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Economic Regulation Authority
4th Floor Albert Facey House
469 Wellington Street
Perth 6000

Submission re: Proposed Revisions to the Western Power Network Access Arrangement – AA4

Dear Sir/Madam,

Thank you for the opportunity to comment on Western Power's proposed revisions to its network access arrangement for AA4 and issues raised in the ERA's Issues Paper. I have worked in the WA electricity industry for 32 years in various roles across the whole supply chain from generation through to customer end-use of electricity, including for Western Power for five years until June 2016. I have worked extensively on demand-side management, renewable energy and non-network solutions.

I comment below on particular aspects raised in the various AA4 documents, in their respective sections where numbered below.

Support for the proposed advanced metering rollout and new time-of-use tariffs – Attachment 11.1 - AA4 Tariff Reforms, & Appendix F.3 - 2018-2019 Price List. Issues Paper – Issue #s 4, 11 & 12

I strongly support Western Power's proposed AA4 advanced meter rollout. An advanced meter rollout was approved by the ERA for AA3, but did not proceed because of government restrictions on funding. This has caused a lost opportunity – the opportunity to be further along the road towards better metering and the more economically efficient outcomes that this would deliver in the SWIS. Horizon Power's advanced metering rollout to almost 100% of its customers is demonstrating the benefits. It is also making possible their award-winning electricity pricing offers to customers.

I also strongly support the introduction of more cost-reflectively structured network and retail electricity tariffs like the four proposed by Western Power, together with customer education programs to support customers' understanding and responses to such tariffs. Many customers would be better off on these tariffs, and those that would not be, should be paying more anyway because they cost more to supply. Customers who need assistance to pay electricity bills should be supported by programs that are separate from electricity tariffs so that new electricity tariffs can deliver the improved outcomes that are available.

I also support the move to fixed metering charges (c/day), from the current variable charges (c/kWh) based on customer energy consumption. Metering costs do not vary with varying customer energy consumption and so it is more cost reflective to charge fixed charges for these. It removes a distortion that the current variable metering charges cause which results in cross subsidies between customers.

The proposed new tariffs RT17, RT18, RT19 & RT20 and tariff reform generally
Having said I support the new time-of-use (TOU) tariffs, I am puzzled why in Table 6.1 of the AA4 2018-2019 Price List the energy rates/kWh are the same in all three TOU tariff time periods (Off peak, Shoulder and On Peak), effectively making them "flat" tariffs. Is this a typographical oversight, or a transition strategy - to start with flat rates and over time and adjust them in future to be cost reflective in the different time periods?

When a new tariff is introduced, ideally it should be set at cost-reflective rates from the start and be applied to customers in an acceptable, managed way to account for the different impacts on customers with different electricity consumption load profiles. I do not support starting the introduction of these new tariffs with rates in each time period that are not cost-reflective.

Effectively structured and priced electricity tariffs are fundamental to effective peak demand management and more economically efficient outcomes.

Network tariff and franchise customer retail tariff reform in WA has been minimal over the last 23 years since the very effective tariff reform program that was in progress up to 1994 in WA. It was stopped due to the disaggregation of SECWA into the original vertically integrated Western Power, and AlintaGas. This tariff reform program did not quite get to addressing residential and small business customer tariff structures because larger customers were the focus first in the years to 1994. Most residential and small business customers have remained on non-cost-reflectively structured flat electricity tariffs over these many years with little or no structural reform.

A brief history – air conditioners and tariffs
It is well known that from the mid-nineteen nineties onwards there has been a boom in air-conditioner take-up by customers across Australia. It is ongoing, with larger centralised systems and multiple split systems being commonly installed now.

The resulting rapid growth in hot weather peak electricity demand to date has required a lot of new generation and network capacity to be built Australia-wide so that the electricity systems could meet the much higher demands in very hot weather, and also in very cold weather where reverse-cycle air conditioners are used for heating and networks are still winter-peaking.

During this 20-year period of high capital expenditure on supply capacity most residential and small business customers installing air conditioners remained on flat (non-time varying) energy-based (c/kWh) electricity tariffs. These tariffs were also kept artificially low in WA for various, mainly politically motivated, reasons up until 2008. The tariffs did not keep up with the increasing costs of supply caused by the significant capex on increasing supply capacity. In fact these tariffs actually subsidise air conditioner installation and use.

