Government of **Western Australia**
Department of **Treasury**

Allocation of capacity credits in a constrained network

Consultation Paper

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Executive Summary

This consultation paper is the second of three papers the Public Utilities Office is releasing as part of its industry consultation on the adoption of the constrained network access framework for Western Power's network in the South West Interconnected System (SWIS).

In electricity markets, a network constraint is a limit on the flow of electricity through a network. A network is said to be experiencing congestion when a constraint restricts the supply of electricity or inhibits the merit order dispatch of electricity generators.

The current Wholesale Electricity Market (WEM) in the SWIS consists of an energy market and a separate capacity market, operating on an unconstrained market design when all network elements are in service. This design approach assumes the network is unconstrained and consequently the generation dispatch process and determination of energy prices does not account for the physical limitations of the transmission network. Constraints, when they occur, are managed in real time by manual intervention. Additionally, new entrant generators have to fund network upgrades to preserve the state of network congestion prior to being connected.

An unconstrained market design for the SWIS is no longer sustainable for three fundamental reasons. The first is that the unconstrained design has become a barrier to new entrant generation facilities (predominantly renewables) seeking to connect to the electricity network. Secondly as the transmission grid has become more congested, operational management of the system has become more complex with further congestion being likely to compromise system security and the efficient dispatch of energy supplies. The third reason is an increasing risk that there are ample capacity resources to meet the Reserve Capacity Target but that they are located such that network constraints restrict the flow of energy to satisfy customer demand in high demand conditions, resulting in possible overpayments to unavailable capacity.

Accordingly, it is proposed to implement a constrained market design for the WEM. This will involve adopting a security constrained dispatch system and revised approach to the allocation of capacity credits to generators through the Reserve Capacity Mechanism to account for physical limitations in the meshed transmission network.

This consultation paper is intended to facilitate discussion on the required changes to Reserve Capacity Mechanism in the WEM resulting from the adoption of a constrained network access model. In this paper, the Public Utilities Office has outlined a proposed process for capacity credit allocation to account for network constraints.

The intent of the proposed approach is to not issue capacity credits beyond physical limitations of the transmission network accounting for forced generator outages. The proposed approach will achieve this by assessing the ability of each generator on the system to export its energy into the network under the expected peak demand load scenario, with capacity credits to be allocated to each generator on that basis.

Where a constraint is identified the total number of capacity credits to facilities affected by the constraint would be limited to the amount of available network capacity.

This assessment would be based on “maximising reserve capacity”, meaning that network constraints will be simultaneously solved in a manner that ensures the least possible number of megawatts of generation capacity would be constrained in order to relieve network constraints. Accordingly, when a network limitation is triggered the generator with the highest contribution to a network limitation would be constrained first.

Where more than one facility is affected by a constraint, a method would be required to determine the assignment of capacity credits and consequent capacity revenues. The proposed approach involves the creation of “capacity priorities” that establish the order in which capacity credits are assigned. Existing facilities at the time of implementation would be granted capacity priorities for their assessed level of unconstrained capacity. Thereafter, capacity priorities would be allocated on a first-come first-served basis subject to physical limitations of the network. It is proposed that capacity priorities would be granted for a period of up to ten years.

The proposal outlined in this paper will require more granularity for implementation. A number of issues that will need to be resolved during further consultation are identified.

A model for assessing the network congestion effects of individual generators will need to be developed. The Public Utilities Office has developed a model to test the feasibility of using such an approach as a basis for allocation of capacity credits. The results from the model will be shared with industry during consultation on the financial implications of the introduction of constrained network access on generator revenues.

The model developed by the Public Utilities Office is only preliminary, this work has demonstrated that the approach proposed in this paper is feasible for further development and implementation through a detailed design process, including further consultation.

There are numerous important matters that need to be addressed in order to move from the proposed conceptual solution in this paper to a detailed design that is ready for implementation. These matters are identified in Section 4 of this paper and will require industry input in order to develop a workable solution.

1. Accreditation of capacity in a constrained network

The Public Utilities Office considers that the Reserve Capacity Mechanism should continue to operate on the basis of a single capacity price to preserve the integrity of these arrangements. However, capacity markets with a single market price can result in perverse signals for capacity investment in a constrained network.

Specifically, there is potential for market failure with a single capacity market price. This model may not provide adequate signals for efficient capacity location, with perverse incentives for capacity to locate behind a network constraint. There are potentially substantial market implications where this occurs in an export constrained region.[1]

With increasing network congestion the likelihood of a generator being unable to generate during peak times will be increased, until such time as a network investment test is satisfied to build out the constraint on the basis of the network benefit to customers. There is potential market failure if all capacity is valued equally using a single market wide price, but some capacity is not able to provide an equal contribution to supply reliability due to network constraints.

