Notes on ERA Issues Paper: Framework and approach for Western Power's fifth access arrangement review

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CONTENTS

KEY POINTS

This is a summary of key points from the paper.

1 The New Access Code Objective

General considerations on the objective and its components

A new process requires the ERA to decide some elements of the access arrangement before Western Power submits its access arrangement proposal. The objective

The new Access Code objective is set out in section 2.1:

> 2.1 The objective of this Code ("**Code objective**") is to promote the efficient investment in, and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers in relation to:
>
> (a) price, quality, safety, reliability and security of supply of electricity;
>
> (b) the safety, reliability and security of covered networks; and
>
> (c) the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts and encouraging energy efficiency and demand management.
>
> {Note: Consumers in the context of the Code objective has the meaning in this Code being "a person who consumes electricity"}

This objective recognises that the long-term interests of consumers are affected by the considerations listed in items (a) to (c). Factors (a) to (c) are the considerations to be taken into account when assessing the how the decision is likely to affect the ultimate criterion – which itself has two arms, namely:

- promote the efficient investment in, and efficient operation and use of, services of networks in Western Australia
- for the long-term interests of consumers

This is analogous in structure to the objective in section 2 of the *Competition and Consumer Act 2010*, which is: "The object of this Act is to enhance the welfare of Australians through the promotion of competition and fair trading and provision for consumer protection." Judicial interpretation of this objective in the context of restrictive trades practices law in Part IV of that Act is that the object takes as given that promoting competition enhances the welfare of Australians. By analogy, in s 2.1 of the Code, the long-term interests of consumers is to be achieved through promoting the efficient investment in, and efficient operation and use of, services of networks in Western Australia. It is assumed within the Code objective that promoting efficiency in this way is in the long-term interests of consumers.

The factors listed in items (a) to (c), which are the relevant considerations, indicate that 'efficient' means economically efficient in the broad sense of including consideration of environmental externalities. The 'interests' of consumers is an economic welfare concept which likewise takes account of all the factors listed in items (a) to (c) of the objective.

The question then is how this objective is to be applied in specific kinds of regulatory decisions, particularly in relation to Western Power, and the assessment by ERA of a proposed access arrangement. The AEMC is guided by similar objectives and it states:

> The focus of the energy objectives is on efficient investment in, and operation and use of, electricity and gas services in the long-term interests of consumers. The question to be answered in the assessment process is therefore, would a proposed change to the rules (or recommendation) promote more efficient decisions across these activities, which would ultimately promote the long-term interests of consumers. (Australian Energy Market Commission (AEMC) 2019b, 4)

That said, the Code objective clearly says that the 'efficiency' of the network and the 'long-term interests' of consumers need to be related back to all of the considerations listed in sub-paragraphs (a) to (c), where relevant.

We would argue that limb (c) of the objective does not invite the ERA to develop environmental policies, but rather should be viewed in the context of the ERA's role within the propose-respond framework for assessing access arrangements. It would be reasonable for the ERA's Framework and Approach to require Western Power to address how its proposed access arrangement promotes each of the elements of the objective, but the ERA should be cautious in regard to being any more pro-active than that. However, in its response to the proposed access arrangement the ERA needs to give consideration to each of the environmental matters listed in limb (c).

Environmental considerations may be relevant to various aspects of an access arrangement, including services offered that facilitate renewable energy; structuring of tariffs to promote energy efficiency (and hence reduced emissions); and the assessment of investment programs that takes environmental shadow prices into account.

There may, for example, be trade-offs to be made between environmental and competition considerations in formulating regulatory measures. In this respect, ERA has indicated that if Western Power were to provide electricity storage services to customers, these may be 'excluded services' when applying the competition test included in the definition of that term. Stronger ring-fencing obligations might be applied to promote competitive neutrality. We would not see this as inconsistent with the environmental aspects of the objective, but rather a balancing of different considerations relevant to the overall objective.

Whilst the amendment of the objective removed reference to promotion of competition in upstream and downstream markets, the Energy Transformation Taskforce has emphasised that promotion of competition in related markets is implied within the objective because effective competition promotes economic efficiency. Further, criterion (a) includes the broad consideration of "price, quality, safety, reliability and security of supply of electricity", which will encompass the competitiveness of services involved in the supply of electricity.

Another trade-off, which may arise in the provision of regulated services, is between the price to consumers and cost of any environmental activities that may be carried out in supplying the services. ERA would then need to assess the efficiency of those costs taking into account not only monetary costs, which flow through to consumers in prices, but also the shadow prices of any environmental benefits.

Thus each limb will need to be valued either explicitly or using value judgements where trade-offs have to be resolved. For example, if there was a conflict between environmental consequences and price or reliability.

Other considerations

Some sections (or parts) of the Code may include criteria or objectives that are specific to that section (or part). As explained in the Issues Paper, sections 2.3 and 2.4 of the Code set out rules for resolving any inconsistency between the Access Code objective and section-specific criteria:

> 2.3 Where this Code specifies one or more specific criteria in relation to a thing (including the making of any decision or the doing, or not doing, of any act), then:
>
> (a) subject to section 2.3(b), the specific criteria and the Code objective all apply in relation to the thing; and
>
> (b) subject to section 2.4, to the extent that a specific criterion and the Code objective conflict in relation to the thing, then:
>
> (i) the specific criterion prevails over the Code objective in relation to the thing; and
>
> (ii) to the extent that the specific criterion conflicts with one or more other specific criteria in relation to the thing, the Code objective applies in determining how the specific criteria can best be reconciled and which of them should prevail.
>
> 2.4 If the Code objective is specified in a provision of this Code as a specific criterion, then the Code objective is to be treated as being also a specific criterion for the purposes of section 2.3, but to the extent that the Code objective conflicts with one or more other specific criteria the Code objective prevails.

Sections 2.3 and 2.4 do not address the interpretation of the Access Code objective, including the balancing of the considerations under the three limbs of that objective. We also note that the Issues Paper states that sections 2.3 and 2.4 may not deal with situations where there is a conflict between the three limbs of the Access Code objective.

Often there will be not be an inconsistency between the Code objective and section-specific criteria, and 2.3(a) stipulates that both the Code objective and the section-specific criteria apply together. An example of where 2.3(b)(i) applies is with regard to pricing. Section 7.3G states: "Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates …". By implication, tariffs must be based on efficient costs of supply and can only be structured in a way designed to promote environmental objectives subject to that principle. It will often be the case that efficient price signals, such as higher prices in periods of highest use, will also be consistent with environmental objectives.

Concluding comments

Just as the service standards adjustment mechanism calls on the regulator to develop an estimate of the value to consumers of the reliability of supply, so too the environmental element of the objective is likely to call for estimates of the value to consumers of certain environmental outcomes. For example, given the importance of environmental consequences in the Code, any net benefit tests will need to assess the costs and benefits of environmental consequences, including the new facilities investment test. This is likely to be a difficult task.

One regulatory tool that may warrant consideration in balancing the different arms of the regulatory objective is ring-fencing. Whilst ring-fencing has not been applied in Western Australia's electricity access regime, it is applied in the NEM, and the AER is currently reviewing the ring-fencing obligations. The main purpose of ring fencing relates to a mechanism to facilitate competition. However, this may well prove very difficult and uncertain in terms of effective mechanisms in the complex, evolving situation facing the energy sector.

2 Classification of services and new technologies

Purposes

For both the ERA and AER the classification of services is important for providing transparency and predictability of what is regulated and the form of regulation that will apply.

The framework and approach to classification of services needs to address:

(a) the categories of services and principles of classification stated in regulatory instruments;

(b) the procedure for assessing and classifying services;

(c) the development of baseline groupings which provide a starting point and assist to focus the classification of services in the development of an access arrangement;

(d) The listing of all reference and non-reference services under the baseline groupings.

Service definitions

The terminology used for service classifications in Western Australian electricity network regulation in some ways differs from the terminology used in the NEM.

When comparing the national and Western Australian electricity network access regime service classifications, there is a rough parallel between the 'revenue target' reference services in the WA regime and the standard control services in the national regime. The kinds of services that fall under non-revenue target services and non-reference services in the WA regime may be broadly similar to alternative control services in the national framework – but there are important differences because in the national framework, a broader range of services are unregulated because they are deemed to be contestable. Another significant difference is that fees and charges for alternative control services in the national framework are regulated much more prescriptively than non-reference services are under the WA regime.

These comparisons suggest that **the following are important considerations for the ERA's framework and approach**:

- The listing of services in the framework and approach applies to all network services and the classification of services at the very least requires:
    - For each service determining whether it should be an excluded service by applying the competitiveness test in the Code. That is, determining which services are contestable.
    - Classifying the remaining services (i.e. the covered services) as either 'revenue target' reference services; 'non-revenue target' reference services; or non-reference services.
- For the list of services that are either 'non-revenue target'; services or non-reference services, determining whether Appendix C.1 of the access arrangement applies to all of those services (Western Power 2019); which is produced in accordance with Appendix 8 of the Code. And if there is a category of non-reference services to which Appendix 8 does not apply, whether there should be analogous statements of pricing policy in relation to that category of services in the access arrangement.

The AER *Electricity Distribution Service Classification Guideline* sets out a 'baseline' service classification which will be used as a starting point in its regulatory assessments.

It may be useful to use the baseline service groupings produced by the AER, by categorising all listed services under these headings, in addition to their regulatory classification of reference services, unregulated services, and excluded services. This would assist the ERA to compare its classification scheme with that of the AER, and to highlight categories of services that are potentially contestable now or in the future.

Multi-function asset principles

A new category is required for a multi-function asset which is defined as a network asset used to provide services other than covered (regulated) services.

Where an asset is used to provide both SCS and unregulated services, clause 6.4.4 of the NER allows the AER to reduce a network service providers regulated revenue by an amount that the AER considers is reasonable to reflect such part of the cost of the asset that is being recovered through charging for unregulated services. Clause 6.4.4 of the NER requires the AER to have regard to the shared asset principles and the Shared Asset Guideline (SAG) in determining shared asset cost reductions.

The current shared asset guideline was finalised in 2013 (AER 2013b). The key elements are as follows:

- A materiality threshold of 1 per cent of a service provider's total annual revenue applies.
- The service providers regulated revenues are reduced by around 10% of the value of unregulated revenues earned from shared assets.
- The reduction cannot exceed the regulated revenue for the shared assets.

Stand-alone power systems

A recent AER Issues Paper (AER 2020b) discusses the updating of ring fencing guidelines for stand-alone power systems and energy storage devices. The Issues Paper notes that in the

NEM, stand-alone power systems (SAPs) are not connected to the national grid and not captured by the economic regulatory framework in the NER and NEL. The AEMC (2019a) has developed a framework that splits a SAPS into two components: a SAPS distribution system and a SAPS generation system. The distribution system component of a SAPS will be regarded as a distribution service under the new rules and would be treated like any other part of a distribution system. The SAPS generation system, however, would need to be provided by a third party (or a DNSP affiliate). For a DNSP to provide the generation system of a SAPS, a ring-fencing waiver will be required. The SAPs framework has not been settled at this stage.

The ERA notes that as Western Power cannot offer stand-alone power systems more generally to its customers or third parties, there is no need to create a new service. It should be captured under the existing reference services and included in the target revenue category. We support this position.

Network-connected batteries

For storage services from network-connected batteries of Western Power to be excluded from regulated services there is a need to pass a competition test. The scope for effective competition in battery storage and network services provided by batteries is uncertain at this time and would need further investigation.

There seems to be some potential for over-recovery by Western Power of capital expenditure on network-connected batteries, even if storage services are excluded services. The scheme is intended to provide Western Power with strong incentives to better utilise network assets where possible. The cost reduction amounting to 30 per cent of the net incremental revenue deriving from a multi-function facility is considerably larger than the AER penalty for unregulated revenue from shared assets.

Distributed energy resources developments

In Western Australia an Energy Transformation Taskforce has been established to implement an Energy Transformation Strategy focussed on developing a decentralised supply chain comprising a variety of distributed energy resources (DER) that are fully integrated into the power system. This entails a number of actions including removing barriers to DER participation, grid support measures, and piloting alternative electricity tariffs (see: Energy Transformation Taskforce 2019a). Details of the actions and responsibilities are set out in a Road Map.

The Road Map notes that distributed battery storage at the household level is very limited reflecting the high cost, community battery storage is fairly new limiting the scope for widespread participation and customers are unable to participated in the provision of network and system services (pp. 22-23). The Road Map also highlights expected problems for network stability and operation arising from increased penetration of rooftop solar PV and that his may require various capital expenditure to ensure power system security, safety and reliability (pp. 31-33).

The Road Map also identifies the roles of various entities for effective DER integration into the power system. These include: aggregators to develop portfolios of market support services based on contracts with DER owners to provide various 'virtual power plant' services; a distribution system operator (DSO) (as part of Western Power's role) to manage the network within technical limits and a distribution market operator (DMO) to operate and settle the wholesale energy market (the Australian Energy Market Operator (AEMO) for the SWIS).

There is no explicit recognition of the role of ERA in implementing economic regulation. The main role would be in relation to approving various costs in accordance with the access code objective.

The AEMC has recently released a package of draft electricity and retail rule changes to facilitate the integration of distributed energy resources such as small scale solar and batteries more efficiently into the electricity grid (AEMC 2021; 2020).

The AEMC draft rule changes are in effect covered in the proposed actions in the WA Energy Transformation Strategy.

3 Reference services

Under the Access Code, covered services that are classified as reference services are to be specified in the access arrangement with a price, a standard contract and service standard benchmarks.

ERA has observed that various changes to the reference services will be needed in consequence of, and to support, the state government's Energy Transformation Strategy. ERA observes that the current reference services to facilitate distributed generation or other non-network solutions should be retained; and services relating to customer direct load control and load limitation should also be retained. ERA has also noted that some tariffs could be rationalised or amended to more clearly specify what the user needs to do to be eligible for the services. Western Power acknowledges there is a need to rationalise some services, to update eligibility criteria, to make amendments to deal with constrained access, and notes that methods of calculating metering charges will need to be reviewed.

ERA prefers to address all of these issues in the framework and approach. ERA also prefers to identify at this stage any new reference services likely to be needed in AA5. However, Western Power prefers flexibility in meeting the eligibility criteria and approach to setting tariffs and considering new services in accordance with the procedure and criteria in clause 4.A14 of the Access Code, and act on them when they are sufficiently justified.

ERA's proactive approach seems to be the more practical where there are clear options to improve the tariff eligibility criteria or better tailor a reference service to customer needs. However, in regard to identifying new services in the framework and approach, given the uncertainties about what they ought to be, the ERA position may be difficult to implement and a flexible approach relying on customers to initiate proposals may be the most practical option.

The new pricing principles in the Code are broadly similar to those implemented by the AEMC in 2014. It is likely that the implementation of cost-reflective distribution charges will require substantial tariff realignments, and ERA should consider requiring Western Power to establish a framework within which it will go about this, including undertaking market analysis, developing cost-reflective tariff options, consulting with customers on them, obtaining the ERA's approval and progressively implementing the preferred options over a period such as five years

4 Method of setting service standard benchmarks

Western Power's access arrangement has both benchmarks and targets for services standards. Benchmarks are the minimum standard that must be met, and the targets are higher, based on average performance over the previous five years.

The main performance measures used in Western Power's current access arrangement for which service standard benchmarks (SSBs) are defined, are:

- for *distribution*: System Average Interruption Duration Index (SAIDI); System Average Interruption Frequency Index (SAIFI); and call centre performance;
- for *transmission*: circuit availability, loss of supply event frequency and average outage duration; and
- there are other performance measures for street lighting, supply abolishment, and remote de-energise and remote re-energise services.

ERA proposes the following changes to the performance measures:

(1) widening the measures of SAIDI and SAIFI to include interruptions to distribution customers due to planned or unplanned outages on Western Power's transmission network. Related to this, ERA proposes that distribution service standard exclusions should no longer exclude faults on the transmission network;

(2) removing the circuit availability measure; and

(3) introducing a new transmission service measure for network entry services provided to generators. This would be based on interruptions to generators' ability to despatch into the transmission network due to a planned or unplanned network outage.

Western Power made a number of objections to the proposed changes but the ERA changes seem reasonable to us. It is noted that ERA has proposed that service standard benchmarks no longer be used in the service standards adjustment mechanism (SSAM), and our main focus is on the SSAM.

As discussed in chapter 9, the Services Standards Adjustment Mechanism (SSAM) in the Western Australian access framework currently uses both service targets and service benchmarks in its formulation. However, ERA has proposed changes which would remove the use of benchmarks in the SSAM, and hence decouple the service benchmarks from the financial incentive scheme in the SSAM. This will assist to simplify the SSAM mechanism, and make it more consistent with the AER's STPIS mechanism.

ERA's method of updating performance benchmarks using the 2.5th percentile performance of the previous five years is, in our view, a reasonable one. It may be noted that the method of setting benchmarks and targets (for the SSAM) are related. The latter is based on the average (which could be the median) performance over the previous five years. However, when setting targets there are also a number of other considerations to take into account other factors expected to materially affect network reliability. Western Power has emphasised its concerns relating to bush fires and other climate related risks. Other factors, likely to be associated with improved reliability include the greater adoption of new technologies such as stand-alone power and network battery storage, may have the potential to significantly reduce interruptions. In light of these considerations, the ERA's proposed approach is unlikely to set unachievable benchmarks.