On flat, energy-based tariffs the revenue from air conditioner consumption (energy) is insufficient to cover the increased costs of supply from the additional generation and network capacity required to supply the air conditioners. This is because the air conditioners on average do not run for enough hours in a year in the SWIS to use enough energy to bring in enough revenue on these poorly structured tariffs to cover supply costs – hence the subsidy.

These non-time varying (non-time-of-use) tariffs also do not motivate customers to manage their consumption more at times of high system demand and supply cost.

The result of all of this has been a widening gap between tariff revenue and costs of supply and has probably been the most significant cause of the need for the annual WA government subsidy to Synergy known at the TAP (Tariff Adjustment Payment).

It is perfectly reasonable for customers to install and run air conditioners when they choose, in order to be comfortable. What is not reasonable is that customers do not pay what it costs to supply those air conditioners and that the flat, energy-based electricity tariffs cause significant, unfair, cross-subsidies between customers. This cross subsidy for air conditioning has recently been estimated by Synergy to be ~$230m/annum.

The **cross subsidies <u>between</u> customers are highest from customers** with no air conditioner, or with small air conditioners that run for more hours in a year (and therefore bring in more revenue relative to their size), **to customers** with large air conditioners that run for relatively few hours of the year and so bring in little revenue relative to their size and supply capacity cost.

I do not support suggestions of customers going without air conditioning at times when they want to run it, but it would help lower electricity supply costs if customers were incentivised to avoid running other "discretionary" appliances, like pool pumps, dishwashers, washing machines, clothes dryers etc. during annual peak electricity demand times – during very hot afternoons/evenings – i.e. between 3pm and 9pm as Western Power's proposed new time of use tariffs would encourage. I support the time periods proposed for the new tariffs.

These discretionary appliances can be used at other times of the day with little inconvenience to customers for those few very hot days of the year and this would mean lower system annual peak demand and less generation and network capacity having to be built or replaced.

Time-of-use tariffs over time would also incentivise houses and other buildings to be designed and built to be more comfortable at the same time as only needing smaller air conditioners to keep them comfortable – also lowering costs of supply.

These responses, for example, will lower supply costs in the longer term.

Take up of new technologies and other approaches like peer-to-peer trading
A key contributor to the rapid take-up of alternative technologies like photovoltaic (PV) systems by customers is also the lack of cost-reflectively structured network and retail tariffs. Existing flat, energy-based tariffs provide greater financial incentives to take up these technologies, and air-conditioners too as discussed above, than is economically efficient.

The widely used flat (non-time-varying) energy-based network and retail tariffs (without a demand component to reflect customer demand that drives network and generation capacity capex) are a key reason that customers install solar PVs and avoid more (bill) costs than is economically efficient.

Similarly, as already discussed, customers installing air-conditioners that contribute significantly to annual system peak demand, but which recover insufficient revenue on flat energy-based tariffs to cover the network and generation supply capacity costs, because they don't operate for enough hours of the year to do so, are being cross-subsidised by other customers and/or consumption due to the flat tariffs.

The introduction of more cost-reflectively structured, time-varying network and retail electricity tariffs would start to drive more economically efficient outcomes, including the beneficial application of energy storage such as batteries.

Even peer-to-peer electricity trading is largely driven by the price differences between electricity consumption and export tariffs that are not time-varying (don't reflect the true time-varying value of the electricity supplied or exported at different times of the day) and do not reflect the actual portion of the network used for the electricity trade (e.g. only to the next door neighbour). More value-reflective tariffs would remove the strong incentive for peer-to-peer trading.

Time varying or demand-based locational network pricing would also help to promote more economically efficient market responses.

Summary

Advanced electricity metering, with its associated tariff price signals and services functionality, is fundamental to being able to achieve good customer consumption behaviour and responses to help achieve more economically efficient supply of electricity. Without good metering services and tariffs, electricity supply system peak demand and supply costs are higher than necessary and unfair cross subsidies exist which cause customer responses that make the situation even worse. The significant cross-subsidisation of air-conditioning, particularly on peak demand days is one current example of the consequences of poor price signals. It has resulted in much higher electricity demand and supply costs than could be the case with effective peak demand management which good metering services and tariffs could facilitate.

Also the take up of solar PV by many customers has been, and is currently, over-incentivised by poor electricity price signals that cause cross-subsidies to it in the majority of instances.

