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Public Utilities Office

By email to [PUOSubmissions@treasury.wa.gov.au](mailto:PUOSubmissions@treasury.wa.gov.au)

## **Submission to the Public Utilities Office on its *Improving access to the Western Power Network* series of consultation papers**

### **Introduction**

Perth Energy submits this paper in response to the Public Utilities Office's (PUO) suite of consultation papers on improving access to the Western Power Network. We have combined our response to questions raised in all three of the PUO's papers in this single submission. We have also taken the opportunity to comment more broadly on the proposed implementation of a constrained network access regime, as well as the need for further energy market reform.

### **Overview**

Perth Energy supports the formal implementation of a constrained network access and dispatch regime in South West Interconnected System (SWIS). The current limitations on generators' ability to connect to the network means there is in effect already a constrained access regime in place for certain types of new generation. Therefore, we recognise the need to establish a formal framework that facilitates network access on a constrained basis and dispatches the market accounting for constraints (security constrained economic dispatch market model). We believe this is an important step towards greater network utilisation and more efficient investment in generation and the network.

Our response to each of the questions raised in the issues papers is provided later in this paper, however, we would like to make the following points at the outset:

1. The messages about future reform(s) is confusing. It would be helpful if market participants could be provided a holistic view of the PUO's market reform package, including detail on what aspects of the previous Government's Electricity Market Review will be pursued. While we can comment on reform items such as constrained network access in isolation, market participants will be able to provide more valuable input if they are provided a clearer picture of the broader reform objectives and how the whole package of energy market reforms hangs together.
2. While constrained access is a sound move in principle, greater analysis of the impacts (both positive and negative) of this reform should be conducted and shared with stakeholders. To-date, the PUO has not quantified the expected benefits of moving to a constrained network. Before proceeding with such a significant market reform, Perth Energy recommends the PUO and/or Western Power estimate the expected reduction in transmission investment that would result from a constrained access regime, and provide further clarity on how this reform will facilitate new investment. Such analysis would enable a much more efficient implementation process and help identify and address transitional issues at the outset.



3. Constrained network access is not sufficient on its own to promote a sustainable level of new private investment in power generation. It must be complemented with prudent network investment to address operationally unsustainable constraints. While we understand one of the objectives of a constrained network access regime is to reduce the need for costly transmission investment, a degree of transmission capacity expansion investment remains necessary. There is a balance that needs to be struck where investment in the transmission network is still required to enable new generation in areas such as Geraldton and Kalgoorlie, but limiting this investment to an efficient level will be key. The current PUO proposed solution does not develop pricing signals sufficient for Western Power to adequately determine the underlying investment case for building out constraints.
4. The PUO's proposed arrangement provides little incentive for new generation to be installed at constrained locations. Using network support service contracts enables Western Power to meet current customer needs but these are not appropriate mechanisms to provide adequate generation in regions behind transmission network constraints. Locational pricing must be implemented in the wholesale market arrangements to provide appropriate pricing signals to investors to locate generation capacity where it is most valuable.
5. The current dispatch engine is inadequate for the present needs of the system. The Australian Energy Market Operator's (AEMO) real time dispatch engine (RTDE) cannot accommodate existing constraints, it cannot accommodate 5-minute dispatch, it cannot accommodate the technical limitations of existing plant, it cannot accommodate 30-minute gate closure and it cannot accommodate dispatch accounting for generator standing data. Perth Energy advises a new dispatch engine should be implemented as a matter of urgency. The proposed 2022 transition to a constrained, co-optimised dispatch solution is too late. We urge the AEMO and PUO to work with the Market Advisory Committee to develop an appropriate specification for an interim replacement dispatch engine.

### **Proposed alternative approach – improving market design**

A fundamental challenge facing the SWIS is making sure the most appropriate type of generation connects in the right areas of the network, if for no other reason than to accommodate the rapidly increasing level of PV on household rooftops. Matching the right capacity, energy and ancillary services to each network region is critical to maintaining energy security and reliability, as well as promoting competition and lower prices for consumers. A constrained access regime is part of the answer; however, it is not the sole solution.

One of the ways we can encourage investment in the generation and ancillary services most suited to each region of the SWIS is to design market and dispatch mechanisms that provide appropriate price signals to investors.

Rather than placing too much emphasis on implementing a constrained access regime, the PUO has an opportunity to deliver incisive reform if it focuses on the design of a simple, effective, main-stream market and dispatch solution for a security-constrained system. Perth Energy recommends adopting market



mechanisms such as those in Italy, France or Spain, which operate under partially constrained access regimes that group constraints into network regions.

A regionally-based, partially constrained access regime would separate the SWIS into regions based on Western Power’s current planning regions and the constraints listed in its Annual Planning Report. The SWIS regions could be defined as suggested in Figure 1.

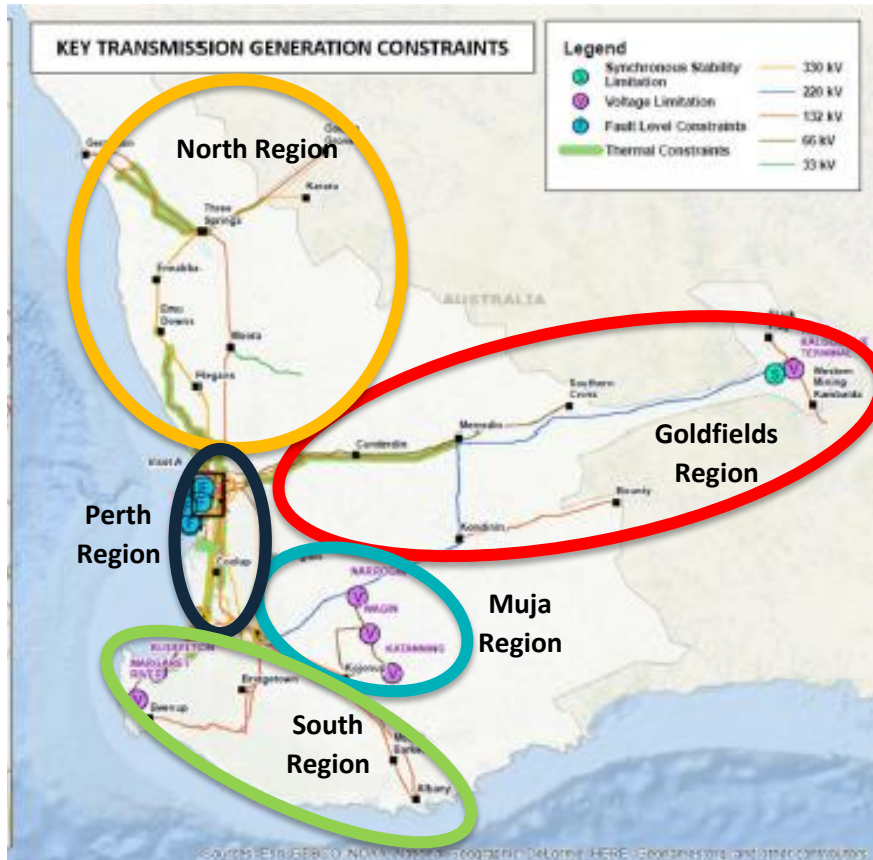


Figure 1: Potential market regions

Under this regime, only constraints between regions would be recognised. Access within each region would remain unconstrained. Dividing the SWIS into regions would enable local balancing and supply and local pricing where necessary, thus providing opportunity to develop appropriate signals for generators and investors. Importantly, the regional price variations would only come into effect when transmission constraints bind. Under normal operations, Perth Energy has been advised that constraints do not bind, which means that the SWIS-wide wholesale price would be uniform for the majority of the year. It is only when constraints actually impact the transmission of electricity that the price would deviate by region.

It is also important to note Perth Energy is not proposing regional electricity retail pricing. The end price to consumers can remain uniform as per the Government’s policy settings. Moreover, we are proposing a method of incentivising efficient and prudent investment via **locational wholesale pricing**.



The benefits of a regionally-based, partially constrained access regime include:

- it can be implemented relatively quickly (potentially before 2020) to replace the current inadequate systems;
- it provides pricing signals for the location of new generators, without necessitating disparate retail prices;
- it does not result in the removal of firm access rights, and therefore avoids sovereign risk and the significant financial compensation that could be required to be paid by the State Government to affected participants;
- it reflects the majority of the requirements of the Access Code, meaning that legislative changes could be minimised;
- it allows the full benefits of constrained access, and can be evolved as required.

Further discussion on how a regionally-based, partially constrained regime could work in the SWIS is provided in Appendix A.

For a regionally-based regime to work efficiently, all stakeholders must fully understand what type of generation capacity, energy and associated services are required in each region. Therefore, as a pre-cursor to market design, Western Power and the AEMO (with the support of the Market Advisory Committee), should identify:

- the demand profile in each region of the SWIS;
- the services required in each region (e.g. spinning reserve, load following, capacity, energy, black start, inertia); and
- the network constraints in each region.

This information can then be shared with market participants, who would then be able to offer their expertise and insight into what market design and incentives would promote the necessary investment.