5 Price control

Prior to 2019-20 a revenue cap applied, with unders and overs adjustments to adjust for under or over recovery for each of the distribution and transmission networks. Since 2019-20 there is no unders and overs adjustment so that price caps in effect apply. This form of price control ensures Western Power is fully exposed to demand risk within a regulatory period.

The ERA proposes to continue the same form of price control subject to some modifications in the Access Code relating to pricing principles. The revised pricing principles require Western Power to undertake a more detailed cost allocation to ensure each reference tariff complies with pricing principles for efficient pricing and to remove a requirement to avoid price shocks. There is also a requirement to minimise distortions to price signals for efficient usage and a requirement to ensure that total expected revenue equals total efficient costs.

The proposed changes for setting specific reference tariffs and to remove separate price controls for transmission and distribution and for the separate side constraints seem reasonable.

However, the Western Power submission considers there also an issue of potential asymmetry in the distribution of revenues that needs to be addressed. However, the asymmetry has not been demonstrated except to refer to individual price caps restricting upside revenue potential.

There is an issue though of the optimality of allocating all demand risk to Western Power and the incentives that would arise to under estimate forecast demand.

If the price cap form of regulation is continued there may be merit in considering whether a threshold (deadband) should be specified such that within the threshold Western Power bears all of the demand risk but beyond the threshold consumers bear all of the demand risk. We understand that the economic literature tends to conclude that some sharing of demand risk is optimal (see: QCA 2012 section 7).

6 Investment adjustment mechanism

Western Power has an investment adjustment mechanism in its current access arrangement that corrects for any economic loss or gain due to differences between forecast and actual expenditure (in present value terms). ERA's preliminary view is that the current mechanism is inconsistent with the price control arrangements applying since 2019/20 which places demand risk on Western Power with the scope for Western Power to retain more revenue where demand is greater than forecast and receive less revenue where demand is less than forecast.

The proposed strict price cap approach and the current investment allowance approach are extremes that are not consistent. However, our understanding of the economic literature is that both extremes should be avoided. Allocation of full demand risk to Western Power and no sharing of capital efficiency cost savings may not represent efficient sharing or risk and could provide strong incentives to under forecast demand and over forecast required capital expenditure. The latter problem may be addressed with effective auditing and disallowing inefficient capital expenditure. But with the full allocation of demand risk the problem of under-forecasting of demand may be difficult to overcome unless some additional mechanism is developed.

7 Gain sharing mechanism

The gain sharing mechanism in the access arrangement for Western Power effectively addresses the periodicity problem for operating expenditure, by ensuring that Western Power retains an efficiency saving realized at any time during the regulatory period for the same period of time thereby providing continuous, consistent incentives to achieve cost efficiencies.

This mechanism seems appropriate and is consistent with the approach adopted by the AER in its Efficiency Benefit Sharing Scheme (EBSS) (AER 2013b) except that the AER Scheme allows retention for six years in total compared with the ERA period of five years in total.

As explained in the ERA Issues Paper some amendments are required due to the Access Code amendments and some consideration needs to be given to the treatment of exclusion. These relate to expenditure savings for failure to meet service standard benchmarks not impacting on the gain sharing mechanism; and the requirement for symmetry with respect to overspends and underspends.

For exclusion, the D-factor adjustment in relation to demand-management initiatives is to be retained on the grounds that it meets the access code amendment to minimise the effects of the mechanism on incentives for implementation of alternative options.

For uncontrollable costs, the current gain sharing mechanism excludes a number of expenditure categories on the basis they are outside Western Power's control. The ERA notes that the AER does not exclude "uncontrollable" costs from its equivalent of the gain sharing mechanism on the basis that there is no compelling reason that the forecasting risk associated with uncontrollable operating expenditure be shared differently between service providers and customers than for "controllable" costs and proposes to remove the exclusion of uncontrollable costs from the gain sharing mechanism.

The AER reasons for excluding non-controllable costs are that the risk of uncontrollable events presents both upside and downside risks, that any material risks can be managed with pass-through events and contingent projects, that network service providers would have some control over such events and excluding such items would reduce incentives to ensure costs were efficient.

It is noted that the AER scheme operates for 6 years in total (compared with 5 years in total for the ERA scheme) and (based on discount rates at the time) means approximately a 30:70 (firm consumer split) sharing arrangement). The 6-year period was chosen to ensure an approximate 30:70 sharing of unders and overs in present value terms to match an exact 30:70 sharing in present value terms for the capital expenditure efficiency sharing scheme operated by the AER.

8 Service standards adjustment mechanism

The service standards adjustment mechanism (SSAM) determines how the service standards outcomes of the access provider relative to performance benchmarks, in an access period, translate into rewards (for overperformance) or penalties (for underperformance) in the next access period.

Western Power's access arrangement has both benchmarks and targets for services standards. Benchmarks are the minimum standard that must be met, and the targets are higher, based on the average performance over the previous five years. At the end of an access period, in the next access review, Western Power receives a financial reward for exceeding the targets and a financial penalty for not meeting the targets in the last period on average.

The main performance measures used in Western Power's current access arrangement are:

- for *distribution*: SAIDI, SAIFI and call centre performance;
- for *transmission*: circuit availability, loss of supply event frequency and average outage duration.

ERA proposes to retain the current mechanism with some modifications. It proposes to continue using the method for calculating the benchmarks based on the 2.5th percentile of actual performance over the previous access period. Proposed modifications to the SSAM include:

(1) changes to some service standard measures, including;

  (a) widening the measures of SAIDI and SAIFI to include interruptions to distribution customers due to unplanned outages on Western Power's transmission network;

  (b) a new measure to capture interruptions to generators' ability to despatch into the transmission network due to a planned or unplanned network outage;

  (c) removing the circuit availability measure.

(2) revising the method of calculating transmission incentive rates, to use only the revenue attributable to those customers to which the transmission service standards apply;

(3) using the most current AER estimates of the value of customer reliability; and

(4) modifications to the caps on financial rewards and penalties consequent on changes to the gain sharing mechanism, and to make them symmetrical. The cap for rewards and penalties for the transmission network would be retained at 1% of transmission revenue, and the caps for the distribution should be symmetrical and set at 1% of total distribution revenue.

The AER has separate service standard performance schemes (STPIS) for distribution and transmission.

The distribution scheme comprises four components:

- A reliability of supply component.
- A quality of supply component.
- A customer service component.
- A guaranteed service level component.

Under the reliability of supply, quality of supply and customer service components of the scheme, a DNSP's revenue is increased (or decreased) based on changes in service performance, as assessed by the AER. The maximum revenue at risk for the scheme components in aggregate is (±) 5%.

Performance targets are based on average performance over the past five regulatory years, calculated after adjusting for excluded events, and modified by:

- the effects of any improvements allowed for in cost benchmarks;
- an adjustment to correct for revenue at risk;
- any other factors expected to materially affect network reliability.

The latest version of the STPIS for transmission (AER 2015) has three key components:

- the service component, which is designed to incentivise TNSPs to reduce unplanned circuit outage events, loss of supply event frequency, and average outage duration and achieve proper operation of equipment. This can lead to a maximum reward or penalty worth 1.25 per cent of the MAR;
- the market-impact component (MIC), which provides an incentive to TNSPs to reduce the impact of planned and unplanned outages on wholesale market outcomes. This has an incentive which falls within the range of ±1 per cent of the MAR;
- the network-capability component, which encourages TNSPs to undertake operational and minor capital expenditure projects (can cost up to a total of one per cent of the MAR per year) that deliver improvements in network capability of those elements of the transmission system most important to determining spot prices or at times when users place the greatest value on the reliability of the system.

In its decision on Western Power's current AA4 access arrangement, ERA adopted the 60/40 weighting for SAIDI and SAIFI in line with the AER's new approach (Economic Regulation Authority (ERA) 2018, 439).

ERA notes that the service standards adjustment mechanism will no longer require the individual penalties to be capped at the service standard benchmark.

The revenue at risk for Western Power under the SSAM of ±1% of total revenue appears to be much lower than the revenue at risk level applying to DNSPs in the NEM of ±5% of total revenue. If that observation is correct, it would imply that the SSAM imposes much weaker incentives for service quality improvement than the equivalent STPIS scheme in the NEM. We understand that the revenue at risk for Western Power was previously higher, and the current lower level may reflect a more cautious view about the reliability of the targets.

As Perth Energy has noted, some of the new technologies likely to be implemented on a substantially greater scale in AA5, such as stand-alone power and network battery storage, may have the potential to significantly reduce interruptions. It would therefore seem to be advisable that ERA should carry out an assessment of the likely effects of these technologies on interruptions. This would need to be assessed in the context of evaluating Western Power's proposed access arrangement, rather than being decided in the framework and approach.

9 Demand management innovation allowance mechanism

This requirement arises from amendments to the Access Code. It is described as a limited scheme to provide Western Power with financial incentives to undertake small-scale R&D initiatives on the network, with the aim of achieving lower cost outcomes over time for customers. This would be in the form of an additional R&D allowance for each year of an access period, which can only be applied to projects meeting specific criteria as approved by ERA in advance of the project being undertaken. Unused allowance cannot be carried over to another year. A similar scheme operates in the NEM for distribution, administered by AER.

The DMIA mechanisms developed by the AER for distribution must be consistent with the following:

- The demand management R&D projects supported by the scheme "should have the potential to deliver ongoing reductions in demand or peak demand, and be innovative and not otherwise efficient and prudent non-network options that a distributor should have provided in its regulatory proposal" (Australian Energy Regulator (AER) 2017b, 4).
- The level of allowance should be reasonable, considering the long-term benefits to retail customers.
- It should provide funding that is not available from another source, including under a relevant distribution determination.
- Recipient distributors must publish and report on the nature and results of demand management R&D projects that are the subject of the allowance.

The DMIA mechanism has three main elements:

- *An allowance*: equal to $200,000 (in base year prices) plus 0.075% of the DNSP's annual revenue requirement (ARR) for each year of the access period. This allowance can only be spent on eligible projects. Qualifying expenditure over this limit is at the DNSP's own cost. Any underspend of the allowance, calculated over the regulatory period as a whole, is deducted from the DNSP's revenue requirement in the next access period.
- *Project eligibility requirements*: The R&D projects must:
  - (a) be a project or program for researching, developing or implementing demand management capability or capacity;
  - (b) be directed at the objective of the scheme;
  - (c) be innovative;

(d) have the potential to reduce long-term network costs; and

(e) not be recoverable under any jurisdictional incentive scheme, or any state or federal government scheme, or are included in forecast capital expenditure or operating expenditure approved in the DSNP's access arrangement determination.

'Innovative' means the project:

- is based on new or original concepts; *or*
- involves technology or a technique not previously implemented in the relevant market; *or*
- is focussed on a customer market segment that has not been exposed to the technology.

- *Compliance reporting requirements:* Each distributor must submit an annual report to the AER which sets out the amount of the allowance claimed, along with specifics of each project funded by the allowance. There must also be, for each project, a project-specific annual report which the AER can publish and which outlines the scope, methodology, outcomes and progress of the project.

In 2019, the AEMC decided that a DMIA mechanism should apply also to TSNPs.

The AER's approach to the DMIA provides a useful template for ERA.

However, the concerns of some stakeholders suggest that some aspects of the scheme may not suit the Western Australian context. Two areas warrant particular attention:

(1) The AER adopts quite broad eligibility criteria. Indeed, many of the projects that have been funded under the scheme are network battery projects that are arguably network rather than non-network solutions, if their predominant purpose is to strengthen the resilience of the network. Perth Energy suggested that there should be more explicit criteria for what is an eligible demand management R&D project. The AEC was concerned that as the scheme provided for full recovery of the costs of research and development it would provide an anti-competitive advantage to the network operator over third party operators. Both the AEC and Perth Energy considered that more limited sums should be adopted for the scheme.

(2) The AER primarily carries out an *ex-post* assessment of whether demand management projects are eligible under the scheme. Perth Energy suggests that there should be public consultation on all proposed initiatives.

1 INTRODUCTION

The ERA has contracted Economic Insights to review the ERA's Issues Paper on the framework and approach for Western Power's fifth access arrangement review and provide advice on any perceived "gaps" or potential improvements in identification of relevant issues and their treatment for the access arrangement.

These notes present our views on key matters in or relating to the Issues Paper as per the ERA request.

2 NEW ACCESS CODE OBJECTIVE

On 18 September 2020, the Electricity Networks Access Code 2004 (2020) was amended to support the delivery of the State Government's Energy Transformation Strategy. As a result of the amendments, the process and some of the regulatory requirements for the AA5 review have changed.

A new process requires the ERA to decide some elements of the access arrangement before Western Power submits its access arrangement proposal. The ERA must set out its decision on these matters in a document called the "framework and approach". Section 4.A2 of the Access Code specifies that the framework and approach must set out the ERA's decision (including its reasons) for the purposes of the next access arrangement review on a number of specific matters as set out in the ERA Issues Paper. Each of the specific matters is considered in subsequent sections of this report.

This section describes the access code objective and our interpretation of how potential conflicts could be treated.

2.1 The objective

The new Access Code objective is set out in section 2.1:

> 2.1 The objective of this Code ("**Code objective**") is to promote the efficient investment in, and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers in relation to:
>
> (a) price, quality, safety, reliability and security of supply of electricity;
>
> (b) the safety, reliability and security of covered networks; and
>
> (c) the environmental consequences of energy supply and consumption, including reducing greenhouse gas emissions, considering land use and biodiversity impacts and encouraging energy efficiency and demand management.
>
> {Note: Consumers in the context of the Code objective has the meaning in this Code being "a person who consumes electricity"}

This objective recognises that the long-term interests of consumers are affected by the considerations listed in items (a) to (c). The factors (a) to (c) are not necessarily the only factors that affect the long-term interests of consumers, but they are the only ones relevant for the ERA's decision-making. Factors (a) to (c) can be thought of as criteria that are proximate or penultimate outcomes of the decision-making, and "the efficient investment in, and efficient operation and use of, services of networks in Western Australia for the long-term interests of consumers" is the ultimate outcome. Factors (a) to (c) are the considerations to be taken into account when assessing the how the decision is likely to affect the ultimate criterion.

The ultimate outcome or criterion itself has two arms, namely:

- promote the efficient investment in, and efficient operation and use of, services of networks in Western Australia

- for the long-term interests of consumers

This is analogous in structure to the objective in section 2 of the *Competition and Consumer Act 2010*, which is: "The object of this Act is to enhance the welfare of Australians through the promotion of competition and fair trading and provision for consumer protection." It is recognised that this has separate elements – i.e., 'promotion of competition', 'fair trading', and 'provision for consumer protection' – that are capable of conflicting (Duke 2018, 35–36). However, there are some parts of that Act which primarily relate to competition (e.g., Part IV, Restrictive Trade Practices) and some that primarily relate to consumer protection (e.g., Schedule 2, The Australian Consumer Law). In the context of Part IV, in *Boral Besser Masonry Ltd v ACCC* [2003] HCA 5, McHugh J said (at [260]):

> The Parliament has determined that it is in the interests of consumers that firms be required to compete because competition results in lower prices, better goods and services and increased efficiency. In Queensland Wire, Mason CJ and Wilson J said that the object of s46 - the protection of consumer interests - is to be achieved through the promotion of competition …

By analogy, in s 2.1 of the Code, the long-term interests of consumers is to be achieved through promoting the efficient investment in, and efficient operation and use of, services of networks in Western Australia. It is assumed within the Code objective that promoting efficiency in this way is in the long-term interests of consumers.

This observation also assists to interpret what is meant by 'efficient' and the 'interests' of consumers. The factors listed in items (a) to (c), which are the relevant considerations, indicate that 'efficient' means economically efficient in the broad sense of including consideration of environmental externalities. The 'interests' of consumers is an economic welfare concept which likewise takes account of all the factors listed in items (a) to (c) of the objective.

The question then is how this objective is to be applied in specific kinds of regulatory decisions, particularly in relation to Western Power, and the assessment by ERA of a proposed access arrangement. The AEMC is guided by similar objectives and it states:

> The focus of the energy objectives is on efficient investment in, and operation and use of, electricity and gas services in the long-term interests of consumers. The question to be answered in the assessment process is therefore, would a proposed change to the rules (or recommendation) promote more efficient decisions across these activities, which would ultimately promote the long-term interests of consumers. (Australian Energy Market Commission (AEMC) 2019b, 4)

That said, the Code objective clearly says that the 'efficiency' of the network and the 'long-term interests' of consumers need to be related back to all of the considerations listed in sub-paragraphs (a) to (c), where relevant. The AEMC states with respect to the regimes it administers:

> The energy objectives all include a specific set of variables – price, quality, safety, reliability and security of supply – which must be objectively considered when assessing a rule change or a review. We must base our decision on how the outcome of a particular

> decision would impact on these variables, where relevant, and these variables alone. (Australian Energy Market Commission (AEMC) 2019b, 7)

The last statement means that the lists of factors to consider in sub-paragraphs (a) to (c) of section 2.1 should be regarded as a complete list.