For these and other reasons I support the proposed rollout of advanced metering and services for new meters and meters that need replacing (replacement meters), <u>as a first step</u> towards the more widespread deployment of advanced metering and services.

In parallel with the advanced metering rollout it is also important that much better structured network and retail electricity tariffs, and customer education and other behavioural response programs, are implemented to achieve the electricity cost savings that are available from better customer responses. Better responses in the take up of new technologies (PV, batteries, electric vehicles etc.) and better consumption patterns in response to customers seeing the time-varying costs of supplying electricity will result in lower costs of electricity supply and lower bills for customers.

I support the 'opt-out' approach proposed by Western Power for tariffs RT17 and RT18 to ensure effective take-up of the new tariffs by new customers. New customers in new premises will not have a bill history for the new premises and so are not as likely to experience price (bill) shock as in an existing premises. In any case, the new tariffs are designed to charge the same amount for an average customer as the old tariffs so price/bill shock should not be a significant issue.

Extended rollout of advanced meters

Once this initial advanced meter rollout is underway it is important that advanced metering and services are then progressively rolled out to other existing customers whose meters are not yet in need of replacement, so that the financial and other benefits of 100% rollout in target areas of the network can be used to justify deferral of network augmentation capex in those areas. Network areas such as Mandurah, Meadow Springs, Bunbury, Busselton and others, where annual peak demand is growing and causing the need for expensive network augmentation, should be targeted first for extended rollout of advanced meters and the other programs needed to help customers assist in slowing the growth of annual peak demand.

Horizon Power is now starting to make use of its advanced meters already rolled out to almost 100% of customers, to offer innovative solutions to a number of issues Horizon Power and customers face.

The functionality offered by these meters is highly valued by Horizon Power and customers who have participated in trials.

With regard to additional functionality that should/could be specified for the advanced metering infrastructure, I recommend that Western Power engage with Horizon Power to understand what additional functionality Horizon Power is using and planning to use from their advanced meters.

It would be very useful to the network operator and wholesale electricity market operator, or retailers and third party aggregators, for customer battery charging, electric vehicle charging and other discretionary loads (that customers don't necessarily need to have on at particular times - like at network peak demand times), or PV systems, to be able to be switched off or on remotely in an aggregated manner with the agreement of customers. Such programs are being demonstrated in other jurisdictions. Such meter functionality should perhaps be specified until such time as a better technology solution is available and widely deployed to achieve the system support flexibility available from distributed energy resources.

Plan a continuous metering and tariff improvement process – other improvement recommendations

I also recommend that the advanced metering services rollout to additional customers (whose meters are not yet in need of replacement), and ongoing tariff improvement, be planned by Western Power to be a continuous process with 'stretch' steps throughout each access arrangement period and not just each time a new access arrangement proposal is prepared.

I would recommend moving to adoption of the new RT19 and RT20 time of use demand tariffs as the default tariffs (with 'opt out' as the standard rather than the 'opt in' proposed by Western Power) for new customers, as soon as customers and the industry can be educated on the benefits of these tariffs and become comfortable with them.

I also strongly recommend that Western Power improve the demand based network tariffs RT5, RT6, RT7 and RT8 in the AA4 proposal further than what has been proposed. Only minimal changes have been proposed by Western Power to these tariffs for larger customers.

I participated in Western Power's consultation process with retailers on metering and tariff changes earlier this year. The following is what I submitted to Western Power in April 2017, but none of it has been included in the AA4 changes proposed by Western Power, as submitted to the ERA.

Request: That Western Power Improve the existing Demand-based Network Tariffs for Access Arrangement AA4

At a Retailer Forum on 23 March 2017, Western Power presented to SWIS Retailers its proposed changes to network tariffs and metering services, to apply in the AA4 Access Arrangement period.

Western Power proposes to introduce more cost-reflectively structured and better time-focussed network tariffs for residential and small business customers, and this is a positive move. So is the proposal to simplify and make metering charges 'fixed' annual charges instead of the current variable charges which cover costs that in reality do not vary materially with consumption.

For medium to large customers, Western Power's presentation stated "Most large customers are already on a demand based tariff therefore little need for change". This short paper contends that change is needed to these demand-based tariffs and explains why.