Further, we recommend any consultation process on the design of incentives in the Wholesale Electricity market (WEM) (as well as changes to firm access rights) should actively engage investors. Investment signals are fundamental to market design. Therefore, it makes sense to engage with the parties who make investment decisions – which is not always the market participant. We advise an infrastructure investment advisory or energy security group could be set up to provide expert advice on what reforms would and would not promote the investment outcomes the PUO wants to achieve.

While we support the PUO's efforts to formalise a constrained access regime, we strongly advise it would be more effective to focus on improving market design as a complementary and necessary step towards achieving lasting WA energy market reform. Constrained access alone is not the answer.

We have provided further detail on our recommended approach in Appendix 1 of this submission. Perth Energy would welcome further discussion with the PUO on this matter.



Should you have any questions in relation to this submission please contact me on (08) 9420 0347 or at [e.aitken@perthenergy.com.au](mailto:e.aitken@perthenergy.com.au).

Regards,

A handwritten signature in blue ink, appearing to read "Liz Aitken".

Liz Aitken  
General Manager Operations



## Responses to the PUO's specific questions

The following sections provide the PUO's responses to questions raised in each of the PUO's issue papers:

- Paper 1: Implementing a constrained access regime;
- Paper 2: Allocation of capacity credits in a constrained network; and
- Paper 3: Modelling the impacts of constrained access – methodology and assumptions.

For context, we recommend the responses provided below are read in conjunction with the relevant issue paper.

### Paper 1: Implementing a constrained access regime

Perth Energy provides the following comments in response to questions raised by the PUO in the consultation paper: *Implementing a constrained access regime*.

While we can comment on reform items such as constrained network access in isolation, market participants would be able to provide more valuable input if they are provided a clearer picture of the broader reform objectives and how the whole package of energy market reforms hangs together. In particular, the proposed WEM design decisions are crucial to understanding the impact of the implementation of a constrained access regime.

This section should be read in the context of Perth Energy's broader feedback relating to the proposed reforms to improve network access.

#### The essential reforms to implement constrained access

**Question 1: Are there other reforms that are essential to implement a constrained network access regime?**

If the market is to realise the full benefits of constrained network access, Perth Energy considers the proposed reforms will need to be supported a number of fundamental changes that have not been discussed in the three discussion papers, or elsewhere in the reform package.

#### Constrained wholesale market and dispatch

The formal establishment of a constrained network access regime requires complementary wholesale market and dispatch solutions. In the absence of market and dispatch solutions allowing for constrained access, the current mechanisms will result in sub-optimal economic dispatch.

The PUO has indicated that it will introduce new, security-constrained economic dispatch and market mechanisms to accompany the constrained network access regime. However, limited detail about the design of these arrangements has been provided. Market design is crucial to any decision about changes to the network access regime.

We note there are alternatives to a fully constrained network access regime that could be implemented in WA as a pragmatic first step. For example, France, Italy, Germany and Spain all operate markets in which some, but not all constraints are compensated for. That is, they operate a market that is partially constrained. For example, Italy defines market zones and compensates generators that are constrained-



off due to intra-zonal constraints, but not due to constraints between zones. This type of market mechanism would remove the need for the revocation of firm access rights and financial compensation altogether. Amendments to the network access regime are an enabler to this market reform and as such Perth Energy urges the PUO to decide on the dispatch and market mechanisms prior to, or at least in parallel with, any decision on network access. The network access regime should not drive changes to the regulatory construct and operation of the WEM.

#### Locational pricing signals

Locational pricing signals, either through the capacity mechanism or the energy market design are critical to deliver efficient market outcomes. Constrained network access alone will not ensure investment is made in the right type of generation for each region.

As was noted in the previous EMR reforms, different types of capacity (such as generation and demand side programmes) deliver different services and should be rewarded as such. We consider this approach should go further, and value each individual service that is required for system security and reliability in each region of the SWIS. This would ensure there is a financial incentive for private sector investors to deliver energy where it is valued, and a disincentive where it is not required.

#### Western Power's Applications and Queuing Policy

Perth Energy's experience is that it currently takes around two years and several hundred thousand dollars for access studies to be undertaken by Western Power prior to a connection agreement being negotiated. We recommend a connection applicant should be able to request connection of a certain set of outputs, rather than specific inputs. For example, an applicant should be able to request connection of a generator type, rather than the exact specifications of a particular generator. This type of approach would significantly reduce both the connection time and cost.

#### Determination of Western Power's network limits

Western Power's network limits are currently set under the Technical Rules and are static. Perth Energy notes this static determination results in a more conservative approach to loading the network elements. This results in constraints 'binding' more frequently, generators' output being constrained more frequently, and a lower sent out capacity quantity than would occur if each network element was dynamically rated.

A dynamic approach to setting network limits would reduce the impact of constraints on the WEM. However, it should be acknowledged that static limits are likely to be preferred by Western Power as they encourage investment in the network. As a regulated monopoly service provider, Western Power earns revenue on the basis of the value of its assets – the higher the value, the higher its returns. This is contrary to the benefits of introducing dynamic network limits.

#### Western Power's Technical Rules

The Technical Rules and WEM Rules overlap on some of the more technical specifications related to system security, reliability and connections. These elements are fundamental to the operation of the WEM. We consider the Technical Rules should be reviewed and any elements that need to be retained included in





the WEM Rules. This will bring them under the authority of the Rule Change Panel and ensure that all market participants' interests are fully accounted for.

#### Western Power's Contributions Policy

Western Power's Contributions Policy is established under the Access Arrangement and outlines how Western Power will calculate the charges to be paid by customers for connection to the network. The purpose of the policy is to balance the interests of the contributing user, other users and consumers when determining the allocation of costs related to a network upgrade.

We recommend the PUO should work with Western Power and the Economic Regulation Authority (ERA) to discuss how it could be amended to better address the objective. This is particularly relevant with respect to the impending operation of the Competing Applications Groups (CAGs). Perth Energy supports the connection of additional generation capacity to reduce the wholesale cost of electricity, and considers that where this benefits customers more broadly, there is an opportunity to share the cost of network augmentation.

#### Transmission use of system

Currently Western Power assigns a quantity of declared sent out capacity (DSOC) to each facility connected to the network. Market participants pay transmission use of system (TUOS) charges on the basis of that DSOC. If a facility exports energy above its DSOC, Western Power applies additional charges as financial penalties.

Under the previous EMR, the PUO proposed to cease charging for TUOS. However, the current consultation papers are not clear about the plans for DSOC and TUOS. Perth Energy requests further information about the application of TOUS and DSOC under the proposed network access arrangements.

We recommend TUOS be removed given that network connected generators are no longer being provided with firm access capacity. Further, the current determination of the maximum permitted export from a generator (DSOC) should reflect its maximum output rather than its output at the expected maximum local temperature. This will reflect the ability of some generators to offer substantially more capacity into the market than their 41°C certified capacity.

#### **Implementation timeline**

**Question 2: Are there other issues associated with the implementation timeline, including the proposed 'go-live' date of 1 October 2022?**

Perth Energy considers this timeline should be achievable and is realistic in terms of aligning changes to network access with the Reserve Capacity Mechanism. This will require strong program management and firm, committed oversight. We consider it essential that oversight be assigned to a single person with the ability and authority to drive the project and explicit accountability for delivery on-time and within budget.





Moreover, there are significant risks associated with the retention of the current dispatch systems. We consider the replacement of the current IT systems for dispatch is critical to system security and economic dispatch, and should be expedited<sup>1</sup>.

The increasing connection of facilities behind constraints has led to the point where the current market system and network operations systems are no longer adequate to facilitate economic dispatch. Western Power's connection of a number of new facilities behind constraints – those in CAGs and subject to the GIA – will exacerbate existing IT and economic dispatch problems.

The IT systems used to operate the SWIS and WEM are beyond their technical lives and need replacing. In the third Allowable Revenue submissions, System Management and the former Independent Market Operator had planned to upgrade and replace critical IT systems by 2016/17. This was delayed with the announcement of the Electricity Market Review in 2014. Over the past year, the reliability of these systems has greatly deteriorated, with several recent unplanned outages of communications systems.

In its 2016/17 review of the AEMO's compliance, the independent market auditor reported issues in the level of documentation supporting the AEMO's dispatch systems, and recommended that the AEMO "puts a very high priority on addressing the future of these systems."

We are concerned delays in agreeing project scopes, and the AEMO securing funding to implement the necessary market and dispatch systems, would further extend the timeframes for the project, which are already tight.

Moreover, the arrangements in relation to transitional assistance are likely to take significant time to negotiate and should be largely finalised prior to the completion of the market design phase.

We note there is an alternate market solution that can be implemented more cheaply and quickly than the PUO's proposed option.

### Managing existing generation firm access

#### Question 3: Are there other principles that should be considered?

Perth Energy considers there are a number of additional principles that should be considered in selecting the approach to changing generator access contracts from firm access to non-firm.

1. Any changes must be fair to generators that have entered the market on the basis of unconstrained network access. The approach must be tailored to deliver fair compensation for each loss type for each individual market participant.
2. The proposed transitional assistance approach should not preserve access rights to the detriment of market design. Transitional arrangements should not result in a compromised market design which is likely to deliver ongoing sub-optimal market outcomes. A more administered approach to compensation is preferable and should be negotiated prior to decisions about market design.