2.2 Further considerations on limbs of the Objective

One of the dimensions of the efficiency of investment in, and operation and use of, the electricity network, and hence ultimately the long-term interests of consumers, is the operational or technical standard of the network. This is reflected in sub-paragraph (b): "the safety, reliability and security of covered networks". The Energy Transformation Taskforce said of this:

> The intent of this second limb was to recognise that as technology drives changes in the number and types of devices connecting to the network, the reliability and security of any covered network should be a consideration under the governance arrangements for the Technical Rules. (Energy Transformation Taskforce 2019b, 11)

Sub-paragraph (c) of s 2.1 is additional to the otherwise equivalent objective stated in s 7 of the National Electricity Law. The Energy Transformation Taskforce said of this:

> The change to the Access Code objective reflects the Energy Transformation Strategy's focus on lower-emissions energy sources. Technological change has the potential to drive environmental objectives in the transition to a lower carbon electricity supply for consumers, particularly in relation to alternative options to traditional grid supply. (Energy Transformation Taskforce 2019b, 11)

We would argue that limb (c) of the objective does not invite the ERA to develop environmental policies, but rather should be viewed in the context of the ERA's role within the propose-respond framework for assessing access arrangements. It would be reasonable for the ERA's Framework and Approach to require Western Power to address how its proposed access arrangement promotes each of the elements of the objective, but the ERA should be cautious in regard to being any more pro-active than that. However, in its response to the proposed access arrangement the ERA needs to give consideration to each of the environmental matters listed in limb (c).

Environmental considerations may be relevant to various aspects of an access arrangement, including services offered that facilitate renewable energy; structuring of tariffs to promote energy efficiency (and hence reduced emissions); and the assessment of investment programs that takes environmental shadow prices into account. In his May submission, Noel Schubert emphasises the inclusion of environmental considerations in cost-benefit analysis: "Energy options could be evaluated from the different perspectives, and then be determined taking into consideration the benefit/cost ratios from multiple perspectives" (Schubert 2021, 1).

Some submitters (eg, Australian Energy Council 2021; Alinta Energy 2020) have raised concerns about competition issues, especially in contexts where Western Power engages in activities that are contestable with other suppliers. These may well also be activities that have a pro-environmental dimension. In that case, there may be trade-offs to be made between environmental and competition considerations in formulating regulatory measures. For example, ERA has indicated that if Western Power were to provide electricity storage services to customers, these may be 'excluded services' when applying the competition test included in the definition of that term. Stronger ring-fencing obligations might be applied to promote competitive neutrality. We would not see this as inconsistent with the environmental aspects of the objective, but rather a balancing of different considerations relevant to the overall objective.

Whilst the amendment of the objective removed reference to promotion of competition in upstream and downstream markets, the Energy Transformation Taskforce has emphasised that promotion of competition in related markets is implied within the objective.

> That is, if energy markets and access to the services of significant infrastructure are efficient in an economic sense, the long-term economic interests of consumers in respect of price, quality, reliability, safety and security of energy services will be maximised. (Energy Transformation Taskforce 2019b, 11)

Since competitiveness in related markets will be an important factor in efficiency of the supply of electricity, it remains a relevant consideration for ERA.

Another trade-off, which may arise in the provision of regulated services, is between the price to consumers and cost of any environmental activities that may be carried out in supplying the services. Perth Energy recommends that "Western Power be required to explicitly show how they have incorporated or costed any environmental considerations in their services or costs" (Perth Energy 2021, 2). ERA would then need to assess the efficiency of those costs taking into account not only monetary costs, which flow through to consumers in prices, but also the shadow prices of any environmental benefits.

Thus each limb will need to be valued either explicitly or using value judgements where trade-offs have to be resolved. For example, if there was a conflict between environmental consequences and price or reliability.

2.3 Other considerations

Some sections (or parts) of the Code may include criteria or objectives that are specific to that section (or part). As explained in the Issues Paper, sections 2.3 and 2.4 of the Code set out rules for resolving any inconsistency between the Access Code objective and section-specific criteria:

> 2.3 Where this Code specifies one or more specific criteria in relation to a thing (including the making of any decision or the doing, or not doing, of any act), then:
>
> (a) subject to section 2.3(b), the specific criteria and the Code objective all apply in relation to the thing; and
>
> (b) subject to section 2.4, to the extent that a specific criterion and the Code objective conflict in relation to the thing, then:

> (i) the specific criterion prevails over the Code objective in relation to the thing; and
>
> (ii) to the extent that the specific criterion conflicts with one or more other specific criteria in relation to the thing, the Code objective applies in determining how the specific criteria can best be reconciled and which of them should prevail.
>
> 2.4 If the Code objective is specified in a provision of this Code as a specific criterion, then the Code objective is to be treated as being also a specific criterion for the purposes of section 2.3, but to the extent that the Code objective conflicts with one or more other specific criteria the Code objective prevails.

Sections 2.3 and 2.4 do not address the interpretation of the Access Code objective, including the balancing of the considerations under the three limbs of that objective. We also note that the Issues Paper states that sections 2.3 and 2.4 may not deal with situations where there is a conflict between the three limbs of the Access Code objective.

Often there will be not be an inconsistency between the Code objective and section-specific criteria, and 2.3(a) stipulates that both the Code objective and the section-specific criteria apply together. An example of where 2.3(b)(i) applies is with regard to pricing. Section 7.3G states: "Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates …". By implication, tariffs must be based on efficient costs of supply and can only be structured in a way designed to promote environmental objectives subject to that principle. It will often be the case that efficient price signals, such as higher prices in periods of highest use, will also be consistent with environmental objectives.

2.4 Concluding comments

Just as the service standards adjustment mechanism calls on the regulator to develop an estimate of the value to consumers of the reliability of supply, so too the environmental element of the objective is likely to call for estimates of the value to consumers of certain environmental outcomes. For example, given the importance of environmental consequences in the Code, any net benefit tests will need to assess the costs and benefits of environmental consequences, including the new facilities investment test. This is likely to be a difficult task.

One regulatory tool that may warrant consideration in balancing the different arms of the regulatory objective is ring-fencing. Whilst ring-fencing has not been applied in Western Australia's electricity access regime, it is applied in the NEM, and the AER is currently reviewing the ring-fencing obligations. It is useful to quote the AER at length:

> In recent years, new kinds of electricity services and new areas of competition have emerged due to technological change and market reform. In some cases these new technologies operate at the boundary between regulated and unregulated electricity markets. In particular, there has been increasing interest in:
>
> - SAPS that provide electricity to a consumer (or group of consumers) without being physically connected to the national electricity system.

> - Energy storage devices, such as grid-scale batteries, that could be used by network service providers (NSP) to offer both regulated and unregulated services.
>
> … our approach to ring-fencing must be compatible with these technologies. … we must ensure the deployment of these technologies by NSPs does not stifle the development of competition in emerging markets created by these technologies. (Australian Energy Regulator (AER) 2020b, 7)

The AER has also made the following general comments about ring-fencing:

> Ring-fencing aims to drive effective competition where it is feasible, to open up new markets to competition and to provide effective regulation where competition is unattainable. Ensuring regulated monopolies do not have an unfair advantage over unregulated competitors is an important element of ensuring the development of competitive markets. That said, ring-fencing obligations should represent a targeted, proportionate and effective regulatory response to the potential harm faced by consumers. The benefit, or likely benefit to consumers of a distribution network service provider (DNSP) complying with an obligation, should outweigh the cost to the DNSP of complying with that obligation. (Australian Energy Regulator (AER) 2020b, 8)

3 CLASSIFICATION OF SERVICES AND NEW TECHNOLOGIES

3.1 Introduction

Section 4.A2(f) of the Access Code requires that the framework and approach for the next access period must include:

> "a list of and classification of services including whether services are reference services or non-reference services, the eligibility criteria for each reference service, the structure and charging parameters for each distribution reference tariff and a description of the approach to setting each distribution reference tariff in accordance with sections 7.2 to 7.12;"[1]

This chapter addresses the list of and classification of services, and the following chapter discusses the additional requirements relating to reference services. Section 3.2 discusses the requirements of the Access Code in relation to the classification of services, and outlines an approach to classification of services based on the AER (2018a) *Electricity Distribution Service Classification Guideline*.

The amendments to the Access Code in 2020 also introduced the concept of a 'multi-function asset', and stipulates principles and requirements in relation to the development of policies and guidelines in relation to them. Multi-function assets are defined in s 6.84 of the Code to be an asset "used to provide services other than covered services". Section 3.3 discusses the Code requirements in relation to multi-function assets services, and describes the approach to that the AER has taken to 'shared assets' in the NEM.

In the Issues Paper the ERA notes that classification of services has become more complex with the introduction of new technologies. Particular topics raised in the issues paper include multi-function assets, stand-alone power systems, and storage services. Sections 3.4 discusses these issues.

3.2 Classification of Services

3.2.1 Purposes

The classification of services in the context of the ERA's (and the AER's) framework and approach to determining electricity network access arrangements serves three important purposes:

- Classifying services under the categories specified in regulatory instruments determines specific aspects of the form of economic regulation (if any) applied to electricity network services.
- Establishing procedures and principles for classification helps to make the regulator's approach to service classification transparent and predictable.

[1] ERA says that only the list of and classification of services is mandatory for AA5.

- By engaging in provisional assessments of certain broad categories of services, the regulator can indicate its preliminary views on whether some types of services have the potential to be provided competitively.

The framework and approach to classification of services needs to address:

(e) the categories of services and principles of classification stated in regulatory instruments;

(f) the procedure for assessing and classifying services;

(g) the development of baseline groupings which provide a starting point and assist to focus the classification of services in the development of an access arrangement;

(h) The listing of all reference and non-reference services under the baseline groupings.

3.2.2 Service definitions in regulatory instruments

Regulatory instruments specify high-level classifications of services, and the main price control framework will be stipulated to apply to only some of those classifications. The terminology used for service classifications in Western Australian electricity network regulation in some ways differs from the terminology used in the NEM.

3.2.2.1 SWIS regime

In the Electricity Network Access Code 2004 ('Code'), a 'covered service' means a 'service' provided by means of a 'covered network',[2] including:

(a) *connection service*: a right to connect facilities and equipment at a connection point. This refers to physical connection, not the right to transfer electricity;

(b) *entry* or *exit service*; an 'entry service' is a service provided at an entry point under which the user may transfer electricity into the network at the entry point. An 'exit service' is a service provided at an exit point under which the user may transfer electricity out of the network at the exit point;

(c) *network use of system service*;

(d) *common service*: a covered service that is ancillary to the provision of one or more of entry services, exit services and network use of system services that ensures the reliability of a network or otherwise provides benefits to users of the network, the costs of which cannot reasonably be allocated to one or more particular users and so needs to be allocated across all users; or

(e) *services ancillary* to any of those listed above.

Covered services also subdivide into:

---

[2] A 'service' here means the conveyance of electricity and other services provided by means of network infrastructure facilities, and services ancillary to such services. A 'covered network' is defined in ss 3.1, 3.2 and 1.3 of the Access Code. The South West interconnected system is a covered network.

(i) *reference services*: a covered service provided to a user and designated as a reference service in an access arrangement, and for which there is a reference tariff, a standard access contract and service standard benchmarks;

(ii) *non-reference services*: a covered service that is not a reference service.

A covered service is a regulated service. Classification into reference and non-reference services determines, at a high level, the form of regulation applied to the service. Reference services are to be specified in the access arrangement with a price, a standard contract and service standard benchmarks. The prices of these services are subject to the price control discussed in chapter 6. ERA has further classified reference services into 'revenue target services' which includes: (a) connection services; (b) exit services; (c) entry services; (d) bi-directional services; (e) all standard metering services except one-off interval meter reads at the customer's request; and (f) streetlight maintenance. The remaining references services are 'non-revenue target services' and includes ancillary services and the remaining metering services.

The terms and conditions on which non-reference services are provided are, by default, to be negotiated in good faith by the access seeker and the DNSP (s 2.4A of the Code). Appendix 8 of the Code ('Detailed provisions regarding contributions for certain work on the Western Power Network') sets out principles and procedures for setting fees for some of non-reference services.

An unregulated service is either a service that is not provided by means of a covered network, or is an 'excluded service'. An excluded service is a service provided by means of a covered network which meets the following criteria:

- the cost of the service is subject to effective competition; and
- the cost of the service is able to be excluded from consideration for price control purposes without departing from the Code objective.

3.2.2.2 National regime

In the NEM, 'distribution services' provided by a distribution network service provider (DSNP) are regulated services. Distribution services are classified as either:

- a 'direct control service': an electricity network service "the price for which, or the revenue to be earned from which, must be regulated under a distribution determination or a transmission determination" (*National Electricity Law* (NEL), s 2B);
- a 'negotiated network service': an electricity network service that is not a direct control service (NEL, s 2C).

Distribution services not classified by the AER are unregulated services. Direct control services are further divided into:

- a 'standard control service': a "direct control service that is subject to a control mechanism based on a Distribution Network Service Provider's total revenue requirement" (*National Electricity Rules* (NER), cl. 10 Glossary)

- an ‘alternative control service’: a distribution service that is a direct control service but not a standard control service.

The form of regulation depends on the classification of the service:

- for *standard control services*, the control mechanism must be of the prospective CPI–X form, or some incentive-based variant;
- for *alternative control services*, the control mechanism must be stated in the distribution determination, and may (but need not) utilise elements of the prospective CPI–X form (with or without modification);
- Negotiated distribution services are regulated through a negotiate-arbitrate approach where negotiation must be conducted in accordance with principles stipulated in cl. 6.7.1 of the NER.

Section 6.2 of the NER sets out the AER’s roles in the classification of distribution services. These are discussed in section 1.2.2. Amongst them, s 6.2.3A of the NER requires the AER to develop and publish Distribution Service Classification Guidelines.

3.2.2.3 Comment

When comparing the Western Australian and national electricity network access regime service classifications, there is a rough parallel between the ‘revenue target’ reference services in the WA regime and the standard control services in the national regime, since:

- a revenue target reference service is a covered service “for which there is a reference tariff, a standard access contract and service standard benchmarks, and the prices for which fall under the revenue target;
- a ‘standard control service’ is a service, the price for which, or the revenue to be earned from which, is regulated under a distribution or transmission determination, and is subject to a control mechanism based on the provider's total revenue requirement.

The kinds of services that are likely to fall under non-revenue target services and non-reference services in the WA regime may be broadly similar to alternative control services in the national framework – but there are important differences because in the national framework, a broader range of services are unregulated because they are deemed to be contestable. Another significant difference is that fees and charges for alternative control services in the national framework are regulated much more prescriptively than non-reference services are under the WA regime.

These comparisons suggest that **the following are important considerations for the ERA’s framework and approach**:

- The listing of services in the framework and approach applies to all network services and the classification of services at the very least requires:
    - For each service determining whether it should be an excluded service by applying the competitiveness test in the Code. That is, determining which services are contestable.

  - Classifying the remaining services (i.e. the covered services) as either ‘revenue target’ reference services; ‘non-revenue target’ reference services; or non-reference services.

- For the list of services that are either ‘non-revenue target’ services or non-reference services, determining whether Appendix C.1 of the access arrangement applies to all of those services (Western Power 2019); which is produced in accordance with Appendix 8 of the Code. And if there is a category of non-reference services to which Appendix 8 does not apply, whether there should be analogous statements of pricing policy in relation to that category of services in the access arrangement.

3.2.3 Consultation

In its issues paper, ERA suggested that a more functional classification of services seems to be needed. “The list of and classification of services has not been explicitly considered in previous access arrangements. … the classification of services has become more complex with the introduction of new technologies” (Economic Regulation Authority (ERA) 2021, 12). ERA also noted that a new category of services is needed for non-covered services provided by means of multi-function assets. This category of assets and their associated services are discussed in section 3.3. ERA also raised issues relating to the classification of stand-alone power systems and the services of network batteries. Stand-alone power systems and distributed energy resources (DER) are discussed in section 3.4. Stakeholder comment on classification was largely directed to these issues and is also discussed in sections 3.3 and 3.4.

3.2.4 AER practice

The ERA’s approach to classification of services can be informed by AER’s *Electricity Distribution Service Classification Guideline (2018a)*. This section outlines the main elements of that guideline.

3.2.4.1 Procedure for classifying services and service groupings

The AER Guideline sets out a process whereby the AER classifies services in accordance with the NER when carrying out its functions such as when deciding on its framework and approach to assessing an access arrangement and when making decisions on the access arrangement. The distribution service classification forms part of the distribution determination and operates for a single regulatory period control period.

The procedure for classifying services set out by the AER has the following main steps:

(1) Establishing whether the service is a service or an input;

(2) Establishing whether the service is a distribution service;

(3) Determining whether economic regulation is necessary;

(4) Classification as direct control vs negotiated distribution service;

(5) Classification as standard control or alternative control service.

Is it a service or an input?

The first part of this question is to determine whether an activity is a service in its ordinary economic meaning, or whether it is an input. The AER defines a service as "the action of helping or doing work for someone" typically provided for payment (Australian Energy Regulator (AER) 2018a, 7). It defines inputs as including "all of the capital and operating inputs that contribute to the provision of a service" which "can be distinguished from a service in that it is not offered to customers on a stand-alone basis" (Australian Energy Regulator (AER) 2018a, 7).

Is it a distribution service?

A distribution service is defined as a 'service' that is provided by means of, or in connection with, a distribution system.[3] "A DNSP is generally not permitted to offer non-distribution services" (Australian Energy Regulator (AER) 2018a, 11). However, it can apply for a waiver under the ring-fencing guideline. It may also offer the service through a separate legal entity.