A revised approach to capacity certification under a constrained network environment must therefore account for these considerations and provide a clear, transparent approach that is understood by all market participants.

1.1 Overview of proposed approach

To ensure a revised approach for assigning capacity credits to account for network constraints does not change the underlying principles of the Reserve Capacity Mechanism, the following objectives must also be satisfied. It should:

- encourage economic and efficient investment in the WEM and preserve the integrity of the mechanism for establishing the price of capacity, including the avoidance of unnecessary barriers to entry and risk minimisation to encourage and support new investment;
- not compromise efficient dispatch in the energy market;
- enable the Reserve Capacity Mechanism to meet the Reserve Capacity Target at least cost to consumers; and
- provide technology neutrality.

Changes to the Reserve Capacity Mechanism directly relating to the introduction of constrained network access should also:

- be consistently applied in a predictable manner; and
- provide transparent signals to the market as to where constraints exist, or will exist, on the network, and importantly, where there are unlikely to be constraints.

[1] An export constrained region is an area where generation capacity exceeds the transmission limits of the network to ‘export’ the capacity to the rest of the system.

The proposed approach is intended to ensure that the amount of capacity credits does not exceed the amount of capacity that the network can physically handle accounting for unplanned generation outages. Where a constraint is identified the total amount of capacity credits allocated to facilities affected by a constraint would need to be limited to the thermal limits of the network. If multiple generators affected by a constraint are competing for the limited capacity, a method of determining the allocation of available capacity credits will be required.

All else being equal, capacity credits should be assigned to the cheapest capacity provider. However, as the Reserve Capacity Mechanism values all capacity equally there is no ability for capacity bid prices to distinguish between facilities. A rules based tie breaker will be required for which the Public Utilities Office has identified three options:

1. The generation facility requiring the least missing money (generally the plant with the lowest energy price);[2]
2. A pro-rata basis; or
3. A first-come first-served basis.

The Public Utilities Office considers that a “first-come first-served” approach should be adopted as a first method of resolving the tie break. With the requirement to adhere to a single market-wide capacity price and maintain the principle that each capacity credit is equal to one megawatt of physical capacity, the first-come first-served approach will lead to the most economically efficient outcome. That is, it should best reflect the outcomes expected to occur if there were locational energy and capacity prices compelling providers to make decisions based on the marginal value they are providing.

This approach would require future capacity providers to consider where their capacity is located and how it contributes to system reliability.

The Public Utilities Office also considers that there would be merit in granting certain facilities a priority to capacity credit revenues (a “capacity priority”) relative to other capacity providers. This priority would be granted on a “first-come, first-served” basis.

Such a capacity priority would not imply any right to energy dispatch. Capacity priorities would be time limited for 10 years, whereby when a capacity priority expires, the facility will be assigned Capacity Credits without any priorities. New priorities would then be assigned, including to the facility whose priorities had expired, based on a set of criteria (see section 1.3.1). Irrespective of facilities being granted capacity priorities, AEMO would not be able to issue more capacity credits than the total physical capacity of the network.

Importantly, facilities without capacity priorities would still be eligible to connect to the network, and under the security constrained market model, would be dispatched based on energy market bids. The assignment, or lack of a capacity priority, would not affect the order of dispatch.

[2] There is technically a fourth option that has a highly correlated result to this option, to assign capacity credits in a way which limits the constraint based on the constraint equation co-efficient. However, the Public Utilities Office has not pursued this option at this time because the results are highly volatile to changes in the network and the load on the network. This means that in the space of a year, a facility could be assigned zero capacity credits while another is assigned credits equal to their full certified capacity, and the following year the assignment could swap.

The Public Utilities Office considers that providing generators an ability to gain capacity priorities in the manner suggested will have the following benefits, as further detailed in Section 2.1 of this paper:

- It will likely promote economically efficient investment signals in most situations.
- It will provide generators with the ability to avoid an otherwise unhedgeable risk of a new entrant inefficiently locating in a constrained area of the network and displacing their future capacity revenue. New investment in capacity may not occur if this risk is seen to be substantial, or may require higher hurdle rates of return.
- It will restrict inefficient wealth transfers between competing generators that are unlikely to result in benefits for consumers.

"Least missing money" option

On first view, assigning capacity credits on the basis of the facility requiring the least "missing money" (the difference between the capital cost and revenues recovered from energy generation) would seem to best reflect an economically efficient outcome. However, this is not the case with the Reserve Capacity Mechanism, predominantly because the capacity and energy pricing regime does not reflect the incremental value of additional resources in each location. Allowing assignment of capacity credits based on the energy costs of a facility would not send economically efficient signals for areas that are constrained.