<sup>1</sup> To the extent that the Reserve Capacity Cycle is driving the delay of the implementation, Perth Energy recommends the PUO considers alternatives such as the deferral of one or two cycles, as was done from 2014 to 2017.



3. Any changes should be designed to minimise sovereign risk. The proposed approach should not put at risk the Government or State's reputation as a desirable investment location. This is crucial to ensure that private sector investment continues, to increase wholesale market competition, to reduce Synergy's market power and place downward pressure on consumers' electricity costs.
4. Market mechanisms, rather than any administrative framework should provide a strong locational pricing signal to incentivise investment in generation of the type that is required, where it is required, and disincentivise investment where the network is constrained.
5. Market design decisions are made to maximise transparency of market information. Transparency is critical to enable effective participation in the wholesale market and deliver efficient market outcomes. In particular, we recommend the publication of information on the operation of the network (e.g. constraints, technical limits, outages) and retail market outcomes are necessary.
6. The market mechanisms should be designed to maximise simplicity and expediency, and minimise the amount of 'tailoring' required. This is critical to maximise market participants' ability to effectively participate in the market, reduce the potential for market outcomes to be distorted by transitional arrangements and reduce the ongoing operations and maintenance costs.

We request the PUO clarifies its proposed principle to minimise the administrative burden and cost. There is a trade-off between up-front administrative activities, and simple and expedient market design. We would like to ensure this principle is not interpreted such that initial, rather than ongoing, administrative effort is discouraged where it may deliver superior market driven outcomes.

We consider our alternative proposed solution of a regionally-based, partially constrained market and dispatch mechanism would better meet the PUO's objectives, as well as meeting the additional objectives outlined above.

**Question 4:**

**(a) Are there other options (including variations of each option above) that could better meet the guiding principles?**

**(b) Are there other advantages and disadvantages of each option (including other alternatives) that should be considered?**

**Question 5:**

**(a) Does this approach best meet the guiding principles?**

**(b) Are there other approaches that should be considered?**

**(c) Are there other legislative provisions should be considered?**

**(d) What consequences could arise from the proposed approach (including the impact on specific arrangements such as bilateral trading agreements)?**



We note there are several market-based alternatives that avoid the removal of firm access rights, and one of these has been outlined in some detail as Appendix A of this paper. Adopting our recommended market design would mean that compensation would not be necessary and that the principles (PUO nominated and those proposed) could be met in a more effective manner.

However, if firm access rights are to be removed, the key to implementing the required changes to existing Electricity Transfer Access Contracts (ETACs) is the provision of appropriate compensation. It was failure to address this issue that prevented the proposed legislation being passed through Parliament during the term of the previous Government. If compensation is seen to be fair then it is likely that most generators could be persuaded to accept amendments to their ETACs.

The impact of the removal of unconstrained network access on each market participant with respect to each facility will vary. This makes it difficult to design a compensation arrangement that delivers fair compensation to all market participants affected.

Market participants and investors must be able to understand exactly how they will be affected by the revocation of firm access rights. The conflation of transitional compensation and market design decisions makes it increasingly difficult to determine the financial implications. We therefore consider compensation arrangements must be agreed prior to any detailed market design decisions. This should be the PUO's first priority.

The PUO's proposed approach will introduce in legislation a 'head-of-power' to allow the Government to provide Western Power with legal protection and market participants with financial compensation as a result of removing firm access rights. Perth Energy acknowledges that overriding legislation to implement these changes may be seen as the quickest solution. However, it relies on all compensation arrangements to be fully understood and firmly in place prior to the introduction of the legislation into Parliament. If this is not done, it is likely that the legislation will be opposed.

The actions of the previous Government had substantial adverse financial impacts on generators and the current Government has given little encouragement to private energy thermal development. There will be little tolerance for Government actions that appear to be self-serving or inequitable.

We consider there are two alternatives:

- **Individual negotiation** – Western Power could negotiate with each private sector market participant and investor group, noting that negotiations between Western Power and Synergy would only result in a wealth transfer between two Government agencies.
- **Independent arbitration** – Government and industry could agree upon an independent arbitrator who would develop a set of amendments to be incorporated into existing ETACs. All parties would then be confident that the resulting changes were equitable and it would ensure that most ETACs were in the same format. An arbitrator could also assist in resolving changes to any provisions specific to one generator.

Perth Energy reiterates that compensation arrangements must be the first thing that is addressed if firm access rights are to be removed.



## Mechanisms to provide transitional assistance

### Question 6: Are there other considerations that should influence the design of a mechanism to provide transitional assistance?

If firm access rights are to be removed, Perth Energy considers the design of the transitional assistance arrangements will need to account for the following issues.

#### Compensation is fair

As noted in response to Question 3, we consider the approach should result in fair compensation for each loss type. This is expected to vary for each facility and each market participant and investor group. A tailored approach to compensation is preferable.

#### Market design outcomes are prioritised

As noted in response to Question 3, we consider the proposed transitional assistance approach should not preserve access rights to the detriment of market design. Transitional arrangements should not result in a compromised market design which is likely to deliver ongoing sub-optimal market outcomes. Compensation should be negotiated prior to decisions about market design.

#### Sovereign risk is minimised

Any changes should be designed to minimise sovereign risk. The proposed approach should not put at risk the Government or State's reputation as a desirable investment location. This is crucial to ensure that private sector investment continues, to increase wholesale market competition, reduce Synergy's market power and place downward pressure on consumers' electricity costs.

#### Impact of policy decisions is able to be passed-through

It is expected that the appropriate level of assistance will heavily depend on how much new plant is encouraged onto the system as a result of making network access easier. It would appear that the most likely new plant will be wind and solar in response to the Federal Government emissions reduction schemes. The proposed National Energy Guarantee is not intended to apply to WA. However, it is expected that the State Government would need to develop a state-based policy response to ensure that it was able to contribute to Australia's emissions reductions. This would increase the amount of renewable energy in the SWIS, further affecting market participants with unconstrained access.

We consider that any transitional assistance should be capable of being adjusted as required, to accommodate the potential impact of such a change in State and Federal Government policy.

## Types of financial losses that should be considered

### Question 7: Are there other types of financial losses that should be considered? Why?

There are a number of different types of losses associated with the revocation of firm access rights for which investors should be fairly compensated, including but not limited to:

- capacity losses;
- energy losses (including the losses associated with the differential of contracted vs spot prices);



- costs associated with increased dispatch risk;
- ancillary services losses;
- redundant capital contributions for network augmentation;
- decreased capital value;
- inefficiencies resulting from changed operations;
- financial penalties (e.g. breaching debt covenants and financial arrangements); and
- costs associated with higher cost equity.

Perth Energy notes that the PUO has engaged EY to model a variety of dispatch scenarios to attempt to determine the impact of the revocation of unconstrained access on each facility. We have assessed the robustness of this modelling for the purposes to determining fair compensation and have serious concerns. These concerns are raised in this submission in our response to Paper 3 below.

We acknowledge the inherent difficulty with forecasting in a dynamic, technologically dependent industry such as the energy industry and appreciates EY's efforts. Respectfully, we do not consider EY can accurately forecast the policy, technology, investment or consumption characteristics affecting the operation or outcomes of the WA electricity market. Consequently, any modelling cannot be relied upon to derive ongoing revenue streams for generation facilities.

**Question 8: Are there other options that could be utilised to provide transitional assistance?**

**Question 9: Is a market solution preferable to an administrative solution?**

If firm access rights are to be removed, Perth Energy considers that each type of loss needs to be compensated in an appropriate manner to deliver a fair outcome.

The PUO's proposed approach to determining the level of transitional assistance is to model the forecast dispatch outcomes over the next 10 years. This type of modelling relies on adequate demand forecasts, predictions of plant investments and retirements, and a reasonable understanding of advancements in new technology for the period. As previously noted, it is unlikely that these inputs can be determined with any accuracy and significantly underestimate the level of demand and price risk that market participants are exposed to. Therefore, the modelling will not result in an accurate (or even approximate) value.

If the PUO is to continue with its proposed approach, we recommend the actual impacts on generators should be reviewed in the short and medium-term, and where required the transitional assistance is 'trued-up' for any generator where the adverse impact has been significantly greater than predicted. Moreover, Perth Energy recommends that where a generator is so seriously affected by the proposed arrangements that its business is essentially destroyed, the Government should consider making payment for it to exit the market.

We consider that a better, alternative approach would be for energy and ancillary services losses to receive market-based payments such as those paid in financial transmission rights, differential pricing or congestion management settlement credits schemes. Alternatively, the AEMO could continue to calculate constrained-off payments as they currently do under the WEM Rules and use this as the basis of an annual compensation amount from the advantaged to the disadvantaged generators.



For the remaining costs, we consider individually negotiated capital payments, either once-off or paid over multiple years would be appropriate. As discussed in response to Questions 4 and 5, there are two alternative ways of determining a fair compensation that should be considered by the PUO: individual negotiation; and independent arbitration. However, compensation could be avoided altogether under Perth Energy's proposed alternative approach.