Is economic regulation of the service necessary?

Whilst clause 6.2.1(a) of the NER requires the AER to classify a service as either a direct control service or a negotiated distribution service, there is a third alternative. If the AER does not classify a service as either a direct control service or a negotiated distribution service, then that service is unregulated. The criteria used to classify the service are:

(1) the 'form of regulation factors'; and

(2) the form of regulation (if any) previously applicable to the relevant service or services and, in particular, any previous classification under the present system of classification or under the previous regulatory system (as the case requires); and

(3) the desirability of consistency in the form of regulation for similar services (both within and beyond the relevant jurisdiction); and

(4) any other relevant factor.

The 'form of regulation factors' are stated in s 2F of the NEL. In summary they include factors relevant to an assessment of whether a service is potentially competitive, or of the degree of market power, such as:

- the presence and extent of any barriers to entry …
- the presence and extent of any network externalities …
- the extent to which any market power possessed by a network service provider …
- the presence and extent of any substitute, and the elasticity of demand, …

[3] Here the NER defines 'services' means the conveyance of electricity and other services provided by means of network infrastructure facilities; and services ancillary to such services.

- *the extent to which there is information available to a prospective network service user …*

Direct control vs negotiated distribution service classification

The same criteria are used to determine whether the service should come under direct price control or be subject to negotiate-arbitrate regulation. The AER says: "If we decide that some level of regulation is necessary, we need to classify the service either as a direct control or a negotiated distribution service. We make a negotiated service classification where we consider that all relevant parties have at least a reasonable degree of countervailing market power to effectively negotiate the provision of those services. Our observation is that in practice this condition rarely occurs" (Australian Energy Regulator (AER) 2018a, 12).

Under the Ring-fencing Guidelines, the AER requires a functional separation between direct control distribution services and negotiated distribution services. In practice, there are few if any negotiated services amongst NEM electricity distributors. Regulated distribution services which have not been functionally separated are classified as direct control services.

Standard control or alternative control service?

Clause 6.2.2(a) of the NER requires direct control services to be further divided into: (1) standard control services; and (2) alternative control services. Typically network services are standard control services. "Alternative control services are only used or requested by certain customers, such as a customer requested electricity pole relocation." (p.12)

The NER requires that AER must undertake this classification having regard to:

(1) the potential for development of competition in the relevant market and how the classification might influence that potential; and

(2) the possible effects of the classification on administrative costs of the AER, the Distribution Network Service Provider and users or potential users; and

(3) the regulatory approach (if any) applicable to the relevant service immediately before the commencement of the distribution determination for which the classification is made; and

(4) the desirability of a consistent regulatory approach to similar services (both within and beyond the relevant jurisdiction); and

(5) the extent the costs of providing the relevant service are directly attributable to the person to whom the service is provided; and

(6) any other relevant factor.

3.2.4.2 Baseline service groupings

The AER *Electricity Distribution Service Classification Guideline* also sets out a 'baseline' service classification which will be used as a starting point in its regulatory assessments. The baseline classification is a description of the core services that DNSPs provide. It is recognised that individual DNSPs may be different, in part due to different jurisdictional requirements, and may therefore put forward a service classification that differs from the baseline list. However, they must provide adequate reasons for doing so.

For a service to be classified, it needs to be identified, in terms of the name and description of the service. It is the responsibility of the DNSP to identify the services it offers to consumers in order to enable service classification.

Services can be grouped together for the purposes of classification (NER s 6.21(b)) where the constituent services have common attributes. The attributes of the group classification then apply to the individual services in that group. The AER has observed that a grouping of services should be defined by the common characteristics of the services, and not by: (i) merely listing the services within that group; (ii) the purposes for which the services are provided; or (iii) the pricing mechanism used for charging for them. Establishing groupings does not obviate the need for individual services need to be described.

The AER's baseline classification is the set of service groupings shown in Table 1.1. Further description of each service category is given below.

Common distribution service

The common distribution service is the provision of access to transporting electricity to customers through the distribution network. The activities that support this service include, among other things, the planning, design, repair, maintenance, construction and operation of the distribution network. These services are classified by the AER as standard control services.

Network ancillary services

These services involve work on, or in relation to, parts of the distribution network, and only the service provider can perform these services in its distribution area. They are typically required only by some customers, and from time to time. They are usually either customer-requested or customer-specific and provided for a fee. The AER classifies these services as *alternative control*, with prices set by the cost of supply to customers.

Metering services

Metering services are limited to metering at the interface between the network and the customers (and excludes network meters). Metering services are made up of a number of activities including: meter provision and installation services, maintenance, and meter reading and data services. The introduction of metering contestability in some jurisdictions means that retailers or other metering providers often provide the services, and DNSPs are often restricted in providing these services unless they have a waiver from the ring-fencing obligations. There are three categories of metering services:

(a) Those competitively available in the NEM;

(b) Legacy meters supplied by DNSPs;

(c) Unmetered loads (public lighting), for which the metering activity is an estimation of energy use.

Table 1.1: AER baseline service groupings

Service grouping	*Description*
Direct control services:	
Common distribution service	Conveyance of electricity through the shared distribution network for consumers, including bundled common services associated with this function. This includes activities related to maintaining network integrity.
Network ancillary service	Services provided by means of the distribution network, but not all customers request or require these services (unlike the common distribution service).
Metering service	Measuring electricity supplied to and from customers via the distribution system, at the interfaces between the network and the customers.
Connection services	Connecting customers to the distribution network and activating electricity services.
Public lighting services	Public lighting services provided by means of the electricity distribution system, and typically supplied to local governments.
Negotiated distribution services	There are no specific negotiated distribution services. Rather, this classification applies to any services negotiated between the parties.
Services not classified	By default, such services are unregulated. It may be that they are provided in a competitive market. Alternatively, they could be services not provided via electricity distribution facilities, however, a DNSP is not permitted to provide such services unless they have a ring-fencing waiver.

The AER treats all metering services as contestable. The only metering services included in the baseline services are: maintenance reading and data services of legacy metres; auxiliary metering services; and legacy meter recovery and disposal. These are classified as *alternative control* services are charged directly to the customer.

Connection services

Connection refers to the physical link between a distribution system and a retail customer's premises to allow the flow of electricity. Connection services are grouped under five headings:

(1) *basic connections*: a simple connection of a customer's premises to the network, with no or minimal extension or augmentation.

(2) *standard connections:* a connection to the network that is not a basic connection service and may involve extension and/or augmentation. They may be provided for a particular class or sub-class of connection applicant. These services are charged on a user-pays basis, and in some jurisdictions they are contestable.

(3) *negotiated connections*: to meet the specific requirements of a connection applicant, and may involve network extension or augmentation. Includes real estate developers, embedded generators and micro-embedded generators.

(4) two less frequently requested services are: connection application and management; and enhanced connection.

In some jurisdictions, where connections are not contestable, small customers do not pay for basic connections, and they are usually treated as direct control services. The other three categories are treated as alternative control services. In jurisdictions where connection services are contestable "the usual practice is the AER would not classify the services and they would be unregulated" (Australian Energy Regulator (AER) 2018a, 18). Given the differences in regulatory treatment between jurisdictions, DNSPs should propose their own connection service classification having regard to the AER's baseline classification, but also to differences in their own jurisdictions.

Public lighting services

Public learning services include the operation, maintenance, repair and replacement of public lighting assets; the alteration and relocation of public lighting assets; and the provision of new public lighting. These services may be provided to local councils or government departments. They are classified as alternative control.

3.2.4.3 Assessment

It may be useful to use the baseline service groupings produced by the AER, by categorising all listed services under these headings, in addition to their regulatory classification of reference services, unregulated services, and excluded services. This would assist the ERA to compare its classification scheme with that of the AER, and to highlight categories of services that are potentially contestable now or in the future.

3.3 Multi-Function Asset Principles

The multi-function asset mechanism is intended to incentivise Western Power to pursue new unregulated services that increase the use of the existing network, whilst also ensuring a "sharing of benefits with end-use customers when a network business uses regulated assets for unregulated purposes" (Energy Transformation Taskforce 2019b, 10).

3.3.1 Definitions – Access Code

A 'multi-function asset' is a network asset used to provide services other than covered services (clause 6.84 of the Code). An access arrangement must include a multi-function asset policy (clause 5.1(m)). In accordance with clause 5.37 of the Code, a multi-function asset policy must:

(a) to the extent reasonably practicable, accommodate the interests of the *service provider* and of *users* and *applicants*; and

(b) be sufficiently detailed to enable *users* and *applicants* to understand in advance how the *multi-function asset policy* will operate; and

(c) set out the method for determining *net incremental revenue*; and

(d) be consistent with the *multi-function asset guidelines*.

Clause 6.88 requires the ERA to establish multi-function asset guidelines to set out its regulatory approach to these assets, consistent with the basic principles for how multi-function assets are to be treated within the regulation framework as set out in clauses 6.84 to 6.88:

> 6.84 If a network asset is used to provide services other than covered services (a 'multi-function asset'), the Authority must, in accordance with the multi-function asset principles, in an access arrangement for an access arrangement period, reduce the target revenue for the service provider for a pricing year within that access arrangement period by an amount equal to 30% of the net incremental revenue.
>
> 6.85 In making a decision under section 6.84, the Authority must have regard to the multi-function asset policy and the multi-function asset guidelines.
>
> 6.86 The multi-function asset principles are as follows:
>
> (a) the service provider should be encouraged to use assets that provide covered services for the provision of other kinds of services where that use is efficient and does not materially prejudice the provision of covered services;
>
> (b) a multi-function asset revenue reduction should not be dependent on the service provider deriving a positive commercial outcome from the use of the asset other than for covered services;
>
> (c) a multi-function asset revenue reduction should be applied where the use of the asset other than for covered services is material;
>
> (d) regard should be had to the manner in which costs of multi-function assets have been recovered or revenues of multi-function assets have been reduced in respect of the relevant asset in the past and the reasons for adopting that manner of reduction; and
>
> (e) any reduction effected under section 6.84 should be compatible with other incentives provided under this Code.
>
> 6.87 For the purpose of section 6.86(c), the use of a multi-function asset other than for covered services is material if the net incremental revenue derived from the use of *all* multi-function assets in a pricing year is greater than $1 million (CPI adjusted).

Here 'net incremental revenue' means "the revenue from all payments received by a service provider in excess of the revenue it would receive if the asset only provided covered services, for a pricing year" (clause 1.3).

3.3.2 Definitions – NER

As ERA has noted in its issues paper, there are similarities between the treatment of multi-function assets under the Code, and the regulation of 'shared assets' in the national electricity access regime.

The NER permits the use of electricity supply assets to provide other, unregulated services, as long at the electricity supply is not compromised (Australian Energy Regulator (AER) 2013b). The regulatory principles applying to shared assets are indicated by clause 6A.5.5 of the NER (Shared transmission assets):

> (a) Where an asset is used to provide both prescribed transmission services and either:
>
> (1) non-regulated transmission services; or
>
> (2) services that are not transmission services,
>
> the AER may, in a revenue determination for a regulatory control period, reduce the annual building block revenue requirement for the Transmission Network Service Provider for a regulatory year within that regulatory control period by such amount as it considers reasonable to reflect such part of the costs of that asset as the Transmission Network Service Provider is recovering though charging for the provision of a service referred to in subparagraph (1) or (2).
>
> (b) In making a decision under paragraph (a), the AER must have regard to the shared asset principles and the Shared Asset Guidelines.
>
> (c) The shared asset principles are as follows:
>
> (1) the Transmission Network Service Provider should be encouraged to use assets that provide prescribed transmission services for the provision of other kinds of services where that use is efficient and does not materially prejudice the provision of those services;
>
> (2) a shared asset cost reduction should not be dependent on the Transmission Network Service Provider deriving a positive commercial outcome from the use of the asset other than for those services;
>
> (3) a shared asset cost reduction should be applied where the use of the asset other than for prescribed transmission services is material;
>
> (4) regard should be had to the manner in which costs have been recovered or revenues reduced in respect of the relevant asset in the past and the reasons for adopting that manner of recovery or reduction;
>
> (5) a shared asset cost reduction should be compatible with the Cost Allocation Principles and Cost Allocation Method; and
>
> (6) any reduction effected under paragraph (a) should be compatible with other incentives provided under the Rules.

The AER is required to produce Shared Asset Guidelines setting out its approach to implementing the foregoing principles, including a methodology to determine reductions in regulated revenue on account of the revenue from non-regulated services supplied by the shared assets (which the AER calls the ‘cost reduction method’).

Clearly the multi-function asset principles in the Code are similar to the shared asset principles in the NER. The AER has adopted a materiality threshold of 1% of the service provider’s annual revenue requirement. If the unregulated revenues from shared assets are less than the materiality threshold in a given year, there is no adjustment to the Annual Revenue Requirement (ARR) for that year. If the unregulated revenue from the shared assets is greater than the materiality threshold, then the ARR is reduced by an amount calculated according to the method set out in the Shared Asset Guidelines.

The AER states that the service provider’s approved cost allocation method (CAM) allocates assets only once. For new assets that provide both regulated and unregulated services, the application of the CAM can, in principle, accurately allocate costs between the regulated and unrelated services that will be supplied by it. The “shared asset mechanism relates to assets for which the initial allocation is no longer accurate” (Australian Energy Regulator (AER) 2013b, 12). For example, the assets are already established and the costs have been fully allocated to reference services before the asset becomes used, in part, for supplying non-reference services. “The shared asset mechanism specifically relates to assets for which the initial cost allocation under an approved CAM comes to understate its use to provide and regulated services” (Australian Energy Regulator (AER) 2013b, 12).

A propose-respond approach is used for determining the cost reduction applied to the ARR,[4] and if the service provider’s proposal is rejected, the AER uses the following method. The cost reduction in a given year is the lesser of:

- 10% of the expected value of unregulated revenues from shared assets; and
- The sum of return on and return of capital on shared assets.

3.3.3 Comment

Under the WA Access Code an amount of 30% of the shared asset ‘net incremental revenue’ is deducted from the target revenue. Net incremental revenue is defined above (section 3.3.1), and is similar to (but not exactly the same as) the notion of unregulated revenues from shared assets used in the NER. Note that non-capital costs associated with providing unregulated services cannot be recovered from regulated tariffs. However, there is no provision under the Code to remove a portion of the value of assets from the capital base where they are used to provide unregulated services. Such assets are therefore classified as multi-function assets. Where a new asset is put in place, which is anticipated to provide both reference and non-reference services, it may not be possible for the ERA to exclude a proportion of the investment from the regulated asset base (as the AER has suggested it will do). This is discussed below in reference to network-connected batteries.

[4] Adjustments are not made to RAB values.

3.4 Network-connected Batteries

3.4.1 ERA Issues Paper

As explained in the ERA Issues Paper, batteries installed by Western Power can provide an alternative to traditional network investments such as new feeders, voltage regulators or capacitor banks to support exit, entry and bi-directional services. When used in this way, the battery is an input to Western Power's current services. However, the same battery could also potentially enable a "storage service" for network customers. The Issues Paper notes that ringfencing provisions in the Access Code would treat a battery installed by Western Power as part of the network business and would not require it to be ringfenced. However, services provided by batteries can be excluded services if they are subject to competition.

Other parties could also connect batteries to the network and compete with Western Power in the provision of electricity storage services. The ERA is considering whether storage services of batteries owned by Western Power should be classified as excluded services, with key considerations being whether there would be effective competition in that service, and whether the cost can be excluded from the price control. For example, the additional operating costs directly attributable to the provision of storage services could be separately accounted for and excluded from the cost base for regulated services. However, as mentioned, it may not be possible to exclude a multi-function asset from the regulatory asset base.

If the batteries are to be fully included in the asset base, there may be a potential problem relating to the over-recovery of revenue to cover the efficient costs of new battery installations by Western Power, or at least in relation to a clear understanding of the regulatory arrangements. This issue was raised by the Australian Energy Council in its submission to the Issues Paper. Although, as discussed below, the problem may not be as serious as claimed and it is not clear that there would be effective competition with an exclusion scenario given the market is in the early stages of development and there is little information that we are aware of describing the competitive environment.

According to the Electricity Networks Access Code (ENAC), capital expenditure on network-connected batteries would be defined as new facilities and subject to a new facilities investment test (NFIT) and then included in the regulated capital base. The NFIT would be satisfied if inter alia (Section 6.52 (b) of ENAC):

> (ii) the new facility provides a net benefit in the covered network over a reasonable period of time that justifies the approval of higher reference tariffs; or
>
> (iii) the new facility is necessary to maintain the safety or reliability of the covered network or its ability to provide contracted covered services;

The network-connected batteries would be defined as a multi-function asset if the asset provides services other than covered services and if so, the ERA would then be required to reduce relevant target revenue by 30 per cent of the net incremental revenue deriving from the new facility (Section 6.84 of ENAC), provided the use of the asset is material (defined as greater than $1 million (CPI adjusted) in a pricing year (Section 6.86(c) and 6.87)).

Our interpretation of these features is that the full cost of the batteries would be included in the regulatory asset base if they passed the NFIT (and hence the return of and return on this capital would be recovered from reference services tariffs), and if they were used to also provide non-covered services then Western Power could retain at least 70% of the net incremental revenue (defined above) and more if the materiality threshold of $1 million (for all multi-function assets combined) was not reached.

