Wholesale Electricity Market
Rule Change Proposal Submission Form

RC_2010_14 Certification of Reserve Capacity

Submitted by

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Submission

1. Please provide your views on the proposal, including any objections or suggested revisions.

ERM Power (ERM) does not support the following Market Rule changes proposed by the IMO in RC_2010_14.

Issue 1: Reserve Capacity Mechanism Timeline

The IMO proposes to bring forward a number of deadlines, in particular moving the application lodgement date from 20 July to 1 July [MR 4.1.11]. The Rule Change specifies implementation from the 2011 Reserve Capacity Cycle. Given the short duration between provisional commencement date (13 June 2011) of the Rule Change and the proposed 1 July deadline for applications, the Rule Change is unacceptable. ERM requests that the amendment apply to the 2012 Reserve Capacity Cycle.

Issue 3: Clarification of Required Availability

The current Market Rule 4.11.1(a) specifies that a Facility's Certified Reserve Capacity is "*not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available ... at daily peak demand times*". The IMO proposes to change the requirement from "at daily peak demand times" to "*for Peak Trading Intervals on Business Days*".

ERM notes that the IMO has presented that the purpose of the Rule Change is to relax the current Market Procedure from 14 hours per day every day to 14 hours per day on business days only. In the interests of ensuring that new-entrant peaking generation can be introduced by IPPs in WA, ERM has maintained a position that it disagreed with the IMO's interpretation of the Market Rules, as set out in the Market Procedure, for the following two key reasons:

1. Gas supply arrangements are typically 90-100% Take or Pay and as such low capacity factor plant will be required to contract and pay for far more gas than used. ERM appointed ACIL Tasman to conduct a review of the proposed change to Market Rule 4.11.1(a) and determine the impact on the market. ACIL's report **attached** concludes that such a requirement would, conservatively as a best case, result in more than 220TJ/day or 55PJ/annum in fuel being contracted firm but not used; ACIL also notes the potential for it to be several times that number. At a market price of $7.50/GJ this would cost the WA State more than $390 Million p.a. in surplus fuel costs (approximately 50% of wholesale energy costs). This excludes expansions of the Dampier to Bunbury Natural Gas Pipeline that would be needed to meet the fuel requirement; and
2. ERM maintains that the original designers of the Market Rules, no doubt recognizing item 1, did not in that specific place in the Rules use the defined term Peak Trading Intervals that is otherwise used throughout the remainder of the Market Rules but rather relied on the administrators of the Market Rules to apply sensible assessments ("IMO's reasonable expectation") to plant given expected operating profiles.

Accordingly ERM does not see the Rule Change as a relaxation but rather as a formalization of an onerous requirement on peaking generators that will preclude any further IPP investment in peaking generation in the WEM. From a gas commodity and transport contracting perspective it is not possible to contract for 'firm' gas supply for business days only. In addition it is not possible to contract for only 10 months of the year as interpreted in the Market Procedure. Note that Market Rule 4.10.2 specifies a 12 hour storage requirement for an alternative fuel source which has typically been applied as a requirement for diesel storage. However Market Rule 4.11.1(a) would appear to apply to primary fuelled diesel peaking plant (to not would be to discriminate between gas and diesel peaking plant) and the proposed amendment would similarly require exceptionally inefficient investment in the diesel fuel supply chain. These costs have not been included in the estimates provided in Item 1 above.

With the IMO having commenced the Reserve Capacity Mechanism review ("RCM Review") ERM recommends that the introduction of any rule change regarding Reserve Capacity Certification, which is a central part of the Reserve Capacity Mechanism, be deferred and rolled into the terms of reference for the RCM Review. In addition, ERM notes that the IMO engaged MMA to carry out an Assessment of Fuel Capacity Requirements to Meet the System Reliability in the SWIS. As far as ERM is aware this body of work has not been concluded.

Based on the above, ERM strongly opposes the amendments proposed to MR 4.11.1(a) and believes that the IMO has not carried out a thorough review of the issue.

Issue 5: Widen requirement for provision of environmental and transmission access approvals

The IMO proposes to review Environmental Approvals as part of the annual certification process rather than a once off for Facilities yet to enter service.

It is unclear as to what environment approval information the IMO would like to see as part of every Facility's annual certification process. The definition of Environment Approvals does not appear to have been amended and refers specifically to construction approvals not operations. Prior to construction a Ministerial Statement and Works Approval is required from the DEC. Once the Facility is constructed the Ministerial Statement does not have an expiry date. Prior to commercial operations an Environment (emissions) License is required from the DEC. This is renewed on an annual basis. However, this is only done for the following year (based on the anniversary of the license) and therefore the timing of the renewal does not fit in with the Reserve Capacity Cycle. Market Generators can submit to the DEC for a 3 year license approval but it would be unacceptable for the IMO to enforce that Market Generators now carry out this process.

