as the Australian Energy Regulator and the Economic Regulation Authority of Western Australia.

In particular, members of certain pairs of WACC parameters are interrelated. One member of the pair does not operate independently of the other. However, for two of the pairs, the IMO's approach holds the risk of internal inconsistency in its calculation of WACC because one member of a pair is updated and the other is not:

- the risk free rate (updated annually by IMO) and the market risk premium (updated by IMO every five years); and
- the debt risk premium (updated annually by IMO) and debt issuance costs (updated by IMO every five years);

In general, the IMO has followed network business precedent for WACC parameters - except for the gearing rations which are more akin but still in excess of available data for, generation businesses.

Absence of calibration of the of outcomes of the IMO's approach

The IMO's approach focuses heavily on the WACC parameters, but not on the resulting WACC. WACC parameters are an input to a pricing outcome, not the outcome itself. The resulting WACC should be calibrated against expectations of industry norms and the objectives of the pricing regime, to help check test all the parameters are appropriate.

For example, regulators in the United Kingdom and IPART commonly use financeability tests to determine whether the rate of return outcomes from the CAPM are consistent with regulators' obligations to balance the interest of investors and customers and to maintain the financial viability of regulated businesses. A financeability test examines the future cash flows that result from rate of return decisions and tests whether they enable a business to meet the regulator's assumed or target credit ratings and key financial ratios that measure financial viability and health. IPART has recently reaffirmed its commitment to using these tests as part of its approach to regulation going forward[9].

PE has compared:

- the results of the IMO's draft WACC determination and its own illustrative calculation of an appropriate WACC, using more apt parameters which are explained and justified in this paper; against
- comparable WACC's for generators and energy retailers, which unlike the network businesses on which the IMO has based its WACC, participate in the wholesale energy market.

The results, which are set out in Sections 3 and 4 of this paper show that:

- the IMO's Draft Determination produces a WACC that is significantly below the level of WACC indicated by:
    - market evidence for generation businesses;
    - regulatory precedent for retail businesses, which would appear significantly closer in their risk profile to generation than the network precedent on which the IMO has relied; and
    - the use of more appropriate WACC parameters indicated by Section 2 of this paper.

[9] For example see IPART, September 2012, Financeability test in price regulation, www.ipart.nsw.gov.au

2 The IMO's calculation of WACC

2.1 The IMO's approach to calculating WACC

The 2015/16 MRCP has been reduced from the previous 2014/15 determination by 6.8 per cent, with the largest single factor attributed to changes in WACC.[10]

The IMO has applied the Capital Asset Pricing Model (CAPM) to calculate the WACC for the MRCP.

The CAPM is a widely accepted technique for calculating a benchmark rate of return for a business. While it is commonly used by access regulators to calculate regulated rates of return for monopoly businesses, there is no constraint on the use of CAPM for such businesses.

The calculation of a WACC under the CAPM requires a range of specific input parameters to the CAPM to be determined.

However, in deriving the input parameters for the WACC for the MRCP, the IMO has:

- referred to regulatory precedents that apply to access regulated monopoly industries and services; and
- drawn heavily on parameters and precedents applicable to network businesses.

This does not appear appropriate or rational because:

- reserve capacity is provided by the generation sector which normally operates in competitive markets. Precedents provided by commercial and market practice, not regulatory practice would be applicable; and
- the operational and investment risks of generation businesses are significantly different to network businesses and revenue capped network businesses in particular. For example, generation businesses are subject to fuel price and supply risk and risks of competition and significantly greater volatility in demand and price.

2.2 Calculating WACC

The IMO's Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year - November 2012, included the following Real and Nominal Pre-tax WACCs and associated parameters.

[10] IMO, November 2012, Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year.