The Australian Energy Council in its submission to the Issues Paper and drawing on a report prepared by Oakley Greenwood (2021) contends that these arrangements would provide a material advantage to Western Power that would have adverse impacts on the scope for competition and dynamic and productive efficiency in the provision of storage services. The Oakley Greenwood paper provides a simplified example of the advantage to Western Power relative to a competitor that could provide the same services from the network-connected batteries. However, in Oakley Greenwood's example, the profitability of a private battery storage project is unaffected, so the incentives provided to Western Power would not diminish the feasibility of a private project. It was, however, argued that the strong incentives given to Western Power would lead it to 'crowd out' private competitors in the storage market. Under this scenario, Western Power could supply storage services to consumers at prices below the efficient cost of supply, because it benefits from recovering a substantial part of its capital costs through the regulated services tariffs. If it supplied storage services at lower than efficient cost, that would render private competitors unprofitable. While this is possible in theory, it is difficult to make an assessment of the size of any cost advantage that Western Power may have over private firms, or of the likelihood of alleged type of conduct.

If the service provided by the network-connected batteries were excluded (not regulated) then the contended financial issue is contained, and arises only in regard to the capital component of the cost of providing storage services and that is at least partially mitigated by the sharing of 30% of net incremental revenue with customers of regulated services.

Exclusion of storage services of network-connected batteries would require consideration as to whether the service is subject to effective competition and whether the cost can be excluded without departing from the Code objective. An assessment of effective competition is likely to require that there be at least one other business providing storage services, providing an alternative choice to the storage service provided by Western Power. The Australian Energy Council supported the classification of network connected batteries as excluded services.

The Perth Energy submission raised concerns about the scope for network-connected batteries to in effect distort the market for the supply of battery type services noting (p. 3):

> "Batteries can offer a number of market essential system services (ESS) which are best provided through a competitive market process rather than by the regulated network operator.
>
> . . .
>
> If it is determined that Western Power can own and operate its own grid-connected batteries then the issue needs to be addressed that these are more than just another technical control facility. Unlike other power control equipment, such as a capacitor

> bank, a battery time shifts the input and output of significant quantities of energy. This means that the value of energy in and energy out is likely to be different and some process needs to be implemented to address this. As such, these batteries need a Financially Responsible Person for their operation to be reflected in both the wholesale and retail markets, otherwise these markets will be distorted by Western Power's operations. This will be particularly exacerbated as the market moves to five-minute settlement where energy prices may be substantially different between five-minute segments."

The Alinta submission also raised concerns about Western Power being able to earn regulated returns on storage assets and associated anti-competitive effects.

The Energy Networks Australia submission noted the various network services that batteries can provide including voltage support and peak demand management but also the scope to increase the viability of these services by providing a shared storage service. ENA did not specifically advocate network-connected batteries to be treated as providing an excluded service but rather noted the need to consider the costs of additional regulation while supporting a flexible regulatory framework that accommodates energy storage devices and associated value stacking when it is in the long-term interests of consumers.

There is essentially a conflict between Western Power's role as a network system operator and its commercial interest in the supply of services from network-connected batteries, particularly when the market moves to five minute settlement. As a network system operator and battery owner it has the scope to favour its own assets in the supply of battery services.

3.4.2 AER practice

A recent AER Issues Paper (AER 2020a) discusses the updating of ring fencing guidelines for stand-alone power systems and energy storage devices. In the Issues Paper, the AER discusses the issue of DNSPs using storage devices to manage network congestion while also providing services in contestable markets. The issue is considered in the context of how ring fencing could apply or may need to be modified.

The AER Issues Paper notes that presently TNSPs are not restricted in using batteries to provide storage services in both regulated and contestable markets and they can provide retailer or generator services up to a cap of five per cent of annual revenue (p.28) but DNSPs must obtain a waiver to provide services other than distribution services. The differences reflect the age of the Distribution and Transmission Guidelines rather than intentionally different approaches.

The AER Issues Paper (p. 23) notes there is currently no proposed regulatory framework specifically for storage devices and that storage devices are still relatively new to the electricity supply chain but expected to rise significantly. The issues were also discussed in the AEMC's Final Report on the *Electricity Network Economic Regulatory Framework 2020 Review* (AEMC 2020a) that highlighted DNSP submissions raising concerns about the restrictions on providing battery access services.

The AER Issues Paper discusses the benefits and costs of allowing DNSPs to provide regulated and contestable services with storage devices that are relevant in considering whether a waiver should be granted. It notes the 'value stacking' and information benefits that exist for a network service provider but that there is no obvious or straightforward method for allocating the cost of storage across different uses particularly given the scope for providing simultaneous services and switching of services within milliseconds. Network service providers have access to confidential information about the network that would be of commercial value to competitors providing network services to the NSP and also control investment and access that could be used to deter competition.

The AER Issues Paper seeks views on how to weigh the benefits and harms to determine if a waiver should be granted.

The AER Issues Paper also notes that the current (2017a) Ring-fencing Guideline for Electricity Distribution allows for (clause 3.1(d)i) the DNSP to grant another legal entity the right to use DNSP assets where doing so does not materially prejudice the provision of direct control services by the DNSP.

Where an asset is used to provide both SCS and unregulated services, clause 6.4.4 of the NER allows the AER to reduce a network service provider's regulated revenue by an amount that the AER considers is reasonable to reflect such part of the cost of the asset that is being recovered through charging for unregulated services. Clause 6.4.4 of the NER requires the AER to have regard to the shared asset principles and the Shared Asset Guideline (SAG) in determining shared asset cost reductions.

The current shared asset guideline was finalised in 2013 (AER 2013b). The key elements are as follows:

- A materiality threshold of 1 per cent of a service provider's total annual revenue applies.
- The service providers regulated revenues are reduced by around 10% of the value of unregulated revenues earned from shared assets.
- The reduction cannot exceed the regulated revenue for the shared assets.

To ensure a level playing field for third parties that connect batteries to the network, the ERA will consider whether services provided by batteries owned by Western Power could be classified as excluded services. As noted above, a covered service can be made an "excluded service" if it is subject to effective competition and the cost can be excluded from the price control.

3.4.3 Assessment

For storage services from network-connected batteries of Western Power to be excluded from regulated services there is a need to pass a competition test. The scope for effective competition in battery storage and network services provided by batteries is uncertain at this time and would need further investigation.

There seems to be some potential for over-recovery by Western Power of capital expenditure on network-connected batteries, even if storage services are excluded services. The scheme is intended to provide Western Power with strong incentives to better utilise network assets where possible. However, the cost reduction amounting to 30 per cent of the net incremental revenue deriving from a multi-function facility is considerably larger than the AER penalty for unregulated revenue from shared assets.

3.5 Stand-alone Power Systems

3.5.1 ERA Issues Paper

The ERA Issues paper notes that the amendments to the *Electricity Industry Act 2004* enable Western Power to supply an existing customer via a stand-alone power system (SAP) rather than a connection to the network where it is more efficient to do so. As Western Power cannot offer stand-alone power systems more generally to its customers or third parties, there is no need to create a new service. The stand-alone power system is an input, rather than a service. It should be captured under the existing reference services and included in the target revenue category.

SAPS can have significant benefits including improved reliability and greater resilience, and in some cases lower costs, compared with traditional network systems.

The Perth Energy submission supported the use of stand-alone power systems as a mechanism to lower costs. The ENA noted both potential cost efficiency and improved resilience.

3.5.2 AER and AEMC developments

As noted, a recent AER Issues Paper (AER 2020b) discusses the updating of ring-fencing guidelines for stand-alone power systems and energy storage devices. The Issues Paper notes that in the NEM, stand-alone power systems (SAPs) are not connected to the national grid and not captured by the economic regulatory framework in the NER and NEL.

As explained in the AER Issues Paper a regulatory framework for DNSP-led SAPS was developed by the Australian Energy Market Commission (AEMC 2019a) and recommended to the Council of Australian Governments (COAG) Energy Council in May 2020. DNSP-led SAPS are referred to as Priority 1 SAPS by the AEMC. The AEMC's recommended framework would enable DNSPs to deploy SAPS to consumers as if they were still connected to the grid. Through COAG, Australian Governments are now developing legislation to enact a framework for SAPS based on the AEMC recommendations.

The AEMC framework splits a SAPS into two components: a SAPS distribution system and a SAPS generation system. The distribution system component of a SAPS will be regarded as a distribution service under the new rules and would be treated like any other part of a distribution system. The SAPS generation system, however, would need to be provided by a third party (or a DNSP affiliate). For a DNSP to provide the generation system of a SAPS, a ring-fencing waiver will be required. The SAPs framework has not been settled at this stage.

3.6 Distributed Energy Resources Developments

3.6.1 Energy Transformation Strategy

In Western Australia an Energy Transformation Taskforce has been established to implement an Energy Transformation Strategy focussed on developing a decentralised supply chain comprising a variety of distributed energy resources (DER) that are fully integrated into the power system. This entails a number of actions including removing barriers to DER participation, grid support measures, and piloting alternative electricity tariffs (see: Energy Transformation Taskforce 2019a).

The Road Map notes that distributed battery storage at the household level is very limited reflecting the high cost. Community battery storage is fairly new limiting the scope for widespread participation and customers are unable to participate in the provision of network and system services (pp. 22-23). The Road Map also highlights expected problems for network stability and operation arising from increased penetration of rooftop solar PV and that this may require various capital expenditure to ensure power system security, safety and reliability (pp. 31-33).

The Road Map also identifies the roles of various entities for effective DER integration into the power system. These include: aggregators to develop portfolios of market support services based on contracts with DER owners to provide various 'virtual power plant' services; a distribution system operator (DSO) (as part of Western Power's role) to manage the network within technical limits and a distribution market operator (DMO) to operate and settle the wholesale energy market (AEMO for the SWIS).

The Road Map identifies a broad set of actions to ensure effective implementation of DER. Various actions and responsibilities have been identified as follows:

- Technology integration – AEMO, Western Power and Energy Policy WA.
- Distribution storage – Western Power and Energy Policy WA.
- Grid response – AEMO, Western Power and Energy Policy WA.
- Power system operation – AEMO and Western Power
- Distribution network visibility – AEMO, Western Power and Energy Policy WA.
- Planning for electric vehicle integration – Western Power.
- Tariffs and investment signals – Energy Policy WA, Synergy, Western Power, Horizon Power.
- DER for tenants – Energy Policy WA.
- Network investment process – Energy Policy WA.
- DER orchestration pilot – Synergy, Energy Policy WA, Western Power, AEMO.
- DSO/DMO functions – Energy Policy WA, Western Power, AEMO.
- Customer Data – Energy Policy WA.
- New business models – Energy Policy WA.

- Customer engagement – Energy Policy WA.

There is no explicit recognition of the role of ERA in implementing economic regulation. The main role would be in relation to approving various costs in accordance with the access code objective.

3.6.2 AEMC rule changes

The AEMC has recently released a package of draft electricity and retail rule changes to facilitate the integration of distributed energy resources such as small scale solar and batteries more efficiently into the electricity grid (AEMC 2021; 2020).

Key aspects of the draft rules include:

- Updating the regulatory framework to clarify that distribution services are two-way and include export services from consumers.
- Promoting incentives to efficiently invest in, operate and use export services. This will encourage distribution networks to deliver export services that customers value. Currently there are no financial penalties for poor network export service and no rewards for improvements.
- Enabling distribution networks to offer two-way pricing for export services, allowing them to develop options that reward owners of distributed energy resources for sending power to the grid when it is needed and charging them for sending power when it is not.
- Allowing flexible pricing solutions at the network level, enabling distribution networks to develop pricing options to suit their capability, customer preferences and jurisdictional policies.

The AEMC draft rule changes are in effect covered in the proposed actions in the WA Energy Transformation Strategy.

4 REFERENCE SERVICES

As noted previously, under the Access Code, covered services that are classified as reference services are to be specified in the access arrangement with a price, a standard contract and service standard benchmarks. The framework and approach must include, among other things:

(a) a list of and classification of services including whether services are reference services or non-reference services,

(b) the eligibility criteria for each reference service,

(c) the structure and charging parameters for each distribution reference tariff; and

(d) a description of the approach to setting each distribution reference tariff.

Item (a) was discussed in the previous chapter. This chapter discusses items (b) to (d), and it also discusses issues relating to adding new references services.

4.1 Consultation

Western Power suggested that whilst ERA's framework and approach should list the reference and non-reference services, it should not address the eligibility criteria, structure and charging parameters and approach to setting tariffs (Western Power 2020, 2). However, ERA appears to prefer that the framework and approach addresses all of these requirements. "Settling the reference services, eligibility criteria and the structure and charging parameters in the framework and approach will provide Western Power with clarity about the tariffs it will need to develop in its access arrangement proposal" (ERA 2021, 15).

ERA has observed that various changes to the reference services will be needed in consequence of, and to support, the state government's Energy Transformation Strategy. ERA observes that the current reference services to facilitate distributed generation or other non-network solutions should be retained; and services relating to customer direct load control and load limitation should also be retained. Examples given by ERA of changes needed to reference services as required by the Code include:

- New supply contracts entered into by Western Power must enable the curtailment of the user's export of electricity into the distribution network, if necessary, when network constraints occur (cl. 2.4C). This will require changes to the terms and conditions of entry reference services and capacity allocation swap services.
- The Code (cl. 6.5G) now provides Western Power with additional target revenue with which to recover expenditure on installing advanced metering infrastructure (AMI) communications across the network. The purpose of this provision is to speed up the process of rolling-out advanced electronic metering. To achieve this purpose, it may be necessary to commensurately reduce metering charges for interval meters.

ERA has also noted that some tariffs could be rationalised or amended to more clearly specify what the user needs to do to be eligible for the services. ERA prefers to address all of these issues in the framework and approach. Western Power acknowledges there is a need to rationalise some services, to update eligibility criteria, to make amendments to deal with constrained access, and notes that methods of calculating metering charges will need to be reviewed.

ERA also prefers to identify at this stage any new reference services likely to be needed in AA5. "A structured approach based on a carefully thought-out plan to introduce these new services would be better than leaving them to ad hoc development" (ERA 2021, 17). Western Power does not appear to share this view, emphasising that it is "trying to achieve a balance between providing reference services where there is a clear demand for them … and letting in the market for future services mature through negotiating non-reference services as an interim position" (Western Power 2021, 11–12). Its preferred approach is to receive and consider proposals for new services from users in accordance with the procedure and criteria in clause 4.A14 of the Access Code, and act on them when they are sufficiently justified. In the interim, there is an appropriate mechanism for users to request customised non-reference services if those services are not likely to be widely used. Some stakeholders, such as Perth Energy, were not aware of any new services needed at present, whereas others including Alinta Energy and AEMO, saw merit in examining whether new services are required by the Energy Transformation Strategy or changes in electricity system operations.

Some stakeholders, such as the WA Local Government Association, felt that much more transparency is needed around non-reference services. Many of these services are not contestable, and yet there is no transparency over the calculation of, and no effective regulatory control over, Western Power's charges.

A particularly important area is the cost reflectiveness and efficient design of tariffs. Under changes to the Code, tariffs will need to reflect the efficient costs of providing the service. Energy Policy WA regarded efficient tariffs as crucial for the transitioning of the power system to higher use of renewable energy. It advocated "network tariff structures (reflected in reference services) that reward efficient use of the power system, provide forward-looking price signals to reduce power system costs over time, and support the adoption and use of technologies such as distributed energy storage and electric vehicles in an efficient manner" (Energy Policy WA 2021, 3).

ERA notes that the current time-of-use periods, among other things, require review to ensure they properly reflect current and forecast demand patterns. Noel Schubert expresses a similar view. "It is important that electricity tariffs provide signals that are in the long-term interest of consumers as the new Access Code objective requires" (Schubert 2020, 3). Western Power agrees with the need for such a review. "The scope of this review should include consideration of the most appropriate time bands and potential grandfathering of existing time bands that are inconsistent with the demand patterns forecast for AA5" (Western Power 2021, 14).

4.1.1 Assessment

ERA's proactive approach to addressing identified issues with the definitions of reference services, where there are clear options to improve the tariff eligibility criteria or better tailor a reference service to customer needs, seems to be the most practical approach. However, in regard to identifying new services in the framework and approach, given the uncertainties about what they ought to be, the ERA position may be difficult to implement and a flexible approach relying on customers to initiate proposals may be the most practical option.

Efficient tariff designs are discussed in the following section. The need for greater transparency in regard to the terms and conditions on which non-reference services are supplied, was discussed in section 3.2.2.3.

4.2 Efficient Network Pricing Principles

4.2.1 Access Code

The 2004 amendments to the Access Code establish new requirements in regard to reference service tariffs, including pricing principles which they must comply with, and the obligation to produce a Tariff Structure Statement which is subject to ERA approval.