Our view is that the risk to the IMO is for construction only and hence the definition of Environment Approvals and the annual certification process should not be amended. This issue needs further clarification and consideration by the IMO.

2. Please provide an assessment whether the change will better facilitate the achievement of the Market Objectives.

Based on the response provided to Issue 3, it is clear that the proposed change to the fuel requirement will most certainly not achieve the economically efficient component of Market Objective *(a) "To promote the economically efficient, safe and reliable production and supply of electricity and electricity related services in the South West Interconnected System."*

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

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

As commented above regarding the timing of the proposed change with respect to the upcoming 2013/14 capacity certification process, ERM maintains that there is insufficient time to implement the proposal.

ATTACHMENT:

ACIL TASMAN REPORT – FUEL AVAILABILITY FOR CAPACITY CREDIT CERTIFICATION

Fuel availability for capacity credit certification

Implications of the proposed WEM rule change
RC_2010_14

Prepared for ERM Power and Infrastructure Capital Group

11 April 2011

ACIL Tasman

Economics Policy Strategy

Reliance and Disclaimer

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Introduction

ACIL Tasman has been engaged by ERM Power and Infrastructure Capital Group to examine the implications of the Independent Market Operator (IMO) proposed rule change in relation to availability requirements for capacity credit certification.

The IMO has published a Draft Rule Change Report: Certification of Reserve Capacity (Ref: RC_2010_14), dated 11 March 2011. This document sets out proposed rule changes to address 12 identified issues.

This report focuses solely upon a subset of Issue #3 - Clarification of Required Availability. With this issue, the IMO considers WEM rule 4.11.1(a) requires clarification because of a few ambiguous terms. Notably, the phrase "likely to be available ... at daily peak times".

The current WEM rule 4.11.1(a) is detailed in Box 1 below.

Box 1 **Current WEM rule 4.11.1 (a)**

4.11.1. Subject to clause 4.11.7, the IMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle to which the application relates:

(a) subject to paragraphs (d) and (e) and clause 4.11.2, the Certified Reserve Capacity for a Facility for a Reserve Capacity Cycle is not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available from that Facility, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, at daily peak demand times in the period from the:

i start of December for Reserve Capacity Cycles up to and including 2009; or

ii trading day starting on 1 October for Reserve Capacity Cycles from 2010 onwards

in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41°C;

Source: WEM Rules Chapter 4, 1 April 2011, http://www.imowa.com.au/f769,1079748/WEM_Rules_Updated20110401.pdf

As noted within the Draft Rule Change Report there are three points which the IMO is seeking to clarify through the proposed rule change:[1]

> The Market Rules currently require the IMO to assess the level of capacity "likely to be available ... at daily peak demand times" (clause 4.11.1(a)) in assessing an application for Certified Reserve Capacity. The IMO considers that this statement requires further clarification in the Market Rules.
>
> - There is ambiguity in the Market Rules around the ability to award Capacity Credits to a Non-Scheduled Generator according to the methodology described in clause 4.11.1(a). A key component of the Reserve Capacity Target is the reserve margin, which allows for the unexpected unavailability of one or more generators on the SWIS. A Non-Scheduled Generator, unable to be directed by System Management to increase its output in the event of Forced Outages, cannot contribute to the reserve margin and thus cannot be expected to be available at "peak demand times". Such a Facility should, therefore, only be eligible for certification under the methodology typically used for Intermittent Generators, as described in clause 4.11.2(b). This methodology currently considers average output during the previous three years.
> - The requirement for a peaking plant to have sufficient fuel to support operation for 14 hours each day for 10 months of the year is extremely onerous and could result in Market Participants incurring unnecessary additional costs. It is unlikely that peaking plants will be required to operate at this level so it would be reasonable to clarify the availability requirement to refer to Peak Trading Intervals on Business Days, particularly given that system demand is typically lower on weekends and public holidays.
> - The Market Rules state that in order for a Facility to be certified as dual fuel it must have sufficient supply and/or supply of the back-up fuel to maintain 12 hours of operation. However, the Market Rules do not state the required level of operation.