Table 2-1 – Capital Asset Pricing Model parameters

Paper Ref	CAPM Parameter	Notation/ Determination	Review Frequency	Value set or TBD	IMO Draft (y=0.5)	IMO Draft (y=0.25)
2.4	Nominal risk free rate of return (%)	*Rf*	Annual	TBD	3.13%	3.13%
2.5	Expected inflation (%)	*i*	Annual	TBD	2.57%	2.57%
2.4	Real risk free rate of return (%)	*Rfr*	Annual	TBD	0.55%	0.55%
2.6	Market risk premium (%)	*MRP*	5-Yearly	6.00	6.00%	6.00%
2.7	Asset beta	βa	5-Yearly	0.5	0.5	0.5
3.7	Equity beta	Be	5-Yearly	0.83	0.83	0.83
2.8	Debt risk premium (%)	*DRP*	Annual	TBD	2.94	2.94
2.9	Debt issuance costs (%)	d	5-Yearly	0.125	0.125	0.125
	Corporate tax rate (%)	*t*	Annual	TBD	30%	30%
2.10	Franking credit value	γ	5-Yearly	0.5	0.5	0.25
2.11	Debt to total assets ratio (%)	*D/V*	5-Yearly	40	40%	40%
3.11	Equity to total assets ratio (%)	E/V	5-Yearly	60	60%	60%
	Nominal pre-tax cost of debt				6.20%	6.20%
	Nominal Post-tax cost of equity				8.11%	8.11%
	WACC (Nominal Pre-tax)				**8.20%**	**8.76%**
	WACC (Real Pre-tax)				**5.49%**	**6.03%**

Note: The IMO determined in its discussion paper that the values for some parameters would be set and some would be determined based on current observations.

The difference between the two IMO versions is Gamma, which is highlighted.

Source – IMO spreadsheets http://www.imowa.com.au/mrcp, as referred to in the IMO Draft Report

2.3 WACC Parameters

PE provides commentary on the specific WACC parameters employed by the IMO, below.

PE also notes that the IMO engaged PwC to provide with information and commentary on regulatory precedents for on certain WACC parameters[11], namely:

- the risk free rate;

[11] PwC, 19 October 2012, Summary of regulatory decisions related to the WACC used in the Maximum Resource Capacity Price.

- the debt risk premium; and
- gamma.

However, the terms of reference provided by the IMO to PwC (and noted by PwC as a constraint) were limited to these three parameters only and required PwC to only identify precedents that were applied from determinations that are subject to a merits review process. This effectively limited PwC's research to decisions made by the Australian Energy Regulator (AER) and the Economic Regulation Authority of Western Australia (ERA). It is assumed that this requirement was implemented to ensure that the regulatory precedents used as part of this review process would be more robust. However, the rationale for this is open to question.

This requirement limits the number of precedents available for the IMO to consider as part of this review, which may reduce the IMO's ability to achieve a regulatory outcome consistent with its objectives given the specific nature of the service being provided. In particular, regulators not subject to merit reviews are subject to other arrangements which ensure the quality of their decisions such as:

- legislative requirements – requirements in the legislative framework may dictate the process used by the regulator in forming its decisions. Where regulators do not meet these requirements, they may be bound in breach of these requirements; and
- terms of reference for the review – where terms of reference are drafted by Government at the commencement of the pricing review, these terms may provide instructions on the approach to be used to make decisions, limiting the ability of the regulator to make decisions or use methods outside the terms of reference.

Importantly, it is not clear that any other Australian regulator has included this restriction in its approach to evaluating regulatory precedents. In fact, regulators such as the AER consider approaches taken by state based regulators such as IPART and the QCA when making pricing decisions.[12]

The ERA in recent pricing decisions has taken a particularly aggressive stance to price regulation, providing atypical results.[13] By placing undue weight on precedent set by the ERA, it is likely that the IMO will determine a MRCP, with similarly atypical results.

In addition, the IMO sets the price of generation capacity, not transmission and distribution network services. The MRCP prices a fundamentally different service. Given the nature of the prices being regulated by the IMO, there may be some benefit in considering a wider pool of regulatory precedents in evaluating the appropriate level of the MRCP. For example, the IMO does not appear to have considered taking into account regulatory precedents for WACC for retailers, for regulated retail tariffs whose participation in wholesale electricity markets would indicate a risk profile closer to a generation business, than a network business. Examples include IPART's review of retail electricity tariffs in 2010 where it considered WACC for a retailer and a generator, and market observations on some WACC parameters for listed companies in Australia operating in the generation sector. Section 4 of this paper illustrates these precedents.

2.4 Risk free rate

The risk free rate is the rate of return an investor receives from holding an asset with guaranteed payments.

The risk free rate is used as a direct input into the CAPM to determine the required return on equity. It is also used as an input into the calculation of the required cost of debt.