Why the demand based tariffs need to be changed so that the demand charges are 'time-based' and do not just apply 'anytime'

Western Power rightly points out that demand is the largest driver of network costs.

It is actually customer demand at the time of the annual peaks of the various network elements, which is the largest driver of these network costs and not customer maximum demand at any (other) time that the tariffs charge for at present.

The RT5 and RT6 metered demand network tariffs charge customers for their rolling 12-month maximum demand (anytime). The RT7 and RT8 Contract Maximum Demand (CMD) network tariffs charge for the customer's (anytime) CMD and customers are penalised significantly if they exceed their CMD anytime, even when the network elements supplying the customer are not highly loaded and have spare (under-utilised) capacity.

The application of these demand charges anytime means that:

1. Customers whose annual maximum demand **coincides with the network annual peak** do not have any flexibility or incentive[1] to shift their maximum demand to another time of day to save and reduce loading on the network at its peak demand time - when it matters to Western Power. This means Western Power has to eventually spend more capital on increasing the capacity of the network, increasing costs of supply unnecessarily.
2. Customers whose annual maximum demand **occurs at a time away from the network annual peak** are incentivised and will focus their effort and investments on reducing their maximum demand at a time that that does not matter to Western Power. It provides no demand reduction benefit to Western Power and reduces its revenue for no gain.

In short, anytime demand charges do not effectively focus customers' effort and investments to achieve benefits for both the customers and Western Power. This results in economically inefficient outcomes because the tariff demand charges are not appropriately time-focussed.

Customers also have less flexibility in ways to manage their electricity costs, because at present they cannot save by shifting their peak demand to another time of day. They are charged the same for their demand at another time.

As the take-up of self-generation, including solar PV and battery storage, increases, it is even more important that the demand based tariffs are better focussed on the time-of-demand cost drivers that matter to the network. Without this customers will install and operate their systems to maximise their own gain from the current tariffs at Western Power's and other customers' expense.

[1] Customers with a maximum demand (MD) less than 1500 kVA do receive a discount based on the relative proportion of their off peak versus total energy consumption, but **this is a very blunt price signal based on moving bulk energy usage over many hours to the off peak period rather than a signal to move short term peak demand at the time of the network peaks.** It also is not available to customers whose MD is greater than 1500 kVA. For customers with a MD between 1000 and 1500 kVA this discount only applies to the portion of MD above 1000 kVA.

Recommendations

It is recommended that Western Power:

1. Introduce time-based demand charges for the RT5, RT6, RT7 and RT8 network reference tariffs to focus the demand charges on time periods that matter to the network and allow customers the flexibility to move their (higher) peak demand to other times of the day, that don't matter to the network, without penalty.
2. On tariffs RT7 and RT8, remove penalties for customers exceeding their CMD (reasonably and within the capacity of the local network) at times that don't matter to the network – i.e. times away from network peak times. This will improve the utilisation of the network and is likely to move customer demand away from network peaks.

Existing time-based demand charges in WA

Two retail tariff examples of where demand charges are time based are the S1 and T1 gazetted tariffs which have been available since the early nineteen nineties and used by many business customers.

The demand part of the bill is calculated by multiplying the demand charge by the 'highest on-peak half-hourly demand' or '30% of the highest off-peak half-hourly demand' - whichever is greater. This effectively means that a customer can have more than three times the demand during the off-peak period compared to their highest on-peak demand, and not get charged any more.

I recommend that the ERA ask Western Power to implement these improvements to the demand-based tariffs for business customers (including tariff TRT1) in AA4 so that the benefits can be realised by customers and the whole electricity supply system, including generation capacity benefits. The outcomes will be more economically efficient than what Western Power has proposed (minimal change).

These changes are also preferable to just imposing the high (2.5 times) Excess Network Usage Charges (ENUC) multiplier Western Power proposes to charge RT7, RT8 and TRT1 customers who are on these contract maximum demand (CMD) tariffs in the Goldfields Mining and Albany substation areas – as given in Table 6.19 of the AA4 Appendix F.3 - 2018-2019 Price List. The ENUC multiplier is only 1.0 for all other areas.

I recognise that the Goldfields Mining and Albany areas have very little, if any, spare network capacity available at peak demand times to supply extra, large loads and this is the reason for imposing these high ENUC 'penalties'. However these excess demands are only a problem at these network areas' peak demand times and not at other times.