**Question 10:**

**(a) Under what conditions should a refund be made available to a transmission connected generator who has paid a capital contribution to augment the shared network?**

**(b) How should the refund be paid to the generator who qualifies for a refund, and who should pay for the refund?**

If firm access rights are to be removed, Perth Energy considers it is fair to compensate those market participants who have paid capital contributions to allow it unconstrained access to Western Power's network.

Capital contributions are calculated as the difference between the cost incurred by Western Power to augment its network to provide access and the expected revenue from the connection. As discussed in response to Question 1, we recommend Western Power's Capital Contributions Policy should be reviewed to ensure it meets its objective. In determining the appropriate capital contribution for each connection, Western Power include market related costs and benefits for end-use customers. We expect that this would lower the amount of capital contributions paid by low-cost generators due to the increase in competition and lowering of the balancing price.

Irrespective of the recommended changes to Western Power's Capital Contributions Policy, we consider Western Power should reimburse those market participants who have paid capital contributions to the value of 'unconsumed' access. This could be simply achieved by pro-rating the contribution over the life of the asset.

**Adoption of security constrained market design**

**Question 11:**

**(a) Are there other considerations that influence the choice of the dispatch engine?**

**(b) Are transitional arrangements required to facilitate the relocation of the reference node?**

Perth Energy recommends the PUO prioritises the design and delivery of a new wholesale electricity market as a matter of urgency. The current existing network constraints are not contemplated in the WEM design, and considerable manual intervention is required to operate the current dispatch engine to prevent any material unintended outcomes. Furthermore, these interventions are not transparent and occur at the discretion of System Management, and so undermine market participants' confidence in the system by introducing uncertainty around how they will be dispatched.



Moreover:

- the system operations systems (including the dispatch engine) was scheduled for replacement in 2016/17;
- there are regular failures to provide the balancing merit order;
- there are increasingly frequent outages of the AEMO's IT systems, including the dispatch engine;
- the old technology and slow processes are not agile enough to accommodate changes in the generation mix, including a significant increase in the:
  - penetration of solar panels which can lead to load swings of several hundred megawatts within very short timeframes;
  - quantity of low inertia, intermittent generation; and
  - proportion of generation dispatched from outside Synergy's balancing portfolio.
- the long gate closure means that the substantial swings in output from renewable generators cannot be economically accommodated;
- the system cannot dispatch on a 5-minute (or less) basis nor a simultaneous buy and sell bid inhibiting the implementation of batteries in the WEM;
- the system cannot accommodate the real-time pricing of any ancillary service;
- forecast accuracy is extremely poor, with errors of up to 400 MW two hours out;
- there is no visibility of the AEMO's operational decision-making processes or outcomes; and
- the current system is unable to account for the technical limitations of power stations such as minimum generation levels and times between starts.

The magnitude of these issues is such that a new dispatch engine is critical and urgent. These situations cannot be allowed to continue. Not only are customers locked into higher prices than is reasonable but there is an increasing risk that dispatch issues will lead to a major system event.

As previously mentioned, we consider market and dispatch mechanisms should drive decisions on changes to the network access regime and reserve capacity mechanism rather than the other way around. To ensure market-driven, efficient outcomes, the PUO must prioritise good market design over all other outcomes. The choice of dispatch engine can only be made once all market design decisions are made and is a matter of implementation. There are many existing off-the-shelf products that can be implemented once a design has been decided upon. Perth Energy note that the AEMO would be best placed to provide this advice.

We urge the PUO to select the dispatch engine on the basis of the market design rather than designing the market around a particular dispatch engine. This is the best way to ensure the longevity of the WEM, and presents an opportunity for WA to be a leader in electricity market design. Moreover, we consider WA's position as disconnected from the National Electricity Market (NEM) as providing a great opportunity to implement next generation systems unconstrained by the bureaucracy that is hampering the east-coast market.

Any new market design, and therefore dispatch engine must accommodate:

- shorter balancing gate closure;
- shorter trading and dispatch intervals;





- the use of generator technical envelopes that are provided within the Standing Data;
- facility bidding for all market participants;
- transparency of network outages and constraints;
- real-time forecasts for each type of service, in each region;
- improved granularity, accuracy and transparency of short-term forecasting;
- effective information transparency to facilitate compliance and market power mitigation;
- improved outage logging processes and systems; and
- dynamic network ratings.

Through the previous Electricity Market Review, the AEMO provided an estimate of the implementation of NEM systems in WA. Under the proposed approach, we would have spent over \$50 million<sup>2</sup> to customise and implement the IT systems developed for the NEM last century. These are the very systems that central to the current debate around the efficiency and effectiveness of the NEM.

In response to the Electricity Market Review’s Energy Market Operations and Processes consultation paper, AEMO provided the assessment of the current state of its NEM systems outlined in the following table<sup>3</sup>.

System	Status	Complexity	Technology	Security
Power system management	Core	Medium	Supported (with upgrade required)	Supported
Real time market	Core	High	End of life	Supported
Day ahead	Core	Low	End of life	TBD
Settlements	Core	Medium	End of life	Managed risk
Retail market	Core	Low	End of life	Managed risk

It should be noted that the proposal is for each of these core systems to be duplicated due to the:

- proposed retention of the reserve capacity mechanism leading to initial design divergence; and
- operation of two distinct sets of rules and rule-making processes leading to ongoing, increasing divergence (as NEM changes are not implemented in the WEM and vice versa).

This will mean that any benefits would only be in the initial design and implementation phase, and even then, are likely to be small. As each system is re-designed and implemented, presumably, several further rounds of customisation would be required, effectively making the initial investment in the NEM systems redundant.

Perth Energy notes that there are full, commercial off-the-shelf market and system operations solutions that have lower up-front capital costs, and in relation to the ongoing maintenance and support for WEM participants<sup>4</sup>, and would be equally or more effective than NEM systems.

<sup>2</sup> The cost could be well in excess of this as it would be dependent on AEMO’s delivery on-time and on-budget.

<sup>3</sup> Available in Appendix B of AEMO’s submission on the Electricity Market Review’s proposed Energy Market Operations and Processes consultation paper, available at: [http://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public\\_Utility\\_Office/Industry\\_reform/energy-market-operations-and-processes-submission-AEMO.pdf](http://www.treasury.wa.gov.au/uploadedFiles/Site-content/Public_Utility_Office/Industry_reform/energy-market-operations-and-processes-submission-AEMO.pdf).

<sup>4</sup> The beneficiaries of these cost savings should only be market participants in the WEM. Perth Energy considers that WEM participants should not be subsidising NEM participants for the upgrade of NEM systems.



Many off-the-shelf systems if adopted would provide additional functionality such as nodal pricing. These systems would also ensure the level of service provided does not deteriorate as would happen with a move from the WEM to NEM systems (e.g. file transfer protocols and participant interfaces). They would also be far lower risk and quicker to implement than completely custom-built software. Particularly as AEMO is not a software development company, market participants would prefer AEMO to purchase a proven solution and customise it than rely on a complete custom build by in-house AEMO developers.

On this basis, we consider it prudent for the Government to undertake a full, independent scoping exercise and undertake a cost-benefit assessment of all available dispatch engines that would implement the final market design. It is noted that this review would need to be commenced immediately, and be completed within the next 3 months. We consider this to be the most critical project that the PUO can undertake in this reform process, and resources should be diverted from other projects to accommodate this.

It should be noted that the PUO has not provided sufficient information for market participants to provide any meaningful comment on the considerations that should be made when selecting a dispatch engine. To provide specific comment on the implementation of security constrained dispatch, it is important for participants to understand how constrained dispatch will actually be achieved operationally. We would like to raise a number of questions:

1. How will two generators will be dispatched if they have both offered the same price into the market and their combined output exceeds the network's capacity to absorb this power? For example, two generators may have both offered at the negative cap in an attempt to force their way into the dispatch stack. Will they be constrained off in proportion to their installed capacity, their certified capacity, their commissioning dates or some other parameter?
2. Will generators will be dispatched up to the point where a constraining network element is operating at its maximum capacity or will Western Power want to keep some operating margin in place? We consider that constraints should only be imposed once the constraining network element is operating at its maximum rating though this may need to be reconsidered if failure of a transmission element might lead to a generation loss that is too large to be covered by spinning reserve.
3. How will the market power mitigation mechanisms such as the short run marginal cost requirements be changed so that bids can reflect the cost of the constraint to generators?

## **Paper 2: Allocation of capacity credits in a constrained network**

Perth Energy provides the following comments in response to questions raised by the PUO in the consultation paper: Allocation of capacity credits in a constrained network.

As noted in the overview of this submission, a solution that enables the investment in, and connection of additional new plant in the SWIS can be achieved without the revocation of unconstrained access. Our proposed alternative option would see the introduction of a regionally-based, partially constrained access regime, which recognised inter-regional constraints, but not intra-regional constraints.

Should the PUO decide to progress with its proposed solution, the key will be to agree the transitional arrangements for compensation. We are concerned that under the PUO's proposal, the transitional



arrangements will significantly distort the allocation of capacity credits for an arbitrarily chosen period of time, and on the basis of inadequate modelling. We consider that amendments to the proposed solution would be required to better reflect the value of unconstrained access.