Given that no asset is truly 'risk free', a proxy is used to determine the risk free rate. Common regulatory practice is to use government bonds. In Australia, this generally refers to the yields from Commonwealth

[12] For example, the AER in its 2009 review of WACC parameters (*Electricity transmission and distribution network service providers – Review of the weighted average cost of capital (WACC) parameters*), considered examples for the equity betas and gamma from state jurisdictional regulators such as IPART, the QCA, ESCOSA and others.

[13] Due to a variety of reasons, the WACC included in the most recent ERA decision, *Final decision on proposed revisions to the Access Arrangement for the Western Power Network*, a lower WACC than recent decisions made by other Australian regulators.

Government Securities (CGS). Perth Energy understands that the IMO has calculated this following regulatory precedents, on the basis of current yields on Commonwealth Government bonds.

However, the IMO has noted that its stakeholders consider that the current depressed values for the risk free rate is more a product of market characteristics (a flight to safety) than an appropriate estimate of the risk free rate that should be applied in the calculation of the WACC. PE considers there to be considerable support for a more long term approach to estimating the risk free rate under current market conditions. This support includes precedent and a recent Australian Competition Tribunal (ACT) decision , *Application by EnergyAustralia and Others (No 2) [2009] ACompT9*.

In the ACT's decision, EnergyAustralia proposed an averaging period for determining the risk free rate that '*is closest to the regulatory control period prior to the emergence of the marked acceleration of the global financial crisis in September 2008'*. This period was proposed on the basis that:

- the AER's specified averaging period for observing key financial data is highly likely to include data that has been impacted by this supervening critical event; and
- *'an averaging period affected by the current abnormal financial market conditions will provide an estimate of the rate of return … which is materially biased below the rate of return required by investors in a similar commercial business'*.

The ACT upheld EnergyAustralia's appeal, and the averaging period proposed by EnergyAustralia was used in its final determination.

Referring to Figure 1 of the IMO's Draft Determination, PE estimates that if the principles set out in the ACT Decision were applied to bond rates immediately prior to the impact of the Euro currency crisis in mid 2011 that has skewed the markets below long term averages, an appropriate risk free rate would be of the order of 5.0 per cent to 5.5 per cent (nominal).

A further precedent for calculating the risk free rate which addresses this volatility is provided by SA Water in its recent pricing proposal[14], which proposed a 180 day observation period to average out the outliers and extend the sample size. In particular, SA Water mentioned that:

- actual financing costs may differ significantly from those estimated under a 20 day averaging period; and
- the 20 day averaging period does not take into account the potential variability in debt market conditions over the regulatory period.

In the SA Water example, a 180 day averaging period to 1 June 2012 for a 10 year Commonwealth Government Bond provided a nominal risk free rate of 3.93 per cent.[15]

Perth Energy submits that the risk free rate for the MRCP (to be applied in 2015 and 2016) should be consistent with the ACT's views and not be distorted below long term averages. Accordingly, a nominal risk free rate of the order of 4 per cent to 5 per cent or more, appears appropriate and significantly less likely to result in distorted pricing than the atypical rate of just over 3 per cent (nominal) included in the IMO's Draft Determination.

2.5 Inflation

Perth Energy notes that the inflation is set at 2.57 per cent which is close to the mid point in the Reserve Bank of Australia target range of 2 per cent to 3 per cent. This is likely to be close to the outturn inflation rate due to the Reserve Bank's actions on adjusting interest rates. The forecast inflation rate is consistent with generally accepted economic forecasts.

[14] [14] SA Water business proposal to ESCOSA http://www.escosa.sa.gov.au/library/121012-SAWaterRegulatoryBusinessProposal_2013.pdf

[15] Using the SA Water example – 180 days observed up to 1 June 2012 on 10 year Commonwealth Government Bonds

2.6 Market risk premium

The market risk premium (MRP) is the expected return over the risk free rate that equity investors would require in order to invest in a well-diversified portfolio of risky assets. It represents the risk premium that investors can expect to earn for bearing only non-diversifiable or systemic risk.

Estimating a forward-looking market risk premium, commensurate with the current market, generally involves having regard to historical estimates on the basis that investors' forward-looking expectations will be based on past experience. Current regulatory practice in Australia is to estimate the market risk premium using historical data on equity premia.