It would be better, and improve average utilisation of these networks, to incentivise these customers to move their high demands to other times of the day when these networks are not so highly loaded. That is what my recommended demand tariff changes would do. The changes I recommend provide customers with a way of helping to keep the network loads within their respective supply capabilities, at the same time as enabling customers to use more power when capacity is available with no penalty. The changes would be 'win-win' for both customers and Western Power.

Application of a time-of-use tariff to large customers – a different view

At the bottom of page 33 of Attachment 11.1 - AA4 Tariff Reforms – Western Power states, with reference to large commercial and industrial load areas and referring to the chart on the next page:

> *"Western Power has several load areas characterised by large commercial and industrial customers, being East Country, Eastern Goldfields, Kwinana, Muja and North Country. Figure 7-8 below shows the average demand profile on peak days in these load areas is relatively flat. In the presence of a flat demand profile, there is likely to be limited merit in the application of a time of use tariff."*

I do not agree with this latter statement.

Firstly, if the chart was plotted with its vertical axis ranging from zero to 150 MW, the variation is demand would be more obvious and not look as flat.

Secondly, plotting average profiles often hides actual variation in demand due to the averaging process.

Thirdly, as existing transmission customers currently have little or no effective time of use pricing signal in their tariffs, they will tend to have flat load profiles more so than if they were incentivised by price signals to move their peak demand away from the network peak demand times.

Even transmission customers with fairly flat load profiles will adopt demand responses over time if time varying price signals are in place. They can do this by changing operational practices, and by implementing technology solutions.

Time varying, locational based, network tariffs will signal to customers when there is spare capacity available from the network and even allow them to increase their consumption when there is spare capacity in the network. This is win-win for both the customers and Western Power, and would improve average utilisation of the network.

An example is one transmission-connected cement manufacturing company south of Perth that in the past ground clinker overnight (during the off-peak period of the retail tariff) and have a load of ~18 MW during that time. It would then cease grinding clinker during the retail tariff peak period and have a demand during that time period of ~10MW.

If network tariffs are not time varying, and only retail tariffs are (for generation cost reasons only), customers have a weaker time-varying signal than if both network and retail tariffs reflect the full time-varying cost of supply. The full time-varying cost will result in more economically efficient responses by customers.

I recommend that Western Power introduce time-based demand charges to its tariffs for large customers as I described above.

Tariff design evaluation

At the bottom of Appendix A - pages 9 & 10 of Attachment 11.1 - AA4 Tariff Reforms – Western Power states, with reference to 'Large business' and 'Transmission' customer tariff options in the tables – under 'Tariff design - CMD with Co-incident Peak (trial candidate end of AA3)' and 'Reasons tariff design excluded':

> *"The benefit of this tariff is that it encourages additional demand reduction at critical times, on critical days. However, accurate prediction of when the peak will occur is difficult, making responding to the price difficult and therefore ineffective.*
>
> *This tariff could be considered for a trial toward the end of AA4, to test revenue sufficiency and customer response."*

I do not agree with the statement about the accurate prediction of when the (network) peak will occur being difficult, making responding to the price difficult and therefore ineffective.

The Reserve Capacity Mechanism (RCM) of the WA Wholesale Electricity Market (WEM) has the IRCR (Individual Reserve Capacity Requirement) as a critical peak pricing signal, and it works.

Customers are able to predict when the critical peaks are likely to occur, because they typically occur on very hot Perth (because Perth is the main load centre of the network), working weekdays in the afternoon/evening. Most people know in advance when such weather will occur from weather forecasts.

The IRCR has even been criticised (because it works successfully to reduce critical peak demand). It is viewed by some as unnecessary in the current situation where there is excess RCM 'generation' supply capacity.

If a network element (e.g. transmission lines to Albany, which is also winter-peaking) has its critical peak demand at some other time than the very hot Perth days mentioned above, then it is possible with technology solutions these days to easily signal to customers when demand on that network element is getting close to critical. Western Power's SCADA systems already monitor this and signals could be provided to customers by Western Power.

Western Power correctly states "*The benefit of this tariff is that it encourages additional demand reduction at critical times, on critical days."*

This is exactly what would benefit the highly loaded parts of the network, to defer major network capex.

I recommend trialling such "CMD with Co-incident Peak" tariff design earlier in AA4 than what Western Power has proposed.