This section should be read in the context of Perth Energy's broader feedback relating to the proposed reforms to improve network access.

### Proposed new design elements

**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 underlying objective of the reserve capacity mechanism is to ensure there is sufficient generating plant in the SWIS to maintain system stability and reliability at peak time. Critical to achieving this objective in a security constrained economic dispatch model is developing priorities between constrained generators that prioritises generators that are willing to contribute to system stability during peak time.

Perth Energy is concerned with the proposed approach to the allocation of Capacity Credits, and capacity priorities using a modelled view of network congestion.

We are particularly concerned that the modelled view of network congestion is highly unlikely to reflect the actual constraints that will bind over the next 10 years. This means that any compensation paid to those market participants with affected generators will have no bearing on actual financial detriment. This will not result in what could be seen to be a fair compensation amount, and is therefore likely to undermine any good faith acceptance of the proposed solution.

We note that energy producing plant will continue to be driven primarily by operating revenue. The main purpose of the reserve capacity mechanism over coming years should be encouragement of more peaking plant to provide fast response and/or ancillary services to support intermittent generation, but the current design proposal inhibits that purpose. These facilities will rely heavily on capacity credit revenue and are unlikely to proceed if their Capacity Credits could be reduced ex-post. Consequently, assignment of credits needs to be done before final plant commitments are made.

Our specific comments to the inadequacy of the modelling in relation to the proposed approach are provided in response to paper 3 in the next section.

The proposed capacity priorities embed the current, uneconomic concept of 'first come first served'. It does not reflect the value to the market of those generators that are more likely to deliver system stability during peak times.

Moreover, the PUO has not explained how Capacity Credits will be assigned when there are too many generators for the available capacity credits behind a constraint. The consultation paper uses the phrase



***“the facilities that contribute the greatest to the constraints are considered to be constrained first.”***

However, more information will need to be provided for market participants to understand what is proposed.

We are concerned that the proposed approach will be an extensive, time-consuming and iterative process to assign Capacity Credits, through what appears to be a staged, multi-party negotiation.

We consider the current method for assigning Capacity Credits to those facilities behind network constraints could continue to be used. This involves a technical study of the reasonable expectation of a facility’s output for new facilities, or by review of actual operation over recent years after the fact for established facilities.

Where a constraint impedes the ability for a generator to receive their certified level of capacity credits, Perth Energy recommends a more efficient prioritising method through the formation of a closed, blind auction. In this situation, those affected market participants would each make a single, final offer of the reserve capacity price that it would be prepared to accept, and the AEMO would use this to allocate capacity credits from least cost to highest cost. Each market participant’s bid would then become the reserve capacity price that they are paid for that facility for that capacity year.

A more competitive, lower capacity price for generators competing for capacity behind constraints will ensure capacity credits are allocated to the most efficient generators whilst lowering the capacity cost for retailers and therefore for consumers within the SWIS.

The PUO has not explained how the Individual Reserve Capacity Requirement (IRCR) mechanism is intended to apply. Perth Energy considers this mechanism must be reviewed in light of the proposed changes to the assignment of Capacity Credits. For example, should a retailer be able to receive an IRCR reduction if its customer is located in a region with excess generation?

### Preparatory stage process

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

The optimal length of the capacity cycle was extensively considered when the reserve capacity mechanism was developed at market start. This consultation process established that a three-year cycle with a non-binding expressions of interest process in year one. It was agreed that a three-year process provided adequate certainty for investors, coupled with flexibility to accommodate:

- the certification of fast-build projects;
- changes to forecast demand;
- facility retirements; and
- responses to Government policy.

The change to make the expressions of interest process mandatory would constitute a barrier to entry and exit from the market, and would make the WEM less dynamic.

We consider the proposed approach would rely heavily on an extensive annual modelling process, which will make the WEM less dynamic. This is contrary to one of the critical benefits of constrained access,



which is that the time taken to connect to Western Power’s network should be greatly reduced from the current four years.

We are unclear as to what the PUO proposes with respect to penalties that may apply where a market participant may change its investment decisions within the three-year timeframe. There are a number of legitimate reasons a market participant may change its investment decision within three years.

We consider screening needs to be sufficiently intense so that incumbent market participants cannot assert undue pressure, creating a barrier to entry by proposing new facilities that they have no intention of building. However, the cost for a developer to take a project to a ‘firm’ status is substantial and is likely to be sufficient in itself.

### Accreditation stage process

**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?**

As discussed in response to Question 2, the PUO has not explained how Capacity Credits will be assigned when there are too many generators for the available capacity credits behind a constraint. More information will need to be provided for market participants to understand what is proposed.

Similarly, the PUO has not explained how the Load for Scheduled Generation (LSG) calculation for non-scheduled facilities will be affected. More information on the assignment of Capacity Credits for Non-Scheduled Generation Facilities will need to be provided.

As noted in response to Questions 1 and 2, Perth Energy recommends that, where a constraint impedes the ability for a generator to receive their certified level of capacity credit the formation of a closed, blind auction.

Those affected market participants would each make a single, final offer of the reserve capacity price that it would be prepared to accept, and the AEMO would use this to allocate capacity credits from least cost to highest cost. Each market participant’s bid would then become the reserve capacity price that they are paid for that facility for that capacity year.

A more competitive, lower capacity price for generators competing for capacity behind constraints will ensure capacity credits are allocated to the most efficient generators whilst lowering the capacity cost for retailers and therefore for consumers within the SWIS.

The effective price of capacity will then be dependent on the levels of binding network constraints and as such provide a locational price signal as the price in areas of the network subject to high levels of constraints will be at a discount to the headline capacity price.



## Capacity priorities

**Question 5: Are capacity priorities required? Is the un-hedgeable risk described in this paper appropriately accounted for?**

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

Peaking plant (and potentially batteries) will continue to rely heavily on capacity payments to justify their investment. This means that the consistency of price and quantity outcomes of the reserve capacity mechanism will be crucial to new investment in the SWIS. However, this consistency should not come at the cost of the economic efficiency or effectiveness of the price signals that must be driven by the capacity mechanism.

The proposed capacity priorities embed the current, uneconomic concept of ‘first come first served’. It does not reflect the value to the market of those generators that are more likely to deliver system stability during peak time.

The sovereign risk issue associated with the revocation of firm access rights under the proposed solution must be acknowledged if a fully constrained market is to be adopted. As such, we recommend the PUO considers assigning capacity priorities for existing facilities less than 25 years old. Any plant that has been in service for more than 25 years could be considered to have met its target life and therefore should not be eligible for capacity priorities. Moreover, Perth Energy considers that if it is decided that capacity priorities are implemented, they should match the investment environment and therefore should be increased from 10 to 15 years for new capacity.

## Demand side management

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

We reiterate our recommendation that facilities are to be paid for capacity and energy relevant to the value of each of these services. This equally applies to demand side management (DSM). Perth Energy considers that the value of not consuming energy may differ from the value of producing more energy, however, each is valuable in certain circumstances, for example DSM will be more valuable where it is acting to reduce load at times of particularly stressful network events, and should be remunerated as such. This approach would be consistent with the current effect of the IRCR regime for behind the meter generation.

The key consideration for the value of DSM and therefore the appropriateness of DSM payments, is the dispatchability of the energy. Non-dispatchable DSM receives the benefit of a reduction in IRCR costs and does not provide equivalent value for its capacity.



### Paper 3: Modelling the impacts of constrained access – methodology and assumptions

Perth Energy provides the following comments in response to questions raised by the PUO in the consultation paper: *Modelling the impacts of constrained access: methodology and assumptions*, and is largely based on the methodology and data contained in the associated EY report.

The common theme across all responses in this section is the need for the PUO to publish additional information and analysis that quantifies the degree of risk facing market participants. A number of assumptions and methodological choices artificially constrain the level of uncertainty in the modelling results. This creates an incomplete picture of the risks associated with the proposed reforms. With amendments, the PUO could deliver more robust insights on the impact of constrained access.

This section should be read in the context of Perth Energy’s broader feedback relating to the proposed reforms to improve network access.

#### Question 1: Is the proposed methodology to model the impact on generators sound?

Arguably, the value of having unconstrained access to the network is highly dependent on the level of competition for that access from facilities. The current methodology assumes the level of competitiveness for network access remains similar over the next 10 years and as such does not provide an accurate value of unconstrained access over the course of the modelled period. The modelling instead needs to be focused on factors that will drive changes in the level of competitiveness for network access regionally.

The major factor affecting the level of competition for network access for an existing generator is the suitability of that location for a new generator and the number or size of new facilities that would cause a network constraint to bind more frequently. Factors that affect the suitability for a new generator to connect to the network have not been considered in the modelling. This is a significant shortcoming in the methodology.

In this context we are of the opinion that that the following factors should be considered:

- **LRET price sensitives** – This has material impact on the business case for new renewable facilities in WA and could result in the displacement of existing generators and create more frequent binding of network constraints.
- **Likely network augmentation** – This has a material impact on the frequency and location of binding constraints and therefore market outcomes. Any changes in required network augmentation costs for new market participants to connect to the network could facilitate new investments.
- **The impact of new ancillary services markets** – The determination of the need for, and appropriate value of, different ancillary service markets over the medium-term will promote the construction of scheduled generation.

