Wholesale Electricity Market – Submission to Procedure Change Proposal

Submitted by

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Date submitted:	*<date submitted to the IMO or System Management>*

Submission

Clause 2.10.7 of the Wholesale Electricity Market Amending Rules provides that any person may make a submission for a Procedure Change Proposal by filling in this Procedure Change Submission form.

Submissions for Procedure Changes that relate to the Power System Operation Procedures and IMO Market Procedures should be submitted to:

Independent Market Operator
Attn: Manager Market Development & System Capacity
PO Box 7096
Cloisters Square, Perth, WA 6850
Fax: (08) 9254 4399
Email: market.development@imowa.com.au

1. Please provide your views on the Procedure Change Proposal, including any objections or suggested revisions:

This procedure change is highly concerning to Tesla. We feel that the revisions do not accurately reflect the true costs of building, connecting and commissioning a generator on the SWIS. If this procedure change were to process in its current form, we envisage a significant reduction in the level of capacity that will be offered into the market and, coupled with the uncertainty in regards to firm offtake with Synergy, this may put a halt to new capacity for some period of time.

The risk to the market is that power generation is a long lead time industry and by the time the mechanism is rectified to encourage new generation, the SWIS may go back to a capacity shortage in a similar fashion to only a short three years ago. It is our view that a major change to the procedure will be viewed by the investment market as the introduction of regulatory risk. This procedure change has wide reaching effects - we note that it has been introduced through the procedure change process, which has a one month consultation period as opposed to through the rule change process, which has multiple periods of consultation and feedback. For a major market impacting change like this, there should be more consultation and feedback, not less. The large effect this change has, coupled with the short period of consultation, will increase the perceived regulatory risk of the WA Electricity Market and may in turn reduce the attractiveness of the market and increase costs to users in the long run.

Given the long term nature of capital investments in power generation plant, decisions are made on a long term basis – capital is recovered over 10 to 20 years. Investment decisions require certainty in terms of procedure and stability – as mentioned above, regulatory risk does not aid certainty in terms of market stability and economic modelling.

<u>Approximation of Construction Costs</u>

In response to the 6 month "approximation" of construction costs, we note that in the real world, a number of costs are front ended – engineering design, deposits for long lead time parts, and approval submission costs amongst others. The Report commissioned by the IMO suggests that a straight line approximation from 12 months out from commissioning to commissioning date closely represents the cashflow of a project. Given the IMO has instigated a two year forward capacity market, and the fact that the IMO requires significant commitment (which can be represented by expenditure) prior to allocating capacity credits for any particular project, it is assumed the IMO also recognises (and requires) more than an insignificant level of funds prior to the commissioning minus two year mark. If it is envisaged by the IMO that funds are expended, in actuality, only from one year out, perhaps the process should be revised to a one year forward capacity market to recognise this fact. Given it has not been a point of discussion thus far, it seems an inconsistent argument to the 6 month expenditure suggested change. We suggest that a one year, or one and a half year period of time be adopted against the 6 month period that has been proposed. This is more consistent with the IMO's position of allocation of capacity credits. It is understood that major payments are required upfront to secure the plant and equipment for delivery around the 3-6 month period prior to commissioning – an assumption that there is a linear expenditure over a one year period is inaccurate.

<u>Inlet Cooling</u>

In response to the inclusion of "inlet cooling" in the capital expenditure, and therefore a reduction in the overall cost of construction, we are supportive. However, in this case, we would like to see the whole power station design re-evaluated as a whole. If the IMO is accepting "inlet cooling" as current standard practice, then perhaps evaluating the cost of closed cycle, or combined cycle stations should be evaluated as well to be consistent with "keeping up with the market". Also, as pointed out at the Public Workshop, the cost of the provision of water to the various land locations has not been priced in to include a water based "inlet cooling" technique. Given this item was overlooked when putting the capital costs of the plant together, a full evaluation of the plant construction should be put into place for incorporation – a partial recalculation of cost is likely to lead to discrepancies in the plant design/costing.

Transmission Cost Methodology

In response to the proposed Transmission Connection Cost Methodology, we believe that Western Power is best placed to determine the future cost of connection to the network. Utilising historical data will guarantee that the connection cost calculation will not be accurate. Western Power's process in determining the cost to connect for input into the MRCP is not the most transparent of processes, but calculating the costs to connect in real life is also not entirely transparent due to the complexities of the network itself. Utilising a pool of historical costs (that as an aside will always lag the true market due to the "weighting" system) will be just as opaque, if not more opaque, as the market will not have the opportunity to see the data set that went to create the final blended price.

Furthermore, utilising historical data will have to be normalised for the various run back schemes that have been put into place. The costs of connection to the network might be somewhat lower to participants that have already connected with a run back scheme implemented, but there is no central register of run back schemes that are in place. As a consequence, there has been no analysis of the capital savings that have occurred because of these run back schemes. As a minimum, as the procedure requires adherence to the Access Code and Technical rules, the historical connection application costs will need to be normalised to a connection cost without run back scheme attached.

As a matter of course, generators wishing to connect to the network pay actual costs to connect which bear little to no relationship to historical costs given the constraints on the network. Again, this emphasises historical costs will not be reflective of the plant the procedure is envisioned to embody.