With surplus capacity, this approach would provide an incentive for new, low cost, energy providers to increasingly add capacity resources when it is not economically required, because they could locate in a manner to "knock out" their rivals.

For example, consider the scenario where the WEM is in an excess capacity situation and a new facility (say a wind farm) wants to enter, with a choice of locating in two different locations: location A, where there is a good wind resource but is fully constrained; and location B where there is a less reliable wind resource, but no constraint. A truly value reflective price would have the capacity in location A at a near zero price because the additional capacity would provide consumers with little to no benefit. Further, the marginal value of energy at that location would also be very low. Therefore the wind farm would not be incentivised to locate in that area if economically efficient signals were being sent.

However, because there is a single market-wide capacity and energy price, the capacity price would not necessarily be zero. Further, the energy price would not necessarily align with the marginal cost of dispatching energy within the constrained region. Accordingly, a new entrant locating in location A would likely receive a price much higher than the value it is contributing to the WEM.

The cost of the new facility choosing to enter location A, would therefore include:

- The additional capacity would not provide any additional supply reliability to the SWIS.
- There would be a wealth transfer from the existing facility to the new facility, without necessarily creating any benefit for consumers.

- If the facility that is "knocked out" is also a sub-marginal energy producing facility, the new facility would not lower the overall cost of energy in the WEM. In fact, because the facility was able to knock out its rival, it would likely be able to increase the cost of energy to the SWIS relative to the cost of energy to the SWIS if it had been established at location B. This provides a perverse incentive for facilities to locate in areas of constraint where a competitor is already located.

This option would also have serious ramifications for the risk profile for existing, and other proposed, facilities. Operators and developers of new and proposed facilities would be faced with an unhedgeable risk where they may, at any time, have a substantial portion of their revenue reduced due to the actions of a new entrant, even if the market wide signal is indicating that the incumbent's product is valuable at that time. Such an unhedgeable risk will be very unattractive to new investors and would be a barrier to entry.

An additional problem, and probably a fatal flaw in itself, with this method is that the calculation of which facility has the least "missing money" would need to be heavily dependent upon a regulator's forecast of production costs and energy prices for the life of the facility. Therefore comparing the potential "missing money" of competing applications for capacity certification would be very difficult and easily disputed by the unsuccessful applicant.

Pro-rata option

This option has similar problems to the lowest missing money option, in that it also creates an unhedgeable risk (i.e. barrier to entry). However, because the risk is "pro-rated" across all providers in the area, the option can be seen as creating a pseudo localised capacity price.

Under this approach all capacity resources in an area with a constraint would receive a smaller share of the total amount of capacity credits, and therefore the payment revenues available for that location (i.e. all parties get a lower quantity which translates into a lower price). This reduces (but does not eliminate) the deficiencies associated with the lack of a localised capacity price inherent in the above option.

There is also an argument that this option could provide for allocation of capacity credits in a manner that facilitates optimal capacity additions across the network by allowing capacity additions which contribute less to constraints than incumbent generators. Because the network is meshed, the dynamic nature of constraints could result in new capacity (with a low, or negative, coefficient)[3] that locates in a congested part of the network having a lower effect on a constraint, meaning more capacity would be available to the market and, potentially, lower energy prices to consumers.

Fundamentally, however, the concern is that this option will provide an investment signal to new entrant generators that greatly exceeds the value of the additional capacity provided by the investment. The price signal will effectively be equivalent to the previous negative 1 sloped administered pricing option that has historically been shown to over-incentivise new capacity when it is not economically needed.

[3] That is, contributing less to a constraint than the incumbent generator.

Additionally, a pro-rata approach will over time increase the price of capacity. This is because the "missing money" that capacity providers need to recoup through capacity payments will increase. The risk of a new entrant losing a portion of capacity and energy revenues will be factored into higher hurdle rates of return. Over the medium term this will act to increase capacity costs and also contribute to a more unstable capacity investment environment.

This type of pricing will however provide more efficient exit signals for generators than the other two options. However, generally exit signals will only be acted on when the locational price is very low or the generator requires an avoidable major capital investment. As has been shown through the previous administered pricing regime, simple pro-rated signals are unlikely to be sufficient to promote plant retirements. Therefore, the Public Utilities Office does not consider the benefits available from pro-rating the capacity available to be sufficient to warrant adoption of this option.

1.2 Accounting for constraints – the current situation

The transition to a constrained network access regime will require changes to two aspects of the current approach to accounting for network constraints in the capacity certification and accreditation processes:

1. How constraints are assessed by AEMO; and
2. When constraints are assessed by AEMO.

1.2.1 How constraints are assessed

Currently, the Wholesale Electricity Market Rules (WEM Rules) require that AEMO must not assign certified reserve capacity to a scheduled generator in excess of AEMO's reasonable expectation of the amount of capacity the facility will be able to deliver at peak times.[4] This necessarily means that AEMO should account for network constraints by assigning certified reserve capacity up to the Declared Sent Out Capacity (DSOC)[5] of a facility, if it has no reason to consider that the facility is likely to be unable to provide its nameplate capacity at peak times.