The underlying value of implementing unconstrained access to the network is very much dependant on the ability for that access to be prioritised in times when you otherwise would not have priority. Central to this is the level of competing proponents trying to access the network at the same time you are trying to access the network. In order to understand the intrinsic value associated with having prioritised access to the network (i.e. unconstrained access) it is fundamental to understand the range of competitiveness





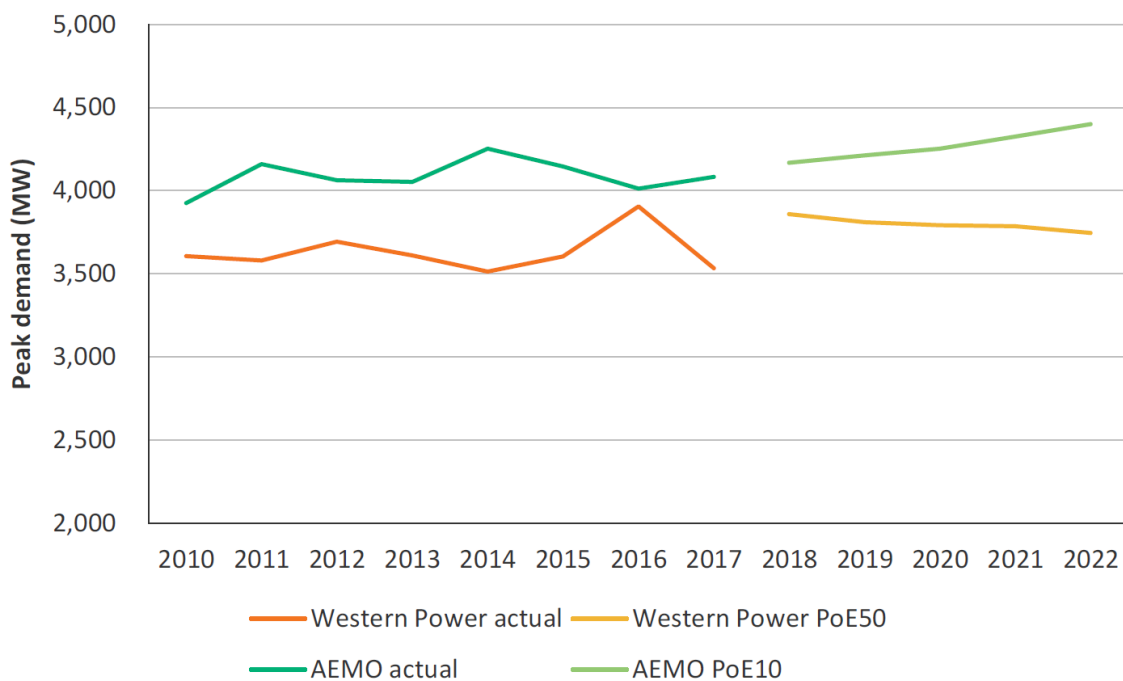
for that access that may reasonably occur over the next 10 years. The EY modelling does not sufficiently develop this range and therefore does not sufficiently provide an estimate of the value in a reduction in access rights to the network from unconstrained to constrained.

We reiterate that the introduction of a regionally-based partially constrained market and dispatch model would avoid this academic and fundamentally flawed exercise altogether.

**Question 2: Are there other, or alternate, input assumptions and / or sources of data that should be considered? (Table 6 in the Paper)**

### Forecast demand

The EY modelling uses the forecast demand from the AEMO's WEM Electricity Statement of Opportunities (ESOO). Western Power produces equivalent peak demand and energy consumption forecasts for the SWIS by substation. We acknowledge the two forecasts are developed for different purposes and using different methodologies. However, the trends are still comparable and are significantly different as shown in Western Power's fourth access arrangement submission<sup>5</sup> provided in the following figure.



<sup>5</sup> Figure 2.4, Access Arrangement Information, Attachment 7.3: Peak demand, energy and customer number forecasts, Western Power, 2 October 2017



In its fourth access arrangement<sup>6</sup>, Western Power also provides an overview of the differences between its forecasts and the AEMO’s forecasts as follows:

Reason	AEMO	Western Power
Model choice	Top-down ordinary least squares structural models – typically good for identifying the cause of variation but have poor predictive capacity	Bottom-up time series models with exogenous variables – less useful for identifying cause but much better predictive capacity Forecasting network exports and imports separately Top-down reconciliations using generalised additive model spline structural models
Variable selection	Excluded all negatively correlated inputs (price, energy efficiency)	Far greater consideration of price and energy efficiency
Technology	AEMO and Western Power took very similar views on PV, battery and electric vehicle uptake, although the assumptions on impact vary	
Block loads (large new customers)	AEMO and Western Power took a very similar view on block loads	
Economic growth	3.3% p.a. (10yr)	1.8% p.a. (5yr)
Population / customers	WA tomorrow (ignores economic downturn)	Regression on customer numbers
Residential consumption	0.3% p.a. (10yr)	-2.1% p.a. (5yr)
Non-residential consumption	0.8% p.a. (10yr)	0.1% p.a. (5yr)

We recommend the PUO considers using Western Power’s more granular demand data in its modelling.

### Network operations

The EY modelling makes key assumptions about the operation of the network including:

- ratings of the transmission network;
- loading of the transmission network; and
- transmission network outages.

We consider the proposed scenarios being modelled have limited divergence in relation to these assumptions and therefore will not accurately reflect those conditions in which constraints are expected to bind. This would provide results that are overly conservative and will result in a substantially lower value of unconstrained access rights than may occur in reality.

### Demand Side Management / Individual Reserve Capacity Requirement

Section 6.1.5 of the EY report makes reference to a demand side management mechanism where some consumers “tend to use less power when prices are high”, and that these bids are incorporated into the modelling process. EY has appeared to conflate the market-based Demand Side Management (DSM) mechanism with responses by customers seeking to minimise their IRCR obligations. The DSM and IRCR mechanisms operate under very different incentive structures, and so should be considered separately.

<sup>6</sup> Table 2.3, *Access Arrangement Information, Attachment 7.3: Peak demand, energy and customer number forecasts*, Western Power, 2 October 2017



Unlike DSM, IRCR responses are not centrally dispatched via the WEM, are not based on real-time market conditions, and do not operate in response to the balancing price. IRCR responses are determined by customer expectations of the probability that daily maximum demand will result in that day's peak being used in the determination of their IRCR liability. The magnitude of the IRCR response is largely dependent on a customer's ability to accurately forecast day-ahead peak demand relative to peak demand throughout the remainder of the hot season.

We recommend the PUO explicitly model the impact of IRCR responses on demand as an additional input to better understand the impact of demand uncertainty on market outcomes. This will enable the PUO to have regard to IRCR responses that:

- occur in different regions of the network, potentially magnifying the impact of regional constraints and therefore generator dispatch;
- vary in magnitude, taking account of whether the peak event was accurately predicted by customers; and
- occur in response to non-peak event conditions due to inaccurate forecasts or highly risk averse customers, increasing the degree of demand variability at a regional level.

The additional information required to conduct the proposed analysis is available in the AEMO's WEM ES00.

#### Allocation of Capacity Credits to intermittent generation facilities

Quantifying generator revenue, capacity credit allocations, and reserve capacity price outcomes are listed as a core purpose of the modelling. The methodology for calculating revenue is set out in Section 5 of the EY report. In the WEM, the allocation of capacity to intermittent generators is determined via the Existing Facilities – LSG methodology set out in Appendix 9 of the WEM Rules. We are concerned that there is no mention in the EY Report as to how the EFLSG methodology has been incorporated into this modelling.

Further clarity should be provided by the PUO regarding:

- whether the modelling incorporates the LSG methodology to determine the Relevant Level of capacity allocated to intermittent generators;
- if LSG has been used, then is the Relevant Level for each facility re-calculated based on a demand profile adjusted for rooftop solar output and other factors set out in Table 6 of the EY Report; and
- if LSG has not been used, then whether the data contained in the spreadsheet tab "SWIS renewable planting list" column F (Capacity Factor) is intended to correspond with an approximation of the Relevant Level for each facility.

The significance of the quantity of capacity allocated to intermittent generators becomes increasingly important because of the 500MW of additional renewable capacity that the PUO is assuming to come online by 2022. For this reason, it is imperative that the modelling accurately reflects the capacity allocation process as set out in the WEM Rules.



**Question 3: Three scenarios are proposed to be modelled (section 4.1 in the Paper).**

**(a) Is the rationale for selecting the scenarios sound?**

**(b) Are there other scenarios that should be modelled?**

Perth Energy does not consider the proposed scenarios sufficiently different to determine an adequate compensation value for the revocation of unconstrained access.

We do not consider the three scenarios adequately capture the full distribution of demand risk facing market participants. Additional demand growth scenarios should be included to evaluate market outcomes in scenarios of high and low (or negative) demand growth.

The PUO proposes to use three demand forecast scenarios to illustrate market outcomes in alternative possible future states. The scenarios align with the high, expected, and low scenarios published by the AEMO in the WEM ESOO. The requirements of the WEM ESOO set out in Section 4.5.10(a) of the WEM Rules define the scenarios as changes “stemming from different levels of **economic** growth”. However, Table 6 of the EY Report references the “Expected, High and Low **demand** scenarios” published in the WEM ESOO.