In the past, Australian regulators consistently applied a market risk premium of 6 per cent. However, in its 2009 review of WACC parameters, the AER concluded that the market risk premium should be increased to 6.5 per cent on the basis of market conditions at the time. Nevertheless in its final decision on Envestra's access arrangement proposal for the South Australian gas network, released in February 2011, the AER used a market risk premium of 6 per cent for the gas business.

In the ElectraNet draft decision[16] (November 2012), the market risk premium was set at 6.5 per cent, consistent with the AER WACC review of May 2009[17], and consistent with ElectraNet's proposal. Murraylink, a single asset transmission interconnector also received a draft decision in November 2012 with an MRP of 6.5 per cent. This is consistent with 6.5 per cent allowed for ETSA Utilities more than two years ago in 2010. These decisions reflect the regulators view that current market conditions remain inconsistent with normal, longer term market conditions and that a higher MRP is warranted.

PE submits that the MRP should represent that component that, when applied in a CAPM, offers sufficient incentive for an investor to make efficient investment in new generation capacity in the WEM. Whilst PE acknowledges that the MRP is not business dependent, it seems difficult to understand how a more risky business operating in more difficult times might be fairly treated by an MRP which was less than that applied in a network business.

PE suggests that the MRP of 6.5 per cent should be considered particularly in light of its concerns about the capacity of the other WACC parameters determined by the IMO, to adequately deal with generator risks.

2.7 Equity beta[18]

The equity beta measures the standardised correlation between the returns on an individual risky asset or business with that of the overall market. That is, it represents the riskiness or volatility of the business' returns relative to the diversified market position as a whole.

Under CAPM, it is assumed that investors can diversify away business-specific risk and therefore only require compensation for bearing non-diversifiable or systemic risk (that is, risk associated with movements in the market as a whole).

An equity beta of one implies that the business' returns have the same level of systemic risk as the overall market. An equity beta of less than one implies that the business' returns are less sensitive to systemic risk, while an equity beta of more than one implies that the business' returns are more sensitive.

In its 2009 WACC Review[19] (for network businesses), the AER changed its previously held position on the value of the equity beta for electricity distribution and transmission businesses from 1.0 to 0.8.

Because the AER WACC review sets some parameters for a period until the next WACC review, the equity beta applied in the recent ElectraNet draft decision was 0.8 (November 2012). This was applied to a

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[16] AER Draft decision on South Australian electricity transmission revenues available at: http://www.aer.gov.au/sites/default/files/ElectraNet%202013%20-%20AER%20-%20draft%20decision%20-%2030%20November%202012.pdf

[17] AER, Statement of the revised WACC parameters (transmission), May 2009, page 6.

[18] This section does not explicitly discuss the asset beta, since this is a derivative of the equity beta.

[19] AER 'Electricity transmission and network service providers – review of the WACC parameters,' Final Decision, May 2009

business with approximately $2 billion in assets, operating a monopoly transmission business under a revenue cap approach. This is therefore a significantly less risky business with more stable revenue streams than a generation business supply reserve capacity.

The question of whether it is appropriate to use the equity beta applied to distribution and transmission businesses in a process to determine an MRCP in WA depends on an assessment of whether there is a difference in the systemic risk faced by network monopolies as compared to generation businesses. Reasons for any differences are primarily due to the nature of activities undertaken by the businesses and the costs incurred. A summary of some of the key differences is set out below.

Table 2-2 – Differences in risk (Generation v Network)

Factor	WA Generation	Australian Electricity Transmission Network business
Beta	0.83 (IMO draft)	0.80 (ElectraNet draft)
Business Revenues	Subject to price bids and competition	Revenue cap – mostly guaranteed
Market Volumes	Subject to weather conditions, government policy, customer demand changes, technology, innovation	Revenue cap – prices adjusted to recover required revenue
Operating costs	Subject to fuel, labour and material variances	Subject to labour and materials variances
Competition	At risk of new entrant exploiting new technologies before end of life	Monopoly licence area

There are further risks specific to the provision of generation capacity that are not considered in any way in a beta derived for a network business and seem very unlikely to be accommodated together with the other risks outlined above, in a differential beta of only 0.03. For example:

- construction delays can place at risk investors' security deposits provided when IMO approved the project and allocated capacity credits to that project. The security is 25 per cent of one year's capacity payment, a substantial sum to put up at the start of the construction process. It is common to have project delays and funders are aware of this and have priced in this risk as power plants cannot pass on additional costs to contract counterparties;
- delay in delivering the plan can lead to capacity refunds. This penalty in the summer period can be as high as six times the revenue received. Accordingly, an entire year's capacity payment could be lost in two months of down time, or if construction delay creeps past the end of the year in which capacity is intended to come on line. Again, such delays and refund penalties have been incurred by most projects;
- a business can be at risk of distress by losing much less than a year's revenue. Losing say 20 per cent of a year's revenue would be enough to lock up equity or cash in a project. It is not clear whether the IMO has considered practical project financing risks that businesses face to provide generation capacity; and
- exposure of investment in generation capacity to forced outages that are beyond the control of a generator.

PE notes that:

- the generators offering reserve capacity for the SWIS do not have a natural monopoly as there are currently 29[20] generation plants operated by 15 generation businesses in the SWIS; and
- the notional 160MW generator used by the IMO in calculating the MRCP represents less than 3 per cent[21] of the WEM, and therefore will not have market power.

PE observes that the Beta of 0.83 is only a fraction above the 0.80 allowed for network businesses. This does not reflect the commercial and market risks of a WA generator when compared to a monopoly network business, and a WACC that recognises this low beta fails to offer sufficient financial incentive to invest in new generation when compared to a regulated network business in the National Electricity Market.

There are listed Australian generators for which a beta can be measured from empirical evidence. (There are other listed generators but arguably other business interests such as energy retailing mask the

[20] 29 Generators of 10MW capacity or more as listed in the Energy Supply Association of Australia annual report

[21] Based on 6,000 MW as listed by the Energy Supply Association of Australia annual report

generation beta.) The five year average beta observed for three Australian Generators (Energy Developments Ltd, Energy World Corp Ltd and Pacific Energy Ltd) is slightly more than 1.0.

PE submits that a beta of 1.0 would be a conservative reflection of the business specific risks associated with generation in the WEM, and offers the minimum financial incentives required for investment in generation capacity.

2.8 Debt risk premium

The debt risk premium is the additional return over the risk free rate required by investors to hold debt that is not risk free (that is, where there is a risk of default). The purpose of including the debt risk premium within the expected cost of debt is to compensate for the benchmark cost of debt capital.

In its Draft Determination, the IMO "has applied the value that represents a strict application of the ERA's approach in the WA Gas Network final revised decision, utilising bands with credit ratings of BBB and BBB+, with a term to maturity of at least two years."[22]

The regulatory approaches reviewed by PwC for the IMO[23] consider the debt risk premium for network businesses. This is not appropriate for the MRCP because it is required to reflect the cost of providing reserve generation capacity rather than a monopoly network system. Differences between the two types of assets may impact:

- the credit rating associated with the business. Generators typically operate in a more competitive market unlike networks, and may be considered riskier assets as a result (see section 2.5 above);
- network businesses can be order of magnitude greater in terms of capital value, than generation businesses and this too will lead to a reasonable expectation that a provider of reserve capacity might expect to experience a higher cost of debt than a network business; and
- the time to maturity of debt financing, and the relevant gearing levels may differ between generation and network businesses.

In addition, the IMO's Draft Determination notes that stakeholders have suggested that they are more likely to access bank financing rather than corporate debt market financing. In network price regulation, debt market financing is used because it is assumed that the regulated businesses have access to these markets. It would be reasonable to assume that network businesses would have access to debt markets. However, it may not be axiomatic that this is also true for a less capital intensive business such as a benchmark provider of Reserve Capacity. There are regulatory precedents for this, which appear more relevant than the large network business precedents on which the IMO has drawn. It would be appropriate for the IMO to consider this matter and its impact on the debt risk premium.

For example, in the case of price regulation of smaller transport firms, IPART considered the costs of bank related financing[24], notwithstanding

The IMO has outlined a range of complex and esoteric, large scale network based precedents to support a debt risk premium of 2.94 per cent in its Draft Determination.