1.2.2 When constraints are assessed

Another problem with the current process is that AEMO is required by the WEM Rules to assign "certified reserve capacity" up to the level of capacity it reasonably considers a facility can provide based on the physical characteristics of the facility and the electricity network.

The "meshed" nature of the network means, amongst other things, that the level and consequence of a network constraint at any one time is influenced by the level of generation from facilities across the network. Hence, allocating capacity credits after certifying each facility in isolation does not accurately account for network constraints, due to insufficient information at that time about the capacity provided by other facilities.

4 See clause 4.11.1(a) of the WEM Rules

5 Declared Sent Out Capacity: this is the amount of network injection capacity a connected generator has contracted with Western Power.

For example, a constraint may only bind if two facilities are allocated capacity credits, but not if only one is allocated capacity credits. Therefore, if one of those facilities chooses to retire after certification, then the constraint would not limit the capacity credits that could be received by the remaining facility.[6] However, the constraint calculated at the time of certification of reserve capacity (i.e. when AEMO assumes both facilities will continue to operate) reduces the ability of both facilities to concurrently generate and, if one exits, the remaining facility would not be eligible to apply at a later stage in that capacity year for more capacity credits than originally assigned.

For the above reasons, the Public Utilities Office considers that capacity credits can only be suitably assigned following a holistic modelling of the network based on those facilities committed to provide capacity for that capacity year.

1.3 Capacity allocation design considerations

1.3.1 Capacity allocation principles

The Reserve Capacity Mechanism assigns capacity credits to a facility no greater than the level of capacity that the facility is able to provide at peak times. The method adopted for assigning capacity credits in a constrained network market design must reflect this fundamental principle.

A related consideration is that capacity accredited above the forecast peak demand has a value (e.g. including the 7.6 per cent margin that forms part of the Planning Criterion), predominantly because it has been determined to be the economic level of reserve margin at time of peak demand, accounting for the cost of capacity and value of unserved energy which would otherwise be higher if the margin was reduced.

Therefore, in applying the above two considerations it is vital that the adopted method:

1. reflects the physical ability for a facility to generate at peak times;

2. reflects the physical ability of the network to accept that generation output under peak load conditions; and

3. accounts for potential outages at other facilities affecting the constraint/s.

Physical ability for a facility to generate at peak times

The Public Utilities Office considers that the current process that AEMO undertakes to assess each facility's stand-alone physical ability to generate is suitable and should continue. However, network constraints should be dealt with at the time of assigning capacity credits and not during the physical assessment of each facility's maximum generation capability.

[6] It is also possible for a facility to have a positive effect on a constraint, whereby if that facility exists it will lessen the constraint, but where if it does not exist, the constraint is worse.

Physical ability of the network to accept that generation under peak load conditions

Network constraints would be assessed based on a network model to be developed by Western Power and AEMO for the expected capacity year. The network model would reflect the expected network configuration that will exist during the period over which the capacity credits are being assigned, i.e. the delivery year. It is expected that the network model to be adopted in the proposed new methodology will be similar to that which would be used in the WEM for energy dispatch (adjusted for any network build expected to occur for the relevant capacity year).

Accounting for potential outages of other facilities behind a constraint

As the method would need to account for outages, it is proposed that the capacity credits assigned to a facility should factor in the probability of another facility affected by the same constraint being on outage.

2. The proposed approach

The approach proposed by the Public Utilities Office involves assessing the ability of each generator on the system to simultaneously export its power into the network under the expected peak demand load scenario while seeking to "maximise reserve capacity". This means that if any network constraints are violated at time of peak demand the objective will be to constrain generation in such a manner so as to minimise the total amount of generation constrained overall. This objective to "maximise reserve capacity" seeks to provide consumers with maximum reliability from the electricity system.

The Generator Interim Access (GIA) solution utilises a similar approach.[7] The GIA process progressively establishes how much additional generation can come from each GIA generator additional to already dispatched generation from existing generators to meet peak demand.

The proposed approach involves three stages, as outlined below.

Stage 1 – Preparatory stage

The first stage would involve Western Power and AEMO publishing state of the network information, including detail about the level of congestion through the network and identifying any areas that are heavily congested. Additionally, AEMO would be required to publish its network model for transmission level constraints.