Clause 7.3 of the Code states that the pricing objective is "that the reference tariffs that a service provider charges in respect of its provision of reference services should reflect the service provider's efficient costs of providing those reference services." Among the pricing principles are the following:

- "7.3G. Each reference tariff must be based on the forward-looking efficient costs of providing the reference service to which it relates to the customers currently on that reference tariff with the method of calculating such cost and the manner in which that method is applied to be determined having regard to:
  - (a) the additional costs likely to be associated with meeting demand from end-use customers that are currently on that reference tariff at times of greatest utilisation of the relevant part of the service provider's network; and
  - (b) the location of end-use customers that are currently on that reference tariff and the extent to which costs vary between different locations in the service provider's network." (cl. 7.3G)
- "7.3H. The revenue expected to be recovered from each reference tariff must:
  - (a) reflect the service provider's total efficient costs of serving the customers that are currently on that reference tariff;
  - (b) when summed with the revenue expected to be received from all other reference tariffs, permit the service provider to recover the expected revenue for the reference services in accordance with the service provider's access arrangement; and
  - (c) comply with sections 7.3H(a) and 7.3H(b) in a way that minimises distortions to the price signals for efficient usage that would result from reference tariffs that comply with the pricing principle set out in section 7.3G."
- "7.3I. The structure of each reference tariff must be reasonably capable of being understood by customers that are currently on that reference tariff, including enabling a customer to predict the likely annual changes in reference tariffs during the access arrangement period, having regard to:

(a) the type and nature of those customers;

(b) the information provided to, and the consultation undertaken with, those customers.”

A Tariff Structure Statement must set out Western Power’s pricing methods, and must include the structures and charging parameters for each proposed distribution reference tariff; and a description of the approach taken in setting each distribution reference tariff. Clause 7.1B states that a tariff structure statement must comply with:

(a) the pricing principles; and

(b) any applicable framework and approach.

By implication, the framework and approach can also address requirements that ERA decides that it should impose on the Tariff Structure Statement.

4.2.2 NEM

In November 2014 the AEMC adopted a rule change that requires DNSPs to develop prices that better reflect the costs of providing services to individual consumers (AEMC 2014). Distribution network prices will need to comply with several new pricing principles. Firstly, the revenue recovered from a service must be greater than the avoidable cost and less than the standalone cost. Second, each network tariff will be based on long-run marginal cost (LRMC) of providing the service. Third, tariffs should be structured so that the total efficient cost of providing services to the consumers assigned to a particular tariff should be recovered from those customers. The difference between LRMC and total efficient costs should be recovered in a way that does not distort signals for efficient use of network services. Fourth, network prices should be reasonably capable of being understood by consumers and consumer impacts must be considered when developing new tariffs and phasing them in. This last principle permitted network businesses to manage the impacts on consumers of price changes by gradually moving to new, more efficient, network prices over five years or more.

4.2.3 Assessment

The new pricing principles in the Code are broadly similar to those implemented by the AEMC in 2014. At that time, the AEMC observed that distribution network prices were generally not cost-reflective:

> “NERA’s case study on air-conditioners shows that a consumer that buys and uses a large air-conditioner does not pay the full costs of that decision. In this case study, the consumer would face about an extra $300 a year in network charges, but the extra network costs caused by the use of the air-conditioner at peak times would be almost $1,000 a year. The $700 difference is recovered through the rest of the customer base facing higher network charges. Several other organisations have also undertaken recent research that shows the extent of these cross-subsidies in network prices. Research by AGL in Victoria shows that hardship consumers are currently the most likely group to be paying more than the costs that their usage causes and are subsidising costs caused by other consumers.” (AEMC

2014, 32).

It is likely that the implementation of cost-reflective distribution charges will require substantial tariff realignments, and ERA should consider requiring Western Power to establish a framework within which it will go about this, including undertaking market analysis, developing cost-reflective tariff options, consulting with customers on them, obtaining the ERA's approval and progressively implementing the preferred options over a period such as five years.

5 METHOD OF SETTING SERVICE STANDARD BENCHMARKS

5.1 ERA Issues Paper

Under s 5.6 of the Code, an access arrangement must include a service standard benchmark for each reference service. The benchmark must be reasonable, and "sufficiently detailed and complete to enable a user or applicant to determine the value represented by the reference service at the reference tariff". Western Power must provide each reference service to a standard at least as good as the service standard benchmark (s 11.1).

Note that at present the service standard benchmarks are used for the purpose of capping Western Power's liability under the service standards adjustment mechanism (SSAM), which is addressed in chapter 8. However, under proposed changes to the SSAM, the revenue at risk constraints will be imposed directly, without relying on the benchmarks, thereby decoupling the benchmarks and the SSAM, which relies on distinct service standard targets.

If Western Power does not achieve the benchmark (or minimum) service standard, the Code contemplates that the ERA should be able to impose a civil penalty, although before doing so it must take account of the effects of any other penalties including the service standards adjustment mechanism (s 11.6). However, we understand that the ERA has not yet been given the powers to impose civil penalties of this kind. Clearly, the framework in the Code that requires Western Power to comply with minimum service standard benchmarks is greatly weakened without an effective means of imposing penalties for non-compliance. Therefore, we think that ERA should be empowered to impose such penalties, in order to give effect to the intent to the Code. Note that the SSAM applies only to incentivise average performance standards and does not provide a financial incentive to meet minimum standards.

The main performance measures used in Western Power's current access arrangement for which service standard benchmarks (SSBs) are defined, are:

- for *distribution*: System Average Interruption Duration Index (SAIDI); System Average Interruption Frequency Index (SAIFI); and call centre performance;
- for *transmission*: circuit availability, loss of supply event frequency and average outage duration; and
- there are other performance measures for street lighting, supply abolishment, and remote de-energise and remote re-energise services.

ERA proposes the following changes to the performance measures:

(1) widening the measures of SAIDI and SAIFI to include interruptions to distribution customers due to planned or unplanned outages on Western Power's transmission network. Related to this, ERA proposes that distribution service standard exclusions should no longer exclude faults on the transmission network;

(2) removing the circuit availability measure; and

(3) introducing a new transmission service measure for network entry services provided to generators. This would be based on interruptions to generators' ability to despatch into the transmission network due to a planned or unplanned network outage.

In regard to (1), Western Power disagreed and felt that separate SSBs should be maintained for transmission and distribution for AA5. It said: "the inclusion of transmission outages in the distribution SAIDI and SAIFI measures will result in a double counting of transmission outages" (Western Power 2021, 23).

In regard to (3), AEMO agreed with the proposed new transmission network availability performance measure, saying that it "supports consideration of the market cost of network outages in the service standard benchmarks and service standard adjustment mechanism". It recommended that "any related metrics should be designed to use data that will already be published by AEMO (and publicly available) as a result of the Energy Transformation reforms, including outage data, constraint data and marginal constraint values" (AEMO 2021, 2). However, Western Power was unenthusiastic. "The impact of planned or unplanned network outages and constraints on the market will be subject to greater focus in the new WEM. Western Power therefore proposes that any new transmission service standard benchmark be considered once the new regime is in place and there is sufficient experience and data to determine appropriate service standard benchmarks" (Western Power 2021, 21).

Other changes to SSBs and performance reporting proposed by ERA included:

(a) distribution service standard exclusions should no longer include force majeure events, given the exclusion of 'major event days';

(b) a new exclusion should be added to distribution service standard exclusions to exclude load interruptions caused or extended by a direction from state or federal emergency services, provided that a fault in, or the operation of the network did not cause, in whole or part, the event giving rise to the direction; and

(c) there should be increased reporting requirements on planned outages.

Western Power disagreed with (a), whilst noting that the "definition of force majeure events is wide ranging and provides Western Power the opportunity to seek exclusion for a force majeure event which is outside of Western Power's control, noting that these such events could extend for many days, weeks or even months" (Western Power 2021, 24). It felt that (b) does not go far enough and should also include local government directives and days of total fire ban. Further, the qualification that a network fault should not be the cause of the incident should be removed. Western Power also disagreed with (c) – increased reporting of planned outages. However, Perth Energy agrees with this proposal (Perth Energy 2021, 4).

On the question of how benchmarks should be set, ERA indicated that it prefers to continue using the current method based on the 2.5th percentile of actual performance outcomes over the previous access period. Western Power disputed this, arguing that there are emerging challenges in the external environment, such as the effects of climate change on the frequency and severity of bushfires, and such developments "are not reflected in the current methodology for setting SSBs" (Western Power 2021, 19). Western Power emphasised that the "SSB compliance levels should be set at levels that can consistently be met during each financial year of AA5" (Western Power 2021, 18); and further argued:

> "Western Power considers the method for calculating service standard benchmarks (SSBs) should be reviewed to ensure that the levels at which SSBs are set continue to provide:
>
> - the right incentives for Western Power to continue to seek cost efficiencies to provide an affordable and valued service to our customers; and,
> - the required SSB levels to deliver on customer expectations with respect to reliability and the customer felt experience" (Western Power 2021, 18–19).

Perth Energy also supported giving further consideration to the method of setting benchmarks. "Given we are moving to a constrained regime, we ask the ERA to consider whether a new approach to determining Service Standard Benchmarks is required" (Perth Energy 2020, 3).

5.2 AER practice

The AER has a Service Target Performance Incentive Scheme (STPIS) which is based on establishing targets for key performance indicators, and subsequently comparing performance outcomes against the targets. This scheme is discussed in chapter 8. Importantly, the targets in this scheme are based on *average* performance over the preceding five-year period. They are not a minimum acceptable level of performance, and hence not analogous to the service performance benchmarks that need to be specified against services in the Western Australian Access Code. The AER does not appear to have a parallel to the performance benchmarks in the WA scheme.

5.3 Assessment

As also discussed in chapter 8, the Services Standards Adjustment Mechanism (SSAM) in the Western Australian access framework currently uses both service targets and service benchmarks in its formulation. However, ERA has proposed changes which would remove the use of benchmarks in the SSAM, and hence decouple the service benchmarks from the financial incentive scheme in the SSAM. This will assist to simplify the SSAM mechanism, and make it more consistent with the AER's STPIS mechanism.

ERA's method of updating performance benchmarks using the 2.5th percentile performance of the previous five years is, in our view, a reasonable one. It may be noted that the method of setting benchmarks and targets (for the SSAM) are related. The latter is based on the average (which could be the median) performance over the previous five years. However, when setting targets there are also a number of other considerations to take into account other factors expected to materially affect network reliability. Western Power has emphasised its concerns relating to bush fires and other climate related risks. Other factors, likely to be associated with improved reliability include the greater adoption of new technologies such as stand-alone power and network battery storage, may have the potential to significantly reduce interruptions. In light of these considerations, the ERA's proposed approach is unlikely to set unachievable benchmarks.

6 PRICE CONTROL

6.1 ERA Issues Paper

At present, Western Power is subject to what the ERA describes as a modified revenue cap. Tariffs in a regulatory period must be consistent with ensuring forecast revenue equals target revenue needed to cover efficient costs but there is no adjustment for any under-recovery or over-recovery of actual revenue compared with forecast revenue from previous years. There are side constraints for each reference tariff specified in a CPI-X form with annual correction factors that mean that the change for each reference tariff can be no more that 2 per cent above the average change in tariffs. Western Power must update its tariffs such that the overall target revenue constraint applies for each of the distribution and transmission networks.

Prior to 2019-20 a revenue cap applied, with unders and overs adjustments to adjust for under or over recovery for each of the distribution and transmission networks. Since 2019-20 there is no unders and overs adjustment so that price caps in effect apply. This form of price control ensures Western Power is fully exposed to demand risk within a regulatory period.

The ERA proposes to continue the same form of price control subject to some modifications in the Access Code relating to pricing principles. The revised pricing principles require Western Power to undertake a more detailed cost allocation to ensure each reference tariff complies with pricing principles for efficient pricing and to remove a requirement to avoid price shocks. There is also a requirement to minimise distortions to price signals for efficient usage and a requirement to ensure that total expected revenue equals total efficient costs.

The access arrangement must include a forecast for each reference price, and Western Power must annually publish a tariff structure statement and reference tariff change forecast for that year. Given these greater obligations on Western Power, ERA now considers that separate price controls for transmission and distribution services and the 2 per cent side constraint for each reference tariff may no longer be needed.

The ERA Issues Paper provides a brief description of the advantages of a form of price control which is more akin to a price cap than a revenue cap. Some additional points are provided here for completeness.

6.2 Revenue cap compared to a price cap

The key differences between a revenue cap and a price cap are who bears the volume risk and the impact of the guarantee of revenue on incentives for efficient output and price structures. The following discussion presents some general features of pure revenue and price caps, not all of which may be relevant for the proposed pricing arrangements depending on individual pricing constraints. The advantages and disadvantages of revenue and price caps are discussed in a QCA (2012) Discussion Paper on Risk and the Form of Regulation.

Under a pure or strict revenue cap, the firm recovers the revenue cap irrespective of the actual demand and there are carry over adjustments to the next regulatory period to ensure the firm realises the revenue cap. Customers bear the full volume risk within the regulatory period.

Revenue stability is achieved but at the expense of price variability.

A revenue cap also provides no incentive for the regulated entity to expand output. This follows because there is a strong price and profit penalty from expansion of services under a revenue cap. There is, in fact, an incentive to reduce output as this will mean higher prices and lower variable costs.

A revenue cap also provides incentives for an inefficient price structure to develop, where prices are higher where demand is more responsive, as this will reduce variable costs strongly and increase profits which is directly contrary to an efficient price outcome where prices should be relatively lower where demand is more responsive. However, in the case of the arrangements for Western Power requirements to set each reference tariff to cover efficient costs would limit the scope for inefficient pricing to arise.

A revenue cap provides stronger incentives for efficient investment than a price cap. Under a revenue cap the infrastructure investor has greater certainty about recovering costs as it is less subject to demand fluctuation and this should facilitate more investment. However, the claimed certainty benefit of a revenue cap over a price cap is limited where there is a major reduction in demand leading to stranded assets. Also the greater price variability under a revenue cap may impact adversely on consumers and investors that use the services of the regulated entity. A revenue cap will still contain incentives for the firm to reduce costs but the incentive is likely to be stronger for a price cap given the greater risk associated with a price cap.

From an administrative perspective, the main potential advantage of a revenue cap (relative to a price cap) is in reducing the need for accurate forecasts of demand by both the regulator and the regulated firm since total costs are effectively guaranteed by unders and overs adjustments. There could still be incentives to forecast higher capital expenditure than is efficient but this also occurs for price caps and can be addressed with capital efficiency audits.

In contrast to a revenue cap, a price cap provides incentives for the firm to increase demand where prices exceed the incremental cost of supply, rather than restrict demand, as is the case for a revenue cap. An overall price cap for a basket of services where individual services can be priced differently allows the firm to adjust prices to demand conditions consistent with achieving allocative economic efficiency. Price constraints at the individual level may mean this is not feasible if there is an overall adverse impact on expected profits. However, there could still be incentives to improve quality if it promoted expansion of demand for some services. However, it should also be noted that expansion of demand may, in some cases, not be consistent with environmental objectives.

The main disadvantages relate to the extent to which revenue variability under a price cap impacts adversely on investment incentives and the incentives for under-estimating forecast demand.

The investment dis-incentive effect from revenue variability can be overstated when price resets are relatively frequent. In addition, the risk can be reduced if there are mechanisms for re-setting prices if major events occur that substantially increase costs. As noted a price cap achieves price stability which is likely to be valued by consumers and investors that use the services of the regulated entity. In addition, in response to the greater revenue risk and its potential impact on profits a price cap is likely to provide stronger incentives to reduce costs to help ameliorate the risk.

However, the use of forecasts of demand provides an incentive for the regulated firm to materially under-estimate the demand forecast. If the regulated firm can successfully argue for a lower demand forecast, the regulated price based on the building blocks methodology will be higher than it would be in the case of a higher forecast for demand. The higher price will then be earned on all of the firm's actual, not forecast, sales. It is understood that a key motivation for the AER adopting revenue caps in place of price caps for network service providers was the persistent and widespread tendency for firms to under-estimate demand in calculating forecast revenue. (see AER references reported by the QCA (2012, p. 19).

6.3 Assessment

The proposed changes for setting specific reference tariffs and to remove separate price controls for transmission and distribution and for the separate side constraints seem reasonable.

As explained in the discussion of the investment adjustment mechanism below, the Western Power submission considers there also an issue of potential asymmetry in the distribution of revenues that needs to be addressed. However, the asymmetry has not been demonstrated except to refer to individual price caps restricting upside revenue potential. There is an issue though of the optimality of allocating all demand risk to Western Power and the incentives that would arise to under-estimate forecast demand. This is discussed further below.

It may be useful for the ERA to give more consideration of the incentive features of a price cap and in particular the incentives for Western Power to under-estimate forecast demand leading to higher revenue than is needed to cover efficient costs. To address some of the problems with a pure price caps hybrid models have been adopted with thresholds or deadbands for sharing unders and overs outcomes between the firm and its customers. It is understood that these apply for some regulated water businesses in Australia and have previously applied in some electricity determinations.

There is also an issue as to whether there are implications for the allowed WACC if a price cap entails more risk than a revenue cap and this has not been considered in the Issues Paper. Although there is a strong conceptual argument that the risks differ, this depends on the whole package of regulatory arrangements including mechanisms for sharing risks and the frequency for resetting prices that cover all efficient costs. There is no clear consensus about the impact in a regulated environment.