To address these identified issues, the IMO's proposed solutions are:[2]

1. stipulate that the methodology described in clause 4.11.1(a) is only applicable to Scheduled Generators
2. clarify the requirement in clause 4.11.1(a) for Facilities to be "likely to be available ... for Peak Trading Intervals on Business Days" to clarify the fuel requirements
3. clarify in clause 4.10.2 that dual-fuelled Facilities must be able to operate for 12 hours at the requested level of Certified Reserve Capacity.

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[1] IMO, Draft Rule Change Report: Certification of Reserve Capacity (Ref: RC_2010_14), 11 March 2011, pg 45.

[2] ibid., pg 46.

This report focuses on the second of the identified problems and the IMO's solution. The following sections sets out the proposed changes to WEM rule 4.11.1(a) and the market implications of such a change.

Proposed rule change

The proposed changes to WEM rule 4.11.1(a) is set out in Box 2 below showing the original text with deletions and additions in red.

Box 2 **Proposed changes to WEM rule 4.11.1 (a)**

4.11.1. Subject to clause 4.11.7, the IMO must apply the following principles in assigning a quantity of Certified Reserve Capacity to a Facility for the Reserve Capacity Cycle ~~to~~ for which ~~the~~ an application for Certified Reserve Capacity has been submitted in accordance with section 4.10 ~~relates~~:

(a) subject to clause 4.11.2, the Certified Reserve Capacity for a ~~Facility~~ Scheduled Generator for a Reserve Capacity Cycle is not to exceed the IMO's reasonable expectation as to the amount of capacity likely to be available ~~from that Facility~~, after netting off capacity required to serve Intermittent Loads, embedded loads and Parasitic Loads, ~~at daily peak demand times~~ for Peak Trading Intervals on Business Days in the period from the:

i start of December for Reserve Capacity Cycles up to and including 2009; or

ii trading day starting on 1 October for Reserve Capacity Cycles from 2010 onwards

in Year 3 of the Reserve Capacity Cycle to the end of July in Year 4 of the Reserve Capacity Cycle, assuming an ambient temperature of 41°C;

Source: Draft Rule Change Report: Certification of Reserve Capacity (Ref: RC_2010_14), dated 11 March 2011 pg 33-34

The key change relates to the deletion of the ambiguous phrase "*at daily peak demand times*" and its replacement with "*for Peak Trading Intervals on Business Days*" which includes two defined terms:

- Peak Trading Intervals: defined as Trading Interval occurring between 8 AM and 10 PM (i.e. 14 hours per day)

- Business Days: defined as a day that is not a Saturday, Sunday, or a public holiday throughout Western Australia.[3]

Continuing ambiguities

The proposed rule change continues the use of the phrase "... IMO's *reasonable expectation* as to the amount of capacity *likely to be available* ..." (emphasis added).

It should be clarified as to exactly what the IMO's reasonable expectation is. Is it a requirement for 'firm' fuel supply and transport entitlements for the entire period? Or is it something less onerous and tailored to the type and expected role of the plant seeking certification? Is this reasonable expectation likely to change over time?

In addition what is the precise meaning of the words "likely to be available"? Can this be quantified? Is it a 50% or 90% likelihood of capacity being available?

ACIL Tasman believes this wording needs to be clarified. Based on discussions with representatives from ERM Power, it is understood that IMO's expectation is that firm fuel supply would need to be procured for the defined period. That is, IMO's reasonable expectation is that fuel supply is 'firm' and this will result in capacity likely to be available.

This view is reinforced by the statements with the proposed rule change document which suggests that the existing rules "*are extremely onerous and could result in Market Participants incurring unnecessary additional costs*."[4]

For the purposes of the subsequent sections, we have taken the view that the meaning of the wording "reasonable expectation" as it relates to fuel procurement, means a requirement for firm supply and transport entitlements for Peak Trading Intervals on Business Days.

Market implications

The IMO appears to suggest that the current rule requires generators to have access to fuel to support generation for 14 hours per day, every day for 10 months:[5]

> The requirement for a peaking plant to have sufficient fuel to support operation for 14 hours each day for 10 months of the year...

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[3] Note that another definition of Business Day applies in relation to settlement clauses 9.16.1(b), 9.16.2(e) and 9.16.4(d).

[4] ibid., pg 45.

[5] ibid., pg 45.

This equates to a firm fuel requirement sufficient to support an annual capacity factor of around 50% (around 4,260 hours out of 8,760 in a standard year).

The change to defined terms for Peak Trading periods on Business days implies that to gain accreditation, a generator must have access to fuel for the defined period. This is the equivalent of having access to firm fuel sufficient to support an annual capacity factor of 40% (14 hours per day for 250 days)[6].