All potential capacity providers would be required to lodge their intent to provide capacity for an upcoming Reserve Capacity Cycle early in the first year of a capacity cycle. This process would become mandatory[8] for capacity providers if they wished to be certified. All capacity priorities would also be updated and published at this stage.

Based on the number of potential capacity providers Western Power would calculate the network limits and thermal ratings and provide this information to AEMO. AEMO would then develop the network model and make this available to registered and verified parties seeking accreditation. It is expected that this stage could take six to nine months for each capacity cycle.

Stage 2 – Assessment stage

This stage would involve AEMO undertaking the 'maximise reserve capacity' modelling to identify the level of capacity credits available to each facility – taking into account facility outage rates and facilities with capacity priority.

Following the technical certification of each facility's capability to provide capacity would be an assessment of the ability of the network to accommodate the specified amount of generation capacity of each facility. This would involve AEMO assessing the ability of generators that have applied for capacity credits to generate at peak times in the manner required in the WEM Rules. This assessment will need to assume:

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[7] For more detail refer to Appendix 11 of the WEM Rules https://www.erawa.com.au/cproot/18373/2/Wholesale%20Electricity%20Market%20Rules%2013%20October%202017.pdf

[8] This must be mandatory so that Western Power and AEMO have the ability to update network models for the new entrant facilities ahead of the accreditation stage.

- Demand on the network (and therefore "flow" on the network) is equal to the 10 per cent PoE demand most recently forecasted by AEMO.
- Non-scheduled facilities (e.g. wind farms and solar farms) are operating at the level of capacity assessed for the facility in accordance with the relevant level methodology under the WEM Rules.
- Constraints are assessed based on the applicable network model developed by AEMO in the Preparatory Stage. A suite of dispatch scenarios would be modelled to identify any network constraints. Once any constraints are identified they must be simultaneously solved in such a manner so as to minimise the total amount of generation constrained.

Where a constraint is found to limit the ability of a facility, or a group of facilities, to generate at peak times, the objective to "maximise capacity" will mean that facilities that contribute the greatest to the constraint are considered to be constrained first, and therefore not be eligible for full capacity credits.

Stage 3 – Accreditation stage

Capacity providers assessed as not eligible for their full quantity of capacity credits would need to confirm their acceptance of this assessment or withdraw from the process. This would require an iteration of the capacity credit assessment with AEMO then assigning credits up to the level accepted.

Assessment and accreditation stages would occur sequentially and could take up to a month due to the requirement to interact with Market Participants.

Once AEMO determines the level of capacity that can be accredited to each facility, it would need to inform participants that will be assigned a lower level of capacity. A provider eligible only for a lower quantity of capacity credits will have the option to withdraw from the process. AEMO would need to seek confirmation from each participant eligible for a lower level of capacity as to whether it will still provide capacity given the lower level. This process would occur one participant at a time, commencing with the participant with the greatest effect on the constraints[9] (i.e. it must first seek confirmation from that participant whose decision to withdraw from capacity accreditation would result in highest total number of capacity credits being available).

Where more than one facility contributes equally to the constraint, the facilities would be assigned capacity credits based on capacity priorities and if there is still a tie then on a pro-rata basis.

Where a participant withdraws, AEMO would need to re-run the accreditation stage (where there is any consequence for other participants).

[9] This will ensure that the optimal amount of capacity is assigned capacity credits, because the capacity provider that chose to stay in the market will affect the level of capacity from other providers. Therefore capacity can only be withdrawn from one participant at a time.

AEMO would be required to sequentially inform those participants to receive lower capacity credits and confirm whether each participant will continue to participate in the Reserve Capacity Mechanism for the relevant year. This process will continue until all capacity providers who have been constrained have either accepted a lower level of capacity or withdrawn from the process.

AEMO would then assign capacity credits to constrained facilities up to the levels accepted.

Alternatively, new entrant facilities could be required to provide flexible offers which incorporates an offer of a minimum acceptable number of capacity credits. If network constraint modelling determines the facility is eligible for a quantity of capacity below its minimum offer then the new facility would be excluded from receiving capacity credits.

2.1 The need for "capacity priorities"

Where more than one facility is affected by a network constraint, a mechanism is required for determining the capacity credits revenue. This mechanism requires the creation of "capacity priorities" that determine the order in which capacity credits are assigned.

The Reserve Capacity Mechanism will maintain the single market-wide capacity price and continue to operate on the principle that one capacity credit is equal to one megawatt of physical capacity. On this basis, a first-come first-served approach to assigning capacity priorities would lead to the most economically efficient outcome.

2.1.1 First-come first-served

At a high level, the first-come, first-served method would involve:

Capacity providers being assigned a "capacity priority" up to the level of generation physically able to be exported to the network. Essentially, a capacity priority is a purely financial construct entitling the holder of the priority to available capacity credit revenue in preference to other generators that do not have a "capacity priority".