Lack of focus on peak demand management

A key reason (largely ignored in Australia) for the higher than necessary electricity prices across most of Australia, and for the WA government subsidies to Synergy to date, has been the lack of focus in Australia on managing annual peak electricity demand. There have been extensive programs in some jurisdictions, e.g. in Queensland - by Energex and Ergon, but generally demand management has not been a key focus of the majority of electricity businesses in most of Australia.

This lack of widespread electricity demand management in Australia has been highlighted recently in comments from Dr Kerry Schott, Chair of the recently formed Energy Security Board (ESB), and has been compared to the strong attention to water demand management in the water industry. See: http://reneweconomy.com.au/esb-chair-says-demand-response-could-kill-need-for-new-power-plants-43585/

Compared to other countries where electricity demand management is well established, Australia has performed poorly over many years and the result is borne out in our high electricity prices.

"Demand Response" (one type of demand management) is now getting increased attention in the National Electricity Market (NEM). Audrey Zibelman, now head of AEMO and also a member of the new ESB, is experienced in the application of "demand management" or "non-network solutions" overseas. Audrey is being influential in helping to arrange capacity for the NEM from demand response to help meet the forecast NEM supply capacity shortages. See: http://www.aemo.com.au/Media-Centre/AEMO-releases-summer-readiness-report-for-2017-18

A concerted focus on economical demand management programs and making use of distributed energy resources could avoid the need for significant network augmentation and conventional generation capacity for some time.

The NEM rules for:

- transmission and distribution network augmentation regulatory tests
- the lower NEM dollar cost thresholds for requiring these tests to be done, than those that apply in the SWIS under the Access Code, and
- the NEM specified processes for engaging with the market to identify alternative (non-network) solutions to network capacity requirements other than network augmentation

have in recent years forced increased attention to demand management and other non-network solutions by network service providers. See more below.

Proposed amendments to the D-factor scheme are supported – Issue 19

I support Western Power's proposed amendments to the D-factor scheme to enable it to lodge an application during the access arrangement period for a determination on whether expenditure satisfies the D factor non-capital costs test (Issue 19).

My many years of experience working in Western Power and its predecessors on alternative (non-network) solutions including demand management, to which the D-factor scheme applies, are that there has often been a 'cultural reluctance' to investigate and implement such solutions. Network solutions have generally been preferred also because of things that make non-network solutions more difficult or less attractive to justify, gain approval for, and implement even when they would be the most economically efficient solution. Having to seek retrospective approval for D-factor (non-capital) expenditure after the access arrangement period in which the expenditure would be incurred is one such 'barrier' that adds to this reluctance.

In my opinion, from experience, these amendments are necessary to help ensure Western Power chooses the overall least cost option when choosing between capital and non-capital solutions.

NEM RIT-T and RIT-D rules for evaluation of non-network solutions are better

I would even go further to say that the National Electricity Market (NEM) requirements (rules) for regulatory investment tests (RITs) and processes that network service providers (NSPs) must follow for transmission and distribution project evaluation and approval (RIT-T & RIT-D) are better (more stringent, with lower capex thresholds) than those that apply to Western Power. The NEM requirements are more likely to ensure more economically efficient solution choices by NSPs.

There is a lot of information available on these requirements from the Australian Energy Regulator's (AER) website. See the following link for a start: https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/rit-t-and-rit-d-application-guidelines-minor-amendments-2017

In 2016 when the WA Electricity Market Review (EMR) was intending that the above NEM rules (among others) would apply to Western Power for the next regulatory control period (RCP1), Western Power decided to carry out the Mandurah/Meadow Springs non-network solutions investigation generally in accordance with the NEM RIT-T requirements that were expected to apply in future under the AER. See: https://westernpower.com.au/about/media/submissions-sought-on-new-approach-to-power-planning/ and: https://westernpower.com.au/media/1995/non-network-options-report-mandurah-load-area-2016-pdf-version-of-dm13874165-13868073.pdf

I commend Western Power for taking this approach. It resulted initially in a one-year deferral of major transmission capex which would have been required to increase the supply capacity of the Mandurah substation.

The proposal to move Western Power under the jurisdiction of the NEM rules and the Australian Energy Regulator (AER) did not happen in the end, so I don't know how likely it is that Western Power would adopt the above process for future projects.