While this requirement is potentially not a concern for baseload generators, it is clearly this is an inefficient outcome for peaking generators which have an expected capacity factor much less than this – in some cases only 1%.

It is not sensible, nor efficient, to impose these fuel requirement upon peaking generators. It would likely cause a short-term reserve capacity shortfall as some existing generators would be unable to meet the requirements and have their capacity credit allocation revised downward. At the same time, new peaking generators would not be able to access sufficient firm fuel capacity to gain accreditation or face exorbitant costs in doing so. These combined effects would substantially increase the cost of meeting the reserve capacity requirement.

Physical implications

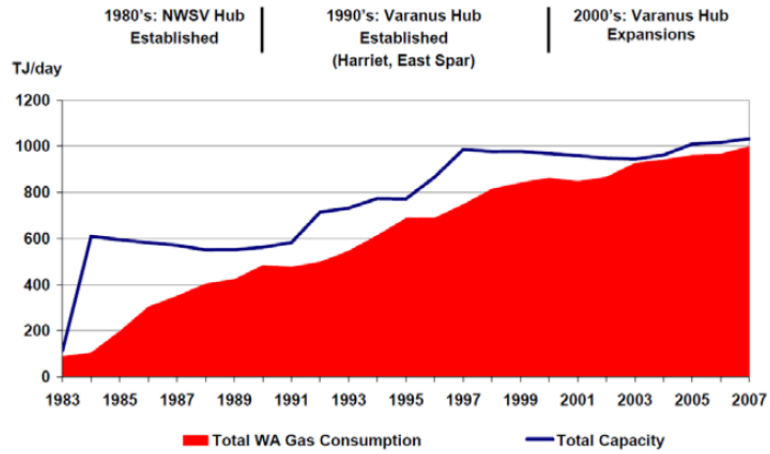
Current upstream gas processing capacity is around 1,000 TJ/day, comprised of:

- North West Shelf domgas: ~600 TJ/day
- Varanus Island: 356 TJ/day (individual plants at Harriet and John Brooks are 240 TJ/day each but the aggregate output is limited by the pipeline to shore)
- Perth Basin: aggregate capacity of 160 TJ/day, but remaining reserves of only ~15 PJ mean that much of this capacity is inactive.

The historic consumption and capacity profile for Western Australian natural gas is shown in Figure 1. Based on this figure, there is limited spare processing capacity in the market.

[6] There are approximately 260 weekdays during the year, less 10 public holidays.

Figure 1 **WA gas consumption and capacity profile**



Data source: Prepared by Woodside with reference to ABARE and APPEA publications, presented at AIE luncheon in Aug 2007. Submission from NWS Project Participants to the Economics and Industry Standing Committee Inquiry into Domestic Gas Prices 2 July 2010.

Current pipeline capacity to the South West is around 900 TJ/day comprised of:

- DBNGP current firm forward haul capacity of 895 TJ/day
- Parmelia Pipeline current firm forward haul capacity of 65 TJ/day.[7]

The DBNGP is fully contracted and currently has no spare firm capacity, although new capacity can be added through additional compression or looping.

ACIL Tasman conservatively estimates that if the IMO was to impose 'firm' gas supply and transport requirements on all gas-fired capacity, it would result in an additional capacity requirement of around 220 TJ/day. This equates to a 20% to 25% increase to the currently installed supply and transport capacity in Western Australia.

Existing generators would not be able to access firm capacity of this magnitude until additional capacity was constructed. This could take a number of years and would constitute a massive investment in new capacity.

Note that the current DBNGP capacity is sufficient to support all gas-fired generators running simultaneously for short periods of time as access to gas and pipeline capacity can be purchased on a short-term basis from other industrial users. However, this gas and pipeline capacity is opportunistic and not firm. Firm supply capacity to support generation at capacity factors of 40% is simply not currently available.

[7] Note that the Parmelia Pipeline only extends from Mondarra in the Perth Basin to Pinjarra south of Perth.

The same arguments would apply for liquid fuelled generation. ACIL Tasman estimates that based on the current plant fleet that uses diesel as a primary fuel, the rule change would require these plant to source in aggregate around 70 TJ/day of fuel. This equates to around 500 million liters of diesel per year – around 18% of BP's Kwinana refinery current diesel production capacity[8]. Getting access to firm supplies for these sort of volumes would require expansion of the refinery and possibly the tank distribution fleet.