- Existing capacity (including GIA generators) would be granted a capacity priority in the first capacity cycle equal to their most recent capacity credits following introduction of this revised approach. New capacity would gain a priority at the time when the facility connects to the network <u>and</u> is first assigned capacity credits. This priority would be expressed in megawatts of capacity.
- New capacity providers awarded capacity credits as a result of "obtaining" capacity from a facility holding a capacity priority would have to financially reimburse the capacity priority holder with a capacity payment covering that capacity year. For example, if a new capacity provider connects and is accredited with 20 MW of capacity credits whereas, an existing capacity provider with capacity priority receives 5 MW less capacity credits (due to the new capacity provider) the new capacity provider will pay (through the market settlement system) 5 MW at the capacity price to the capacity priority holder.
- Allocating capacity credits up to the priority would be limited to the physical ability of the network to continue to accept the generation output from the facility and all other facilities with capacity priorities (e.g. if a load centre subsequently experienced a major change in composition that reduced the physical ability for the network to accept a facility's generation output, the level of priority would remain the same as initially granted but the number of capacity credits would be reduced).

- Capacity priorities would have a "use it or lose it" clause, meaning that a facility operator would not be able to horde capacity priorities if they were not being used to provide capacity.[10] Intermittent generators would have their capacity priorities reduced if their certified capacity drops.
- A priority would be forfeited in the event that a facility is not certified for Reserve Capacity.
- Capacity priorities would be time limited and expire after ten years. The Public Utilities Office considers this time period provides a reasonable trade-off between investor certainty and promoting efficient plant retirements and new entry.
- Facilities without a capacity priority (and consequently without capacity credits) would still be eligible to connect to the network, and in a security constrained market model would be dispatched based on energy market bids. The lack of a capacity priority would not affect the order of dispatch.
- The total amount of available capacity will change over time as demand grows, or large loads connect/disconnect, or the network is augmented.

2.1.2 Economic rationale for adoption of capacity priorities

Adopting the first-come first-served model will encourage developers to locate their facilities in areas providing maximum capacity to the system – this concept is consistent with the concept of a system wide capacity price, as developers will be responding to market-based signals. New developers wanting to locate in a constrained part of the network will face an effective price that is more responsive to the level of capacity in this location, or even a price of zero if the region is already completely constrained.

Capacity priorities will provide another benefit in reducing the unhedgeable risk of an investment being exposed to new and unnecessary facilities locating in a slightly better location and taking that facility's capacity revenue.[11] Capacity priorities would greatly improve the risk profile faced by current and future generators (compared to the situation without such a mechanism), and result in a more consistent and predictable income stream. This in turn would encourage sustainable investments in the WEM at a lower cost.

Importantly, a capacity priority would only relate to the holder's ability to receive capacity credits revenue and not provide rights of dispatch and/or energy revenue. Therefore, incorporating capacity priorities into the Reserve Capacity Mechanism would still align with the separate reforms to introduce security constrained economic dispatch.

The approach proposed here is similar to the approach used in PJM in the United States whereby capacity providers are given "capacity rights" up to their level of unconstrained capacity when they connect to the network. Where a capacity provider proposes to build a new facility in a location that cannot accept all of the capacity from the facility, the provider must pay for the network to be upgraded in order to qualify for the full amount of capacity.[12]

[10] "Use-it or lose-it" in this context refers to a process where, if a facility does not apply for capacity credits up to the level of their "capacity priority" the priority is forfeited.

[11] Here "unnecessary" is a reference to a situation where there is no signal being sent by the market as a whole that new capacity or energy is required.

[12] An important difference between the US approach and the approach proposed in this paper is that, in the US once the rights are granted, the network operator is obliged to maintain the network in a manner consistent with those rights.

This is similar in nature to the current "unconstrained capacity" concept in the WEM. However, unlike the current arrangements, where a facility does not pay for the required upgrades and is not granted full capacity rights, the facility may still connect and be deemed (for capacity above its capacity rights) to be an "energy" provider (able to participate in the energy and ancillary services market).

As an example of how these capacity priorities would operate in the WEM, consider a scenario of excess capacity and a new facility seeking to join the market with a choice of locating in two different positions: location A, where there is a good fuel resource but the network is fully constrained, and location B where there is a less accessible fuel resource, but no constraint.