Scenarios defined by varying levels of economic growth combine input assumptions that have opposing effects on electricity demand. For example, high economic growth will simultaneously contribute to high population growth and a more rapid uptake of rooftop PV. The former increases demand while the latter decreases the rate of growth in peak electricity demand, but increases the demand for ancillary services. This averaging effect moderates demand in the high and low scenarios, and does not take into account the dramatically changing load shape.

The need to include more extreme demand scenarios is further highlighted by previous 90% POE forecasts that have exceeded observed annual maximum demand over the past two years. The 2017 WEM ESOO forecast a 90% POE for the 2017/18 capacity year of 3,709MW. Maximum operational load in the 2017/18 hot season was only 3,663MW. Similarly, the 90% POE forecast for the 2016/17 capacity year was 3,598MW, as published in the (deferred) 2015 WEM ESOO. Maximum operational load in the 2016/17 hot season was only 3,583MW. While these outcomes are not impossible, they are statistically improbable, lending weight to the need for a more detailed examination of the demand scenarios used in this modelling.

To provide a more complete view of the demand risk facing WEM participants, the PUO should include in the modelling at least two additional ‘extreme’ high and low scenarios based on credible combinations of inputs from the WEM ESOO and from Western Power.

**Question 4: What, if any, sensitivities should be modelled?**

Sensitivities should be published in cases where small changes to assumptions have a significant impact on the financial position or operation of generation facilities. Relevant examples include the retirement of one or more significant thermal generation units and wholesale gas prices.

With access to the model, the PUO is best placed to determine and communicate to stakeholders which input assumptions have the greatest impact on the modelling outputs. We recommend that the PUO



provides information on the sensitivity of each assumption and conducts further consultation on the assumptions that have a significant impact on modelling outcomes.

**Question 5: Are the key simulation parameters appropriate? (Table 3 in the Paper)**

Perth Energy considers the use of two reference years insufficient to adequately represent the level of demand and weather variability observed in the WEM. For example, the 2015/16 capacity year included one-in-fifty-year heatwave conditions that delivered a series of peak demand events between 8 February 2016 and 10 February 2016. Similarly, 5 January 2015 had temperatures exceeding 44°C, with daily maximum temperatures 10°C lower on the days before and after. This level of variability is not adequately represented in only two years' worth of data.

Furthermore, the (current) quantity of installed capacity of rooftop PV in the WEM means that small variations in forecast cloud cover have a significant effect on scheduled generator output. As the installed capacity of rooftop PV increases in the future, the effect of cloud cover is magnified, making robust modelling of weather variability critical. The full range of possible cloud cover/weather scenarios is not represented by using only two reference years of data.

To address these issues, Perth Energy recommends the PUO consider options for expanding the number of reference years considered in the analysis.

**Question 6: The modelling conservatively assumes no uncommitted transmission augmentation across the Study Period. Should an alternative be considered?**

Perth Energy questions whether the modelling adequately accounts for Western Power's plans for supporting system reliability and security behind constraints<sup>7</sup> by contracting network control services (NCS)<sup>8</sup>.

In its Annual Planning Report, Western Power provided the following table of limitations that it expects to seek NCS and demand management solutions to address:

Area of network limitation	Issue	Capacity shortfall
Mandurah substation	Transformer capacity shortfall	<10 MW within 5 years
South of Picton	Voltage stability issues in the area	<30 MW within 5 years
Katanning and Narrogin	Thermal overload on Kojonup to Wagin 66 kV circuit and voltage stability issues in the area	<10 MW within 5 years
Bunbury Harbour	Transformer capacity shortfall	<15 MW within 5 years
Eastern Goldfields	Power transfer limitations	Subject to customer demand

<sup>7</sup> Perth Energy understands that the majority of these constraints were 'grandfathered' into the current network design arrangements when Western Power's Technical Rules were established at market-start.

<sup>8</sup> See Table 24, Annual Planning Report 2017, Western Power, June 2017



We note that the retirement of three Synergy generation facilities is likely to exacerbate the current constraints. In its fourth Access Arrangement<sup>9</sup>, Western Power stated:

*During the AA4 period we are expecting the retirement of the Muja AB, West Kalgoorlie and Mungara generators that are currently used for security of supply and network reliability. This will cause additional pressure on the network in all of our already constrained regional load areas:*

- North Country
- East Country
- Eastern Goldfields
- Muja (which connects the South West).

*We have not had time to fully consider the impact of these retirements in our investment plan. We are in the process of the annual update of our Network Development Plan, which will assess and document these impacts, however, we anticipate a significant impact on our transmission measures.*

We consider Western Power's response to these retirements (either network augmentation investment or NCS operating expenditure) is fundamental to determining the impact of network constraints, and consequentially dispatch outcomes. These plans do not appear to have been considered in EY's modelling.

We recommend the PUO and EY work with the Western Power network planning team to gain a detailed understanding of Western Power's plans for the future of the network as will be provided in response to the ERA's impending draft decision on its AA4 submission and include additional scenarios in the modelling as required.

**Question 7: The list of new entrant generators in service by 2022 (Table 9 in the Paper) has been selected from the best available public information:**

**(a) Are there generators on this list that are unlikely to be in service by 2022?**

**(b) What additional generators should be considered? Why?**

The modelling appears to only consider the additional connection of:

- generation facilities currently included in Western Power's CAGs; and
- a number of renewable Synergy facilities included in the green power fund.

It is highly improbable that these will be the only facilities connected over the next 10 years.

Moreover, we consider it highly improbable that the only retirements of generation facilities are those already announced by Synergy to meet the former Minister for Energy's thermal generation limit. Under the current RCM, once the slope of the 'Lantau curve' exceeds about two-to-one, Synergy sets the reserve capacity price and has a financial incentive to retire generation capacity to increase the price and

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<sup>9</sup> Page 97, Access Arrangement Information, Access arrangement revisions for the fourth access arrangement period, Western Power, 2 October 2017



therefore their overall RCM revenue. Sufficient market power mitigation arrangements will need to be put in place to ensure Synergy cannot take advantage of this.

We recommend the PUO models another scenario taking account of expected additional retirements of Synergy thermal generation plant and additional renewable capacity installed in the SWIS. Western Power's 'Rapid Change Network Outlook' in its 2017 Annual Planning Report<sup>10</sup> should be used as the basis of this scenario. This outlook reflects the following assumptions:

- Engaged consumers and strong centralised action contribute to significant changes to the electricity market.
- The longer-term return of carbon pricing, combined with State-based schemes, result in WA building its pro-rata share of RET generation.
- Aging capacity is retired.

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<sup>10</sup> Page 22, 2017 Annual Planning Report, Western Power, June 2017





## Appendix A: Perth Energy's proposed alternative solution – improving market design

### The problem to be addressed

Perth Energy considers a fundamental challenge facing the South West Interconnected System (SWIS) is making sure the most appropriate type of generation connects in the right areas of the network. Matching the right capacity, energy and ancillary services to each network region is critical to maintaining energy security and reliability, as well as promoting competition and lower prices for consumers.

Therefore, if the PUO and Government were to address this issue, it would lead to more incisive, impactful and long-lasting improvements to the WA energy market.

Several barriers to increased competition currently exist in the framework that regulates the electricity industry in WA:

- the evolution of the wholesale market has been stifled as a result of the previous Government's ill-fated reform plans;
- Synergy continues to have market power in both the generation and supply of electricity;
- Western Power's informal transition from unconstrained network access to partially constrained network access is not adequately reflected in the wholesale market and dispatch arrangements;
- the current constrained, time-ordered network access rights do not result in the least-cost economic dispatch of electricity to meet load requirements;
- Western Power's proposed process of connecting generators on non-firm connections behind network constraints (the Generator Interim Access (GIA) solution) is unworkable, does not result in economic dispatch and is in contravention of the Wholesale Market Objectives; and
- Western Power's cost of electricity transportation in the SWIS is high as a result of the requirement to build out network constraints in an effort to provide generators firm access.

The PUO has an opportunity to remove these barriers by introducing reforms that go further than solely implementing a constrained network access regime. To increase competition in the WEM, security-constrained economic dispatch and market mechanisms must be implemented as soon as practicable to better achieve the Wholesale Market Objectives.

### Principles that should apply

The PUO recommends the following principles when designing a solution to allow additional generators to connect to the Western Power Network:

- the approach establishes the regulatory and market arrangements for constrained access by 2020 to allow implementation activities to commence;
- the way inconsistent contractual provisions are managed should provide sufficient certainty to Western Power and generators;
- regulatory intervention in private contractual rights will be limited to the extent necessary to achieve a constrained network access regime; and
- the approach should minimise administrative burden and cost.



Perth Energy considers the following principles should also be considered:

- any changes must be fair to generators that have entered the market on the basis of unconstrained network access;
- the proposed transitional assistance approach should not preserve access rights to the detriment of market design;
- any changes should be designed to minimise sovereign risk;
- market design decisions should maximise transparency of market information;
- market mechanisms must provide a strong locational pricing signal to incentivise investment in generation where it is required, and disincentivise investment where the network is constrained; and
- market mechanisms should be designed to maximise simplicity and expediency, and minimise the amount of tailoring required.