The Energy Policy WA submission considered that network tariffs that reflect the current and longer-term costs of providing network services and signal customer behaviours that support the efficient operation of the power system are an essential foundation for the development of retail tariffs (including tariffs for customers with electric vehicles) consistent with a high DER future. As such, Energy Policy WA supports methods of price control that provide a basis for offering tariffs that support the transition of the power system to a high renewable energy (including high DER) future. This recommendation is reflected in the Energy Transformation Strategy Road Map discussed above where Energy Policy WA, Synergy, Western Power, and

Horizon Power have had responsibility for tariff pilots that were scheduled to be commenced by March 2020 (Energy Transformation Taskforce, 2019, p. 48). The results from the pilot will need to be incorporated in tariff changes in accordance with the Access Code Objective which has been amended such that there is scope to implement tariffs that are consistent with achieving the various aspects of economic efficiency, including in relation to price, the safety, reliability and security of networks and the environmental consequences of energy supply and consumption.

The Perth Energy submission raised concerns about the removal of the requirement to avoid price shocks but this can be addressed by the new requirement to minimise distortions to price signals and the requirement in the access arrangement for consultation on the price path.

The Western Power submission considers that separate controls and side constraints may no longer be required but, as noted, only supports removal of the investment adjustment mechanism (discussed below) if the requirement to set tariffs such that forecast revenue is equal to target revenue is removed and a revenue uncertainty mechanism is implemented to recover a portion of under or over recovery of revenue if it is sufficiently material.

The Western Power proposals are motivated by a concern about potential asymmetry in the price control arrangements. However, as noted, the scope for the asymmetry has not been demonstrated and if it did exist would be modified by resetting of prices (even without unders and overs adjustments) in the subsequent regulatory period.

The requirements to set individual tariffs to reflect efficient costs should ensure total revenue recovery is broadly in line with total efficient costs but it is considered to be important to check this with an overall total revenue constraint for Western Power.

To conclude, if the price cap form of regulation is continued there may be merit in considering whether a threshold (deadband) should be specified such that within the threshold Western Power bears all of the demand risk but beyond the threshold consumers bear all of the demand risk. The economic literature tends to conclude that some sharing of demand risk is optimal (QCA 2012, Section 7).

7 INVESTMENT ADJUSTMENT MECHANISM

7.1 ERA Issues Paper

The 'investment adjustment mechanism' determines how a discrepancy between benchmarks and outturns for new facilities investment in the last regulatory period is to be treated in the next access arrangement review. Western Power has an investment adjustment mechanism in its current access arrangement that corrects for any economic loss or gain due to differences between forecast and actual expenditure (in present value terms). ERA's preliminary view is that the current mechanism is inconsistent with the price control arrangements applying since 2019/20 which places demand risk on Western Power with the scope for Western Power to retain more revenue where demand is greater than forecast and receive less revenue where demand is less than forecast. This is considered to imply less need for the existing investment adjustment mechanism.

The Western Power submission supports removal of the investment adjustment mechanism but providing a contended asymmetry in the pricing arrangements is addressed. In this respect, the Western Power submission considers that the potential distribution of gains and losses is not symmetric because there is an effective upside potential cap arising from the form of price control not matching downside potential risk associated with downside volume risk. Western Power also considers there is merit in sharing the burden of demand side risk where the risk is outside the control of Western Power.

7.2 Assessment

In assessing investment adjustment schemes from the point of economic efficiency there are a number of considerations (some of which have already been discussed in relation to revenue and price cap forms of regulation).

- The price cap form of price control allocates all demand risk to Western Power and this will provide incentives for Western Power to under-estimate demand and realise higher allowed tariffs that will mean higher prices if actual demand exceeds forecast demand. With no unders and overs adjustment there is likely to be a strong incentive to under-estimate forecast demand if Western Power has strong commercial profit incentives. In addition, this mechanism is not focussed on incentives to ensure capital expenditure is efficient (see following point).
- While it will be profitable to under-estimate demand under the existing price control it will also be profitable to over-estimate efficient capital expenditure which in absence of an effective profit-sharing scheme will need to be addressed with a capital efficiency audit.
- Incentives to reduce costs should be continuous and not suffer from the 'periodicity' problem that provides a stronger incentive to reduce costs early in a regulatory period or defer expenditure if retention periods are not equal across all years. This applies to both capital and operating expenditure.

- Incentives to reduce costs should be balanced so that there is not a bias in favour of capital or operating expenditure.
- Some sharing of risk is likely to be more economically efficient than extremes that allocate all risk to either the firm or consumers, reflecting a combination of scope to bear risk, risk preferences and information problems.

These considerations raise the issue of the extent to which the proposed form of price control together with the investment adjustment mechanism and the gain sharing mechanism ensure efficient outcomes for both operating and capital expenditure. This is a complex issue that would require further detailed consideration.

7.3 AER practice

In addressing these matters, there may be merit in considering capital efficiency sharing schemes as developed by the AER (AER 2020a). The AER has recently revised its guideline for capital assessment for electricity distribution determinations. The AER assesses forecast capital expenditure on an ex ante basis to confirm the forecast capital expenditure is prudent and efficient using a number of techniques. Forecasts are then set at a level where the distributor has a reasonable opportunity to recover its efficient costs. The ex ante assessment techniques include: trend analysis; category analysis; bottom-up analysis, top-down analysis and economic benchmarking.

Once the ex ante allowance is established there is an incentive for distributors to provide services at the lowest possible cost and the savings are shared with consumers in future regulatory periods. The sharing arrangements in the capital expenditure sharing scheme (CESS) specify that a business will retain or bear 30 per cent of an underspend or overspend, while consumers will retain or bear 70 per cent of the underspend or overspend (in present value terms). However, if a distributor overspends consumers only share in the costs if the expenditure is confirmed to be prudent and efficient in an ex post assessment. It is understood that similar arrangements apply for transmission determinations.

The 30/70 split was originally chosen to be consistent with the present value split for the efficiency benefit sharing scheme that applied to operating expenditure which depended on the discount rate and time period i.e. to achieve balanced incentives for capital and operating expenditure.

8 GAIN SHARING MECHANISM

8.1 ERA Issues Paper

The Issues Paper explains that:

> "Western Power's current gain sharing mechanism provides for an adjustment to target revenue in the next access arrangement period so that Western Power retains the benefit of operating cost efficiencies for five years (the year the efficiency was made plus four additional years) regardless of which year the efficiency was made."

The gain sharing mechanism in the access arrangement for Western Power effectively addresses the periodicity problem,[5] for operating expenditure, by ensuring that Western Power retains an efficiency saving realized at any time during the regulatory period for the same period of time thereby providing continuous, consistent incentives to achieve cost efficiencies.

This mechanism seems appropriate and is consistent with the approach adopted by the AER in its Efficiency Benefit Sharing Scheme (EBSS) (AER 2013a) except that the AER Scheme allows retention for six years in total compared with the ERA period of five years in total.

As explained in the ERA Issues Paper some amendments are required due to the Access Code amendments and some consideration needs to be given to the treatment of exclusion. These are as follows:

- In relation to service standards the requirement that the above-benchmark surplus does not exist to the extent that a service provider achieves efficiency gains by failing to comply with the service standard benchmarks has been removed. The gain sharing mechanism must be amended to take account of this change. This will simplify the gain sharing mechanism.
- The gain share mechanism must be amended to make the treatment of underspend and overspend (where there is currently no deduction) symmetrical.
- The Access Code amendments include a requirement to minimise the effects of the mechanism on incentives for the implementation of alternative options. The D-factor in Western Power's access arrangement provides for the recovery of operating expenditure incurred by Western Power from deferring/substituting a capital expenditure project or for demand-management initiatives. This type of expenditure is excluded from the gain sharing mechanism and the ERA considers that this deals adequately with the Access Code requirement.
- The current gain sharing mechanism excludes a number of expenditure categories on the basis they are outside Western Power's control. The ERA notes that the AER does not exclude "uncontrollable" costs from its equivalent of the gain sharing mechanism

[5] The 'periodicity' problem refers to a situation, where in the in the absence of an appropriate incentive mechanism, the incentive to achieve cost efficiencies would decline over a regulatory period. This is because the present value of savings that are retained depends on the time over which the savings accrue.

on the basis that there is no compelling reason that the forecasting risk associated with uncontrollable operating expenditure be shared differently between service providers and customers than for "controllable" costs (see 7.3 below). The ERA considers this argument has merit and proposes to remove the exclusion of uncontrollable costs from the gain share mechanism.

8.2 Assessment

We consider that the above approaches are justified. The Perth Energy submission supports the proposed ERA treatments. Western Power supports the D-factor treatment but does not agree with removing some of the non-controllable costs and considers they are not reasonable.

8.3 AER approach

The AER equivalent of the gain sharing scheme is its EBSS for operating expenditure. The AER (2013a, 26) notes that its treatment means approximately a 30:70 (firm consumer split) sharing arrangement for a five year carryover period (six years in total), that the risk of uncontrollable events presents both upside and downside risks, that any material risks can be managed with pass-through events and contingent projects, that network service providers would have some control over such events and excluding such items would reduce incentives to ensure costs were efficient.

9 SERVICE STANDARDS ADJUSTMENT MECHANISM

9.1 ERA Issues Paper

The service standards adjustment mechanism (SSAM) determines how the service standards outcomes of the access provider relative to performance benchmarks, in an access period, translate into rewards (for overperformance) or penalties (for underperformance) in the next access period. Western Power's access arrangement has both benchmarks and targets for services standards. Benchmarks are the minimum standard that must be met, and the targets are higher, based on average performance over the previous five years. At the end of an access period, in the next access review, Western Power receives a financial reward for exceeding the targets and a financial penalty for not meeting the targets in the last period on average.

The main performance measures used in Western Power's current access arrangement are:

- for *distribution*: SAIDI, SAIFI and call centre performance;
- for *transmission*: circuit availability, loss of supply event frequency and average outage duration.

There are other performance measures for street lighting, supply abolishment, and remote de-energise and remote re-energise services.

ERA proposes to retain the current mechanism with some modifications. It proposes to continue using the method for calculating the benchmarks based on the 2.5th percentile of actual performance over the previous access period. Proposed modifications to the SSAM include:

(1) changes to some service standard measures, including;

(a) widening the measures of SAIDI and SAIFI to include interruptions to distribution customers due to unplanned outages on Western Power's transmission network;

(b) a new measure to capture interruptions to generators' ability to despatch into the transmission network due to a planned or unplanned network outage;

(c) removing the circuit availability measure.

(2) revising the method of calculating transmission incentive rates, to use only the revenue attributable to those customers to which the transmission service standards apply;

(3) using the most current AER estimates of the value of customer reliability; and

(4) modifications to the caps on financial rewards and penalties consequent on changes to the gain sharing mechanism, and to make them symmetrical. The cap for rewards and penalties for the transmission network would be retained at 1% of transmission revenue, and the caps for the distribution network would be revised to also be set at 1% of total distribution revenue.

Western Power did not agree with (1)(a) or (2), but it agreed with (1)(c) and (3). AEMO agreed with (1)(b), saying that it "supports consideration of the market cost of network outages in the service standard benchmarks and service standard adjustment mechanism". It recommended that "any related metrics should be designed to use data that will already be published by AEMO (and publicly available) as a result of the Energy Transformation reforms, including outage data, constraint data and marginal constraint values" (Australian Energy Market Operator (AEMO) 2021, 2).

Western Power questioned ERA's method of updating *benchmarks* by using the 2.5th percentile of average performance in the previous access period, because it felt this did not give enough attention to various emerging climate concerns, including bush fires etc. ERA did not discuss how it will update performance *targets*. We discuss this question in section 9.3. Perth Energy noted that it "would expect to see the targets for distribution reliability rise as more stand-alone systems are deployed" (Perth Energy 2021, 5).

Perth Energy rejected some of the main design features of the Western Power's SSAM. "Perth Energy considers that there is a fundamental flaw in the arrangement to pay additional money to Western Power if it exceeds certain performance standards. These standards have been set as realistic minimum targets for end use customers to operate under and that are achievable by Western Power within its approved budget" (Perth Energy 2021, 4). It also argued that, if there are to be rewards in the SSAM, "any payment for above target performance should only be paid if all targets have been met." (Perth Energy 2021, 5).

9.2 AER approach

9.2.1 Distribution

The AER service target performance incentive scheme (STPIS) for distribution (AER 2018b) is intended to ensure that distributors' service levels do not reduce as result of efforts to achieve efficiency gains. The AER adjusted the STPIS formula in November 2018 to better balance the weight given to the frequency and duration of supply interruptions. The modified STPIS will increase the incentive for distributors to reduce the average duration of supply interruptions for all customers, while keeping the number of outages at low levels.

The AER has found that the STPIS has delivered improvements in the reliability of electricity supply, but that distributors have focused on reducing the numbers of short interruptions to supply, rather than also reducing the number of longer interruptions. As a result, the average length of supply restoration time has increased, meaning that customers, particularly at the end of networks (often in rural or remote areas) may not receive the same supply improvements as customers in urban areas. The changes to the STPIS are designed to achieve better reliability outcomes for all customers, including those in rural areas.

The changes to the STPIS followed a 2016 Australian Energy Market Commission (AEMC) review of the framework for measuring reliability performance in the National Energy Market (NEM). The AEMC proposed a number of changes to the current method for measuring interruptions to supply, including changing the definition of "momentary interruption" from less than one minute to less than three minutes. Along with other recommended changes, this resulted in alterations to the measurement method for the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). The

STPIS was amended in order to reflect the revised measurement methods.

The distribution scheme comprises, in principle, four components:

- A reliability of supply component.
- A quality of supply component (however, no parameters are currently specified for this component).
- A customer service component.
- A guaranteed service level component (which does not apply if jurisdictional legislation imposes a similar scheme).

Under the reliability of supply and customer service components of the scheme, a DNSP's revenue is increased (or decreased) based on changes in service performance, as assessed by the AER. The maximum revenue at risk for the scheme components in aggregate is (±) 5%.

The reliability of supply measures are: unplanned SAIDI, unplanned SAIFI and MAIFIe or MAIFI (a momentary interruptions parameter). Measures of the frequency of momentary interruptions are only used in Victoria (since they rely on advanced metering). The electricity distribution network is divided into segments by 'network type'. These are: CBD; urban; short rural; and long rural feeders. The reliability supply measures are calculated for each network type.

The outcome achieved for each service parameter is compared against a target to obtain a measure of outperformance or underperformance on each parameter, which are aggregated using an 'incentive rate' for each parameter. The aggregate so calculated is called the 's-factor', and measures either a percentage increase or decrease in allowed revenue, or else a dollar amount. The AER has recently moved to using a dollar rather than a percentage (AER 2018c). There is a lag in the calculation of the s-factor, but ignoring time periods, the formula for the reliability of supply s-factor is:

$$S^{ROS} = \sum_{p} ir_p \left[Tar_p - Act_p \right] \qquad (1)$$

where p refers to parameters (eg, SAIDI, SAIFI); ir_p is the incentive rate for parameter p; and Tar_p, and Act_p are target and actual performance respectively for parameter p. The revenue at risk constraints are then superimposed on the resulting s-factor. As later discussed, the service standards adjustment mechanism (SSAM) formula used in Western Power's AA4 differs from equation (1).

Performance targets are based on average performance over the past five regulatory years, calculated after adjusting for excluded events, and modified by:

- the effects of any improvements allowed for in cost benchmarks;
- an adjustment to correct for revenue at risk;
- any other factors expected to materially affect network reliability.

The incentive rates are based on the value that customers place on supply reliability referred to as the 'value of customer reliability' (VCR). The VCR is decomposed into two parts, one relating to SAIDI and the other to SAIFI, and these values are used to calculate the individual incentive rates in appropriate units. Until recently, the AER allocated 50% of VCR to SAIDI and 50% to SAIFI, but it now allocates 60% to SAIDI and 40% to SAIFI (Australian Energy Regulator (AER) 2018c). The previous weighting was giving insufficient incentive to reduce the average duration of interruptions, measured by the Customer Average Interruption Duration Index (CAIDI).[6]

The customer service component includes parameters for: telephone answering; streetlight repair; new connections; and response to written enquiries. The maximum revenue at risk for all customer service parameters is 1% and 0.5% for an individual parameter.

The guaranteed service level component includes parameters for: frequency of interruptions; duration of interruptions; streetlight repair, new connections and notice of planned interruptions. Dollar value payments are specified for each parameter.

9.2.2 Transmission

The current STPIS for transmission was published in 2015 (AER 2015). The AER's amendment to the scheme introduced financial incentives for forced outage service component sub parameters, making the market impact component symmetrical by providing a reward/penalty of ±1 per cent of maximum allowed revenue and for the network capability component, pro rating the annual financial incentive payments to the annual average cost of the approved projects and strengthening the ex-post assessment of projects.

The latest version of the STPIS has three key components:

- the service component, which is designed to incentivise TNSPs to reduce unplanned circuit outage events, loss of supply event frequency, and average outage duration and achieve proper operation of equipment. This can lead to a maximum reward or penalty worth 1.25 per cent of the MAR;
- the market-impact component (MIC), which provides an incentive to TNSPs to reduce the impact of planned and unplanned outages on wholesale market outcomes. This has an incentive which falls within the range of ±1 per cent of the MAR;
- the network-capability component, which encourages TNSPs to undertake operational and minor capital expenditure projects (can cost up to a total of one per cent of the MAR per year) that deliver improvements in network capability of those elements of the transmission system most important to determining spot prices or at times when users place the greatest value on the reliability of the system.