Commercial implications

A typical peaking generator seeking capacity credit certification would be required to purchase firm gas supply for an equivalent capacity factor of around 40% (14 hours a day per business day). This capacity would be requirement to be 'firm', that is, available upon request by the user. This requirement would include upstream processing capacity as well as pipeline capacity. However it would rarely be expected to generate and hence would be seeking a very low take-or-pay (essentially the user would be requesting supply capacity be installed and funded by producers and reserved for their exclusive use and only pay for gas that they actually use). Such gas supply contracts are simply not available in Western Australia – or anywhere else for that matter.

A typical gas supply contract is specified in capacity terms (in TJ/day) and have an associated take-or-pay volume, expressed as a percentage of capacity. Due to the tight market conditions, suppliers have been noted to decrease flexibility offered under new contracts with 100% take-or-pay conditions now common[9] (historically 90% has been more typical range).

It would be prohibitively expensive for a peaking generator to purchase gas on a 100% take-or-pay basis when its actual requirements were only a small percentage of this total. It would be faced with the unlikely prospect of on-selling gas not required into the gas market (if its contract conditions even allowed this). This may be possible when the volumes are relatively small. It is not uncommon to see 5 TJ or 10 TJ of re-trading, but certainly not at the scale considered here.

In terms of annual volumes, the 220 TJ/day equates to around 55 PJ/a of additional purchases. Assuming that only 5% of this volume is actually required, generators would be looking to on-sell around 52 PJ/a. At a market

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[8] BP factsheet, http://www.bp.com/liveassets/bp_internet/globalbp/STAGING/global_assets/downloads/A/abp_wwd_australia_kwinana_fact_sheet.pdf

[9] Economics and Industry Standing Committee, Inquiry into Domestic Gas Prices, Report No. 6 in the 38th Parliament 2011, pg 63.

price of $7.50/GJ, this would equate to an exposure of approximately $390 million per annum.

The above estimate is based on a realistic assessment of current fuel and pipeline capacity entitlements. Given that some market participants are currently long on gas supplies this results in a conservative value. More generally, the rule change is essentially suggesting that all generators must have access to 'firm' fuel to support generation at 40% capacity factor. This results in all generators whose expected capacity factor is below this (all peakers and some intermediate plant) would be expected to purchase more fuel than they require. The upper bound of additional fuel requirements therefore may well be several times bigger than the $390 million per annum stated above.

Similar arguments exist in relation to pipeline transport capacity. Peaking and intermediate gas-fired generators rely on 'as-available' pipeline capacity to varying extents. It is simply not economic to purchase and reserve pipeline capacity when it is only likely to be required for a small portion of the year.

Impact on the MRCP

Under the proposed rule change any new peaking capacity looking to enter the WEM would be forced to fund the development of upstream and transport infrastructure. This would need to be factored into the IMO's calculation of the Maximum Reserve Capacity Price.

For example, a 160 MW gas-fired peaker would require firm fuel entitlements to support full station output for 14 hours of operation. At a thermal efficiency of 32% HHV, such a station would consume around 1.8 TJ/hour. This would mean an aggregate capacity requirement of around 25.2 TJ/day.

The cost of acquiring firm supply and transport capacity would not be insignificant.

Gas production costs from the Reindeer gas project which is the most recently committed development to supply domgas in WA cost an estimated $842 million to develop 215 TJ/day.[10] Based on this observation, a reasonable benchmark for upstream capital costs may lie between $3-$4 million per TJ of sales gas production capacity. Using the lower bound of this range of $3 million per TJ, the upstream capital cost required is around $75.6 million.

The recent expansions of the DBNGP have seen a capital expenditure of around $1.8 billion to enable an additional 300 TJ/day of firm capacity

[10] Santos media release: Reindeer Project Sanctioned, 7 April 2008. Note the Santos share of the project is 45%. The project does include production of condensate and this would contribute to capital costs somewhat.

($6m/TJ). The most recent expansion project, Stage 5B, cost an estimated $675 million to yield an additional 110 TJ/day ($6.1m/TJ).[11] Using a transmission capacity benchmark of $6m/TJ the transmission capital cost required to support an additional 25.2 TJ/day is around $151.2 million.

Therefore the total additional capex required is approximately $227 million, making it more expensive than the power station used within the MRCP calculation itself. If this was added to the EPC contract cost for the power station, the calculated 2013-14 MRCP would increase from $240,600/MW/year to $536,100/MW/year (a 123% increase).[12]

While the above is a relatively crude calculation, it does give an indication of the potential scale of the issue the proposed rule change brings about.

[11] DBNGP press release, January 5, 2010

[12] Calculated using the IMO MRCP calculation spreadsheet. It is noted that the economic life used with the MRCP is only 15 years which is too short for gas supply and transmission infrastructure.