However Perth Energy observes that:

- the premia represented by the differential between the five year Australian Government Bonds (GACGB5) and the BBB Corporate Bonds (C356Y) as at 30 June 2012 are:

  A.1 when measured on a 20 day average to 30 June: 3.69 per cent;

  A.2 when measured on a 40 day average to 30 June: 3.69 per cent; and

  A.3 when measured on a 180 day average to 30 June: 3.61 per cent

- the IMO's Draft Determination does not recognise that the risks of a generation business differ significantly from network businesses' risks on which it has based its debt risk premium; and

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[22] IMO, November 2012, Draft Report: Maximum Reserve Capacity Price for the 2015/16 Capacity Year, p 22.

[23] PwC, 19th October 2012, Summary of regulatory decisions related to the WACC used in the Maximum Reserve Capacity Price

[24] IPART, Review of fares for private ferry services and the Stockton ferry service for 2012 - December 2011*, page 31, available at* *www.ipart.nsw.gov.au*

- the IMO's Draft Determination does not recognise that a generation business is less likely to be able to access bond markets and achieve a BBB credit rating.

Because of these reasons, Perth Energy submits that a debt risk premium of ***at least*** 3.6 per cent would be more appropriate to the calculation of WACC for the MRCP.

2.9 Debt issuance costs

While using a consistent level for some parameters over time is a well accepted approach to price regulation (for example, the market risk premium is often kept stable over time by regulators), it seems reasonable to question whether debt issuance costs should be left fixed while the debt risk premium is calculated annually. In times of uncertainty, the costs of issuing debt can vary. This may coincide with large changes in the debt risk premium. Given the potential for debt issuance costs to vary, there may be a benefit in calculating the debt.

2.10 Gamma

A full imputation tax system for companies has been adopted in Australia since 1 July 1987. Under the tax system of dividend imputation, a franking credit is received by Australian resident shareholders, when determining their personal income taxation liabilities, for corporate taxation paid at the company level. In a dividend imputation tax system, the proportion of company tax that can be fully rebated (credited) against personal tax liabilities may be best viewed as personal income tax collected at the company level. With the full tax imputation system in Australia, the company tax is effectively eliminated if all the franking values are used as credits against personal income tax liabilities.

The actual value of franking credits, represented in the WACC by the parameter 'gamma', depends on the proportion of:

- the franking credits that are created by the firm through the payment of Australian company tax and most importantly the value of credits that are distributed; and
- the value that the investor attaches to the credit, which depends on the investor's tax circumstances (that is, their marginal tax rate and whether they can use the franking credits).

As these factors will differ across investors, the value of imputation credits may be between nil and the full value of franking credits (i.e. a gamma value between zero and one).

There has been and continues to be significant debate concerning the appropriate value to ascribe to imputation credits.

PE submits that the move from a gamma of 0.5 to 0.25 recognises that there are different investors participating in the market and that international investors and others do not value franking credits in the same way as an Australian resident taxpayer. The adoption of a gamma of 0.25 in the Australian Competition Tribunal decision recognises the reduction in value of franking credits attributed to a mix of equity providers. It is noted that there are many instances of Australian generation businesses with foreign ownership to support the notion that franking credits should be valued at the lower end of the scale. Australian generators with foreign ownership apart from PE include:

- Alinta Energy;
- Meridian Energy;
- ATCO Australia;
- TruEnergy;
- IPR-GDF SUEZ Australia;
- Intergen (Australia);
- Mitsui; and
- Transalta.

Given that the generation sector is more likely to need foreign investment to satisfy the equity needs for a new generation project, the gamma should be zero, or at least approach zero to offer sufficient incentive to maintain access to the necessary capital and provide benefits of competition in the WA generation market.

2.11 Gearing

Gearing is defined as the ratio of the value of debt to total capital (that is, debt over debt plus equity). For regulatory purposes, the benchmark gearing ratio is usually considered to be the capital structure of a benchmark efficient business. This is intended to provide companies with an incentive to manage the costs associated with debt and equity efficiently.

Regulated network businesses have typically received gearing levels in regulatory decisions of 60 per cent debt and 40 per cent equity. This is evidenced in regulatory decisions such as the recent ElectraNet decision in November 2012.

PE notes that the gearing in the IMO Draft Determination provides gearing with 40 per cent debt. This is lower gearing than for network businesses for example and is more consistent with the typical structures of generation businesses.