9.2.3 Value of Customer Reliability

In 2018, the AER became responsible for determining the values customers place on having a reliable electricity supply. The ‘value of customer reliability’ (VCR) is an unobserved shadow

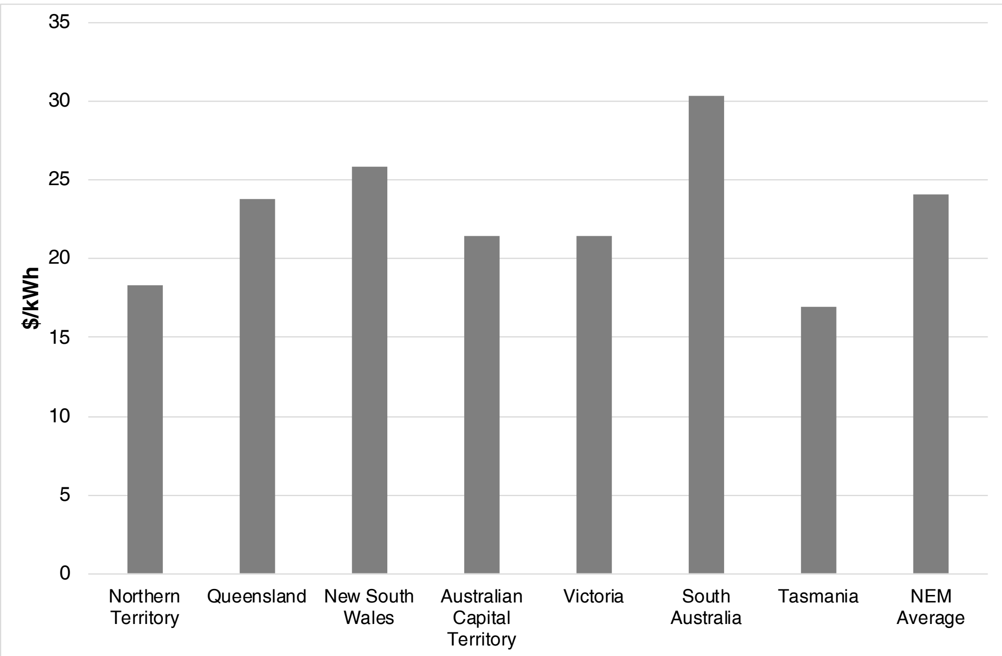
[6] By definition: CAIDI × SAIFI = SAIDI.

price which is crucial information in a wide range of planning decisions which require trading off the costs and benefits of additional capital and operating expenditure to improve the reliability of an electricity supply system. VCRs are also used to calculate incentive rates for the STPIS incentive mechanism for supply reliability.

In 2019, the AER developed VCR estimates for different types of customers on different network segments. The customer types include residential, small-medium businesses, and large businesses. The network segments are direct supply from transmission and supply off four distribution segments: CBD, Urban, rural short and rural long feeder. The AER used two main methods. The VCRs for customers with a peak demand of less than 10 megavolt-amperes (MVA) were derived using contingent valuation and choice modelling survey techniques. VCRs for customers with peak demand greater than 10 MVA were based on direct cost surveying (AER 2019a). The AER will be updating these estimates every five years.

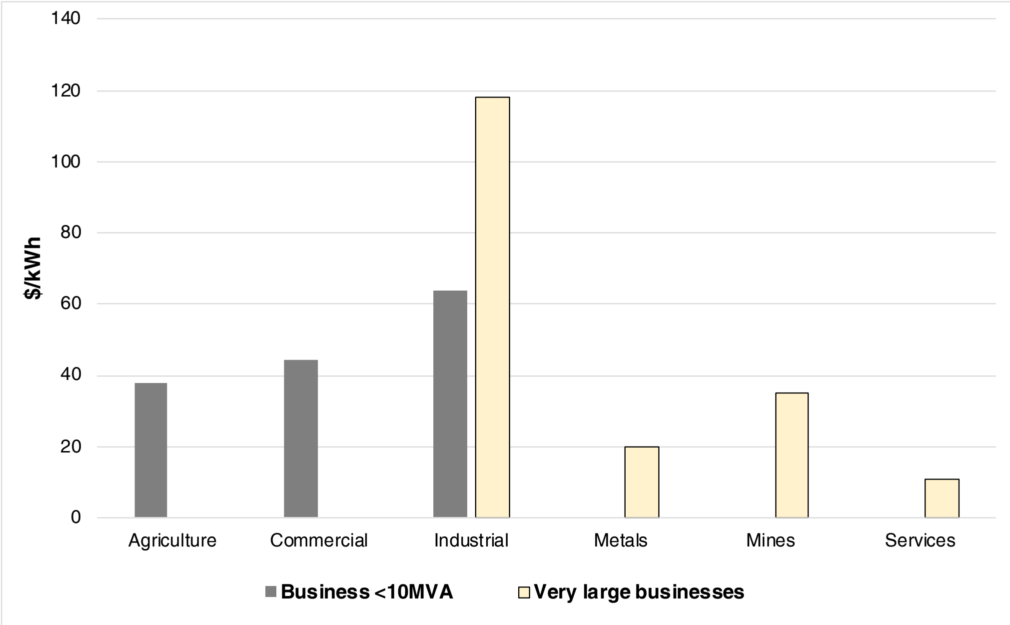
The VCRs published by AER represent the aggregate value which residential and business customers place on standard outages (relatively localised outages that last up to 12 hours in duration). The high-level findings are an average over different times of the day in seasons of the year. However, the AER also presents separate estimates by length of outage, peak and off-peak, and winter and summer periods (AER 2019b). Figure 9.1 shows the AER estimates of VCR for residential customers by state and for the NEM as a whole.

Figure 9.1: Residential NEM and state VCR comparison ($/kWh, 2019$)



The variation in VCR between states is said by the AER to be at least partially due to differences in climate. Figure 9.2 shows VCRs for businesses with peak demand less than 10 MVA per year, and very large business customers, by industry. Some very large businesses are supplied directly off the transmission network and some off the distribution network. The AER also produces separate estimates of VCR for large businesses supplied directly off the transmission network and very large businesses supplied off the distribution network.

Figure 9.2: Business VCR comparison by industry ($/kWh, 2019$)



9.3 Assessment

In its decision on Western Power's current AA4 access arrangement, ERA adopted the 60/40 weighting for SAIDI and SAIFI in line with the AER's new approach (ERA 2018, 439). Western Power's SSAM works as follows (assuming lower values of the parameter mean better performance, as is the case for SAIDI and SAIFI):

$$S^{ROS} = \sum_p ir_p[Tar_p - Act_p] \qquad \text{if } Act_p < Ben_p \qquad (2)$$

$$= \sum_p ir_p[Tar_p - Ben_p] \qquad \text{if } Act_p \geq Ben_p$$

This formula effectively caps the penalty for underperformance to the penalty that would apply if performance was at the benchmark. ERA notes that the service standards adjustment mechanism will no longer require the individual penalties to be capped at the service standard benchmark. We take this to mean that formula (2) could then be aligned with formula (1).

The revenue at risk for Western Power under the SSAM of ±1% of total revenue appears to be much lower than the revenue at risk level applying to DNSPs in the NEM of ±5% of total revenue. If that observation is correct, it would imply that the SSAM imposes much weaker incentives for service quality improvement than the equivalent STPIS scheme in the NEM. We understand that the revenue at risk for Western Power was previously higher, and the current lower level may reflect a more cautious view about the reliability of the targets.

The AER's estimates for VCR can be used to establish incentive rates in the SSAM. This would presumably involve:

- choosing the closest comparator among the state or NEM-wide VCR estimates for residential customers;
- calculating a weighted average estimate of the VCR estimates for businesses, depending on size groups, and depending on the industry mix of such customers in the SWIS.

In regard to determining the performance targets for AA5, the AER bases these on average performance over the previous five years, but also takes account of:

- the effects of any capital or operating expenditure directed to improving service quality performance;
- an adjustment to correct for revenue at risk;
- any other factors expected to materially affect network reliability.

As Perth Energy has noted, some of the new technologies likely to be implemented on a substantially greater scale in AA5, such as stand-alone power and network battery storage, may have the potential to significantly reduce interruptions. It would therefore seem to be advisable that ERA should carry out an assessment of the likely effects of these technologies on interruptions. This would need to be assessed in the context of evaluating Western Power's proposed access arrangement, rather than being decided in the framework and approach.

10 DEMAND MANAGEMENT INNOVATION ALLOWANCE MECHANISM

This requirement arises from amendments to the Access Code. It is described as a limited scheme to provide Western Power with financial incentives to undertaken small-scale R&D initiatives on the network, with the aim of achieving lower cost outcomes over time for customers. This would be in the form of an additional R&D allowance for each year of an access period, which can only be applied to projects meeting specific criteria as approved by ERA in advance of the project being undertaken. Unused allowance cannot be carried over to another year. A similar scheme operates in the NEM, administered by AER.

10.1 Consultation

This scheme is required by amendments to the Access Code. It is similar to a scheme operating in the NEM, administered by AER. It is intended to be a limited scheme to provide Western Power with financial incentives to undertake small-scale R&D initiatives in relation to demand management, with the aim of achieving lower cost outcomes over time for customers. It takes the form of an additional R&D allowance for each year of an access period, which can only be applied to projects the meet specific eligibility criteria, as approved by ERA in advance of the project being undertaken. Unused allowance cannot be carried over and must be repaid by the access provider through adjustment to its revenue requirement.

Western Power would like to see the scheme administered more flexibly than the NEM scheme, and adopt a broader definition of demand management to include network solutions in addition to non-network solutions. "Western Power notes that the schemes operating in the NEM are highly prescriptive and administratively complex and considers that a less complex approach with lower administrative overheads is in the long-term interests of consumers" (Western Power 2021, 36) However, this contrasts with the views of other stakeholders. Common themes in the submissions were that the ERA should establish clear criteria as to the kinds of R&D projects that could qualify under the scheme, and should conduct a robust approval process for projects proposed to be funded under the scheme to ensure that they meet the eligibility criteria and have positive net benefit (Australian Energy Council 2020, 3; Perth Energy 2020, 4). AEMO suggested that the eligibility criteria should require that project proposals include an assessment of potential impacts on power system security, power system reliability, and the WEM (AEMO 2021, 2). Proposed demand management R&D projects should also be publicly consulted on, and include KPIs that will be published as the project proceeds (Alinta Energy 2020, 3–4; Perth Energy 2020, 3–4).

10.2 NEM Demand Management Innovation Allowance Mechanism

10.2.1 NER requirements

Clause 6.6.3A of the NER requires the AER to develop a demand management innovation allowance (DMIA) mechanism. The objective of the DMIA is to provide DNSPs "with funding for research and development in demand management projects that have the potential to reduce long term network costs" (cl. 6.6.3A(b)). Demand management refers to initiatives, for example, to reduce peak demand or change the demand profile as an alternative to increasing network capacity to meet demand.

The AER defines demand management in this context as 'the act of modifying the drivers of network demand' (AER 2017b, 13). This is a broader definition than that used for the Demand Management Incentive Scheme (DMIS), where the AER defines demand management as modifying the drivers of network demand with the purpose of removing a network constraint. The broader definition is used for the DMIA because it is possible that research and development (R&D) projects will not be directed at removing an existing network constraint but rather to address future network constraints and lowering long-term network costs via modifying demand drivers.

The DMIA mechanisms developed by the AER must be consistent with the following:

- The demand management R&D projects supported by the scheme "should have the potential to deliver ongoing reductions in demand or peak demand, and be innovative and not otherwise efficient and prudent non-network options that a distributor should have provided in its regulatory proposal" (AER 2017b, 4).
- The level of allowance should be reasonable, considering the long-term benefits to retail customers.
- It should provide funding that is not available from another source, including under a relevant distribution determination.
- Recipient distributors must publish and report on the nature and results of demand management R&D projects that are the subject of the allowance.

10.2.2 The DMIA Mechanism

10.2.2.1 Overview

The DMIA mechanism has three main elements:

- *An allowance*: equal to $200,000 (in base year prices) plus 0.075% of the DNSP's annual revenue requirement (ARR) for each year of the access period. This allowance can only be spent on eligible projects. Qualifying expenditure over this limit is at the DNSP's own cost. Any underspend of the allowance, calculated over the regulatory period as a whole, is deducted from the DNSP's revenue requirement in the next access period.
- *Project eligibility requirements*: The R&D projects must:
  - (f) be a project or program for researching, developing or implementing demand management capability or capacity;
  - (g) be directed at the objective of the scheme;
  - (h) be innovative;

(i) have the potential to reduce long-term network costs; and

(j) not be recoverable under any jurisdictional incentive scheme, or any state or federal government scheme, or are included in forecast capital expenditure or operating expenditure approved in the DSNP's access arrangement determination.

'Innovative' means the project:

- is based on new or original concepts; *or*
- involves technology or a technique not previously implemented in the relevant market; *or*
- is focussed on a customer market segment that has not been exposed to the technology.

- *Compliance reporting requirements:* Each distributor must submit an annual report to the AER which sets out the amount of the allowance claimed, along with specifics of each project funded by the allowance. There must also be, for each project, a project-specific annual report which the AER can publish and which outlines the scope, methodology, outcomes and progress of the project.

10.2.2.2 Implementation Procedure

The main steps in giving effect to the DMIA mechanism in a particular access arrangement are:

1. In its access proposal, the DSNP proposes how the mechanism should apply to it during the forthcoming regulatory control period.
2. The AER determines how the mechanism will apply to the DSNP in the regulatory period, including the allowance available.
3. The DNSP identifies eligible projects against the AER's project criteria, and may either:
   (a) proceed with the project. In the default case, the AER evaluates the project against the criteria *ex-post*; or
   (b) apply to the AER for 'up-font consideration'; i.e, AER staff level consideration of whether a proposed project or program would be an eligible project. If so, AER staff can provide a 'letter of comfort';
4. The DNSP submits annual reports on its activities, expenditures, projects and programs undertaken under the scheme in each year of the regulatory period, as well as outputs of completed projects and expected outputs of current projects.
5. The AER considers the mechanism's outcomes through an annual review process. In this process the AER approves expenditure *ex-post*, and publishes project-specific reports.
6. After the end of the regulatory period, the AER calculates the amount of any

underspend of the allowance; which is called the 'carryover amount'. If there is a carryover amount, the AER makes an adjustment to the DNSP's ARR for the next access period. An NPV calculation is used to quantify the underspend to ensure that the DNSP is indifferent as to the timing of the DMIA projects it carries out.

10.2.2.3 Assessment & compliance reporting

The compliance reports serve two purposes:

- enables the AER to assess compliance with the requirements; and
- assists to socialise knowledge derived from the project.

The DNSP must annually provide: (i) an overall annual report to report on activities undertaken under the scheme in the last year; and (ii) a series of project-specific reports for each project currently being undertaken or recently completed under scheme.

The overall annual report includes: (a) total amount of allowance spent; (b) a list of all projects on which allowance was spent and a description of each project; (c) for projects that span a series of years, how the spending will be staggered across those years; (d) the objective of each project and a justification of its compliance with the eligibility criteria; and (e) a statutory declaration that the project is not and cannot be funded as prudent opex or capex or via an external demand management incentive scheme.

The requirement for separate project-specific reports which are publishable, assists with the aim of socialising knowledge. "For innovation to have an optimal impact in the electricity market, its leanings and benefits should be shared with all participants. By providing a clear means by which this knowledge can be socialised, the Mechanism can help deliver this outcome." (p.26) The project-specific reports must include information such as: (a) the project aim, method and rationale; (b) the implementation method; (c) how outcomes will be evaluated; and (d) activity to date. For completed projects it will also include: (i) the quantitative results and analysis of them; (ii) an explanation of how the project will inform future demand management

10.2.3 Activity under the scheme

The AER says that "many demand management projects involve distributors partnering with a third party (for instance, a start-up or academic institution) to test the feasibility of a solution developed by the third party" (AER 2017c, 19–20). Of the R&D projects carried out to date under the scheme "grid storage projects made up the largest proportion of expenditure by a significant margin" (AER 2017c, 11). Tariff trials and pricing research are one of the lowest categories of expenditure.

In 2019, the AEMC decided that a DMIA mechanism should apply also to TSNPs. Introducing a DMIA for transmission "is expected to encourage transmission businesses to expand and share their knowledge and understanding of innovative demand management projects that have the potential to reduce long term network costs and, consequently, could lower prices for consumers. Such innovation may play an important role in the transformation of the energy sector. The AER is expected to socialise network approaches and learnings by publishing DMIA reports for each transmission business on its website, as it currently does for distribution networks" (AEMC 2019b, i).

10.3 Assessment

The AER's approach to the DMIA provides a useful template for ERA.

However, the concerns of some stakeholders suggest that some aspects of the scheme may not suit the Western Australian context. Two areas warrant particular attention:

(1) The AER adopts quite broad eligibility criteria. Indeed, many of the projects that have been funded under the scheme are network battery projects that are arguably network rather than non-network solutions, if their predominant purpose is to strengthen the resilience of the network. Perth Energy suggested that there should be more explicit criteria for what is an eligible demand management R&D project. The AEC was concerned that as the scheme provided for full recovery of the costs of research and development it would provide an anti-competitive advantage to the network operator over third party operators. Both the AEC and Perth Energy considered that more limited sums should be adopted for the scheme.

(2) The AER primarily carries out an *ex-post* assessment of whether demand management projects are eligible under the scheme. Perth Energy suggests that there should be public consultation on all proposed initiatives.

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