If the existing generators in location A had capacity priorities, the new resource would only be eligible for capacity credit payments up to the spare capacity in the network, and therefore only be paid for the additional capacity it adds to the system. The new resource developer would then need to assess whether positioning in location A, and receiving lower capacity revenues (reflective of the true unconstrained capacity it is adding to the market) plus the greater energy revenue from the better fuel resource, is better or worse than if it was established in location B. Here, the outcomes are:

- The new generator would only be paid for the increased system wide reliability it provides – consistent with the concept of a single capacity price.
- If the facility was established in location B, the additional capacity and energy would be available at a reduced cost to consumers, so consumers would receive the benefit of the additional capacity (rather than there merely being a wealth transfer between the two facilities behind the constraint).
- The facility would see strong incentives to establish in location B. Therefore, if there was a sub-marginal energy producing facility affected by a constraint, the energy from both facilities would be available to consumers and the overall energy price would be reduced in the market.

2.1.3 Additional features of a "capacity priority"

Priorities would be limited to the ability of the network to accept capacity from all priority holders

The introduction of capacity priorities would require AEMO to model network capacity and first assign capacity credits to only those providers with capacity priorities. Once the capacity available from each provider with a capacity priority is set, AEMO would then conduct the modelling again with all potential capacity providers included but with a view to determine if any of the potential capacity providers would obtain capacity belonging to a provider with capacity priorities. The potential capacity provider would need to be notified of the amount of capacity they will have to reimburse the holders of capacity priorities.[13]

If a new capacity provider proceeds with its capacity credit application then the reimbursement of capacity revenue would occur during the monthly AEMO settlement process.

[13] This will not necessarily be a one to one relationship. Due to differing contributions to a network constraints it is possible that a new capacity provider receives more capacity credits then the level held by a capacity provider with priorities.

Importantly, a capacity priority would not entitle a facility to be assigned capacity credit revenue up to the level of the priority where the network changes in such a manner that a facility can no longer provide the capacity up to the level of the priority (at the same time as all other capacity priority holders). The capacity provider would then only be assigned capacity credits (in that year) up to the level that the network can accept for that facility. AEMO would not be able to assign more capacity credits to generators in a specific section of the network in excess of the capability of that section of network to accept the combined power output of those generators at peak times.

Where more than one priority holder is constrained, meaning that the total capacity volume of priorities is higher than the available capacity, a process to determine which facility should "lose" the capacity credits is required. The Public Utilities Office considers this priority order should be the same as the priority order for determining which facilities originally gain the capacity priorities: that is, the facilities that contribute least to the constraint should be assigned capacity over the facilities that make the greatest contribution to constraints. This approach is consistent with the intent to deliver the most capacity onto the network.

An important element of the capacity priorities is that they would continue to exist even where a facility is unable to be assigned capacity credits in a year due to changes in the network. For example, a facility may have 100 capacity credits and capacity priority for 100 MW in year one, located behind a 100 MW constraint (so the generator is located in a constrained part of the network). If in year 2, the network changes such that the provider can only provide 50 MW of capacity, the provider will have 50 MW of capacity credits and 100 MW of capacity priority[14].

If in the third year a new entrant joins in that location and the network capacity also increases up to 75 MW of capacity, the original facility in that location would be eligible for capacity credits before the new entrant (up to the 100 MW of capacity priority level).

Priorities need to be time limited

In addition to the "use-it or lose-it" quality to capacity priorities, capacity priorities would need to be time limited (i.e. expire after a predetermined period). Capacity priorities are not designed as a mechanism to simply grandfather incumbent generation.

The choice of the expiry period requires a trade-off between reducing the risk to the holder of the priority (requiring a longer expiry period) and the need to facilitate, and encourage, efficient retirement of less efficient plant on the system. The Public Utilities Office acknowledges that the current Benchmark Reserve Capacity price is calculated by annualising the cost of capital over a 15 year period. Therefore the upper band of an acceptable expiry period should be no longer than 15 years. However, a 15 year expiry period may be considered too long for existing facilities on the SWIS, many of which are closer to retirement than 15 years. The Public Utilities Office considers a 10 year expiry period as a suitable trade-off between reducing risk and facilitating efficient plant retirements.

[14] Being assigned a lower level of capacity does not extinguish a generator’s capacity priority rights under the “use-it or lose-it” rule. This rule only applies where the facility has been assigned a lower level of Certified Reserve Capacity and/or applies for a lower level of capacity credits (e.g. where the facility either can no longer provide the same level of capacity or the proponent no longer wishes to be obligated to provide the capacity credits).

Because capacity priorities are assigned to all new generators that connect to the SWIS up to the level of unconstrained capacity across the network, the time limited priorities would apply equally to existing and future capacity providers and capacity priorities would “expire” at different times depending upon when they were granted to a facility.

3. Demand side management capacity

Assignment of capacity credits to Demand Side Management facilities in a constrained environment provides unique challenges. The first challenge is that loads, unlike generators, are not penalised for turning off and a load cannot be asked to fund additional network capacity if turning off makes a network limitation worse. A load has discretion to turn off when and by however much it wishes to, this will not change under a constrained access regime. So while capacity credits to generation facilities can be allocated based on their constrained access to the network, this approach may unnecessarily penalise demand side capacity resources.