More economically efficient solution choices and outcomes would result if network investment rules such as the NEM RIT-T and RIT-D rules applied in WA.

I recommend that the same rules be adopted in the SWIS for application to Western Power to increase its attention to alternative/non-network solutions, to defer significant network augmentation capex in areas where peak demand is growing. I guess to achieve this would require amendments to the Access Code and perhaps other regulation.

Is the Access Code 'fit for purpose' to assess the AA4 Proposal?

The ERA intends to assess Western Power's AA4 proposal against the requirements of the Access Code.

Since the Access Code was last reviewed and revised[2], there has been significant electricity industry technological and other change. Also, a common comment in the industry is that regulation is not keeping up with the changes.

There are a number of Access Code requirements that cause unnecessary and undesirable restrictions/barriers to achieving better electricity industry outcomes and efficiencies. Some of these are discussed in this submission.

For example, does the Access Code limit what the ERA as regulator can <u>require</u> Western Power to do, when an alternative approach (that may have been suggested by the ERA or in a submission from others) to what has been proposed by Western Power would result in better, more

[2] A review of the Access Code was started around 2011/12, but this was stopped and not completed.

economically efficient outcomes? If so, then this would suggest that the Access Code needs revision in this regard.

I understand that the ERA (the 'Regulator') will not be reviewing and making changes to the Access Code for this AA4 assessment (not be the rule maker and rule enforcer).

The question still remains then for the Minister for Energy and the Public Utilities Office, "is the Access Code fit for purpose, and does it require review and revision now to ensure acceptable, or preferable "best practise", outcomes from AA4?"

An alternative to costly network asset replacement

Western Power is proposing to spend a significant amount of capex in the AA4 period on replacing aging assets like transformers, power lines etc. This is to reduce the risk of failure of these assets causing loss of supply to customers. This is normal practise in network utilities.

Having worked in the Network Planning section of Western Power for some time, I observed that the following alternative to such asset replacement had not been fully investigated and developed by Western Power, to avoid or delay expensive asset replacement.

The alternative approach is to pre-arrange alternative contingency measures to cover certain asset failures should they occur, and then continue to run the aging assets until failure, knowing that a backup plan was in place should the failure occur. Some aging assets may not fail for a long time yet, and so significant capex could be avoided or deferred.

Such pre-arranged contingency measures/plans could consist of arrangements like:

- Establishing standby contracts with emergency generator rental companies or others, to supply and install generators and step-up transformers etc. to connect to the network to supply load that could no longer be supplied fully from the network should a network asset fail.
- Establish connection points in the network at strategic locations to allow rapid connection of such generators.
- Establish standing contracts with customers and/or aggregators of customers, to be able to make use of customer capacity to generate to supply loads or to decrease load during critical periods following a network asset failure. Network Control Services contracts allow such arrangements already.

Many customers already have standby/emergency generators installed that could provide such contingency capacity. There is probably more than 50MW of customer standby generators located in the Perth CBD that could be used to support supply to that part of the network. I have been involved in investigating this in the past.

A senior Western Power network operations manager has also previously suggested that Western Power arrange for emergency generators, with step up transformers suitable for connection at up to 22kV, to be available at short notice for asset failure backup purposes.

As battery storage becomes more widely adopted by customers there will be an increasing amount of capacity that could be used for backup purposes with the right incentives and arrangements in place.

NEM rules for justifying asset replacement
The AEMC has recently tightened its reporting requirements regarding information to be provided by NSPs to justify asset replacement decisions. See: http://www.aemc.gov.au/Rule-Changes/Replacement-Expenditure-Planning-Arrangements/Final/AEMC-documents/Information-sheet.aspx

I recommend that significant asset replacement decisions be more closely scrutinised to determine whether any alternative approaches would be more economically efficient.

Focus on increasing average network utilisation

The average utilisation of many network assets is very low due to the very peaky (low load factor) load profiles supplied by the networks (highest demands are present for very few hours of the year but network capacity is provided to meet these peaks) and also due to planning approaches that cause a lot of backup network capacity to be built to cover potential outages. The transmission N-1 planning approach is one example.

The Eastern Goldfields 220 kV transmission line does not have network backup (is N-0), but a reasonably reliable supply still results because of local generation that can supply the local load should the 220 kV line be out of service. This illustrates that an alternative approach is feasible in certain situations. In this case it results in much better average utilisation of the transmission line than if it were duplicated to meet N-1 requirements, which would be very high cost and not economically efficient.