Our research into listed Australian generators (Energy Developments Ltd, Energy World Corp Ltd and Pacific Energy Ltd) identified an average debt of 27 per cent and 28 per cent for two year average and five year average observations.

Therefore:

- the debt to equity ratio assumed by the IMO appears more consistent with the generation sector, albeit with a higher debt ratio than is experienced in the sector; and
- the IMO's approach of recognising the distinguishing characteristics of the generation sector in this WACC parameter, but not in others, appears to be mutually inconsistent and supports PE's view that the WACC for the MRCP should be based on relevant generation sector business characteristics.

3 An illustrative appropriate WACC for the MRCP

The discussion in the previous chapter demonstrates views on the WACC parameters that recognise

- more appropriate market conditions and observations;
- the fact that this decision is for the generation sector and not a monopoly network sector; and
- the need to drive appropriate incentives to attract generation investment in the SWIS.

Section 4 overleaf demonstrates that the illustrated WACC above is more closely aligned with market outcomes and relevant WACC determinations than the IMO's Draft Determination.

The following table compares the IMO Draft Determination with the WACC that more appropriate WACC parameters provides. It illustrates that the IMO Draft Determination appears to have materially understated WACC.

Table 3-1 – Capital Asset Pricing Model parameters

CAPM Parameter	**Notation/ Determination**	**IMO Draft (y=0.5)**	**IMO Draft (y=0.25)**	**Illustrative**
Nominal risk free rate of return (%)	*Rf*	3.13%	3.13%	5.00%
Expected inflation (%)	*i*	2.57%	2.57%	2.57%
Real risk free rate of return (%)	*Rfr*	0.55%	0.55%	
Market risk premium (%)	*MRP*	6.00%	6.00%	6.00%
Asset beta	βa	0.5	0.5	-
Equity beta	Be	0.83	0.83	1.00
Debt risk premium (%)	*DRP*	2.94%	2.94%	3.60%
Debt issuance costs (%)	d	0.125	0.125	0.125
Corporate tax rate (%)	*t*	30%	30%	30%
Franking credit value	γ	0.5	0.25	0.00
Debt to total assets ratio (%)	*D/V*	40%	40%	35%
Equity to total assets ratio (%)	E/V	60%	60%	65%
Nominal pre-tax cost of debt		6.20%	6.20%	8.73%
Nominal Post-tax cost of equity		8.11%	8.11%	11.00%
WACC (Nominal Pre-tax)		**8.20%**	**8.76%**	**13.27%**
WACC (Real Pre-tax)		**5.49%**	**6.03%**	**10.43%**

Note: The IMO determined in its discussion papers that the values for some parameters would be set and some would be determined based on current observations.

Source – IMO spreadsheets http://www.imowa.com.au/mrcp.

4 Comparative WACCs observed in other decisions and in the market

The IMO's calculation of WACC has failed to recognise other regulatory decisions and market observations and instead has relied on network based regulatory precedent and assumptions. The IMO has therefore presented a view which is not representative of market conditions.

The following table compares the IMO WACC (with a gamma of 0.25) with:

- recent WACC determinations by IPART[25] for the retail and generation sectors; and
- WACC in the generation and retail sectors calculated based on:
  - 5 years' market observations of beta and gearing for five Australian businesses for which data is available;
  - assumptions for the risk free rate, debt margin, debt issuance costs, and market risk premium consistent with the illustrative example used in section 3; and
  - gamma which is set at 0.25 to recognise the fact that the examples are Australian listed corporations.