The second challenge is that, unlike generation capacity, the location of demand side capacity resources is currently mostly unknown to the system operator. This creates a problem because the location of load is an important element when developing a network constraint model. If a load that is presumed to be available to "soak up" some of the generation on a particular constrained transmission line is not available, the constraint equation written for that line is no longer valid.

In recognition of these challenges, the Public Utilities Office proposes that under the revised approach demand side capacity resources should be accredited capacity credits on an unconstrained basis. The certification process for demand side resources would in large part be similar to the existing process, however additional information regarding load location will be required.

Demand side capacity resources would not be subject to the “unhedgeable risk” that would exist for generation capacity, meaning that assignment of capacity priorities would not be required for these resources.

4. Consultation and next steps

4.1 Invitation for submission

Respondents are invited to comment on the proposed process for capacity credit allocation to account for network constraints as outlined in this paper. Submissions need not be limited to those items identified for comment below.

Submissions are due by 5pm (WST) on **30 March 2018** and can be emailed to PUOSubmissions@treasury.wa.gov.au.

Submissions should have the following email subject line format:

"*Response to Consultation Design Paper: Allocation of capacity credits in a constrained network – [Name of submitting company or individual]*"

The Public Utilities Office will consider applications to extend the due date for submissions. If a new due date is set, it will apply to all respondents. The Public Utilities Office will advise industry through the Department of Treasury's website and through email.

Publication of submissions

Unless respondents request otherwise, submissions will be publicly available on the Department of Treasury's website.

Respondents should indicate clearly on the front of the submission if they require the Public Utilities Office to treat all or part of the submission as confidential. Contact information, other than the Respondent's name and organisation (where applicable) will not be published.

Note that requests may be made under the *Freedom of Information Act 1992 (WA)* for confidential submissions to be made available. Requests are determined in accordance with the provisions of that Act.

4.2 Consultation

Comments are invited on the introduction of the proposed three new fundamental elements:

- basing the allocation of capacity credits on a modelled view of network congestion;
- the issuing of capacity priorities; and
- changes to the certification and allocation arrangements for capacity credits.

> Question 1: Are these three elements likely to result in the efficient allocation of capacity credits in a constrained network?
>
> Question 2: Are there any additional elements that must be incorporated into the final solution?

The Public Utilities Office will undertake further consultation on the detailed design elements necessary for implementation (including the matters listed below) commencing from April 2018. This consultation will occur through formal and informal workshops with industry, including presentations to the AEMO Electricity Generator Forum and the Market Advisory Committee.

Dispatch scenarios

The modelling used to identify the level of capacity credits will use dispatch scenarios as an input. These dispatch scenarios are fundamental to the final calculation of capacity credits. It is imperative that the scenarios are developed in a clear, transparent, robust and accurate manner. The Public Utilities Office will seek to work with industry and AEMO on designing the methodology used to determine the dispatch scenarios in the first half of 2018.

Preparatory stage process

The preparatory stage in the capacity credit allocation process would require new information from Western Power, AEMO and new entrant facilities. The exact nature of this information is yet to be determined. The Public Utilities Office will work with industry and AEMO to develop the process needed to commence a capacity cycle including the timing, information requirements and in particular participation obligations on new entrant facilities.

Question 3: For a new facility, what level of screening should be required before the facility is included in the network model?

Accreditation stage process

The accreditation stage proposes two options to resolve a tie break situation where two new facilities are seeking more capacity than can be allocated. The Public Utilities Office will consult with industry on these two options to determine the preferred approach. Following that determination work will commence on the detailed design of the accreditation process including timing and practical considerations.

Question 4: Which is the preferred approach to resolve the tie break where two or more new facilities are seeking more capacity than can be allocated?

Capacity priorities

The introduction of capacity priorities is a major change to the Reserve Capacity Mechanism. The Public Utilities Office will further develop this concept with the industry as a matter of importance.

Question 5: Are capacity priorities required? Is the unhedgeable risk described in this paper appropriately accounted for?

Question 6: Is the proposed 10 year time period for capacity priorities suitable?

Demand side management

The proposed approach for allocation of capacity credits to demand side management capacity, whereby demand side capacity is not penalised for the impact this capacity resource may have on constraints, is unique to only that form of capacity. The Public Utilities Office will further develop measures to address the practical considerations related to enabling demand side capacity participation in the capacity market.

Question 7: What practical considerations arise with the allocation of capacity credits to demand side management capacity on an unconstrained basis?

5. Disclaimer