Perth Energy is concerned that the current proposal to introduce a constrained network access regime will only address the first of the PUO's principles, and very few (if any) of the others. Bearing all the above principles in mind, Perth Energy has developed an alternative proposal for consideration by the PUO and Government.

#### **Perth Energy's proposed alternative**

We submit that a regionally-based, partially constrained access regime would address all of the above principles.

Western Power's 2017 Annual Planning Report provides the following list of constraints in the network:

- north country 132 kV capacity for flows from south to north;
- north country 132 kV capacity for flows from north to south limited by:
  - 132 kV network capacity in the adjacent Neerabup load area;
  - 132 kV network capacity between Mungarra and Three Springs, including the Three Springs bus bar for generation connected north of Three Springs;
  - 132 kV network capacity between Three Springs and Pinjar for generation connected south of Three Springs;
  - 132 kV network capacity between Three Springs substation and Three Springs terminal;
- south country 132 kV capacity for flows from south to north;
- east country 132 kV capacity for flows from east to west;
- east country 132 kV capacity for flows from west to east;
- fault level limitations in the Kwinana and Northern terminal load areas.

We question whether these constraints alone necessitate the removal of the property rights of all generators.

Perth Energy's alternative solution would see these key constraints acknowledged through a regionally-based, partially constrained market. To a large extent, this market design would reflect the current network access arrangements.



A regionally-based, partially constrained access regime would separate the SWIS into regions whereby locational wholesale pricing can be applied to incentivise efficient investment where transmission constraints bind. Five market regions would be established, based on Western Power’s current planning regions:

- North Region;
- Goldfields Region;
- Perth Region;
- Muja Region; and
- South Region.

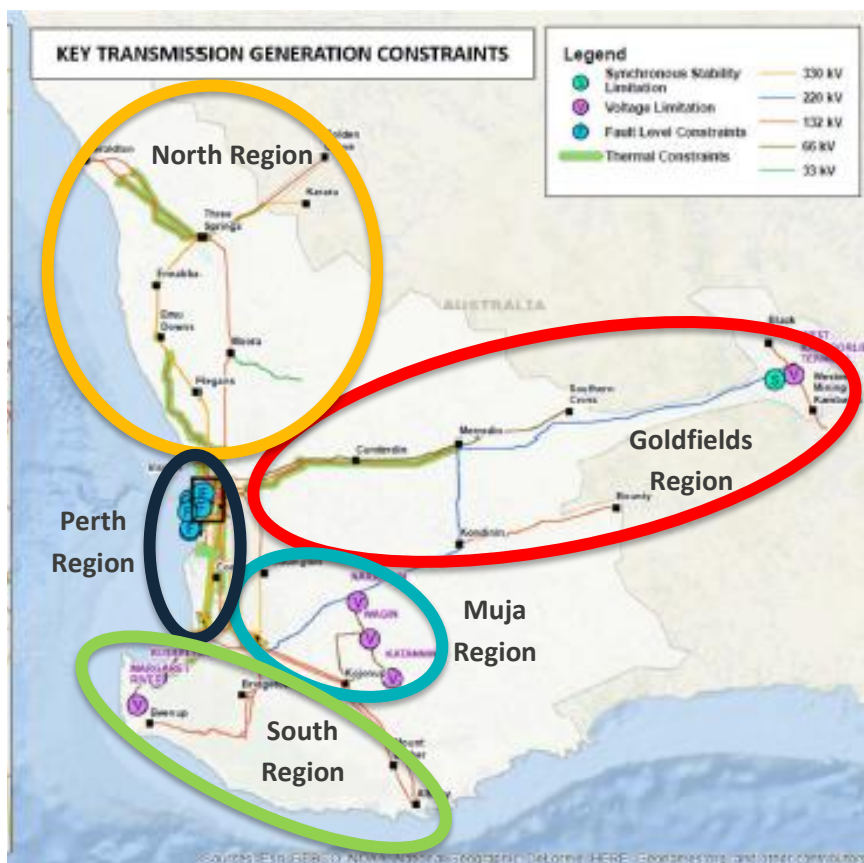


Figure 1: Potential market regions

Under this regime, only constraints between regions would be recognised. Access within each region would remain unconstrained. We submit that in this market model:

- AEMO would be responsible for forecasting long, medium and short-term demand and supply for each service in each region;
- Western Power would be responsible for network planning and developing constraint equations for inter-regional transfers;
- System Management would be responsible for balancing supply and demand SWIS-wide, or regionally where a constraint binds;



- Western Power would be responsible for augmenting the network or procuring network support services to facilitate unconstrained access within in each region; and
- market participants would be responsible for purchasing or delivering electricity physically across regions.

Under normal operation of the network, it is understood that the constraints do not regularly bind. This would mean that there is one single wholesale electricity price for the SWIS the majority of the time. It is only when a constraint binds that a regional price would deviate from the SWIS-wide price.

For example, if the north country 132 kV transmission line constrained load flow from south to north, the North Region price would deviate from the SWIS-wide price. Currently there are not many generators in this region. The price in this area is likely to increase significantly, as expensive generation is required to meet demand. Should this happen frequently, it would provide a price signal for new investors to locate generators in the area. As new investment is attracted to the area, the price will gradually normalise to levels closer to the SWIS-wide price.

The reverse is also true and is perhaps more important given the expected significant increase in renewable generation in that region. Where a generator is dependent on a fuel source, an investor is likely to locate the plant to optimise that fuel source irrespective of network constraints. Where this occurs, again, the regional price will deviate downward from the SWIS-wide price as plant is bid in to the market to continue running. Should this happen frequently, it would provide a signal for:

- investors with a price signal to locate elsewhere in the network if possible; and
- Western Power to augment the network to increase the network's ability to transfer this low-cost electricity to the load centre.

It is important to note Perth Energy is not proposing regional electricity retail pricing. The end price to consumers can remain uniform as per the Government's policy settings. Moreover, we are proposing a method of incentivising efficient and prudent investment via **locational wholesale pricing**.

### **Benefits of a partially constrained market model**

Perth Energy considers the proposed alternative solution will provide mechanisms to address the problem, without many of the costs associated with the PUO's currently proposed approach. This is because:

- it can be implemented relatively quickly (potentially before 2020) to replace the current inadequate systems, including:
  - Western Power's automatic runback schemes which do not result in the least-cost economic dispatch and are in conflict with Wholesale Market Objectives;
  - Western Power's proposed GIA solution which is unworkable and does not result in economic dispatch and is in conflict with Wholesale Market Objectives; and
  - the AEMO RTDE which is unreliable and requires significant manual intervention;
- it provides locational pricing signals for the location of new generators, without necessitating disparate retail prices;
- it provides a market signal for Western Power to augment the network where (verifiable) modelling quantifies improvement in market outcomes;



- it avoids reliance on medium-term forecasting in a rapidly changing industry to determine the impact of each existing market participant, and therefore financial compensation;
- it does **not** result in the removal of firm access rights, and therefore avoids sovereign risk and the significant financial compensation that could be required to be paid by the State Government to affected participants;
- it allows the full benefits of constrained access and can be evolved as required, with additional regions as required;
- it does not necessarily require changes to the reserve capacity mechanism;
- it does not compromise market design; and
- it maximises transparency of market information.

### **Critical elements of the market design required to support the approach**

Perth Energy notes there are additional considerations to facilitate the effective implementation of this solution. These are summarised below.

#### Market power mitigation

Synergy continues to have market power in both the generation and supply of electricity in the SWIS. This would not change significantly with the implementation of a partially constrained market model, nor in fact any constrained market model.

Adequate mechanisms will need to be developed to ensure market power is not used by any market participants on a regional basis. It is likely that the greater transparency resulting from a regionally segregated bidding will increase the ability for the ERA to monitor and enforce a market power mitigation regime.

#### Update of contracts

Market participants will need to review their energy contracts to determine whether any changes are required as a result of the alternative proposed solution. Depending on the type and content of energy contracts, change may be limited to a reference to a particular node in a region, or no changes may be required. However, it is unlikely to require significant re-negotiation.

#### Risk management tools

Market participants would need to be provided with sufficient financial markets to adequately manage the risk of regional price separation. The current Short Term Energy Market (STEM) would need to be reviewed and improved.

#### Transmission charging

The current Transmission Use of System Changes should be reviewed. With the removal of transmission network access rights, this pricing mechanism should be amended to reflect the value each participant receives from the network on a regional basis.



### **Recommendation**

Perth Energy submits that introducing a regionally-based, partially constrained access regime is a workable option that will resolve many of the issues highlighted by the PUO and market participants. Our aim is that the proposal we have outlined in this paper can be the precursor to more detailed discussion on this issue with the PUO, with a view to developing it into a practicable solution.

We are happy to work with the PUO, Western Power and other key stakeholders to flesh out this regional market design. Implementation of this or any other major reform would be led by the PUO, and Perth Energy is willing to share its resources and expertise to deliver meaningful WEM improvements.