It also is not likely that the "average per unit capacity" cost of connection is an accurate representation of the likely connection cost for a 160MW. The cost of connecting a plant to the 330kV system is likely to be significantly higher than the cost of connecting a plant to the distribution network for example. However, the revised procedure will likely take a distribution connected plant into account when calculating the average cost. Following this thought process; it is also likely there is a threshold at which connection prices incur a step change (i.e. not follow an average per unit capacity theory). For example, a 100MW connection may be below a large upgrade threshold (and the proponent would have sized accordingly). The 160MW connection would be subject to a higher average per unit capacity cost, but would not be reflected in a historic average calculation. This seems inconsistent with the terms of reference.

Western Power has stated in its most recent Annual Planning Report that the transmission system is reaching the "limit of its ability to transfer power across the system". These limits are impacting on the ability of new generation to connect to the network at a reasonable connection cost. While Western Power is working on "unleashing" their network capacity, this has not yet occurred and is envisioned to take a number of years. In the meantime, applications are made, but either put on hold or withdrawn due to high connection costs. While these connection costs are real, under the proposed process, these would not be counted in the "average per unit capacity" cost. It is a flaw in the proposed process where real connection applications are not being counted when the proponent cannot proceed to financial close due to high connection costs. Western Power has only recently requested further significant increases in their recoverable revenue due to the urgent need for network upgrades. This exemplifies the high cost of connection to the SWIS.

This process is likely to result in either an inaccurate data set of historical prices, or will result in proponents pushing forward to the Access Proposal stage with uneconomical projects to ensure these are registered in the future data sets. This will place an unnecessary burden on Western Power to process applications which may not be feasible.

Removal of Locational Characteristics

There is also the issue of removing the locational characteristics of the "model plant". It is unclear as to how a proponent would build a plant from taking a blended and historical Western Power Connection cost at an unknown location blended with the lowest land price available. By simple logic, it is likely that the lower cost connection points are being (or have been) taken up by other proponents. In our view, the proposed methodology no longer reflects a potential project, but the conglomeration of the minimum of each input cost available. This does not seem consistent with the required outcomes of the MRCP methodology.

Fixed O&M Costs

We also would be looking for modification to the process that the network access charges utilised for the "fixed O&M costs" portion are inflated to a fair expectation of cost at the time of operation – it appears that the WEM is undergoing a structural shift in the network access charges as exemplified by the consistent increases in the access charges allocated by Western Power year on year. These have been significantly above CPI for the last number of increases which may not have been incorporated into the MRCP calculation. It is important to note the procedure merely utilises CPI for the growth rate where in actual fact in April 2010, transmission tariff components were increased by 14% and distribution tariff components by 16%. In addition, in April 2011, an increase of transmission tariffs of 8.7%, transmission tariff components for distribution connected customer's increase of 15.7% and distribution tariff components increase of 15% were approved by the ERA. Moving back to a previous point, the structural shift that is represented by tariff increases may be lost when moving to an averaged historical cost basis.

The IMO should also consider including an allowance for the "assumed forced outage" rate a model plant would experience. If the MRCP is theoretically calculated to compensate for fixed costs and an outage rate is also assumed to be fixed, then an allowance when calculating the required return for an investor is a necessary inclusion.

On balance, we believe further thought into the modification of the MRCP methodology must be put into place prior to any implementation.

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2. Please provide an assessment whether the Procedure Change Proposal is consistent with the Market Objectives and the Wholesale Electricity Market Amending Rules.

Tesla's view on the market objectives are below:

a) To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West interconnected system:

   The proposed change will introduce a level of regulatory risk in revenue models for all generators previously not present in the market. It will take time, but the market will react and amend its perception of risk in the WEM. This may not lead to the most economically efficient outcome. We do not believe it is consistent with the market objective (a).

b) To encourage competition among generators and retailers in the South West interconnected system, including by facilitating efficient entry of new competitors:

The proposed change has no impact on the competition between generators and retailers (within each group) but effects a value transfer from retailers to generators. The value transfer will not facilitate an efficient entry of new competitors as the regulatory landscape (and indeed economic returns) from this procedure change (from the point of view of the generator) will reduce. Therefore we believe the proposed change is not consistent with the market objective (b).

c) To avoid discrimination in that market against particular energy options and technologies, including sustainable energy options and technologies such as these that make use of renewable resources or that reduce overall greenhouse gas emissions:

The proposed change has no impact on this market objective in our view.

d) To minimise the long-term cost of electricity supplied to customers from the South West interconnected system:

The proposed change will (in the long-term) increase the cost of electricity supplied to customers, as the proposed change will reduce the attractiveness of the market to new generators and therefore reduce the level of new generation capacity on the network. It will also reduce the security of the network as a whole, as generation will become more centralised; relying on transmission for energy transfer instead of distributed embedded generation, which more networks around the world are moving to. In the short term, electricity costs will be reduced (if Synergy pass on the savings incurred) but in the long term, overall system costs will increase. Therefore we believe that the proposed change is not consistent with market objective (d).

e) To encourage the taking of measures to manage the amount of electricity used and when it is used:

The proposed change has no impact on this market objective in our view.

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3. Please indicate if the Procedure Change Proposal will have any implications for your organisation (for example changes to your IT or business systems) and any costs involved in implementing these changes.

The proposed rule change has significant implications for our organisation. The suddenness of the change, coupled with the size of the proposed change will likely result in a review of our financing facilities and possibly higher financing costs.

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4. Please indicate the time required for your organisation to implement the changes, should they be accepted as proposed.

Not applicable.