Managing annual peak demand on network elements, and implementing alternative approaches can improve the average utilisation of network assets – getting more out of existing assets rather than building new ones.

The more widespread adoption of distributed energy resources (DER – e.g. customer generation, battery storage) in future will provide a resource that can be incentivised and used to defer network capex and reduce the risk of network capacity being built and becoming a stranded asset.

Improvements to reliability of supply to edge of grid customers

There are a number of towns/communities in the 'long rural' category where Western Power has not complied to date with the requirements of the Network Quality and Reliability of Supply (NQRS) Code. Customers have had more than 16 supply interruptions in a year, or one or more interruptions of longer than 12 hours per interruption in a year, and Western Power has not remedied the causes or entered into alternative arrangements to the customer's satisfaction as required by the NQRS Code. Towns such as Kalbarri, Walpole, Denmark, Ravensthorpe and surrounds, Morawa, Perenjori and quite a few others have experienced such outages in the past.

Western Power rightly argues that to fix such non-compliance through network solutions is prohibitively expensive and so customers have been left to bear the consequences of their unreliable supply. It has generally only been addressed in the past when complaints escalated to such a degree that Ministerial direction caused solutions to be implemented, as happened for Bremer Bay in the early 2000's and Ravensthorpe since then.

The current feasibility study into options for improving Kalbarri's reliability of supply has largely been initiated by the huge customer outcry over the frequent and lengthy outages experienced in prior summers.

Western Power is to be commended for undertaking the Stand-alone Power System (SPS) trial in the Ravensthorpe area, the Perenjori battery storage trial, and the Kalbarri investigation into other solutions.

These trials should pave the way for alternative approaches to improve reliability of supply to edge of grid customers, providing that regulatory allowances and incentives which apply to Western Power will allow or encourage these approaches.

At present the SAIDI and SAIFI reliability indices and targets that apply to Western Power do not encourage such edge of grid solutions sufficiently for customers to receive acceptable supply reliability that meets the NQRS code.

These existing service standard benchmarks, which are (or have been?) proposed to be transferred into the revised NQRS Code without material modification, are based on average performance in each different category - such as 'Long Rural'. Many edge of grid towns have such low customer numbers that their poor reliability of supply figures do not materially alter the average results of these indices, which can therefore appear acceptable by meeting the (average) target.

The indices do not incentivise the network service provider (NSP) to improve the performance for those individual customers or communities whose supply is unacceptable, when their customer numbers are small and so have little effect on the average service standard performance results.

I recommend that this be taken into account in the review of Western Power's AA4 proposal and any reviews of regulation (the Access Code, the NQRS Code etc.) that may be necessary to achieve acceptable outcomes.

Momentary Interruptions – introduction of MAIFI

Western Power has been recording momentary supply interruptions as required by the ERA's AA3 final decision.

The increasing uptake of electronic equipment makes more customer equipment susceptible to momentary interruptions in a way that annoys or inconveniences customers.

I suggest that appropriate service standard benchmarks (e.g. MAIFI - momentary average interruption frequency index) be introduced to cover momentary interruptions as was envisaged by the ERA's AA3 final decision so that there is a greater focus on improving MAIFI performance also.

Some editorial discrepancies

To avoid confusion, I suspect that the following items in these Western Power AA4 documents require revision, or corrections to be noted.

Attachment 7.3 - Peak Demand … Forecasts. On page 3 in section 2.1 the text states that "around 20 per cent of its capacity (is) required for around two hours each year". From the chart on the same page, I suspect that this is meant to say "for around two percent of the year" – i.e. ~180 hours each year.

Attachment 11.1 – AA4 Tariff Reforms. In table 3.1 the descriptions of RT19 and RT20 should read "Time of use demand … tariff" rather than "energy".

Appendix F.3 – 2018-19 Price List. The table at the end of section 4.4.1 needs correcting to be clear what off-peak and on-peak time periods apply on weekdays, public holidays and Saturday-Sunday.

Similarly, the tables at the end of sections 4.3.1 and 4.13 need to explain what times apply on public holidays.

Thank you for the opportunity to comment. I would be pleased to be able to elaborate on any of these matters.

Yours sincerely,

Noel Schubert