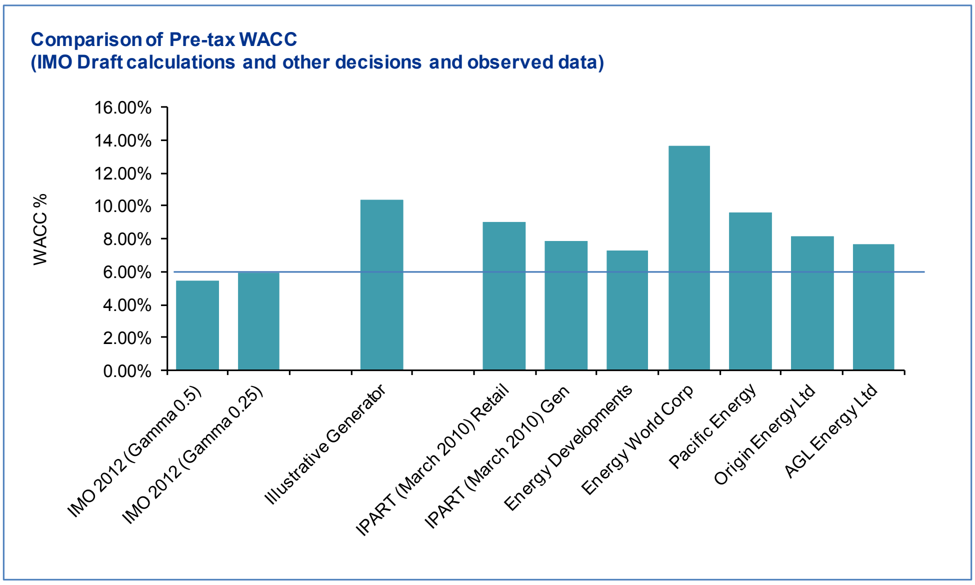
Table 4-1 – Capital Asset Pricing Model parameters

	Regulatory Decision			Market observations of Beta and Gearing				
CAPM Parameter	**IMO Draft (y=0.25)**	**IPART March 2010 Retail**	**IPART March 2010 Generation**	**Energy Developments**	**Energy World Corporation**	**Pacific Energy**	**Origin Energy**	**AGL Energy**
Nominal risk free rate of return (%)	3.13%	5.50%	5.50%	5.00%	5.00%	5.00%	5.00%	5.00%
Expected inflation (%)	2.57%	3.00%	3.00%	2.57%	2.57%	2.57%	2.57%	2.57%
Real risk free rate of return (%)	0.55%							
Market risk premium (%)	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%	6.00%
Asset beta	0.5							
Equity beta	0.83	1.00	1.00	0.63	1.49	0.93	0.65	0.57
Debt risk premium (%)	2.94%	2.85%	2.85%	3.60%	3.60%	3.60%	3.60%	3.60%
Debt issuance costs (%)	0.125%	0.00%	0.00%	0.125%	0.125%	0.125%	0.125%	0.125%
Corporate tax rate (%)	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%	30.00%
Franking credit value	0.25	0.40	0.40	0.25	0.25	0.25	0.25	0.25

[25] IPART, March 2010, Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity – Final Report

Debt to total assets ratio (%)	40%	30.00%	50.00%	47.00%	15.00%	24.00%	18.00%	17.00%
Equity to total assets ratio (%)	60%	70.00%	50.00%	53.00%	85.00%	76.00%	82.00%	83.00%
Nominal pre-tax cost of debt	6.20%	8.35%	8.35%	8.73%	8.73%	8.73%	8.73%	8.73%
Nominal Post-tax cost of equity	8.11%	11.50%	11.50%	8.78%	13.94%	10.58%	8.90%	8.42%
WACC (Nominal Pre-tax)	**8.76%**	**12.32%**	**11.19%**	10.11%	16.60%	12.47%	10.99%	10.50%
WACC (Real Pre-tax)	**6.03%**	**9.05%**	**7.95%**	7.35%	13.68%	9.65%	8.21%	7.73%

The comparison, which is shown graphically overleaf, illustrates that the IMO's WACC is significantly less than independent derived comparatives for generators and other participants in wholesale electricity markets.



What is most relevant in this comparison are the facts that:

- IPART chose to apply an equity beta of 1.00 for both retail and generation in the assessment of electricity pricing[26], clearly well above a beta of 0.80 as chosen by IMO.
- The market observations for beta in the Australian listed companies with generation interests show a range of 0.57 to 1.49, with an average of 0.85. Even with some data points with lower betas, the average is higher than that allowed by the IMO, and the range extends to 1.47.
- The market observations also show gearing levels of 15 per cent to 47 per cent with an average of 24 per cent. The gearing for these energy companies is quite low. The IMO has adopted a gearing of 40 per cent debt which whilst lower than a regulatory assumption for networks of 60 per cent, does not reflect the market observations for generators. The IMO has therefore overestimated the gearing in its calculation of WACC for the MRCP.

[26] IPART – Review of regulated retail tariffs and charges for electricity 2010-2013, Electricity – Final Report dated March 2010